

DRAFT: February 1, 2016

California Code of Regulations, Title 17, Division 3, Chapter 1, Subchapter 10
Climate
Change, Article 4

PROPOSED REGULATION ORDER

Subarticle 13: Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities

§ 95665. Purpose and Scope.

The purpose of this article is to establish greenhouse gas emission standards for crude oil and natural gas facilities identified in section 95666. This article is designed to serve the purposes of the California Global Warming Solutions Act, AB 32, as codified in sections 38500-38599 of the Health and Safety Code.

NOTE: Authority cited: Sections 38510, 38562, 39600, 39601 and 41511, Health and Safety Code. Reference: Sections 38560, 39600 and 41511, Health and Safety Code.

§ 95666. Applicability.

- (a) ~~Except small producers,~~ this article applies to owners or operators of equipment and components listed in section 95668 located within California, including California waters, that are associated with facilities in the sectors listed below, regardless of emissions level:
- (1) Onshore and offshore crude oil or natural gas production; and,
 - (2) Crude oil, condensate, and produced water separation and storage; and,
 - (3) Natural gas underground storage; and,
 - (4) Natural gas gathering and boosting stations; and,
 - (5) Natural gas processing plants; and,
 - (6) Natural gas transmission compressor stations.
- (b) Owners and operators must ensure that their facilities, equipment, and components comply at all times with all requirements of this subarticle, including all of the standards and requirements identified in section 95668. Owners and operators are jointly and severally liable for compliance with this subarticle.

NOTE: Authority cited: Sections 38510, 38562, 39600, 39601 and 41511, Health and Safety Code. Reference: Sections 38560, 39600 and 41511, Health and Safety Code.

§ 95667. Definitions.

- (a) For the purposes of this article, the following definitions apply:

- (1) "Air district or local air district" means the local Air Quality Management District or the local Air Pollution Control District.
- (2) "Air Resources Board or ARB" means the California Air Resources Board.
- (3) "API gravity" means a scale used to reflect the specific gravity (SG) of a fluid such as crude oil, condensate, produced water, or natural gas. The API gravity is calculated as $[(141.5/SG) - 131.5]$, where SG is the specific gravity of the fluid at 60°F, and where API refers to the American Petroleum Institute.
- (4) "Centrifugal compressor" means equipment that increases the pressure of natural gas by centrifugal action.
- (5) "Centrifugal compressor seal" means a wet or dry seal around the compressor shaft where the shaft exits the compressor case.
- ~~(6)~~ (6) "Circulation tank" means a tank or portable tank used to circulate, ~~store, or hold liquids water or solids from during~~ a crude oil or natural gas well ~~bore sand cleanout process~~ during or following a well stimulation treatment.
- ~~(6)~~ (7) "Commercial quality natural gas" means a mixture of gaseous hydrocarbons with at least 80 percent methane by volume (≥ 80 vol%) and less than ten percent by weight (<10 wt%) VOC and meets the criteria specified in Public Utilities Commission (PUC) General Order 58-A.
- ~~(7)~~ (8) "Continuous bleed" means the continuous venting of natural gas from a gas powered pneumatic device to the atmosphere. Continuous bleed pneumatic devices must vent continuously in order to operate.
- ~~(8)~~ (9) "Crude oil" means any of the naturally occurring liquids and semi-solids found in rock formations composed of complex mixtures of hydrocarbons ranging from one to hundreds of carbon atoms in straight and branched chain rings.
- ~~(9)~~ (10) "Condensate" means hydrocarbon or other liquid either produced or separated from crude oil or natural gas during production and which condenses due to changes in pressure or temperature.
- ~~(10)~~ (11) "Component" means a valve, fitting, flange, threaded-connection, process drain, stuffing box, pressure-vacuum valve, pipe, seal fluid system, diaphragm, hatch, sight-glass, meter, open-ended line, natural gas-driven pneumatic device, natural gas-driven pneumatic pump, centrifugal natural gas compressor wet seal, or reciprocating natural compressor rod packing or seal in methane service.

~~(11)~~(12) "Critical component" means any component that would require the shutdown of a critical process unit if that component was shut down or disabled. ~~---~~

~~(42)~~(13) "Critical process unit" means a process unit that must remain in service because of its importance to the overall process that requires it to continue to operate, and has no equivalent equipment to replace it or cannot be bypassed, and it is technically infeasible to repair leaks from that process unit without shutting it down and opening the process unit to the atmosphere.

~~(43)~~(14) "Crude oil and produced water separation and storage" means all activities associated with separating, storing or holding of emulsion, crude oil, condensate, or produced water at facilities to which this subarticle applies.

~~(14)~~(15) "Emissions" means the discharge of ~~natural gas~~ methane into the atmosphere.

~~(45)~~(16) "Emulsion" means any mixture of crude oil, condensate, or produced water with varying quantities of natural gas entrained in the liquids.

~~(46)~~(17) "Equipment" means any stationary or portable machinery, object, or contrivance covered by this subarticle, as set out by sections 95666 and 95668.

~~(47)~~(18) "Facility" means any building, structure, or installation to which this subarticle applies and which has the potential to emit natural gas. Facilities include all buildings, structures, or installations which:

- (1) Are under the same ownership or operation, or which are owned or operated by entities which are under common control;
- (2) Belong to the same industrial grouping either by virtue of falling within the same two-digit standard industrial classification code or by virtue of being part of a common industrial process, manufacturing process, or connected process involving a common raw material; and,
- (3) Are located on one or more contiguous or adjacent properties.

~~(48)~~(19) "Flash or flashing" means a process during which gas entrained in crude oil, condensate, or produced water under pressure is released when the liquids are subject to a decrease in pressure ~~or increase in temperature~~, such as when the liquids are transferred from an underground reservoir to the earth's surface.

(20) "Flash analysis testing" means the determination of emissions from crude oil, condensate, and produced water by using sampling and laboratory procedures used for measuring the volume and composition of gases released from the liquids, including the molecular weight, the weight percent of individual compounds, and a gas-oil or gas-water ratio.

(19)(21) "Global warming potential" or "GWP" means the ratio of the time-integrated radiative forcing from the instantaneous release of one kilogram of a trace substance relative to that of one kilogram of a reference gas, i.e., CO2. For the purposes of this regulation, the GWP of Methane is 21 (SAR GWP for 100-yr Time Horizon; Table 2.14, IPCC Fourth Assessment Report: Climate Change 2007).

(20)(22) "Inaccessible component" means any component located over fifteen feet above ground when access is required from the ground; or any component located over six (6) feet away from a platform when access is required from the platform.

(21)(23) "Intermittent bleed" means the intermittent venting of natural gas from a gas powered pneumatic device to the atmosphere. Intermittent bleed pneumatic devices may vent all or a portion of their supply gas when control action is necessary but do not vent continuously.

(22)(24) "Leak or fugitive leak" means the unintentional release of emissions at a rate greater than or equal to the leak thresholds specified in this article.

(23)(25) "Leak detection and repair or LDAR" means the inspection of components to detect leaks of total hydrocarbons and the repair of components with leaks above specified standards within specified timeframes.

(24)(26) "Liquids unloading" means an activity conducted with the use of pressurized natural gas to remove liquids that accumulate at the bottom of a natural gas well and obstruct gas flow.

(25)(27) "Minimize" means ~~tightening, adjusting, or replacing components or equipment for the purpose of stopping or reducing leaks below the lowest leak threshold specified in this subarticle.~~ reducing a leak to the lowest achievable level without damaging the component using best modern practices which include, but are not limited to, adding sealing material to the component, tightening the component, or adjusting the component without shutdown of the process that the component serves and that can be safely accommodated.

(26)(28) "Natural gas" means a naturally occurring mixture or process derivative

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of hydrocarbon and non-hydrocarbon gases. Its constituents include the greenhouse gases methane and carbon dioxide, as well as heavier hydrocarbons. Natural gas may be field quality (which varies widely) or pipeline quality.

~~(27)~~(29) "Natural gas gathering and boosting station" means all equipment and components located within a facility fence line associated with moving natural gas to a processing plant or natural gas transmission pipeline.

~~(28)~~(30) "Natural gas processing plant" means a plant used for the separation of natural gas liquids (NGLs) or non-methane gases from produced natural gas, or the separation of NGLs into one or more component mixtures.

~~(29)~~(31) "Natural gas transmission compressor station" means all equipment and components located within a facility fence line associated with moving natural gas from production fields or natural gas processing plants through natural gas transmission pipelines.

~~(30)~~(32) "Natural gas transmission pipeline" means a Federal Energy Regulatory Commission rate-regulated Interstate pipeline, a state rate-regulated Intrastate pipeline, or a pipeline that falls under the "Hinshaw Exemption" as referenced in section 1(c) of the Natural Gas Act, 15 U.S.C. 717-717z (2015).

~~(31)~~(33) "Natural gas underground storage" means all equipment and components associated with the subsurface storage of natural gas in depleted crude oil or natural gas reservoirs or salt dome caverns.

~~(32)~~(34) "Offshore" means all marine waters located within the boundaries of the State of California.

~~(33)~~(35) "Onshore" means all lands located within the boundaries of the State of California.

~~(34)~~(36) "Operator" means any entity, including an owner or contractor, having operational control of components or equipment, including leased, contracted, or rented components and equipment to which this subarticle applies.

~~(35)~~(37) "Owner" means the entity that owns or operates components or equipment to which this subarticle applies.

~~(36)~~(38) "Photo-ionization detector or PID instrument" means a gas detection device that utilizes ultra-violet light to ionize gas molecules and is commonly employed in the detection of non-methane volatile organic compounds.

~~(37)~~(39) "Pneumatic device" means an automation device that uses natural gas, compressed air, or electricity to control a process.

~~(38)~~(40) "Pneumatic pump" means a device that uses natural gas or compressed air to power a piston or diaphragm in order to circulate or pump liquids.

~~(39)~~(41) "Pond" means any very large excavation that is used for the storage and or disposal of clean produced water (as defined in San Joaquin Air Pollution Control District Rule 4402), is not used for the separation of oil and water, and has no more than five percent visible oil-covered surface area.~~an excavation or impoundment for the storage and disposal of produced water and is not used for crude oil separation or processing.~~

~~(40)~~(42) "Portable equipment" means equipment designed for, and capable of, being carried or moved from one location to another and which it resides for less than 365 days. Portability indicators include, but are not limited to, the presence of wheels, skids, carrying handles, dolly, trailer, or platform.

~~(41)"Portable pressurized separator" means a pressure vessel that can be moved from one location to another by attachment to a motor vehicle without having to be dismantled and is capable of separating and sampling crude oil, condensate, or produced water at the steady-state temperature and pressure of the separator required for sampling.~~

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Comment [YS1]: Term not used in the regulation. Appendix C has its own definitions.

~~(42)~~(43) "Portable tank" means a tank that can be moved from one location to another by attachment to a motor vehicle without having to be dismantled.

~~(43)~~(44) "Pressure vessel" means any a hollow container used to hold gas or liquid and rated, as indicated by an ASME pressure rating stamp, and operated to contain normal working pressures of at least 15 psig without continuous vapor loss to the atmosphere and may be used for the separation of crude oil, condensate, produced water, or natural gas.

~~(44)~~(45) "Production" means all activities associated with the production or recovery of emulsion, crude oil, condensate, produced water, or natural gas at facilities to which this subarticle applies.

~~(45)~~(46) "Produced water" means water recovered from an underground reservoir as a result of crude oil, condensate, or natural gas production and which may be recycled, disposed, or re-injected into an underground reservoir.

~~(46)~~(47) "Reciprocating natural gas compressor" means equipment that increases the pressure of natural gas by positive displacement of a piston in a compression cylinder and is powered by an internal combustion engine or electric motor with a horsepower rating supplied by the manufacturer.

~~(47)~~(48) "Reciprocating natural gas compressor rod packing" means a seal comprising of a series of flexible rings in machined metal cups that fit around the reciprocating compressor piston rod to create a seal limiting the amount of compressed natural gas that vents into the atmosphere

~~(48)~~(49) "Reciprocating natural gas compressor seal" means any device or mechanism used to limit the amount of natural gas that vents from a compression cylinder into the atmosphere.

~~(49)~~(50) "Separator" means any tank used for the separation of crude oil, condensate, produced water, or natural gas. For the purpose of this subarticle, in crude oil production, the first pressure vessel that receives crude oil and natural gas directly from a well and is used to separate crude oil and produced water is also considered a separator; in dry natural gas production, the first pressure vessel that receives natural gas and condensate directly from a well and is used to separate gas from water is also considered a separator.

~~(51)~~ "Separator and tank system" means the first a separator that receives crude oil and produced water directly from a well and any tank ~~or sump~~ connected directly to the first separator. ~~For the purpose of this article, in crude oil production, a pressure vessel used to separate crude oil and produced water is also considered a separator; in dry natural gas production, a pressure vessel used to separate gas from water is also considered a separator.~~

~~(52)~~ "Small Producer" means an owner or operator who produces an average of less than 6,000 barrels per day of crude oil or condensate from all operations in the state of California, and does not engage in refining, transporting or marketing of refined petroleum products.

~~(50)~~(53) "Successful repair" means tightening or adjusting or replacing equipment or a component for the purpose of stopping or reducing fugitive leaks below the lowest leak threshold specified in this subarticle.

~~(54)~~(54) "Sump" means a lined or unlined surface impoundment or depression in the ground that, during normal operations, is used to separate, store, or hold emulsion, crude oil, condensate, or produced water.

~~(52)~~(55) "Tank" means any container constructed primarily of non-earthen materials used for the purpose of storing, holding, or separating emulsion, crude oil, condensate, or produced water and that is designed to operate below 15 psig normal operating pressure.

~~(53)~~(56) "Underground injection well" means, for the purpose of this subarticle, any well that is used for the subsurface injection of natural gas for disposal.

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(54)(57) "Vapor collection system" means equipment and components installed on pressure vessels, separators, tanks, or sumps including piping, connections, and flow-inducing devices used to collect and route ~~emissions~~ methane to a processing, sales gas, or fuel gas system; to an underground injection well; or to a vapor control device.

(55)(58) "Vapor control device" means destructive or non-destructive equipment used to control emissions.

(56)(59) "Vapor control efficiency" means the ability of a vapor control device to control emissions, expressed as a percentage, which can be estimated by calculation or by measuring the total hydrocarbon concentration at the inlet and outlet of the vapor control device.

(57)(60) "Vapor pressure" means the equilibrium partial vapor pressure exerted by an organic liquid measured at maximum tank temperature.

(58)(61) "Vent or venting" means the intentional or automatic release of natural gas into the atmosphere from components, equipment or activities described in this subarticle.

(59)(62) "Well" means a boring in the earth that is designed to bring emulsion, crude oil, condensate, produced water, or natural gas to the surface, or to inject natural gas into underground storage.

(60)(63) "Well stimulation treatment" means the treatment of a well designed to enhance crude oil and natural gas production or recovery by increasing the permeability of the formation and as further defined by the Division of Oil, Gas, and Geothermal Resources SB 4 Well Stimulation Treatment Regulations, Chapter 4, Subchapter 2, Article 2, section 1761(a) (December 30, 2014).

NOTE: Authority cited: Sections 38510, 38562, 39600, 39601 and 41511, Health and Safety Code. Reference: Sections 38560, 39600 and 41511, Health and Safety Code

§ 95668. Standards.

(a) *Crude Oil, Condensate, and Produced Water Separation and Storage*

- (1) Except as provided in section 95668(a)(2), the requirements in sections 95668(a)(3) through (9) apply to ~~pressure vessels, separators, tanks, and sumps~~ separator and tank systems located at facilities listed in section 95666.
- (2) The requirements of this subsection do not apply to the following:

(A) ~~Pressure vessels, separators, tanks, and sumps~~ Separator and tank systems that have not contained crude oil, condensate, or produced water for at least 30 calendar days.

(B) ~~Separator and Tank~~ Separator and Tank systems used for temporarily separating, storing, or holding emulsion, crude oil, condensate, or produced water from any newly constructed well for up to 30 calendar days following initial production from that well but only if the tank is not used to circulate liquids from a well that has been subject to a well stimulation treatment.

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(C) Portable pressurized separators used for collecting samples used for the "Test Procedure for Determining Annual Flash Emission Rate of Methane from Crude Oil, Condensate, and Produced Water"

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~~(3) Beginning January 1, 2017, pressure vessels not already subject to a district leak detection and repair program shall comply with the leak detection and repair requirements specified in section 95669.~~

~~(4)(3)~~ (3) Beginning January 1, 201~~8~~⁷ and by no later than September 1, 201~~7~~⁸, owners or operators of new and existing separator and tank systems which are not controlled for emissions with the use of a vapor collection system shall ~~conduct annual flash analysis testing of the crude oil, condensate, or produced water~~ the requirements as described below.

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(A) Determine the initial annual methane emissions from each separator and tank system using one of the following methods –

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Conduct initial flash analysis testing in accordance with the ARB Test Procedure for Determining Annual Flash Emission Rate of Methane from Crude Oil, Condensate, and Produced Water as described in Appendix C; or

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-For separator and tank systems where there is not enough produced fluid to conduct flash testing, the owner/operator may use representative flash test from another separator and tank system located within the same field; or

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(A) Conduct an engineering evaluation based on operations data.

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(B) Sum the annual ~~flash analysis testing results for~~ methane emissions for the crude oil, condensate, and produced water.

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(C) Maintain a record of flash analysis testing as specified in section 95671 and report the results to ARB as specified in section 95672.

~~Demonstrate that the results of the flash analysis testing are representative of the crude oil, condensate, and produced water processed or stored in the separator and tank system. The ARB Executive Officer may request additional flash analysis testing or information in the event that the test results reported do not reflect representative results of similar systems.~~

~~(5)(4)~~ Beginning January 1, 201~~8~~9, owners or operators of separator and tank systems with a measured annual flash emission rate greater than 100 metric tons per year of methane shall control the emissions from the separator and tank system with the use of a vapor collection system as specified in section 95668(c).

~~with the use of a vapor collection system as specified in section 95668(c).~~

~~(6)(5)~~ Beginning January 1, 201~~8~~9, separator and tank systems s, tanks, and covered sumps subject to the vapor collection system requirements specified in section 95668(a)(~~4~~6) shall comply with the leak detection and repair requirements specified in section 95669.

(6) Owners or operators of separator and tank systems with a measured initial annual flash emission rate less than or equal to 50 metric tons per year of methane are not subject to 95668(a)(7) – (9).

(7) Owners or operators of separator and tanks systems with a measured initial flash emission rate greater than 50 metric tons per year but less than or equal to 100 metric tons per year of methane~~less than or equal to 10 metric tons per year of methane~~ shall conduct flash analysis testing and reporting annually. If the results of flash analysis testing are less than or equal to 100 metric tons per year of methane using three consecutive years of test results the owner or operator may reduce the frequency of testing and reporting to once every five years.

~~consecutive years of test results the owner or operator may reduce the frequency of testing and reporting to once every five years.~~

~~(8) Flash analysis testing, record keeping, and reporting shall be conducted within one calendar year of adding a new well to the separator and tank system since the time of previous flash analysis testing.~~

(8) Owners or operators of separator and tank systems with measured or estimated (using an engineering evaluation) flash emission rate greater than 100 metric tons of methane determined during 2019 or later shall control the emissions from the separator and tank system with the use of a vapor collection system as specified in section 95668(c) within one calendar year following the flash liberation testing.

(9) Flash emissions shall be recalculated if the annual crude oil, condensate, or produced water throughput increases by more than 240 percent (maintained continuously over a 3 month period) since the time of the previous flash analysis testing. ~~provided that the increase in throughput is not a result of adding a new well to the separator and tank system which requires additional flash analysis testing as specified in section 95668(a)(8).~~

(A) The owner or operator shall maintain and make available upon request by the ARB Executive Officer a record of the revised flash emission calculation.

(b) *Circulation Tanks for Well Stimulation Treatments*

(1) Beginning January 1, 20198, circulation tanks used in conjunction with well stimulation treatments used at facilities listed in section 95666 shall be controlled for emissions of natural gas according to one of the following methods:

(A) The circulated liquids shall be safely controlled for emissions of natural gas prior to entering the circulation tank using a pressure vessel or separator and a vapor collection system as specified in section 95668(c) ~~and the circulation tank shall be covered and comply with the leak detection and repair requirements specified in section 95669; or,~~

(B) Circulation tanks shall be covered and safely controlled for emissions of natural gas using a vapor collection system as described in section 95668(c) ~~and the tank shall comply with the leak detection and repair requirements specified in section 95669; or,~~

(C) Develop and implement an approved best practices management plan to limit methane emissions from circulation tanks. Best practices may include but are not limited the following:

- i. Use of SandX or similar tanks instead of shaker pits
- ii. Minimize the duration of circulation of water with visual monitoring
- iii. Influx Control Plan

The plan must be available for review by ARB 30-days prior to each well stimulation event.

(c) *Vapor Collection Systems and Vapor Control Devices*

(1) Beginning January 1, 20198, the following requirements apply to equipment at facilities listed in section 95666 that are subject to the vapor collection system and control device requirements specified in this

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- (2) Unless section 95668(c)(3) applies, the vapor collection system shall safely direct the collected vapors to one of the following:
 - (A) Existing sales gas system; or,
 - (B) Existing fuel gas system; or,
 - (C) Existing underground injection well not currently under review by the Division of Oil and Gas and Geothermal Resources.

- (3) If no safe existing sales gas system, fuel gas system, or underground injection well specified in section 95668(c)(2) is available at the facility, the owner or operator must control the collected vapors as follows:
 - (A) For facilities without an existing vapor control device installed at the facility, the owner or operator must install a new vapor control device as specified in section 95668(c)(4); or,
 - (B) For facilities currently operating a vapor control device and which are required to control additional vapors as a result of this subarticle, the owner or operator must replace the existing vapor control device with a new vapor control device as specified in section 95668(c)(4) to control all of the collected vapors.

- (4) Any vapor control device required in section 95668(c)(3) must meet the following requirements:
 - (A) If the vapor control device is to be installed in a region classified as in attainment with all state or federal ambient air quality standards, the vapor control device must achieve at least 95% vapor control efficiency of total emissions and must meet all applicable federal, state, and local air district requirements; or,
 - (B) If the vapor control device is to be installed in a region classified as non-attainment with, or which has not been classified as in attainment of, all state and federal ambient air quality standards, the owner or operator must install one of the following devices that meets all applicable federal, state, and local air district requirements:
 1. A non-destructive vapor control device that achieves at least 95% vapor control efficiency of total emissions and does not result in emissions of nitrogen oxides (NOx); or,
 2. A vapor control device that achieves at least 95% vapor control efficiency of total emissions and does not generate more than 15 parts per million volume (ppmv) NOx when measured at 3% oxygen.

~~(5) If the collected vapors cannot be controlled as specified in section 95668(c)(2) through (4), the equipment subject to the vapor collection and control requirements specified in this subarticle may not be used or installed and must be removed from service by January 1, 2018.~~

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(5) A separator or a tank is not required to be served by a vapor control system during maintenance/repairs/upset conditions for up to 600 hours per rolling 12 calendar month period. During temporary periods of maintenance/repair/upsets, operator shall use best work practices to minimize emissions.

(6) Vapor collection systems and control devices are allowed up to 30 calendar days per year for maintenance. A time extension to perform maintenance not to exceed 14 calendar days may be granted by the ARB Executive Officer. The owner or operator is responsible for maintaining a record of the number of calendar days per calendar year that the vapor collection system or vapor control device is out of service and shall provide a record of such activity at the request of the ARB Executive Officer.

(A) If an alternate vapor control device compliant with this section is installed prior to conducting maintenance and the vapor collection and control system continues to collect and control vapors during the maintenance operation, the event does not count towards the 360 calendar day limit.

(B) Vapor collection system and control device shutdowns that result from utility power outages are not subject to enforcement action provided the equipment resumes normal operation as soon as normal utility power is restored. Vapor collection system and control device shutdowns that result from utility power outages do not count towards the 360 calendar day limit for maintenance.

(d) *Reciprocating Natural Gas Compressors*

~~(1) The following requirements apply to reciprocating natural gas compressors at crude oil or natural gas production facilities listed in section 95666 which are not covered under section 95668(d)(2):~~

~~(A) Beginning January 1, 2017, components on driver engines and compressors shall comply with the leak detection and repair requirements specified in section 95669.~~

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~~(B) Beginning January 1, 2017, for any compressors without a vapor collection system used to control the rod packing or seal vent gas, the rod packing or seal shall comply with the leak detection and repair~~

~~requirements specified in section 95669; and,~~

~~(C) The owner or operator shall maintain a record of the rod packing or seal leak concentration measurement as specified in Appendix A, Table 5.~~

~~(D) A reciprocating natural gas compressor with a rod packing or seal leak concentration measured above the minimum standard specified in section 95669 and which has been approved by the ARB Executive Officer as a critical component as specified in section 95670, shall be successfully repaired by the end of the next process shutdown or within 180 calendar days from the date of the initial leak concentration measurement, whichever is sooner.~~

~~(2)~~(1) The following requirements apply to reciprocating natural gas compressors at natural gas gathering and boosting stations, processing plants, transmission compressor stations, and underground natural gas storage facilities listed in section 95666 and which are not covered under section 95668(d)(1):

(A) Beginning January 1, 201~~7~~8, components on driver engines and compressors shall comply with the leak detection and repair requirements specified in section 95669.

(B) Beginning January 1, 201~~7~~8, any compressor without a vapor collection system used to control the rod packing or seal vent gas shall be equipped with a meter or instrumentation that can measure the rod packing or seal emissions flow rate; or,

(C) The compressor shall be equipped with a clearly identified access port installed in the rod packing or seal vent stack at a height of no more than six (6) feet above ground level or a permanent support surface for making individual or combined rod packing or seal emission flow rate measurements; and,

(D) The rod packing or seal emissions flow rate shall be measured annually by direct measurement (high volume sampling, bagging, calibrated flow measuring instrument) while the compressor is running at normal operating temperature. Flow rates measured annually as per the methods described in Greenhouse Gas Mandatory Reporting Regulation Section 95153(n) are acceptable.

~~(D)~~
(E) Beginning January 1, 201~~9~~8, a compressor with a rod packing or seal with a measured emission flow rate greater than two (2) standard cubic feet per minute (scfm), or a combined rod packing or seal emission

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flow rate greater than the number of compression cylinders multiplied by two (2) scfm, shall be repaired or replaced within 30 calendar days from the date of the initial emission flow rate measurement.

(F) A reciprocating natural gas compressor with a rod packing or seal emission flow rate measured above the standard specified in section 95688(d)(2)(E) and which has been ~~approved by the ARB Executive Officer~~ identified as a critical component as specified in section 95670, shall be successfully repaired by the end of the next process shutdown or within ~~180 days~~ 1 year from the date of the initial flow rate measurement, whichever is sooner.

(F)

(e) Centrifugal Natural Gas Compressors with Wet Seals

- (1) The following requirements apply to centrifugal natural gas compressors with wet seals at facilities listed in section 95666:

~~(2) Beginning January 1, 2017, components on driver engines and compressors shall comply with the leak detection and repair requirements specified in section 95669.~~

- ~~(3)~~(2) Beginning January 1, 2017~~8~~, any compressor without a vapor collection system used to control the wet seal vent gas shall be equipped with a meter or instrumentation that can measure the wet seal emissions flow rate; or

- ~~(4)~~(3) The compressor shall be equipped with a clearly identified access port installed in the wet seal vent stack at a height of no more than six (6) feet above ground level or a permanent support surface for making wet seal emission flow rate measurements; and,

- ~~(5)~~(4) The wet seal emissions flow rate shall be measured annually by direct measurement (high volume sampling, bagging, calibrated flow measuring instrument) while the compressor is running at normal operating temperature. Flow rates measured annually as per the methods described in Greenhouse Gas Mandatory Reporting Regulation Section 95153(m) are acceptable.

- ~~(6)~~(5) Beginning January 1, 201~~7~~8, a compressor with a wet seal emission flow rate greater than three (3) scfm or a combined wet seal emission flow rate greater than the number of wet seals multiplied by three (3) scfm a shall control the wet seal emission vent gas with the use of a vapor collection system as specified in section 95668(c); or,

- ~~(7)~~(6) Minimize the wet seal emission flow rate within 30 calendar days from

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the date of the initial emission flow rate measurement and replace the wet seal with a dry seal by no later than January 1, 2020.

~~(8)~~(7) A centrifugal natural gas compressor with a wet seal emission flow rate measured above the standard specified in section 95668(e)(6) and which has been ~~approved by the ARB Executive Officer~~ identified as a critical component as specified in section 95670, shall be successfully repaired by the end of the next process shutdown or within ~~180 days~~ 1 year from the date of the initial flow rate measurement, whichever is sooner.

(f) *Natural Gas Powered Pneumatic Devices and Pumps*

- (1) Except as provided in section 95668(f)(~~23~~), the requirements in sections 95668(f)(~~34~~) through (~~76~~) apply to natural gas powered pneumatic devices and pumps at facilities listed in section 95666:
- (2) A natural gas powered pneumatic device installed prior to January 1, 201~~85~~ may be used provided it meets all of the following requirements:
 - (A) The device does not vent natural gas at a rate greater than 6 standard cubic feet per hour (scfh); and,
 - (B) The device is clearly marked with a permanent tag that identifies the vent rate as less than or equal to 6 scfh; and,
 - (C) The device is tested during each inspection period as specified in section 95669 by using a direct measurement method (high volume sampling, bagging, calibrated flow measuring instrument); and,

A device with a measured emissions flow rate greater than 6 scfh shall be repaired or replaced within 14 calendar days from the date of the initial emission flow rate measurement; or

(D) The device is tested during each inspection period as specified in section 95669 by using Method 21 not including PID and,

~~(D)~~ A device with a measured emissions flow rate greater than leak thresholds specified in section 95669 shall be repaired or replaced within 14 calendar days from the date of the initial emission flow rate measurement.

- (3) Pneumatic devices installed on or after January 1, 2018, shall not Beginning January 1, 2018, pneumatic devices shall not vent natural gas continuously to the atmosphere and shall comply with the leak detection and repair requirements specified in section 95669.

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(4) Beginning January 1, 2018, intermittent bleed pneumatic devices shall not vent natural gas when not actuating determined by testing the device when not actuating in accordance with the leak detection and repair requirements specified in section 95669.

(5) ~~Pneumatic pumps installed on or after January 1, 2018~~ ~~Beginning January 1, 2018, pneumatic pumps~~ shall not vent natural gas to the atmosphere and shall comply with the leak detection and repair requirements specified in section 95669.

(6) Beginning January 1, 2018, existing continuous bleed pneumatic devices and pumps shall be retrofitted or replaced to prevent natural gas from venting to the atmosphere or shall be controlled according to one of the following methods except as provided in 95668(f)(6)(C) and 95668(f)(6)(D) below:

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(A) Collect all vented natural gas with the use of a vapor collection system as specified in section 95668(c); or,

(B) Use compressed air or electricity to operate.

(C) For continuous bleed devices in service prior to January 1, 2018, the owner/operator shall submit justification for the devices to be in service due to safety and/or process purposes by September 30, 2017. ARB or the local air district shall be deemed to have approved the justification if it does not object to the owner/operator within 30-days of receipt.

(D) For continuous bleed devices placed in service on or after January 1, 2018, the owner/operator shall submit justification for the devices to be installed due to safety and/or process purposes at least 30-days prior to installation. ARB or the local air district shall be deemed to have approved the justification if it does not object to the owner/operator within 30-days of receipt.

~~(B)~~

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(g) *Liquids Unloading of Natural Gas Wells*

(1) Beginning January 1, 201~~9~~⁸, owners or operators of natural gas wells at facilities listed in section 95666 that are vented to the atmosphere for the purpose of liquids unloading shall perform one of the following:

(A) Collect the vented natural gas with the use of a vapor collection system as specified in section 95668(c); or,

(B) Measure the volume of natural gas vented by direct measurement (high volume sampling, bagging, calibrated flow measuring

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instrument); or,

(C) Calculate the volume of natural gas vented using the Liquid Unloading Calculation listed in Appendix B or according to the Air Resources Board Regulation for the Mandatory Reporting of Greenhouse Gas Emissions, Title 17, Division 3, Chapter 1, Subchapter 10, Article 2, Section 95153(e) (February, 2015).

(2) Owners or operators must maintain and report a record of the volume of natural gas vented to perform liquids unloading as well as equipment installed in the natural gas well(s) designed to automatically perform liquids unloading (e.g., foaming agent, velocity tubing, plunger lift, etc.) once per calendar year as specified in sections 95670 and 95671 of this subarticle.

(h) Natural Gas Underground Storage Facility Well Monitoring Requirements

(1) The following requirements apply to natural gas underground storage facilities listed in section 95666:

(2) By January 1, 201~~8~~⁷, each facility shall develop a plan for surface leak monitoring at the facility on a continuous basis or, if continuous is not feasible, a daily basis. The plan will be evaluated based on sensitivity of instrumentation, coverage of the facility, appropriateness for site, and other relevant criteria. The ARB Executive Officer will approve, in full or in part, or disapprove, in full or in part, the plans with full implementation of monitoring by January 1, 201~~9~~⁸.

[Staff is considering a leak emission reduction requirement for large or catastrophic leaks at any oil and gas facility covered by this regulation]

§ 95669. Leak Detection and Repair

(a) The following requirements apply to components at facilities listed in section 95666 which are not already subject to a local air district leak detection and repair program.

~~Beginning January 1, 2017, an owner or operator shall audio-visually (by hearing and by sight) inspect components for leaks at least once every 24 hours for facilities that are visited daily, or at least once per calendar week for unmanned facilities.~~

~~Any audio-visual inspection that indicates a leak which cannot be repaired immediately shall be tested as specified in section 95669(f) within 24 hours after conducting the audio-visual inspection.~~

(b) Except as provided in section 95669(~~ce~~), the requirements in sections

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95669(~~df~~) through (~~em~~) apply to components at facilities listed in section 95666:

- (c) Leak detection and repair requirements do not apply to the following unless required by the local air district:
 - (1) Components at a facility upstream of a transfer of custody meter used exclusively for the delivery of commercial quality natural gas to the facility.
 - (2) Components incorporated into produced water lines located downstream of produced water tanks that are controlled with the use of a vapor collection system.
 - (3) Components that are buried below ground. ~~Portion of well casing that is visible aboveground extends to the surface~~ is not considered a buried component.
 - (4) One-half inch and smaller stainless steel tube fittings including those used for instrumentation.
 - (5) Components incorporated in lines operating exclusively under negative pressure or below atmospheric pressure.
 - (6) Components and piping located downstream from the point where crude oil, condensate, or natural gas transfer of custody occurs, including components and piping located outside the facility boundaries of natural gas compressor stations and underground storage facilities.
 - (7) Temporary components or equipment used for general maintenance purposes and used less than 300 hours per calendar year if the owner or operator maintains and can provide a record of the date when the components were installed and the number of hours the components have been in operation.
 - (8) Components which are unsafe to monitor when conducting EPA Method 21 measurements and as documented in a safety manual or policy and approved by the ARB Executive Officer.
 - (9) Components exclusively handling liquid streams which have less than 10 percent by weight (<10 wt%) evaporation at 150°C.
 - (10) Components handling liquids with 90 percent by volume or greater (≥90 vol%) water concentration.

(11) Components exclusively handling non-hydrocarbon streams.

(12) Components exclusively handling streams which have methane concentration less than 10 percent by weight (<10 wt%).

(d) Beginning January 1, 2017~~8~~, components (not including pipes) shall be inspected at least once each calendar ~~quarter-year~~ for leaks of total hydrocarbons in units of parts per million volume (ppmv) calibrated as methane in accordance with EPA Reference Method 21 excluding the use of PID instruments. On an annual basis, operators shall visually inspect pipes that are not already subject to an existing Local Air District or DOGGR or SPCC visual inspection program. If a leak is detected during a visual inspection, Method 21 follow-up will be performed to determine the leak concentration.

(A) If a leak is found to be above the thresholds specified in Tables 3 or 4, the leak shall be repaired as soon as practicable but not later than the time frame specified in Table 1 or 2 of this rule.

(B) The annual inspection frequency will be increased to quarterly if components have been measured above the number of allowable leaks for each leak threshold during the calendar year specified in Table 4.

The quarterly inspection frequency may be reduced to annually provided that both of the following conditions are met: All components have been measured below the number of allowable leaks for each leak threshold specified in Table 4 for five (5) consecutive calendar quarters.

(A)(C) A quarterly inspection frequency may be reduced back to annual provided that both of the following conditions are met: All components have been measured below the number of allowable leaks for each leak threshold specified in Table 4 for five (5) consecutive calendar quarters.

(B) The change in inspection frequency is substantiated by documentation and approved by the ARB Executive Officer.

~~(2) The inspection frequency shall revert to quarterly at any time the number of allowable leaks specified in Table 4 is exceeded during any inspection period.~~

(e) Owners or operators shall maintain and report a record of each leak inspection and the component leak concentration(s) and repair date(s) as specified in sections 95671 and 95672.

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- (f) Owners or operators shall minimize leaks immediately, but not later than one (1) calendar day after initial leak detection.
- (g) Hatches shall remain closed at all times except during sampling, adding process material, or attended maintenance operations.
- (h) Open-ended lines and valves located at the end of lines shall be sealed with a blind flange, plug, cap or a second closed valve, at all times except during operations requiring liquid or gaseous process fluid flow through the open- ended line.
- (i) Components or component parts which incur five (5) repair actions within a continuous 12-month period shall be replaced or removed from service.
- (j) From January 1, 2017~~8~~ and through December 31, 2019~~8~~, any component with a leak concentration measured above the following standards shall be repaired within the time period specified:
 - (1) Leaks with measured total hydrocarbons greater than or equal to 10,000 ppmv but not greater than 49,999 ppmv shall be successfully repaired or removed from service within 14 calendar days of initial leak detection.
 - (2) Leaks with measured total hydrocarbons greater than or equal to 50,000 ppmv shall be successfully repaired or removed from service within five (5) calendar days of initial leak detection.
 - (3) Components measured above the standards specified and which have been ~~approved by the ARB Executive Officer identified~~ as a critical component as specified in section 95670, shall be repaired to minimize the leak to the maximum extent possible within one (1) calendar day of initial leak detection and the final repair shall be completed by the end of the next process shutdown or within ~~180 days~~ 1 year from the date of initial leak detection, whichever is sooner.

Table 1
Repair Time Periods January 1, 2017~~8~~ through December 31, 2019~~8~~

Leak Threshold	Repair Time Period
10,000-49,999 ppmv	14 calendar days
50,000 ppmv or greater	5 calendar days
Critical Components	Next shutdown or within 180 calendar days <u>1 year</u>

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(k) By January 1, 20~~2019~~, any component with a leak concentration measured above the following standards shall be repaired within the time period specified:

(1) Leaks with measured total hydrocarbons greater than or equal to 1,000 ppmv but not greater than 9,999 ppmv shall be successfully repaired or removed from service within 14 calendar days of initial leak detection.

~~(2)~~ Leaks with measured total hydrocarbons greater than or equal to 10,000 ppmv but not greater than 49,999 ppmv shall be successfully repaired or removed from service within five (5) calendar days of initial leak detection.

~~(2)~~

(3) Leaks with measured total hydrocarbons greater than or equal to 50,000 ppmv shall be successfully repaired or removed from service within two ~~(2)~~ calendar days of initial leak detection.

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Table 2
Repair Time Periods On or After January 1, ~~2019~~2020

Leak Threshold	Repair Time Period
1,000-9,999 ppmv	14 calendar days
10,000-49,999 ppmv	5 calendar days
50,000 ppmv or greater	2 calendar days
Critical Components	Next shutdown or within 180 calendar days 1 year

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(l) Upon detection of a component with a leak concentration measured above the standards specified, the owner or operator shall affix to that component a weatherproof readily visible tag that identifies the date and time of leak detection measurement and the measured leak concentration. The tag shall remain affixed to the component until all of the following conditions are met:

- (1) The leaking component has been repaired or replaced; and,
- (2) The component has been re-inspected and measured below the lowest standard specified for the inspection year when measured in accordance with EPA Reference Method 21, excluding the use of PID instruments.

- (3) Components measured above the standards specified and which have been ~~approved by the ARB Executive Officer identified~~ as a critical component as specified in section 95670, shall be repaired to minimize the leak to the maximum extent possible within one (1) calendar day of initial leak detection and the final repair shall be completed by the end of the next process shutdown or within ~~180 days~~ 1 year from the date of initial leak detection, whichever is sooner.

(m) Compliance with Leak Detection and Repair Requirements:

- (1) The failure of an owner or operator to meet any of the requirements specified shall constitute a violation of this subarticle.
- (2) Between January 1, 201~~7~~8 and December 31, 201~~8~~9, no facility shall exceed the number of allowable leaks specified in Table 3 during any inspection period as determined by the ARB Executive Officer or by the facility owner or operator in accordance with Method 21, excluding the use of PID instruments.
- (3) By January 1, 20~~20~~19, no facility shall exceed the number of allowable leaks specified in Table 4 during any inspection period as determined by the ARB Executive Officer or by the facility owner or operator in accordance with Method 21, excluding the use of PID instruments.

~~By January 1, 2019, no component shall exceed a leak of total hydrocarbons greater than or equal to 50,000 ppmv as determined by the ARB Executive Officer or by the facility owner or operator in accordance with Method 21, excluding the use of PID instruments.~~

**Table 3 - Allowable Leaks Per Number of Components Inspected
January 1, 201~~7~~8 through December 31, 201~~8~~9**

Leak Threshold	200 or Less Components	More than 200 Components
10,000-49,999 ppmv	5	2% of total inspected
50,000 ppmv or greater	3 <u>2</u>	1% of total inspected

**Table 4 - Allowable Leaks Per Number of Components Inspected
On or After January 1, 20~~19~~20**

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Leak Threshold	200 or Less Components	More than 200 Components
1,000-9,999 ppmv	5	2% of total inspected
10,000-49,999 ppmv	32	1% of total inspected
50,000 ppmv or greater	20	<u>0.5% of total inspected</u>

NOTE: Authority cited: Sections 38510, 38562, 39600, 39601 and 41511, Health and Safety Code. Reference: Sections 38560, 39600 and 41511, Health and Safety Code.

§ 95670. Critical Components

- (a) Beginning January 1, 201~~7~~8, critical components used in conjunction with a critical process unit at facilities listed in section 95666 must be ~~pre-approved by the ARB Executive Officer identified if by~~ owners or operators who wish to claim any critical component exemptions available under this subarticle.
- (b) Each critical component shall be identified as shown in Appendix A, Table A3 and submitted to ARB for approval by no later than June 30, 201~~7~~8 or within 180 days from the installation of a new critical component.
- (c) Owners or operators must provide sufficient documentation showing that a critical component is required as part of a critical process unit and that shutting down the critical component would result in emissions greater than the emissions measured from the component.

~~Approval of a critical component may be granted only if owners or operators fully comply with this section. The ARB Executive Officer retains discretion to deny any application for approval.~~

NOTE: Authority cited: Sections 38510, 38562, 39600, 39601 and 41511, Health and Safety Code. Reference: Sections 38560, 39600 and 41511, Health and Safety Code

§ 95671. Record Keeping Requirements.

- (a) ~~The requirements of this section do not apply to operators who are subject to the recordkeeping requirements of Greenhouse Gas Mandatory Reporting Regulation for the parameters described below.~~ Beginning January 1, 201~~7~~8, owners or operators of facilities listed in section 95666 subject to requirements specified in sections 95668 and 95669 shall maintain, and make available upon request by ARB a copy of the following records:

Flash Analysis Testing

- (1) Maintain, for at five years from the date of each test, a record of flash analysis testing that shall include the following:

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- (A) A sketch or diagram of each separator and tank system tested that identifies the liquid sampling location and all pressure vessels, separators tanks, and sumps, ~~and ponds~~ within the system; and,
- (B) A record of the flash analysis testing results, calculations, and a description of the separator and tank system as specified in Appendix A Table A1; and,
- (C) A field testing form for each flash analysis test conducted as specified in Appendix C Form 1; and,
- (D) The laboratory report(s) for each flash analysis test conducted.

Liquids Unloading of Natural Gas Wells

- (2) Maintain, for at least two years following the measurement or calculation, a record of the measured or calculated volume of natural gas vented to perform liquids unloading and equipment installed in the natural gas well(s) designed to automatically perform liquids unloading (e.g., foaming agent, velocity tubing, plunger lift, etc.) as specified in Appendix A Table A2.

Leak Detection and Repair

- (3) Maintain, for at least two years from each inspection, a record of each leak detection and repair inspection as specified in Appendix A Table A4.
- (4) Maintain, for at least two years from each inspection, a component leak concentration and repair form for each inspection as specified in Appendix A Table A5.

NOTE: Authority cited: Sections 38510, 38562, 39600, 39601, 39607, and 41511, Health and Safety Code. Reference: Sections 38560, 39600 and 41511, Health and Safety Code.

§ 95672. Reporting Requirements.

- (a) The requirements of this section do not apply to operators who are subject to the reporting requirements of Greenhouse Gas Mandatory Reporting Regulation for the parameters described below. Beginning January 1, 2018~~9~~, owners or operators of facilities listed in section 95666 subject to requirements specified in sections 95668 and 95669 shall report the following information to ARB or implementing Air Districts within the timeframes specified:

Flash Analysis Testing

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- (1) Within 90 days of performing flash analysis testing, report the test results, calculations, and a description of the separator and tank system as specified in Appendix A Table A1.-

Liquids Unloading of Natural Gas Wells

- (2) Annually, report the measured or calculated volume of natural gas vented to perform liquids unloading and equipment installed in the natural gas well(s) designed to automatically perform liquids unloading as specified in Appendix A Table A3.

Leak Detection and Repair

- (3) Once per calendar year, report the results of each leak detection inspection conducted during the calendar year as specified in Appendix A Table A4.
- (4) Once per calendar year, report the initial and final component leak concentration(s) for each inspection conducted during the calendar year as specified in Appendix A Table A5.

- (b) Reports may be e-mailed electronically to ARB with the subject line "O&G GHG Regulation Reporting" to oil&gas@arb.ca.gov or mailed to:

California Air Resources Board
Attention: O&G GHG Regulation Reporting
Industrial Strategies Division
1001 I Street
Sacramento, California 95814

NOTE: Authority cited: Sections 38510, 38562, 39600, 39601, 39607, and 41511, Health and Safety Code. Reference: Sections 38560, 39600 and 41511, Health and Safety Code.

§ 95673. Implementation.

(a) *Implementation by ARB and by the Local Air Districts*

- (1) The requirements of this subarticle are provisions of state law and are enforceable by both ARB and the local air districts where equipment covered by this subarticle is located. Local air districts may incorporate the terms of this subarticle into local air district rules. An owner or operator of equipment subject to this subarticle must pay any fees assessed by a local air district for the purposes of recovering the district's cost of implementing and enforcing the requirements of this subarticle. Any penalties secured by a local air district as the result of an enforcement action that it undertakes to enforce

the provisions of this subarticle may be retained by the local air district.

- (2) The ARB Executive Officer, at his or her discretion, may enter into an agreement or agreements with any local air district to further define implementation and enforcement processes, including arrangements further specifying approaches for implementation and enforcement of this subarticle, and for information sharing between ARB and local air districts relating to this subarticle.
- (3) Implementation and enforcement of the requirements of this subarticle by a local air district may in no instance result in a standard, requirement, or prohibition less stringent than provided for by this subarticle, as determined by the Executive Officer. The terms of any local air district permit or rule relating to this subarticle do not alter the terms of this subarticle, ~~which remain as separate requirements for all sources subject to this subarticle.~~
- (4) ~~Implementation and enforcement of the requirements of this subarticle by a local air district, including inclusion or exclusion of any of its terms within any local air district permit, or within a local air district rule, or registration of a facility with a local air district or ARB, does not in any way waive or limit ARB's authority to implement and enforce upon the requirements of this subarticle.~~ A facility's permitting or registration status also in no way limits the ability of a local air district to enforce the requirements of this subarticle.

(b) Requirements for Regulated Facilities ~~Covered Entities~~

- (1) Local Air District Permitting Requirements
 - (A) Owners or operators of facilities or equipment regulated by this subarticle, and who are required by federal, state, or local law to hold local air district permits that cover those facilities or equipment shall ensure that their local air district permits for those facilities or equipment contain terms ensuring compliance with this article. This requirement applies to facilities or equipment upon issuance of any new local air district permit covering these facilities or equipment, or upon the scheduled renewal of an existing permit covering these facilities or equipment.
 - (B) If, after the effective date of this subarticle, any local air district amends or adopts permitting rules that result in additional equipment or facilities regulated by this subarticle becoming subject to local air district permitting requirements, then owners or operators of that equipment or facility must ensure that any applicable local air district permits for that equipment or facility ensures compliance with this subarticle upon issuance of any relevant permit.

Comment [YS2]: "Covered Entities" has a specific meaning in Cap & Trade which is inappropriate here. There is no definition of the term in this regulation.

(2) Registration Requirements

(A) Owners or operators of facilities or equipment that is regulated by this subarticle shall register the equipment at each facility by reporting the following information to ARB as specified in Appendix A Table A6 no later than January 1, 20~~20~~19, unless the local air district has established a registration or permitting program that collects at least the following information, and has entered into an MOU with ARB specifying how information is to be shared with ARB.

1. The owner or operator's name and contact information.
2. The address or location of each facility with equipment regulated by this subarticle.
3. A description of all equipment covered by this subarticle located at each facility including the following:
 - (a) The number of crude oil or natural gas wells at the facility.
 - (b) A list identifying all pressure vessels, tanks, separators, sumps, and ponds at the facility, including the size of each tank and separator in units of barrels.
 - (c) The annual crude oil, natural gas, and produced water throughput of the facility.
 - (d) A list identifying all reciprocating and centrifugal natural gas compressors at the facility,
 - (e) A count of all pneumatic devices and pumps at the facility.
4. The permit numbers of all local air district permits issued for the facility or equipment, and an identification of permit terms that ensure compliance with the terms of this subarticle, or an explanation of why such terms are not included.
5. An attestation that all information provided in the registration is provided by a party authorized by the owner or operator to do so, and that the information is true and correct.

(B) Updates to these reports, recording any changes in this information, must be filed with ARB, or, as relevant, with the local air district no later than January 1 of the calendar year after the year in which any information required by this subarticle has changed. ▸

(3) Owners or operators of equipment subject to this subarticle must comply with all the requirements of sections 95666, 95667, 95668, 95669, 95670,

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95671, 95672, and 95673 of this subarticle, regardless of whether or not they have complied with the permitting and registration requirements of this subsection.

NOTE: Authority cited: Sections 38510, 38562, 39600, 39601, 39603, 39607, and 41511, Health and Safety Code. Reference: Sections 38560, 39600, 40701, 40702, 41511, 42300, 42301, and 42311, Health and Safety Code.

§ 95674. Enforcement.

- (a) Failure to comply with the requirements of this subarticle at each individual piece of equipment subject to this subarticle constitutes a single, separate, violation of this subarticle.
- (b) Each day, or portion thereof, that an owner or operator is not in full compliance with the requirements of this subarticle is a single, separate, violation of this subarticle.
- (c) Each metric ton of methane emitted in violation of this subarticle constitutes a single, separate, violation of this subarticle.
- (d) Failure to submit any report required by this subarticle shall constitute a single, separate violation of this subarticle for each day or portion thereof that the report has not been received after the date the report is due.
- (e) Failure to retain and failure to produce any record that this subarticle requires to be retained or produced shall each constitute a single, separate violation of this subarticle for each day or portion thereof that the record has not been retained or produced.

(f) Submitting or producing inaccurate information required by this subarticle shall be a violation of this subarticle.

~~(f)(g)~~ Falsifying any information or record required to be submitted or retained by this subarticle, ~~or submitting or producing inaccurate information,~~ shall be a violation of this subarticle.

NOTE: Authority cited: Sections 38510, 38562, 38580, 39600, 39601, 39607, and 41511, Health and Safety Code. Reference: Sections 38560, 39600 and 41511, Health and Safety Code.

§ 95675. No Preemption of More Stringent Air District or Federal Requirements

This regulation does not preempt any more stringent requirements imposed by any Air District. Compliance with this subarticle does not excuse noncompliance with any Federal regulation. The ARB Executive Officer retains authority to determine whether

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an Air District requirement is more stringent than any requirement of this subarticle.

NOTE: Authority cited: Sections 38510, 38562, 39600, 39601 and 41511, Health and Safety Code. Reference: Sections 38560, 39600 and 41511, Health and Safety Code.

§ 95676. Severability

Each part of this subarticle is deemed severable, and in the event that any part of this subarticle is held to be invalid, the remainder of the subarticle shall continue in full force and effect.

NOTE: Authority cited: Sections 38510, 38562, 39600, 39601 and 41511, Health and Safety Code. Reference: Sections 38560, 39600 and 41511, Health and Safety Code.

Appendix A
Record Keeping and Reporting Forms

Table A1
Flash Analysis Testing Record Keeping and Reporting Form

Tank System ID:						
Testing Date:						
Facility Name:				Air District:		
Owner/Operator Name:				Signature*:		
Address:						
City:			State:		Zip:	
Contact Person:			Phone Number:			
Crude Oil or Condensate Flash Test and Calculation Results						
API Gravity	GOR (scf/bbl)	Molecular Weight	WT %	Sample Temp	Throughput	Metric Tons CH4/Yr
Produced Water Flash Test and Calculation Results						
GWR (scf/bbl)	Molecular Weight	WT %	Sample Temp	Throughput	Metric Tons CH4/Yr	
Days in Operation per Year:						
Combined Annual Methane Emission Rate:					MTCH4/Yr	
Separator and Tank System Description						
Total Number in Separator and Tank System				Total Number on Vapor Collection		
Wells:						
Pressure Vessels:						
Separators:						
Tanks:						
Sumps:						
Ponds:						

*By signing this form, I am attesting that I am authorized to do so, and that the

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information provided is true and correct.

**Table A2
Liquids Unloading Record Keeping and Reporting Form**

Facility Name:		Air District:	
Owner/Operator Name:		Signature*:	
Address:			
City:	State:	Zip:	
Contact Person:		Phone Number:	
Date	Well ID	Volume of Natural Gas Vented (Mcf)	Automation Equipment**

*By signing this form, I am attesting that I am authorized to do so, and that the information provided is true and correct.

**Automation equipment includes foaming agent, velocity tubing, plunger lift, etc.

**Table A3
Designated Critical Component Form**

Facility Name:		Air District:	
Owner/Operator Name:		Signature*:	
Address:			
City:	State:	Zip:	
Contact Person:		Phone Number:	
Component Description:			Approval Date:

*By signing this form, I am attesting that I am authorized to do so, and that the information provided is true and correct.

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**Table A4
Leak Detection and Repair Inspection
Record Keeping and Reporting Form**

Inspection Date:		
Facility Name:		Air District:
Owner/Operator Name:	Signature*:	
Address:		
City:	State:	Zip:
Contact Person:	Phone Number:	
Inspection Company Name:		
Total Number of Components Inspected:		
Number of Leaks per Leak Threshold Category		Percentage of Total Number Inspected
1,000 to 9,999 ppmv:		
10,000 to 49,999 ppmv:		
50,000 ppmv or Greater:		

*By signing this form, I am attesting that I am authorized to do so, and that the information provided is true and correct.

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**Table A5
Component Leak Concentration and Repair
Record Keeping and Reporting Form**

Inspection Date:			
Facility Name:		Air District:	
Owner/Operator Name:		Signature*:	
Address:			
City:		State:	Zip:
Contact Person:		Phone Number:	
Inspection Company Name:			
Method 21 Instrument Make/Model:			
Instrument Calibration Date:			
Component Type	Initial Leak Concentration (ppmv)	Repair Date	Concentration After Repair (ppmv)

*By signing this form, I am attesting that I am authorized to do so, and that the information provided is true and correct.

Appendix B

Calculation for Determining Vented Natural Gas Volume from Liquids Unloading of Natural Gas Wells

$$E_{scf} = \left(\frac{V * P_1 * T_2}{P_2 * T_1} \right) + (FR * HR)$$

Where:

E_{scf} is the natural gas emissions per event in scf

$V = \pi * r^2 * D$ (volume of the well)

$r = \frac{CD}{2}$ (radius of the well)

CD is the casing diameter in feet

D is the depth of the well in feet

P_1 is the shut-in pressure of the well in psia

P_2 is 14.7 psia (standard surface pressure)

T_1 is the temperature of the well at shut-in pressure in °F

T_2 is 60 °F (standard surface temperature)

FR is the metered flowrate of the well or the sales flowrate of the well in scf/hour

HR is the hours the well was left open to atmosphere during unloading

$$CH_4 \text{ emissions} = E_{scf} * MF_{CH_4} * MV * MW_{CH_4} * \left(\frac{\text{metric ton}}{2204.6 \text{ lb}} \right)$$

Where:

$CH_4 \text{ emissions}$ is in metric tons per event

$MF_{CH_4} = \frac{\text{lbmole } CH_4}{\text{lbmole gas}}$ (mole fraction of CH₄ in the natural gas)

$MV = \frac{1 \text{ lbmole gas}}{379.3 \text{ scf gas}}$ (molar volume)

$MW_{CH_4} = \frac{16 \text{ lb } CH_4}{\text{lbmole } CH_4}$ (molecular weight of CH₄)

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Appendix C

Test Procedure for Determining Annual Flash Emission Rate of Methane from Crude Oil, Condensate, and Produced Water

1. PURPOSE AND APPLICABILITY

In crude oil and natural gas production, flash emissions may occur when gas entrained in crude oil, condensate, or produced water is released from the liquids due to a decrease in pressure or increase in temperature, such as when the liquids are transferred from an underground reservoir to the earth's surface. This procedure is used for determining the annual flash emission rate from tanks used to separate, store, or hold crude oil, condensate or produced water. The laboratory methods required to conduct this procedure are used to measure methane and other gaseous compounds.

2. PRINCIPLE AND SUMMARY OF TEST PROCEDURE

This procedure is conducted by collecting one sample of crude oil or condensate and one sample of produced water upstream of a separator or tank where flashing may occur. Samples shall be collected under pressure and according to the methods specified in this procedure. If a pressure vessel is not available upstream of a separator or tank that can be used for collecting samples under pressure, sampling shall be conducted using a portable pressurized separator.

Two sampling methods are specified for collecting liquid samples while maintaining a positive pressure within a sampling cylinder to prevent flashing within the cylinder. The first method requires a double valve cylinder for collecting crude oil or produced water samples. The second method requires a cylinder equipped with a pressurized piston for collecting condensate or produced water samples. Both methods shall be conducted as specified in this procedure.

The laboratory methods specified for this procedure are based on American Standards and Testing Materials (ASTM), US Environmental Protection Agency (EPA), and Gas Processor Association (GPA) methods. These laboratory methods measure the volume and composition of gases that flash from the liquids, including a Gas-Oil or Gas-Water Ratio, as well as the molecular weight and weight percent of the gaseous compounds. The laboratory results are used with the crude oil or condensate or produced water throughput to calculate the mass of emissions that are flashed from the liquids per year.

3. DEFINITIONS

For the purposes of this procedure, the following definitions apply:

- 3.1** "Air Resources Board or ARB" means the California Air Resources Board.
- 3.2** "API Gravity" means a scale used to reflect the specific gravity (SG) of a fluid such as crude oil, condensate, produced water, or natural gas. The API gravity is calculated as $[(141.5/SG) - 131.5]$, where SG is the specific gravity of the fluid at 60°F, and where API refers to the American Petroleum Institute.
- 3.3** "Condensate" means hydrocarbon and other liquid either produced or separated from crude oil or natural gas during production and which condenses due to changes in pressure or temperature.
- 3.4** "Crude oil" means any of the naturally occurring liquids and semi-solids found in rock formations composed of complex mixtures of hydrocarbons ranging from one to hundreds of carbon atoms in straight and branched chain rings.
- 3.5** "Double valve cylinder" means a metal cylinder equipped with valves on either side for collecting crude oil or produced water samples.
- 3.6** "Emissions" means the discharge of natural gas into the atmosphere.
- 3.7** "Emulsion" means any mixture of crude oil, condensate, or produced water with varying amounts of natural gas contained in the liquid.
- 3.8** "Flash or flashing" means a process during which gas entrained in crude oil, condensate, or produced water under pressure is released when subject to a decrease in pressure or increase in temperature, such as when liquids are transferred from an underground reservoir to a tank on the earth's surface.
- 3.9** "Gas-Oil Ratio (GOR)" means a measurement used to describe the volume of gas that is flashed from a barrel of crude oil or condensate.
- 3.10** "Gas-Water Ratio (GWR)" means a measurement used to describe the volume of gas that is flashed from a barrel of produced water.
- 3.11** "Natural gas" means a naturally occurring mixture or process derivative of hydrocarbon and non-hydrocarbon gases, of which its constituents include methane, carbon dioxide, and heavier hydrocarbons. Natural gas may be field quality (which varies widely) or pipeline quality.
- 3.12** "Operating pressure" means the steady-state pressure of the vessel from which a sample is collected. If no pressure gauge is available or the

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sampling train pressure gauge reading is greater than +/- 5 psig of the vessel pressure, the sampling train pressure gauge reading shall be used to record the steady state pressure on Form 1.

- 3.13** "Operating temperature" means the steady-state temperature of the vessel from which a sample is collected. If no temperature gauge is available or the sampling train temperature gauge reading is greater than +/- 4⁰F of the vessel temperature, the sampling train temperature gauge reading shall be used to record the steady state temperature on Form 1.
- 3.14** "Percent water cut" means the volume percentage of produced water to crude oil or condensate.
- 3.15** "Piston cylinder" means a metal cylinder containing an internal pressurized piston for collecting condensate or produced water samples.
- 3.16** "Portable pressurized separator" means a sealed vessel that can be moved from one location to another by attachment to a motor vehicle without having to be dismantled and is used for separating and sampling crude oil, condensate, or produced water at the steady-state temperature and pressure of the separator and tank system required for sampling.
- 3.17** "Pressure vessel" means any vessel rated, as indicated by an ASME pressure rating stamp, and operated to contain normal working pressures of at least 15 psig without vapor loss to the atmosphere and may be used for the separation of crude oil, condensate, produced water, or natural gas..
- 3.18** "Produced water" means water recovered from an underground reservoir as a result of crude oil, condensate, or natural gas production and which may be recycled, disposed, or re-injected into an underground reservoir.
- 3.19** "Separator" means any tank designed to contain a normal working pressure of less than 15 psig and is used for the separation of crude oil, condensate, produced water, or natural gas.
- 3.20** "Separator and tank system" means any combination of pressure vessels or tanks used to separate, store, or hold emulsion, crude oil, condensate, or produced water with varying quantities of natural gas.
- 3.21** "Tank" means any container constructed primarily of non-earthen materials used for the purpose of storing or holding emulsion, crude oil, condensate, or produced water.
- 3.22** "Throughput" means the average volume of crude oil, condensate, or produced water expressed in units of barrels per day.

4. BIASES AND INTERFERENCES

- 4.1 The sampling method used to collect a liquid sample will have an impact on the final results reported. Liquid samples shall be collected in accordance with the sampling procedures specified in this procedure.
- 4.2 The location from where a sample is collected will have an impact on the final results reported. Liquid samples shall be collected from a pressure vessel or portable pressurized separator as specified in this procedure.
- 4.3 Collecting liquid samples from a pressure vessel or portable pressurized separator that periodically drains liquids will have an impact on the final results reported. Samples shall not be collected from a pressure vessel or portable pressurized separator while it periodically drains liquids.
- 4.4 Collecting liquid samples using an empty double valve cylinder without displacing an immiscible liquid from the cylinder will allow gases to flash from the cylinder and will have an impact on the final results reported. Samples collected using a double valve cylinder shall be collected as specified in this procedure.
- 4.5 Displacing liquids from a double valve cylinder that are reactive and not immiscible with the sample liquid collected will result in gas composition or volume errors and will affect the final results reported. Displacement liquids shall be pre-tested by a laboratory to verify that the liquid is non-reactive and is immiscible with the sample liquid collected.
- 4.6 Non-calibrated equipment including pressure or temperature gauges will have an impact the final results reported. All pressure and temperature measurements shall be conducted with calibrated gauges as specified in this procedure.
- 4.7 Conducting laboratory procedures other than those specified in this procedure will have an impact on the final results reported. All laboratory methods and quality control and quality assurance procedures shall be conducted as specified in this procedure.

5. SAMPLING EQUIPMENT SPECIFICATIONS

- 5.1 A pressure gauge capable of measuring liquid pressures of less than 50 pound per square inch gauge pressure within +/-10% accuracy.
- 5.2 A pressure gauge capable of measuring liquid pressures greater than 50 pounds per square inch gauge pressure within +/- 5% accuracy.
- 5.3 A temperature gauge capable of reading liquid temperature within +/- 2^oF

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and within a range of 32^oF to 250^oF.

- 5.4 A graduated cylinder capable of measuring liquid in at least five (5) milliliter increments with at least the same capacity as the double valve cylinder used for liquid sampling.
- 5.5 A portable pressurized separator that is sealed from the atmosphere and is used for collecting crude oil, condensate, and produced water samples at the steady state temperature and pressure of the separator and tank system being sampled.

6. SAMPLING EQUIPMENT

- 6.1 A double valve cylinder or a piston cylinder.
- 6.2 A graduated cylinder for use with double valve cylinder.
- 6.3 A waste container suitable for capturing and disposing sample liquid.
- 6.4 High-pressure rated metal components and control valves that can withstand the temperature and pressure of the pressure vessel or portable pressurized separator being sampled.
- 6.5 Pressure gauges with minimum specifications listed in section 5.
- 6.6 A temperature gauge with minimum specifications listed in section 5.
- 6.7 If required, a portable pressurized separator with minimum specifications listed in section 5.

7. DATA REQUIREMENTS

- 7.1 The data requirements required to conduct this procedure shall be provided by the facility owner or operator prior to conducting the sampling methods specified in this procedure. Field sampling shall not be performed until all data requirements are provided as listed in section 7.2 and as specified on Form 1.
- 7.2 For each pressure vessel or portable pressurized separator sampled, the following data shall be recorded on the sample cylinder identification tag and on Form 1 prior to conducting a sample collection method:
 - (a) The separator identification number or description.,
 - (b) The separator temperature and pressure if available.
 - (c) Crude oil or condensate throughput.
 - (d) Produced water throughput.

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- (e) Percent water cut
- (f) Gas flow rate of three phase separator if available.
- (g) Number of wells in the separator and tank system.
- (h) Days of operation per year.

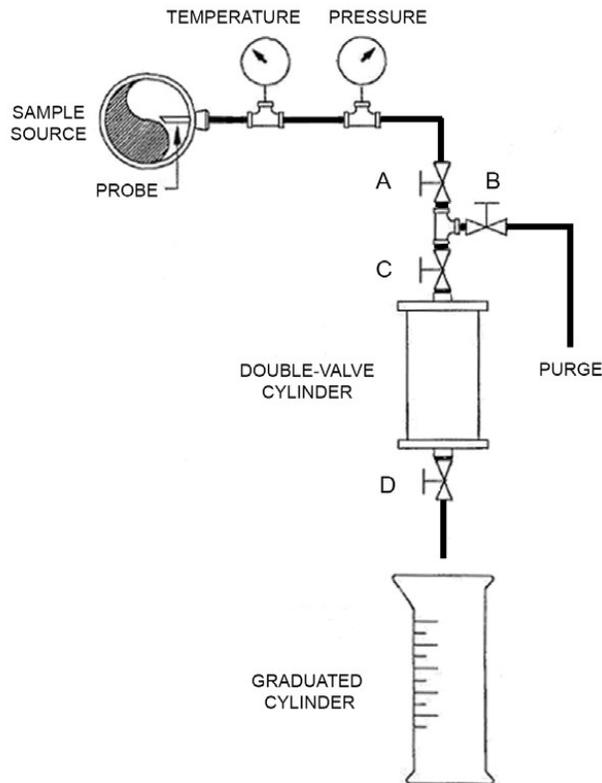
8. DOUBLE VALVE CYLINDER SAMPLING METHOD

- 8.1** The double valve cylinder sampling method is used for collecting crude oil or produced water samples and is not applicable for collecting samples of condensate. Liquid samples of condensate shall be collected using the piston cylinder sampling method specified in section 9.
- 8.2** Fill the double valve cylinder with non-reactive liquid that is immiscible with the liquid to be collected to prevent flashing within the cylinder and to prevent the displacement liquid from mixing or attaining homogeneity with the sample liquid.
- 8.3** Locate a pressure vessel immediately upstream of the separator or tank required for testing and verify it is pressurized to at least 15 psig. Install a portable pressurized separator if no pressure vessel is available immediately upstream of the separator or tank that can be used to collect crude oil and produced water samples.
- 8.4** Record the sample collection data requirements specified in section 7 on the cylinder identification tag and on Form 1.
- 8.5** Locate the sampling port(s) for collecting liquid samples.
- 8.6** Connect the sampling train as illustrated in Figure 1 to the sampling port on the pressure vessel or portable pressurized separator while minimizing tubing between the purge valve and cylinder as shown. Bushings or reducers may be required.
- 8.7** Purge the sampling train: Place the outlet of valve B into the waste container. With valves B, C and D closed, slowly open valve A completely, and then slowly open valve B to purge the sample train until a steady stream of liquid without gas pockets is observed, and then close valve B.
- 8.8** Prepare for sampling: Orient the double-valve cylinder in the vertical position so that displacement liquid can readily be discharged from the cylinder. Note that the orientation of valves C and D depend on the type of sample being collected and the liquid used for displacement. Based on density differences in liquids, the heaviest liquid must be introduced or expelled from the bottom of cylinder. See Figure 2
- 8.9** Slowly open valve C to the full open position and place the outlet of valve D

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into the graduated cylinder.

Figure 1: Double Valve Cylinder Sampling Train



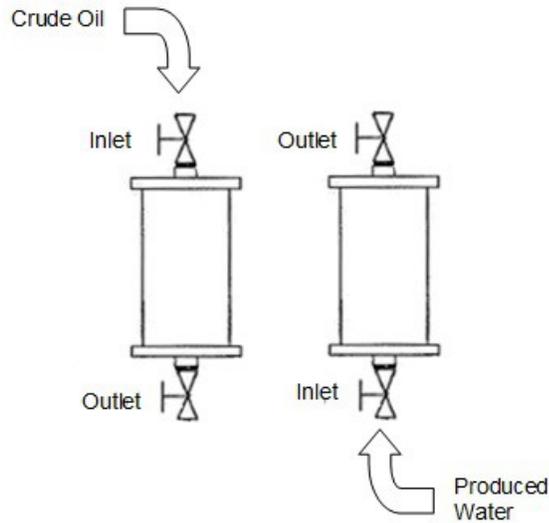
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8.10 Collect liquid sample: Slowly open valve D to allow a slow displacement of the non-reactive displacement liquid at a rate between 150 and 200 milliliters per minute (3 drips per second) to prevent the sample liquid from flashing inside the cylinder. Continue until 80 to 95 percent of the displacement liquid is measured in the graduated cylinder, then close valves D and C.

8.11 Record the steady state pressure and temperature on Form 1.

Figure 2: Double Valve Cylinder Orientation



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- 8.12 Record the double valve cylinder volume and the volume of liquid sampled on the cylinder identification tag and on Form 1.
- 8.13 Disconnect the sample cylinder from the sampling train and verify that both valves are sealed.
- 8.14 Remove sampling train: With valves D and C closed, purge any remaining liquid in the sampling train through valve B. Then close valves A and B. Disconnect the sampling train from the pressure vessel or portable pressurized separator.
- 8.15 Verify that all of the data requirements are recorded on the cylinder identification tag and on Form 1.
- 8.16 Transport the cylinder to the laboratory for conducting the laboratory methods specified in section 12.

9. PISTON CYLINDER SAMPLING METHOD

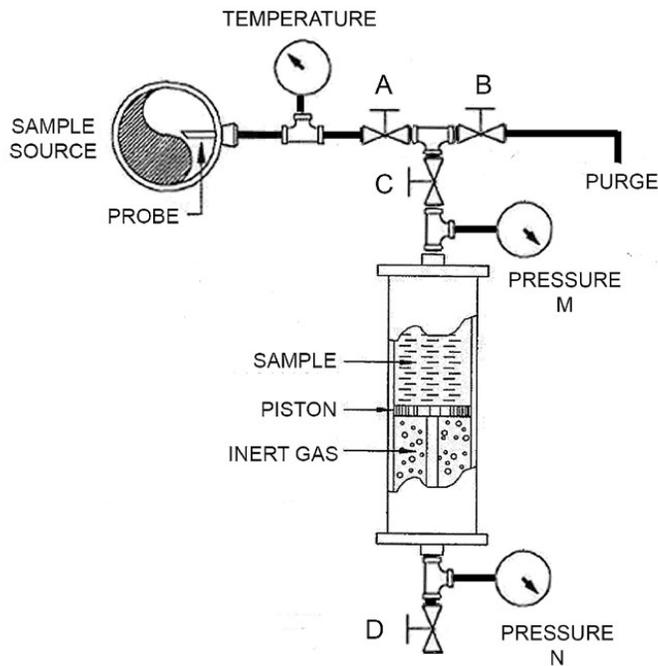
- 9.1 Locate a pressure vessel immediately upstream of the separator or tank required for testing and verify it is pressurized to at least 15 psig. Install a portable pressurized separator if no pressure vessel is available immediately upstream of the separator or tank that can be used to collect condensate and

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produced water samples.

- 9.2 Record the sample collection data requirements specified in section 7 on the cylinder identification tag and on Form 1.
- 9.3 Locate the sampling port(s) for collecting liquid samples.
- 9.4 Connect the sampling train as illustrated in Figure 3 to the pressure vessel or pressurized portable separator while minimizing tubing between the purge valve and cylinder as shown. Bushings or reducers may be required.
- 9.5 Purge the sampling train: Place the outlet of valve B into the waste container. With valves B, C and D closed, slowly open valve A completely, and then slowly open valve B to purge the sample train until a steady stream of liquid without gas pockets is observed, and then close valve B.

Figure 3: Piston Cylinder Sampling Train



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- 9.6 Prepare for sampling: With valve B closed and valve A open, slowly open

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valve C to the full open position, then slowly open valve D until the pressure indicated on Gauge N is equal to Gauge M.

- 9.7 Collect liquid sample: Slowly open Valve D to allow liquid to enter the piston cylinder at a rate of 150 to 200 milliliters per minute until 80 to 95 percent of the cylinder is filled with liquid. Then close valves C and D.
- 9.8 Record the steady state pressure and temperature on Form 1.
- 9.9 Record the cylinder volume and volume of liquid sampled on the cylinder identification tag and on Form 1.
- 9.10 Disconnect the sample cylinder from the sampling train and verify that both valves are sealed.
- 9.11 Remove sampling train: Place the outlet of valve B into the waste container and slowly open valve B to purge all liquid from the sampling train. Then close valves A and B. Disconnect the sampling train from the pressure vessel or portable pressurized separator.
- 9.12 Verify that all of the data requirements are recorded on the cylinder identification tag and on Form 1.
- 9.13 Transport the cylinder to the laboratory for conducting the laboratory methods as specified in section 12.

10. LABORATORY REQUIREMENTS AND METHODS

10.1 Quality Control, Quality Assurance, and Field Records

- (a) Quality control requirements shall be performed in accordance with the laboratory methods specified in this test procedure.
- (b) Each day of sampling, at least one field duplicate sample shall be collected per matrix type (crude oil, condensate, produced water). The field duplicate samples are collected to demonstrate acceptable method precision by the laboratory at the time of analysis. Through this process the laboratory can evaluate the consistency of sample collection and analytical measurements as well as matrix variation. The laboratory should establish control limits based on relative percent difference to evaluate the validity of the measured results.
- (c) Laboratory procedures shall be in place for establishing acceptance criteria for field activities described in sections 7, 8 and 9 of this procedure. All deviations from the acceptance criteria shall be documented. Deviations from the acceptance criteria may or may not affect data quality.

- (d) Laboratory procedures shall be in place to ensure that field staff have been trained on the sampling methods specified in this procedure and retrained on sampling methods if this procedure changes.
- (e) Field records shall provide direct evidence and support necessary for technical interpretations, judgments, and discussions concerning project activities and shall, at a minimum, include a completed copy of Form 1 as provided in this procedure for each sample collected.

10.2 Laboratory Flash Analysis Equipment

- (a) All laboratory equipment used to conduct measurements shall be calibrated in accordance with the manufacturer specifications and in accordance with the laboratory methods specified in this procedure.
- (b) Any chromatograph system that allows for the collection, storage, interpretation, adjustment, or quantification of chromatograph detector output signals representing relative component concentrations may be used to conduct this procedure. All test methods and quality control requirements shall be conducted in accordance with each laboratory method specified.
- (c) The minimum reporting limit of the instruments used for reporting gaseous compounds must be at least 100 parts per million (ppm) for both hydrocarbon and fixed gases.
- (d) The laboratory apparatus used for heating sample cylinders must be capable of heating and maintaining the steady state temperature measured at the time of sampling as reported on Form 1.
- (e) The laboratory apparatus used for collecting gas flashed from liquids must be capable of precisely measuring gas volume, temperature, and pressure.
- (f) The laboratory vessel used for collecting gas flashed from liquids must be capable of collecting or storing gas for chromatography analysis without sample degradation and without compromising the integrity of the sample.
- (g) Additional sample preparation guidance can be found in GPA 2174, GPA 2261 and GPA 2177.

10.3 Laboratory Flash Analysis Procedure

- (a) Heat the sample cylinder to the sample collection temperature as reported on Form 1 and allow the temperature to stabilize for a minimum of 30 minutes.

- (b) After the cylinder temperature has stabilized, open the cylinder and collect all gas flashed from the liquid for a minimum of 30 minutes while monitoring the gas pressure and temperature.
- (c) After all gas has flashed from the cylinder for a minimum of 30 minutes, ensure that the gas pressure has stabilized at ambient pressure with no changes in gas pressure observed. In the event that the gas pressure changes or remains above ambient pressure after 30 minutes, continue to allow the cylinder to flash until the gas pressure stabilizes at ambient pressure. The collected gas sample can now be used for gas chromatography analysis.
- (d) At least 0.20 standard cubic feet of sample gas per barrel of liquid is required to conduct the laboratory procedures specified in this procedure. If insufficient gas volume is collected during the flash analysis procedure, additional laboratory analyses cannot be completed while maintaining the accuracy requirements specified in this procedure.
- (e) After the flash analysis procedure is completed, remove all liquid from the sample cylinder and measure the total liquid volume and volume fractions (for example, 300ml total volume, 285 ml crude oil, 15 ml water) and adjust for any displacement liquid that was not displaced during the sample collection procedure.

10.4 Gas-Oil and Gas-Water Ratio Calculation Methodology

- (a) Convert the volume of gas vapor measured during the laboratory flash analysis procedure to standard atmospheric conditions as derived from the Ideal Gas Law as follows:

$$Vapor_{Std} = \frac{(Volume_{Lab})(459.67 + 60F)(P_{Lab})}{(459.67 + T_{Lab})(14.696)} \quad \text{Equation 4}$$

Where:

Vapor Std = Standard cubic feet of vapor at 60°F and 14.696 psia. Volume Lab = Volume of vapor measured at laboratory conditions. TLab = Temperature of vapor at laboratory conditions, °F.

PLab = Pressure of vapor at laboratory conditions, psia.

459.67 = Conversion from Fahrenheit to Rankine

60F = Standard temperature of 60°F.

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14.696 = Standard atmospheric pressure, psia.

- (b) Convert the volume of crude oil or produced water measured after conducting the laboratory flash analysis procedure to standard conditions as follows:

$$Liquid_{Std} = \left(\frac{Mass_{Liquid}}{Density_{60F}} \right) \left(\frac{1 \text{ gallon}}{3785.412 \text{ ml}} \right) \left(\frac{1 \text{ STB}}{42 \text{ gallons}} \right) \quad \text{Equation 5}$$

Where:

Liquid Std = Standard volume of post-flash liquid at 60°F, barrels. Mass Liquid = Mass of liquid at laboratory conditions, grams.

Density 60F = Density of liquid at 60°F, grams/milliliter.

3785.412 = Conversion from milliliter to US gallons.

STB = Stock Tank Barrel.

42 gallons = Volume of a stock tank barrel at 60°F.

- (d) Calculate the Gas-Oil or Gas-Water Ratio as follows:

$$G = \frac{(Vapor_{Std})}{(Liquid_{Std})} \quad \text{Equation 6}$$

Where:

G = The Gas-Oil or Gas-Water Ratio.

Vapor Std = Standard cubic feet of vapor at 60°F and 14.696 psia. Liquid Std = Standard volume of post-flash liquid at 60°F, barrels.

Note: For condensate, the volume of liquid used for calculating the Gas-Oil Ratio shall be obtained from the piston cylinder measurement reported on Form 1 at the time of liquid sampling due to the rapid flashing of condensate that occurs during the laboratory flash analysis procedure.

10.5 Analytical Laboratory Methods and Requirements

The following methods are required to evaluate and report flash emission rates from crude oil, condensate, and produced water.

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- (a) Oxygen, Nitrogen, Carbon Dioxide, Hydrogen Sulfide (High-Level), Methane, Ethane, Propane, i-Butane, n-Butane, i-Pentane, n-Pentane, Hexanes, Heptanes, Octanes, Nonanes, Decanes+: Evaluate per GPA 2286, ASTM D- 1945, ASTM D-3588, and ASTM D-2597 (GC/TCD).
- (b) BTEX: Evaluate per EPA 8021 B (GC/FID) or use ASTM D-3170, GPA 2286, EPA 8260B, EPA TO-14, and EPA TO-15 as alternate methods.
- (c) API Gravity of whole oil at 60°F by ASTM D 287 (Hydrometer Method), ASTM D 4052 (Densitometer), D 5002 (Densitometer), or ASTM D 70 (Pycnometer).

Note: if water is entrained in sample, use ASTM D 287. If needed calculate Specific Gravity 60/60°F = 141.5 / (131.5 + API Gravity at 60°F)

- (d) Specific Gravity of Produced Water at 60°F by ASTM D 287 (Hydrometer Method), ASTM D 4052 (Densitometer), D 5002 (Densitometer), or ASTM D 70 (Pycnometer). If needed calculate API at 60°F = (141.5 / SG at 60°F) - 131.5
- (e) Molecular Weight of gaseous phase by calculation per ASTM D-3588.
- (f) Water and Sediment in Crude Oil by Centrifuge Method per ASTM D-4007.

10.6 Nitrogen and Oxygen Correction

Samples containing oxygen may be an indication that ambient air was introduced during the sample collection or laboratory procedures. For the purpose of this procedure, the detection of oxygen shall be assumed to have been contributed by ambient air that was not contained in the original liquid sample. Any detectable amount of oxygen requires a result for nitrogen to be corrected and the result for oxygen to be reported as zero as follows:

- (a) For the purposes of this procedure, ambient air contains 79% nitrogen and 21% oxygen.
- (b) Correct the amount of nitrogen contained in the sample as follows:

$$Correction_{N_2} = \%N_2 - \left(\frac{79}{21} x \%O_2 \right) \quad \text{Equation 7}$$

Where:

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Correction N2 = Corrected value of nitrogen in the sample.
%N2 = Mole percent of nitrogen in the sample.
%O2 = Mole percent of oxygen in the sample.

- (c) If the corrected value for nitrogen calculated in section 10.6(b) is less than or equal to zero, report a value of zero for nitrogen and zero for oxygen and normalize all remaining values to 100% after removing the contributions of nitrogen and oxygen from the summed total; or,
- (d) If the corrected value for nitrogen calculated in section 10.6(b) is greater than zero, use the value for nitrogen calculated in section 10.6(b) and zero for oxygen and normalize all remaining values to 100%.

11. CALCULATING RESULTS

The following calculations are performed in conjunction with the data requirements specified in section 7 and the laboratory reports specified in section 12. The same calculations are used for crude oil, condensate, and produced water.

11.1 Calculate the volume of gas flashed from the liquid per year using the Gas Oil or Gas Water Ratio obtained from the laboratory report as follows:

$$Ft^3 / Year = (G) \left(\frac{Barrels}{Day} \right) \left(\frac{Days}{Year} \right) \quad \text{Equation 1}$$

Where:

$Ft^3/Year$ = standard cubic feet of gas produced per year
G = Gas Oil or Gas Water Ratio (from laboratory report)
Barrels/Day = barrels per day of liquid (Form 1)
Days/Year = days of operation per year (Form 1)

11.2 Convert the gas volume to pounds as follows: **Equation 2**

$$Mass_{Gas} / Year = \left(\frac{Ft^3}{Year} \right) \left(\frac{gram}{gram - mole} \right) \left(\frac{gram - mole}{23.690 l} \right) \left(\frac{28.317 l}{Ft^3} \right) \left(\frac{lb}{454 grams} \right)$$

Where:

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Mass Gas /Year = pounds of gas per year
Ft³/Year = cubic feet of gas produced per year (Equation 1)
Gram/Gram-Mole = Molecular weight (from laboratory report)
23,690 l/gr-mole = molar volume of ideal gas at 14.696 psi and 60⁰F

11.3 Calculate the annual mass of methane as follows:

$$Mass_{Methane} / Year = \left(\frac{WT\% \text{ Methane}}{100} \right) \left(\frac{Mass_{Gas}}{Year} \right) \left(\frac{metric \ ton}{2205 \ lb} \right) \quad \text{Equation 3}$$

Where:

Mass Methane /Year = metric tons of methane
Mass Gas /Year = pounds of gas per year (Equation 2)
WT% Methane = Weight % of methane (from laboratory report)

12. LABORATORY REPORTS

- 12.1 The results of this procedure are used by owners or operators of separator and tank systems to report annual methane flash emissions to ARB. The following information shall be compiled as a report by the laboratory conducting this procedure and provided to the owner or operator each time flash analysis testing is conducted:
- (a) A sketch or diagram of the separator and tank system depicting the sampling location; and,
 - (b) A copy of Form 1 as specified in this procedure for each liquid sample collected; and,
 - (c) The laboratory results for each liquid sample evaluated as specified in section 12.4; and,
 - (d) Other documentation or information necessary to support technical interpretations, judgments, and discussions.
- 12.2 Reports shall be made available to the owner or operator no later than 60 days from the date of liquid sampling.

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- 12.3 Reports shall be maintained by the laboratory conducting this procedure for a minimum of five (5) years from the date of liquid sampling and additional copies shall be made available at the request of the owner or operator.
- 12.4 Laboratory reports shall include, at minimum, a listing of results obtained using the laboratory methods specified in this procedure and as specified in Table 1.

Table 1: Laboratory Data Requirements

WT% CO ₂ , CH ₄
WT% C ₂ -C ₉ , C ₁₀ +
WT% BTEX
WT% O ₂
WT% N ₂
WT% H ₂ S
Molecular Weight of gas sample (gram/gram-mole)
Liquid phase specific gravity of produced water
Gas Oil or Gas Water Ratio (scf/stock tank barrel)
API gravity of whole oil or condensate at 60 ^o F
Water and Sediment of whole oil (ASTM D-4007)
Post-Test Cylinder Water Volume
Post-Test Cylinder Oil Volume

13. ALTERNATIVE TEST PROCEDURES, SAMPLING METHODS OR LABORATORY METHODS

Alternative test procedures, sampling methods, or laboratory methods other than those specified in this procedure shall only be used if prior written approval is obtained from ARB. In order to secure ARB approval of an alternative test procedure, sampling method, or laboratory method, the applicant is responsible for demonstrating to the ARB's satisfaction that the alternative test procedure, sampling method, or laboratory method is equivalent to those specified in this test procedure.

- (1) Such approval shall be granted on a case-by-case basis only. Because of the evolving nature of technology and procedures and methods, such approval shall not be granted in subsequent cases without a new request for approval and a new demonstration of equivalency.

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- (2) Documentation of any such approvals, demonstrations, and approvals shall be maintained in the ARB files and shall be made available upon request.

13. REFERENCES

ASTM D-70	<i>Standard Test Method for Density of Semi-Solid Bituminous Materials (Pycnometer Method)</i>
ASTM D-287	<i>Standard Test Method for API Gravity of Crude Petroleum and Petroleum Products (Hydrometer Method)</i>
ASTM D-1945M	<i>Standard Test Method for Analysis of Natural Gas by Gas Chromatography</i>
ASTM D-2597	<i>Standard Test Method for Analysis of Demethanized Hydrocarbon Liquid Mixtures Containing Nitrogen and Carbon Dioxide by Gas Chromatography</i>
ASTM D-3710	<i>Standard Test Method for Boiling Range Distribution of Gasoline and Gasoline Fractions by Gas Chromatography</i>
ASTM D-3588	<i>Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels</i>
ASTM D-4007	<i>Standard Test Method for Water and Sediment in Crude Oil by the Centrifuge Method</i>
ASTM D-4052	<i>Standard Test Method for Density, Relative Density, and API Gravity of Liquids by Digital Density Meter</i>
ASTM D-5002	<i>Standard Test Method for Density and Relative Density of Crude Oils by Digital Density Analyzer</i>
ASTM D-5504	<i>Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Chemiluminescence</i>
ASTM D-6228	<i>Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Flame Photometric Detection</i>
EPA Method 15	<i>Determination of Hydrogen Sulfide, Carbonyl Sulfide, and Carbon Disulfide Emissions from Stationary Sources</i>

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EPA Method 16	<i>Semicontinuous Determination of Sulfur Emissions from Stationary Sources</i>
EPA Method 8021B	<i>Aromatic and Halogenated Volatiles By Gas Chromatography Using Photoionization And/Or Electrolytic Conductivity Detectors</i>
EPA Method 8260B	<i>Volatile Organic Compounds By Gas Chromatography/Mass Spectrometry (GC/MS)</i>
EPA Method TO-14	<i>Determination Of Volatile Organic Compounds (VOCs) In Ambient Air Using Specially Prepared Canisters With Subsequent Analysis By Gas Chromatography</i>
EPA Method TO-15	<i>Determination Of Volatile Organic Compounds (VOCs) In Air Collected In Specially-Prepared Canisters And Analyzed By Gas Chromatography/Mass Spectrometry (GC/MS)</i>
GPA 2174	<i>Analysis Obtaining Liquid Hydrocarbon Samples For Analysis by Gas Chromatography</i>
GPA 2177	<i>Analysis of Natural Gas Liquid Mixtures Containing Nitrogen and Carbon Dioxide by Gas Chromatography</i>
GPA 2261	<i>Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography</i>
GPA 2286	Method for the Extended Analysis of Natural Gas and Similar Gaseous Mixtures by Temperature Program Gas Chromatography
SCAQMD 307	South Coast Air Quality Management District Determination of Sulfur in a Gaseous Matrix

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FORM 1
Flash Analysis Testing Field Data Form

Date of Testing:	
Production Company Name:	
Address:	
City:	
Contact:	Phone:
Sampling Company Name:	
Address:	
City:	
Contact:	Phone:
Portable Pressurized Separator ID:	
Pressure Vessel ID:	
Steady State Pressure:	psig
Steady State Temperature:	°F
Crude Oil or Condensate Throughput:	Barrels/Day
Produced Water Throughput:	Barrels/Day
Gas Flow Rate (if metered):	Mcf/Day
Days of Operation of Separator and Tank System per Year:	
Percent Water Cut: %	Number of wells in system:
Sample Type (circle one): crude oil condensate produced water	
Sample Cylinder ID Number:	
Cylinder Type:	Displacement Liquid:
Cylinder Volume: ml	Volume of Liquid Collected: ml