Appendix A:

PROPOSED REGULATION ORDER

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

(Note: The entire text of sections 95665, 95666, 95667, 95668, 95669, 95670, 95671, 95672, 95673, 95674, 95675, and 95676, set forth below is new language in "normal type" proposed to be added to title 17, California Code of Regulations.)

Adopt new Subarticle 13, and sections 95665, 95666, 95667, 95668, 95669, 95670, 95671, 95672, 95673, 95674, 95675, 95676, Appendix A, Appendix B, and Appendix C, title 17, California Code of Regulations, to read as follows:

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 38551, 38560, 39600 and 41511, Health and Safety Code.

§ 95666. Applicability.

(a) 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 38551, 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) “Circulation tank” means a tank or portable tank used to circulate, store, or hold liquids or solids from a crude oil or natural gas well during or following a well stimulation treatment.

(7) "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) “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) “Condensate” means hydrocarbon or other liquid, excluding steam, either produced or separated from crude oil or natural gas during production and which condenses due to changes in pressure or temperature.

(10) “Commercial quality natural gas” means a mixture of gaseous hydrocarbons with at least 80 percent methane by volume and less than 10 percent by weight volatile organic compounds and meets the criteria specified in Public Utilities Commission General Order 58-A.

(11) “Component” means a valve, fitting, flange, threaded-connection, process drain, stuffing box, pressure-vacuum valve, pipes, seal fluid system, diaphragm, hatch, sight-glass, meter, open-ended line, well casing, pneumatic device, pneumatic pump, or reciprocating compressor rod packing or seal.

(12) “Critical component” means any component that would require the shutdown of a critical process unit if that component was shutdown or disabled.

(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.

(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.

(15) “Emissions” means the discharge of natural gas into the atmosphere.

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

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

(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:

(A) Are under the same ownership or operation, or which are owned or operated by entities which are under common control;

(B) 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,

(C) Are located on one or more contiguous or adjacent properties.

(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, 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.

(21) “Fuel gas system” means, for the purposes of this subarticle, any system that supplies natural gas as a fuel source to on-site natural gas powered equipment other than a vapor control device.

(22) “Gas disposal well” means, for the purpose of this subarticle, any well that is used for the subsurface injection of natural gas for disposal.

(23) “Gauge tank” means a tank found upstream of a separator and tank system which is used for measuring the amount of liquid produced by an oil well and receives or stores crude oil, condensate, or produced water.

(24) "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 or a permanent support surface when access is required from the platform.

(25) "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.

(26) “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.

(27) “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 the standards specified in this subarticle and within the timeframes specified in this subarticle.

(28) “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.

(29) “Natural gas” means a naturally occurring mixture or process derivative 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.

(30) "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.

(31) “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.

(32) “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.

(33) "Natural gas transmission pipeline" means 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).

(34) “Natural gas underground storage” means all equipment and components associated with the temporary subsurface storage of natural gas in depleted crude oil or natural gas reservoirs or salt dome caverns. Natural gas storage does not include gas disposal wells.

(35) “Offshore” means all marine waters located within the boundaries of the State of California.

(36) “Onshore” means all lands located within the boundaries of the State of California.

(37) “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.

(38) “Owner” means the entity that owns or operates components or equipment to which this subarticle applies.

(39) "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.

(40) “Pneumatic device” means an automation device that uses natural gas, compressed air, or electricity to control a process.

(41) “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.

(42) "Pond" means an excavation or impoundment for the storage and disposal of produced water and which is not used for crude oil separation or processing.

(43) “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.

(44) "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.

(45) "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.

(46) "Pressure separator" means a pressure vessel used for the primary purpose of separating crude oil and produced water or for separating natural gas and produced water.

(47) "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 vapor loss to the atmosphere.

(48) “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.

(49) “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.

(50) “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.

(51) “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.

(52) “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.

(53) “Separator” means any tank or pressure separator used for the primary purpose of separating crude oil and produced water or for separating natural gas, condensate, and produced water. In crude oil production a separator may be referred to as a Wash Tank or as a three-phase separator. In natural gas production a separator may be referred to as a heater/separator.

(54) "Separator and tank system" means the first separator in a crude oil or natural gas production system and any tank or sump connected directly to the first separator.

(55) "Successful repair" means tightening, adjusting, or replacing equipment or a component for the purpose of stopping or reducing fugitive leaks below the minimum leak threshold or emission flow rate standard specified in this subarticle.

(56) “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.

(57) “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.

(58) "Unsafe-to-Monitor Components" means components installed at locations that would prevent the safe inspection or repair of components as defined by OSHA standards or in provisions for worker safety found in 29 CFR 1910.

(59) “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 to a processing, sales gas, or fuel gas system; to a gas disposal well; or to a vapor control device.

(60) “Vapor control device” means destructive or non-destructive equipment used to control emissions.

(61) “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.

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

(63) ”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.

(64) “Well casing vent” means an opening on a well head that blocks or allows natural gas to flow to the atmosphere or to a vapor collection system.

(65) “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 38551, 38560, 39600 and 41511, Health and Safety Code

§ 95668. Standards.

The following standards apply at all times to facilities listed in section 95666. The availability of an exemption for any particular component or facility, or compliance with one of the standards, does not exempt the owner or operator of a facility from complying with other standards for equipment or processes located at a facility.

(a) *Separator and Tank Systems*

(1) Except as provided in section 95668(a)(2), the following requirements apply to separator and tank systems located at facilities listed in section 95666.

(2) The requirements of section 95668(a) do not apply to the following:

(A) Separator and tank systems that receive less than 50 barrels of crude oil per day and that receive less than 200 barrels of produced water per day.

(B) Separator and tanks systems that are controlled with the use of a vapor collection system.

(C) Separators, tanks, and sumps that have not contained crude oil, condensate, or produced water for at least 30 calendar days.

(D) Tanks used for temporarily separating, storing, or holding liquids from any newly constructed well for up to 90 calendar days following initial production from that well provided that the tank is not used to circulate liquids from a well that has been subject to a well stimulation treatment.

(E) Tanks used for temporarily separating, storing, or holding liquids from wells undergoing rework or inspection for up to 90 calendar days provided they are not used to circulate liquids from a well that has been subject to a well stimulation treatment.

(F) Tanks that recover less than 10 gallons per day of any petroleum product from equipment provided that the owner or operator maintains, and can make available at the request of the ARB Executive Officer, a record of the amount of liquid recovered.

(3) By January 1, 2018, owners or operators of existing separator and tank systems that are not controlled for emissions with the use of a vapor collection system shall conduct flash analysis testing of the crude oil, condensate, or produced water processed, stored, or held in the system.

(4) Beginning January 1, 2018, owners or operators of new separator and tank systems that are not controlled for emissions with the use of a vapor collection system shall conduct flash analysis testing of the crude oil, condensate, or produced water processed, stored, or held in the system within 90 days of initial system startup.

(5) Flash analysis testing shall be conducted as follows:

(A) Testing shall be conducted 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.

(B) Testing shall be conducted so that no crude oil, condensate, or produced water is diverted through a gauge tank that is open to the atmosphere and located upstream of the separator and tank system while testing is conducted.

(C) Calculate the annual methane emissions for the crude oil, condensate, and produced water using the test results provided by the laboratory.

(D) Sum the annual methane emissions for the crude oil, condensate, and produced water.

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

(F) 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.

(6) By January 1, 2019, owners or operators of an existing separator and tank system with an annual emission rate greater than 10 metric tons per year of methane shall control the emissions from the separator and tank system and uncontrolled gauge tanks located upstream of the separator and tank system with the use of a vapor collection system as specified in section 95668(c).

(7) Beginning January 1, 2018, owners or operators of new separator and tank systems with an annual emission rate greater than 10 metric tons per year of methane shall control the emissions from the separator and tank system and uncontrolled gauge tanks located upstream of the separator and tank system with the use of a vapor collection system as specified in section 95668(c) within 180 days of conducting flash analysis testing.

(8) Beginning January 1, 2019, owners or operators of a separator and tank system with an annual emission rate less than or equal to 10 metric tons per year of methane shall conduct flash analysis testing and reporting annually. If the results of three consecutive years of test results show that the system has an annual emission rate of less than or equal to 10 metric tons per year of methane the owner or operator may reduce the frequency of testing and reporting to once every five years.

(A) After the third consecutive year of testing, if the annual crude oil, condensate, or produced water throughput increases by more than 20 percent after one year from the date of previous flash analysis testing, then the annual methane emissions shall be recalculated using the laboratory reports from previous flash analysis testing.

(B) The owner or operator shall maintain, and make available upon request by the ARB Executive Officer, a record of the revised flash emission calculation as specified in Appendix A, Table A1 and shall report the results to ARB within 90 days as specified in section 95672 of this subarticle.

(b) *Circulation Tanks for Well Stimulation Treatments*

(1) By January 1, 2018, owners or operators of circulation tanks used in conjunction with well stimulation treatments at facilities listed in section 95666 shall implement a best practices management plan that is designed to limit methane emissions from circulation tanks, and shall provide that plan to ARB. Each plan must contain a list of best practices, identified on the basis of substantial evidence recorded in the plan, to address the following issue areas:

(A) Inspection practices to minimize emissions from circulation tanks.
(B) Practices to reduce venting of emissions from circulation tanks.
(C) Practices to minimize the duration of liquid circulation.
(D) Alternative practices to control vented and fugitive emissions.

(2) By January 1, 2019, owners or operators of circulation tanks used in conjunction with well stimulation treatments shall provide the ARB Executive Officer with a written report that details the results of equipment used to control emissions from circulation tanks with at least 95% vapor collection and control efficiency.

(A) The report shall include the results of testing conducted by the owner or operator or equipment manufacturers that demonstrate the vapor collection and control efficiency of the equipment.

(3) By January 1, 2020, owners or operators of circulation tanks used in conjunction with well stimulation treatments shall control emissions from the tanks with at least 95% vapor collection and control efficiency.

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

(1) Beginning January 1, 2019, 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 subarticle:

(2) Unless section 95668(c)(3) applies, the vapor collection system shall direct the collected vapors to one of the following:

(A) Existing sales gas system; or,
(B) Existing fuel gas system; or,
(C) Existing gas disposal well not currently under review by the Division of Oil and Gas and Geothermal Resources.

(3) If no existing sales gas system, fuel gas system, or gas disposal 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, if the device does not already meet the requirements specified in section 95668(c)(4).

(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 and 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 and does not require the use of supplemental fuel gas, other than gas required for a pilot burner, to operate.

(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.

(6) Vapor collection systems and control devices are allowed to be taken out of service for up to 30 calendar days per year for performing 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 consistent with the applicable standards specified in section 95668(c)(4), the event does not count towards the 30 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 30 calendar day limit for maintenance.

(d) *Reciprocating Natural Gas Compressors*

(1) Except as provided in section 95668(d)(2), the following requirements apply to reciprocating natural gas compressors located at facilities listed in section 95666.

(2) The requirements of section 95668(d) do not apply to the following:

(A) Reciprocating natural gas powered compressors that operate less than 200 hours per calendar year provided that the owner or operator maintains, and makes available upon request by the ARB Executive Officer a record of the operating hours per calendar year.

(3) The following requirements apply to reciprocating natural gas compressors located at crude oil or natural gas production facilities and are not covered under section 95668(d)(4):

(A) Beginning January 1, 2018, components on driver engines and compressors shall comply with the leak detection and repair requirements specified in section 95669; and,

(B) The compressor rod packing or seal shall be tested during each inspection period in accordance with the leak detection and repair requirements specified in section 95669 while the compressor is running at normal operating temperature.

(C) Beginning January 1, 2019, compressor vent stacks used to vent rod packing or seal emissions shall be controlled with the use of a vapor collection system as specified in section 95688(c); or,

(D) A compressor with a rod packing or seal leak concentration measured above the minimum leak threshold specified in section 95669 shall be successfully repaired within 30 calendar days from the date of initial measurement.

(E) The owner or operator shall maintain, and make available upon request by the ARB Executive Officer, a record of a rod packing leak concentration measurement found above the minimum leak threshold as specified in Appendix A, Table 5 and shall report the results to ARB once per calendar year as specified in section 95672 of this subarticle.

(F) 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 12 months from the date of the initial leak concentration measurement, whichever is sooner.

(4) 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)(3):

(A) Beginning January 1, 2018, components on driver engines and compressors shall comply with the leak detection and repair requirements specified in section 95669; and,

(B) The compressor rod packing or seal emission flow rate through the rod packing or seal vent stack shall be measured annually by direct measurement (high volume sampling, bagging, calibrated flow measuring instrument) while the compressor is running at normal operating temperature using one of the following methods:

1. Vent stacks shall be equipped with a meter or instrumentation to measure the rod packing or seal emissions flow rate; or,

2. Vent stacks shall be equipped with a clearly identified access port installed 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.

(C) Beginning January 1, 2019, compressor vent stacks used to vent rod packing or seal emissions shall be controlled with the use of a vapor collection system as specified in section 95668(c); or,

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

(E) The owner or operator shall maintain, and make available upon request by the ARB Executive Officer, a record of the flow rate measurement as specified in Appendix A, Table A7 and shall report the result to ARB once per calendar year as specified in section 95672 of this subarticle.

(F) A reciprocating natural gas compressor with a rod packing or seal emission flow rate measured above the standard specified in section 95688(d)(4)(D) 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 12 months from the date of the initial flow rate measurement, whichever is sooner.

(e) *Centrifugal Natural Gas Compressors*

(1) Except as provided in section 95668(e)(2), the following requirements apply to centrifugal natural gas compressors located at facilities listed in section 95666.

(2) The requirements of section 95668(e) do not apply to the following:

(A) Centrifugal natural gas powered compressors that operate less than 200 hours per calendar year provided that the owner or operator maintains, and can make available upon request by the ARB Executive Officer, a record of the operating hours per calendar year.

(3) Beginning January 1, 2018, components on driver engines and compressors that use a wet seal or a dry seal shall comply with the leak detection and repair requirements specified in section 95669; and,

(4) Centrifugal compressor wet seals shall be measured annually by direct measurement (high volume sampling, bagging, calibrated flow measuring instrument) while the compressor is running at normal operating temperature in order to determine the wet seal emission flow rate using one of the following methods:

(A) Vent stacks shall be equipped with a meter or instrumentation to measure the wet seal emissions flow rate; or,

(B) Vent stacks shall be equipped with a clearly identified access port installed 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.

(5) Beginning January 1, 2019, centrifugal compressors with wet seals shall control the wet seal vent gas with the use of a vapor collection system as described in section 95668(c); or,

(6) A compressor with a wet seal emission flow rate greater than three (3) scfm, or a combined flow rate greater than the number of wet seals multiplied by three (3) scfm, shall be successfully repaired within 30 calendar days of the initial flow rate measurement; or,

(7) Replace the wet seal with a dry seal by no later than January 1, 2020.

(8) The owner or operator shall maintain, and make available upon request by the ARB Executive Officer, a record of the flow rate measurement as specified in Appendix A, Table A7 and shall report the result to ARB once per calendar year as specified in section 95672 of this subarticle.

(9) 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 as a critical component as specified in section 95670, shall be successfully repaired by the end of the next process shutdown or within 12 months from the date of the initial flow rate measurement, whichever is sooner.

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

(1) The following requirements apply to natural gas powered pneumatic devices and pumps located at facilities listed in section 95666:

(2) By January 1, 2019, continuous bleed natural gas pneumatic devices shall not vent natural gas to the atmosphere and shall comply with the leak detection and repair requirements specified in section 95669.

(A) Continuous bleed natural gas powered pneumatic devices installed prior to January 1, 2016 may be used provided they meet all of the following requirements:

1. No device shall vent natural gas at a rate greater than 6 standard cubic feet per hour (scfh).,

2. All devices are clearly marked with a permanent tag that identifies the natural gas flow rate as less than or equal to 6 scfh.

3. All devices are tested annually using a direct measurement method (high volume sampling, bagging, calibrated flow measuring instrument); and,

4. Any device with a measured emissions flow rate greater than 6 scfh shall be successfully repaired within 14 calendar days from the date of the initial emission flow rate measurement.

5. The owner or operator shall maintain, and make available upon request by the ARB Executive Officer, a record of the flow rate measurement as specified in Appendix A, Table A7 and shall report the result to ARB once per calendar year as specified in section 95672 of this subarticle.

(3) Beginning January 1, 2018, intermittent bleed pneumatic devices shall comply with the leak detection and repair requirements specified in section 95669 when the device is idle and not controlling.

(4) By January 1, 2019, pneumatic pumps shall not vent natural gas to the atmosphere and shall comply with the leak detection and repair requirements specified in section 95669.

(5) Pneumatic devices and pumps which need to be replaced or retrofitted to comply with the requirements specified in section 95668(f) shall do so by one of the following methods:

(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.

(g) *Liquids Unloading of Natural Gas Wells*

(1) Beginning January 1, 2018, 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 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); and,

(D) Record the volume of natural gas vented and specify the calculation method used or specify if the volume was measured by direct measurement as specified in Appendix A, Table A2.

(2) Owners or operators shall maintain, and make available upon request by the ARB Executive Officer, 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.) as specified in Appendix A, Table A2 and shall report the results to ARB once per calendar year as specified in section 95672 of this subarticle.

(h) Well Casing Vents

(1) Beginning January 1, 2018, owners or operators of wells located at facilities listed in section 95666 with a well casing vent that is open to the atmosphere shall measure the natural gas flow rate from the well casing vent annually by direct measurement (high volume sampling, bagging, calibrated flow measuring instrument); and,

(2) The owner or operator shall maintain, and make available upon request by the ARB Executive Officer, a record of each well casing vent flow rate measurement as specified in Appendix A, Table 7 and shall report the results to ARB once per calendar year as specified in section 95672 of this subarticle.

(i) Natural Gas Underground Storage Facility Monitoring Requirements

(1) As of the effective date of this subarticle, owners or operators of natural gas underground storage facilities listed in section 95666 that have a leak detection protocol approved by the Department of Conservation Division of Oil, Gas, and Geothermal Resources shall continue to implement that plan until a plan approved under this subarticle is in place. Then, by January 1, 2018, owners or operators of natural gas underground storage facilities listed in section 95666 shall submit to ARB a monitoring plan that contains equipment specifications and procedures used to perform the following types of monitoring at the facility:

(A) Continuous monitoring of the ambient air at the facility for emissions of natural gas in conjunction with a monitoring system that can be accessed remotely by the ARB and other state or local agencies specified by the ARB Executive Officer.

(B) Daily screening of each natural gas injection/withdrawal wellhead assembly, attached pipelines, and the surrounding area within a 200 foot radius of the wellhead assembly for leaks of natural gas. The facility may propose to perform daily leak screening with the use of US EPA Method 21 (which is incorporated herein by reference), Optical Gas Imaging (OGI), or other screening instruments; or,

(C) Continuous monitoring of each natural gas injection/withdrawal wellhead assembly, attached pipelines, and the surrounding area within a 200 foot radius of the wellhead assembly for leaks of natural gas with the use of a monitoring and alarm system that is both audible and visible in the control room and at remote control centers.

1. The alarm system shall be triggered any time a leak is detected.

2. The alarm system shall be triggered in the event of a sensor failure.

3. The monitoring system shall use a data logging system with the ability to store at least two (2) years of continuous monitoring data.

4. Quarterly, the alarm system shall be tested to ensure that the system and sensors are functioning properly. Any defective instrumentation shall be repaired or replaced within 14 calendar days from the date of alarm system testing.

5. At least annually, all sensors shall be calibrated as specified by the equipment manufacturer. Any defective instrumentation shall be repaired or replaced within 14 calendar days from the date of calibration.

6. The owner or operator shall maintain, and make available upon request by the ARB Executive Officer, records of monitoring system data, records of calibration, and records of alarm system testing.

(2) By March 1, 2018, the ARB Executive Officer will approve in full or in part, or disapprove in full or in part, a monitoring plan based on whether it is sufficient to meet the requirements specified in section 95668(i)(1).

(3) Beginning September 1, 2018, owners or operators of natural gas underground storage facilities listed in section 95666 shall monitor each facility according to the monitoring plan specified in 95668(i)(1) that has been fully approved by the ARB Executive Officer; and,

(4) All leaks detected at each natural gas injection/withdrawal wellhead assembly during daily leak inspections or as indicated with the use of a continuous system shall be measured 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 within 24 hours of initial leak detection; and,

(5) All leaks shall be successfully repaired within the repair timeframes specified for each leak threshold as specified in section 95669 of this subarticle; and,

(6) At any time is leak is measured above the maximum leak threshold specified in section 95669 during leak inspections conducted at each natural gas injection/withdrawal wellhead assembly, attached pipelines, and the surrounding area within a 200 foot radius of the wellhead, or at any time an air monitoring system detects levels of natural gas that exceed more than 10 percent of baseline conditions, the owner or operator shall notify the ARB, the Department of Oil, Gas, and Geothermal Resources, and the local air district within 24 hours to report the emissions measurement as specified in 95672 of this subarticle; and,

(7) Owners or operators shall maintain, and make available upon request by the ARB Executive Officer, a record of the initial and final leak concentration measurement for leaks identified during daily inspections or identified by a continuous leak monitoring system and measured above the minimum allowable leak threshold as specified in Appendix A Table A5; and,

(8) Owners or operators shall report the results of the initial and final leak concentration measurement for leaks identified during daily inspections or identified by a continuous leak monitoring system and measured above the minimum allowable leak threshold once per calendar quarter as specified in section 95672 of this subarticle.

NOTE: Authority cited: Sections 38510, 38562, 39600, 39601 and 41511, Health and Safety Code. Reference: Sections 38551, 38560, 39600 and 41511, Health and Safety Code

§ 95669. Leak Detection and Repair.

(a) Except as provided in section 95669(b), the following leak detection and repair requirements apply to facilities listed in section 95666.

(b) The requirements of this section do not apply to the following:

(1) Components, including components found on tanks, separators, and pressure vessels that are subject to local air district leak detection and repair requirements prior to January 1, 2018.

(2) Components, including components found on tanks, separators, and pressure vessels used exclusively for crude oil with an API Gravity less than 20.

(3) Components incorporated into produced water lines located downstream of a separator and tank system that is controlled with the use of a vapor collection system.

(4) Natural gas distribution pipelines located at a crude oil production facility used for the delivery of commercial quality natural gas and which are not owned or operated by the crude oil production facility.

(5) Components that are buried below ground. The portion of well casing that is visible above ground is not considered a buried component.

(6) One-half inch and smaller stainless steel tube fittings used to supply compressed air to equipment or instrumentation.

(7) One-half inch and smaller stainless steel tube fittings used to supply natural gas to equipment or instrumentation that have been tested using

US EPA Method 21 and reported to be below the minimum allowable leak threshold.

(8) Components operating under a negative gauge pressure or below atmospheric pressure.

(9) Components at a crude oil or natural gas production facility that are located downstream from the point of transfer of custody and which are not owned or operated by the production facility.

(10) Temporary components used for general maintenance and used less than 300 hours per calendar year if the owner or operator maintains, and can make available at the request of the ARB Executive Officer, a record of the date when the components were installed.

(11) Well casing vents that are open to the atmosphere which are subject to the requirements specified in section 95668(h) of this subarticle.

(c) Beginning January 1, 2018, all components, including components found on tanks, separators, and pressure vessels not identified in section 95669(b) shall be inspected and repaired within the timeframes specified in this section.

(d) The ARB Executive Officer may perform inspections at facilities at any time to determine compliance with the requirements specified in this section.

(e) Owners or operators shall audio-visually inspect (by hearing and by sight) all hatches, pressure-relief valves, well casings, stuffing boxes, and operating pump seals for leaks or indications of leaks at least once every 24 hours for facilities that are visited daily, or at least once per calendar week for unmanned facilities; and,

(1) Owners or operators shall audio-visually inspect all pipes for leaks or indications of leaks at least once every 12 months.

(f) Any audio-visual inspection specified in 95669(e) that indicates a leak that cannot be repaired within 24 hours shall be tested using Method 21 within 24 hours after initial leak detection, and the leak shall be repaired in accordance with the repair timeframes specified in this section.

(1) For leaks detected during normal business hours, the leak measurement shall be performed within 24 hours. For leaks detected after normal business hours or on a weekend or holiday, the deadline is shifted to the end of the next normal business day.

(2) Any leaks measured above the minimum leak threshold shall be successfully repaired within the timeframes specified in this section.

(g) At least once each calendar quarter, all components shall be tested 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.

(1) The quarterly inspection frequency may be reduced to annually provided that the following conditions are met:

(A) All components have been measured for five (5) consecutive calendar quarters and the number of leaks has been determined to be below the number of allowable leaks for each leak threshold category specified in Table 1 or 3; and,

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

(C) The inspection frequency shall revert to quarterly at any time the number of allowable leaks specified in Table 1 or 3 is exceeded during any inspection period.

(2) Optical Gas Imaging (OGI) instruments may be used as a leak screening device provided they are approved for use by the local air district and used by a technician with minimum Level II Thermographer or equivalent training; and,

(A) All leaks detected with the use of an OGI instrument shall be measured using EPA Method 21 within two calendar days of initial OGI leak detection or within 14 calendar days of initial OGI leak detection of an inaccessible or unsafe to monitor component to determine compliance with the leak thresholds and repair timeframes specified in this section.

(3) All inaccessible or unsafe to monitor components shall be inspected at least once annually using Method 21.

(h) Beginning January 1, 2018 and through December 31, 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 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) Critical components shall be successfully repaired by the end of the next process shutdown or within 12 months from the date of initial leak detection, whichever is sooner.

Table 1 - Allowable Number of Leaks
January 1, 2018 through December 31, 2019

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	2	1% of total inspected

Table 2 - Repair Time Periods
January 1, 2018 through December 31, 2019

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

(i) On or after January 1, 2020, 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.

(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.

(4) Critical components shall be successfully repaired by the end of the next process shutdown or within 12 months from the date of initial leak detection, whichever is sooner.

Table 3 - Allowable Number of Leaks
On or After January 1, 2020

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	2	1% of total inspected
50,000 ppmv or greater	0	0

Table 4 - Repair Time Periods
On or After January 1, 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

(j) 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 successfully 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) Tags shall be removed from components following successful repair.

(k) Owners or operators shall maintain, and make available upon request by the ARB Executive Officer, a record of all leaks found at the facility as specified in Appendix A, Tables A4 and A5, and shall report the results to ARB once per calendar year as specified in section 95671 of this subarticle.

<u>Additional Requirements</u>

(l) Hatches shall remain closed at all times except during sampling, adding process material, or attended maintenance operations.

(m) 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. Open-ended lines do not include vent stacks used to vent natural gas from equipment and cannot be sealed for safety reasons.

(n) Components or component parts which incur five (5) repair actions within a continuous 12-month period shall be replaced with a compliant component in working order and must be re-measured using Method 21 to determine that the component is below the minimum leak threshold. A record of the replacement must be maintained in a log at the facility, and shall be made available upon request by the ARB Executive Officer.

(o) 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, 2018 and December 31, 2019, no facility shall exceed the number of allowable leaks specified in Table 1 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) On or after January 1, 2020, 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.

(4) On or after January 1, 2020, 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.

NOTE: Authority cited: Sections 38510, 38562, 39600, 39601 and 41511, Health and Safety Code. Reference: Sections 38551, 38560, 39600 and 41511, Health and Safety Code.

§ 95670. Critical Components.

(a) By January 1, 2018 or within 180 days from installation, 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 if owners or operators wish to claim any critical component exemptions available under this subarticle.

(b) Owners or operators must provide sufficient documentation demonstrating 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, or would impact safety or reliability of the natural gas system.

(c) A request for critical component approval is made by submitting a record of the component as specified in Appendix A, Table A3 along with supporting documentation to the ARB at the address listed in section 95672(b).

(d) Owners or operators shall maintain, and make available upon request by the ARB Executive Officer, a record of all critical components located at the facility as specified in Appendix A, Table A3.

(e) Each critical component must be identified using a weatherproof, readily visible tag that indicates it as an ARB approved critical component and includes the date of ARB Executive Officer approval.

(f) 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 request for critical component approval.

NOTE: Authority cited: Sections 38510, 38562, 39600, 39601 and 41511, Health and Safety Code. Reference: Sections 38551, 38560, 39600 and 41511, Health and Safety Code

§ 95671. Record Keeping Requirements.

(a) Beginning January 1, 2018, 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 flash analysis test, a record of the flash analysis testing that shall include the following:

(A) A sketch or diagram of each separator and tank system tested that identifies the liquid sampling location and all pressure vessels, separators tanks, 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.

Reciprocating Natural Gas Compressors

(2) Maintain, for at least five years from the date of each leak concentration measurement, a record of each rod packing leak concentration measurement found above the minimum leak threshold as specified in Appendix A, Table A5.

(3) Maintain, for at least five years from the date of each emissions flow rate measurement, a record of each rod packing emission flow rate measurement as specified in Appendix A, Table A7.

Centrifugal Natural Gas Compressors

(4) Maintain, for at least five years from the date of each emissions flow rate measurement, a record of each wet seal emission flow rate measurement as specified in Appendix A, Table A7.

Natural Gas Powered Pneumatic Devices

(5) Maintain, for at least five years from the date of each emissions flow rate measurement, a record of the emission flow rate measurement as specified in Appendix A, Table A7.

Liquids Unloading of Natural Gas Wells

(6) Maintain, for at least five years from the date of each liquids unloading 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.

Well Casing Vents

(7) Maintain, for at least five years from the date of each emissions flow rate measurement, a record of each well casing vent emission flow rate measurement as specified in Appendix A, Table A7.

Underground Natural Gas Storage

(8) Maintain, for at least five years from the date of each leak concentration measurement, a record of the initial and final leak concentration measurement for leaks identified during daily inspections or identified by a continuous leak monitoring system and measured above the minimum allowable leak threshold as specified in Appendix A Table A5

Leak Detection and Repair

(9) Maintain, for at least five years from each inspection, a record of each leak detection and repair inspection as specified in Appendix A Table A4.

(10) Maintain, for at least five years from the date of 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 38551, 38560, 39600 and 41511, Health and Safety Code.

§ 95672. Reporting Requirements.

(a) Beginning January 1, 2018, 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 within the timeframes specified:

Flash Analysis Testing

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

Reciprocating Natural Gas Compressors

(2) Annually, report the leak concentration for each rod packing or seal measured above the minimum leak threshold as specified in Appendix A, Table A5.

(3) Annually, report the emission flow rate measurement for each rod packing or seal as specified in Appendix A, Table A7.

Centrifugal Natural Gas Compressors

(4) Annually, report the emission flow rate measurement for each wet seal as specified in Appendix A, Table A7.

Natural Gas Powered Pneumatic Devices

(5) Annually, report the emission flow rate measurement for each pneumatic device with a designed emission flow rate of less 6 scfh as specified in Appendix A, Table A7.

Liquids Unloading of Natural Gas Wells

(6) 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.

Well Casing Vents

(7) Annually, report the emission flow rate measurement for each well casing vent that is open to atmosphere as specified in Appendix A, Table A7.

Underground Natural Gas Storage

(8) Within 24 hours of identify a leak that is measured above the maximum leak threshold specified in section 95669 during leak inspections conducted at each natural gas injection/withdrawal wellhead assembly, attached pipelines, and the surrounding area within a 200 foot radius of the wellhead, the owner or operator shall notify the ARB, the Department of Oil, Gas, and Geothermal Resources, and the local air district to report the leak concentration measurement.

(9) Within 24 hours of receiving an alarm signaled by an air monitoring system that detects levels of natural gas that exceed more than 10 percent of baseline conditions, the owner or operator shall notify the ARB, the Department of Oil, Gas, and Geothermal Resources, and the local air district to report the emissions measurement.

(10) Quarterly, report the initial and final leak concentration measurement for leaks identified during daily inspections or identified by a continuous leak monitoring system and measured above the minimum allowable leak threshold as specified in Appendix A Table A5.

Leak Detection and Repair

(11) Annually, report the results of each leak detection and repair inspection conducted during the calendar year as specified in Appendix A, Table A4.

(12) Annually, report the initial and final leak concentration measurements for components measured above the minimum allowable leak threshold 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 38551, 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 funding, 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*

(1) Local Air District Permitting Application 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 apply for local air district permit 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 apply for terms in any applicable local air district permits for that equipment or facility that ensure compliance with this subarticle.

(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, 2018, 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 natural gas powered 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, 95671, 95672, and 95673 of this subarticle, regardless of whether or not they have complied with the permitting and registration requirements of this section.

NOTE: Authority cited: Sections 38510, 38562, 39600, 39601, 39603, 39607 and 41511, Health and Safety Code. Reference: Sections 38551, 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 any 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.

(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 38551, 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 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 38551¸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 38551, 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% CH4	Sample Temp (^oF)	Throughput (bbl/day)	Metric Tons CH4/Yr
Produced Water Flash Test and Calculation Results						
GWR (scf/bbl)	Molecular Weight	WT% CH4	Sample Temp (^oF)	Throughput (bbl/day)	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:						
Pressure Separators:						
Separators:						
Tanks:						
Sumps:						
Ponds:						

*By signing this form, I am attesting that I am authorized to do so, and that the 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)	Calculation Method or Measured	Automation Equipment**

*By signing this form, I am <u>attesting that I am</u> 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 Type:		Approval Date:

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

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:		
Number of Leaks per Leak Threshold Category	Percentage of Total Components Inspected	
1,000 to 9,999 ppmv:		
10,000 to 49,999 ppmv:		
50,000 ppmv or Greater:		
Total Components Inspected:		

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

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 <u>attesting that I am</u> authorized to do so, and that the information provided is true and correct.

Table A6
Reporting and Registration Form for Facilities

Date:			
Facility Name:		Air District:	
Facility Address or Location:			
Owner/Operator Name:		Signature*:	
Address:			
City:		State:	Zip:
Contact Person:		Phone Number:	
Crude Oil Annual Throughput: (bbls)		Number of Wells:	
Condensate Annual Throughput: (bbls)		Number of Wells:	
Produced Water Annual Throughput: (bbls)		Number of Wells:	
Description and Size of Separators, Tanks, Sumps and Ponds (bbls)	Description of Natural Gas Compressors	Number of Gas Powered Pneumatic Devices	Number of Gas Powered Pneumatic Pumps

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

Table A7
Emission Flow Rate Record Keeping and Reporting Form

Facility Name:	Air District:	
Facility Address or Location:		
Owner/Operator Name:	Signature*:	
Address:		
City:	State:	Zip:
Contact Person:	Phone Number:	
Type of Equipment or Well ID	Measurement Date	Flow Rate (scfm or scfh)

*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

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

Where:

$CH_4\ emissions$ is in metric tons per event

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

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

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

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 separator is not available for collecting samples, 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, 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 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 +/- 4^{o}F 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 separator" means a pressure vessel used for the primary purpose of separating crude oil and produced water or for separating natural gas and produced water.

3.18 “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.

3.19 “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.

3.20 “Separator” means any tank or pressure separator used for the primary purpose of separating crude oil and produced water or for separating natural gas, condensate, and produced water. In crude oil production a separator may be referred to as a Wash Tank or as a three-phase separator. In natural gas production a separator may be referred to as a heater/separator.

.**3.21** "Separator and tank system" means the first separator in a crude oil or natural gas production system and any tank or sump connected directly to the first separator.

3.22 “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.

3.23 "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 separator or portable pressurized separator as specified in this procedure.

4.3 Collecting liquid samples from a pressure separator 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 separator 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.

4.8 The collection and testing of duplicate samples is recommended in order to verify the reported results.

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^{o}F and within a range of 32^{o}F to 250^{o}F.

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 of at least 300 milliliters in volume for collecting crude oil or condensate samples or at least 800 milliliters in volume for collecting produced water samples.

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 separator 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.
(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 separator 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 separator 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.

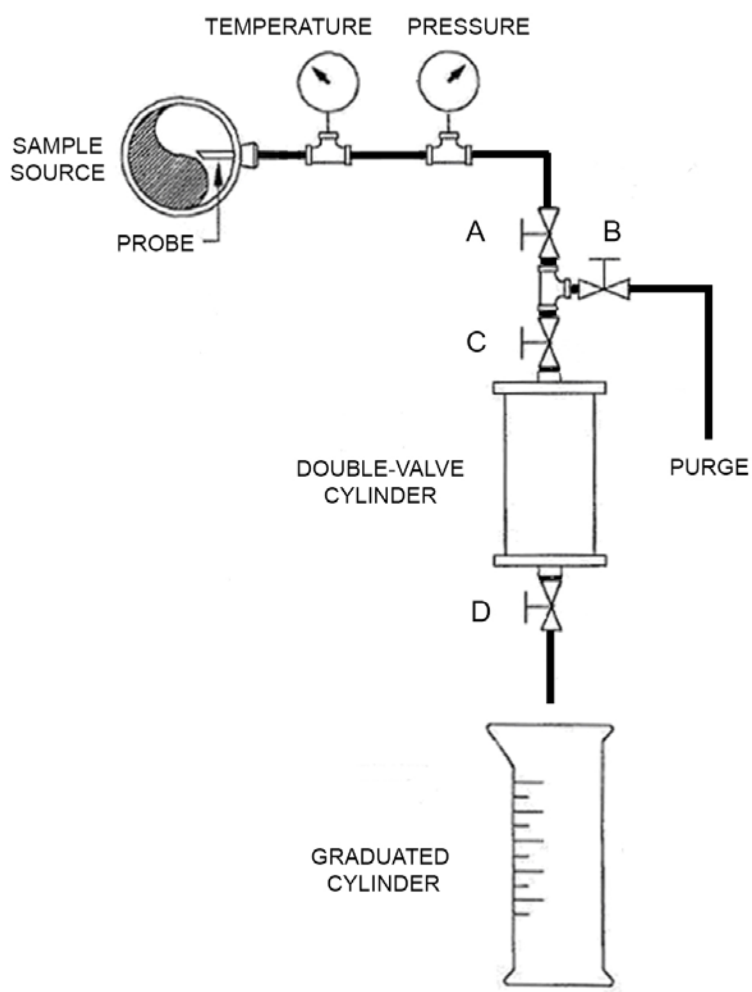
8.6 Connect the sampling train as illustrated in Figure 1 to the sampling port on the pressure separator or portable pressurized separator while minimizing tubing between the purge valve and cylinder as shown. Bushings or reducers may be required.

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 into the graduated cylinder.

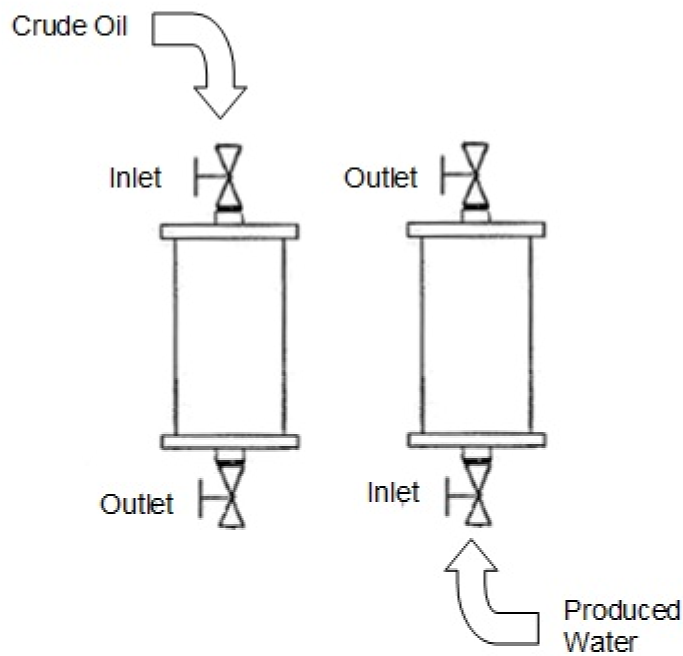
Figure 1: Double Valve Cylinder Sampling Train



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, and then close valves D and C.

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

Figure 2: Double Valve Cylinder Orientation



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 separator 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 separator 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 separator is available immediately upstream of the separator or tank that can be used to collect condensate and produced water samples.

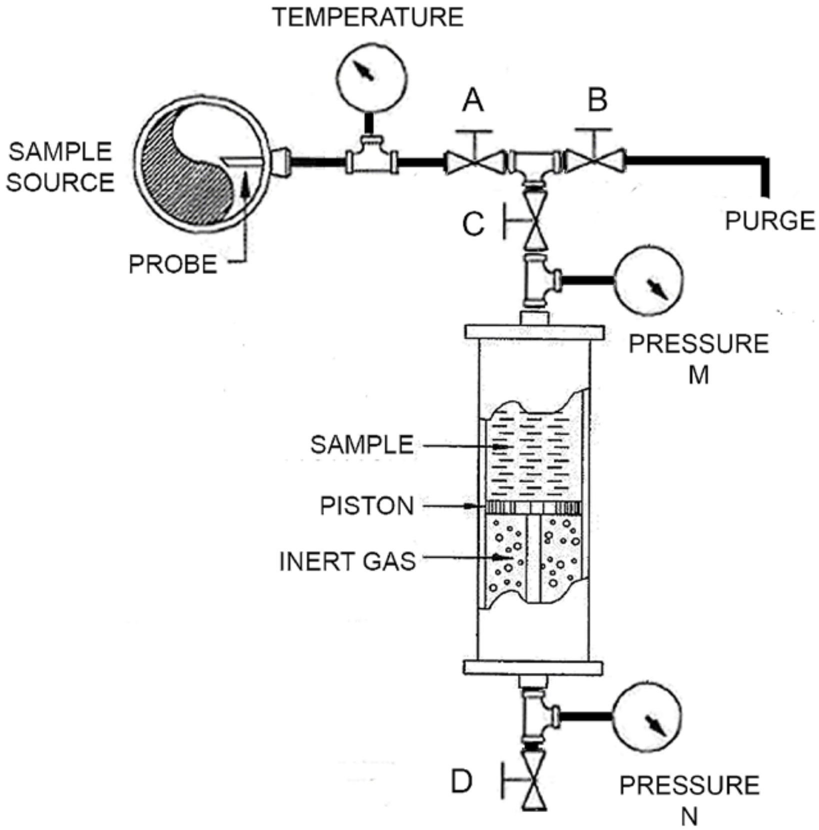
9.2 Record the sample collection data requirements specified in section 7 on the cylinder identification tag and on Form 1.

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 separator 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



9.6 Prepare for sampling: With valve B closed and valve A open, slowly open 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 separator or portable pressurized separator.

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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 2174-93, GPA 2261-00 and GPA 2177-03.

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:

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

Where:

Vapor $_{Std}$ = Standard cubic feet of vapor at 60^{o}F and 14.696 psia.
Volume $_{Lab}$ = Volume of vapor measured at laboratory conditions.
T_{Lab} = Temperature of vapor at laboratory conditions, ^{o}F.
P_{Lab} = Pressure of vapor at laboratory conditions, psia.
459.67 = Conversion from Fahrenheit to Rankine
60F = Standard temperature of 60^{o}F.
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:

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

Where:

Liquid $_{Std}$ = Standard volume of post-flash liquid at 60^{o}F, barrels.
Mass $_{Liquid}$ = Mass of liquid at laboratory conditions, grams.
Density $_{60F}$ = Density of liquid at 60^{o}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^{o}F.

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

$$G = \frac{(Vapor_{Std})}{(Liquid_{Std})}$$ **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.

(a) Oxygen, Nitrogen, Carbon Dioxide, Methane, Ethane, Propane, i-Butane, n-Butane, i-Pentane, n-Pentane, Hexanes, Heptanes, Octanes, Nonanes, Decanes+: Evaluate per GPA 2286-95, ASTM D-1945-03, ASTM D-3588-98, and ASTM D-2597-10 (GC/TCD).

(b) BTEX: Evaluate per EPA 8021B (GC/FID) or use ASTM D-3710-95, GPA 2286-95, EPA 8260B, EPA TO-14, and EPA TO-15 as alternate methods.

(c) API Gravity of whole oil at 60°F by ASTM D 287-92 (Hydrometer Method), ASTM D-4052-09 (Densitometer), ASTM D 5002-16 (Densitometer), or ASTM D-70-09 (Pycnometer). Note: if water is entrained in sample, use ASTM D 287-92. 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 287-92 (Hydrometer Method), ASTM D 4052-09 (Densitometer), ASTM D 5002-16 (Densitometer), or ASTM D 70-09 (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-3588-98.

(f) Water and Sediment in Crude Oil by Centrifuge Method per ASTM D-4007-08.

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:

$$Ft^3/Year = (G)\left(\frac{Barrels}{Day}\right)\left(\frac{Days}{Year}\right)$$ **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:

Mass $_{Gas}$ /Year = pounds of gas per year
Ft^3/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 60^0F

11.3 Calculate the annual mass of methane as follows:

$$Mass_{Methane}/Year = \left(\frac{WT\%\,Methane}{100}\right)\left(\frac{Mass_{Gas}}{Year}\right)\left(\frac{metric\ ton}{2205\,lb}\right)$$ **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.

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% C2-C9, C10+
WT% BTEX
WT% O_2
WT% N_2
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-4007-08)
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.

(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-70-09 *Standard Test Method for Density of Semi-Solid Bituminous Materials (Pycnometer Method), which is incorporated herein by reference. 2009.*

ASTM D-287-92 *Standard Test Method for API Gravity of Crude Petroleum and Petroleum Products (Hydrometer Method), which is incorporated herein by reference. Reapproved 2000.*

ASTM D-1945-03 *Standard Test Method for Analysis of Natural Gas by Gas Chromatography, which is incorporated herein by reference. Reapproved 2010.*

ASTM D-2597-10 *Standard Test Method for Analysis of Demethanized Hydrocarbon Liquid Mixtures Containing Nitrogen and Carbon Dioxide by Gas Chromatography, which is incorporated herein by reference. 2010*

ASTM D-3710-95 *Standard Test Method for Boiling Range Distribution of Gasoline and Gasoline Fractions by Gas Chromatography, which is incorporated herein by reference. Reapproved 2009.*

ASTM D-3588-98	*Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels, which is incorporated herein by reference. Reapproved 2003.*
ASTM D-4007-08	*Standard Test Method for Water and Sediment in Crude Oil by the Centrifuge Method (Laboratory Procedure), which is incorporated herein by reference. 2008.*
ASTM D-4052-09	*Standard Test Method for Density, Relative Density, and API Gravity of Liquids by Digital Density Meter, which is incorporated herein by reference. 2009.*
ASTM D-5002-16	*Standard Test Method for Density and Relative Density of Crude Oils by Digital Density Analyzer, which is incorporated herein by reference. 2016*
EPA Method 8021B	*Aromatic and Halogenated Volatiles by Gas Chromatography Using Photoionization and/or Electrolytic Conductivity Detectors, which is incorporated herein by reference. 2014.*
EPA Method 8260B	*Volatile Organic Compounds by Gas Chromatography/Mass Spectrometry (GC/MS), which is incorporated herein by reference. 1996.*
EPA Method TO-14	*Determination of Volatile Organic Compounds (VOCs) In Ambient Air Using Specially Prepared Canisters with Subsequent Analysis By Gas Chromatography, which is incorporated herein by reference. 1999.*
EPA Method TO-15	*Determination of Volatile Organic Compounds (VOCs) In Air Collected In Specially-Prepared Canisters and Analyzed By Gas Chromatography/Mass Spectrometry (GC/MS), which is incorporated herein by reference. 1999.*
GPA 2174-93	*Analysis Obtaining Liquid Hydrocarbon Samples for Analysis by Gas Chromatography, which is incorporated herein by reference. 2000.*
GPA 2177-03	*Analysis of Natural Gas Liquid Mixtures Containing Nitrogen and Carbon Dioxide by Gas Chromatography, which is incorporated herein by reference. 2003.*
GPA 2261-00	*Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography, which is incorporated herein by reference. 2000.*
GPA 2286-95	*Tentative Method for the Extended Analysis of Natural Gas and Similar Gaseous Mixtures by Temperature Program Gas Chromatography, which is incorporated herein by reference. Reprinted 1999.*

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:	^{o}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