Subarticle 5. Reporting Requirements and Calculation Methods for Petroleum and Natural Gas Systems.

The following definitions will be located in section 95102(a) of the Mandatory Reporting Regulation. They were formerly incorporated by reference from U.S. EPA's Greenhouse Gas Rule, 40 CFR Part 98, Subpart W. For ease of review, they are listed below. Definitions that were already included in section 95102(a) and did not change, have not been added to the list below.

"Absorbent circulation pump" means a pump commonly powered by natural gas pressure that circulates the absorbent liquid between the absorbent regenerator and natural gas contactor.

"Air injected flare" means a flare in which air is blown into the base of a flare stack to induce complete combustion of gas.

"Associated gas" or "produced gas" means a natural gas that is produced ~~from gas wells or gas produced~~ in association with the production of crude oil.

"Calibrated bag" means a flexible, non-elastic, anti-static bag of a calibrated volume that can be affixed to an emitting source such that the emissions inflate the bag to its calibrated volume.

"Centrifugal compressor wet seal degassing vent emissions" means emissions that occur when the high-pressure oil barriers for centrifugal compressors are depressurized to release absorbed natural gas or CO_2. High-pressure oil is used as a barrier against escaping gas in centrifugal compressor seals.

"Dehydrator vent emissions" means natural gas and CO_2 release from a natural gas dehydrator system absorbent (typically glycol) reboiler or regenerator to the atmosphere or a flare, including stripping natural gas and motive natural gas used in absorbent circulation pumps.

"Demethanizer" means the natural gas processing unit that separates methane rich residue gas from the heavier hydrocarbons (e.g., ethane, propane, butane, pentane-plus) in feed natural gas stream.

"Distribution pipeline" means a pipeline that is designated as such by the Pipeline and Hazardous Material Safety Administration (PHMSA) in 49 CFR §192.3.

"Facility," with respect to natural gas distribution for purposes of reporting under this subpart and for the corresponding section 95101 requirements, means the collection of all distribution pipelines and metering-regulating stations that are operated by a Local Distribution Company (LDC) within the State of California that is regulated as a separate operating company by the California Public Utilities Commission or that are operated as an independent municipally-owned distribution system.

“Facility,” with respect to onshore petroleum and natural gas production for purposes of reporting under this article, and for the corresponding section 95101requirements, means all petroleum and natural gas equipment on a well-pad or associated with a well pad and CO_2 EOR operations that are under common ownership or common control including leased, rented, or contracted activities by an onshore petroleum and natural gas production owner or operator and that are located in a single hydrocarbon basin as defined in section 95102. Where a person or entity owns or operates more than one well in a basin, then all onshore petroleum and natural gas production equipment associated with all wells that the person or entity owns or operates in the basin would be considered one facility.

“Farm taps” are pressure regulation stations that deliver gas directly from transmission pipelines to generally rural customers. In some cases a nearby LDC may handle the billing of the gas to the customer(s).

“Forced extraction of natural gas liquids” means removal of ethane or higher carbon number hydrocarbons existing in the vapor phase in natural gas, by removing ethane or heavier hydrocarbons derived from natural gas into natural gas liquids by means of a forced extraction process. Forced extraction processes include but are not limited to refrigeration, absorption (lean oil), cryogenic expander, and combinations of these processes. Forced extraction does not include in and of itself; natural gas dehydration, or the collection or gravity separation of water or hydrocarbon liquids from natural gas at ambient temperatures, or the condensation of water or hydrocarbon liquids through passive reduction in pressure or temperature, or portable dewpoint suppression skids.

“Fugitive equipment leak” means the unintended or incidental emissions of greenhouse gases from the production, transmissions, processing, storage, use or transportation of fossil fuels, greenhouse gases, or other.

“Gas conditions” mean the actual temperature, volume, and pressure of a gas sample.

“Gas-Oil-Ratio (GOR)” means the ratio of gas produced from a barrel of crude oil or condensate when cooling and depressurizing these liquids to standard conditions, measured in terms of standard cubic feet of gas per barrel of oil.

“Gas-Water-Ratio (GWR)” means the ratio of gas produced from a barrel of produced water when cooling and depressurizing produced water to standard conditions, measured in terms of standard cubic feet of gas per barrel of water.

“High-bleed pneumatic devices” are automatic, continuous or intermittent bleed flow control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. Part of the gas power stream that is regulated by the process condition flows to a valve actuator controller where it vents continuously or intermittently (bleeds) to the atmosphere at a rate in excess of 6 standard cubic feet per hour.

"Horizontal well" means a well bore that has a planned deviation from primarily vertical to primarily horizontal inclination or declination tracking in parallel with and through the target formation.

"Intermittent bleed pneumatic devices" means automated flow control devices powered by pressurized natural gas and used for automatically maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. These are snap-acting or throttling devices that discharge all or a portion of the full volume of the actuator intermittently when control action is necessary, but do not bleed continuously. Intermittent bleed devices which bleed at a cumulative rate of 6 scf/hr or greater are considered high bleed devices for the purposes of this regulation.

"Low-bleed pneumatic devices" means automated flow control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. Part of the gas power stream that is regulated by the process condition flows to a valve actuator controller where it vents continuously or intermittently bleeds to the atmosphere at a rate equal to or less than six standard cubic feet per hour.

"Meter/regulator run" means a series of components used in regulating pressure or metering natural gas flow or both.

"Metering/regulating station" means a station that meters the flowrate, regulates the pressure, or both, of natural gas in natural gas distribution facility. This does not include customer meters, customer regulators, or farm taps.

"Natural gas" means a naturally occurring mixture or process derivative of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the earth's surface, of which its constituents include methane, heavier hydrocarbons and carbon dioxide. Natural gas may be field quality (which varies widely) or pipeline quality. For the purposes of this article, the definition of natural gas includes similarly constituted fuels such as field production gas, process gas and fuel gas.

"Onshore petroleum and natural gas production owner or operator" means the person or entity who holds the permit to operate petroleum and natural gas wells on the drilling permit or an operating permit where no drilling permit is issued, which operates an onshore petroleum and/or natural gas production facility (as described in section 95150(a)) Where petroleum and natural gas wells operate without a drilling or operating permit, the person or entity that pays the State or Federal business income taxes is considered the owner or operator.

"Pump seals" means any seal on a pump drive shaft used to keep methane and/or carbon dioxide containing light liquids from escaping ~~the~~ inside of a pump case to the atmosphere.

"Re-condenser" means heat exchangers that cool compressed boil-off gas to a temperature that will condense natural gas to a liquid.

"Sales oil" means produced crude oil or condensate measured at the production lease automatic custody transfer (LACT) meter or custody transfer tank gauge.

"Sour natural gas" means natural gas that contains significant concentrations of hydrogen sulfide (H_2S) and/or carbon dioxide that exceed the concentrations specified for commercially saleable natural gas delivered from transmission and distribution pipelines.

"Steam generator" means equipment that produces steam using an external heat source.

"Sweet gas" is natural gas with low concentrations of hydrogen sulfide (H_2S) and/or carbon dioxide (CO_2) that does not require (or has already had) acid gas treatment to meet pipeline corrosion-prevention specifications for transmission and distribution.

"Third party line hit" means damages to gas pipelines and surface facilities resulting from natural causes or third party incidents. Natural causes include corrosion, abrasion, rock damage, frost heaving or settling. Third party damages may include hits on surface facilities and dig-ins. Specific examples of dig-ins include grader/dozer/scraper excavation, demolition/breakout, general agriculture, driving bars/stakes/posts/anchors, backhoe/trackhoe excavation, ditch shaping, snow removal, landscaping/tree planting, hand excavation, bobcat/loader excavation, blasting/vibrosis, deep tillage, horizontal augering/boring, and other such anthropogenic ground disturbances.

"Transmission-distribution (T-D) transfer station" means a Federal Energy Regulatory Commission rate-regulated Interstate 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. 717-717 (w)(1994), incorporated herein by reference.

"Transmission pipeline" means a high pressure cross country pipeline transporting sellable~~saleable~~ quality natural gas from production or natural gas from processing to natural gas distribution pressure let-down, metering, regulating stations, where the natural gas is typically odorized before delivery to customers.

"Vapor recovery system" means any equipment located at the source of potential gas emissions to the atmosphere or to a flare, that is composed of piping, connections, and, if necessary, flow-inducing devices, and that is used for routing the gas back into the process as a product and/or fuel.

"Vertical well" means a well bore that is primarily vertical but has some unintentional deviation to enter one or more subsurface targets that are off-set horizontally from the surface location, intercepting the targets either vertically or at an angle.

"Well testing venting and flaring" means venting and/or flaring of natural gas at the time the production rate of a well is determined for regulatory, commercial, or technical purposes. If well testing is conducted immediately after a well completion or workover, then it is considered part of well completion or workover.

§95150 Definition of the source category.

(a) This source category consists of the following industry segments:

(1) *Offshore petroleum and natural gas production.* Offshore petroleum and natural gas production is any platform structure, affixed temporarily or permanently to offshore submerged lands, that houses equipment to extract hydrocarbons from the ocean or lake floor and that processes and/or transfers such hydrocarbons to storage, transport vessels, or onshore. In addition, offshore production includes secondary platform structures connected to the platform structure via walkways, storage tanks associated with the platform structure and floating production and storage offloading equipment (FPSO). This source category does not include reporting emissions from offshore drilling and exploration that is not conducted on production platforms.

(2) *Onshore petroleum and natural gas production.* Onshore petroleum and natural gas production means all equipment on a well-pad or associated with a well pad (including but not limited to compressors, generators, dehydrators, storage vessels, and portable non-self-propelled equipment which includes well drilling and completion equipment, workover equipment, gravity separation equipment, auxiliary non-transportation-related equipment, and leased, rented or contracted equipment) used in the production, extraction, recovery, lifting, stabilization, separation or treating of petroleum and/or natural gas (including condensate). This equipment also includes associated storage or measurement vessels and all enhanced oil recovery (EOR) operations (both thermal and non-thermal), and all petroleum and natural gas production equipment located on islands, artificial islands, or structures connected by a causeway to land, an island, or an artificial island.

(3) *Onshore natural gas processing.* Natural gas processing means the separation of natural gas liquids (NGLs) or non-ethane gases from produced natural gas, or the separation of NGLs into one or more component mixtures. Separation includes one or more of the following: forced extraction of natural gas liquids, sulfur and carbon dioxide removal, fractionation of NGLs, or the capture of CO_2 separated from natural gas streams. This segment also includes all residue gas compression equipment owned or operated by the natural gas processing plant. This industry segment includes

processing plants that fractionate gas liquids, and processing plants that do not fractionate gas liquids but have an annual average throughput of 25 MMscf per day or greater.

(4) *Onshore natural gas transmission compression.* Onshore natural gas transmission compression means any stationary combination of compressors that move natural gas from production fields, natural gas processing plants, or other transmission compressors through transmission pipelines to natural gas distribution pipelines, LNG storage facilities, or into underground storage. In addition, a transmission compressor station includes equipment for liquids separation, and tanks for the storage of water and hydrocarbon liquids. Residue (sales) gas compression that is part of onshore natural gas processing plants are included in the onshore natural gas processing segment and are excluded from this segment.

(5) *Underground natural gas storage.* Underground natural gas storage means subsurface storage, including depleted gas or oil reservoirs and salt dome caverns that store natural gas that has been transferred from its original location for the primary purpose of load balancing (the process or equalizing the receipt and delivery of natural gas); natural gas underground storage processes and operations (including compression, dehydration and flow measurement, and excluding transmission pipelines); and all the wellheads connected to the compression units located at the facility that inject and recover natural gas into and from the underground reservoirs.

(6) *Liquefied natural gas (LNG) storage*. LNG storage means onshore LNG storage vessels located above ground, equipment for liquefying natural gas, compressors to capture and re-liquefy boil-off-gas, re-condensers, and vaporization units for regasification of the liquefied natural gas.

(7) *LNG import and export equipment*. LNG import and export equipment means all onshore or offshore equipment that receives imported LNG via ocean transport, stores LNG, re-gasifies LNG, and delivers re-gasified natural gas to a natural gas transmission or distribution system in California. LNG export equipment means all onshore or offshore equipment that receives natural gas, liquefies natural gas, stores LNG, and transfers the LNG via ocean transportation to any location, including locations in the United States.

(8) *Natural gas distribution.* Natural gas distribution means the distribution pipelines and metering and regulating equipment at metering-regulating stations that are operated by a Local Distribution Company (LDC) within California that is regulated by a public utility commission or that is operated as an independent municipally-owned distribution system. This segment also excludes customer meters and regulators, infrastructure, and pipelines (both interstate and intrastate) delivering natural gas directly to major industrial users and farm taps upstream of the local distribution company inlet.

§95151 Reporting threshold

(a) The operator of a facility must report GHG emissions under this subpart if the facility contains petroleum and natural gas systems and the facility meets the requirements of section 95101(b). Facilities listed in section 95150 must report emissions if stationary combustion and process emission sources emit 10,000 metric tons of CO_2 equivalent or more per year, or their stationary combustion, process, fugitive and vented emissions equal or exceed 25,000 metric tons of CO_2 equivalent or more per year.
(b) For applying the threshold defined in section 95101(b), natural gas processing facilities must also include owned or operated residue gas compression equipment.

§95152 Greenhouse gases to report

(a) The operator of a facility must report CO_2, CH_4, and N_2O emissions from each industry segment specified in paragraph (b) through (i) of this section, CO_2, CH_4, and N_2O emissions from each flare as specified in paragraph (b) through (i) of this section, and stationary and portable combustion emissions as applicable and as specified in paragraph (j) of this section.

(b) For offshore petroleum and natural gas production, the operator must report CO_2, CH_4, and N_2O emissions from equipment leaks, vented emissions, and flare emission source types as identified in the data collection and emissions estimation study conducted by BOEMRE in compliance with 30 CFR §§250.302 through 304. Offshore platforms do not need to report portable emissions. In addition, offshore production facilities must report combustion emissions from supply and transportation vessels (e.g., ships and helicopters) used to transport personnel, equipment and products to and from the production facility using methods found in subpart C.

(c) For an onshore petroleum and natural gas production facility, the operator must report CO_2, CH_4, and N_2O emissions from the following source types on a well-pad or associated with a well-pad:

(1) Metered natural gas pneumatic device and pump venting;
(2) Non-metered natural gas pneumatic device venting;
(3) Acid gas removal vents;
(4) Dehydrator vents Flare stack emissions;
(5) Well venting for liquids unloading;
(6) Gas well venting during well completions and workovers;
(7) Equipment and pipeline blowdowns;
(8) Onshore production and storage tanks;
(9) Well testing venting and flaring;
(10) Associated gas venting and flaring;
(11) Flare stack or other destruction device emissions;
(12) Centrifugal compressor venting;

(13) Reciprocating compressor rod packing venting;
(14) EOR injection pump blowdown;
(15) Hydrocarbon liquids dissolved CO_2 and CH_4;
(16) Produced water CO_2 and CH_4;
(17) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, pumps, flanges, and other equipment leak sources (such as instruments, loading arms, stuffing boxes, compressor seals, dump lever arms, and breather caps); and
(18) The operator must use the methods in section 95153(y) and report under this subpart the emissions of CO_2, CH_4, and N_2O from stationary or portable fuel combustion equipment that cannot move on roadways under its own power and drive train, and that is located at an onshore petroleum and natural gas production facility as defined in section 95150. Stationary or portable equipment includes equipment which is integral to the extraction, processing, and movement of oil and/or natural gas; such as well pad construction equipment, well drilling and completion equipment, equipment used for abandoned well plugging and site reclamation, workover equipment, natural gas dehydrators, natural gas compressors, electrical generators, steam boilers, and process heaters.

(d) For onshore natural gas processing, the operator must report CO_2, CH_4, and N_2O emissions from the following sources:

(1) Acid gas removal vents;
(2) Dehydrator vents;
(3) Equipment and pipeline blowdowns;
(4) Flare stack or other destruction device emissions;
(5) Centrifugal compressor venting;
(6) Reciprocating compressor rod packing venting;
(7) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, and meters.

(e) For onshore natural gas transmission compression, the operator must report CO_2, CH_4, and N_2O emissions from the following sources:

(1) Metered natural gas pneumatic device and pump venting;
(2) Non-metered natural gas pneumatic device venting;
(3) Equipment and pipeline blowdowns;
(4) Transmission storage tanks;
(5) Flare stack or other destruction device emissions;
(6) Centrifugal compressor venting;
(7) Reciprocating compressor rod packing venting;
(8) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, and meters.

(f) For underground natural gas storage, the operator must report CO_2, CH_4, and N_2O from the following sources:

(1) Metered natural gas pneumatic device and pump venting;
(2) Non-metered natural gas pneumatic device venting;
(3) Equipment and pipeline blowdowns;
(4) Flare stack or other destruction device emissions;
(5) Centrifugal compressor rod packing venting;
(6) Reciprocating compressor rod packing venting;
(7) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, and meters.

(g) For LNG storage, the operator must report CO_2, CH_4, and N_2O emissions from the following sources:

(1) Equipment and pipeline blowdowns.
(2) Flare stack or other destruction device emissions;
(3) Centrifugal compressor rod packing venting;
(4) Reciprocating compressor rod packing venting;
(5) Equipment leaks from valves; pump seals; connectors; vapor recovery compressors, and other equipment leak sources.

(h) For LNG import and export equipment, the operator must report CO_2, CH_4, and N_2O emissions from the following sources:

(1) Equipment and pipeline blowdowns.
(2) Flare stack or other destruction device emissions;
(3) Centrifugal compressor rod packing venting.
(4) Reciprocating compressor rod packing venting.
(5) Equipment leaks from valves, pump seals, connectors, vapor recovery compressors, and other equipment leak sources.

(i) For natural gas distribution, the operator must report CO_2, CH_4, and N_2O emissions from the following sources:

(1) Meters, regulators, and associated equipment at above grade transmission-distribution transfer stations, including equipment leaks from connectors, block valves, orifice meters, regulators, and open ended lines.
(2) Equipment leaks from vaults at below grade transmission-distribution transfer stations.
(3) Meters, regulators, and associated equipment at above grade metering-regulating stations.
(4) Equipment leaks from vaults at below grade metering-regulating stations.
(5) Equipment and pipeline blowdowns.
(6) Service line equipment leaks.
(7) Report under 95150 of this part the emissions of CO_2, CH_4, and N_2O emissions from stationary combustion sources following the methods in 95153(y).
(8) Flare stack emissions.
(9) Third party line hits and uncontrolled pipeline blowdowns.

(j) The operator of a facility must report emissions of CO_2, CH_4, and N_2O from each stationary fuel combustion unit by following the requirements of section 95115 of this article except for facilities under onshore petroleum and natural gas production and natural gas distribution. Operators of onshore petroleum and natural gas production facilities must report stationary and portable combustion emissions as specified in section 95152(c)(15). Natural gas distribution facilities must report stationary combustion emissions as specified in paragraph (i) of this section.

(k) Operators of facilities must report CO_2 emissions captured and transferred off site by following the requirements of section 95123 of this article (Suppliers of Carbon dioxide).

§ 95153 Calculating GHG emissions

The operator of a facility must calculate and report the annual GHG emissions as prescribed in this section. The facility operator who is a local distribution company reporting under section 95122 of this article must comply with section 95153 for reporting emissions from the applicable source types in section 95152(i) of this article.

(a) *Metered Natural Gas Pneumatic Device and Pneumatic Pump Venting*. The operator of a facility who is subject to the requirements of section 95153(a) and (b) must calculate emissions from natural gas powered high bleed control device and pneumatic pump venting using the method specified in paragraph (a)(1) below when the natural gas flow to the device is metered. By January 1, 2015, natural gas consumption must be metered for all the operator's pneumatic high bleed devices and pneumatic pumps. The operator may choose to also meter flow to any or all low bleed natural gas powered devices. For the purposes of this reporting requirement, high bleed devices are defined as all natural gas powered devices (both intermittent and continuous bleed devices) which bleed at a rate greater than 6 scf/hr. For unmetered devices the operator must use the method specified in section 95153(a) and (c) as applicable. Vented emissions from natural gas driven pneumatic pumps covered in paragraph (d) of this section do not have to be reported under paragraph (a) of this section.

(1) The operator must calculate vented emissions for all metered natural gas powered pneumatic devices and pumps using the following equation:

$$E_m = \sum_1^n B_n \qquad \text{(Eq. 1)}$$

Where:

E_m = Annual natural gas emissions at standard conditions, in cubic feet, for all metered natural gas powered pneumatic devices.

n = Total number of meters.

B_n = Natural gas consumption for meter n.

(2) For both metered and unmetered natural gas powered devices, CH_4 and CO_2 volumetric and mass emissions must be calculated from volumetric natural gas emissions using methods in paragraphs (s) and (t) of this section.

(b) *Non-metered Natural Gas Pneumatic Device Venting*. The operator must calculate CH_4 and CO_2 emissions from all un-metered natural gas powered pneumatic low and high bleed devices using the following method:

$$E_{nm,i,x} = \sum_1^i \sum_1^x EF_i * T_{i,x} \qquad \text{(Eq. 2)}$$

Where:

$E_{nm,i}$ = Annual natural gas emissions at standard conditions for all unmetered natural gas powered devices and pumps (in scf).
i = Total number of unmetered component types
x = Total number of component type i.
EF_i = Population emission factor for natural gas pneumatic device type i (scf/hour/component) listed in Tables 1A, 3, and 4 of this subpart for onshore petroleum and natural gas production, onshore natural gas transmissions compression, and underground natural gas facilities, respectively.
$T_{i,x}$ = Total number of hours type i component x was in service. Default is 8760 hours.

(1) GHG (CO_2 and CH_4) volumetric and mass emissions must be calculated from volumetric natural gas emissions using methods in paragraphs (s) and (t) of this section.

(c) *Acid gas removal (AGR) vents.* For AGR vent (including processes such as amine, membrane, molecular sieve or other absorbents and adsorbents), the operator must calculate emissions for CO_2 only (not CH_4) vented directly to the atmosphere or through a flare, engine (e.g. permeate from a membrane or de-adsorbed gas from a pressure swing adsorber used as fuel supplement), or sulfur recovery plant using any of the calculation methodologies described in paragraph (c) of this section.

(1) *Calculation Methodology 1.* If the operator operates and maintains a CEMS that has both a CO_2 concentration monitor and volumetric flow rate meter, they must calculate CO_2 emissions under this subpart by following the Tier 4 Calculation Methodology and all associated calculation, quality assurance, reporting, and recordkeeping requirements for Tier 4 in section ~~95153~~ 95115 of this part (Stationary Fuel Combustion Sources). Alternatively, the operator may follow the manufacturer's instructions or industry standard practice. If a CO_2 concentration monitor and volumetric flow rate monitor are not available, the operator may elect to install a CO_2 concentration monitor and a volumetric flow rate monitor that comply with all the requirements specified for the Tier 4 Calculation Methodology in section ~~95153~~ 95115 (Stationary Fuel Combustion Sources). The calculation and reporting of CH_4 and N_2O emissions is not required as part of the Tier 4 requirements for AGRs.

(2) *Calculation Methodology 2*. If CEMS is not available but a vent meter is installed, the operator must use the CO_2 composition and annual volume of vent gas to calculate emissions using Equation 3 of this section.

$$E_{a,CO2} = V_S * Vol_{CO2} \quad \text{(Eq. 3)}$$

Where:

$E_{a,CO2}$ = Annual volumetric CO_2 emissions at actual conditions, in cubic feet per year.
V_S = Total annual volume of vent gas flowing out of the AGR unit in cubic feet per year at actual conditions as determined by flow meter using methods set forth in section 95154(b). Alternatively, the facility operator may follow the manufacturer's instructions or industry standard practice for calibration of the vent meter.
Vol_{CO2} = Volume fraction of CO_2 content in the vent gas out of the AGR unit as determined in (c)(6) of this section.

(3) *Calculation Methodology 3*. If CEMS or a vent meter is not installed, the operator may use the inlet flow rate of the acid gas removal unit to calculate emissions for CO_2 using Equation 4 of this section.

$$E_{CO2} = V_{in} * \left[Y_{CO2-in} * \left(1 - Y_{H2S-spec}\right) - Y_{CO2-out} * \left(1 - Y_{H2S-in}\right)\right] / \left(1 - Y_{H2S-spec} - Y_{CO2-out}\right) \quad \text{(Eq. 4)}$$

Where:

$E_{a,CO2}$ = Annual volumetric CO_2 emissions at actual conditions, in cubic feet per year.
V_{in} = Total annual volume of natural gas flow into the AGR unit in cubic feet per year at actual condition as determined using methods specified in paragraph (c)(4) of this section.
Y_{CO2-in} = Mole fraction of CO_2 in natural gas into the AGR unit as determined in paragraph (c)(5) of this section.
$Y_{CO2-out}$ = Mole fraction of CO2 in natural gas out of the AGR unit as determined in paragraph (c)(6) of this section.
$Y_{H2S-spec}$ = Mole fraction of H_2S in the natural gas out of the AGR unit as defined by the most recent emissions testing or no testing data is available, the performance specification of the AGR.
Y_{H2S-in} = Mole fraction of H_2S in natural gas into the AGR unit as determined in paragraph (c)(7) of this section.

(4) Record the gas flow rate of the inlet and outlet natural gas stream of an AGR unit using a meter according to methods set forth in section 95154(b).

(5) If a continuous gas analyzer is installed on the inlet gas stream, then the continuous gas analyzer results must be used. If continuous gas analyzer is not available, either install a continuous gas analyzer or take monthly gas samples from the inlet gas stream to determine Y_{CO2-in} according to methods according to methods set forth in section 95154(b).

(6) Determine volume fraction of CO_2 content in natural gas or acid gas out of the AGR unit using one of the methods specified in paragraph (c)(6) of this section:

(A) If a continuous gas analyzer is installed on the outlet gas stream, then the continuous gas analyzer results must be used. If a continuous gas analyzer is not available, the facility operator may install a continuous gas analyzer.
(B) If a continuous gas analyzer is not available or installed, monthly gas samples may be taken from the outlet gas stream to determine Y_{CO2} according to methods set forth in section 95154(b).

(7) Determine volume fraction of H_2S content in natural gas or acid gas into the AGR unit using continuous gas analyzer data (if available), or other know or commonly accepted industry standard methods (if continuous data is not available).

(8) Calculate CO_2 volumetric emissions at standard conditions using calculations in paragraph (r) and (s) of this section.

(9) Mass CO_2 emissions shall be calculated from volumetric CO_2 emissions using calculations in paragraph (t) of this section.

(10) Determine if emissions from the AGR unit are recovered and transferred outside the facility. Adjust the emissions estimated in paragraph (c)(1) through (c)(9) of this section downward by the magnitude of emissions recovered and transferred outside the facility.

(d) *Dehydrator vents*. For dehydrator vents, calculate annual CH_4, CO_2, and N_2O emissions using any of the calculation methodologies described in paragraph (d) of this section.

(1) Calculate annual mass emissions from dehydrator vents using a software program, such as AspenTech HYSYS® or GRI-Calc, that uses the Peng-Robinson equation of state to calculate the equilibrium coefficient, speciates CH_4 and CO_2 emissions from dehydrators, and has provisions to include regenerator control devices, a separator flash tank, stripping gas and a gas injection pump or gas assist pump. A minimum of the following parameters determined by engineering estimate based on best available data must be used to characterize emissions from dehydrators.

(A) Feed natural gas flow rate.
(B) Feed natural gas water content.
(C) Outlet natural gas water content.
(D) Absorbent circulation pump type (natural gas pneumatic/air pneumatic/electric).
(E) Absorbent circulation rate.
(F) Absorbent type: including triethylene glycol (TEG), diethylene glycol (DEG) or ethylene glycol (EG).
(G) Use of stripping gas.
(H) Use of flash tank separator (and disposition of recovered gas).
(I) Hours operated.
(J) Wet natural gas temperature and pressure.
(K) Wet natural gas composition. Determine this parameter by selecting one of the methods described under paragraph (d)(1)(K) of this section.

1. Use the wet natural gas composition as defined in section 95153(s)(2).
2. If wet natural gas composition cannot be determined using paragraph 95153(s)(2) of this section, select a representative analysis.
3. The facility operator may use an appropriate standard method published by a consensus-based standards organization or the facility operator may use an industry standard practice as specified in section 95154(b) to sample and analyze wet natural gas composition.
4. If only composition data for dry natural gas is available, assume the wet natural gas is saturated.

(2) Determine if the dehydrator unit has vapor recovery. Adjust the emissions estimated in paragraphs (d)(1) or (d)(4) of this section downward by the magnitude of emissions captured.

(3) Calculate annual emissions from dehydrator vents to flares or regenerator fire-box/fire tubes as follows:

(A) Use the dehydrator vent volume and gas composition as determined in paragraph (d)(1) of this section.
(B) Use the calculation methodology of flare stacks in paragraph (l) of this section to determine dehydrator vent emissions from the flare or regenerator combustion gas vent.

(4) In the case of dehydrators that use desiccant, operators must calculate emissions from the amount of gas vented from the vessel when it is depressurized for the desiccant refilling process using Equation 5 of this section.

$$E_{s,n} = n(H * D^2 * \pi * \%G * P_2/(4 * P_1)) \qquad \text{(Eq. 5)}$$

Where:

$E_{S,n}$ = Annual natural gas emissions at standard conditions in cubic feet.
n = number of fillings in reporting period.
H = Height of the dehydrator vessel (ft).
D = Inside diameter of the vessel (ft).
π = pi (3.1416)
%G = Percent of packed vessel volume that is gas (expressed as a decimal, e.g.,15% = 0.15).
P_1 = Atmospheric pressure (psia).
P_2 = Pressure of the gas (psia)

(5) For glycol dehydrators, both CH_4 and CO_2 mass emissions must be calculated from volumetric GHG_i emissions using calculations in paragraph (t) of this section. For dehydrators that use desiccant, both CH_4 and CO_2 volumetric and mass emissions must be calculated from volumetric natural gas emissions using calculations in paragraphs (s) and (t) of this section.

(e) *Well venting for liquids unloadings.* Calculate CO_2 and CH_4 emissions from well venting for liquids unloading using one of the calculation methodologies described in paragraphs (e)(1), (e)(2) or (e)(3) of this section.

(1) *Calculation Methodology 1*. Calculate the total emissions for well venting for liquids unloading using Equation 6 of this section.

$$E_{S,n} = \sum_{p=1}^{W}\left[V_p * \left((0.37 * 10^{-3}) * CD_p^2 * WD_p * SP_p\right) + \sum_{p=1}^{V_p}\left(SFR_p * \left(HR_{p,q} - 1.0\right) * Z_{p,q}\right)\right]$$

(Eq. 6)

Where:

$E_{S,n}$ = Annual natural gas emissions at standard conditions, in cubic feet/year.
W = Total number of well venting events for liquids unloading for each sub-basin.
0.37×10^{-3} = {3.14(pi)/4}/{14.7x144}(psia converted to pounds per square feet).
CD_p = Casing diameter for each well, p, in inches.
WD_p = Well depth from either the top of the well or the lowest packer to the bottom of the well, for each well, p, in feet.
SP_p = Shut-in pressure or surface pressure for wells with tubing production and no packers or casing pressure for each well, p, in pounds per square inch absolute (psia).
V_p = Number of unloading events per year per well, p.
SFR_p = Average flow-rate of gas for well p, at standard conditions in cubic feet per hour. Use Equation 30 to calculate the average flow-rate at standard conditions.
$HR_{p,q}$ = Hours that each well, p, was left open to the atmosphere during each unloading event, q.
1.0 = Hours for average well to blowdown casing volume at shut-in pressure.
$Z_{p,q}$ = If $HR_{p,q}$ is less than 1.0 then $Z_{p,q}$ is equal to 0. If $HR_{p,q}$ is greater than or equal to 1.0 then $Z_{p,q}$ is equal to 1.

(A) Both CH_4 and CO_2 volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (s) and (t) of this section.

(2) *Calculation Methodology 2.* Calculate emissions from each well venting to the atmosphere for liquids unloading with plunger lift assist using Equation 7 of this section.

$$E_{S,n} = \sum_{p=1}^{W}\left[V_p * \left((0.37 * 10^{-3}) * TD_p^2 * WD_p * SP_p\right) + \sum_{q=1}^{V_p}\left(SFR_p * \left(HR_{p,q} - 0.5\right) * Z_{p,q}\right)\right]$$

(Eq. 7)

Where:

$E_{S,n}$ = Annual natural gas emissions at standard conditions, in cubic feet/year.

W = Total number of well venting liquid unloading events at wells using plunger lift assist technology for each sub-basin.
0.37×10^{-3} = {3.14(pi)/4}/{14.7 x 144} (psia converted to pounds per square feet).
TD_p = Tubing internal diameter for each well, p, in inches.
WD_p = Tubing depth to plunger bumper for each well, p, in feet.
SP_p = Flow-line pressure for each well, p, in pounds per square inch absolute (psia).
V_p = Number of unloading events per year for each well, p.
SFR_p = Average flow-line rate of gas for well, p, at standard conditions in cubic feet per hour. Use Equation 30 to calculate the average flow-line rate at standard conditions.
$HR_{p,q}$ = Hours that each well, p, was left open to the atmosphere during each unloading, q.
0.5 = Hours for average well to blowdown tubing volume at flow-line pressure.
$Z_{p,q}$ = If $HR_{p,q}$ is less than 0.5, then $Z_{p,q}$ is equal to 0. If $HR_{p,q}$ is greater than or equal to 0.5, then $Z_{p,q}$ is equal to 1.

(3) Both CH_4 and CO_2 volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (s) and (t) of this section.

(f) *Gas well venting during well completions and well workovers*. Using one of the calculation methodologies in this paragraph (f)(1) through (f)(5) below, operators must calculate CH_4, CO_2 and N_2O (when flared) annual emissions from gas well venting during both conventional completions and completions involving hydraulic fracturing in wells and both conventional well workovers and well workovers involving hydraulic fracturing.

(1) *Calculation Methodology 1*. Measure total gas flow with a recording flow meter (analog or digital) installed in the vent line ahead of a flare or vent id used. The facility operator must correct total gas volume vented for the volume of CO_2 or N_2 injected and the volume of gas recovered into a sales lines as follows:

$$E_a = V_M - V_{\frac{CO2}{N2}} - V_{SG} \qquad \text{(Eq. 8)}$$

Where:

E_a = Natural gas emissions during the well completion or workover at actual conditions (m^3).
V_M= Volume of vented gas measured during well completion or workover (m^3).
$V_{CO2/N2}$ = Volume of CO_2 or N_2 injected during well completion or workover (m^3).
V_{SG} = Volume of natural gas recovered into a sales pipeline (m^3).

(A) All gas volumes must be corrected to standard temperature and pressure using methods in section (r)
(B) Calculate CO_2 and CH_4 volumetric and mass emissions using the methodologies in sections (s) and (t).

(2) *Calculation Methodology 2.*

(A) Record the well flowing pressure upstream (P_1) and downstream (P_2) of a well choke, upstream temperature and elapsed time of venting according to methods set forth in section 95154(b) to calculate the well backflow during well completions and workovers.

(B) The operator must record this data at a time interval (e.g., every five minutes) suitable to accurately describe both sonic and subsonic flow regimes.

(C) Sonic flow is defined as the flow regime where $P_2/P_1 \leq 0.542$.

(D) Calculate the average flow rate during sonic conditions using Equation 9 of this section.

$$FR_a = 1.27 * 10^5 * A * \sqrt{187.08 * T_u} \qquad \text{(Eq. 9)}$$

Where:

FR_a = Average flow rate in cubic feet per hour, under actual sonic flow conditions.
A = Cross sectional open area of the restriction orifice (m^2).
T_u = Upstream temperature (degrees Kelvin).
187.08 = Constant with units of $m^2/(sec^2 x\ K)$.
1.27×10^5 = Conversion from m^3/second to ft^3/hour.

(E) Calculate total gas volume vented during sonic flow conditions as follows:

$$V_S = FR_a * T_S \qquad \text{(Eq. 10)}$$

Where:

V_s = Volume of gas vented during sonic flow conditions (m^3)
T_S = Length of time that the well vented under sonic conditions (hours).

(F) For each of the sets of data points (T_u, P_1, P_2, and elapsed time under subsonic flow conditions) recorded as the well vented under subsonic flow conditions, calculate the instantaneous gas flow rate as follows:

$$FR_a = 1.27 * 10^5 * A * \sqrt{3430 * T_u * [(P_2/P_1)^{1.515} - (P_2/P_1)^{1.758}]} \qquad \text{(Eq. 11)}$$

Where:

FR_a = Instantaneous flow rate in cubic feet per hour, under actual subsonic flow conditions.
A = Cross sectional open area of the restriction orifice (m^2).
P_1 = Upstream pressure (psia).
T_u = Upstream temperature (degrees Kelvin).
P_2 = Downstream pressure (psia).
3430 = Constant with units of $m^2/(sec^2 xK)$.
1.27×10^5 = Conversion from m^3/second to ft^3/hour.

(G) Calculate the total gas volume vented during subsonic flow conditions, V_{SS}, as the total volume under the curve of a plot of FR_a and elapsed time under subsonic flow conditions.

(H) Correct V_{SS} to standard conditions using the methodology found in section (r).

(I) Sum the vented volumes during subsonic and sonic flow and adjust vented emissions for the volume of CO_2 and N_2 injected and the volume of gas recovered to a sales line as follows:

$$E_S = V_S + V_{SS} - V_{\frac{CO2}{N2}} - V_{SG} \qquad \text{(Eq. 12)}$$

Where:

E_s = Total volume of natural gas vented during the well completion or workover (scf).

V_s = Volume of natural gas vented during sonic flow conditions for the well completion or workover (scf) (see Eq. 10)

V_{ss} = Volume of natural gas vented during subsonic flow conditions for the well completion or workover (scf) (see 95153(f)(2)(G) above).

$V_{CO2/N2}$ = Volume of CO_2 or N_2 injected during the well completion or workover (scf).

V_{SG} = Volume of gas recovered to a sales line during the well completion or workover (scf)

(3) The volume of CO_2 of N_2 injected into the well reservoir during energized hydraulic fractures must be measured using an appropriate meter as described in section 95154(b) or using receipts of gas purchases that are used for the energized fracture job.

(A) Calculate gas volume at standard conditions using calculations in paragraph (r) of this section

(4) Determine if the backflow gas from the well completion or workover is recovered with purpose designed equipment that separates natural gas from the backflow, and sends this natural gas to a flow-line (*e.g.,* reduced emissions completion or workover).

(A) Use the factor V_{SG} in Equation 8 of this section, to adjust the emissions estimated in paragraphs (f)(1) through (f)(4) of this section by the magnitude of emissions captured using purpose designed equipment that separates saleable gas from the backflow as determined by engineering estimate based on best available data.

(B) Calculate gas volume at standard conditions using calculations in paragraph (r) of this section.

(5) Both CH_4 and CO_2 volumetric and mass emissions must be calculated from volumetric total emissions using calculations in paragraphs (s) and (t) of this section.

(g) *Equipment and pipeline blowdowns*. Calculate CO_2 and CH_4 blowdown emissions from depressurizing equipment and natural gas pipelines to reduce system pressure for planned or emergency shutdowns resulting from human intervention or to take equipment out of service for maintenance (excluding depressurizing to a flare, over-pressure relief, operating pressure control venting and blowdown of non-GHG gases; desiccant dehydrator blowdown venting before reloading is covered in paragraphs (d)(4) of this section) as follows:

(1) Calculate the unique physical volume (including pipelines, compressor case or cylinders, manifolds, suction bottles, discharge bottles, and vessels) between isolation valves determined by engineering estimates based on best available data.

(2) Calculate the total annual venting emissions for unique volumes using either Equation 13 or 14 of this section.

$$E_{s,n} = N * \left(V\left(\frac{(459.67+T_s)P_a}{(459.67+T_a)P_s}\right) - V * C\right) \quad \text{(Eq. 13)}$$

Where:

$E_{s,n}$ = Annual natural gas venting emissions at standard conditions from blowdowns in cubic feet.
N = Number of occurrences of blowdowns for each unique physical volume in the calendar year.
V = Unique physical volume (including pipelines, compressors and vessels) between isolation valves in cubic feet.
C = Purge factor that is 1 if the unique physical volume is not purged or zero if the unique physical volume is purged using non-GHG gases.
T_s = Temperature at standard conditions (60˚F).
T_a = Temperature at actual conditions in the unique physical volume (˚F).
P_s = Absolute pressure at standard conditions (14.7 psia).
P_a = Absolute pressure at actual conditions in the unique physical volume (psia).

$$E_{s,n} = \sum_1^{PV} \sum_1^{N} [V((459.67 + T_s)(P_{(a,b,p)} - P_{(a,e,p)}))/(459.67 + T_{(a,p)})\,P_s)]$$
(Eq. 14)

Where:

$E_{s,n}$ = Annual natural gas venting emissions at standard conditions from blowdowns in cubic feet.
PV = Number of unique physical volumes blowndown.
N = Number of occurrences of blowdowns for each unique physical volume.
V = Total physical volume (including pipelines, compressors and vessels) between isolation valves in cubic feet for each blowdown “p”.
T_s = Temperature at standard conditions (60˚F).

$T_{a,p}$ = Temperature at actual conditions in the unique physical volume (°F).
P_s = Absolute pressure at standard conditions (14.7 psia).
$P_{a,b,p}$ = Absolute pressure at actual conditions in the unique physical volume (psia) at the beginning of the blowdown "p".
$P_{a,e,p}$ = Absolute pressure at actual conditions in the unique physical volume (psia) at the end of the blowdown "p"; 0 if blowdown volume is purged using non-GHG gases.

(3) Calculate both CH_4 and CO_2 volumetric and mass emissions using calculations in paragraph (s) and (t) of this section.
(4) Calculate total annual venting emissions for all blowdown vent stacks by adding all standard volumetric and mass emissions determined in Equation 14 and paragraph (g)(43) of this section.

(h) *Onshore production storage tanks.* *[ARB staff are considering applying the Draft Test Procedure: Determination of Methane, Carbon Dioxide, and Volatile Organic Compounds from Crude Oil and Natural Gas Separation and Storage Tank Systems for quantifying emissions from this section. This proposed change would eliminate the calculation methods described in 95153(h). ARB staff would appreciate comments from stakeholders with regards to this proposed modification.]*
Calculate CH_4, CO_2 and N_2O (when flared) emissions from atmospheric pressure fixed roof storage tanks receiving hydrocarbon produced liquids from onshore petroleum and natural gas production facilities (including stationary liquid storage not owned or operated by the facility operator). Calculate annual CH_4 and CO_2 emissions using one of the methodologies described in this paragraph (h).

(1) *Calculation Methodology 1*. Calculate annual CH_4 and CO_2 emissions from onshore production storage tanks using operating conditions in the last wellhead gas-liquid separator before liquid transfer to storage tanks. Calculate flashing emissions with a software program such as AspenTech HYSYS® or API 4697 E&P Tank, that uses the Peng-Robinson equation, and speciates CH_4 and CO_2 emissions that will result when oil from the separator enters an atmospheric pressure storage tank. A minimum of the following parameters determined for typical operating conditions over the year by engineering estimate and process knowledge based on best available data must be used to characterize emissions from liquid transferred to tanks.

(A) Separator temperature
(B) Separator pressure.
(C) Sales oil or stabilized oil API gravity.
(D) Sales oil or stabilized oil production rate.
(E) Ambient air temperature.
(F) Ambient air pressure.
(G) Separator oil composition and Reid vapor pressure. If this data is not available, determine these parameters by selecting one of the methods described under paragraph (h)(1)(G) of this section.

1. If separator oil composition and Reid vapor pressure default data are provided with the software program, select the default values that most closely match the separator pressure first, and API gravity secondarily.
2. If separator oil composition and Reid vapor pressure data are available through a previous analysis select the latest available analysis that is representative of produced crude oil or condensate from the sub-basin category.
3. Analyze a representative sample of separator oil in each sub-basin category for oil composition and Reid vapor pressure using an appropriate standard method published by a consensus-based standards organization.

(2) *Calculation Methodology 2*. Calculate annual CH_4 and CO_2 emissions from onshore production storage tanks for wellhead gas-liquid by assuming that all of the CH_4 and CO_2 in solution at separator temperature and pressure is emitted from oil sent to storage tanks using Equation 15. The facility operator may use an appropriate standard method published by a consensus-based standards organization if such a method exists or use an industry standard practice as described in section 95154(b) to sample and analyze separator oil composition at separator pressure and temperature.

$$E_i = GOR * Q_o * Y_i * \rho_i * 0.001 \qquad \text{(Eq 15)}$$

Where:

E_i = Annual emissions of greenhouse gas i (CO_2 or CH_4) metric tons/year).
GOR = Gas Oil Ratio.
Q_o = Oil production rate (barrels per year).
Y_i = Mole fraction of GHG i (CO_2 or CH_4) in tank vapor.
ρ_i = Density of GHG_i (Use 0.0526 kg/ft^3 for CO_2 and N_2O and 0.0192 kg/ft^3 for CH_4 at 60˚F and 14.7 psia.
0.001 = Conversion factor (tons/kg).

(3) Determine if the storage tank receiving the separator oil has a vapor recovery system. Count only separators or wells that feed oil directly to the storage tank.

(A) Adjust the emissions estimated in paragraphs (h)(1) and (h)(2) of this section downward by the magnitude of emissions recovered using a vapor recovery system as determined by engineering estimate based on best available data.

(4) Determine if the storage tank receiving the separator oil is sent to flare(s).

(A) Use separator flash gas volume and gas composition as determined in this section.
(B) Use the calculation methodology of flare stacks in paragraph (l) of this section to determine the contribution to storage tank emissions from the flare.

(5) Calculate emissions from occurrences of well pad gas-liquid separator liquid dump valves not closing during the calendar year by using Equation 16 of this section.

$E_{s,i} = (CF_n * E_n/8760 * T_n) + (E_t/8760 * (8760 - T_n))$ (Eq. 16)

Where:

$E_{s,n}$ = Annual total volumetric GHG emissions at standard conditions from each storage tank in cubic feet.
E_n = Storage tank emissions as determined in Calculation Methodology 1 or 2 paragraphs in sections (h)(1) or (h)(2) of this section (with wellhead separators) standard in cubic feet per year.
T_n = Total time the dump valve is not closing properly in the calendar year in hours. T_n is estimated by maintenance or operations records (records) such that when a record shows the valve to be open improperly, it is assumed the valve was open for the entire time period preceding the record starting at either the beginning of the calendar year or the previous record showing it closed properly within the calendar year. If a subsequent record shows it is closing properly, then assume from that time forward the valve closed properly until either the next record of it not closing properly or, if there is no subsequent record, the end of the calendar year.
CF_n = Correction factor for tank emissions for time period T_n is 3.87 for crude oil production. Correction factor for tank emissions for time period T_n is 5.37 for gas condensate production. Correction factor for tank emissions for time period T_n is 1.0 for periods when the dump valve is closed.
E_t = Storage tank emissions as determined in Calculation Methodology 1 or 2 in paragraphs (h)(1) and (h)(2) of this section at maintenance or operations during the time the dump valve is closing properly (i.e. 8760-T_n) in cubic feet per hour.
8,760 = Conversion to hourly emissions.

(6) Calculate both CH_4 and CO_2 mass emissions from volumetric natural gas emissions using calculations in paragraphs (s) and (t) of this section.

(i) *Transmission storage tanks*. For vent stacks connected to one or more transmission condensate storage tanks, either water or hydrocarbon, without vapor recovery, in onshore natural gas transmission compression, the operator of a facility must calculate CH_4, CO_2 and N_2O annual emissions from condensate scrubber dump valve leakage as follows:

(1) Monitor the tank vapor vent stack annually for emissions using an optical gas imaging instrument according to methods set forth in section 95154(a)(1) or by directly measuring the tank vent using a flow meter or high volume sampler according to methods in section 95154(b) through (d) for a duration of 5 minutes, or a calibrated bag according to methods in section 95154(b). Or the facility operator may annually monitor leakage through compressor scrubber dump valve(s) into the tank using an acoustic leak detection device according to methods in paragraph 95154(a)(5).

(2) If the tank vapors from the vent stack are continuous for 5 minutes, or the acoustic leak detection device detects a leak, then use one of the following two methods in paragraph (i)(2) of this section to quantify annual emissions:

(A) Use a meter, such as a turbine meter, calibrate bag, or high flow sampler to estimate tank vapor volumes from the vent stack according to methods set forth in section 95154(b) through (d). If a continuous flow measurement device is not installed, the facility operator may install a flow measuring device on the tank vapor vent stack. If the vent is directly measured for five minutes under paragraph (i)(1) of this section to detect continuous leakage, this serves as the measurement.

(B) Use an acoustic leak detection device on each scrubber dump valve connected to the tank according to the method set forth in section 95154(a)(5).

(C) Use the appropriate gas composition in paragraph (s)(2)(C) of this section.

(D) Calculate GHG volumetric and mass emissions at standard conditions using calculations in paragraphs (r), (s), and (t) of this section, as applicable to the monitoring equipment used.

(3) If the leaking dump valve(s) is fixed following leak detection, the annual emissions shall be calculated from the beginning of the calendar year to the time the valve(s) is repaired.

(4) Calculate annual emissions from storage tanks to flares as follows:

(A) Use the storage tank emissions volume and gas composition as determined in paragraphs (i)(1) through (i)(3) of this section.

(B) Use the calculation methodology of flare stacks in paragraph (l) of this section to determine storage tank emissions sent to a flare.

(j) Well testing venting and flaring. Calculate CH_4, CO_2 and N_2O (when flared) well testing venting and flaring emissions as follows:

(1) Determine the gas to oil ratio (GOR) of the hydrocarbon production from all oil well(s) tested. Determine the production rate from all gas well(s) tested.

(2) If GOR cannot be determined from available data, then the facility operator must measure quantities reported in this section according to one of the two procedures in paragraph (j)(2) of this section to determine GOR.

(A) The facility operator may use an appropriate standard method published by a consensus-based standards organization if such a method exists.

(B) Or the facility operator may use an industry standard practice as described in section 95154(b).

(3) Estimate venting emissions using Equation 17A or Equation 17B of this section.

$$E_{a,n} = GOR * FR * D \qquad \text{(Eq-17A)}$$

$$E_{a,n} = PR * D \qquad \text{(Eq. 17B)}$$

Where:

$E_{a,n}$ = Annual volumetric natural gas emissions from well(s) testing in cubic feet under actual conditions.

GOR = Gas to oil ratio, for well p in sub-basin q, in cubic feet of gas per barrel of oil; oil here refers to hydrocarbon liquids produced of all API gravities.

FR = Flow rate in barrels of oil per day for the oil well(s) being tested.

PR = Average annual production rate in actual cubic feet per day for the gas well(s) being tested.
D = Number of days during the year, the well(s) is tested.

(4) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (r) of this section.
(5) Calculate both CH_4 and CO_2 volumetric and mass emissions form volumetric natural gas emissions using the calculations in paragraphs (s) and (t) of this section.
(6) Calculate emissions from well testing to flares as follows:

(A) Use the well testing emissions volume and gas composition as determined in paragraphs (j)(1) through (3) of this section.
(B) Use the calculation methodology of flare stacks in paragraph (l) of this section to determine well testing emissions from the flare.

(k) Associated gas venting and flaring. Calculate CH_4, CO_2 and N_2O (when flared) associated gas venting and flaring emissions not in conjunction with well testing as follows:

(1) Determine the GOR of the hydrocarbon production from each well whose associated natural gas is vented or flared. If GOR from each well is not available, the GOR from a cluster of wells in the same sub-basin category shall be used.
(2) If GOR cannot be determined from available data, then use one of the two procedures in paragraph (k)(2) of this section to determine GOR.

(A) Use an appropriate standard method published by a consensus-based standards organization if such a method exists.
(B) Or the facility operator may use an industry standard practice as described in section 95154(b).

(3) Estimate venting emissions using Equation 18 of this section.

$$E_{a,n} = \sum_{q=1}^{y} \sum_{p=1}^{x} GOR_{p,q} * V_{p,q} \qquad \text{(Eq.18)}$$

Where:

$E_{a,n}$ = Annual volumetric natural gas emissions, at the facility level, from associated gas venting under actual conditions, in cubic feet.
$GOR_{p,q}$ = Gas to oil ratio, for well p in basin q, in cubic feet of gas per barrel of oil; oil here refers to hydrocarbon liquids produced of all API gravities.
$V_{p,q}$ = Volume of oil produced, for well p in basin q, in barrels in the calendar year during which associated gas was vented or flared.
x = Total number of wells in the basin that vent or flare associated gas.
y = Total number of basins that contain wells that vent or flare associated gas.

(4) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (r) of this section.

(5) Calculate both CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using calculations in paragraphs (s) and (t) of this section.

(6) Calculate emissions from associated gas to flares as follows:

(A) Use the associated natural gas volume and composition as determined in paragraph (k)(1) through(k) (4) of this section.

(B) Use the calculation methodology of flare stacks in paragraph (l) of this section to determine associated gas emissions from the flare.

(l) Flare stack or other destruction device emissions. Calculate CO_2, CH_4 and N_2O emissions from a flare stack or other destruction device as follows:

(1) For the purposes of this reporting requirement, the facility operator must calculate emission from all flares, incinerators, oxidizers and vapor combustion units.

(2) If a continuous flow measurement device is installed on the flare or destruction device, the measured flow volumes must be used to calculate the flare gas emissions. If all of the gas or liquid sent to the flare or destruction device is not measured by the existing flow measurement device, then the flow not measured can be estimated using engineering calculations based on best available data or company records. If a continuous flow measurement device is not installed on the flare or destruction device, a flow measuring device can be installed on the flare or destruction device or engineering calculations based on process knowledge, company records, and best available data may be sued.

(3) If a continuous gas composition analyzer is installed on the gas or liquid calculating emissions. If a continuous gas composition analyzer is not installed on gas or liquid supply to the flare or destruction device, use the appropriate gas composition for each stream of hydrocarbons going to the flare as follows:

(A) For onshore natural gas production, determine natural gas composition using (l)(3) of this section.

(B) For onshore natural gas processing, when the stream going to the flare is natural gas, use the GHG mole percent in feed natural gas for all streams upstream of the de-methanizer or dew point control, and GHG mole percent in facility specific residue gas to transmissions pipeline systems for all emissions sources downstream of the de-methanizer overhead or dew point control for onshore natural gas processing facilities. For onshore natural gas processing plants that solely fractionate a liquid stream, use the GHG mole percent in feed natural gas liquid for all streams.

(C) For any applicable industry segment, when the stream going to the flare is a hydrocarbon product stream, such as methane, ethane, propane, butane, pentane-plus and mixed light hydrocarbons, then the facility operator may use a representative composition from the source for the stream determined by engineering calculation based on process knowledge and best available data.

(4) Determine flare combustion efficiency from manufacturer. If not available, assume that flare combustion efficiency is 98 percent.

(5) Calculate GHG volumetric emissions at actual conditions using Equations 19, 20, and 21 of this section.

$$E_{a,CH4}(uncombusted) = V_a * (1 - \eta) * X_{CH4} \quad \text{(Eq. 19)}$$

$$E_{a,CO2}(uncombusted) = V_a * X_{CO2} \quad \text{(Eq. 20)}$$

$$E_{a,CO2}(combusted) = \sum_{j=1}^{5}\left(\eta * V_a * Y_j * R_j\right) \quad \text{(Eq. 21)}$$

Where:

$E_{a,CH4}$(uncombusted) = Contribution of annual un-combusted CH_4 emissions from flare stack in cubic feet, under actual conditions.
$E_{a,CO2}$ (uncombusted) = Contribution of annual un-combusted CO_2 emissions from flare stack in cubic feet, under actual conditions.
$E_{a,CO2}$(combusted) = Contribution of annual combusted CO_2 emissions from flare stack in cubic feet, under actual conditions.
V_a = Volume of gas sent to flare in cubic feet, during the year.
Ƞ = Fraction of gas combusted by a burning flare (default is 0.98). For gas sent to an unlit flare, η is zero.
X_{CH4} = Mole fraction of CH_4 in gas to the flare.
X_{CO2} = Mole fraction of CO_2 in gas to the flare.
Y_j = Mole fraction of gas hydrocarbon constituents j (such as methane, ethane, propane, and pentanes-plus).
R_j = Number of carbon atoms in the gas hydrocarbon constituent j: 1 for methane, 2 for ethane, 3 for propane, 4 for butane, and 5 for pentanes-plus.

(6) Calculate GHG volumetric emissions at standard conditions using calculations in paragraph (r) of this section.
(7) Calculate both CH_4 and CO_2 mass emissions from volumetric CH_4 and CO_2 emissions using calculation in paragraph (t) of this section.
(8) Calculate N_2O emissions from flare stacks using Equation 41 in paragraph (x) of this section.
(9) If the facility operator operates and maintains a CEMS that has both a CO_2 concentration monitor and volumetric flow rate monitor, calculate only CO_2 emissions for the flare. The facility operator must follow the Tier 4 Calculation Methodology and all associated calculation, quality assurance, reporting, and record keeping requirements for Tier 4 in section 95115. If a CEMS is used to calculate flare stack emissions, the requirements specified in paragraphs (l)(1) through (l)(8) are not required. If a CO_2 concentration monitor and volumetric flow rate monitor are not available, the facility operator may elect to install a CO_2 concentration monitor and a volumetric flow rate monitor that comply with all of the requirements specified for the Tier 4 Calculation Methodology in section 95115 of this part (Stationary Fuel Combustion Sources).
(10) The flare emissions determined under paragraph (l) of this section must be corrected for flare emissions calculated and reported under other paragraphs of this section to avoid double counting of these emissions.

(11) If source types in section 95153 use Equations 19 through 21 of this section, use estimate of emissions under actual conditions for the parameter, V_a, in these equations.

(m)Centrifugal compressor venting. Calculate CH_4, CO_2 and N_2O (when flared) emissions from both wet seal and dry seal centrifugal compressor vents as follows:

(1) For each centrifugal compressor with a rated horsepower of 250hp or greater covered by section 95152(c)(19), (d)(2), (e)(2), (f)(2), (g)(2), and (h)(2) the operator must conduct an annual measurement in each operating mode in which it is found for more than 200 hours in a calendar year. Measure emissions from all vents (including emissions manifolded to common vents) including wet seal oil degassing vents, unit isolation valve vents, and blowdown valve vents. Record emissions from the following vent types in the specified compressor modes during the annual measurement.

(A) Operating mode, blowdown valve leakage through the blowdown vent, wet seal and dry seal compressors.
(B) Operating mode, wets seal oil degassing vents.
(C) Not operating depressurized mode, unit isolation valve leakage through open blowdown vent, without blind flanges, wet seal and dry seal compressors.

1. For the not operating depressurized mode, each compressor must be measured at least once in any three consecutive calendar years. If a compressor is not operated and has blind flanges in place throughout the 3 year period, measurement is not required in this mode. If the compressor is in standby depressurized mode without blind flanges in place and is not operated throughout the 3 year period, it must be measured in the standby depressurized mode.

(2) For wet seal oil degassing vents, determine vapor volumes sent to an atmospheric vent or flare, using a temporary meter such as a vane anemometer or permanent flow meter according to section 95154(b) of this section. If a permanent flow meter is not installed, the operator may install a permanent flow meter on the wet seal oil degassing tank vent.
(3) For blowdown valve leakage and isolation valve leakage to open ended vents, use one of the following methods: Calibrated bagging or high volume sampler according to methods set forth in section 95154(c) and section 95154(d), respectively. For through valve leakage, such isolation valves, the facility operator may install a port for insertion of a temporary meter, or a permanent flow meter, on the vents.
(4) To determine Y_i, use gas composition data from a continuous gas analyzer if a continuous gas analyzer is installed, or quarterly measurements of gas composition where a continuous gas analyzer is not installed.
(5) Estimate annual emissions using the flow measurement and Equation 22 of this section.

$$E_{s,i,m} = \sum_m MT_m * T_m * Y_i * (1 - CF) \qquad \text{(Eq. 22)}$$

Where:

$E_{s,i,m}$ = Annual GHG (either CH_4 or CO_2) volumetric emissions at standard conditions, in cubic feet.
MT_m = Measured gas emissions in standard cubic feet per hour during operating mode m as described in sections (m)(1)(i) through (m)(1)(iii).
T_m = Total time the compressor is in the mode for which $E_{s,i}$ is being calculated, in the calendar year in hours.
Y_i = Mole fraction of GHG_i in the vent gas.
CF = Fraction of centrifugal compressor vent gas that is sent to vapor recovery or fuel gas as determined by keeping logs of the number of operating hours for the vapor recovery system and the amount of gas that is directed to the fuel gas or vapor recovery system.

(6) For each centrifugal compressor with a rated horsepower of less than 250hp covered by 95152(c)(19), (d)(2), (e)(2), (f)(2), (g)(2), and (h)(2), the operator must calculate annual emissions from both wet seal and dry seal centrifugal compressor vents using Equation 23 of this section.

$$E_{s,i} = Count * EF_i \qquad \text{(Eq. 23)}$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions from centrifugal compressors (<250hp) in cubic feet.
Count = Total number of centrifugal compressors less than 250hp.
EF_i = Emission factor for GHGi. Use 1.2×10^7 standard cubic feet per year per compressor for CH_4 and 5.30×10^5 standard cubic feet per year per compressor for CO_2 at 60˚F and 14.7 psia.

(7) Calculate both CH_4 and CO_2 mass emissions from volumetric emissions using calculations in paragraph (t) of this section.

(8) Calculate emissions from seal oil degassing vent vapors to flares as follows:

(A) Use the seal oil degasing vent vapor volume and gas composition as determined in paragraphs (m)(2) through (m)(4) of this section.

(B) Use the calculation methodology of flare stacks in paragraph (l) of this section to determine degassing vent vapor emissions from the flare.

(n) Reciprocating compressor venting. Calculate CH_4 and CO_2, and N_2O (when flared) emissions from all reciprocating compressor vents as follows:

(1) For each reciprocating compressor with a rated horsepower of 250hp or greater covered in sections 95152(c)(11), (d)(1), (e)(1), (f)(1), (g)(1), and (h)(1) the facility operator must conduct an annual measurement for each compressor in each operating mode in which it is found for more than 200 hours in a calendar year. Measure emissions from (including emissions manifolded to common vents) reciprocating rod packing vents, unit isolation valve vents, and blowdown valve vents. Record emissions

from the following vent types in the specified compressor modes during the annual measurement as follows:

(2) Operating or standby pressurized mode, blowdown vent leakage through the blowdown vent stack.

(3) Operating mode, reciprocating rod packing emissions.

(4) Not operating depressurized mode, unit isolation valve leakage through the blowdown vent stack, without blind flanges.

(A) For the not operating, depressurized mode, each compressor must be measured at least once in any three consecutive calendar years if this mode is not found in the annual measurement. If a compressor is not operated and has blind flanges in place throughout the 3 year period, measurement is not required in this mode. If the compressor is in standby depressurized mode without blind flanges in place and is not operated throughout the 3 year period, it must be measured in the standby depressurized mode.

(5) If reciprocating rod packing and blowdown vent are connected to an open-ended vent line, use one of the following two methods to calculate emissions:

(A) Measure emissions from all vents (including emissions manifolded to common vents) including rod packing, unit isolation valves, and blowdown vents using either calibrated bagging or high volume sampler according to methods set forth in section 95154(c) and section 95154(d), respectively.

(B) Use a temporary meter such as a vane anemometer or a permanent meter such as an orifice meter to measure emissions from all vents (including emissions manifolded to a common vent) including rod packing vents and unit isolation valve leakage through blowdown vents according to methods set forth in section 95154(b). If a permanent flow meter is not installed, the facility operator may install a port for insertion of a temporary meter or a permanent flow meter on the vents. For through-valve leakage to open ended vents such as unit isolation valves on not operating, depressurized compressors, use an acoustic detection device according to methods set forth in section 95154(a).

(6) If reciprocating rod packing is not equipped with a vent line use the following method calculate emissions:

(A) The facility operator must use the methods described in section 95154(a) to conduct annual leak detection of equipment leaks from the packing case into an open distance piece, or from the compressor crank case breather cap or other vent with a closed distance piece.

(B) Measure emissions found in paragraph (n)(5)(i) of this section using an appropriate meter, or calibrated bag, or high volume sampler according to the methods set forth in section 95154(b), (c), and (d) respectively.

(7) To determine Y_i, use gas composition data from a continuous gas analyzer if a continuous gas analyzer is installed, or quarterly measurements of gas composition where a continuous gas analyzer is not installed.

(8) Estimate annual emissions using the flow measurement and Equation 24 of this section.

$$E_{s,i,m} = \sum_m MT_m * T_m * Y_i * (1 - CF) \quad \text{(Eq. 24)}$$

Where:

$E_{s,i,m}$ = Annual GHG_i (either CH_4 or CO_2) volumetric emissions at standard conditions, in cubic feet.
MT_m = Measured gas emissions in standard cubic feet.
T_m = Total time the compressor is in the mode for which $E_{s,i,m}$ is being calculated, in the calendar year in hours.
Y_i = Mole fraction of GHG_i in the vent gas.
CF = Fraction of reciprocal compressor vent gas that is sent to vapor recovery or fuel gas as determined by keeping logs of the number of operating hours for the vapor recovery system and the amount of gas that is directed to the fuel gas or vapor recovery system.

(9) For each reciprocating compressors with a rated horsepower of less than 250hp, the operator must calculate annual emissions using Equation 25 of this section.

$$E_{s,i} = Count * EF_i \quad \text{(Eq. 25)}$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions from reciprocating compressors in cubic feet.
Count = Total number of reciprocating compressors for the facility operator.
EF_i = Emission factor for GHG_i. Use 9.48×10^3 standard cubic feet per year per compressor for CH_4 and 5.27×10^2 standard cubic feet per year per compressor for CO_2 at 60˚F and 14.7 psia.

(10) Estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using the calculations in paragraphs (s) and (t) of this section.

(o) Leak detection and leaker emission factors. The operator must use the methods described in section 95154(a) to conduct leak detection(s) of equipment leaks from all components types listed in sections 95152(c)(21), (d)(7), (e)(7), (f)(5), (g)(3), (h)(4), and (i)(1). This paragraph (o) applies to component types in streams with gas content greater than 10 percent CH_4 plus CO_2 by weight. Component types in streams with gas content less than 10 percent CH_4 plus CO_2 by weight do not need to be reported. Tubing systems equal to or less than one half inch diameter are exempt from the requirements of this paragraph (o) and do not need to be reported. If equipment leaks are detected for sources listed in this paragraph (o), calculate equipment leak emissions per component type per reporting facility using Equations 26 or 27 of this section for each component type. Use Equation 26 for industry segments listed in section 95150(a)(1) –(a)(7). Use Equation 27 for natural gas distribution facilities as defined in section 95150(a)(8).

$$E_{s,i} = GHG_i * \sum_{p=1}^{x} (EF * T_p) \quad \text{(Eq. 26)}$$

$$E_{s,i} = GHG_i * \sum_{q=t-n+1}^{t} \sum_{p=1}^{x} (EF * T_{p,q}) \quad \text{(Eq. 27)}$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions from each component type in cubic feet, as specified in (o)(1) through (o)(8) of this section.
X = Total number of each component type.
EF = Leaker emission factor for specific component types listed in Table 2 through 7 of this subpart.
GHG_i = For onshore natural gas processing facilities, concentration of GHG_i, CH_4 or CO_2, in the total hydrocarbon of the feed natural gas; for onshore natural gas transmission compression and underground natural gas storage, GHG_i equals 0.975 for CH_4 and 1.1 x 10^{-2} for CO_2; for LNG storage and LNG import and export equipment, GHG_i equals 1 for CH_4 and 0 for CO_2; and for natural gas distribution, GHG_i equals 1 for CH_4 and 1.1 x 10^{-2} for CO_2.
T_p = The total time the component, p, was found leaking and operational, in hours. If one leak detection survey is conducted, assume the component was leaking for the entire calendar year. If multiple leak detection surveys are conducted, assume that the component found to be leaking has been leaking since the previous survey (if not found leaking in the previous survey) or the beginning of the calendar year (if it was found leaking in the previous survey) or the beginning of the calendar year (if it was found leaking in the previous survey). For the last leak detection survey in the calendar year, assume that all leaking components continue to leak until the end of the calendar year.
t = Calendar year of reporting.
n = The number of years over which one complete cycle of leak detection is conducted over all the T-D transfer stations in a natural gas distribution facility; $0 < n \le 5$. For the first (n-1) calendar years of reporting the summation in Equation 27 should be for years that the data is available.
$T_{p,q}$ = The total time the component, p, was found leaking and operational, in hours, in year q. If one leak detection survey is conducted, assume the component was leaking for the entire period n. If multiple leak detection surveys are conducted, assume the component found to be leaking has been leaking since the previous survey) or the beginning of the calendar year (if it was found to be leaking in the previous survey). For the last leak detection survey in the cycle, assume that all leaking components continue to leak until the end of the cycle.

(1) The operator must select to conduct either one leak detection survey in a calendar year or multiple complete leak detection surveys in a calendar year. The number of leak detection surveys selected must be conducted during the calendar year.

(2) Onshore natural gas processing facilities must use the appropriate default leaker emission factors listed in Table 2 of this subpart for equipment leaks detected from valves, connectors, open ended lines, pressure relief valves, and meters.

(3) Onshore natural gas transmission facilities shall use the appropriate default leaker emission factors listed in Table 3 of this subpart for equipment leaks detected from valves, connectors, open ended lines, pressure relief valves, and meters.

(4) Underground natural gas storage facilities for storage stations shall use the appropriate default leaker emission factors listed in Table 4 of this subpart for equipment leaks detected from valves, connectors, open ended lines, pressure relief valves, and meters.

(5) LNG storage facilities shall use the appropriate default leaker emission factors listed in Table 5 of this subpart for equipment leaks detected from valves, pump seals, connectors, and other.

(6) LNG import and export facilities shall use the appropriate default leaker emission factors listed in Table 6 of this subpart for equipment leaks detected from valves, pump seals, connectors, and other.

(7) Natural gas distribution facilities for above ground transmission-distribution transfer stations, shall use the appropriate default leak emission factors listed in Table 7 of this subpart for equipment leaks detected from connectors, block valves, control valves, pressure relief valves, orifice meters, regulators, and open ended lines. Leak detection at natural gas distribution facilities is only required at above grade stations that qualify as transmission-distribution transfer stations. Below grade transmission-distribution transfer stations and all metering-regulating stations that do meet the definition of transmission-distribution transfer stations are not required to perform component leak detection under this section.

(A) Natural gas distribution facilities may choose to conduct leak detection at the T-D transfer stations over multiple years, not exceeding a five year period to cover all T-D transfer stations. If the facility chooses to use the multiple year option then the number of T-D transfer stations that are monitored in each year should be approximately equal across all years in the cycle without monitoring the same station twice during the multiple year survey.

(p) Population count and emission factors. This paragraph applies to emissions sources listed in sections 95152(f)(5), (g)(3), (h)(4), (i)(2), (i)(3), (i)(4), (i)(5), and (i)(6) on streams with gas content greater than 10 percent CH_4 plus CO_2 by weight. Emissions sources in streams with gas content less than 10 percent CH_4 plus CO_2 by weight do not need to be reported. Tubing systems equal to or less than one half inch diameter are exempt from the requirements of paragraph (p) of this section and do not need to be reported. Calculate emissions from all sources listed in this paragraph using Equation 28 of this section.

$$E_{s,i} = Count_s * EF_s * GHG_i * T_s \qquad \text{(Eq. 28)}$$

Where:

$E_{s,i}$ = Annual volumetric GHG emissions at standard conditions from each component type in cubic feet.

Counts = Total number of this type of emission source at the facility. For onshore petroleum and natural gas production, average component counts are provided by major equipment piece in Table 1B and Table 1C of this subpart. Use average component counts as appropriate for operations in Western U.S., according to Table 1D of this subpart for 2012 data. For 2013 calendar year emissions and onwards, actual components counts for individual facilities must be used. Underground natural gas storage shall count the components listed for population emission factors in Table 4. LNG storage shall count the number of vapor recovery compressors. LNG import and export shall count the number of vapor recovery compressors. Natural gas distribution shall count the meter/regulator runs as described in paragraph (p)(6) of this section.

EF = Population emission factor for the specific component type, as listed in Table 1A and Tables 3 through Table 7 of this subpart. Use appropriate emission factor for operations in Eastern and Western U.S., according to Table 1D of this subpart. EF for meter/regulator runs at above grade metering-regulator stations is determined in Equation 32 of this section.

GHG_i = For onshore petroleum and natural gas production facilities, concentration of GHG_i, CH_4 or CO_2, in produced natural gas as defined in paragraph (s)(2) of this section; for onshore natural gas transmission compression and underground natural gas storage, GHG_i equals 0.975 for CH_4 and 1.1×10^{-2} for CO_2; for LNG storage and LNG import and export equipment, GHG_i equals 1 for CH_4 and 0 for CO_2; for natural gas distribution, GHG_i equals 1 for CH_4 and 1.1×10^{-2} for CO_2.

T_s = Total time that each component type associated with the equipment leak emission was operational in the calendar year, in hours, using engineering estimate based on best available data.

(1) Calculate both CH_4 and CO_2 mass emissions from volumetric emissions using calculations in paragraph (t) of this section.

(2) Onshore petroleum and natural gas production facilities shall use the appropriate default population emission factors listed in Table 1A of this subpart for equipment leaks from valves, connectors, open ended lines, pressure relief valves, pump, flanges, and other. Major equipment and components associated with gas wells are considered gas service components in reference to Table 1A of this subpart and major natural gas equipment in reference to Table 1B of this subpart. Major equipment and components associated with crude oil wells are considered crude service components in reference to Table 1A of this subpart and major crude oil equipment in reference to Table 1C of this subpart. Where facilities conduct EOR operations the emissions factor listed in Table 1A of this subpart shall be used to estimate all streams of gases, including recycle CO_2 stream. The component count can be determined using either of the methodologies described in this paragraph (p)(2). The same methodology must be used for the entire calendar year.

(A) *Component Count Methodology 1*. For all onshore petroleum and natural gas production operations in the facility perform the following activities:

1. Count all major equipment listed in Table 1B and Table 1C of this subarticle. For meters/piping, use one meters/piping per well-pad.
2. Multiply major equipment counts by the average component counts listed in Table 1B and 1C of this subpart for onshore natural gas production and onshore oil production, respectively. Use the appropriate factor in Table 1A of this subpart for operations in Eastern and Western U.S. according to the mapping in Table 1D of this subpart.

(B) *Component Count Methodology 2*. Count each component individually for the facility. Use the appropriate factor in Table 1A of this subpart for operations in Western U.S.

(3) Underground natural gas storage facilities for storage wellheads must use the appropriate default population emission factors listed in Table 4 of this subpart for equipment leak from connectors, valves, pressure relief valves and open ended lines.
(4) LNG storage facilities must use the appropriate default population emission factors listed in Table 5 of this subpart for equipment leak from vapor recovery compressors.
(5) LNG import and export facilities must use the appropriate emission factor listed in Table 6 of this subpart for equipment leak from vapor recovery compressors.
(6) Natural gas distribution facilities must use the appropriate emission factors as described in paragraph (p)(6) of this section.

(A) Below grade metering-regulating stations; distribution mains; and distribution services, shall use the appropriate default population emission factors listed in Table 7 of this subpart. Below grade T-D transfer stations shall use the emission factor for below grade metering-regulating stations.
(B) Emissions from all above grade metering-regulating stations (including above grade TD transfer stations) shall be calculated by applying the emission factor calculated in Equation 29 and the total count of metering/regulator runs at all above grade metering-regulating stations (inclusive of TD transfer stations) to Equation 28. The facility wide emission factor in Equation 29 will be calculated by using the total volumetric GHG emissions at standard conditions for all equipment leak sources calculated in Equation 27 in paragraph (p)(8) of this section and the count of meter/regulator runs located at above grade transmission-distribution transfer stations that were monitored over the years that constitute one complete cycle as per (p)(8)(i) of this section. A meter on a regulator run is considered one meter regulator run. Facility operators that do not have above grade T-D transfer stations shall report a count of above grade metering-regulating stations only and do not have to comply with section 95157(c)(16)(T).

$$EF = E_{s,i}/(8760 * Count) \qquad \text{(Eq. 29)}$$

Where:

EF = Facility emission factor for a meter/regulator run per component type at above grade meter/regulator run for GHG_i in cubic feet per meter/regulator run per hour.

$E_{s,i}$ = Annual volumetric GHG_i emissions, CO_2 or CH_4 at standard condition from each component type at all above grade TD transfer stations, from Equation 30B.

Count = Total number of meter/regulator runs at all TD transfer stations that were monitored over the years that constitute one complete cycle as per (p)(8)(i) of this section.

8760 = Conversion to hourly emissions.

(q) Offshore petroleum and natural gas production facilities. Operators must report CO_2, CH_4, and N_2O emissions for offshore petroleum and natural gas production from all equipment leaks, vented emission, and flare emission source types as identified in the data collection and emissions estimate study conducted by BOEMRE in compliance with 30 CFR §§250.302 through 304.

(1) Offshore production facilities under BOEMRE jurisdiction must report the same annual emissions as calculated and reported by BOEMRE in data collection and emissions estimate study published by BOEMRE referenced in 30 CFR §§250.302 through 304 (GOADS).

(A) For any calendar year that does not overlap with the most recent BOEMRE emissions study publication year, report the most recent BOEMRE reported emissions data published by BOEMRE referenced in 30 CFR §§250.302 through 304 (GOADS). Adjust emissions based on the operating time for the facility relative to the operating time in the most recent BOEMRE published study.

(2) Offshore production facilities that are not under BOEMRE jurisdiction must use monitoring methods and calculation methodologies published by BOEMRE referenced in 30 CFR §§250.302 through 304 to calculate and report emissions (GOADS).

(A) For any calendar year that does not overlap with the most recent BOEMRE emissions study publication, report the most recent emissions data with emissions adjusted based on the operating time for the facility relative to the operating time for the facility in the previous reporting period.

(3) If BOEMRE discontinues or delays their data collection effort by more than 4 years, then offshore operators must once in every 4 years use the most recent BOEMRE data collection and emissions estimation methods to report emission from the facility sources.

(4) For either the first or subsequent year reporting, offshore facilities either within or outside of BOEMRE jurisdiction that were not covered in the previous BOEMRE data collection cycle must use the most recent BOEMRE data collection and emissions estimation methods published by BOEMRE referenced in 30 CFR §§250.302 through 304 to calculate and report emissions (GOADS) to report emissions.

(r) Volumetric emissions. If Equation parameters in section 95153 are already at standard conditions which results in volumetric emissions at standard conditions, then this paragraph does not apply. Calculate volumetric emissions at standard conditions as specified in paragraphs (r)(1) or (2) of this section, with actual pressure and temperature determined by engineering estimates based on best available data unless otherwise specified.

(1) Calculate natural gas volumetric emissions at standard conditions using actual natural gas emission temperature and pressure, and Equation 30 of this section for conversion of $E_{a,n}$ or conversion of Fr_a (whether subsonic or sonic).

$$E_{s,n} = E_{a,n} * (459.67 + T_s) * P_a/(459.67 + T_a) * P_s \quad \text{(Eq. 30)}$$

Where:

$E_{s,n}$ = GHG i volumetric emissions at standard temperature and pressure (STP) conditions in cubic feet except $E_{s,n}$ equals ($FR_{s,p}$) for each well p, when calculating either subsonic or sonic flow rates under 98.233(g).
$E_{a,n}$ = Natural gas volumetric emissions at actual conditions in cubic feet.
T_s = Temperature at standard conditions (60˚F).
T_a = Temperature at actual conditions (˚F).
P_s = Absolute pressure at standard conditions (14.7 psia).
P_a = Absolute pressure at actual conditions (psia).

(2) Calculate GHG volumetric emissions at standard conditions using actual GHG emissions temperature and pressure, and Equation 31 of this section.

$$E_{s,i} = E_{a,i} * (459.67 + T_s) * P_a/(459.67 + T_a) * P_s \quad \text{(Eq. 31)}$$

Where:

$E_{s,i}$ = GHG i volumetric emissions at actual conditions in cubic feet.
$E_{a,i}$ = GHG i volumetric emissions at actual conditions in cubic feet.
T_s = Temperature at standard conditions (60˚F).
P_s = Absolute pressure at standard conditions (14.7 psia).
P_a = Absolute pressure at actual conditions (Psia).

(3) Facility operators using 68˚F for standard temperature may use the ratio 519.67/527.67 to convert volumetric emissions from 68˚F to 60˚F.

(s) GHG volumetric emissions. Calculate GHG volumetric emissions at standard conditions as specified in paragraphs (s)(1) and (s)(2) of this section, with mole fraction of GHGs in the natural gas determined by engineering estimate based on best available data unless otherwise specified.

(1) Estimate CH_4 and CO_2 emissions from natural gas emissions using Equation 32 of this section.

$$E_{s,i} = E_{s,n} * M_i \qquad \text{(Eq. 32)}$$

Where:

$E_{s,i}$ = GHG i (either CH_4 or CO_2) volumetric emissions at standard conditions in cubic feet.
$E_{s,n}$ = Natural gas volumetric emissions at standard conditions in cubic feet.
M_i = Mole fraction of GHG i in the natural gas.

(2) For Equation 32 of this section, the mole fraction, M_i, must be the annual average mole fraction for each sub-basin category or facility, as specified in paragraphs (s)(2)(A) through (s)(2)(G) of this section.

(A) GHG mole fraction in produced natural gas for onshore petroleum and natural gas production facilities. If the facility has a continuous gas composition analyzer for produced natural gas, the facility operator must use an annual average of these values for determining the mole fraction. If the facility does not have a continuous gas composition analyzer, then the facility operator must use an annual average gas composition based on the most recent available analysis of the sub-basin category or facility, as applicable to the emissions source.

(B) GHG mole fraction in feed natural gas for all emissions sources upstream of the de-methanizer or dew point control and GHG mole fraction in facility specific residue gas to transmission pipeline system for all emissions sources downstream of the de-methanizer overhead or dew point control for onshore natural gas processing facilities. For onshore natural gas processing plants that solely fractionate a liquid stream, use the GHG mole percent in feed natural gas liquid for all streams. If the facility has a continuous gas composition analyzer on feed natural gas, the facility operator must use these values for determining the mole fraction. If the facility does not have a continuous gas composition analyzer, then annual samples must be taken according to methods set forth in 95154(b).

(C) GHG mole fraction in transmission pipeline natural gas that passes through the facility for the onshore natural gas transmission compression industry segment. If the facilty has a continuous gas composition analyzer, the facility operator must use these values for determining the mole fraction. If the facility does not have a continuous gas composition analyzer, then annual samples must be taken according to methods set forth in section 95154(b).

(D) GHG mole fraction in natural gas stored in the underground natural gas storage industry segment. If the facility has a continuous gas composition analyzer, the facility operator must use these values for determining the mole fraction. If the facility does not have a continuous gas composition analyzer, then annual samples must be taken according to methods set forth in section 95154(b).

(E) GHG mole fraction in natural gas stored in the LNG storage industry segment. If the facility has a continuous gas composition analyzer, the facility operator must use these values for determining the mole fraction. If the facility does not have a continuous gas composition analyzer, then annual samples must be taken according to methods set forth in section 95154(b).

(F) GHG mole fraction in natural gas stored in the LNG import and export industry segment. If the facility has a continuous gas composition analyzer, the facility operator must use these values for determining the mole fraction. If the facility does not have a continuous gas composition analyzer, then annual samples must be taken according to methods set forth in section 95154(b).

(G) GHG mole fraction in local distribution pipeline natural gas that passes through the facility for natural gas distribution facilities. If the facility has a continuous gas composition analyzer, the facility operator must use these values for determining the mole fraction. If the facility does not have a continuous gas composition analyzer, then annual samples must be taken according to methods set forth in section 95154(b).

(t) GHG mass emissions. Calculate GHG mass emissions in carbon dioxide equivalent by converting the GHG volumetric emissions at standard conditions into mass emissions using Equation 33 of this section.

$$Mass_i = E_{s,i} * \rho_i * 10^{-3} \quad \text{(Eq. 33)}$$

Where:

$Mass_i$ = GHG_i (either CH_4, CO_2, or N_2O) mass emissions in metric tons GHG_i.
$E_{s,i}$ = GHG_i (either CH_4, CO_2, or N_2O) volumetric emissions at standard conditions, in cubic feet.
P_i = Density of GHG_i. Use 0.0526 kg/ft^3 for CO_2 and N_2O, and 0.0192 kg/ft^3 for CH_4 at 60˚F and 14.7 psia.

(u) EOR injection pump blowdown. Calculate CO_2 pump blowdown emissions from EOR operations using critical CO_2 injection as follows:

$$Mass_{CO2} = N * V_v * R_c * GHG_i * 10^{-3} \quad \text{(Eq. 34)}$$

Where:

$Mass_{CO2}$ = Annual EOR injection gas venting emissions in metric tons from blowdowns.
N = Number of blowdowns for the equipment in the calendar year.
R_c = Density of critical phase EOR injection gas in kg/ft^3. The facility operator may use an appropriate standard method published by published by a consensus based organization if such a method exists or the facility operator may use an industry standard practice to determine density of super-critical emissions.
GHG_i = Mass fraction of GHG_i in critical phase injection gas.
1x 10^{-3} = Conversion factor from kilograms to metric tons.

(v) Hydrocarbon liquids dissolved CO_2 and CH_4. Calculate dissolved CO_2 and CH_4 in produced hydrocarbon liquids as follows:

$$Mass_{co2} = (S_{hl} * V_{hl})(1 - VR * CE) \quad \text{(Eq. 35)}$$

Where:

$Mass_{CO2}$ = Annual CO_2 emissions from CO_2 retained in hydrocarbon liquids produced through EOR operations beyond tankage, in metric tons.

S_{hl} = Amount of CO_2 retained in hydrocarbon liquids in metric tons per barrel, under standard conditions.

V_{hl} = Total volume of hydrocarbon liquids produced at the EOR operations in barrels in the calendar year.

VR = Percentage of time the vapor recovery unit was operational (expressed as a decimal).

CE = Collection efficiency of the vapor recovery system (expressed as a decimal).

(1) S_{hl} shall be determined annually by conducting an annual flash liberation test of hydrocarbon liquids using an established sampling and analytical methodology such as the ARB Draft Test Procedure entitled *Determination of Methane, Carbon Dioxide, and Volatile Organic Compounds from Crude Oil and Natural Gas Separation and Storage Tank Systems (2012)*.

(w) Produced water CO_2 and CH_4. The operator must calculate emissions of dissolved CO_2 and CH_4 in produced water sent to a storage tank or holding facility.

(1) Calculate CO_2 and CH_4 emissions from produced water degassing as follows:

$$E_{CO2/CH4} = (S_{pw} * V_{pw})(1 - VR * CE) \qquad \text{(Eq. 36)}$$

Where:

$E_{CO2/CH4}$ = Annual CO_2 or CH_4 emissions in metric tons.

S_{pw} = Mass of CO_2 or CH_4 liberated in a flash liberation test per barrel of produced water as determined in section (w)(1)(A).

V_{pw} = Volume of produced water sent to tank, pond or holding facility annually (barrels of water).

VR = Percentage of time the vapor recovery unit was operational (expressed as a decimal).

CE = Collection efficiency of the vapor recovery system (expressed as a decimal).

(2) S_{pw} shall be determined annually by conducting an annual flash liberation test of produced water using an established sampling and analytical methodology such as the ARB Draft Test Procedure entitled *Determination of Methane, Carbon Dioxide, and Volatile Organic Compounds from Crude Oil and Natural Gas Separation and Storage Tank Systems (2012)*.

(3) Operations where the produced water is directly routed from separation to re-injection into a hydrocarbon reservoir (the produced water is not exposed to atmospheric pressure) are exempt from this reporting requirement.

(x) Third Party Line-hits and uncontrolled pipeline blowdowns. Calculate emissions from third party line hits as follows:

(1) For each dig-in incident and pipeline rupture which releases more than 50 scf, calculate volumetric flow rate prior to pipeline isolation for both catastrophic pipeline ruptures and pipeline puncture incidents using the appropriate methodology below:

(A) For catastrophic pipeline ruptures where the pipeline is severed, use the following methodology:

$$Q_s = 3.6 * 10^6 * A/\rho_s * \sqrt{K * \frac{MW}{1{,}000} * R * (273.15 + T_a)} * P_a * M/(1 + K - 1/2 * M^2)^{K+1/2(K-1)} \quad \text{(Eq. 37)}$$

Where:

$M = \sqrt{2[(P_a/P_e)^{K-1/K} - 1]}/(K-1)$, (for M ≤1), M = 1 (for all other cases)

Where:

Q_s = Natural gas venting volumetric flow rate (scf/hr).
A = Cross-sectional flow area of the [pipe (m^2, A = $\pi D^2/4000$).
D = Inside diameter of the [pipe (mm).
K = specific heat ratio of the gas (dimensionless – 1.299 for methane).
M = Mach number of the flow (m/s).
MW = molecular weight of the gas (kg/mole, 16.043 kg/mole for methane).
P_a = pressure inside the pipe at supply (kPaa) (usually taken at the point where the damaged main branches off a larger main). The supply pressure values should represent a stable supply pressure; however, it is important to account for the lower pressure which will occur because of the flow of gas from the break.
P_e = Pressure at the damage point (local atmospheric pressure, kPaa).
R = Universal gas constant (8.3145 kPam^3/kmol/K).
T_a = Temperature inside pipe at the supply (˚C).
P_s = Gas density at standard conditions (kg/m^3) (0.6785 kg/m^3 for CH_4)

(B) For pipeline punctures, use the following methodology (for flows not choked):

$$Q_s = A_e/\rho_s \sqrt{2000 * \frac{K}{(K-1)} * (P_a/\rho_a)[(P_{Atm}/P_a)^{2/K} - (P_{Atm}/P_a)^{(K+1)/K}]} \quad \text{(Eq. 38)}$$

Where:

A_e = Size of the hole in the pipe (m^2).
P_a = Pressure inside the pipe at the puncture location (kPaa).
ρ_a = Gas density inside the pipe at the puncture location (kg/m^3).
MW = Molecular weight of the natural gas (16.043 for methane).
T_a = Temperature inside the pipe (˚C).
$(P_{atm}/P_a)_c$ = 0.546 – lower limit for choked flow.

(C) Check for choked flow.

1. If (P_{atm}/P_a) is ≥ 0.546 flow is not choked and the facility operator must use the equations in section (z)(1)(ii) above.
2. If (P_{atm}/P_a) < 0.546 flow is choked and A must be set to the cross sectional flow area of the pipe and the facility operator must use the equations in section (z)(1)(i) above.

(D) For controlled pipeline blowdowns use the calculation methodologies found in section 95153(g).

(E) Calculate volumetric natural gas emissions by multiplying Q_s for each pipeline rupture and puncture by the total elapsed time from pipeline rupture or puncture until isolation and final bleed-down to atmospheric pressure.

(F) Calculate GHG (CH_4 and CO_2 emissions) mass emissions using the methodologies in sections (s) and (t) of this section.

(y) Onshore petroleum and natural gas production and natural gas distribution combustion emissions. Calculate CO_2, CH_4, and N_2O combustion-related emissions from stationary or portable equipment, except as specified in paragraph (y)(3) and (y)(4) of this section as follows:

(1) If a fuel combusted in the stationary or portable equipment is listed in Table C-1 of section 95115 of this article, or is a blend containing one or more listed in Table C-1, calculate emissions according to (y)(1)(i). If the fuel combusted is natural gas and is of pipeline quality specification and has a minimum high heat value of 970 Btu per standard cubic foot, use the calculation methodology described in (y)(1)(i) and the facility operator may use the emission factor provided for natural gas as listed in Table C-1. If the fuel is natural gas, and is not pipeline quality calculate emissions according to (y)(2). If the fuel is field gas, process vent gas, or a blend containing field gas or process vent gas, calculate emissions according to (y)(2).

(A) For fuels listed in Table C-1 or a blend containing one or more fuels listed in Table C-1 of section 95115, calculate CO_2, CH_4, and N_2O emissions according to any Tier listed in section 95115.

(B) Emissions from fuel combusted in stationary or portable equipment at onshore natural gas and petroleum production facilities and at natural gas distribution facilities will be reported according to the requirements specified in section 95157(c)(19) and not according to the reporting requirements specified in section 95115 of this part.

(2) For fuel combustion units that combust field gas, process vent gas, a blend containing field gas or process vent gas, or natural gas that is not of pipeline quality, calculate combustion emissions as follows:

(A) The operator may use company records to determine the volume of fuel combusted in the unit during the reporting year.

(B) If a continuous gas composition analyzer is installed and operational on fuel supply to the combustion unit, the operator must use these compositions for determining the concentration of gas hydrocarbon constituent in the flow of gas to the unit. If a continuous gas composition analyzer is not installed on gas to the combustion unit, the facility operator must use the appropriate gas compositions for each stream of hydrocarbons going to the combustion unit as specified in (s)(2) of this section.

(C) Calculate GHG volumetric emissions at actual conditions using Equations 39 and 40 of this section:

$$E_{a,CO2} = (V_a * Y_{CO2}) + \eta * \sum_{j=1}^{5} V_a * Y_j * R_j \qquad \text{(Eq. 39)}$$

$$E_{a,CH4} = V_a * (1-\eta) * Y_{CH4} \qquad \text{(Eq. 40)}$$

Where:

$E_{a,CO2}$ = Contribution of annual CO_2 emissions from portable or stationary fuel combustion sources in cubic feet, under actual conditions.
V_a = Volume of fuel gas sent to combustion unit in cubic feet, during the year.
Y_{CO2} = Concentration of CO_2 constituent in gas sent to combustion unit.
$E_{a,CH4}$ = Contribution of annual CH_4 emissions from portable or stationary fuel combustion sources in cubic feet, under actual conditions.
η = Fraction of gas combusted for portable and stationary equipment determined using engineering estimation. For internal combustion devices, a default of 0.995 can be used.
Y_j = Concentration of gas hydrocarbon constituent j (such as methane, ethane, propane, butane and pentanes plus) in gas sent to combustion unit.
R_j = Number of carbon atoms in the gas hydrocarbon constituent j; 1 for methane, 2 for ethane, 3 for propane, 4 for butane, and 5 for pentanes plus, in gas sent to combustion unit.
Y_{CH4} = Concentration of methane constituent in gas sent to combustion unit.

(iv) Calculate N_2O mass emissions using Equation 4~~3~~1 of this section.

$$Mass_{N2O} = (1\,x\,10^{-3}) * Fuel * HHV * EF \qquad \text{(Eq. 41)}$$

Where:

$Mass_{N2O}$ = Annual N_2O emissions from the combustion of a particular type of fuel (metric tons N_2O).
Fuel = Mass or volume of the fuel combusted (mass or volume per year, choose appropriately to be consistent with the units of HHV).
HHV = For the higher heating value for field gas or process vent gas, use 1.235 x 10^{-3} mmBtu/scf for HHV.
EF = Use 1.0 x 10^{-4} kg N_2O/mmBtu.
1 x 10^{-3} = Conversion factor from kilograms to metric tons.

(3) External fuel combustion sources with a rated heat capacity equal to or less than 5 mmBtu/hr do not need to report combustion emissions or include these emissions for threshold determination in section 95101(e). The operator must report the type and number of each external fuel combustion unit.

(4) Internal fuel combustion sources, not compressor-drivers, with a rated heat capacity equal to or less than 1 mmBtu/hr (or equivalent of 130 horsepower), do not need to report combustion emissions or include these emissions for threshold determination in section 95105(e). The operator must report the type and number of each internal fuel combustion unit.

§95154 Monitoring and QA/QC requirements

The GHG emissions data for petroleum and natural gas emissions sources must be quality assured as applicable and as specified in this section. Offshore petroleum and natural gas production facilities must adhere to the monitoring and QA/QC requirements as set forth in 30 CFR §250.

(a) Facility operators must use any of the methods described as follows in this paragraph to conduct leak detection(s) of equipment leaks and through-valve leakage from all source types listed in section 95153(i), (m), (n) and (o) that occur during a calendar year, except as provided in paragraph (a)(4) of this section.

(1) *Optical gas imagining instrument*. Use an optical gas imagining instrument for equipment leak detection in accordance with 40 CFR part 60, subpart A, §60.18 of the *Alternative work practice for monitoring equipment leaks*, §60.18(i)(1)(i); §60.18(i)(2)(i) except that the monitoring frequency shall be annual using the detection sensitivity level of 60 grams per hour as stated in 40 CFR Part 60, subpart A, Table 1: *Detection Sensitivity Levels*; §60.18(i)(2)(ii) and (iii) except the gas chosen shall be methane, and §60.18(i)(2)(iv) and (v); §60.18(i)(3); §60.18(i)(4)(i) and (v); including the requirements for daily instrument checks and distances, and excluding requirements for video records. Any emissions detected by the optical gas imagining instrument is a leak unless screened with Method 21 (40 CFR part 60, appendix A-7) monitoring, in which case 10,000 ppm or greater is designated a leak. In addition, facility operators must operate the optical gas imagining instrument to image the source types required by this subpart in accordance with the instrument manufacturer's operating parameters. Unless using methods in paragraph (a)(2) of this section, an optical gas imagining instrument must be used for all source types that are inaccessible and cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface.

(2) *Method 21.* Use the equipment leak detection methods in 40 CFR part 60, appendix A-7, Method 21. If using Method 21 monitoring, if an instrument reading of 10,000 ppm or greater is measured, a leak is detected. Inaccessible emissions sources, as defined in 40 CFR part 60, are not exempt from this subpart. Owners or operators must use

alternative leak detection devices as described in paragraph (a)(1) or (a)(2) of this section to monitor inaccessible equipment leaks or vented emissions.

(3) *Infrared laser beam illuminated instrument.* Use an infrared laser beam illuminated instrument for equipment leak detection. Any emissions detected by the infrared laser beam illuminated instrument is a leak unless screened with Method 21 monitoring, in which case 10,000 ppm or greater is designated a leak. In addition, the facility operator must operate the infrared laser beam illuminated instrument to detect the source types required by this subpart in accordance with the instrument manufacturer's operating instructions.

(4) *Optical gas imagining instrument.* An optical gas imagining instrument must be used for all source types that are inaccessible and cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface.

(5) *Acoustic leak detection device*. Use the acoustic leak detection device to detect through-valve leakage. When using the acoustic leak detection device to quantify the through-valve leakage, use the instrument manufacturer's calculation methods to quantify the through-valve leak. When using the acoustic leak detection device, if a leak of 3.1 scf per hour or greater is calculated, a leak is detected. In addition, the facility operator must operate the acoustic leak detection device to monitor the source valves required by this subpart in accordance with the instrument manufacturer's operating parameters. Acoustic stethoscope type devices designed to detect through valve leakage when put in contact with the valve body and that provide an audible leak signal but do not calculate a leak rate can be used to identify non-leakers with subsequent measurement required to calculate the rate if through-valve leakage is identified. Leaks are reported if a leak rate of 3.1 scf per hour or greater is measured. In addition, the facility operator must operate the acoustic leak detection device to monitor the source valves required by this subpart in accordance with the instrument manufacturer's operating parameters.

(b) The operator must operate and calibrate all flow meters, composition analyzers and pressure gauges used to measure quantities reported in section 95153 according to the procedures in section 95103(k) and the procedures in paragraph (b) of this section. The facility operator may use an appropriate standard method published by a consensus-based standards organization if such a method exists or use an industry standard practice. Consensus-based standards organizations include the following: ASTM International, the American National Standards Institute (ANSI), the American Gas Association (AGA), the American Society of Mechanical Engineers (ASME), the American Petroleum Institute (API), and the North American Energy Standards Board (NAESB).

(c) Use calibrated bags (also known as vent bags) only where the emissions are at near-atmospheric pressures and below the maximum temperature specified by the vent bag manufacturer such that the vent bag is safe to handle. The bag opening must be of sufficient size that the entire emission can be tightly encompassed for measurement till the bag is completely filled.

(1) Hold the bag in place enclosing the emissions source to capture the entire emissions and record the time required for completely filling the bag. If the bag inflates in less than one second, assume one second inflation time.
(2) Perform three measurements of the time required to fill the bag, report the emissions as the average of the three readings.
(3) Estimate natural gas volumetric emissions at standard conditions using calculations in section 95153(r).
(4) Estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using the calculations in sections 95153(s) and (t).

(d) Use a high volume sampler to measure emissions within the capacity of the instrument.

(1) A technician following manufacturer instructions shall conduct measurements, including equipment manufacturer's operating procedures and measurement methodologies relevant to using a high volume sampler, including positioning the instrument for complete capture of the equipment leak without creating backpressure on the source.
(2) If the high volume sampler, along with all attachments available from the manufacturer, is not able to capture all the emissions from the source then use anti-static wraps or other aids to capture all emissions without violating operating requirements as provided in the instrument manufacturer's manual.
(3) Estimate natural gas volumetric emissions at standard conditions using calculations in section 95153(r). Estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using the calculations in sections 95153(s) and (t).
(4) Calibrate the instrument at 2.5 percent methane with 97.5 percent air and 100 percent CH_4 by using calibrated gas samples by following manufacturer's instructions for calibration.

(e) Peng-Robinson Equation of State means the equation of state defined by Equation 44 of this section.

$$p = \frac{RT}{(V_m - b)} - a\alpha/(V_m^2 + 2bV_m - b^2) \qquad \text{(Eq. 44)}$$

Where:

p = Absolute pressure.
R = Universal gas constant
T = Absolute temperature.
V_m = Molar volume.

$$a = 0.45724R^2T_c^2/p_c$$

$$b = 0.7780RT_c/p_c$$

$$\alpha = \left(1 + (0.37464 + 1.54226\omega - 0.26992\omega^2)\left(1 - \sqrt{T/T_c}\right)\right)^2$$

Where:

ω = Acentric factor of the species.
T_c = Critical temperature.
P_c = Critical pressure.

§95155 Procedures for estimating missing data.

(a) A complete record of all estimated and/or measured parameters used in the GHG emissions calculations is required. If data are lost or an error occurs during annual emissions estimation or measurements, the operator must repeat the estimation or measurement activity for those sources within the measurement period. In cases where repeat sampling and/or analysis cannot be completed, the operator must follow the missing data substitution procedures for 2013 and later emissions data reports. ~~For the 2012 emissions data report, the operator must follow the requirements of 40 CFR §98.235.~~

(1) To substitute for missing data for emission reported under section 95115 of this article (stationary combustion units and units using continuous emissions monitoring systems); the operator must follow the requirements of section 95129 of this article.

(2) If data required by this subarticle are missing and additional sampling and/or analysis is not possible, the operator must generate a substitute value as follows:

(A) If the analytical data capture rate is at least 90 percent for the data year, the operator must substitute for each missing value using available process data.

(B) If the analytical data capture rate is at least 80 percent but not at least 90 percent for the data year, the operator must substitute for each missing value with the highest quality assured value recorded for the parameter during the given data year, as well as the two previous data years.

(C) If the analytical data capture rate is less than 80 percent for the data year, the operator must substitute for each missing value with the highest quality assured value recorded for the parameter in all records kept according to section 95105(a).

~~**§ 95151. Reporting Threshold and Reporting Entity.**~~

~~(a) The operator of a facility with one or more source categories in section 95150 who is required to report under section 95101 of this article, and who is not eligible for abbreviated reporting under section 95103(a), must comply with this subarticle in reporting GHG emissions from petroleum and natural gas systems to ARB.~~

~~(b) In determining wh ether a facility in section 95150 meets the reporting threshold defined in section 95101(e), the operator must include combustion emissions from portable equipment that cannot move on roadways under its own power and drive train and that is stationed at a wellhead, including drilling rigs, dehydrators, compressors, electrical generators, steam boilers, and heaters. Natural gas processing facilities must also include owned or operated residue gas compression equipment.~~

~~NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4 and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.~~

~~§ 9515~~1~~2. GHGs to Report.~~

~~(a) The operator must monitor, calculate and report CO_2, CH_4, and N_2O emissions as applicable from each source type specified in paragraphs (b) through (k) of this section, according to the requirements of sections 95153 through 95156.~~

~~(b) For offshore petroleum and natural gas production, the operator must report emissions from all "stationary fugitive" and "stationary vented" sources as specified in 40 CFR §98.232(b).~~

~~(c) For onshore petroleum and natural gas production, the operator must report emissions from the source types specified in 40 CFR §98.232(c)(1)-(17) and (19)-(22), and additional applicable source types for which methods are specified in section 95153. Additional data must be reported in aggregated and disaggregated form as specified in section 95156(a)-(b).~~

~~(d) For onshore natural gas processing, the operator must report emissions from the sources identified in 40 CFR §98.232(d).~~

~~(e) For onshore natural gas transmission compression, the operator must report emissions the sources identified in 40 CFR §98.232(e), and natural gas driven pneumatic pump venting.~~

~~(f) For underground natural gas storage, the operator must report emissions from the sources identified in 40 CFR §98.232(f), and natural gas driven pneumatic pump venting. Additional data must be reported as specified in section 95156(c).~~

~~(g) For liquefied natural gas (LNG) storage, the operator must report emissions from the sources identified in 40 CFR §98.232(g).~~

~~(h) For LNG import and export equipment, the operator must report emissions from the sources identified in 40 CFR §98.232(h).~~

~~(i) For natural gas distribution, the operator must report emissions from the sources identified in 40 CFR §98.232(i),~~

~~(j) The operator in all applicable industry segments must report the CO_2, CH_4, and N_2O emissions from each flare.~~

~~(k) The operator must report emissions of CO_2, CH_4, and N_2O from each stationary fuel combustion unit by following the requirements of section 95115 of this article.~~

~~NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4 and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.~~

~~§ 95153. Calculating GHG Emissions.~~

~~The operator who is a local distribution company reporting under section 95122 of this article must comply with 40 CFR §98.233 in reporting emissions from the applicable source types in section 95152(e)-(i) of this article. Other operators must comply with 40 CFR §98.233 in reporting applicable emissions by source type, except as otherwise provided in this section.~~

~~(a) *Natural Gas Pneumatic High Bleed Device and Pneumatic Pump Venting.* The operator who is subject to the requirements of 40 CFR §98.233(a) and (c) must calculate emissions from natural gas high bleed flow control device and pneumatic pump venting using the method specified in paragraph (a)(1) below when the device or pump is metered. By January 1, 2015, natural gas consumption must be metered for all of the operator's pneumatic high bleed devices and pneumatic pumps. For the purposes of this reporting requirement, high bleed devices are defined as all natural gas powered devices (both intermittent and continuous bleed devices) which bleed at a rate greater than 6 scf/hr. For unmetered devices the operator must use the method specified in 40 CFR §98.233(a) and (c) as applicable. Vented emissions from natural gas driven pneumatic pumps covered in paragraph (d) of this section do not have to be reported under paragraph (a) of this section.~~

~~(1) The operator must calculate vented emissions for all metered pneumatic high bleed devices and pneumatic pumps using the following equation:~~

$$\cancel{E_m = \sum_{1}^{n} B_n}$$

~~Where:~~

~~E_m = Annual natural gas emissions at standard conditions, in cubic feet for all pneumatic high bleed devices and pneumatic pumps where gas is metered.~~

~~n = Total number of meters.~~

~~B_n = Natural gas consumption for meter n.~~

~~(2) For both metered and unmetered devices and pumps, CH_4 and CO_2 volumetric and mass emissions must be calculated from volumetric natural gas emissions using calculations in paragraphs (s) and (t) of this section.~~

~~(b) *Natural Gas Pneumatic Low Bleed Device Venting.* The operator must calculate CH_4 and CO_2 emissions from natural gas pneumatic low bleed devices using either the method specified in paragraph (a)(1) of this section or the method specified in 40 CFR §98.233(a). For the purposes of this reporting requirement, low bleed devices are defined as all natural gas powered devices (both intermittent and continuous bleed devices) which bleed at a rate less than or equal to 6 scf/hr.~~

~~(1) CH_4 and CO_2 volumetric and mass emissions must be calculated from volumetric natural gas emissions using calculations in paragraphs (s) and (t) of this section.~~

~~(c) *Acid Gas Removal (AGR) Vent Stacks.* The operator who is subject to the reporting requirements of 40 CFR §98.233(d) for AGR vents must use the applicable Calculation Methodology 1, 2, or 3 in 40 CFR §98.233(d). The operator who uses Calculation Methodology 3 must also use the methodology in paragraph (c)(1) below.:~~

~~(1) To measure natural gas volume into the AGR unit, the operator must use the following formula:~~

$$\cancel{E_{a,CO2} = V_{IN}(Vol_{IN} - Vol_{OUT})}$$

~~Where:~~

~~$E_{a,CO2}$ = Annual volumetric CO_2 emissions at actual conditions, in cubic feet per year.~~

~~V_{IN}= Total annual volume of natural gas flow into the AGR unit in cubic feet per year at actual conditions using methods specified in paragraph (c)(2) of this section.~~

~~Vol_{IN} = Volume fraction of CO_2 content in natural gas into the AGR unit as determined in 40 CFR §98.233(d)(7).~~

~~Vol_{OUT} = Volume fraction of CO_2 content in natural gas out of the AGR unit as determined in 40 CFR §98.233(d)(8).~~

~~(2) If the operator measures natural gas volume out of the AGR, the operator must use the following formula:~~

$$\cancel{E_{a,CO2} = \left[V_{OUT} / 1 \quad (Vol_{IN} \quad Vol_{OUT})\right](Vol_{IN} \quad Vol_{OUT})}$$

~~Where:~~

~~$E_{a,CO2}$ = Annual volumetric CO_2 emissions at actual conditions, in cubic feet per year.~~

~~V_{OUT}= Total annual volume of natural gas flow out of AGR unit in cubic feet per year at actual conditions using methods specified in paragraph (c)(2) of this section.~~

~~Vol_{IN} = Volume fraction of CO_2 content in natural gas into the AGR unit as determined in paragraph (c)(4) of this section.~~

~~Vol_{OUT} = Volume fraction of CO_2 content in natural gas out of the AGR unit as determined in paragraph (c)(4) of this section.~~

~~(3) Record the gas flow rate of the inlet and outlet natural gas stream of an AGR unit using a meter according to methods set forth in 40 CFR §98.234(b).~~

~~(4) If a continuous gas analyzer is not available on the vent stack, either install a continuous gas analyzer or take quarterly gas samples from the vent gas stream to determine Vol_{CO2} according to methods set forth in 40 CFR §98.234(b).~~

~~(5) If a continuous gas analyzer is installed on the inlet gas stream, then the continuous gas analyzer results must be used. If a continuous gas analyzer is not available, either install a continuous gas analyzer or take quarterly gas samples from the inlet gas stream to determine Vol_{IN} or Vol_{OUT} according to methods set forth in 40 CFR §98.234(b).~~

~~(6) Determine volume fraction of CO_2 content in natural gas out of the AGR unit using one of the methods specified in 40 CFR §98.233(d)(8).~~

~~(A) If a continuous gas analyzer is installed on the outlet gas stream, then the continuous gas analyzer results must be used. If a continuous gas analyzer is not available, the operator may install a continuous gas analyzer.~~

~~(B) If a continuous gas analyzer is not available or installed, quarterly gas samples may be taken from the outlet gas stream to determine Vol_{O} according to methods set forth in 40 CFR §98.234(b).~~

~~(7) Calculate CO_2 volumetric emissions at standard conditions using calculations in paragraph (r) of this section.~~

~~(8) Mass CO_2 emissions shall be calculated from volumetric CO_2 emissions using calculations in paragraph (t) of this section.~~

~~(9) Determine if emissions from the AGR unit are recovered and transferred outside the facility. The operator who is required to report these transferred emissions under section 95123 of this article is not required to report CO_2 transferred off-site in this section.~~

~~(d) *Dehydrator Vent Stacks.* The operator who is subject to the reporting requirements for dehydrator vents in 40 CFR §98.233(e) must use Calculation Methodology 1 in 40 CFR §98.233(e) and follow the requirements in 40 CFR §98.233(e)(3)-(5). The operator who uses Calculation Methodology 1 must determine the model input parameters of 40 CFR §98.233(e)(1)(i)-(xi) under normal operating conditions. Wet natural gas composition must be determined using an industry standard method. When using the methodology found in 40 CFR §98.233(e)(5) for desiccant dehydrators, the operator must use the following methodology and equation:~~

~~(1) For dehydrators that use desiccant, the operator shall calculate emissions from the amount of gas vented from the vessel every time the desiccator is depressurized for the desiccant refilling process, using the following equation. Desiccant dehydrators covered in paragraph (g) of this section do not have to report emissions under this paragraph.~~

$$\cancel{E_{s,n} = n(H * D^2 * \pi * P_2 * \%G)/(4 * P_1 * 1{,}000cf/Mcf)}$$

~~Where;~~
~~$E_{S,n}$ = Annual natural gas emissions at standard conditions (Mcf).~~
~~n = number of dessicant refillings during the reporting period.~~
~~H = Height of the dehydrator vessel (ft).~~
~~D = Inside diameter of the vessel (ft).~~
~~P_1 = Atmospheric pressure (psia)~~
~~P_2 = Pressure of the gas (psia).~~
~~π = pi (3.1416).~~
~~%G = Percent of packed vessel volume that is gas (expressed as a decimal).~~

~~(2) Both CH_4 and CO_2 volumetric and mass emissions must be calculated from volumetric natural gas emissions using the calculations in paragraphs (s) and (t) of this section.~~

~~(e) *Well Venting For Liquids Unloadings*~~

~~(1) The operator who is subject to the reporting requirements of 40 CFR §98.233(f) must calculate emissions from each well venting for liquids unloading using the methods found in 40 CFR §98.233(f)(2)-(4).~~

~~(f) *Gas Well Venting During Completions and Workovers.*~~

~~The operator who is subject to the reporting requirements in 40 CFR §98.233(g) and/or §98.233(h) must calculate emissions for each well completion and workover using one of the following methods.~~

~~(1) *Calculation Methodology 1:*~~

~~(A) The operator must measure total gas flow with a recording flow meter (analog or digital) installed in the vent line.~~

~~(B) The operator must correct total gas volume vented for the volume of CO_2 or N_2 injected and the volume of gas recovered into a sales lines as follows:~~

$$V_{c/wo} = V_M - V_{CO2/N2)} - SG$$

~~Where:~~

~~$V_{c/wo}$ = Volume of gas vented during the well completion or workover.~~

~~V_M = Volume of vented gas measured during well completion or workover.~~

~~$V_{CO2/N2}$ = Volume of CO_2 or N_2 injected during well completion or workover.~~

~~SG = Volume of gas recovered into a sales pipeline.~~

~~(C) All gas volumes must be corrected to standard temperature and pressure using methods in paragraph (r) of this section.~~

~~(D) The operator must calculate CO_2 and CH_4 mass emissions from gas venting using the methods found in paragraphs (r) and (s) of this section.~~

~~(2) *Calculation Methodology 2:*~~

~~(A) The operator must make a series of measurements of upstream pressure (P_1) and downstream pressure (P_2) across a choke installed in the vent line and upstream gas temperature according to methods in section 95154 during each well completion and well workover. The operator must record this data at a time interval (*e.g.*, every five minutes) suitable to accurately describe both sonic and subsonic flow regimes. Sonic flow is defined as the flow regime where $P_2/P_1 \leq 0.542$. Subsonic flow is defined as the flow regime where $P_2/P_1 > 0.542$. The operator must then calculate flow rate for both sonic and subsonic flow regimes using the following equations:~~

~~1. Sonic flow regime~~

~~a. The operator must calculate average flow rate during sonic flow conditions as follows:~~

$$FR_s = 1.27 * 10^5 * A * \sqrt{187.08 * T_u}$$

~~FR_s = Average flow rate in cubic feet per hour under sonic flow conditions.~~
~~$1.27*10^5$ = Conversion factor from m^3/second to ft^3/hour.~~
~~A = Cross sectional area of the orifice (m^2).~~
~~187.08 = Constant with units of $m^2/(sec^2*K)$.~~
~~T_u = Upstream gas temperature (degrees Kelvin).~~

~~b. The operator must calculate total gas volume vented during sonic flow conditions as follows:~~

$$V_s = T_s * FR_s$$

~~Where:~~
~~V_s = Volume of gas vented during sonic flow conditions (scf).~~
~~T_s = Total time the specific source associated with the equipment leak emission was operational in the calendar year, in hours.~~
~~FR_s = Average flow rate in cubic feet per hour under sonic flow conditions.~~

~~c. The operator must correct V_s to standard conditions using the methodology in paragraph (r) of this section.~~

~~2. Subsonic flow regime~~

~~a. The operator must calculate instantaneous gas flow rates during subsonic flow conditions as follows:~~

$$FR_{i/ss} = 1.27 * 10^5 * A * \sqrt{3430 * T_u[(P_2/P_1)^{1.515} - (P_2/P_1)^{1.758}]}$$

~~Where:~~
~~$FR_{i/ss}$ = Instantaneous flow rate at time T_i during subsonic~~

~~flow conditions.~~
~~$1.27*10^5$ = Conversion factor from m^3/second to ft^3/hr.~~
~~A = Cross sectional area of the orifice (m^2).~~
~~3430 = Constant with units of m^2/(sec*K).~~
~~T_u = Upstream gas temperature (degrees Kelvin).~~
~~P_2 = Downstream pressure (psia).~~
~~P_1 = Upstream pressure (psia).~~

~~b. The operator must determine total gas volume vented during subsonic flow conditions (V_{ss}) as the total volume under the curve of a plot of $FR_{i/ss}$ and Time (T_i) for the time period during which the well was flowing under subsonic conditions.~~

~~c. The operator must sum the vented volumes during sonic and subsonic flow and adjust emissions for the volume of CO_2 or N_2 injected and the volume of gas recovered into a sales lines as follows:~~

$$\cancel{V_{c/wo} = V_s + V_{ss} - V_{\frac{CO2}{N2}} - SG}$$

~~Where:~~
~~$V_{c/wo}$ = Volume of gas vented during well completion or workover (scf).~~
~~V_s = Volume of gas vented during sonic flow conditions (scf).~~
~~V_{ss} = Volume of gas vented during subsonic flow conditions (scf).~~
~~$V_{CO2/N2}$ = Volume of CO_2 or N_2 injected during well completion or workover.~~
~~SG = Volume of gas recovered into a sales pipeline (scf).~~

~~d. The operator must correct all gas volumes to standard conditions using methods in paragraph (r) of this section.~~

~~e. The operator must sum emissions from all well completions and workovers and calculate CO_2 and CH_4 volumetric and mass emissions using the methods in paragraphs (s) and (t) of this section.~~

~~(g) *Transmission storage tanks.* The operator who is subject to the requirements of 40 CFR §98.233(k) must use the calculation methodologies in 40 CFR §98.233(k).~~

~~(h) *Blowdown Vent Stacks.* The operator who is subject to the requirements of 40 CFR §98.233(i) must use the reporting methodologies in 40 CFR §98.233(i).~~

~~(i) *Onshore Production and Processing Storage Tanks.* The operator who is subject to the requirements of 40 CFR §98.233(j) must use the calculation methodologies in 40 CFR §98.233(j).~~

~~(j) *Well Testing Venting and Flaring.* The operator who is subject to the reporting requirements in 40 CFR §98.2333(l) must use the calculation methodologies in 40 CFR §98.233(l).~~

~~(k) *Associated Gas Venting and Flaring.* The operator who is subject to the reporting requirements of 40 CFR §98.233(m) must use the calculation methodology found in 40 CFR §98.233(m).~~

~~(l) *Flare Stacks.* The operator who is subject to the reporting requirements in 40 CFR §98.233(n) must use the calculation methodologies found in 40 CFR §98.233(n).~~

~~(m) *Centrifugal Compressor Venting.*~~

~~(1) The operator must calculate CO_2, CH_4, and N_2O (when flared) emissions from both wet seal and dry seal centrifugal compressor vents for all compressors with rated horsepower of 250hp or greater using the methodologies found in 40 CFR §98.233(o)(1)-(6) and (8)-(9).~~

~~(2) The operator must calculate CO_2, CH_4, and N_2O (when flared) emissions for all centrifugal compressors with rated horsepower less than 250hp using the methodologies found in 40 CFR §98.233(o)(7).~~

~~(n) *Reciprocating Compressor Rod Packing Venting.* The operator must calculate annual CH_4, CO_2, and N_2O (when flared) emissions from each reciprocating compressor rod packing venting for each applicable operational mode for all compressors with a rated horse power of 250hp or greater using the methodologies found in 40 CFR §98.233(p)(1)-(8) and (10). The operator must calculate CO_2, CH_4, and N_2O (when flared) emissions from reciprocating compressor rod packing venting for each applicable operational mode for all reciprocating compressors with a rated horse power less than 250hp using the methodologies found in 40 CFR §98.233(p)(9).~~

~~(o) *Leak Detection and Leaker Emission Factors.* The operator who is subject to the reporting requirements found in 40 CFR §98.233(q) must use the calculation methodologies found in 40 CFR §98.233(q).~~

~~(p) *Population Count and Emission Factors.* The operator who is subject to the reporting requirements found in 40 CFR §98.233(r) must use the calculation methodologies found in 40 CFR §98.233(r).~~

~~(q) *Offshore Petroleum and Natural Gas Production Facilities*. The operator who is subject to the reporting requirements found in 40 CFR §98.233(s) must use the calculation methodologies found in 40 CFR §98.233(s).~~

~~(r) *Volumetric Emissions.* The operator must use the calculation methodologies found in 40 CFR §98.233(t) when calculating volumetric emissions at standard conditions using the calculation methodologies found in 40 CFR §98.233(t).~~

~~(s) *GHG Volumetric Emissions.* The operator must calculate GHG volumetric emissions at standard conditions as specified in 40 CFR §98.233(u).~~

~~(t) *GHG Mass Emissions.* The operator must calculate GHG mass emissions using the following equation:~~

$$\cancel{Mass_{s,i} = E_{s,i} * \rho_i * 10^{-3}}$$

~~Where:~~

~~$Mass_{s,i}$ = GHG i (either CO_2 or CH_4) mass emissions at standard conditions in metric tons.~~

~~$E_{s,i}$ = GHG i (either CO_2 or CH_4) volumetric emissions at standard conditions, in cubic feet.~~

~~P = Density of GHG i. Use 0.0538 kg/ft^3 for CO_2 and N_2O, and 0.0196 kg/ft^3 for CH_4 at 68˚F and 14.7 psia or 0.0530 kg/ft^3 for CO_2 and N_2O, and 0.0193 kg/ft^3 for CH_4 at 60˚F and 14.7 psia.~~

~~(u) *EOR Injection Pump Blowdown.* The operator who is subject to the reporting requirements in 40 CFR §98.233(w) must use the calculation methodologies found in 40 CFR §98.233(w).~~

~~(v) *Produced Water Dissolved CO_2 and CH_4.* The operator must calculate dissolved CO_2 and CH_4 in produced water. Emissions must be reported for produced water sent to a storage tank or ponds and holding facilities.~~

~~(1) Calculate CO_2 and CH_4 emissions from produced water using the following equation:~~

$$\cancel{E_{CO2/CH4} = \left(S_{pw} * V_{pw}\right)(1 - VR * CE)}$$

~~Where:~~

~~$E_{CO2/CH4}$ = Annual CO_2 or CH_4 emissions in metric tons.~~

~~S_{pw} = Mass of CO_2 or CH_4 liberated in a flash liberation test per barrel of produced water (as determined in section (v)(A)(i) or mass of CO_2 or CH_4 recovered in a VRU per barrel of produced water (as determined in section (v)(A)(ii).~~

~~V_{pw} = Barrels of produced water sent to tank, pond or holding facility annually.~~

~~VR = Percentage of time the vapor recovery unit was operational (expressed as a decimal).~~

~~CE = Collection efficiency of the vapor recovery system (expressed as a decimal).~~

~~(A) S_{pw} (the mass of CO_2 or CH_4 per barrel of produced water) shall be determined using one of the following methods:~~

~~1. Flash liberation test. Measure the amount of CO_2 and CH_4 liberated from produced water when the water changes temperature and pressure from well stream to standard atmospheric conditions using a sampling methodology and a flash liberation test such as adopted Gas Processor Association standards. The flash liberation test results must provide the metric tons of CO_2 and CH_4 liberated per barrel of produced water.~~

~~2. Vapor recovery system method. For storage tank systems connected to a vapor recovery system, calculate the mass of CO_2 and CH_4 liberated from produced water by sampling (under representative operating conditions) and analysis of the VRU gas stream to determine the mass of CO_2 and CH_4 captured by the vapor recovery system per barrel of water produced. A gas analysis of the processed vapor is required to determine the mole percentage of CO_2 and CH_4 in the gas stream and to calculate the annual emission rate.~~

~~(B) Emissions resulting from the destruction of the VRU gas stream shall be reported using the Flare Stack reporting provisions in paragraph (l) of this section.~~

~~(2) EOR operations that route produced water from separation directly to re-injection into the hydrocarbon reservoir are exempt from paragraph (v) of this section.~~

~~(w) *Stationary and Portable Equipment Combustion Emissions.* The operator must use the methods in section 95115 to report the emissions of CO_2, CH_4, and N_2O from stationary or portable fuel combustion equipment as defined in 40 CFR §98.232(c)(22).~~

~~NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4 and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.~~

~~§ 95154. Monitoring and QA/QC Requirements.~~

~~(a) The operator must conform with the monitoring and QA/QC requirements of 40 CFR §98.234.~~

~~NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4 and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.~~

NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4 and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.

§ 95156. Additional Data Reporting Requirements.

Operators must conform with the data reporting requirements in ~~40 CFR §98.236~~ <u>section 95156</u> except as specified below.

(a) In addition to the data required by 40 CFR ~~40 CFR §98.236 (a)-(c), t~~The operator of an onshore <u>and offshore</u> petroleum and natural gas production facility must report the following data disaggregated within the basin by each facility that lies within contiguous property boundaries:

(1) CO_2e emissions, including CO_2, CH_4, and N_2O as applicable for the source types specified in section 95152(c);
(2) For combustion sources for which emissions are reported, fuel use by fuel type;
<u>(3) For cogeneration sources:</u>

<u>(A) Total thermal output (MMBtu) and the portion of CO_2e emissions associated with this output;</u>
<u>(B) Net electricity generation (MWh) and the portion of CO_2e emissions associated with this generation;</u>

(C) Amount of electricity generation (MWh) not consumed within the facility (i.e., exported offsite or to another facility owner/operator) and the portion of CO_2e emissions associated with this generation;

(4) For steam generator sources:

(A) Total thermal output (MMBtu) and the CO_2e emissions associated with this output;
(B) Thermal output (MMBtu) not utilized within the facility (i.e., exported offsite or to another facility owner/operator) and the CO_2e emissions associated with this output;

(5) For electricity generation sources, not included in section 95156(a)(3):

(A) Net electricity generation (MWh) and the CO_2e emissions associated with this generation;
(B) Amount of electricity generation (MWh) not consumed within the facility (i.e., exported offsite or to another facility owner/operator) and the portion of CO_2e emissions associated with this generation;

(6) Total steam (MMBtu) utilized but not generated at the facility and the CO_2e emissions associated with this output, if known;
~~(3)~~(7) Barrels of crude oil produced using thermal enhanced oil recovery, ~~and the portion of CO_2e emissions associated with this production~~;
~~(4)~~(8) Barrels of crude oil produced using methods other than thermal enhanced oil recovery, ~~and the portion of CO_2e emissions associated with this production.~~;
(9) MMBtu of associated natural gas produced using thermal enhanced oil recovery;
(10) MMBtu of associated natural gas produced using methods other than thermal enhanced oil recovery.

(b) In lieu of the requirements of ~~40 CFR §98.236(c)(19)~~section 95157(c)(19), the operator of an onshore petroleum and natural gas production facility must submit combustion emissions data according to the requirements of ~~40 CFR §98.36~~section 95115(c).

(c) For dry gas production, the operator must report the volume of dry natural gas produced (Mscf).

~~(c)~~ (d) For underground natural gas storage, the operator must report the volume of natural gas extracted (Mscf).

§95157 Data Reporting Requirements. In addition to the information required by section 95103, each annual report must contain reported emissions and related information as specified in this section.

(a) Report annual emissions in metric tons per year for each GHG separately for each of the industry segments listed in paragraphs (a)(1) through (8) of this section:

(1) Onshore petroleum and natural gas production.
(2) Offshore petroleum and natural gas production
(3) Onshore natural gas processing.
(4) Onshore natural gas transmission compression.
(5) Underground natural gas storage.
(6) LNG storage.
(7) LNG import and export.
(8) Natural gas distribution.

(b) For offshore petroleum and natural gas production, report emissions of CH_4, CO_2, and N_2O as applicable to the source type (in metric tons per year at standard conditions) individually for all of the emissions source types listed in the most recent BOEMRE study.

(c) Report the information listed in this paragraph for each applicable source type in metric tons for each GHG. If a facility operates under more than one industry segment, each piece of equipment should be reported under the unit's respective majority use segment. When a source type listed under this paragraph routes gas to flare, separately report the emissions that were vented directly to the atmosphere without flaring, and the emissions that resulted from flaring of the gas. Both the vented and flared emissions will be reported under respective source types and not under flare source type.

(1) For natural gas pneumatic devices (refer to Equations 1 and 2 of section 95153), report the following:

(A) Actual count and estimated count separately of natural gas pneumatic high bleed devices as applicable.
(B) Actual count and estimated count separately of natural gas low bleed devices as applicable.
(C) Actual count and estimated count separately of natural gas pneumatic intermittent bleed devices as applicable.
(D) Report annual CO_2 and CH_4 emissions at the facility level, expressed in metric tons for each gas, for each of the following pieces of equipment: high bleed pneumatic devices; intermittent bleed pneumatic devices; low bleed pneumatic devices.

(2) For natural gas driven pneumatic pumps (refer to Equation 1 and 2 of section 95153), report the following:

(A) Count of natural gas driven pneumatic pumps.
(B) Report annual CO_2 and CH_4 emissions at the facility level, expressed in metric tons for each gas, for all natural gas driven pneumatic pumps combined.

(3) For each acid gas removal unit (refer to Equation 3 and Equation 4 of section 95153), report the following:

(A) Total throughput of the acid gas removal unit using a meter or engineering estimate based on process knowledge or best available data in million cubic feet per year.
(B) For Calculation Methodology 1 and Calculation Methodology 2 of 95153(c), annual fraction of CO_2 content in the vent from acid gas removal unit (refer to 95153(c)(6)).
(C) For Calculation Methodology 3 of 95153(c), annual average volume fraction of CO_2 content of natural gas into and out of the acid gas removal unit (refer to 95153(c)(6)).
(D) Report the annual quantity of CO_2, expressed in metric tons that was recovered from the AGR unit and transferred outside the facility, under 95123 of this part.
(E) Report annual CO_2 emissions for the AGR unit, expressed in metric tons.
(F) For the onshore natural gas processing industry segment only, report a unique name or ID number for the AGR unit.
(G) An indication of which methodology was used for the AGR unit.

(4) For dehydrators, report the following:

(A) For each Glycol dehydrator (refer to section 95153(d)(1)), report the following:

1. Glycol dehydrator feed natural gas flow rate in MMscfd, determined by engineering estimate based on best available data.
2. Glycol dehydrator absorbent circulation pump type.
3. Whether stripper gas is used in glycol dehydrator.
4. Whether a flash tank separator is used in glycol dehydrator.
5. Type of absorbent.
6. Total time the glycol dehydrator is operating in hours.
7. Temperature, in degrees Fahrenheit and pressure, in psig, of the wet natural gas.
8. Concentration of CH_4 and CO_2 in wet natural gas.
9. What vent gas controls are used (refer to section 95153(d)(3) and (d)(4)).
10. For each glycol dehydrator, report annual CO_2 and CH_4 emissions that resulted from venting gas directly to the atmosphere, expressed in metric tons for each gas.
11. For each glycol dehydrator, report annual CO_2, CH_4, and N_2O emissions that resulted from flaring process gas from the dehydrator, expressed in metric tons for each gas.
12. For the onshore natural gas processing industry segment only, report a unique name or ID number for (each) glycol dehydrator.

(B) For absorbent desiccant dehydrators (refer to Equation 5 of section 95153), report the following:

1. Count of desiccant dehydrators.

2. Report annual CO_2 and CH_4 emissions at the facility level, expressed in metric tons for each gas, for all absorbent desiccant dehydrators combined.

(5) For well venting for liquids unloading, report the following:

(A) For Calculation Methodology 1 (refer to Equation 6 of section 95153), report the following:

1. Count of wells vented to the atmosphere for liquids unloading.
2. Count of plunger lifts. Whether the well had a plunger lift (yes/no).
3. Cumulative number of unloadings vented to the atmosphere.
4. Internal casing diameter or internal tubing diameter in inches, where applicable, and well depth of each well, in feet.
5. Casing pressure, in psia, of each well that does not have a plunger lift.
6. Tubing pressure, in psia, of each well that has a plunger lift.
7. Report annual CO_2 and CH_4 emissions, expressed in metric tons for each gas.

(B) For Calculation Methodologies 2 (refer to Equation 6 of wection 95153), report the following for each sub-basin category:

1. Count of wells vented to the atmosphere for liquids unloading.
2. Count of plunger lifts.
3. Cumulative number of unloadings vented to the atmosphere.
4. Average internal casing diameter, in inches, of each well, where applicable.
5. Report annual CO_2 and CH_4 emissions, expressed in metric tons for each GHG gas.

(6) For well completions and workovers, report the following for each basin category:

(A) For gas well completions and workovers by basin report the following:

1. Total count of completions in calendar year
2. Total count of workovers in calendar year.
3. Report number of completions employing purposely designed equipment that separates natural gas from the backflow and the amount of natural gas, in standard cubic feet, recovered using engineering estimate based on best available data.
4. Report number of workovers employing purposely designed equipment that's separates natural gas from the backflow and the amount of natural gas recovered using engineering estimate based on best available data.
5. Annual CO_2 and CH_4 emissions that resulted from venting gas directly to the atmosphere, expressed in metric tons for each gas.
6. Annual CO_2, CH_4, and N_2O emissions that resulted from flares, expressed in metric tons for each gas.

(7) For each equipment and pipeline blowdown event (refer to Equation 13 and Equation 14 of section 95153), report the following:

(A) For each unique physical volume that is blowdown more than once during the calendar year, report the following:

1. Total number of blowdowns for each unique physical volume, expressed in metric tons for each gas.
2. Annual CO_2 and CH_4 emissions for each unique physical blowdown volume, expressed in metric tons for each gas.
3. A unique name or ID number for the unique physical volume.

(B) For all unique volumes that are blow down once during the calendar year, report the following:

1. Total number of blowdowns for all unique physical volumes in the calendar year.
2. Annual CO_2 and CH_4 emissions from all unique physical volumes as an aggregate per facility, expressed in metric tons for each gas.

(8) For gas emitted from produced oil sent to atmospheric tanks:

(A) For Calculation Methodology 1 and 2 of section 95153(h), report the following by sub-basin category, unless otherwise specified:

1. Number of wellhead gas-liquid separators with oil throughput greater than or equal to 10 barrels per day.
2. Estimated average separator temperature, in degrees Fahrenheit, and estimated pressure, in psig.
3. Estimated average sales oil stabilized API gravity, in degrees.
4. Count of hydrocarbon tanks at well pads.
5. Best estimate of count of stock tanks not at well pads receiving oil.
6. Total volume of oil from all wellhead separators sent to tank(s) in barrels per year.
7. Count of tanks with emissions control measures, either vapor recovery system or flaring, for tanks at well pads, receiving the oil.
8. Best estimate of count of stock tanks assumed to have emissions control measures not at well pads, receiving the oil.
9. Range of concentrations of flash gas, CH_4 and CO_2.
10. Annual CO_2 and CH_4 emissions that resulted from venting gas to the atmosphere, expressed in metric tons for each gas, for all wellhead gas-liquid separators or storage tanks using Calculation Methodology 1, and for all wellhead gas-liquid separators or storage tanks using Calculation Methodology 2 of section 95153(h).

11. Annual CO_2, CH_4 and N_2O gas quantities that were recovered, expressed in metric tons for each gas, for all wellhead gas-liquid separators or storage tanks using Calculation Methodology 1, and for all wellhead gas-liquid separators or storage tanks using Calculation Methodology 2 of section 95153(h).
12. Annual CO_2, CH_4 and N_2O emissions that resulted from flaring gas, expressed in metric tons for each gas, for all wellhead gas-liquid separators or storage tanks using Calculation Methodology 1,and for all wellhead gas-liquid separators or storage tanks using Calculation Methodology 2 of section 95153 (h).

(B) If wellhead separator dump valve is functioning improperly during the calendar year (refer to Equation 16 of section 95153), report the following:

1. Count of wellhead separators that dump valve factor is applied.
2. Annual CO_2 and CH_4 emissions that resulted from venting gas to the atmosphere, expressed in metric tons for each gas, at the sub-basin level for improperly functioning dump valves.

(9) For transmission tank emissions identified using optical gas imagining instrument pursuant to section 95154(a) (refer to section 95153(i)), or acoustic leak detection of scrubber dump valves, report the following:

(A) For each vent stack, report annual CO_2 and CH_4 emissions that resulted from venting gas directly to the atmosphere, expressed in metric tons for each gas.
(B) For each transmission storage tank, report annual CO_2, CH_4 and N_2O emissions that resulted from flaring process gas from the transmission storage tank, expressed in metric tons for each gas.
(C) A unique name or ID number for the vent stack monitored according to 95153(i).

(10) For well testing venting and flaring (refer to Equation 17A or 17B of section 95153), report the following:

(A) Number of wells tested per basin in calendar year.
(B) Average gas to oil ratio for each basin.
(C) Average number of days the well is tested in a basin.
(D) Report annual CO_2 and CH_4 emissions at the facility level, expressed in metric tons for each gas, emissions from well testing venting.
(E) Report annual CO_2, CH_4 and N_2O emissions at the facility level, expressed in metric tons for each gas, emissions from well testing flaring.

(11) For associated natural gas venting and flaring (refer to Equation 18 of section 95153), report the following for each basin:

(A) Number of wells venting or flaring associated natural gas in a calendar year.

(B) Average gas to oil ratio for each basin.

(C) Report annual CO_2 and CH_4 emissions at the facility level, expressed in metric tons for each gas, emission s from associated natural gas venting.

(D) Report annual CO_2, CH_4 and N_2O emissions at the facility level, expressed in metric tons for each gas, emissions from associated natural gas flaring.

(12) For flare stacks (refer to Equation 19, 20, and 21 of section 95153), report the following for each flare:

(A) Whether flare has a continuous flow monitor.

(B) Volume of gas sent to flare in cubic feet per year.

(C) Percent of gas sent to un-lit flare determined by engineering estimate and process knowledge based on best available data and operating records.

(D) Whether flare has a continuous gas analyzer.

(E) Flare combustion efficiency.

(F) Report uncombusted CH_4 emissions, in metric tons (refer to Equation 19 of section 95153).

(G) Report uncombusted CO_2 emissions, in metric tons (refer to Equation 20 of section 95153).

(H) Report combusted CO_2 emissions, in metric tons (refer to Equation 21 of section 95153).

(I) Report N_2O emissions, in metric tons.

(J) For the natural gas processing industry segment, a unique name or ID number for the flare stack.

(K) In the case that a CEMS is used to measure CO_2 emissions for the flare stack, indicate that a CEMS was used in the annual report and report the combusted CO_2 and uncombusted CO_2 as a combined number.

(13) For each centrifugal compressor:

(A) For compressors with wet seals in operational mode (refer to Equation 22 and 23 of section 95153), report the following for each degassing vent:

1. Number of wets seals connected to the degassing vent.
2. Fraction of vent gas recovered for fuel or sales or flared.
3. Annual throughput in million scf, use an engineering calculation based on best available data.
4. Type of meters used for making measurements.
5. Total time the compressor is operating in hours.
6. Report seal oil degassing vent emissions for compressors measured (refer to Equation 22 of section 95153) and for compressors not measured (refer to Equation 23 of section 95153).

(B) For wet and dry seal centrifugal compressors in operating mode, (refer to Equation 22 and 23 of section 95153), report the following:

1. Total time in hours the compressor is in operating mode.
2. Report blowdown vent emissions when in operating mode (refer to Equation 22 and 23 of section 95153).

(C) For wet and dry seal centrifugal compressors in not operating, depressurized mode (refer to Equations 22 and 23 of section 95153), report the following:
1. Total time in hours the compressor is in shutdown, depressurized mode.
2. Report the isolation valve leakage emissions in not operating, depressurized mode in cubic feet per hour (refer to Equations 23 of section 95153).

(D) Report total annual compressor emissions from all modes of operation.

(14) For reciprocating compressors:

(A) For reciprocating compressors rod packing emissions with or without a vent in operating mode, report the following:

1. Annual throughput in million scf, use an engineering calculation based on best available data.
2. Total time in hours the reciprocating compressor is in operating mode.
3. Report rod packing emissions for compressors measured (refer to Equation 24 of section 95153).

(B) For reciprocating compressors blowdown vents not manifold to rod packing vents, in operating and standby pressurized mode, report the following:

1. Total time in hours the compressor is in standby, pressurized mode.
2. Report blowdown vent emissions when in operating and standby modes.

(C) For reciprocating compressors in not operating, depressurized mode report the following:
1. Total time the compressor is in not operating depressurized mode.
2. Facility operator emission factor for isolation valve emissions in not operating mode, depressurized mode in cubic feet per hour.
3. Report the isolation valve leakage emissions in not operating, depressurized mode.

(D) Report total annual compressor emissions from all modes of operation.
(E) For reciprocating compressors in onshore petroleum and natural gas production report the following:

1. Count of compressors.
2. Report emissions collectively.

(15) For each component type (major equipment type for onshore production) that uses emission factors for estimating emissions (refer to sections 95153(o) and (p).

(A) For equipment leaks found in each leak survey (refer to 95153(o)), report the following:

1. Total count of leaks found in each complete survey listed by date of survey and each component type for which there is a leak emission factor in Tables 2, 3, 4, 5, 6, and 7 of this subpart.
2. For onshore natural gas processing, range of concentrations of CH_4 and CO_2.
3. Annual CO_2 and CH_4 emissions, in metric tons for each gas by component type.

(B) For equipment leaks calculated using population counts and factors (refer to section 95153(p)), report the following:

1. For source categories listed in section 95150(a)(4), (a)(5), (a)(6), and (a)(7), total count for each component type in Tables 2, 3, 4, 5, and 6 of this subpart for which there is a population emission factor, listed by major heading and component type.
2. For onshore production (refer to section 95150 (a)(2)), total count for each type of major equipment in Table 1B and Table 1C of this subpart, by facility.
3. Annual CO_2 and CH_4 emissions, in metric tons for each gas by component type.

(16) For local distribution companies, report the following:

(A) Total number of above grade T-D transfer stations in the facility.
(B) Number of years over which all T-D transfer stations will be monitored at least once.
(C) Number of T-D stations monitored in calendar year.
(D) Total number of below grade T-D transfer stations in the facility.
(E) Total number of above grade metering-regulating stations (this count will include above grade T-D transfer stations) in the facility.
(F) Total number of below grade metering-regulating stations (this count will include below grade T-D transfer stations) in the facility.
(G) Leak factor for meter/regulator run developed in Equation 29 of section 95153.
(H) Number of miles of unprotected steel distribution mains.
(I) Number of miles of protected steel distribution mains.
(J) Number of miles of plastic distribution mains.
(K) Number of miles of cast iron distribution mains.
(L) Number of unprotected steel distribution services.
(M) Number of protected steel distribution services.
(N) Number of plastic distribution services.
(O) Number of copper distribution services.
(P) Annual CO_2 and CH_4 emissions, in metric tons for each gas, from all below grade T-D transfer stations combined.

(Q) Annual CO_2 and CH_4 emissions, in metric tons for each gas, from all above grade metering-regulating stations (including T-D transfer stations) combined.
(R) Annual CO_2 and CH_4 emissions, in metric tons for each gas, from all below grade metering-regulating stations (including T-D transfer stations) combined.
(S) Annual CO_2 and CH_4 emissions, in metric tons for each gas, from all distribution mains combined.
(T) Annual CO_2 and CH_4 emissions, in metric tons for each gas, from all distribution services combined.

(17) For each EOR injection pump blowdown (refer to Equation 34 of section 95153), report the following:

(A) Pump capacity, in barrels per day.
(B) Volume of critical phase gas between isolation valves.
(C) Number of blowdowns per year.
(D) Critical phase EOR injection gas density.
(E) For each EOR pump, report annual CO_2 and CH_4 emissions, expressed in metric tons for each gas.

(18) For EOR hydrocarbon liquids dissolved CO_2 for each sub-basin category (refer to section 95153(v)), report the following:

(A) Volume of crude oil produced in barrels per year.
(B) Amount of CO_2 retained in hydrocarbon liquids in metric tons per barrel, under standard conditions.
(C) Report annual CO_2 emissions at the basin level.

(19) For onshore petroleum and natural gas production and natural gas distribution combustion emissions, report the following:

(A) Cumulative number of external fuel combustion units with a rated heat capacity equal to or less than 5 mmBtu/hr, by type of unit.
(B) Cumulative number of external fuel combustion units with a rated heat capacity larger than 5 mmBtu/hr, by type of unit.
(C) Report annual CO_2, CH_4, and N_2O emissions from external fuel combustion units with a rated heat capacity larger than 5 mmBtu/hr, expressed in metric tons for each gas, by type of unit.
(D) Cumulative volume of fuel combusted in external fuel combustion units with a rated heat capacity larger than 5 mmBtu/hr, by type of unit.
(E) Cumulative number of internal fuel combustion units, not compressor-drivers, with a rated heat capacity equal to or less than 1 mmBtu/hr or 130 horsepower, by type of unit.
(F) Report annual CO_2, CH_4 and N_2O emissions from external fuel combustion units with a rated heat capacity larger than 5 mmBtu/hr, expressed in metric tons for each gas, by type of unit.

(G) Cumulative volume of fuel combusted in internal combustion units with a rated heat capacity larger than 1 mmBtu/hr or 130 horsepower, by fuel type.

(d) Report annual throughput as determined by engineering estimate based on best available data for each industry segment listed in paragraphs (a)(1) through (a)(8) of this section.

(e) For onshore petroleum and natural gas production, report the best available estimate of API gravity, best available estimate of gas to oil ratio, and best available estimate of average low pressure separator pressure for each oil sub-basin category.

§951587~~7~~. Records That Must Be Retained.

The operator shall follow the document retention requirements of section 95105 of this article, in addition to those of 40 CFR §98.237.

NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4 and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.

Table 1A to section 95150 – Default Whole Gas Emission Factors for Onshore Petroleum and Natural Gas Production

Onshore petroleum and natural gas production	Emission factor (scf/hour/ component)
Eastern U.S. **Population Emission Factors - All components, Gas Service:**[1]	
Valve	0.027
Connector	0.003
Open-ended line	0.061
Pressure relief valve	0.040
Low Continuous Bleed Pneumatic Device Vents[2]	1.39
High Continuous Bleed Pneumatic Device Vents[2]	37.3
Intermittent Bleed Pneumatic Device Vents[2]	13.5
Pneumatic Pumps[3]	13.3
Population Emission Factors – All Components, Light Crude Service:[4]	
Valve	0.05
Flange	0.003
Connector	0.007
Open-ended Line	0.05
Pump	0.01
Other[5]	0.30
Population Emission Factors – All Components, Heavy Crude Service:[6]	

Valve	0.0005
Flange	0.0009
Connector (other)	0.0003
Open-ended Line	0.006
Other[5]	0.003
Western U.S. **Population Emission Factors All components, Gas Service:[1]**	
Valve	0.121
Connector	0.017
Open-ended line	0.031
Pressure relief valve	0.193
Low Continuous Bleed Pneumatic Device Vents[2]	1.39
High Continuous Bleed Pneumatic Device Vents[2]	37.3
Intermittent Bleed Pneumatic Device Vents[2]	13.5
Pneumatic Pumps[3]	13.3
Population Emission Factors – All Components, Light Crude Service:[4]	
Valve	0.05
Flange	0.003
Connector	0.007
Open-ended Line	0.05
Pump	0.01
Other[5]	0.30
Population Emission Factors – All Components, Heavy Crude Service:[6]	
Valve Flange	0.0005 0.0009
Connector (other)	0.0003
Open-ended Line	0.006
Other[5]	0.003

[1] For multi-phase flow that includes gas, use the gas service emissions factors
[2] Emissions factor is in units of “scf/hour/device”.
[3] Emission Factor is in units of “scf/hour/pump”.
[4] Hydrocarbon liquids greater than or equal to 20˚API are considered “light crude”.
[5] “Other” category includes instruments, loading arms, pressure relief valves, stuffing boxes, compressor seals, dump lever arms, and vents.
[6] Hydrocarbon liquids less than 20˚API are considered “heavy crude”.

Table 1B to section 95150 – Default Average Component Counts for Major Onshore Natural Gas Production Equipment

Major equipment	Valves	Connectors	Open-ended lines	Pressure relief valves
Eastern U.S.				
Wellheads	8	38	0.05	0
Separators	1	6	0	0

Meters/piping	12	45	0	0
Compressors	12	57	0	0
In-line heaters	14	65	2	1
Dehydrators	24	90	2	2
Western U.S.				
Wellheads	11	36	1	0
Separators	34	106	6	2
Meters/piping	14	51	1	1
Compressors	73	179	3	4
In-line heaters	14	65	2	1
Dehydrators	24	90	2	2

Table 1C to section 95150 – Default Average Component Counts for Major Crude Oil Production Equipment

Major equipment	Valves	Flanges	Connectors	Open-ended lines	Other components
Eastern U.S.					
Wellhead	5	10	4	0	1
Separator	6	12	10	0	0
Heater-treater	8	12	20	0	0
Header	5	10	4	0	0
Western U.S.					
Wellhead	5	10	4	0	1
Separator	6	12	10	0	0
Heater-treater	8	12	20	0	0
Header	5	10	4	0	0

Table 2 to section 95150 – Default Total Hydrocarbon Emission Factors for Onshore Natural Gas Processing

Onshore natural gas processing	Emission Factor (scf/hour/component)
Leaker Emission Factors – Compressor Components, Gas Service	
Valve[1]	14.84
Connector	5.59
Open-Ended Line	17.27
Pressure Relief Valve	39.66
Meter	19.33
Leaker Emission Factors – Non-Compressor Components, Gas Service	
Valve[1]	6.42

Connector	5.71
Open-Ended Line	11.27
Pressure Relief Valve	2.01
Meter	2.93

[1] Valves include control valves, block valves and regulator valves.

Table 3 to section 95150 – Default Total Hydrocarbon Emission factors for Onshore Natural Gas Transmission Compression

Onshore Natural Gas Transmission compression	Emission Factor (scf/hour/component)
Leaker Emission Factors – Compressor Components, Gas Service	
Valve[1]	14.84
Connector	5.59
Open-Ended Line	17.27
Pressure Relief Valve	39.66
Meter	19.33
Leaker Emission Factors – Non-Compressor Components, Gas Service	
Valve[1]	6.42
Connector	5.71
Open-Ended Line	11.27
Pressure Relief Valve	2.01
Meter	2.93
Population Emission Factors – Gas Service	
Low Continuous Bleed Pneumatic Device Vents[2]	1.37
High Continuous Bleed Pneumatic Device Vents[2]	18.20
Intermittent Bleed Pneumatic Device Vents[2]	2.35

[1] Valves include control valves, block valves, and regulator valves.
[2] Emission Factor is in units of “scf/hour/component”

Table 4 to section 95150 – Default Total Hydrocarbon Emission Factors for Underground Natural Gas Storage

Underground natural gas storage	Emission Factor (scf/hour/component)
Leaker Emission Factors – Storage Station, Gas Service	
Valve[1]	14.84
Connector	5.659
Open-Ended Line	17.27
Pressure Relief valve	39.66
Meter	19.33
Population Emission Factors – Storage Wellheads, Gas Service	
Connector	0.01
Valve[1]	0.1

Pressure Relief Valve	0.17
Open Ended Line	0.03
Population Emission Factor – Other Components, Gas Service	
Low Continuous Bleed Pneumatic Device Vents[2]	1.37
High Continuous Bleed Pneumatic Device Vents[2]	18.20
Intermittent Bleed Pneumatic Device Vents[2]	2.35

[1] Valves include control valves, block valves and regulator valves.
[2] Emission Factor is in units of "scf/hour/device.

Table 5 to section 95150 – Default Methane Emission Factors for Liquified Natural Gas (LNG) Storage

LNG Storage	Emission Factor (scf/hour/component)
Leaker Emission Factors – LNG storage Components, Gas and Liquids Service	
Valve	1.19
Pump Seal	4.00
Connector	0.34
Other[1]	1.77
Population Emission Factors – LNG Storage Compressor, Gas Service	
Vapor Recovery Compressor[2]	4.17

[1] "other" equipment type should be applied for any equipment type other than connectors, pumps, or valves
[2] Emission Factor is in units of "scf/hour/compressor"

Table 6 to section 95150 – Default Methane Emission Factors for LNG Import and Export Equipment.

LNG import and export equipment	Emission Factor (scf/hour/component)
Leaker Emission Factors – LNG Terminals Components, Gas and Liquid Service	
Valve	1.19
Pump Seal	4.00
Connector	0.34
Other[1]	1.77
Population Emission Factors – LNG Terminal Compressor, Gas Service	
Vapor Recovery Compressor[2]	4.17

[1] "other" equipment type should be applied for any equipment type other than connectors, pumps, or valves.
[2] Emission Factor is in units of "scf/hour/compressor"

Table 7 to section 95150 – Default Methane Emission Factors for Natural Gas Distribution

Natural gas distribution	Emission Factor (scf/hour/component)
Leaker Emission Factors – Above Grade M&R at City Gate Stations[1] Components	
Connector	1.69
Block Valve	0.557
Control Valve	9.34
Pressure Relief Valve	0.27
Orifice Meter	0.212
Regulator	0.772
Open-ended Line	26.131
Population Emission Factors – Below Grade M&R [2] Components, Gas Service	
Below Grade M&R Station, Inlet Pressure >300 psig	1.30
Below Grade M&R Station, Inlet Pressure 100 to 300 psig	0.20
Below Grade M&R Station, Inlet Pressure <100 psig	0.10
Population emission Factors – Distribution Mains, Gas Service[4]	
Unprotected steel	12.58
Protected Steel	0.35
Plastic	1.13
Cast Iron	27.25
Population Emission Factors – Distribution Services, Gas Service[5]	
Unprotected Steel	0.19
Protected Steel	0.02
Plastic	0.001
Copper	0.03

[1] City gate stations at custody transfer and excluding customer meters.
[2] Excluding customer meters
[3] Emission Factor is in units of “scf/hour/station”
[4] Emission Factor is in units of “scf/hour/mile”
[5] Emission factor is in units of “scf/hour/number of services.”