1 **Normal Operations:** . Emissions from normal operations can be divided into two main source categories: (1) venting and flaring and (2) discharges from process vents, chronic leaks, etc.

Venting and Flaring - Venting and flaring refers to the disposal of gas that cannot be contained or otherwise handled. Such venting and flaring activities are associated with combined oil and gas production and take place in production areas where gas pipeline infrastructure is incomplete and the natural gas is not injected into reservoirs (emissions from process vents are not included here - see below).

Venting activities release methane because the vented gas typically has a high methane content. If the excess gas is burned in flares the emissions of methane will depend on how efficient the burning processes are. Generally the combustion efficiency for flare sources are assumed to be between 95 and 100 per cent. However a new study based upon measurements carried out by Norwegian Oil Industry Association - OLF (1993) indicates very small amounts of unburned methane from flares, less than 0.1 per cent of the gas flared. To estimate the methane emissions from venting and flaring activities satisfactorily it is required to know the flare efficiency rates and the division between the quantity of gas vented and gas flared.

The *combined* quantity of gas vented and flared is reported by countries that produce oil and gas (Barns and Edmonds, 1990). A few countries also are able to report separately gas vented and gas flared. The reliability of the data is questionable in many cases because vented and flared amounts are not normally metered but inferred from the difference between total production and disposals.

Discharges from Process Vents, Chronic Leaks etc. - These include:

- Emissions from pneumatic devices (gas-operated controls such as valves and actuators) depend on the size, type, age of the devices, the frequency of their operation and the quality of their maintenance.
- Leaks from system components are unintentional and usually continuous releases resulting from the failure of a seal or the development of a flaw, crack or hole in a component designed to contain or convey oil or gas. Connections, valves, flanges, instruments, and compressor shafts can develop leaks from flawed or worn seals, while pipelines and storage tanks can develop leaks from cracks or from corrosion.
- Emissions from process vents, such as vents on glycol dehydrators and vents on crude oil tankers and storage tanks resulting from normal operation of the facilities. However such process vents are minor methane sources in most gas production facilities.
- Emissions from starting and stopping reciprocating engines and turbines.
- Emissions during drilling activities, e.g., gas migration from reservoirs through wells.

2 **Maintenance:** Includes regular and periodic activities performed in the operation of the facility. These activities may be conducted frequently, such as launching and receiving scrapers (“pigs”) in a pipeline, or infrequently, such as evacuation of pipes ("blowdown") for periodic testing. In each case, the required procedures release gas from the affected equipment. Releases also occur during maintenance of wells ("well workovers") and during replacement or maintenance of fittings.

3 **System Upsets and Accidents:** System upsets are unplanned events in the system, the most common of which is a sudden pressure surge resulting from the failure of a pressure regulator. The potential for unplanned pressure surges is

considered during facility design, and facilities are provided with pressure relief systems to protect the equipment from damage due to the increased pressure. Relief systems vary in design. In some cases, gases released through relief valves may be collected and transported to a flare for combustion or re-compressed and re-injected into the system. In these cases, methane emissions associated with pressure relief events will be small. In older facilities, relief systems may vent gases directly into the atmosphere or may send gases to flare systems where complete combustion may not be achieved.

The frequency of system upsets varies with the facility design and operating practices. In particular, facilities operating well below capacity are less likely to experience system upsets and resulting emissions. Emissions associated with accidents are also included under the category of upsets. Occasionally, gas transmission and distribution pipelines are accidentally ruptured by construction equipment or other activities.

Table 1-56 lists the most important sources of emissions within each segment of the oil and gas industry. Based on available information, the sources listed as "major" account for the majority of emissions from each segment. Because data are limited and, because there is considerable diversity among oil and gas systems throughout the world, other possible sources are listed which may, in some cases, be important contributors to emissions.

TABLE 1-56
METHANE EMISSIONS FROM OIL AND NATURAL GAS ACTIVITIES

Segment	Major Emission Sources	Other Possible Emission Sources
Oil and Gas Production Oil and Gas Wells Gathering lines Treatment facilities	Venting Normal operations: fugitive emissions; deliberate releases from pneumatic devices and process vents	Flaring, maintenance, system upsets and accidents
Crude oil transportation and Refining Pipelines Tankers Storage tanks Refineries	Normal operations: fugitive emissions; deliberate releases from process vents at refineries, during loading and unloading of tankers and storage tanks	Flaring, maintenance, system upsets and accidents
Natural Gas Processing, Transportation, and Distribution Gas Plants Underground storage reservoirs Transmission Pipelines Distribution Pipelines	Normal operations: fugitive emissions; deliberate releases from pneumatic devices and process vents	Flaring, maintenance, system upsets and accidents

1.8.4 Available Emissions Data

Only very limited data are available that describe methane emissions from natural gas and oil activities. Estimating the types of emissions defined above is complicated by the fact that emissions rates from similar activities in various regions and countries are influenced by differences in the industry's supporting infrastructure, operating and maintenance practices, and level of technology used. Because natural gas and oil activities are complex, it is not easy to define simple relationships between emissions and gross descriptors of the activities undertaken.

The available published data were reviewed to identify emissions estimates that include: a detailed consideration of the physical attributes of oil and gas systems; the operation and maintenance characteristics of key facilities; and country- or region-specific factors that may influence emission rates. The following data were identified:

- **Surveys:** Several studies have surveyed system operators to estimate emissions as a fraction of production or throughput. These studies include Alphatania (1989), AGA (1989), and INGAA (1989). While these studies provide a basis for identifying the activities that operators believe are likely to be major sources of emissions, they are not based on detailed assessments of emission rates and therefore do not provide a quantitative basis for making estimates of methane emissions from oil and natural gas activities.

- **Estimates Based on "Reported Unaccounted For Gas":** Several studies, such as Hitchcock and Wechsler (1972), Abrahamson (1989) and Cicerone and Oremland (1988), have assumed that emissions can be approximated by reported amounts of "unaccounted for" gas. Unaccounted for gas is defined as the difference between gas production and gas consumption on an annual basis. Like estimates of venting and flaring, unaccounted for gas often is used as an accounting convenience to balance company or national production and consumption estimates.

  The use of unaccounted for gas estimates as estimates of emissions is questionable because factors other than emissions account for the majority of the gas listed as unaccounted for. These include: meter inaccuracies, use of gas within the system itself, theft of gas (PG&E, 1990), variations in temperature and pressure and differences in billing cycles and accounting procedures between companies receiving and delivering the gas (INGAA, 1989). Furthermore, because known releases of gas are not reflected in unaccounted for gas estimates, such as emissions from compressor exhaust, the unaccounted for gas estimates cannot unambiguously be considered an upper or lower bound on emissions.

- **Engineering Studies and Measurements:** A small number of studies are based on detailed engineering and/or field measurement analyses. Several engineering analyses have considered the manner in which actual or model facilities are built and operated, and extrapolate facility emissions to a system-wide basis. Several measurement studies have measured emissions from operating facilities or identified actual leaks and extrapolated these measurements to estimate system-wide emissions. In general, data from engineering studies and measurements are the preferred basis for emission estimates. However, only a few of these types of studies have been performed, thereby limiting the ability to estimate emissions nationally, regionally and globally from oil and gas systems. Table 1-57 lists the studies identified and the information they contain. The methane emissions estimates from the studies in the table have been converted to common units of kilograms of emissions per petajoule of energy (kg/PJ). A total of five studies are listed, with emissions estimates for parts of North America (US EPA, 1992), Eastern Europe (Rabchuk et al., 1991), and Western Europe (Schneider-Fresenius et al., 1989, Norwegian SPCA, 1992b and Norwegian Oil Industry Association OLF, 1993). Additionally, Barns and Edmonds (1990) present estimates based on a global assessment. Further studies are needed to improve the basis for making emissions estimates.

TABLE 1-57
SUMMARY OF METHANE EMISSION FACTORS

Data source	Study methodology	Emission factors	Applicability
US EPA (1992) All emissions have been scaled down to 1988 energy consumption or production levels	Compilation of estimates from: • detailed engineering analyses • field measurement studies	**Oil and Gas Production:**	
		290 - 4 670 kg/PJ of oil produced	Emissions from non-gas producing oil wells including fugitive emissions and maintenance emissions in the USA
		39 590 - 104 220 kg/PJ of gas produced	Emissions from gas production, including fugitive emissions, dehydrator venting, bleeding from pneumatic devices, maintenance, and systems upsets in the USA
		2 870 - 13 920 kg/PJ of total oil and gas produced	Venting and flaring emissions from oil and gas production and fugitive emissions from gas-producing oil wells in the USA
		Crude Oil Transportation and Refining:	
		110 - 1 666 kg/PJ of oil refined	Emissions from oil refining and related oil storage tanks in the USA
		Natural Gas Processing, Transmission and Distribution:	
		59 660 - 116 610 kg/PJ of gas consumed	Emissions from gas processing, transmission and distribution including fugitive emissions, dehydrator venting, bleeding from pneumatic devices, maintenance, and system upsets in the USA
Rabchuk et al. (1991)	Compilation of estimates from: • previous measurement studies • official data for 1989	**Oil and Gas Production:**	
		218 000 - 567 600 kg/PJ of gas produced	Emissions from leakages at gas wells including routine equipment venting in the former USSR
		Natural Gas Processing, Transmission and Distribution:	
		340 000 - 715 800 kg/PJ of gas consumed	Emissions from leakages at underground storage facilities, compressor stations, linear part of main pipelines and distribution networks in the former USSR
Schneider-Fresenius et al. (1989)	Compilation of results from: • Batelle study's 1988 literature survey	**Oil and Gas Production:**	
		14 800 - 270 00 kg/PJ of gas produced	Emissions from gas production and treatment facilities in Germany
		Natural Gas Processing, Transmission and Distribution:	
		58 000 - 111 000 kg/PJ of gas consumed	Emissions from transportation, distribution and storage of gas in Germany

TABLE 1-57 (CONTINUED)
SUMMARY OF METHANE EMISSION FACTORS

Data source	Study Methodology	Emission Factors	Applicability
Barns and Edmonds (1990)	Compilation of:	**Oil and Gas Production:**	
	official reports and projections on international emissions	96 000 kg/PJ of natural gas production	Emissions from gas production and separation facilities in the world
		6 300 - 1 019 000 kg/PJ of gas production	Emissions from venting and flaring activity by region of the world
Norwegian SPCA (1992b)	Summary of:	**Oil and Gas Production:**	
	emissions estimates for 1989 based on:	12 800 kg/PJ of gas produced	Emissions from cold vents and fugitive emissions
	information and measurements collected from oil companies	3 200 kg/PJ of gas produced	Flare and gas turbines
	and industry associations	200 kg/PJ of gas produced	Pre-production emissions (well testing)
		Crude oil transportation:	
		2 500 kg/PJ oil tankered	Emissions from offshore loading of crude oil
		Natural gas processing:	
		1 800 kg/PJ of gas processed	Emissions from one Norwegian gas processing terminal
Norwegian Oil Industry Association (OLF), 1993	Summary of emission estimates based on:	**Oil and Gas Production:**	
	information and measurements collected from oil associations	3 000 - 7 500 kg/PJ of gas produced	Emissions from cold vents and fugitive emissions
		100 - 400 kg/PJ of gas produced	Pre-production emissions

1.8.5 Recent Revisions to Emission Factors

The above methodology and emission factors are based on the report of an expert group convened to advise the IPCC/OECD/IEA programme on methods and data in this specific area (Ebert, et al., 1993). Since that group delivered its report in mid-1993, a more recent analysis (US EPA, 1994b) has provided a somewhat different interpretation of some emission factors. While this very detailed analysis endorses the basic tiered methodology included in this *Manual*, the emission factors it derives differ from those presented here. This evaluation was based on essentially the same set of measurement data as cited in this *Manual*, but draws different results from the limited available data. The results of the recent US EPA analysis are summarised in Table 1-58. The most significant differences are in natural gas processing, transportation and distribution, where a more detailed set of emission factor ranges are recommended for non-OECD countries, some which are based on production of natural gas and some which are based on consumption of natural gas (which is the case for all of the factors provided above). Where emission factors are provided for more than one subcategory, they are intended to be additive, and would result in a higher total emissions estimates. Other differences in this US EPA analysis are that venting and flaring emissions for Western Europe are based on oil rather than gas production, and there are minor revisions to some factors for fugitive and other emissions from gas production.

These differences are significant, even given the overall uncertainty in this category, and should be considered carefully by national experts in regions where emissions from this source category are significant. It is hoped that the differences can be resolved or explained in more detail in a subsequent version of these *Guidelines*.

TABLE 1-58
REVISED REGIONAL EMISSION FACTORS FOR METHANE FROM OIL AND GAS ACTIVITIES (kg/PJ)

Source Type	**Basis**	**Western Europe**	**US & Canada**	**Former USSR, Central & Eastern Europe**	**Other Oil Exporting Countries**	**Rest of the World**
OIL & GAS PRODUCTION						
Fugitive and Other Maintenance Emissions from Oil Production	Oil Produced	300 - 5 000	300 - 5 000	300 - 5 000	300 - 5 000	300 - 5 000
Fugitive and Other Maintenance Emissions from Gas Production	Gas Produced	15 000 - 27 000	46 000 - 84 000	140 000 - 314 000	46 000 - 96 000	46 000 - 96 000
Venting & Flaring from Oil and Gas Production	Oil & Gas Produced(a)	-	3 000 - 14 000	-	-	-
	Oil Produced	1 000 - 3 000	-	-	-	-
	Gas Produced	-	-	6 000 - 30 000	758 000 - 1 046 000	175 000 - 209 000
CRUDE OIL TRANSPORTATION, STORAGE AND REFINING						
Transportation	Oil Tankered	745	745	745	745	745
Refining	Oil Refined	90 - 1 400	90 - 1 400	90 - 1 400	90 - 1 400	90 - 1 400
Storage Tanks	Oil Refined	20 - 250	20 - 250	20 - 250	20 - 250	20 - 250
NATURAL GAS PROCESSING, TRANSPORT AND DISTRIBUTION						
Emissions from Processing, Distribution and Transmission	Gas Produced	-	-	288 000 - 628 000	288 000 (high)(b)	288 000 (high)(b)
	Gas Consumed	72 000 - 133 000	57 000 - 118 000	-	118 000 (low)(c)	118 000 (low)(c)
Leakage at industrial plants and power stations	Non-residential Gas Consumed(d)	-	-	175 000 - 384 000	0 - 175 000	0 - 175 000
Leakage in the residential and commercial sectors	Residential Gas Consumed(e)	-	-	87 000 - 192 000	0 - 87 000	0 - 87 000

(a) In the US and Canada, the emissions are based on total production of both oil and gas produced.

(b) The emission factor of 288 000 kg/PJ of gas produced is used only for the high emissions estimate.

(c) The emission factor of 118 000 kg/PJ of gas consumed is used only for the low emissions estimate.

(d) Gas consumption by utilities and industries.

(e) Gas consumption by the residential and commercial sectors.

Source: US EPA (1994b).

1.8.6 Methodologies For Estimating Methane Emissions

A three-tiered approach is presented for estimating methane emissions from oil and gas activities. The specific tiers are listed below in the order of increasing sophistication, data requirements, and accuracy:

- Tier 1 - Production-Based Average Emission Factors Approach,
- Tier 2 - Mass Balance Approach, and
- Tier 3 - Rigorous Source-Specific Approach.

Countries should select the approach or combination of approaches that is most suited to their circumstances. Some important considerations may include the relative contribution of oil and natural gas to total methane emissions for the country, the available information and resources, and the complexity of the local oil and gas industry.

Regardless of the method that is used, the results must be aggregated back to a Tier 1 format to provide a consistent basis for comparison.

Note that methane emissions from combustion plant and incomplete combustion in flaring processes in the non-oil and gas industry are excluded. They are accounted for separately in the section on methane emissions from combustion and industry.

Tier 1 - Production-Based Average Emission Factors Approach

This is the simplest approach for estimating CH_4 emission from oil and gas activities, and is the only one that does not require any direct interaction with the oil and gas industry and associated regulatory agencies. Accordingly, it is the least reliable of the methods.

The required activity data may be easily referenced from published documents of the IEA or the United Nations Statistical Division, and the necessary emission factors are provided in this document. The Tier 1 Approach can be used as a starting point for any country, and may be all that is needed where the emissions from a country's oil and gas industry are comparatively small and/or where data or resources are not available to pursue a more rigorous approach.

Production Base: To estimate emissions, the following steps are recommended as a default estimation procedure:

1 Global oil and gas systems have been divided into regions with relatively homogeneous oil and gas system characteristics. Each country should decide which system characterisation best fits its own oil and gas system(s).

2 For each region, representative emission factors for each activity within each segment have been selected with the objective of taking into account the various system designs and operating practices found in each region.

3 For each country, country-specific activity levels must be obtained and multiplied by the appropriate emission factor. Emission factors for countries should be selected from those corresponding to the appropriate region.

As more data become available for oil and gas producing activities within different countries, the default methodology described above (including activity data and emission factors) should be refined. Each step is discussed below in more detail.

Regional Definitions: Regions have been defined considering the limitations in data on emission factors and activity levels, but also recognising the key differences in oil and gas systems that are found globally. The following five regions are recommended at this time:

- **USA and Canada:** The United States is a large producer and importer of oil and is a large producer of gas. Detailed emissions estimates are available for the United States.
- **Former USSR and Eastern Europe:** Indications are that emission rates from this region are much higher than emission rates from other regions, in particular for the gas system. This region includes the former USSR (which is by far the largest oil and gas producer in the region), Albania, Bulgaria, Czech & Slovak Republics, Hungary, Poland, Romania, and the former Yugoslavia.
- **Western Europe:** This region is a net importer of oil and gas, and mainly produces oil and gas off shore. This region includes: Austria, Belgium, Denmark, Faroe Islands, Finland, France, Germany, Gibraltar, Greece, Iceland, Ireland, Italy, Luxembourg, Malta, Netherlands, Norway, Portugal, Spain, Sweden, Switzerland, and the United Kingdom.
- **Other Oil Exporting Countries:** This region includes the world's other major oil producing countries: the 11 OPEC members (Algeria, Libya, Nigeria, Venezuela, Indonesia, Iran, Iraq, Kuwait, Qatar, Saudi Arabia and the United Arab Emirates), Gabon, Ecuador and Mexico. Generally, these countries produce large quantities of oil and have limited markets for gas.
- **Rest of the World:** This region includes the remaining countries of Asia, Africa, Middle East, Oceania and Latin America.

In defining these regions, countries with relatively similar oil and gas systems were aggregated. Additional investigation would likely improve the definition of the regions.

Emission Factors: As discussed above, the basis for selecting emission factors is weak because very few detailed studies of emissions have been performed. Using the information summarised in Table 1-57, emission factors should be selected by industry segment and emission type for each of the regions. In some cases data from the United States were used when region-specific information was not available.

Tables 1-60 to 1-64 offer emission factors for each region. Emission factors from US EPA (1992) were used for the United States. Key emission factors for Eastern Europe and the Former USSR were taken from Rabchuk et al. (1990) and Barns and Edmonds (1990). Estimates were used for emission factors for venting and flaring for the several regions, including Eastern Europe.

Studies by Schneider-Fresenius et al. (1989) and Norwegian SPCA (1992b) were adopted as representative of emission factors for Western European gas production, venting and flaring. No region-specific data were available for the Other Oil Exporting countries and the Rest of the World. Emission factors in these regions are expected to fall between the relatively low rates found in North America and Western Europe and the relatively high rates found in Eastern Europe. Consequently, a range of emission factors is suggested for these regions unless more information can be obtained.

Activity Levels: Data on the quantity of oil and gas produced, refined, and consumed can be obtained from the IEA or the UN Statistical Division. Sources are described in Section 1.2.1 Data Sources. Data on oil refining capacity can be used to approximate oil refined. Data on oil tankered were not available by region. It is important for national experts to ensure that production figures used in calculation of apparent consumption for CO_2 emissions estimates (described in the Tier 1 method for CO_2) are consistent with those used in this section.

Tier 2 - Mass Balance Approach

The Mass Balance Approach is only recommended for oil system releases of CH_4, and should not be used for releases from natural gas activities. No Tier 2 method exists for natural gas activities. This is a priority for future work. The Mass Balance Approach employs standard, generally easy-to-obtain, oil and gas data (i.e., production volumes, gas-to-oil ratios (GORs), and gas compositions) to estimate the maximum amount of methane that could be emitted to the atmosphere by different sectors of the oil and gas industry. These amounts are then scaled to reflect actual emissions by applying appropriate emission factors. The minimum emission factors account for the amount of gas that is disposed of by control devices, consumed by combustion equipment, conserved, or reinjected. Leak emission factors account for the amounts lost through leaks from these control/utilisation systems.

The basic procedures for performing the mass balance calculations for each oil and gas activity are set out below. Total CH_4 emissions is the sum of emissions for each of these activities. Default data and factors are provided where possible.

Oil Production: Emissions from oil production may be estimated using the relation,

$$E_{\text{Oil-P}} = Q_{\text{Oil-P}} \times GOR \times Y_{CH_4} \times K_{\text{Oil-P}} \times D_{GOR} \times 10^{-12}$$

where

$E_{\text{Oil-P}}$ = methane emissions from oil production (Tg/year)

$Q_{\text{Oil-P}}$ = oil produced (m^3/year)

GOR = gas to oil ratio; defines the amount of gas produced (in volume) per unit of oil produced (in volume). (m^3/m^3, or dimensionless).

Y_{CH_4} = methane Fraction; the volume of gas dissolved in the oil that is methane, on a volume basis, for example, 0.1 m^3 of methane per 1.0 m^3 of gas. (may be considered dimensionless)

$K_{\text{Oil-P}}$ = emission factor for oil production, see below (dimensionless)

D_{GOR} = density of methane at the temperature and pressure at which the GOR is estimated, (g/m^3). The relevant temperature and pressure may vary, depending on the values used to calculate the GOR. For example, at 0°C and a pressure of 1 atmosphere, the density of methane is 715.4 g/m^3, and at 20°C, and a pressure of 1 atmosphere, the density of methane is 666.6 g/m^3.

The first two terms ($Q_{\text{Oil-P}}$ and GOR) estimate the total amount of gas that is withdrawn from the ground while the oil is produced. The term Y_{CH_4} converts the total gas quantity into the quantity of methane (still on a volume basis). The emission factor ($K_{\text{Oil-P}}$) is the fraction of the total gas withdrawn that is emitted. At most, $K_{\text{Oil-P}} = 1$. To put the emissions estimate on a mass basis, D_{GOR} is used to estimate grams, and the conversion to teragrams follows.

TABLE 1-2 (CONTINUED)
1990 COUNTRY-SPECIFIC NET CALORIFIC VALUES FOR OECD COUNTRIES

(Terajoule per kilotonne)

	Australia	Austria	Belgium	Canada	Den-mark	Finland	France	Germany	Greece	Iceland	Ireland	Italy
OIL												
Crude Oil	43.21	42.75	42.75	42.79	42.71	42.66	42.75	42.75	42.75	-	42.83	42.75
NGL	45.22	45.22	-	45.22	-	-	45.22	-	45.22	-	-	45.22
Refinery Feedst.	42.50	42.50	42.50	42.50	42.50	42.50	42.50	42.50	42.50	-	42.50	42.50
COAL												
Coking Coal												
Production	28.34	-	-	28.78	-	-	28.91	28.96	-	-	-	-
Imports	-	28.00	29.31	27.55	-	34.33	30.50	28.96	-	27.44	29.10	30.97
Exports	28.21	-	-	28.78	-	-	-	28.96	-	-	-	-
Other Bituminous Coal and Anthracite[(a)]												
Production	24.39	-	25.00	28.78	-	-	26.71	24.96	-	-	26.13	26.16
Imports	-	28.00	25.00	27.55	26.09	26.38	25.52	26.52	27.21	25.85	29.98	26.16
Exports	25.65	-	25.00	28.78	26.09	-	26.43	31.71	-	-	26.13	-
Sub-Bituminous Coal												
Production	17.87	-	18.06	17.38	-	-	-	-	-	-	-	-
Imports	-	-	-	-	-	-	-	-	-	-	-	-
Exports	-	-	18.20	-	-	-	-	-	-	-	-	-
Lignite												
Production	9.31	10.90	-	14.25	-	-	17.94	8.41	5.74	-	-	10.47
Imports	-	10.90	21.56	-	-	-	17.94	14.88	-	-	19.82	10.47
Exports	-	10.90	-	14.25	-	-	-	8.40	-	-	-	-
Coal Products												
Patent Fuel/BKB	21.00	19.30	23.81	-	18.27	-	28.80	20.64	15.28	-	20.98	-
Coke Oven/Gas Coke	25.65	28.20	29.31	27.39	31.84	28.89	28.71	28.65	29.30	26.65	32.66	29.30

(a) In IEA statistics Anthracite is combined with Other Bituminous Coal – the NCVs given above reflect this combination.

The NCVs for oil and coal are those used by the IEA in the construction of energy balances.

The NCVs for coal product groupings listed are calculated from the values of their constituents.

Source: OECD/IEA, 1993a.

TABLE 1-2 (CONTINUED)
1990 COUNTRY-SPECIFIC NET CALORIFIC VALUES FOR OECD COUNTRIES

(Terajoule per kilotonne)

	Japan	Luxem-bourg	Nether-lands	NZ	Norway	Portugal	Spain	Sweden	Switzer-land	Turkey	UK	USA
OIL												
Crude Oil	42.62	-	42.71	43.12	42.96	42.71	42.66	42.75	42.96	42.79	42.83	42.71
NGL	46.05	-	45.22	46.05	45.22	-	45.22	-	-	-	46.89	45.22
Refinery Feedst.	42.50	-	42.50	44.80	42.50	42.50	42.50	42.50	42.50	42.50	42.50	42.50
COAL												
Coking Coal												
Production	30.63	-	-	28.00	-	-	29.16	-	-	33.49	29.27	29.68
Imports	30.23	-	29.30	28.00	-	29.30	30.14	30.00	-	33.49	30.07	-
Exports	-	-	-	28.00	-	-	-	-	-	-	29.27	29.68
Other Bituminous Coal and Anthracite[(a)]												
Production	23.07	-	-	26.00	28.10	-	21.07	14.24	-	29.30	24.11	26.66
Imports	24.66	29.30	29.30	-	28.10	26.59	25.54	26.98	28.05	27.21	26.31	27.69
Exports	-	-	29.30	-	28.10	-	23.00	26.98	28.05	-	27.53	28.09
Sub-Bituminous Coal												
Production	-	-	-	21.30	-	17.16	11.35	-	-	-	-	19.43
Imports	-	-	-	-	-	-	11.35	-	-	-	-	-
Exports	-	-	-	-	-	-	-	-	-	-	-	-
Lignite												
Production	-	-	-	14.10	-	-	7.84	-	-	9.63	-	14.19
Imports	-	20.03	20.00	-	-	-	-	8.37	-	12.56	-	-
Exports	-	-	20.00	-	-	-	-	-	-	-	-	14.19
Coal Products												
Patent Fuel/BKB	27.05	20.10	23.53	-	-	-	20.31	20.10	21.76	20.93	26.26	-
Coke Oven/Gas Coke	28.64	28.50	28.50	-	28.50	28.05	30.14	28.05	28.05	29.28	26.54	27.47

(a) In IEA statistics Anthracite is combined with Other Bituminous Coal – the NCVs given above reflect this combination.

The NCVs for oil and coal are those used by the IEA in the construction of energy balances.

The NCVs for coal product groupings listed are calculated from the values of their constituents.

Source: OECD/IEA, 1993a.

TABLE 1-3
NET CALORIFIC VALUES FOR OTHER FUELS
(TJ/10^3 tonnes)

Refined Petroleum Products	
Gasoline (aviation and auto)	44.80
Jet Kerosene	44.59
Other Kerosene	44.75
Shale Oil	36.00
Gas/Diesel Oil	43.33
Residual Fuel Oil	40.19
LPG	47.31
Ethane	47.49
Naphtha	45.01
Bitumen	40.19
Lubricants	40.19
Petroleum Coke	31.00
Refinery Feedstocks	44.80
Refinery Gas	48.15
Other Oil Products	40.19
Other Products	
Coal Oils and Tars derived from Coking Coal	28.00
Oil Shale	9.40
Orimulsion	27.50

Source: OECD/IEA, Paris, 1996a.

Select Carbon Emission Factors and Estimate Carbon Content

Carbon emission factors may vary considerably both among and within primary fuel types:

- For natural gas, the carbon emission factor depends on the composition of the gas which, in its delivered state, is primarily methane, but can include small quantities of ethane, propane, butane, and heavier hydrocarbons. Natural gas flared at the production site will usually be "wet", i.e., containing far larger amounts of non-methane hydrocarbons. The carbon emission factor will be correspondingly different.
- Carbon content per unit of energy is usually less for light refined products such as gasoline than for heavier products such as residual fuel oil.
- For coal, carbon emissions per tonne vary considerably depending on the coal's composition of carbon, hydrogen, sulphur, ash, oxygen, and nitrogen.

Estimates of carbon emission factors for fuels from several studies are summarised in Table 1-4.

TABLE 1-4
CARBON EMISSION FACTORS FOR FUELS FROM DIFFERENT STUDIES
(t C/terajoule, net calorific value basis)(a)

Study		Anthracite	Bit. Coal	Sub-Bit. Coal	Lignite	Peat
Marland & Rotty (1984)			25.5(a)			
Marland & Pippin (1990)			25.4(a)			
Grubb (1989)		26.8(a)	25.8(a)		27.6(a)	28.9(a)
OECD (1991)			25.8(a,b)			
Study	**Crude Oil**	**Gasoline**	**Kerosene**	**Gas/Diesel Oil**	**Fuel Oil**	**Natural Gas**
Marland & Rotty (1984)	21.0(a)				15.2(a)	
Marland & Pippin (1990)	21.0(a)	19.4(a)	19.4(a)	19.9(a)	21.1(a,c)	15.3(a)
Grubb (1989)	20.0(a)	18.9(a)	19.5(a)	20.0(a)	21.1(a)	15.3(a)
OECD (1991)	20.0					15.3

(a) Values were originally based on gross calorific value; they were converted to net calorific value by assuming a 5% difference in calorific value for coal and oil, and 10% for natural gas. These percentage adjustments are the IEA assumptions on how to convert from gross to net calorific values.

(b) Average value for all coal: sub-bituminous through anthracite.

(c) Midpoint of range from 20.7 for light fuel oil (#4 fuel oil) to 21.6 for residual fuel oil (#6 fuel oil).

One approach for estimating the carbon emission factors was presented by Marland and Rotty (1984). For natural gas, the carbon emission factor was based on the actual composition of dry natural gas. They sampled the composition of natural gas from 19 countries and then calculated a weighted average global gas composition, breaking the gas out into methane, ethane, propane, other hydrocarbons, CO_2 and other gases. The composition of the gas then determined both the calorific values of the gas and the carbon content. The carbon emission factor of the gas (t C/terajoule, using gross calorific values) was expressed using the following relationship:

$$C_g = 13.708 + (0.0828 \times 10^{-3}) \times (H_v - 37\ 234)$$

where C_g is the carbon emission factor of the gas in t C/terajoule (TJ) and H_v is the calorific value of the gas (gross calorific value, see OECD/IEA, 1996a) in kJ/cubic metre. The coefficients of the equation (13.708, 0.0828×10^{-3}, and 37 234) were estimated using regression analysis based on data from the 19 countries. The carbon content of oil was assumed to be a function of the API gravity: using an estimate of world average API gravity of $32.5^{o} \pm 2^{o}$, they estimated a composition of 85 ± 1 per cent carbon. Converting this to units of carbon per terajoule yielded an estimate of 21.0 t C/TJ on a net calorific value basis (assuming 42.62 terajoules per kilotonne, gross calorific value, as reported in Marland & Rotty, 1984). For coal, the literature suggested that the carbon content of coal was predominantly a function of the energy content (calorific value) and that the carbon content on a per tonne coal-equivalent basis was around 74.6 ± 2 per cent (Marland and Rotty 1984). The carbon emission factor was estimated to be 25.5 t C/TJ.

The approach used by Grubb (1989) to estimate carbon emission factors is very similar but based on more recent research. All carbon emission factors were originally reported on a gross calorific value basis, but are converted here to a net calorific value basis. He provides carbon factors for methane, ethane, propane, and butane and using data from

Marland and Rotty (1984), estimates an average emission factor for natural gas of 15.3 t C/TJ ± 1 per cent. For oil and some refined petroleum products the estimates are based on data from the literature, as summarised in Table 1-4. The carbon emission factor of coal, excluding anthracite, was defined as:

$$C_C = 32.15 - (0.234 \times H_v)$$

where C_C is the carbon emission factor in t C/TJ and H_V is the gross calorific value of the coal when the calorific value is from 31 to 37 TJ/kilotonne on a dry mineral matter free (dmf) basis. Anthracites fall outside this range and a value of 26.8 t C/TJ is used.

Since the publication of the original OECD Background Document (OECD 1991), additional information has been made available on carbon emission factors. At an IPCC-sponsored workshop in October 1992 (IPCC/OECD, 1993), experts recommended several revised emission factors based on national inventory submissions to the OECD. Additional emission factors were also made available based on the work of the expert group on GHG Emissions from Fuel Combustion during Phase II of the IPCC/OECD/IEA Programme on National GHG Inventories in 1996.

The IPCC Reference Approach relies primarily on the emission factors from Grubb (1989), with additions from other studies as discussed above, to estimate total carbon content. The suggested carbon emission factors are listed in Table 1-1. The basic formula for estimating total carbon content is:

$$\begin{gathered}\text{Total Carbon Content (Gg C)} = \\ \sum \text{Apparent Energy Consumption (by fuel type in TJ)} \\ \times \text{ Carbon emission factor (by fuel type in t C/TJ)} \\ \times 10^{-3}\end{gathered}$$

Apparent consumption of the fuels is estimated in Table 1-1 (Column 6). The carbon emission factors for the fuels are average values based on net calorific value. This approach has been recommended by the IPCC because it explicitly treats each major fuel type differently according to its carbon emission factor. When countries use local values for the carbon emission factors they should note the differences from the default values and provide documentation supporting the values used in the national inventory calculations.

Estimate Carbon Stored in Products

The next step is to estimate the amount of fossil fuel carbon that is stored in non-energy products and the portion of this carbon expected to oxidise over a long time period (e.g., greater than 20 years). All fossil fuels are used for non-energy purposes to some degree. Natural gas is used for ammonia production. LPGs are used for a number of purposes, including production of solvents and synthetic rubber. A wide variety of products is produced from oil refineries, including asphalt, naphthas and lubricants. Two by-products of the coking process, oils and tars, are used in the chemical industry.

Not all non-energy uses of fossil fuels, however, result in storage of carbon. For example, the carbon from natural gas used in ammonia production is oxidised quickly. Many products from the chemical and refining industries are burned or decompose within a few years. Several approaches for estimating the portion of carbon stored in products are reviewed in Box 2.

BOX 2
APPROACHES FOR ESTIMATING CARBON STORED IN PRODUCTS

The approach used by Marland and Rotty (1984) relied on historical data for determining non-energy applications and varied depending on fossil fuel type. For natural gas they assume that close to 1/3 of the carbon used for non-energy purposes (equivalent to 1 per cent of total carbon from natural gas production) does not oxidise over long periods of time. For oil products they assume that some portion of LPG, ethane, naphthas, asphalt and lubricants does not oxidise quickly. Specifically, they assume that about 50 per cent of LPG and ethane from gas processing plants is sold for chemical and industrial uses and that 80 per cent of this amount, or 40 per cent of all LPG and ethane, goes into products that store the carbon. About 80 per cent of the carbon in naphthas is assumed to end up in products such as plastics, tires, and fabrics and oxidises slowly. All of the carbon in asphalt is assumed to remain unoxidised for long periods, while about 50 per cent of the carbon in lubricants is assumed to remained unoxidised. For coal they assume that on average 5.91 per cent of coal going to coke plants ends up as light oil and crude tar, with 75 per cent of the carbon in these products remaining unoxidised for long periods.

Grubb (1989) basically uses the Marland and Rotty (1984) approach, but suggests several changes, including higher estimates of methane losses during production and transportation of natural gas to market and a wide range of estimates concerning the fraction of carbon in refinery products that remain unoxidised. He does use Marland and Rotty's estimate of the amount of carbon in coal that does not oxidise, but also quantifies the amount of carbon emissions from SO_2 scrubbing (in which CO_2 is released during the chemical interactions in the desulphurisation process) using the formula: (% sulphur by weight) x (coal consumption) x 12/32.

Okken and Kram (1990) introduce the concept of actual and potential emissions of CO_2 where potential emissions are defined as carbon that is stored in products from non-energy uses or by-products from combustion and actual emissions as all carbon from fuels that are emitted immediately or within a short period of time. Actual emissions plus potential emissions equal total carbon in the fuels. They assume that carbon from the following non-energy uses of fossil fuels oxidises quickly: fertiliser production (ammonia), lubricants, detergents, volatile organic solvents, etc. Carbon from the following non-energy uses of fossil fuels remains stored for long periods of time (in some cases, hundreds of years): plastics, rubber, bitumen, formaldehyde, and silicon carbide.

For the IPCC Reference Approach, the suggested formula for estimating carbon stored in products for each country is:

$$\begin{gathered}\text{Total Carbon Stored (Gg C)} = \\ \text{Non-Energy Use } (10^3 \text{ t}) \\ \times \text{ Conversion Factor } (\text{TJ}/10^3 \text{ t}) \\ \times \text{ Emission Factor (t C/TJ)} \\ \times \text{ Fraction Carbon Stored} \\ \times\ 10^{-3}\end{gathered}$$

Most of the suggested categories conform to those used by Marland and Rotty (1984) and include naphthas, bitumen (asphalt), lubricants, LPG, and coal oils and tars. The data available from the UN reports (e.g., 1996) correspond to these categories, with the exception of coal oils and tars, which are not reported.

The assumptions of 75 per cent for naphtha as a feedstock and 50 per cent for gas/diesel oil as a feedstock, used in Table 1-5 (Column 6) should be viewed as potential overestimates, since not all of the carbon from the intermediate products will be stored. For example, carbon emissions may occur due to losses in the production of final products or incineration of final products. At this time these percentages can be used as the upper bound when determining stored carbon.

This suggested approach for estimating carbon stored in products is illustrated in Table 1-5. Whenever possible, countries should substitute assumptions that represent more accurately the practices within their own countries and provide documentation for these assumptions. The resulting estimates from Table 1-5 (Column 7) should be subtracted from carbon content of apparent consumption to determine net carbon emissions that could be oxidised. This calculation is done by entering the values from Table 1-5 (Column 7) for the relevant fuels/products into Table 1-1 (Column 11). In Table 1-1, carbon stored in products is subtracted from total carbon in the fuels (“carbon content”) to get net carbon available for emission (“net carbon emissions”).

Currently the fraction of carbon stored applied to the carbon content of the fuels used for product manufacture takes into account the release of carbon from the use or destruction of the products in the short term. The fraction is therefore lower than the fraction of carbon entering the products (see Box 2). The emissions resulting from the use or destruction of the products may occur in:

- industrial processes – both the production of non-fuel products from energy feedstocks, and the emissions from use of these products in industrial processes (e.g., oxidation of anodes made from petroleum coke which occurs during aluminium production);
- other end uses of products (e.g., lubricants oxidised in transportation);
- waste disposal – particularly incineration of plastics and other fossil fuel based products.

TABLE 1-5
ESTIMATION OF CARBON STORED IN PRODUCTS

	1 Estimated Fuel Quantities[a]	2 Conversion Factor	3 Estimated Fuel Quantities[b]	4 Emission Factor	5 Carbon Content[c]	6 Fraction Carbon Stored	7 Carbon Stored[d]
Product/Fuel[e]	(Original Units)	TJ/Units	(TJ)	(t C/TJ)	(Gg C)		(Gg C)
Lubricants	calc	Table 1-3	calc	Table 1-1	calc	0.50	calc
Bitumen	calc	Table 1-3	calc	Table 1-1	calc	1.0	calc
Coal Oils and Tars from Coking Coal	calc[f]	Table 1-3	calc	Table 1-1[g]	calc	0.75	calc
Naphtha as Feedstock	calc	Table 1-3	calc	Table 1-1	calc	0.75	calc
Gas/Diesel Oil as Feedstock	calc	Table 1-3	calc	Table 1-1	calc	0.50	calc
Natural Gas as Feedstock	calc	Table 1-3	calc	Table 1-1	calc	0.33	calc
LPG as Feedstock	calc	Table 1-3	calc	Table 1-1	calc	0.80	calc
Ethane as Feedstock	calc	Table 1-3	calc	Table 1-1	calc	0.80	calc

(a) Either Apparent Consumption plus domestic (manufactured) production, or Feedstock Use.

(b) Estimated Fuel Quantities in TJ (Col. 3) equals Estimated Fuel Quantities (Col. 1) times a Conversion Factor (Col. 2).

(c) Carbon Content (Col. 5) equals Estimated Fuel Quantities in TJ (Col. 3) times an Emission Factor (Col. 4).

(d) Carbon Stored (Col. 7) equals Carbon Content (Col. 5) times Fraction Carbon Stored (Col. 6) divided by 10^3.

(e) This is an incomplete list of products/fuels which account for the majority of carbon stored. Where data are available for other fuels, the estimation of stored carbon is strongly encouraged.

(f) Use 6% of apparent consumption of Coking Coal.

(g) Use the emission factor for coking coal (25.8 t C/TJ).

Estimate Carbon Unoxidised During Fuel Use

A small part of the fuel carbon entering combustion escapes oxidation but the majority of this carbon is later oxidised in the atmosphere. It is assumed that the carbon that remains unoxidised is stored indefinitely. Based on work by Marland and Rotty (1984), since 1991 the IPCC has been recommending that 1 per cent of the carbon in fossil fuels would remain unoxidised. This assumption was based on the following findings from Marland and Rotty for the amount unoxidised:

- For natural gas, less than 1 per cent of the carbon is unoxidised during combustion and remains as soot in the burner, stack, or in the environment.
- For oil 1.5% ±1% passes through the burners and is deposited in the environment without being oxidised. This estimate is based on 1976 US statistics of emissions of hydrocarbons and total suspended particulates.
- For coal 1% ±1% of carbon supplied to furnaces is discharged unoxidised, primarily in the ash.

However, several countries have commented that the amount of carbon remaining unoxidised is more variable than indicated by the 1 per cent assumption across all fuels. For example, it has been noted that the amount of unburnt carbon varies depending on several factors, including type of fuel consumed, type of combustion technology, age of the equipment, and operation and maintenance practices.

Information submitted by the Coal Industry Advisory Board of the OECD (Summers 1993), provided the following observations for coal combustion technologies:

- Unoxidised carbon from electric power stations in Australia averaged about 1 per cent. Test results from stoker-fired industrial boilers, however, were higher, with unoxidised carbon amounting to 1 to 12 per cent of total carbon with coals containing from 8 to 23 per cent ash. As average values, 2 per cent carbon loss was suggested for best practices, 5 per cent carbon loss for average practices, and 10 per cent carbon loss for worst practices. In those cases when coal is used in the commercial or residential sectors, carbon losses would be on the order of 5 to 10 per cent (Summers, 1993).
- In related work British Coal has provided information on the percentage of unburnt carbon for different coal combustion technologies:

Pulverised Coal	1.6%
Travelling Grate Stoker	2.7-5.4%
Underfeed Stoker	4.0-6.6%
Domestic Open Fire	0.6-1.2%
Shallow Bed AFBC[10]	Up to 4.0%
PFBC/CFBC[10]	3.0%

- Evaluations at natural gas-fired boiler installations indicate that combustion efficiency is often 99.9 per cent at units reasonably well-maintained.

It is clear from the available information that a single global default assumption of 1 per cent unoxidised carbon is not always accurate. While some additional information is available to refine the assumptions for this portion of the methodology, most of the new information requires some level of detail on the type of technology in which the fuel is combusted or information on which sector is consuming the fuel. The Reference Approach requires data only on the amount of fuels consumed in a country, not data by technology type or sector of the economy. As a result, based on the information available at this point, the default values presented in Table 1-6 are recommended for the percentage of carbon oxidised during combustion by fuel. It should be recognised that the value for coal is highly variable based on fuel quality and technology types. National experts are encouraged to vary this assumption if they have data on these factors, suggesting that different average values for their countries are appropriate. It is clear from the information available at this time that additional research should be conducted on this topic.

TABLE 1-6
FRACTION OF CARBON OXIDISED
(RECOMMENDED DEFAULT ASSUMPTIONS)

Coal(a)	0.98
Oil and Oil Products	0.99
Gas	0.995
Peat for electricity generation(b)	0.99

(a) This figure is a global average but varies for different types of coal, and can be as low as 0.91.

(b) The fraction for peat used in households may be much lower.

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[10] AFBC = Advanced Fluidised Bed Combustion
CFBC = Circulating Fluidised Bed Combustion
PFBC = Pressurised Fluidised Bed Combustion

Convert carbon emissions to full molecular weight CO_2

Net carbon emissions (Column 12 in Table 1-1) are then multiplied by the fraction of carbon oxidised to give actual carbon emissions (Column 13 of Table 1-1), and then summed across all fuel types, to determine the total amount of carbon oxidised from the combustion of fuel. To express the results as carbon dioxide (CO_2), total carbon oxidised should be multiplied by the molecular weight ratio of CO_2 to C, (44/12).

1.4.1.2 EMISSIONS BY SOURCE CATEGORIES

A sectoral breakdown of national CO_2 emissions using the defined IPCC source categories is needed for monitoring and abatement policy discussions. The IPCC Reference Approach provides a rapid method to estimate the total CO_2 emissions from fuels supplied to the country but it does not break down the emissions by sector. The development of a Tier 1 method giving non-CO_2 GHG emissions by sector (Section 1.4.2) has been extended to CO_2 so that sectoral information can be obtained simply for this gas. However, the range of the carbon emission factors for fuels and the special consideration given to CO_2 emissions from biofuels mean that the calculations for CO_2 differ in a number of respects from those used for the non-CO_2 gases.

The more detailed calculations used for this approach are essentially similar in content to those used for the Reference Approach.

The formula is:

carbon emissions

=

∑ fuel consumption expressed in energy units (TJ) for each sector

x carbon emission factor

- carbon stored

x fraction oxidised

There are seven key considerations when calculating CO_2 emissions by sector some of which have already been discussed for the Reference Approach:

- Identification of the quantities of fuels consumed (combusted) in energy industries;
- A clear understanding of how emissions from electricity generation and heat are treated;
- Identification of the fraction of carbon released during the use of fuels for non-energy purposes;
- Adjustments for carbon unoxidised;
- Identification of the quantities of fuels used for international transport;
- Separation of the emissions from the combustion of biofuels;
- Separation of the quantities of fuels used in the Agriculture/Forestry/Fisheries between mobile sources and stationary plant.

Quantities of fuels combusted in the energy industries.

For emission calculations there are three principal groups of activities involving fuels in the energy and transformation sector:

(i) The transformation of primary fuels into secondary fuels by physical or chemical processes not involving combustion of the primary fuel. For example, manufacture of petroleum products from crude oil.

(ii) The production of heat for sale or for electricity generation.

(iii) Combustion of fuels to support the main energy extraction or production business of the enterprise. For example, use of refinery gas for heating distillation columns, use of colliery methane at mines for heating purposes.

Activities within the first group are mainly those of refining and manufacture of solid fuels and derived gases. By definition, group (i) does not lead to fuel combustion emissions. Only fuels entering the activities in groups (ii) and (iii) should be considered for the calculation of emissions.

The underlying model of carbon flow which drives the reporting for the energy and transformation sector is that primary fuel carbon entering group (i) will appear either in the secondary products or be lost as fugitive emissions which are reported separately in Category 1B, Fugitive Emissions from Fuels. Carbon in secondary products will be partly or entirely stored or combusted either:

1) within the transformation industry as a group (iii) activity (e.g, refinery fuel or coke oven gas for heating coke ovens), or

2) as a group (ii) activity, or

3) by final consumers outside the energy industry.

In short therefore, because the pathways for carbon *leaving* a transformation process are covered by reporting on the worksheets in Module 1, there is no need to report quantities of primary fuels used exclusively for refining or solid fuel manufacture, notably, crude oil and coking coal. If, however, a country does use crude oil for electricity generation, for example, then the relevant quantity should be reported.

The scope of the activities to be included under group (ii) also needs further definition and this will be considered now.

Generation of electricity and heat

The Overview to this chapter (Section 1.1) describes the steps taken to harmonise reporting and inventory compilation required from those countries completing inventories according to both IPCC and EMEP/CORINAIR reporting requirements. An important step towards harmonisation has been the decision to align the IPCC reporting of emissions from electricity and heat generation by autoproducers (see Box 3) with that of CORINAIR.

In the 1995 *Guidelines* emissions from autoproducers were included with those from main power producers (referred to as “Public Electricity and Heat”). In this edition of the *Guidelines*, emissions from autoproduction are attributed to the industrial or commercial branches in which the generation activity occurs. Emissions reported under “Public Electricity and Heat” should be those from main power producers only.

BOX 3

AUTOPRODUCERS

An autoproducer of electricity or heat is an enterprise which generates electricity or sells heat as a secondary activity, i.e., not as its main business. This should be contrasted with main power producers who generate electricity or who sell heat as their main business (primary activity) and may be publicly or privately owned. Supplies from main power producers are referred to as “Public” electricity and heat supply although an increasing part of public supply is being met by autoproducers.

Wherever possible the quantities of fuel used for, and the resulting emissions from, autoproduction should be identified in the worksheets used for this calculation. The worksheets make provision for this. As a growing amount of public electricity supply comes from autoproduction, calculation of the related emissions will assist identification of total emissions from electricity generation.

Carbon release during the non-energy use of fuels

The calculation of carbon content of fuels consumed, as a step for the estimation of the CO_2 emissions from fuel combustion, must be adjusted for the quantities of carbon which are stored within products made from fuels used as raw materials or within products used for their physical properties rather than combusted (e.g., bitumen or lubricants). The approach used to do this and the types of fuels involved are fully discussed under “Stored Carbon” in Section 1.4.1.1 and the arguments will not be repeated. There are two aspects of this adjustment, however, which need to be mentioned explicitly here because the calculation of carbon release at the level of fuel deliveries permits certain simplifications not available at the level of fuel supplies used for the Reference Approach. This arises because the Reference Approach estimates emissions from the supply of primary fuels and external trade in secondary fuels whereas the sectoral approach uses the carbon content of delivered fuels from which the full quantities of fuels entering long-term storage may be identified.

1. Bitumen and coal tars are usually not combusted but used in a manner which causes most of the carbon content to enter long-term storage. As a result, these products are excluded from the calculation of fuel combustion emissions and do not feature in the list of commodities on the worksheet.
2. Other fuels that are only partly combusted are included within the worksheet and the fraction of carbon entering long-term storage estimated by means of a carbon storage factor. A similar method is used for the Reference Approach. In the present sectoral calculation, however, no special steps are required to obtain deliveries data as the approach relies on them for all of its calculations.

Adjustments For Carbon Unoxidised

As discussed above under the Reference Approach, the amount of carbon that may remain unoxidised from combustion activities can vary for many reasons, including type of fuel consumed, type of combustion technology, age of the equipment, and operation and maintenance practices. Since the present approach relies on more disaggregated fuel consumption data, it is possible to specify the assumptions for unoxidised carbon by application. Unless other data are available, countries should use as default values the assumptions recommended in the Reference Approach: 2 per cent of carbon in fuel consumed is unoxidised for coal, 1 per cent for oil-derived fuels, 0.5 per cent for natural gas and 1 per cent for peat used for electricity generation. In addition, the following assumptions (from Summers, 1993) are recommended:

- For stoker-fired industrial boilers an average value for carbon unoxidised is 5 per cent. If countries believe that their operation and maintenance procedures achieve maximum efficiency, a 2 per cent carbon loss is suggested. If these procedures are believed to lead to very poor efficiency, then a 10 per cent carbon loss is recommended.
- In those cases when coal is used in the commercial or residential sectors, the assumption for unoxidised carbon should be 5 per cent.

Clearly, much additional research needs to be done in this area. These adjustments are suggested as initial default values. As more work is done, countries are encouraged to report any additional information they may have to refine understanding of the amount of carbon unoxidised in various applications.

Fuels used for international transport

The exclusion from national totals of emissions from (bunker) fuels used for international marine and air transport has been discussed in Section 1.4.1.1, Reference Approach. As in that approach, the emissions from international bunkers should not be omitted entirely but reported separately on the worksheet. The definitions of national and international movements for ships and aircraft are covered under the "Definition of Source Categories" (Energy) in Volume 1, *Reporting Instructions*.

Combustion of biofuels

CO_2 emissions from the combustion of biomass fuels are not to be included in the total national CO_2 emissions but should be reported separately on the worksheet.

Fuel use for mobile sources and stationary plant in the Agriculture/Forestry/Fisheries sector

The separation of fuel combustion between the two types of combustion sources in this sector has been introduced to permit the aggregation of CO_2 emissions from them with the emissions of the non-CO_2 gases. Whatever methods are used for estimating the quantities of fuels used by these two types when calculating the non-CO_2 emissions from this sector should be used for CO_2. Delivery statistics do not usually distinguish between combustion plant types in any economic activity sector.

1.4.2 Non-CO_2 Emissions

1.4.2.1 METHANE (CH_4) EMISSIONS FROM FUEL COMBUSTION

The contribution of fuel combustion to global emissions of methane is minor and the uncertainty is high. For these reasons, an aggregated fuel/sector split is sufficient for a Tier 1 approach, although exact product detail needs to be determined for CH_4 from biomass combustion. Fuel wood, charcoal, agricultural residues, agricultural waste and municipal waste combustion is by far the major contributor to CH_4 emissions within the fuel combustion group. Traditional charcoal making, which is a typical smouldering process, is a large source of methane which should be reported under Fugitive Emissions from Energy. Consequently, CH_4 emissions from developing countries with large biomass consumption could be significant.

Methane is produced in small quantities from fuel combustion due to incomplete combustion of hydrocarbons in fuel. The production of methane is dependent on the temperature in the boiler/stove. In large, efficient combustion facilities and industrial applications, the emission rate is very low, with utility emission rates being less than I per cent of average rates for residential coal combustion. In smaller combustion sources, emission rates are higher, particularly when smouldering occurs. The highest rates of methane emissions from fuel combustion occur in residential applications (small stoves and open burning).

The CH_4 emissions from mobile sources are a function of the methane content of the motor fuel, the amount of hydrocarbons passing unburnt through the engine, the engine type, and any post-combustion controls. In uncontrolled engines the proportion of methane emissions is highest at low speeds and when the engine is idle. Poorly tuned engines may have a particularly high output of CH_4.

The general method for estimating CH_4 can be described as:

$$\text{Emissions} = \sum (EF_{ab} \times \text{Activity}_{ab})$$

where:

EF = Emission Factor (kg/TJ);

Activity = Energy Input (TJ);

a = Fuel type; and

b = Sector-activity.

The following default emission factors have been developed by the IPCC based on the CORINAIR90 database, the CORINAIR 1994 default emission factors, the EDGAR Version 2.0 database, National Communications to the FCCC, Berdowski, et al. (1993a and 1993b), Radian Corporation (1990) and US EPA (1995). Additional research will need to be undertaken to further improve the quality of the emission factors.

TABLE 1-7
CH_4 DEFAULT (UNCONTROLLED) EMISSION FACTORS (IN KG/TJ)

			Coal(a)	Natural Gas	Oil	Wood/ Wood Waste	Charcoal	Other Biomass and Wastes(c)
Energy Industries			1	1	3	30(b)	200(b)	30
Manufacturing Industries and Construction			10	5	2	30	200	30
Transport	Aviation(d)				0.5			
	Road			50	Gasoline 20(e) Diesel 5			
	Railways		10		5			
	Navigation		10		5			
Other Sectors	Commercial/Institutional		10	5	10	300	200	300
	Residential		300	5	10	300	200	300
	Agriculture/ Forestry/ Fishing	Stationary	300	5	10	300	200	300
		Mobile		5	5			

Note: These factors are considered as the best available global default factors to date.

(a) The emission factors for brown coal may be several times higher than those for hard coal.

(b) These factors are for fuel combustion in the energy industries. For charcoal production, please refer to Table 1-14, Default Non-CO_2 Emission Factors for Charcoal Production.

(c) Includes dung and agricultural, municipal and industrial wastes.

(d) In the cruise mode CH_4 emissions are assumed to be negligible (Wiesen et al., 1994). For LTO cycles only (i.e., below an altitude of 914 metres (3000 ft.)) the emission factor is 5 kg/TJ (10% of total VOC factor) (Olivier, 1991). Since globally about 10% of the total fuel is consumed in LTO cycles (Olivier, 1995), the resulting fleet averaged factor is 0.5 kg/TJ.

(e) Emission factors for 2-stroke engines may be three times higher than those for 4-stroke engines.

1.4.2.2 NITROUS OXIDE (N_2O) EMISSIONS FROM FUEL COMBUSTION

As with methane, the contribution of fuel combustion to global emissions of N_2O is minor and the uncertainty is high. Reliable emission factors are not yet available for all sources. For these reasons, an aggregated fuel/sector split is sufficient for a Tier 1 approach.

Nitrous oxide is produced directly from the combustion of fossil fuels. It has been determined that lower combustion temperatures (particularly below 1200 K) cause higher N_2O emissions with a maximum of N_2O production occurring around 1000 K. For combustion temperatures below 800 K or over 1200 K the emissions of N_2O are negligible (de Soete, 1993). Compared to emissions from conventional stationary combustion units, emissions of nitrous oxides from fluidised bed combustion are relatively high (Rentz et al., 1992). Nitrous oxide is formed by different catalytic reduction processes. For more detailed information on N_2O chemistry see de Soete (1993). The mechanisms of N_2O chemistry seem to be relatively well understood, but experimental data are limited.

N_2O emissions from vehicles have only recently been studied in detail. Global emissions from this source are still thought to be small relative to total anthropogenic emissions, but may be substantially higher when emission controls (especially catalysts on road vehicles) are used.

Published emission rates for non-commercial fuel combustion, in particular fuelwood, charcoal, agricultural wastes and dung are few and it is uncertain whether they are representative for global application (Olivier, 1993).

The general method for estimating N_2O can be described as:

Emissions = $\sum (EF_{ab} \times Activity_{ab})$

where:

EF = Emission Factor (kg/TJ);
Activity = Energy Input (TJ);
a = Fuel type; and
b = Sector-activity.

The following default emission factors have been developed by the IPCC based on the CORINAIR90 database, the CORINAIR 1994 default emission factors, Radian Corporation (1990), the EDGAR Version 2.0 database, National Communications to the FCCC and de Soete (1993). Additional research will need to be undertaken to further improve the quality of the emission factors.

TABLE 1-8
N_2O DEFAULT (UNCONTROLLED) EMISSION FACTORS (IN KG/TJ)

			Coal(a)	**Natural Gas**	**Oil**	**Wood/ Wood Waste**	**Charcoal**	**Other Biomass and Wastes(c)**
Energy Industries			1.4	0.1	0.6	4(b)	4(b)	4
Manufacturing Industries and Construction			1.4	0.1	0.6	4	4	4
Transport	Aviation				2			
	Road			0.1	Gasoline 0.6(d) Diesel 0.6			
	Railways		1.4		0.6			
	Navigation		1.4		0.6			
Other Sectors	Commercial/Institutional		1.4	0.1	0.6	4	1	4
	Residential		1.4	0.1	0.6	4	1	4
	Agriculture/ Forestry/ Fishing	Stationary	1.4	0.1	0.6	4	1	4
		Mobile		0.1	0.6			

Note: These factors are considered as the best available global default factors to date.

(a) Brown coals may produce less N_2O than bituminous coals; some measurements have shown that N_2O emissions by hard coal combustion in power plants may be negligible. N_2O emissions from FBC are generally about 10 times higher than from boilers.

(b) These factors are for fuel combustion in the energy industries. For charcoal production, please refer to Table 1-14, Default Non-CO_2 Emission Factors for Charcoal Production.

(c) Includes dung and agricultural, municipal and industrial wastes.

(d) When there is a significant number of cars with 3-way catalysts in the country, road transport emission factors should be increased accordingly. Emission factors for 2-stroke engines may be three times higher than those for 4-stroke engines.

1.4.2.3 NITROGEN OXIDES (NO_x) EMISSIONS FROM FUEL COMBUSTION

Nitrogen oxides[11] are indirect greenhouse gases. They have been the target of environmental policies for their role in forming ozone (O_3), as well for their direct acidification effects.

Fuel combustion activities are the most significant anthropogenic source of NO_x. Within fuel combustion, the most important sources are the energy industries and mobile sources.

Generally two different formation mechanisms can be distinguished:

- formation of “fuel NO” from the conversion of chemically bound nitrogen in the fuel,
- formation of “thermal NO” from the fixation of the atmospheric nitrogen in the combustion process (Joint EMEP/CORINAIR, February 1996).

The majority of NO_x emitted from coal (80-90 per cent) is formed from fuel nitrogen. Thermal NO_x contributes less than 20 per cent and depends on combustion temperature. Excess air and high temperatures found in some firing configurations encourage the production of NO_x and these conditions are dependent on boiler type and operation of technology. For oil, the share of fuel NO_x may be less than 50 per cent. From gaseous fuels, only “thermal NO” is formed.

The NO_x emissions from mobile sources are related to the air-fuel mix and combustion temperatures, as well as pollution control equipment. For uncontrolled vehicles the proportion of NO_x emissions from a diesel-fuelled vehicle is generally lower than that for a gasoline-fuelled vehicle, and lower for a light-duty vehicle than that for a heavy-duty vehicle. Heavy-duty vehicles contribute significant emissions, which are difficult to reduce.

The general method for estimating NO_x can be described as:

$$\text{Emissions} = \sum (EF_{ab} \times \text{Activity}_{ab})$$

where:

EF = Emission Factor (kg/TJ);
Activity = Energy Input (TJ);
a = Fuel type; and
b = Sector-activity.

If abatement technologies for NO_x emissions reduction are used, the estimated emission factors of NO_x should be adjusted. Reduction efficiency (n) values for different types of abatement may vary; primary measures may range from 5 to 50 per cent (Joint EMEP/CORINAIR, 1996) and secondary measures from 50 to 95 per cent (Rentz, et al., 1992).

The following default values can be used for the reduction efficiency of primary measures in coal-fired installations when no information concerning the type of installation is available (Joint EMEP/CORINAIR, 1996).

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[11] The convention in this document is that NO_x ($NO+NO_2$) emissions from fossil fuel combustion are expressed on a full molecular basis assuming that all NO_x emissions are emitted as NO_2.

Default Values for Reduction Efficiency (n)		
Type of primary measure	**Hard coal**	**Lignite**
no measure (mainly relevant for old installations)	0 %	0 %
old installations / optimised operation	15 - 20 %	15 %
old installation / retrofitted	50 %	50 %
new installation	40 %	35 %

Due to large differences in emission factors for various sectors, fuel consumption should be allocated to the IPCC main source category groups.

Nitrogen oxides emission factors are available by detailed fuel/sector split for most of the fuel combustion sources. The following default emission factors have been developed by the IPCC based on the CORINAIR90 database, Radian Corporation (1990), US EPA (1995), the EDGAR Version 2.0 database, and National Communications to the FCCC. The aggregated emission factors in this table allow a rough estimation of NO_x emissions.

TABLE 1-9
NO_X DEFAULT (UNCONTROLLED) EMISSION FACTORS (IN KG/TJ)(a)

			Coal	Natural Gas	Oil	Wood/ Wood Waste	Charcoal	Other Biomass and Wastes(b)
Energy Industries			300	150	200	100(c)	100(c)	100
Manufacturing Industries and Construction			300	150	200	100	100	100
Transport	Aviation				300			
	Road			600	Gasoline 600 Diesel 800(d)			
	Railways		300		1200			
	Navigation		300		1500			
Other Sectors	Commercial/Institutional		100	50	100	100	100	100
	Residential		100	50	100	100	100	100
	Agriculture/ Forestry/ Fishing	Stationary	100	50	100	100	100	100
		Mobile(e)		1000	1200			

Note: These factors are considered as the best available global default factors to date. The emission factors may be reduced to take into account reduction efficiencies, see default values for reduction efficiencies given above.

(a) NO_X emission factors for small combustion facilities tend to be much smaller than for large facilities due to lower combustion temperatures.

(b) Includes dung and agricultural, municipal and industrial wastes.

(c) These factors are for fuel combustion in the energy industries. For charcoal production, please refer to Table 1-14, Default Non-CO_2 Emission Factors for Charcoal Production.

(d) Assuming the major part is consumed by Heavy Duty Vehicles (HDV). When a country has a relatively high proportion of passenger cars running on diesel, the average emission factor may be substantially lower, as is indicated in Tables I-31 to 1-34.

(e) The countries should, when possible, allocate the fuel consumption to road and off-road traffic. Emission factors for ships, boats, locomotives and farm equipment may be more than double those of duty vehicles.

1.4.2.4 CARBON MONOXIDE (CO) EMISSIONS FROM FUEL COMBUSTION

Carbon monoxide is an indirect greenhouse gas. The majority of CO emissions from fuel combustion come from motor vehicles. Another large contributor is the residential sector with small combustion equipment.

Carbon monoxide is an intermediate product of the combustion process and in particular under stoichiometric combustion conditions. The formation mechanism of CO is directly influenced by usage patterns, technology type and size, vintage, maintenance, and operation of the technology. Emission rates may vary by several orders of magnitude for facilities that are poorly operated or improperly maintained, such as might be the case of older units.

Size and age of unit may indicate that in smaller and older units, combustion is less controlled and hence emissions are likely to be higher than from larger and newer plants. In addition, many wood stoves (where there is a great variation in technology by geographic region) have particularly high emissions due to their largely inefficient combustion of fuel.

Carbon monoxide emissions from mobile sources are a function of the efficiency of combustion and post combustion emission controls. Emissions are highest when air-fuel mixtures are rich, with less oxygen than required for complete combustion. This occurs especially in idle, low speed, and cold start conditions in spark ignition engines.

The general method for estimating CO can be described as:

$$\boxed{\text{Emissions} = \sum (EF_{ab} \times \text{Activity}_{ab})}$$

where:

EF = Emission Factor (kg/TJ);
Activity = Energy Input (TJ);
a = Fuel type; and
b = Sector-activity.

Due to large differences in emission factors for various sectors, fuel consumption must be allocated to the IPCC main activity groups.

Carbon monoxide emission factors are available by detailed fuel/sector split for most of the fuel combustion sources. The following default emission factors have been developed by the IPCC based on the CORINAIR90 database, Radian Corporation (1990), US EPA (1995), the EDGAR Version 2.0 database, and National Communications to the FCCC. The aggregated emission factors in this table allow a rough estimation of CO emissions.

TABLE 1-10
CO DEFAULT (UNCONTROLLED) EMISSION FACTORS (IN KG/TJ)

			Coal	Natural Gas	Oil	Wood/ Wood Waste	Charcoal	Other Biomass and Wastes(a)
Energy Industries			20	20	15	1000(b)	1000(b)	1000
Manufacturing Industries and Construction			150	30	10	2000	4000	4000
Transport	Aviation(c)				100			
	Road			400	Gasoline 8000(d) Diesel 1000			
	Railways		150		1000			
	Navigation		150		1000			
Other Sectors	Commercial/Institutional		2000	50	20	5000	7000	5000
	Residential		2000	50	20	5000	7000	5000
	Agriculture/ Forestry/ Fishing	Stationary	2000	50	20	5000	7000	5000
		Mobile		400	1000			

Note: These factors are considered as the best available global default factors to date.

(a) Includes dung and agricultural, municipal and industrial wastes.

(b) These factors are for fuel combustion in the energy industries. For charcoal production, please refer to Table 1-14, Default Non-CO_2 Emission Factors for Charcoal Production.

(c) The emission factor for aviation in the above table is for jet kerosene. The emission factor for aviation gasoline ranges from 10 000 to 20 000 kg/TJ (default value: 15 000 kg/TJ).

(d) Generally the emission factors for gasoline vehicles are highest for motorcycles and passenger cars without emissions control equipment.

1.4.2.5 NON-METHANE VOLATILE ORGANIC COMPOUNDS (NMVOC) EMISSIONS FROM FUEL COMBUSTION

Non-Methane Volatile Organic Compounds[12] are indirect greenhouse gases.

The most important sources of NMVOCs from fuel combustion activities are mobile sources and residential combustion (especially biomass combustion).

Emissions of NMVOC (e.g., olefins, ketones, aldehydes) are the product of incomplete combustion. They are directly influenced by fuel used, usage patterns, technology type and size, vintage, maintenance and operation of the technology. Emission rates may vary by several orders of magnitude for facilities that are poorly operated or improperly maintained, such as might be the case of older units.

The emissions are very low for large-combustion plants. NMVOC emissions tend to decrease with increases in plant size and increasing efficiency of the combustion process.

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[12] Non-methane volatile organic compounds: all hydrocarbon compounds, including those where hydrogen atoms are partly, or fully, replaced by other atoms (S,N,O, halogens) excluding those inventoried under the Montreal protocol. They are volatile under ambient air conditions and expressed as mass units as measured.