ATTACHMENT A

PROPOSED REGULATION ORDER

NOTE: Changes to the regulation are shown in underline; deletions from the regulation are shown in ~~strikeout~~. "***" indicates that sections of regulation not printed are not changed.

PROPOSED AMENDMENTS TO THE REGULATION FOR THE MANDATORY REPORTING OF GREENHOUSE GAS EMISSIONS

Amend Division 3, Chapter 1, Subchapter 10, Article 2, sections 95101, 95102, 95103, 95104, 95105, 95111, 95112, 95113, 95114, 95115, 95119, 95120, 95121, 95122, 95123, 95130, 95131, 95132, 95133, 95150, 95151, 95152, 95153, 95154, 95155, 95156, and 95157, title 17, California Code of Regulations; and add new section 95158, title 17, California Code of Regulations to read as follows:

Article 2: Mandatory Greenhouse Gas Emissions Reporting

Subarticle 1. General Requirements for Greenhouse Gas Reporting

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§ 95101. Applicability.

(a) *General Applicability.*

(1) This article applies to the following entities:

(A) Operators of facilities located in California with source categories listed below are subject to this article regardless of emissions level: ~~categories included in Tables A-3 or A-4 of 40 CFR Part 98, and operators of facilities with emissions from stationary fuel combustion or geothermal electricity generation, subject to the limitations of this~~ :

1. Electricity generation units that report CO_2 mass emissions year round through 40 CFR Part 75~~Facilities with source categories in Table A-3 are subject to this article regardless of emissions level.~~;
2. Cement production~~Facilities with source categories in Table A-4 are subject to this article when stationary combustion emissions equal or exceed 10,000 metric tons CO_2e for 2012 or a later calendar year.~~;
3. Lime manufacturing~~Facilities with source categories in Table A-4 are also subject to this article when emissions from all applicable source categories in paragraph (b) of this equal or exceed 25,000 metric tons CO_2e, for 2011 or a later calendar year.~~;
4. Nitric acid production;
5. Petroleum refineries;

6. Geologic sequestration of carbon dioxide;
7. Injection of carbon dioxide.

(B) Operators of facilities located in California with source categories listed below, are subject to this article when stationary combustion and process emissions equal or exceed 10,000 metric tons CO_2e for a calendar year:

1. Stationary fuel combustion, which includes electricity generating units not subject to 40 CFR Part 75;
2. Glass production;
3. Hydrogen production;
4. Iron and steel production;
5. Pulp and paper manufacturing;
6. Petroleum and natural gas systems;
7. Geothermal electricity generation.

(~~B~~C) Suppliers of fuels provided for consumption within California that are specified below in ~~subsection~~ paragraph (c);

(~~C~~D) Carbon dioxide suppliers as specified below in ~~subsection~~ paragraph (c), including CO_2 producers regardless of quantity produced, and CO_2 importers and exporters when bulk imports or exports equal or exceed 10,000 metric tons for 2011 or a later calendar year;

(~~D~~E) Electric power entities as specified below in ~~subsection~~ paragraph (d); and,

(~~E~~F) Operators of petroleum and natural gas systems as specified below in ~~subsection~~ paragraph (e).

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(b) *Calculating GHG Emissions Relative to Thresholds.* For industrial facilities for which an emissions-based applicability threshold is specified in section 95101(a)(1)~~40 CFR §98.2~~, the operator must calculate emissions for comparison to applicable thresholds using the requirements of 40 CFR §98.2(b)-(c), except as specified below~~.~~:

(1) For the purpose of computing emissions relative to the 25,000 metric ton CO_2e threshold specified in section 95812 of the cap-and-trade regulation, operators must include all covered emissions.

(2) For the purpose of computing emissions relative to the 10,000 metric ton CO_2e threshold for reporting applicability, operators must include emissions of CO_2, CH_4 and N_2O from stationary combustion sources and process emissions, but may exclude ~~process,~~ vented~~,~~ and fugitive emissions from the estimate.

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(c) *Fuel and Carbon Dioxide Suppliers.* The suppliers listed below, as defined in section 95102(a), are required to report under this article when they produce, import and/or deliver an annual quantity of fuel that, if completely combusted, oxidized, or used in other processes, would result in the release of greater than or equal to 10,000 metric tons of CO_2e in California, unless otherwise specified in this article:

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(5) California consignees of liquefied petroleum gas, compressed natural gas, or liquefied natural gas, as described in section 95122;

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(e) *Petroleum and Natural Gas Systems.* The facility types listed below, as further specified in section 95150, are required to report under this article when their stationary combustion and process emissions equal or exceed 10,000 metric tons of CO_2e, or their stationary combustion, process, fugitive, and vented emissions equal or exceed 25,000 metric tons of CO_2e.

(1) Offshore petroleum and natural gas production facilities;
(2) Onshore petroleum and natural gas production facilities~~, as defined in section 95102~~;

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(h) *Cessation of Reporting*. ~~Except as otherwise specified below, a~~A facility operator or supplier whose emissions fall below the applicable emissions reporting thresholds of this article and who wishes to cease annual reporting must comply with ~~40 CFR §98.2(i)~~ the requirements specified in this paragraph. The operator or supplier must provide the letter notifications specified below ~~in 40 CFR §98.2(i)~~ to the address indicated in section 95103 of this article. ~~For purposes of this article:~~

(1) ~~Wherever 40 CFR §98.2(i)(1) states "25,000 metric tons of CO_2e per year," the phrase "10,000 metric tons of CO_2e per year" shall be substituted, and reporting shall be required for three years rather than five years.~~ For facilities with source categories in section 95101(a)(1)(A) that are subject to the requirements of this article regardless of emissions level, cessation of reporting provisions in section 95101(h)(1) apply, but the 2011 data year is the earliest year that criteria for cessation can be applied.

If reported emissions are less than 10,000 metric tons of CO_2e per year for three consecutive years, then the owner, operator, or supplier may discontinue complying with this article provided that the owner, operator, or supplier submits a notification to ARB that announces the cessation of reporting and explains the reasons for the reduction in emissions. The notification must be submitted no later than March 31 of the year immediately following the third consecutive year in which emissions are less than 10,000 metric tons of CO_2e per year. The owner, operator, or supplier must maintain the corresponding records required under section 95103 for each of the five consecutive years and retain such records for five years following the year that reporting was discontinued. The owner, operator, or supplier must resume reporting if annual emissions in any future calendar year increase to 10,000 metric tons of CO_2e per year or more.

(2) ~~In cases of permanent shutdown as specified in 40 CFR §98.2(i)(3), a reporter must submit an emissions data report for the year in which a facility or supplier's GHG-emitting processes and operations ceased to operate, and for the first full year of non-operation that follows.~~ If the operations of a facility or supplier are changed such that all applicable GHG-emitting processes and operations listed in paragraph (a)(1) of this section cease to operate or are permanently shut down, the owner, operator, or supplier must submit an emissions data report for the year in which a facility or supplier's GHG-emitting processes and operations ceased to operate, and for the first full year of non-operation that follows. The owner, operator, or supplier must submit a notification to ARB that announces the cessation of reporting and certifies to the closure of all GHG-emitting processes and operations no later than March 31 of the year following such changes. Paragraph 95101(h)(2) does not apply to seasonal or other temporary cessation of operations. The owner, operator, or supplier must resume reporting for any future calendar year during which any of the GHG-emitting processes or operations resume operation and are subject to reporting pursuant to section 95101(a)(1).

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(4) Electric power entities must comply with the following requirements for cessation of reporting:

(A) Electric power entities that import or export electricity in 2011 or 2012 must continue to submit, certify, and verify an emissions data report through the 2014 data year, the end of the first compliance period. If an electric power entity has zero imports or exports, it must indicate as such in its emissions data report.

(B) Electric power entities that import or export electricity in any year of a subsequent compliance period must continue to submit, certify, and verify an emissions data report through the end of the same compliance period. If an electric power entity has zero imports or exports, it must indicate as such in its emissions data report.

(C) Electric power entities no longer importing or exporting electricity at the beginning of a subsequent compliance period are not required to submit, certify, and verify an emissions data report demonstrating that they have no imports or exports pursuant to this article, but must notify the Executive Officer in writing of the reason(s) for cessation of reporting. The notification must be submitted no later than March 31 of the year following the last year that the electric power entity is required to submit an emissions data report.

(D) Electric power entities who meet the definition of “retail provider” must always report retail sales for each calendar year. WAPA and DWR must always report pump loads for each calendar year.

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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.

§ 95102. Definitions.

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

(1) “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.

*** [no changes were made except to renumber]

(~~9~~10) “Air dried ton of paper” means paper with 6~~%~~ percent moisture content.

(11) “Air injected flare” means a flare in which air is blown into the base of a flare stack to induce complete combustion of gas.

*** [no changes were made except to renumber]

(~~17~~19) “Asset-controlling supplier” means any entity that owns or operates electricity generating facilities or serves as an exclusive marketer for certain generating facilities even though it does not own them, and is assigned a supplier-specific identification number and specified source emission factor by ARB for the wholesale electricity procured from its system and imported into California. ~~Bonneville Power Administration (BPA) is recognized by ARB as an asset-controlling supplier.~~

*** [no changes were made except to renumber]

(~~19~~21) “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.

*** [no changes were made except to renumber]

(42) “Boiler” means a closed vessel or arrangement of vessels and tubes, together with a furnace or other heat source, in which water is heated to produce hot water or steam.

*** [no changes were made except to renumber]

(51) “Butylene” or “n-Butylene” means an olefinic straight-chain hydrocarbon with molecular formula C_4H_8.

*** [no changes were made except to renumber]

(55) “Calcined coke” means petroleum coke purified to a dry, pure form of carbon suitable for use as anode and other non-fuel applications.

*** [no changes were made except to renumber]

(58) “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.

*** [no changes were made except to renumber]

(~~71~~67) “Carbon dioxide weighted tonne” or “CO_2 weighted tonne” or “CWT” means a metric created to evaluate the greenhouse gas efficiency of petroleum refineries and related processes, stated in units of metric tons. The CWT value for an individual refinery is calculated using actual refinery throughput to specified process units and emission factors for these process units. The emission factor is denoted as the CWT factor and is representative of the greenhouse gas emission intensity at an average level of energy efficiency, for the same standard fuel type for each process unit for production, and for average process emissions of the process units across a sample of refineries. Each CWT factor is expressed as a value weighted relative to crude distillation.

*** [no changes were made except to renumber]

(71) “CBOB-summer” or “conventional blendstock for oxygenate blending-summer” means a petroleum product which, when blended with a specified type and percentage of oxygenate, meets the definition of conventional-summer.

(72) “CBOB-winter” or “conventional blendstock for oxygenate blending-winter” means a petroleum product which, when blended with a specified type and percentage of oxygenate, meets the definition of conventional-winter.

*** [no changes were made except to renumber]

(76) “Centrifugal compressor dry seals” mean a series of rings around the compressor shaft where it exits the compressor case that operate mechanically under the opposing forces to prevent natural gas or CO_2 from escaping to the atmosphere.

(77) “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.

*** [no changes were made except to renumber]

(~~74~~84) "Cogeneration" means an integrated system that produces electric energy and useful thermal energy for industrial, commercial, or heating and cooling purposes, through the sequential or simultaneous use of the original fuel energy. Cogeneration must involve generation of electricity and useful thermal energy and some form of waste heat recovery. Some examples of cogeneration include: (a) a gas turbine or reciprocating engine generating electricity by combusting fuel, which then uses a heat recovery unit to capture useful heat from the exhaust stream of the turbine or engine; (b) Steam turbines generating electricity as a byproduct of steam generation through a fired boiler; (c) Cogeneration systems in which the fuel input is first applied to a thermal process such as a furnace and at least some of the heat rejected from the process is then used for power production. For the purposes of this article, a combined-cycle power generation unit, where ~~all of the generated steam is used for electricity generation~~ none of the generated thermal energy is used for industrial, commercial, or heating and cooling purposes (these purposes exclude any thermal energy utilization that is either in support of or a part of the electricity generation system), is not considered a cogeneration unit.

*** [no changes were made except to renumber]

(98) "Compressed natural gas" or "CNG" means natural gas in high-pressure containers that is highly compressed (though not to the point of liquefaction), typically to pressures ranging from 2900 to 3600 psi.

*** [no changes were made except to renumber]

(~~93~~104) "Continuous bleed" means a continuous flow of pneumatic supply natural gas to the process ~~measurement~~control device (e.g. level control, temperature control, pressure control) where the supply gas pressure is modulated by the process condition, and then flows to the valve controller where the signal is compared with the process set-point to adjust gas pressure in the valve actuator.

*** [no changes were made except to renumber]

(106) "Continuous physical transmission path" means the full transmission path shown in the physical path table of a single NERC e-tag from the first point of receipt closest to the generation source to the final point of delivery closest to the final sink. This is one criterion to establish direct delivery.

(107) “Conventional-summer” means finished gasoline formulated for use in motor vehicles, the composition and properties of which do not meet the requirements of the reformulated gasoline regulations promulgated by the U.S. Environmental Protection Agency under 40 CFR §80.40, but which meet summer RVP standards required under 40 CFR §80.27 or as specified by the state. Note: This category excludes conventional gasoline for oxygenate blending (CBOB) as well as other blendstock.

(108) “Conventional-winter” means finished gasoline formulated for use in motor vehicles, the composition and properties of which do not meet the requirements of the reformulated gasoline regulations promulgated by the U.S. Environmental Protection Agency under 40 CFR §80.40 or the summer RVP standards required under 40 CFR §80.27 or as specified by the state. Note: This category excludes conventional blendstock for oxygenate blending (CBOB) as well as other blendstock.

*** [no changes were made except to renumber]

(111) “Covered product data” means all product data included in the allocation of allowances under sections 95870, 95890, and 95891 of the cap-and-trade regulation, regardless of whether the cap-and-trade regulation imposes a compliance obligation for the data year.

*** [no changes were made except to renumber]

(118) “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.

(~~103~~119) “Delayed coking” means a process by which heavier crude oil fractions are thermally decomposed under conditions of elevated temperature and pressure to produce a mixture of lighter oils and petroleum coke.

*** [no changes were made except to renumber]

(121) “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 the feed natural gas stream.

*** [no changes were made except to renumber]

(~~108~~125) “Direct delivery of electricity” or “directly delivered” means electricity that meets any of the following criteria:

(A) The facility has a first point of interconnection with a California balancing authority;

(B) The facility has a first point of interconnection with distribution facilities used to serve end users within a California balancing authority area;

(C) The electricity is scheduled for delivery from the specified source into a California balancing authority via a continuous physical transmission path from interconnection of the facility in the balancing authority in which the facility is located to a sink~~final point of delivery~~ located in the state of California; or

(D) There is an agreement to dynamically transfer electricity from the facility to a California balancing authority.

*** [no changes were made except to renumber]

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

*** [no changes were made except to renumber]

(136) "Electric Power Entity" or "EPE" means those entities specified in section 95101(d) of this article, including electricity importers and exporters; retail providers, including multi-jurisdictional retail providers; the California Department of Water Resources (DWR); the Western Area Power Administration (WAPA); and the Bonneville Power Administration (BPA).

*** [no changes were made except to renumber]

(~~118~~137) "Electricity exporter" means electric power entities~~marketers and retail providers~~ that deliver exported electricity. ~~For electricity delivered between balancing authority areas, t~~The entity that exports electricity is identified on the NERC e-Tag as the purchasing-selling entity (PSE) on the last segment of the tag's physical path, with the point of receipt located inside the state of California and the point of delivery located outside the state of California.

(~~121~~140) "Electricity importers" ~~are marketers and retail providers that~~ deliver imported electricity. For electricity that is scheduled with a NERC e-Tag to a final point of delivery inside the state of California~~delivered between balancing authority areas~~, the electricity importer is identified on the NERC e-Tag as the purchasing-selling entity (PSE) on the last segment of the tag's physical path with the point of receipt located outside the state of California and the point of delivery located inside the state of California. For facilities physically located outside the state of California with the first point of interconnection to a California balancing authority's transmission and distribution system when the electricity is not scheduled on a NERC e-Tag, the importer is the facility operator or scheduling coordinator. Federal and state agencies are subject to the regulatory authority of ARB under this article and include Western Area Power Administration (WAPA), Bonneville Power Administration (BPA), and California Department of Water Resources (DWR).

*** [no changes were made except to renumber]

(~~128~~147) "Emissions data verification statement" means the final statement rendered by a verification body attesting whether a reporting entity's covered emissions data in their emissions data report is free of material misstatement, and whether the emissions data conforms to the requirements of this article.

*** [no changes were made except to renumber]

(~~133~~152) "Enterer" means an entity that imports into California motor vehicle fuel, diesel fuel, fuel ethanol, biodiesel, non-exempt biomass-derived fuel or renewable fuel and who is the importer of record under federal customs law or the owner of fuel upon import into California if the fuel is not subject to federal customs law. Only enterers that import the fuels specified in this definition outside the bulk transfer/terminal system are subject to reporting under the regulation.

*** [no changes were made except to renumber]

(~~137~~156) "Equipment leak detection" means the process of identifying emissions from equipment, components, and other point sources.

*** [no changes were made except to renumber]

(158) "Ethanol" is an anhydrous alcohol with molecular formula C_2H_5OH.

(159) "Ethylene" is an olefinic hydrocarbon with molecular formula C_2H_4.

*** [no changes were made except to renumber]

(~~144~~165) "Facility," unless otherwise specified in relation to natural gas distribution facilities and onshore petroleum and natural gas production facilities as defined in section 95102(a), means any physical property, plant, building, structure, source, or stationary equipment located on one or more contiguous or adjacent properties in actual physical contact or separated solely by a public roadway or other public right-of -way and under common ownership or common control, that emits or may emit any greenhouse gas. Operators of military installations may classify such installations as more than a single facility based on distinct and independent functional groupings within contiguous military properties.

(166) "Facility," with respect to natural gas distribution for the purposes of sections 95150 to 95158 of this article, 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 a public utility commission or that are operated as an independent municipally-owned distribution system.

(167) "Facility," with respect to onshore petroleum and natural gas production for the purposes of sections 95150 to 95158 of this article, 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(a). 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.

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

*** [no changes were made except to renumber]

(~~147~~171) "Field," in the context of oil and gas systems, means oil and gas fields identified in the United States as defined by the Energy Information Administration Oil and Gas Field Code Master List 2008, DOE/EIA 0370(08), January 2009, which is hereby incorporated by reference.

(172) "Field accuracy assessment" means a test, check, or engineering analysis intended to confirm that a flow meter or other mass or volume measurement device is operating within an acceptable accuracy range. A field accuracy assessment should be conducted in a manner that does not interrupt operations or require removal of the meter or require primary element inspection, if possible. The selected method for field accuracy assessment will vary based on meter type and piping system design, and may be performed by the facility operator, a third party meter servicing firm, or the original equipment manufacturer.

(173) "Final point of delivery" means the sink specified on the NERC e-Tag, where defined points have been established through the NERC Registry. When NERC e-Tags are not used to document electricity deliveries, as may be the case within a balancing authority, the final point of delivery is the location of the load. Exported electricity is disaggregated by the final point of delivery on the NERC e-Tag.

(174) “First deliverer of electricity” or “first deliverer” means the owner or operator of an electricity generating facility in California or an electricity importer.

(175) “First point of delivery in California” means the first defined point on the transmission system located inside California at which imported electricity and electricity wheeled through California may be measured, consistent with defined points that have been established through the NERC Registry.

(176) “First point of receipt” means the generation source specified on the NERC e-Tag, where defined points have been established through the NERC Registry. When NERC e-Tags are not used to document electricity deliveries, as may be the case within a balancing authority, the first point of receipt is the location of the individual generating facility or unit, or group of generating facilities or units. Imported electricity and wheeled electricity are disaggregated by the first point of receipt on the NERC e-Tag.

*** [no changes were made except to renumber]

(~~150~~179) “Flare combustion efficiency” means the fraction of ~~hydrocarbon gas~~liquid and gases sent to the flare, on a volume or mole basis, that is combusted at the flare burner tip.

(~~151~~180) “Flare stack emissions” means CO_2 and N_2O from partial combustion of hydrocarbon gas sent to a flare plus CH_4 emissions resulting from the incomplete combustion of hydrocarbon gas in the flare~~s~~.

*** [no changes were made except to renumber]

(183) “Flow meter” means a measurement device consisting of one or more individual components that is designed to measure the bulk fluid movement of liquid or gas through a piped system at a designated point. Bulk fluid movement can be measured with a variety of devices in units of mass flow or volume.

*** [no changes were made except to renumber]

(188) “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 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.

*** [no changes were made except to renumber]

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

*** [no changes were made except to renumber]

(209) “Gas conditions” means the actual temperature, volume, and pressure of a gas sample.

*** [no changes were made except to renumber]

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

*** [no changes were made except to renumber]

(~~182~~216) “Generation providing entity” or “GPE” means a ~~merchant selling energy from owned, affiliated, or contractually bound generation. Ffor~~ purposes ~~of reporting delivered electricity pursuant to section 95111, a GPE is the PSE, operator, or scheduling coordinator with prevailing rights to claim electricity from a specified source. A~~ facility or generating unit operator, full or partial owner, party to a contract for a fixed percentage of net generation, sole party to a tolling agreement with the owner, or exclusive marketer ~~is~~ recognized by ARB ~~as a generation providing entity~~ that is either the electricity importer or exporter with prevailing rights to claim electricity from the specified source.

*** [no changes were made except to renumber]

(231) “High-bleed pneumatic devices” means 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.

*** [no changes were made except to renumber]

(233) “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.

*** [no changes were made except to renumber]

(246) “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 standard cubic feet per hour or greater are considered high bleed devices for the purposes of this regulation.

(~~210~~247) “Internal combustion” means the combustion of a fuel that occurs with an oxidizer (usually air) in a combustion chamber. In an internal combustion engine the expansion of the high-temperature and high–pressure gases produced by combustion applies direct force to a component of the engine, such as pistons, turbine blades, or a nozzle. This force moves the component over a distance, generating useful mechanical energy. Internal combustion equipment may include gasoline and diesel industrial engines, natural gas-fired reciprocating engines, and gas turbines.

*** [no changes were made except to renumber]

(252) “Isobutane” is a paraffinic branch chain hydrocarbon with molecular formula C_4H_{10}.

(253) “Isobutylene” is an olefinic branch chain hydrocarbon with molecular formula C_4H_8.

(254) “Isopentane” is the methylbutane or 2-methylbutane, branched chain, isomer of C_5H_{12} under the International Union of Pure and Applied Chemistry (IUPAC) nomenclature.

*** [no changes were made except to renumber]

(260) “Last point of delivery in California” means the last defined point on the transmission system located inside California at which exported electricity may be measured, consistent with defined points that have been established through the NERC Registry.

*** [no changes were made except to renumber]

(~~221~~262) "Lead verifier independent reviewer" or "independent reviewer" means a lead verifier within a verification body who has not participated in conducting verification services for a reporting entity, offset project developer, or authorized project designee for the current reporting year who provides an independent review of verification services rendered to the reporting entity as required in section 95131. The independent reviewer is not required to meet the requirements for a sector specific verifier.

*** [no changes were made except to renumber]

~~(224) "Liquefied hydrogen" means hydrogen in a liquid state.~~

*** [no changes were made except to renumber]

(~~226~~266) "Liquefied petroleum gas" or "LP-Gas" or "LPG" means a flammable mixture of hydrocarbon gases used as a fuel. LPG is a natural gas liquid (NGL) that is primarily a mixture~~s~~ of propane~~,~~ and butane, with small amounts of propene (propylene) and ethane. The most common specification categories are propane grades HD-5, HD-10, and commercial grade propane, and propane/butane mix. LPG also includes both odorized and non-odorized liquid petroleum gas, and is also referred to as propane.

(267) "Liquid hydrogen" means hydrogen in a liquid state.

*** [no changes were made except to renumber]

(273) "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.

*** [no changes were made except to renumber]

(~~235~~277) "Material misstatement" means any discrepancy, omission, or misreporting, or aggregation of the three, identified in the course of verification services that leads a verification team to believe that the total reported ~~GHG~~covered emissions (metric tons of CO_2e) or ~~a~~ total reported ~~single~~ covered product data ~~component~~ contains errors greater than 5%, as applicable, in an emissions data report. Material misstatement is calculated separately for covered emissions and covered product data, ~~for each type of data~~ as specified in section 95131(b)(12)(A).

*** [no changes were made except to renumber]

(280) “Meter/regulator run” means a series of components used in regulating pressure or metering natural gas flow or both.

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

*** [no changes were made except to renumber]

(284) “Midgrade gasoline” means gasoline that has an octane rating greater than or equal to 88 and less than or equal to 90. This definition applies to the midgrade categories of conventional-summer, conventional-winter, reformulated-summer, and reformulated-winter. For midgrade categories of RBOB-summer, RBOB-winter, CBOB-summer, and CBOB-winter, this definition refers to the expected octane rating of the finished gasoline after oxygenate has been added to the RBOB or CBOB.

*** [no changes were made except to renumber]

(~~251~~296) “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.

*** [no changes were made except to renumber]

(~~254~~299) “Natural gas liquids” or “NGLs” ~~“~~means those hydrocarbons in natural gas that are separated from the gas as liquids through the process of absorption, condensation, adsorption, or other methods. Natural gas liquids can be classified according to their vapor pressures as low (condensate), intermediate (natural gasoline), and high (liquefied petroleum gas) vapor pressure. Generally, such liquids consist of ethane, propane, butanes, ~~and~~ pentanes ~~plus~~, and higher molecular weight hydrocarbons. Bulk NGLs refers to mixtures of NGLs that are sold or delivered as undifferentiated product from natural gas processing plants.

*** [no changes were made except to renumber]

(301) “Natural gasoline” means a mixture of liquid hydrocarbons (mostly pentanes and heavier hydrocarbons) extracted from natural gas. It includes isopentane. Natural gasoline is a natural gas liquid of intermediate vapor pressure.

*** [no changes were made except to renumber]

(~~257~~303) “Net generation” or “net power generated” means the gross generation minus station service or unit service power requirements (during time periods when the generating unit is generating electricity), expressed in megawatt hours (MWh) per year. In the case of cogeneration, this value is intended to include internal consumption of electricity for the purposes of a production process, as well as power put on the grid.

*** [no changes were made except to renumber]

(316) “Offset project specific verifier” means an individual who has been accredited by ARB to verify offset projects of a specific offset project type.

*** [no changes were made except to renumber]

(319) “Oil and gas systems specialist” means a verifier accredited to meet the requirements of section 95131(a)(2) for providing verification services to operators petroleum refineries, hydrogen production units or facilities, and petroleum and natural gas systems listed in section 95101(e).

*** [no changes were made except to renumber]

(~~274~~322) “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 95102(a) ~~40 CFR §98.230(a)(2)~~). 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.

*** [no changes were made except to renumber]

(329) “Pentane” is the n-pentane, straight chain, isomer of C_5H_{12} under the International Union of Pure and Applied Chemistry (IUPAC) nomenclature.

(330) “Pentanes plus” or “C5+” means a mixture of hydrocarbons that is a liquid at ambient temperature and pressure, and consists mostly of pentanes (five carbon chain) and higher carbon number hydrocarbons. Pentanes plus includes normal pentane, isopentane, hexanes-plus (natural gasoline), and plant condensate.

*** [no changes were made except to renumber]

(~~282~~332) “Performance review” means an assessment conducted by ARB of an applicant seeking to become accredited as a verification body, verifier, lead verifier, offset project specific verifier, or sector specific verifier pursuant to section 95132 of this article. Such an assessment may include a review of applicable past sampling plans, verification reports, verification statements, conflict of interest submittals, and additional information or documentation regarding the applicant's fitness for qualification.

*** [no changes were made except to renumber]

(~~291~~341) "Point of delivery" or "POD" means the point on an electricity transmission or distribution system where a deliverer makes electricity available to a receiver, or available to serve load. This point can be an interconnection with another system or a substation where the transmission provider's transmission and distribution systems are connected to another system, or a distribution substation where electricity is imported into California over a multi-jurisdictional retail provider's distribution system.

(~~292~~342) "Point of receipt" or "POR" means the point on an electricity transmission or distribution system where an electricity receiver receives electricity from a deliverer. This point can be an interconnection with another system or a substation where the transmission provider's transmission and distribution systems are connected to another system.

*** [no changes were made except to renumber]

(~~296~~346) "Position holder" means an entity that holds an inventory position in motor vehicle fuel, ethanol, distillate fuel, biodiesel, or renewable diesel as reflected in the records of the terminal operator or a terminal operator that owns motor vehicle fuel or diesel fuel in its terminal. "Position holder" does not include inventory held outside of a terminal, fuel jobbers (unless directly holding inventory at the terminal), retail establishments, or other fuel suppliers not holding inventory at a fuel terminal.

(~~297~~347) "Positive emissions data verification statement" means a verification statement rendered by a verification body attesting that the verification body can say with reasonable assurance that the covered emissions data in the submitted emissions data report is free of material misstatement and that the emissions data conforms to the requirements of this article.

(~~298~~348) "Positive product data verification statement" means a verification statement rendered by a verification body attesting that the verification body can say with reasonable assurance that the covered product data in the submitted emissions data report is free of material misstatement and that the product data conforms to the requirements of this article.

*** [no changes were made except to renumber]

(~~301~~351) “Power contract” or “written power contract,” as used for the purposes of documenting specified versus unspecified sources of imported and exported electricity, means a written document, including associated verbal or electronic records if included as part of the written power contract, arranging for the procurement of electricity. Power contracts may be, but are not limited to, power purchase agreements, enabling agreements, and tariff provisions, without regard to duration, or written agreements to import on behalf of another entity, as long as that other entity also reports to ARB the same imported or exported electricity.

(352) “Premium grade gasoline” is gasoline having an antiknock index, i.e., octane rating, greater than 90. This definition applies to the premium grade categories of conventional-summer, conventional-winter, reformulated-summer, and reformulated-winter. For premium grade categories of RBOB-summer, RBOB-winter, CBOB-summer, and CBOB-winter, this definition refers to the expected octane rating of the finished gasoline after oxygenate has been added to the RBOB or CBOB.

*** [no changes were made except to renumber]

(~~303~~354) “Primary refinery products” means aviation gasoline, motor gasoline (finished), kerosene-type jet fuel, distillate fuel oil, renewable liquid fuels, and asphalt. For the purpose of calculating this value for each refinery ARB will convert blendstocks into their finished fuel volumes by multiplying blendstocks by an assumed blending ratio.

*** [no changes were made except to renumber]

(359) “Process Heater” means equipment for the heating of process streams (gases, liquids, or solids) other than water through heat provided by fuel combustion.

(360) “Process emissions specialist” means a verifier accredited to meet the requirements of section 95131(a)(2) for providing verification services to operators of facilities engaged in cement production, glass production, lime manufacturing, pulp and paper manufacturing, iron and steel production, and nitric acid production.

*** [no changes were made except to renumber]

(~~312~~365) “Product data verification statement” means the final statement rendered by a verification body attesting whether a reporting entity’s covered product data in their emissions data report is free of material misstatement, and whether the product data conforms to the requirements of this article.

*** [no changes were made except to renumber]

(369) “Propylene” is an olefinic hydrocarbon with molecular formula C_3H_6.

*** [no changes were made except to renumber]

(~~326~~380) “Qualified positive emissions data verification statement” means a statement rendered by a verification body attesting that the verification body can say with reasonable assurance that the covered emissions data in the submitted emissions data report is free of material misstatement and is in conformance with section 95131(b)(9), but the emissions data may include one or more other nonconformances with the requirements of this article which do not result in a material misstatement.

(~~327~~381) “Qualified positive product data verification statement” means a statement rendered by a verification body attesting that the verification body can say with reasonable assurance that the covered product data in the submitted emissions data report is free of material misstatement and is in conformance with section 95131(b)(9), but the product data may include one or more other nonconformance(s) with the requirements of this article which do not result in a material misstatement.

(~~328~~382) “Qualified positive verification statement” means a statement rendered by a verification body attesting that the verification body can say with reasonable assurance that the submitted emissions data report is free of material misstatement and is in conformance with section 95131(b)(9), but the emissions data report may include one or more other nonconformance(s) with the requirements of this article which do not result in a material misstatement. This definition applies to the qualified positive emissions data verification statement and the qualified positive product data verification statement.

*** [no changes were made except to renumber]

(385) “RBOB-summer” or “reformulated blendstock for oxygenate blending-summer” means a petroleum product which, when blended with a specified type and percentage of oxygenate, meets the definition of reformulated-summer.

(386) “RBOB-winter” or “reformulated blendstock for oxygenate blending-winter” means a petroleum product which, when blended with a specified type and percentage of oxygenate, meets the definition of reformulated-winter.

*** [no changes were made except to renumber]

(390) “Reciprocating internal combustion engine” or “RICE” or “piston engine” means an engine that uses heat from the internal combustion of fuel to create pressure that drives one or more reciprocating pistons, creating mechanical energy.

(391) “Re-condenser” means heat exchangers that cool compressed boil-off gas to a temperature that will condense natural gas to a liquid.

*** [no changes were made except to renumber]

(398) “Reformulated-summer” means finished gasoline formulated for use in motor vehicles, the composition and properties of which meet the requirements of the reformulated gasoline regulations promulgated by the U.S. Environmental Protection Agency under 40 CFR §80.40 and 40 CFR §80.41, and summer RVP standards required under 40 CFR §80.27 or as specified by the state. Reformulated gasoline excludes RBOB as well as other blendstock.

(399) “Reformulated-winter” means finished gasoline formulated for use in motor vehicles, the composition and properties of which meet the requirements of the reformulated gasoline regulations promulgated by the U.S. Environmental Protection Agency under 40 CFR §80.40 and 40 CFR §80.41, but which do not meet summer RVP standards required under 40 CFR §80.27 or as specified by the state. Note: This category includes Oxygenated Fuels Program Reformulated Gasoline (OPRG). Reformulated gasoline excludes RBOB as well as other blendstock.

(400) “Regular grade gasoline” is gasoline having an antiknock index, i.e., octane rating, greater than or equal to 85 and less than 88. This definition applies to the regular grade categories of conventional-summer, conventional-winter, reformulated-summer, and reformulated-winter. For regular grade categories of RBOB-summer, RBOB-winter, CBOB-summer, and CBOB-winter, this definition refers to the expected octane rating of the finished gasoline after oxygenate has been added to the RBOB or CBOB.

*** [no changes were made except to renumber]

(402) “Rendered animal fat” or “tallow” means fats extracted from animals which are generally used as a feedstock in making biodiesel.

(405) “Renewable Energy Credit” or “REC” has the same meaning as ascribed to the cap-and-trade regulation section 95802(a).

*** [no changes were made except to renumber]

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

*** [no changes were made except to renumber]

(418) “Sector specific verifier” means a verifier accredited pursuant to section 95132(b)(5)(A) as one or more of the following types of specialists defined pursuant to this section: a transactions specialist, an oil and gas systems specialist, or a process emissions specialist.

*** [no changes were made except to renumber]

(~~358~~) ~~“Single product data component” means each individual annual product data item that is required to be reported pursuant to the product data requirements of this article.~~

(423) “Sink” or “sink to load” or “load sink” means the sink identified on the physical path of NERC e-Tags, where defined points have been established through the NERC Registry. Exported electricity is disaggregated by the sink on the NERC e-Tag, also referred to as the final point of delivery on the NERC e-Tag.

*** [no changes were made except to renumber]

(427) “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.

*** [no changes were made except to renumber]

(430) “Source of generation” or “generation source” means the generation source identified on the physical path of NERC e-Tags, where defined points have been established through the NERC Registry. Imported electricity and wheels are disaggregated by the source on the NERC e-Tag, also referred to as the first point of receipt.

*** [no changes were made except to renumber]

(437) “Steam generator” means equipment that produces steam using an external heat source.

*** [no changes were made except to renumber]

(445) “Sweet gas” means 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.

*** [no changes were made except to renumber]

(~~391~~460) “Total thermal output” means the total amount of usable thermal energy generated by a cogeneration or bigeneration unit that can potentially be made available for use in any industrial or commercial processes, heating or cooling applications, or delivered to other end users. This quantity excludes the heat content of returned condensate and makeup water, but includes the thermal energy used for supporting (but not directly used for) power generation, thermal energy used in other on-site processes or applications that are not in support of or a part of the electricity generation system, thermal energy provided or sold to particular end-user, and thermal energy that is otherwise not utilized. Thermal energy directly used for power generation (e.g., steam used to drive a steam turbine generator for electricity generation) is not included in total thermal output.

(461) "Transactions specialist" means a verifier accredited to meet the requirements of section 95131(a)(2) for providing verification services to electric power entities; suppliers of petroleum products and biofuels; suppliers of natural gas, natural gas liquids, and liquefied petroleum gas; and suppliers of carbon dioxide.

(462) "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).

(~~392~~463) "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.

*** [no changes were made except to renumber]

(465) "Turbine" means any of various types of machines in which the kinetic energy of a moving fluid is converted into mechanical energy by causing a bladed rotor to rotate.

*** [no changes were made except to renumber]

(~~399~~471) "Unspecified source of electricity" or "unspecified source" means a source of electricity that is not a specified source at the time of entry into the transaction to procure the electricity. ~~procured and delivered without limitation at the time of transaction to a specific facility's or unit's generation. Unspecified sources contribute to the bulk system power pool and typically are dispatchable, marginal resources that do not serve baseload~~.

*** [no changes were made except to renumber]

(476) "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.

(477) "Vegetable oil" means oils extracted from vegetation that are generally used as a feedstock in making biodiesel.

*** [no changes were made except to renumber]

(487) "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.

*** [no changes were made except to renumber]

(491) "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.

*** [no changes were made except to renumber]

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.

§ 95103. Greenhouse Gas Reporting Requirements.

The facilities, suppliers, and entities specified in section 95101 must monitor emissions and submit emissions data reports to the Air Resources Board following the requirements specified in 40 CFR §98.3 and §98.4, except as otherwise provided in this part.

(a) *Abbreviated Reporting for Facilities with Emissions Below 25,000 Metric Tons of CO_2e.* A facility operator may submit an abbreviated emissions data report under this article if all of the following conditions have been met: the facility operator does not have a compliance obligation under the cap-and-trade regulation during any year of the current compliance period; the operator is not subject to the reporting requirements of 40 CFR Part 98; and the facility total stationary combustion, process, fugitives and venting emissions are below 25,000 metric tons of CO_2e in 2011 and each subsequent year. This provision does not apply to suppliers or electric power entities. Abbreviated reports must include the information in paragraphs (1)-(~~6~~7) below, and comply with the requirements specified in paragraphs (~~7~~8)-(11~~0~~) below:

***

(3) Total facility GHG process emissions aggregated for all process emissions sources and calculated according to the requirements in the following parts, expressed in metric tons of total CO_2, CO_2 from biomass-derived fuels, CH_4, and N_2O, as applicable:

(A) 40 CFR §98.143 for glass production;
(B) 40 CFR §98.163 for hydrogen production;
(C) 40 CFR §98.173 for iron and steel production;
(D) 40 CFR §98.273 for pulp and paper manufacturing;
(E) Subarticle 5 of this article for petroleum and natural gas systems.

(4~~3~~) Identification of the methods chosen for determining emissions.

(5~~4~~) Any facility operating data or process information used for the GHG emission calculations, including fuel use by fuel type, reported in million standard cubic feet for gaseous fuels, gallons for liquid fuels, short tons for solid fuels, and bone-dry short tons for biomass-derived solid fuels. If applicable, include high heat values and carbon content values used to calculate emissions. Missing fuel use or fuel characteristics data must be substituted according to the requirements of 40 CFR §98.35.

(6~~5~~) For facilities with on-site electricity generation or cogeneration, the applicable information specified in sections 95112(a)-(b) of this article. Geothermal facilities must also report the information specified in section 95112(e).

(7~~6~~) A signed and dated certification statement provided by the designated representative of the owner or operator, according to the requirements of 40 CFR §98.4(e)(1).

(8~~7~~) Abbreviated emissions data reports submitted under this provision must be certified as complete and accurate no later than June 1 of each calendar year. This requirement begins in 2012 for facilities who were required to report GHG emissions to ARB in 2011, and begins in 2013 for facilities not previously reporting to ARB.

(9~~8~~) Subsequent revisions according to the requirements of 40 CFR §98.3(h) must be submitted only if cumulative errors are found to exceed 5 percent of total CO~~2~~$_2$e emissions, or if error correction would cause the emissions total to exceed 25,000 metric tons of CO~~2~~$_2$e, in which case a report that meets the full requirements of this article must be submitted within ninety days of discovery.

(10~~9~~) For abbreviated reports submitted under this provision, records must be kept according to the requirements of 40 CFR §98.3(g), except that a written GHG Monitoring Plan is not required.

(11~~0~~) An abbreviated emissions data report is not subject to the third-party verification requirements of this article.

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(f) *Verification Requirement and Deadlines.* The requirements of this paragraph apply to each reporting entity submitting an emissions data report for the previous calendar year that indicates emissions equaled or exceeded 25,000 metric tons of CO_2e, including CO_2 from biomass-derived fuels and geothermal sources, or each reporting entity that has or has had a compliance obligation under the cap-and-trade regulation in any year of the current compliance period. The reporting entity subject to verification must obtain third-party verification services for that report from a verification body that meets the requirements specified in Subarticle 4 of this article. Such services must be completed and separate verification statements for emissions data and for product data, as applicable, must be submitted by the verification body to the Executive Officer by September 1 each year. Each reporting entity must ensure that these verification statements are submitted by this deadline. Contracting with a verification body without providing sufficient time to complete the verification statements by the applicable deadline will not excuse the reporting entity from this responsibility. These requirements are additional to the requirements in 40 CFR §98.3(f).

***

(j) *Calculating, Reporting, and Verifying Emissions from Biomass-Derived Fuels.* The operator or supplier must separately identify and report all biomass-derived fuels as described in section 95852.2(a) of the cap-and-trade regulation. Except for operators that use the methods of 40 CFR §98.33(a)(2)(iii) or §98.33(a)(4), the operator or supplier must separately identify, calculate, and report all direct emissions of CO_2 resulting from the combustion of biomass-derived fuels as specified in sections 95112 and 95115 for facilities, and sections 95121 and 95122 for suppliers. A biomass-derived fuel not listed in section 95852.2(a) of the cap-and-trade regulation must be identified as non-exempt biomass-derived fuel. For a fuel listed under section 95852.2 of the cap-and-trade regulation, reporting entities must also meet the verification requirements in section 95131(i) of this article and the requirements of section 95852.1.1 of the cap-and-trade regulation, or the fuel must be identified as non-exempt biomass-derived fuel. Carbon dioxide combustion emissions from non-exempt biomass-derived fuel will be identified as non-exempt biomass-derived CO_2. The responsibility for obtaining verification of a biomass-derived fuel falls on the entity that is claiming there is not a compliance obligation for the fuel, as indicated in section 95852.2 of the cap-and-trade regulation.

***

(2) When reporting the use of forest derived wood and wood waste as identified in section 95852.2(a)(4) of the cap-and-trade regulation and harvested pursuant to any of the California Forest Practice Rules Title 14, California Code of Regulations, Chapters 4, 4.5 and 10 of~~r~~ the F~~f~~ederal National Environmental Policy Act, the reporting entity must report: the bone-dry mass received; ~~and~~information about the supplier, including the name, physical address, mailing address, contact person with phone number and e-mail address~~,~~; and the corresponding identification number under which the wood was removed.

***

(4) Reporting of fuel consumption from non-exempt biomass-derived fuel is subject to the requirements of section 95103(k) and reporting of emissions from non-exempt biomass-derived fuels is subject to the requirements of sections 95110 to 95157~~7~~8.

(k) *Measurement Accuracy Requirement*. The operator or supplier subject to the requirements of 40 CFR §98.3(i) must meet those requirements, except as otherwise specified in this paragraph. In addition, the following accuracy requirements apply to data used for calculating covered emissions and covered product data. ~~t~~The operator or supplier with covered product data or covered emissions equal to or exceeding 25,000 metric tons of CO_2e or a compliance obligation under the cap-and-trade regulation in any year of the current compliance period must meet the requirements of paragraphs (k)(1)-(10) below for calibration and measurement device accuracy. Inventory measurement, stock measurement, or tank drop measurement methods are subject to paragraph (11) below. The requirements of paragraphs (k)(1)-(11~~0~~) apply to fuel consumption monitoring devices, feedstock consumption monitoring devices, process stream flow monitoring devices, steam flow devices, product data measuring devices, mass and fluid flow meters, weigh scales, conveyer scales, gas chromatographs, mass spectrometers, calorimeters, and devices for determining density, specific gravity, and molecular weight. ~~Unless otherwise required by 40 CFR §98.3(i), t~~The provisions of ~~this section~~ paragraph (k)(1)-(11) do not apply to: stationary fuel combustion units that use the methods in 40 CFR §98.33(a)(4) to calculate CO_2 mass emissions; emissions reported as *de minimis* under section 95103(i); and devices that are solely used to measure parameters used to calculate emissions that are not covered emissions or that are not covered product data. The provisions of paragraphs (k)(1)-(9) and (k)(11) do not apply to stationary fuel combustion units that use the methods in 40 CFR Part 75 Appendix G §2.3 to calculate CO_2 mass emissions, but the provisions in paragraph (k)(10) are applicable to such units.

(1) Except as otherwise provided in sections ~~parts~~ 95103(k)(7) through (9), all ~~monitoring and sampling~~ flow meter and other measurement devices used to provide data for the GHG emissions calculations or covered product data must be calibrated prior to the year data collection is required to begin using the procedures specified in this section, and subsequently recalibrated according to the frequency specified in paragraph (4). ~~Each of these devices~~ A flow meter device consists of a number of individual components which might include a flow constriction component, mechanical component, and temperature and pressure measurement components. Each meter or measurement device must meet the applicable accuracy specification in section 95103(k)(6), however each individual component of a flow meter device is not required to meet the accuracy specifications. The procedures and methods used to quality-assure the data from each measurement device must be documented in the written monitoring plan required by section 95105(c).

(2) All flow meters and other measurement devices that provide data used to calculate GHG emissions or product data must be calibrated according to either the manufacturer's recommended procedures or a method specified in an applicable sub of 40 CFR 98. The calibration method(s) used must be documented in the monitoring plan required under section 95105(c), and are subject to verification under this article and review by ARB to ensure that measurements used to calculate GHG emissions or product data have met the accuracy requirements of this section.

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(4) Except as otherwise provided in sections 95103(k)(7) through (9), subsequent recalibrations of the flow meter and other measurement devices subject to the requirements of this section must be performed no less frequently than at one of the following time intervals, whichever is shortest:

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(E) Immediately upon replacement or repair of a device that is deemed out of calibration as determined in paragraph (6).

(~~E~~F) If the device manufacturer explicitly states in the product documentation that calibration is required at a period exceeding three years, the operator may follow the procedures in ~~sub~~paragraph (9) to obtain Executive Officer approval to relieve the operator from having to comply with provisions (A) and (C) of this subparagraph.

***

(6) In addition to the specific calibration and field accuracy assessment requirements specified below, all flow meter and other measurement devices covered by this part, regardless of type, must be selected, installed, operated, and maintained in a manner to ensure ~~an~~ accuracy within ±5 percent~~%~~.

(A) Perform all mass and volume measurement device calibration as specified in the original equipment manufacturers (OEM) documentation. If OEM documentation is unavailable, calibrate as specified in 40 CFR §98.3(i)(2)-(3), except that a minimum of three calibration points must be used spanning the normal operating conditions. When using the three calibration points, one point must be at or near the zero point, one point must be at or near the upscale point, and one point at or near the mid-point of the devices operating range. If OEM documentation does not specify a method or is unavailable, and calibration methods specified in 40 CFR §98.3(i)(2)-(3) are not possible for a particular device, the procedures in section 95109(b) must be followed to obtain approval for an alternative calibration procedure. Additionally:

1. Pressure differential devices must be inspected at a frequency specified in ~~sub~~paragraph (k)(4) of this section. The inspection must be conducted as described in the appropriate part of ISO 5167-2 (2003), or AGA Report No 3 (2003) Part 2, both of which are incorporated by reference, or a method published by an organization listed in 40 CFR §98.7 applicable to the analysis being conducted. If the ~~plate~~ device fails any one of the tests then the meter shall be deemed out of calibration. If OEM guidance for a particular pressure differential device recommends against disassembly and inspection of the device, disassembly and inspection requirements in this paragraph do not apply. Documentation of OEM guidance must be made available to verifiers and ARB upon request.

   a. Records of all tests must be preserved pursuant to section 95105 and made available to verifiers and ARB upon request.
   b. Where inspection requirements apply, ~~In addition to the inspection,~~ the primary element must also be photographed on both sides prior to any treatment or cleanup of the element to clearly show the condition of the element as it existed in the pipe.

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(B) Operators and suppliers may conduct an annual field accuracy assessment of mass and volume measurement devices to test for field accuracy in years between successive calibrations to ensure the device is maintaining measurement accuracy within ±5 percent. When performing a field accuracy assessment, the as-found condition must be recorded to ensure the device is measuring with accuracy within ±5 percent. Should a device be found to be operating outside the ±5 percent accuracy bounds, the device shall be deemed out of calibration. Records of all field accuracy assessments must clearly indicate the assessment procedure and the as-found condition, be preserved pursuant to section 95105, and be made available to verifiers and ARB upon request. Device accuracy may be assessed using one of the following options:

1. Engineering analysis;
2. OEM calibration guidance or other OEM recommended methods;
3. Standard industry practices; or
4. Portable instruments.

(C) Pursuant to paragraph (k)(10) of this section, in the event of a failed calibration or recalibration, operators or suppliers who choose not to perform the annual field accuracy assessment specified in paragraph

(6)(B) of this section for one or more mass or volume measurement devices must demonstrate data accuracy going back multiple years to the most recent successful calibration. Multiple years of data may be deemed invalid if accuracy cannot be demonstrated by other means. For operators and suppliers who conduct the annual field accuracy assessment, and a device is found to be out of calibration, accuracy must be demonstrated back to the most recent successful calibration or the most recent successful field accuracy assessment, whichever is most recent.

(7) ~~Financial transaction meters are exempted from the calibration requirements of section 95103(k) provided that the supplier and purchaser do not have any common owners and are not owned by subsidiaries or affiliates of the same company. For a flow meter or measurement device that has been previously calibrated in accordance with section 95103(k)(1) through (5), an additional calibration is not required by the date specified in section 95103(k)(1) if, as of that date, the previous calibration is still active (i.e., the device is not yet due for recalibration because the time interval between successive calibrations has not elapsed). In this case, the deadline for the successive calibrations of the flow meter or measurement device shall be set according to section 95103(k)(4).~~ The requirements of section 95103(k) do not apply under the following circumstances:

(A) Financial transaction meters are exempted from the calibration requirements of section 95103(k) if the supplier and purchaser do not have any common owners and are not owned by subsidiaries or affiliates of the same company. Financial transaction meters where the supplier and the purchaser do have common owners or are owned by subsidiaries or affiliates of the same company are exempt from the calibration requirements of section 95103(k) if one of the following is true:

1. The financial transaction meter is also used by other companies that do not share common ownership with the fuel supplier; or

2. The financial transaction meter is sealed with a valid seal from the county sealer of weights and measures or from a county certified designee; or

3. The financial transaction meter is operated by a third party.

(B) Upstream ethanol and additive meters used to ensure proper blendstock percentage for finished gasoline are exempted from the calibration requirements of section 95103(k).

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(9) In cases of continuously operating units and processes where calibration or inspection is not possible without operational disruption, the operator must demonstrate by other means to the satisfaction of the Executive Officer that measurements used to calculate GHG emissions and product data still meet the accuracy requirements of section 95103(k)(6). The Executive Officer must approve any postponement of calibration or required recalibration beyond January 1, 2012.

(A) A written request for postponement must be submitted to the Executive Officer not less than 30 days before the required calibration, recalibration or inspection date except in 2012, where the postponement request must be received by the reporting deadline in section 95103(e). The Executive Officer may request additional documentation to validate the operator's claim that the device meets the accuracy requirements of this section. The operator shall provide any additional documentation to ARB within ten (10) working days of a request by ARB.

(B) The request must include:

1\. The date of the required calibration, recalibration, or inspection;
2\. The date of the last calibration or inspection;
3\. The date of the most recent field accuracy assessment, if applicable;
4\. The results of the most recent field accuracy assessment, if applicable, clearly indicating a pass/fail status;
5\. The proposed date for the next field accuracy assessment, if applicable;
~~3~~6. The proposed date for calibration, recalibration, or inspection which must be during the time period of the next scheduled shutdown. If the next shutdown will not occur within three years, this must be noted and a new request must be received every three years until the shutdown occurs and the calibration, recalibration or inspection is completed.
~~4~~7. A description of the meter or other device, including at a minimum:
- a. make,
- b. model,
- c. install date,
- d. location,
- e. annual emissions calculated or annual product data reported using data from the device,
- f. sources for which the device is used to calculate emissions or product data,
- g. calibration or inspection procedure,
- h. reason for delaying calibration or inspection,

i. proposed method to assure the accuracy requirements of section 95103(k)(6) are met,

j. name, title, phone number and e-mail of contact person capable of responding to questions regarding the device.

(10) If the results of an initial calibration, ~~or a~~ recalibration, or field accuracy assessment fail to meet the required accuracy specification, and the emissions or product data estimated using the data provided by the device represent more than 5 percent of total facility emissions or product data on an annual basis, the operator must demonstrate by other means to the satisfaction of the verifier or ARB that measurements used to calculate GHG emissions and product data still meet the ± 5% accuracy requirements going back to the last instance of successful field accuracy assessment or calibration of the device. Where the results of an initial calibration, recalibration, or field accuracy assessment fail to meet the accuracy specifications, ~~T~~the verifier shall note at a minimum a nonconformance as part of the emissions data verification statement.

(11) When using an inventory measurement, stock measurement, or tank drop measurement method to calculate volumes and masses, the method must be accurate to ±5 percent~~%~~ for the time periods required by this article, including annually for covered~~single~~ product data~~ components~~. Techniques used to quantify amounts stored at the beginning and end of these time periods are not subject to the calibration requirements of this part. Uncertainties in beginning and end amounts are subject to verifier review for material misstatement under section 95131(b)(12) of this article. If any devices used to measure inputs and outputs do not meet the requirements of paragraphs (1)-(10) above, the verifier must account for this uncertainty when evaluating material misstatements. Reported values must be calculated using the following equations:

Fuel consumed (volume or mass) = (inputs during time period – outputs during time period) + (amount stored at beginning of time period) – (amount stored at end of time period)

Product produced (volume or mass) = (outputs during time period - inputs during time period) + (amount stored at end of time period - amount stored at beginning of time period)

(l) *Reporting and Verifying Product Data*. The reporting entity must separately identify, quantify, and report all product data as specified in sections 95110-95123 and 95156 of this article. It is the responsibility of the reporting entity to obtain verification services for the product data. Product data will be evaluated for conformance and material misstatement independent of GHG emissions data. Covered product data is evaluated for material misstatement, while the remaining reported product data is evaluated for conformance. ~~The operator must not replace data when calculating product data.~~

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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.

§ 95104. Emissions Data Report Contents and Mechanism.

The reporting entities specified in section 95101 must develop, submit, and certify greenhouse gas emissions data reports to the Air Resources Board each year in accord with the following requirements.

(a) *General Contents.* In addition to the items specified at 40 CFR §98.3(c), each reporting entity must include in the emissions data report the following California information: ARB identification number, air basin, air district, county, ~~and~~ geographic location, and indicate whether the reporting entity qualifies for small business status pursuant to California Government Code 11342.610. Electricity generating units must also provide Energy Information Administration and California Energy Commission identification numbers, as applicable.

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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.

§ 95105. Recordkeeping Requirements.

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(c) *GHG Monitoring Plan for Facilities and Suppliers*. Each facility or supplier that reports under 40 CFR Part 98, each facility or supplier with covered emissions equal to or exceeding 25,000 MT~~mt~~CO_2e, and each facility or supplier with a compliance obligation under the cap-and-trade regulation in any year of the current compliance period, must complete and retain for review by a verifier or ARB a written GHG Monitoring Plan that meets the requirements of 40 CFR §98.3(g)(5). For facilities, the Plan must also include the following elements, as applicable:

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(d) *GHG Inventory Program for Electric Power Entities that Import or Export Electricity.*

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(6) Reference to other independent or internal data management systems and records, including written power contracts and associated verbal or

electronic records, full or partial ownership, invoices, and settlements data used to document whether reported transactions are specified or unspecified and whether the requirements for adjustments to covered emissions pursuant to sections 95852(b)(1)(B), 95852(b)(4) and 95852(b)(5) of the cap-and-trade regulation are met;

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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.

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§ 95111. Data Requirements and Calculation Methods for Electric Power Entities.

The electric power entity who is required to report under section 95101 of this article must comply with the following requirements.

(a) *General Requirements and Content for GHG Emissions Data Reports for Electricity Importers and Exporters.*

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(5) *Imported Electricity Supplied by Asset-Controlling Suppliers.* The reporting entity must separately report imported electricity supplied by ~~Bonneville Power Administration, an~~ asset-controlling suppliers recognized by ARB. The asset-controlling supplier~~Bonneville Power Administration~~ must be identified on the physical path of NERC e-Tags as the PSE at the first point of receipt~~.~~, regardless of whether the reporting entity and asset-controlling supplier are adjacent in the market path. The reporting entity must:

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(8) *Electricity Wheeled Through California.* The electric power entity must separately report electricity wheeled through California, aggregated by first point of receipt ~~outside California~~, and must exclude wheeled power transactions from reported imports and exports. When reporting electricity wheeled through California, the power entity must include the quantities of electricity wheeled through California as measured at the first point of delivery inside the state of California.

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(b) *Calculating GHG Emissions*.

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(2) *Calculating GHG Emissions from Specified Facilities or Units.* For electricity from specified facilities or units, the electric power entity must calculate

emissions using the following equation:

$$CO_2e = MWh \times TL \times EF_{sp}$$

Where:

CO_2e = Annual CO_2 equivalent mass emissions from the specified electricity deliveries from each facility or unit claimed (MT of CO_2e).

MWh = Megawatt-hours of specified electricity deliveries from each facility or unit claimed.

EF_{sp} = Facility-specific or unit-specific emission factor published on the ARB Mandatory Reporting website and calculated using total emissions and transactions data as described below. The emission factor is based on data from the year prior to the reporting year.

EF_{sp} = 0 MT of CO_2e for facilities below the GHG emissions compliance threshold for delivered electricity pursuant to the cap-and-trade regulation during the first compliance period.

***

(3) *Calculating GHG Emissions of Imported Electricity Supplied by Specified Asset-Controlling Suppliers.* Based on annual reports submitted to ARB pursuant to section 95111(f), ARB will calculate and publish on the ARB Mandatory Reporting website the system emission factor for all ~~Bonneville Power Administration, an~~ asset-controlling suppliers recognized by the ARB. The reporting entity must calculate emissions for electricity supplied using the following equation:

$$CO_2e = MWh \times TL \times EF_{ACS}$$

Where:

CO_2e = Annual CO_2 equivalent mass emissions from the specified electricity deliveries from ARB-recognized asset-controlling suppliers~~Bonneville Power Administration~~ (MT of CO_2e).

MWh = Megawatt-hours of specified electricity deliveries.

EF_{ACS} = Supplier-specific emission factor published on the ARB Mandatory Reporting website (MT CO_2e/MWh). ARB will assign the system emission factors for all asset-controlling suppliers ~~Bonneville Power Administration (BPA) a default system emission factor equal to 20 percent of the default emission factor for unspecified sources, or when available,~~ based on a previously verified GHG report submitted to ARB pursuant to section 95111(f)~~, beginning in the 2010 data year and meeting the requirements for asset-controlling suppliers~~. The supplier-specific system emission factor is calculated annually by ARB. The calculation is derived from data contained in annual reports submitted pursuant to section 95111(f) that have received a positive or qualified positive verification statement. The emission factor is based on data from two years prior to the reporting year.

TL = Transmission loss correction factor.

TL = 1.02 when deliveries are not reported as measured at a first point of receipt located within the balancing authority area of the asset-controlling supplier.

TL = 1.0 when deliveries are reported as measured at a first point of receipt located within the balancing authority area of the asset-controlling supplier.

***

(5) Calculation of C~~c~~overed E~~e~~missions. For imported electricity with covered emissions as defined pursuant to section 95102(a), the electric power entity must calculate and report covered emissions pursuant to the equation in 95852(b)(1)(B) of the cap-and-trade regulation and include the following information:

$CO_2e_{covered}$ = Sum of covered emissions defined pursuant to section 95102(a) and calculated pursuant to the equation in section 95852(b)(1)(B) of the cap-and-trade regulation (MT of CO_2e).

CO_2e_{unsp} = Sum of CO_2 equivalent mass emissions from imported electricity from unspecified sources (MT of CO_2e).

CO_2e_{sp} = Sum of CO_2 equivalent mass emissions from imported electricity that meets the requirements in section 95111(g) for reporting electricity from specified sources (MT of CO_2e).

$CO_2e_{sp\text{-}not\ covered}$ = Sum of CO_2 equivalent mass emissions from imported electricity that meets the requirements in section 95111(g) for reporting electricity from specified sources and is explicitly listed as ~~not covered~~ emissions without a compliance obligation pursuant to section 95852.2 of the cap-and-trade regulation (MT of CO_2e).

$CO_2e_{RPS\ adjust}$ = Sum of CO_2 equivalent mass emissions adjustment is calculated using the following equation for electricity generated by each eligible renewable energy resource located outside the state of California and registered with ARB by the reporting entity pursuant to section 95111(g)(1), but not directly delivered as defined pursuant to section 95102(a). Electricity included in the RPS adjustment must meet the requirements pursuant to section 95852(b)(4) of the cap-and-trade regulation (MT of CO_2e).

$$CO_2e_{RPS\_adjust} = MWh_{RPS} \times EF_{unsp} (MTCO_2e / MWh)$$

Where:

MWh_{RPS} = Sum of MWh generated by each eligible renewable energy resource located outside of the state of California, registered with ARB pursuant to section 95111(g)(1), and meeting requirements pursuant to section 95852(b)(4) of the cap-and-trade regulation.

$CO_2e_{\text{QE adjust}}$ = Sum of CO_2 equivalent mass emissions adjustment for qualified exports as defined in section 95102(a) and that meet the requirements pursuant to section 95852(b)(5) of the cap-and-trade regulation (MT of CO_2e).

CO_2e_{linked} = Sum of CO_2e mass emissions recognized by ARB pursuant to linkage under subarticle 12 of the cap-and-trade regulation (MT of CO_2e).

$$\cancel{CO_2e_{RPS\_adjust} = MWh_{RPS} \times AF}$$

~~Where:~~

~~MWh_{RPS} = Sum of MWh generated by each eligible renewable energy resource located outside of the state of California procured by the reporting entity, registered with ARB pursuant to section 95111(g)(1), and meeting requirements pursuant to section 95852(b)(4) of the cap-and-trade regulation.~~

~~$AF = EF_{unsp}$ (MT CO_2e/MWh)~~

(c) ~~*GHG Emissions Data Report:*~~ *Additional Requirements for Retail Providers, excluding Multi-jurisdictional Retail Providers.* Retail providers must include the following information in the GHG emissions data report for each report year, in addition to the information identified in sections 95111(a)-(b) and (g).

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(4) Retail providers that report as electricity importers or exporters also must separately report electricity imported from specified and unspecified sources by other electric power entities to serve their load, designating the electricity importer. In addition, all imported electricity transactions documented by NERC e-Tags where the retail provider is the PSE at the sink must be reported.

(d) ~~*GHG Emissions Data Report:*~~ *Additional Requirements for Multi-Jurisdictional Retail Providers.* Multi-jurisdictional retail providers that provide electricity into

California at the distribution level must include the following information in the GHG emissions data report for each report year, in addition to the information identified in section 95111(a)-(b).

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(e) *~~GHG Emissions Data Report: ~~Additional Requirements for WAPA and DWR*.

***

(f) *~~GHG Emissions Data Report: Additional~~ Requirements for Asset-Controlling Suppliers.* Owners or operators of electricity generating facilities or exclusive marketers for certain generating facilities may apply for an asset-controlling supplier designation from ARB. Approved asset-controlling suppliers may request that ARB calculate a supplier-specific emission factor pursuant to section 95111(b)(3).

~~Bonneville Power Administration request that ARB calculate its supplier-specific emission factor based on a previously verified GHG report that meets the requirements for asset-controlling suppliers, instead of a default system emission factor equal to 20 percent of the default emission factor for unspecified sources. An~~ To apply for asset-controlling supplier designation, the applicant ~~that chooses this option~~ must:

(1) Meet the requirements in this article, including reporting pursuant to section 95112 as applicable for each generating facility or unit in the supplier's fleet;
(2) Include in its emissions data report wholesale power purchased and taken (MWh) from specified and unspecified sources and wholesale power sold from specified sources according to the specifications in this section, and as required for ARB to calculate a supplier-specific emission factor;
(3) Retain for verification purposes documentation that the power sold by the supplier originated from the supplier's fleet of facilities and either that the fleet is under the supplier's operational control or that the supplier serves as the fleet's exclusive marketer;
(4) Provide the supplier-specific ARB identification number to electric power entities who purchase electricity from the supplier's system.
(5) To apply for and maintain asset-controlling supplier status, the entity shall submit as part of its emissions data report the following information, annually:
   (A) General business information, including entity name and contact information;
   (B) List of officer names and titles;
   (C) Data requirements per section 95111(b)(3);
   (D) Data requirements per section 95111(g)(1);
   (E) A list and description of electricity generating facilities for which the reporting entity is a generation providing entity pursuant to 95102(a); and
   (F) An attestation, in writing and signed by an authorized officer of the applicant, as follows:

“I certify under penalty of perjury under the laws of the State of California that I am duly authorized by [name of entity] to sign this attestation on behalf of [name of entity], that [name of entity] meets the definition of an asset-controlling supplier as specified in section 95102(a) of the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions, title 17, California Code of Regulations, section 95100 et seq., and that the information submitted herein is true, accurate, and complete.”

Asset-controlling suppliers must annually adhere to all reporting and verification requirements of this article, or be removed from asset-controlling supplier designation. Asset-controlling suppliers will also lose their designation if they receive an adverse verification statement, but may reapply in the following year for re-designation.

(g) *Requirements for Claims of Specified Sources of Electricity and for Eligible Renewable Energy Resources in the RPS Adjustment.*

Each reporting entity claiming specified facilities or units for imported or exported electricity must register its anticipated specified sources with ARB pursuant to subsection 95111(g)(1) and by February 1 following each data year to obtain associated emission factors calculated by ARB for use in the emissions data report required to be submitted by June 1 of the same year. Each reporting entity claiming specified facilities or units for imported or exported electricity must also meet requirements pursuant to section 95111(g)(2)-(5) in the emissions data report. Each reporting entity claiming an RPS adjustment, as defined in section 95111(b)(5), pursuant to section 95852(b)(4) of the cap-and-trade regulation must include registration information for the eligible renewable energy resources pursuant to section 95111(g)(1) in the emissions data report. Prior registration and section 95111(g)(2)-(5) do not apply to RPS adjustments. Registration information and the amount of electricity claimed in the RPS adjustment must be fully reconciled and corrections must be certified within 45 days following the emissions data report due date.

(1) *Registration Information for Specified Sources and Eligible Renewable Energy Resources in the RPS Adjustment.* The following information is required:

(A) The facility names and, for specification to the unit level, the facility and unit names.

***

(M) Provide the serial numbers of Renewable Energy Credits (RECs) as specified below:

1. RECs associated with electricity procured from an eligible renewable energy resource and reported as an RPS adjustment as well as whether the RECs have been placed in a retirement subaccount and

designated as retired for the purpose of compliance with the California RPS program.

2. RECs associated with electricity procured from an eligible renewable energy resource and reported as an RPS adjustment in a previous emissions data report year that later were withdrawn from the retirement subaccount, the associated emissions data report year the RPS adjustment was claimed, and date of REC withdrawal.
3. RECs associated with electricity generated, directly delivered, and reported as specified imported electricity and whether or not the RECs have been placed in a retirement subaccount.

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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.

§ 95112. Electricity Generation and Cogeneration Units.

The operator of a facility who is required to report under section 95101 of this article, and who is not eligible for abbreviated reporting under section 95103(a), must report as specified below and comply with Subparts C and D of 40 CFR Part 98 (§§98.30 to 98.48), as applicable, in reporting emissions and other data from electricity generating and cogeneration units to ARB, except as otherwise provided in this section. Notwithstanding the above, the operator of a facility with total facility nameplate generating capacity of less than 1 MW may elect to follow section 95115 in reporting electricity generating units as general combustion sources, in lieu of the requirements of section 95112. If engineering estimation is used to report disposition of generated energy or energy flow data that are not used directly to determine emissions, facility operators must demonstrate accuracy of the chosen engineering estimation method.

(a) *Information About the Electricity Generating Facility*.

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(4) The disposition of generated electricity in MWh, reported at the facility-level, including:

(A) Generated electricity provided or sold to a retail provider or electricity marketer who distributes the electricity over the electric power grid for wholesale or retail customers of the grid. The operator must report the name of the retail provider or electricity marketer;

(B) Generated electricity provided or sold directly to particular end-users (as defined in section 95102). A reportable end-user includes any entity, under the same or different operational control, that is not a part of the facility. Report each end-user's facility name, NAICS code, and ARB ID if applicable;

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(5) The disposition of the thermal energy (MMBtu) generated by the cogeneration unit or bigeneration unit, if applicable, reported at the facility-level including:

(A) Thermal energy provided or sold to particular end-users (as defined in section 95102). A reportable end-user includes any entity, under the same or different operational control, that is not a part of the facility. Report each end-user's facility name, NAICS code, ARB ID if applicable, and the types of thermal energy product provided. Exclude from this quantity the amount of thermal energy that is vented, radiated, wasted, or discharged before the energy is provided to the end-user~~;~~.

(B) Thermal energy used for supporting power production~~,~~ that has been included in the quantity reported under paragraph 95112(b)(3) but that is not accounted for in the quantities reported under paragraphs 95112(a)(5)(A) and (C). This thermal energy quantity must not include steam directly used for power production, such as the steam used to drive a steam turbine generator to generate electricity. Activities for supporting power generation may include~~ing~~ steam used for power augmentation, NO_x control, sent to a de-aerator, or sent to a cooling tower~~;~~.

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(b) *Information About Electricity Generating Units.* Notwithstanding any limitations in 40 CFR Parts 75 or 98, the operator of an electricity generating unit must include in the emissions data report the information listed in this paragraph. For aggregation of electricity generating units, the operator must~~that~~ meet the applicable criteria in 40 CFR §98.36(c)(1)-(4), unless otherwise specified in sections 95115(h) and 95112(b).~~ the operator may elect to report the following information for a group of aggregated units consisting of only electricity generating units of the same type, (e.g., all cogeneration units, all bigeneration units, or all generating units that are neither cogeneration or bigeneration in the grouping), except when 40 CFR 98.36(c) applies to the grouping, in lieu of separately reporting for each single unit.~~ For an electricity generation system (a cogeneration system, a bigeneration system, a combined cycle electricity generation system, or a system with boilers and steam turbine generators), the operator may aggregate all the units that are integrated into the system for the purpose of reporting data to ARB. Operators of Part 75 units may also aggregate units to the system level according to this paragraph, notwithstanding the limitation in 40 CFR §98.36(d)(1)(i). If there is more than one system present at the facility, each system must be reported separately. For electricity generating units that are not part of an integrated generation system, aggregation of electricity generating units is limited to units of the same type, as specified in section 95115(h). Operators of geothermal facilities, hydrogen fuel cells, and renewable electricity generating units must follow paragraph (e), (f), or (g) of this section, whichever is applicable, instead of paragraph (b) of this section. For bottoming cycle cogeneration units, the operator is not required to report the data specified in section 95112(b)(4)-(6) except for any fuels combusted for supplemental firing as specified in section 95112(b)(7).

(1) Basic information about the generating unit, including:
   (A) Nameplate generating capacity in megawatts (MW);
   (B) Prime~~r~~ mover technology;
   (C) For aggregation of units, provide a description of the individual equipment included in the aggregation;
   (D) If the unit generates both electricity and thermal energy, indicate whether the unit is a cogeneration or a bigeneration unit. If the unit is a cogeneration unit, indicate whether it is topping or bottoming cycle.

(2) Net and gross power generated, in megawatt hours (MWh).
(3) If the unit is a cogeneration or bigeneration unit, the operator must report the total thermal output (MMBtu), as defined in section 95102, that was generated by the unit. Exclude from this quantity the heat content of returned condensate and makeup water and steam used to drive a steam turbine generator for electricity generation.
(4) Fuel consumption by fuel type, reported in units of million standard cubic feet for gases, gallons for liquids, short tons for non-biomass solids, and bone dry short tons for biomass-derived solids.
(5) If not already required to be reported under 40 CFR §98.3~~5~~6(b) for Subarticle C units and §98.46 for Subarticle D units, annual CO_2, CH_4, and N_2O emissions from the unit, expressed in metric tons of each gas.
(6) If used to calculate CO_2 emissions and not already required to be reported under 40 CFR §98.36(e)(2)(ii)(C) and (iv)(C), report weighted or arithmetic average carbon content and high heat value by fuel type, whichever is used in calculating emissions as specified in 40 CFR §98.33.
(7) For cogeneration ~~units~~systems, where supplemental firing has been applied to support electricity generation or ~~industrial~~ thermal output, report the information in paragraphs (~~a~~b)(4)-(6). Indicate by fuel type the portion of the total fuel consumption (MMBtu) that is used for supplemental firing, and indicate the purpose of the supplemental firing.
(8) Other ~~steam used~~heat input for electricity generation. If the electricity generation unit uses additional heat input that is not already accounted for in paragraphs 95112(b)(4)-(6) (for example, if ~~Where~~ steam or heat is acquired from outside of the electricity generation system boundary or acquired from another facility for the generation of electricity), report the amount of acquired steam or heat (MMBtu) ~~for electricity generation~~. For bottoming cycle cogeneration units only, also report the input steam to the steam turbine (MMBtu) and the output of the heat recovery steam generator (MMBtu) ~~the amount of steam used (MMBtu) for generation of electricity~~.

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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.

§ 95113. Petroleum Refineries.

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(l) *Additional Product and Process Data*.

(1) ~~Finished Products.~~*Finished Products.* The operator must report production quantities for the data year of each petroleum product listed in Table C-1 of 40 CFR 98, ~~and~~ each additional transportation fuel product listed in Table MM-1 of 40 CFR Part 98 (standard cubic feet for gaseous products, barrels for liquid products, short tons for solid products), and calcined coke (short tons). For calcined coke, specify whether the calciner is integrated with the petroleum refinery operation. Among the products reported, only calcined coke and primary refinery products will be subject to review for material misstatement under the requirements of section 95131(b)(12).

(A) For calcined coke, the operator may voluntarily report the annual short tons of calcined coke for calendar years 2011 and 2012. If the operator chooses to report this 2011 and 2012 product data, then they must submit the data to ARB by April 10, 2013 and follow the verification requirements of this article. For emissions data reports submitted in 2014 and any subsequent year, the operator must report and verify the annual short tons of calcined coke.

(2) *Energy Intensity Index.* For refineries that participate in the Solomon Energy Reviews, the operator must report Solomon EII values for the applicable data year. ~~In the 2012 emissions data report the operator must report Solomon EII values for data years 2008, 2009, 2010, and 2011. In subsequent emissions data reports the operator must continue to report the Solomon EII value for the applicable data year.~~

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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.

§ 95114. Hydrogen Production.

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(i) *Transferred CO_2.* The operator must calculate and report the mass of all CO_2 captured, transferred off-site, and reported by the hydrogen production facility as a supplier of CO_2 using reporting provisions found in section 95123. Hydrogen production facilities should adjust reported emissions for CO_2 that is captured and sold or transferred off-site to avoid double counting.

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(~~i~~j) *Additional Product Data.* Operators must report the annual mass of hydrogen gas and ~~liquefied~~liquid hydrogen produced (~~short~~ metric tons) and specify if the hydrogen plant is an integrated refinery operation.

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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.

§ 95115. Stationary Fuel Combustion Sources.

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(c) *Choice of Tier for Calculating CO_2 Emissions.*

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(2) The operator may select the Tier 2 calculation method specified in 40 CFR §98.33(a)(2) for natural gas when it is pipeline quality as defined in section 95102 of this article, and for distillate fuels listed in Table 1 of this section. Tier 1 may be selected when the fuel supplier is providing pipeline quality natural gas measured in units of therms or million Btu. Equation C-2c of 40 CFR §98.33(a) may be selected for the units specified in paragraph (a) of this section.

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(4) The operator must use either the Tier 3 or the Tier 4 calculation method specified under 40 CFR §98.33(a)(3)-(4) for any other fuel, including non-pipeline quality natural gas and fuel with emissions identified as non-exempt biomass-derived CO_2, subject to the limitations of 40 CFR §98.33(b)(4)-(5) requiring use of the Tier 4 method. The operator using Tier 3 must determine annual average carbon content with weighted fuel use values, as required by Equation C-2b of 40 CFR §98.33. When fuel mass or volume it measured by lot, the term “n” in Equation C-2b is substituted as the number of lots received in the year.

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(e) *Procedures for Biomass CO_2 Determination.*

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(3) When calculating emissions from a biomethane and natural gas mixture as described in 40 CFR §98.33(a)(2) using the annual MMBtu of fuel combusted in place of the product of Fuel and HHV in Equation C-2a, the operator must calculate emissions based on contractual deliveries of biomethane subject to the requirements of 95131(i), using the natural gas emission factor in the following equations:

$$E_{biomass\cancel{ethane}} = EF_{natural\ gas} \times MMBtu_{biomethane} \times 0.001$$

$$E_{natural\ gas} = EF_{natural\ gas} \times (MMBtu_{annual} - MMBtu_{biomethane}) \times 0.001$$

Where:

$E_{biomass}$ = The annual biomass CO_2, CH_4 or N_2O emissions from biomethane (metric tons)

$E_{natual\ gas}$ = The annual fossil CO_2, CH_4 or N_2O emissions from natural gas (metric tons)

~~E_{total} = The total annual CO_2, CH_4 or N_2O emissions from a source, determined using 40 CFR §98.33(a)(3)-(4) methodology or Sub D of 40 CFR 98 (metric tons)~~

$EF_{natural\ gas}$ = The natural gas emission factor from Tables C-1 and C-2 of 40 CFR Part 98 (kg/MMBtu)

$MMBtu_{annual}$ = The total delivered MMBtus for the reporting year based on utility bills or meters meeting the accuracy requirements of section 95103(k)

$MMBtu_{biomethane}$ = The total biomethane deliveries subject to the requirements of section 95131(i) for the reporting year based on contractual deliveries

***

(h) *Aggregation of Units.* Facility operators may elect to aggregate units according to 40 CFR §98.36(c), except as otherwise provided in this paragraph. Facility operators that are reporting under more than one source category in paragraphs 95101(a)(1)(A)-(B)~~Tables A-3, A-4, and A-5 of 40 CFR Part 98, with the exception of 40 CFR Part 98 Subpart C,~~ and that elect to follow 40 CFR §98.36(c)(1), (c)(3) or (c)(4), must not aggregate units that belong to different source categories. For the purpose of unit aggregation, units subject to 40 CFR 98 Subarticle C that are associated with one source category must not be grouped with other Subarticle C units associated with another source category, except when 40 CFR §98.36(c)(2) applies. Aggregation of stationary fuel combustion units is limited to units of the same type, where the unit type categories are: boiler, reciprocating internal combustion engine, turbine, process heater, and other (none of the above). Units subject to section 95112 must use the criteria for aggregation in section 95112(b). Facility operators that choose to aggregate units according to the common stack provision in 40 CFR §98.36(c)(2) may report emissions according to 40 CFR §98.36(c)(2), but they must separately report the heat input (MMBtu) by fuel type for each individual unit or each group of units of the same type, such that the grouping of units still meets the limitations for unit aggregation specified elsewhere in this paragraph.

***

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.

***

§ 95119. Pulp and Paper Manufacturing

***

(d) *Additional Product Data.* In addition to the information required by 40 CFR §§98.276, the operator must report the annual production (air dried short tons) of recycled boxboard, recycled linerboard, recycled medium and tissue. For tissue, the operator must also report a description of the process used to produce tissue, such as through use of an air dryer.

***

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.

§ 95120. Iron and Steel Production

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(a) *CO_2 from Fossil Fuel Combustion.* When calculating CO_2 emissions from fossil fuel combustion at a stationary combustion unit under 40 CFR §98.172(a), the operator must use a method in 40 CFR §98.33(a)(1) to §98.33(a)(4) as specified by fuel type in section 95115 of this article.

***

(d) Additional Product Data. In addition to the information required by 40 CFR §98.176, the operator must report the annual production of ~~primary~~ iron and steel products in short tons, a description of the product(s), and, the process used to produce the products, such as use of an electric arc furnace.

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.

§ 95121. Suppliers of Transportation Fuels.

Any position holder, enterer, or refiner who is required to report under section 95101 of this article must comply with Subpart MM of 40 CFR Part 98 (§§98.390 to 98.398) in reporting emissions and related data to ARB, except as otherwise provided in this section.

(a) *GHGs to Report.*

***

(2) Refiners that supply fuel at a rack onsite, and position holders of fossil fuels and biomass-derived fuels and enterers outside the bulk transfer/terminal system of fossil fuels~~ ~~must report the CO_2, CO_2 from biomass-derived fuels, CH_4, N_2O, and CO_2e emissions that would result from the complete combustion or oxidation of each Blendstock, Distillate Fuel Oil or biomass-derived fuel (Biomass-Based Fuel and Biomass) listed in <u>Table 2 of this section.</u> ~~MM-1 or MM-2 of 40 CFR 98, except that~~ <u>However,</u> ~~Distillate Fuel Oil is limited to diesel fuel as defined in this regulation and except~~ <u>reporting is not required</u> for fuel ~~for~~ <u>in</u> which a final destination outside California can be demonstrated. No fuel shall be reported as finished fuel. Fuels must be reported as the individual Blendstock, Distillate Fuel Oil or biomass-derived fuel listed in <u>Table 2 of this section.</u> ~~40 CFR Part 98 Tables MM-1 and MM-2.~~

(b) *Calculating GHG emissions.*

(1) Refiners, position holders at California terminals, and enterers who bring fuel into California outside the bulk transfer/terminal system must use Equation MM-1 as specified in 40 CFR §98.393(a)(1) to estimate the CO_2 emissions that would result from the complete combustion of the fuel<u>. Emissions must be based on the quantity of fuel</u> removed from the rack (for refiners and position holders), <u>fuel</u> imported and not delivered to the bulk transfer/terminal system (by enterers), <u>and fuel</u> sold to unlicensed entities as specified in section 95121(d)(3) (by refiners). For fuels that are blended, emissions must be reported for each individual Blendstock, Distillate Fuel Oil or biomass-derived fuel listed in <u>Table 2 of this section</u> ~~40 CFR Part 98 Tables MM-1 and MM-2~~ separately, and not as motor gasoline (finished), biofuel blends, or other similar finished fuel. Emissions from denatured fuel ethanol must be calculated as 100% ethanol only. The volume of denaturant is assumed to be zero and is not required to be reported. Emission factors must be taken from column C of 40 CFR 98 Table MM-1 or MM-2 as specified in Calculation Method 1 of 40 CFR §98.393(f)(1). If a position holder in diesel or biodiesel fuel does not have sealed or financial transaction meters at the rack, and the position holder is the sole position holder at the terminal, the position holder must calculate emissions based on the delivering entity's invoiced volume of fuel or a meter that meets the requirements of section 95103(k) either at the rack or at a point prior to the fuel going into the terminal storage tanks.

***

(d) *Data Reporting Requirements.* In addition to reporting the information required in 40 CFR §98.3(c), the following entities must also report the information identified below:

(1) California position holders must report the annual quantity in barrels, as reported by the terminal operator, of each Blendstock, Distillate Fuel Oil, or biomass-derived fuel listed in Table 2 of this section, ~~Tables MM-1 and MM-2 of 40 CFR Part 98~~ that is delivered across the rack in California, ~~except that distillate fuel oil is limited to diesel fuel and~~ except for fuel for which a final destination outside California can be demonstrated. Denatured fuel ethanol will be reported with the entire volume as 100% ethanol only. The volume of denaturant is assumed to be zero and is not required to be reported.

(2) California position holders that are also terminal operators and refiners with on-site racks must report the annual quantity in barrels delivered across the rack of each Blendstock, Distillate Fuel Oil, or biomass-derived fuel listed in Table 2 of this section, ~~Tables MM-1 and MM-2 of 40 CFR Part 98, except distillate fuel oil is limited to diesel fuel and~~ except for fuel for which a final destination outside California can be demonstrated. Denatured fuel ethanol will be reported with the entire volume as 100% ethanol only. The volume of denaturant is assumed to be zero and is not required to be reported. If there is only a single position holder at the terminal, and only diesel or biodiesel is being dispensed at the rack then the position holder must report the annual quantity of fuel using a meter meeting the requirements of section 95103(k) or billing invoices from the entity delivering fuel to the terminal.

(3) Refiners that supply fuel within the bulk transfer system to entities not licensed by the California Board of Equalization as a fuel supplier must report the annual quantity in barrels delivered of each Blendstock, Distillate Fuel Oil, or biomass-derived fuel listed in Table 2 of this section, ~~Tables MM-1 and MM-2 of 40 CFR Part 98, except Distillate Fuel Oil is limited to diesel fuel and~~ except for fuel for which a final destination outside California can be demonstrated. Denatured fuel ethanol will be reported with the entire volume as 100% ethanol only. The volume of denaturant is assumed to be zero and is not required to be reported.

(4) Enterers of fossil-derived transportation fuels not directly delivered to the bulk transfer/terminal system must report the annual quantity in barrels, as reported on the bill of lading or other shipping documents of each Blendstock, Distillate Fuel Oil, or biomass-derived fuel listed in Table 2 of this section, ~~Tables MM-1 and MM-2 of 40 CFR Part 98 that is imported into California, except that Distillate Fuel Oil is limited to diesel fuel and~~ except for fuel for which a final destination outside California can be demonstrated. Denatured fuel ethanol will be reported with the entire volume as 100% ethanol only. The volume of denaturant is assumed to be zero and is not required to be reported.

(5) In addition to the information required in 40 CFR §98.396, ~~petroleum refineries~~ refiners must also report the volume of liquefied petroleum gas in barrels supplied in California as well as the volumes of the individual components as listed in 40 CFR 98 Table MM-1, except for fuel for which a final destination outside California can be demonstrated

*** [no changes to sections 95121(e); add Table 2 after section 95121(e)]

Table 2
Blendstocks, Distillate Fuel Oils, and Biomass-Derived Fuels Subject to Reporting under section 95121

CBOB—Summer
Regular
Midgrade
Premium
CBOB—Winter
Regular
Midgrade
Premium
RBOB—Summer
Regular
Midgrade
Premium
RBOB—Winter
Regular
Midgrade
Premium
Distillate Fuel Oils
Distillate No. 1
Distillate No. 2
Liquefied Petroleum Gas (LPG)
Ethane
Ethylene
Propane
Propylene
Butane
Butylene
Isobutane
Isobutylene
Pentanes Plus
Biomass-Derived Fuel
Ethanol (100%)
Biodiesel (100%, methyl ester)
Rendered Animal Fat
Vegetable Oil

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.

§ 95122. Suppliers of Natural Gas, Natural Gas Liquids, ~~and~~ Liquefied Petroleum Gas, Compressed Natural Gas, and Liquefied Natural Gas.

***

(a) *GHGs to Report.*

***

(3) The California consignee for liquefied petroleum gas, compressed natural gas, or liquefied natural gas must ~~will~~ report the CO_2, CH_4, N_2O and CO_2e emissions that would result from the complete combustion or oxidation of the annual quantity of liquefied petroleum gas, compressed natural gas, and liquefied natural gas imported into the state, except for products for which a final destination outside California can be demonstrated

(b) *Calculating GHG Emissions.*

***

(9) The California consignee for liquefied petroleum gas must use calculation methodology 2 described in 40 CFR §98.403(a)(2) for calculating CO_2 emissions except that for liquefied petroleum gas t~~T~~able MM-1 of 40 CFR 98 must be used in place of Table NN-2. For liquefied petroleum gas, t~~T~~he consignee must sum the emissions from the individual components of the ~~liquefied petroleum~~ gas~~,~~ to calculate the total emissions. If the composition is not supplied by the producer, the consignee must use the default value for liquefied petroleum gas presented in Table C-1 of 40 CFR Part 98. The California consignee for compressed natural gas or liquefied natural gas must estimate CO_2 using calculation methodology 1 as specified in 40 CFR §98.403(a)(1), except that the product of HHV and Fuel is replaced by the annual MMBtu of natural gas received.

(10) The California consignee for liquefied petroleum gas, compressed natural gas, or liquefied natural gas must estimate and report CH_4 and N_2O emissions using equation C-8 and Table C-2 as described in 40 CFR §98.33(c)(1).

***

(d) *Data Reporting Requirements.*

***

(2) For the emissions calculation method selected under section 95122(b), local distribution companies must report all the data required by 40 CFR §98.406(b) subject to the following modifications:

***

(D) For each publicly-owned natural gas utility to which a local distribution company delivers natural gas, the local distribution companies must report the annual volumes ~~(~~in Mscf~~)~~, annual energy in ~~(~~MMBtu~~)~~, and the information required in 40 CFR §98.406(b)(12), including EIA number. These requirements are in addition to the requirements of 40 CFR §98.406(b)(6).

***

(5) In addition to the information required in 40 CFR §98.3(c), the California consignee for liquefied petroleum gas must report the annual quantity of liquefied petroleum gas imported as the total volume in barrels as well as the volume of its individual components for all components listed in 40 CFR 98 Table MM-1, if supplied by the producer, and report CO_2, CH_4, N_2O, and CO_2e annual mass emissions in metric tons using the calculation methods in section 95122(b). All California consignees of natural gas or natural gas liquids must record the annual quantities imported, in standard cubic feet or barrels, respectively, and report CO_2, CH_4, N_2O, and CO_2e annual mass emissions in metric tons separately for natural gas and natural gas liquids using the calculation methods in section 95122(b).

***

~~(f) *Additional Product Data.* The operator of a natural gas liquid fractionating facility must report the annual production of liquefied petroleum gas in barrels corrected to 60 degrees Fahrenheit.~~

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.

§ 95123. Suppliers of Carbon Dioxide.

***

(b) *Missing Data Substitution Procedures.* The supplier must comply with 40 CFR §98.~~165~~425 when substituting for missing data, except for 2013 and later emissions data reports as otherwise provided below.

***

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.

***

§ 95130. Requirements for Verification of Emissions Data Reports.

The reporting entity who is subject to verification ~~required to report under section 95101 of this article, and who is not eligible for abbreviated reporting under section 95103(a),~~ must obtain the services of an accredited verification body for purposes of verifying each emissions data report submitted under this article, as specified in section 95103(f).

***

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.

§ 95131. Requirements for Verification Services.

***

(a) *Notice of Verification Services.*

***

(2) Documentation that the verification team has the skills required to provide verification services for the reporting facility. This shall include a demonstration that a verification team includes at least one member accredited as a ~~to provide~~ sector specific verifier ~~verification services~~ when required below:

***

(b) Verification services shall include, but are not limited to, the following*:*

***

(3) *Site Visits.* At least one accredited verifier in the verification team, including the sector ~~specialist~~ specific verifier, if applicable, shall at a minimum make one site visit, during each year full verification is required, to each facility for which an emissions data report is submitted. The verification team member(s) shall visit the headquarters or other location of central data management when the reporting entity is a retail provider, marketer, or fuel supplier. During the site visit, the verification team member(s) shall conduct the following:

***

(7) *Sampling Plan.* As part of confirming emissions data, product data, electricity transactions, or fuel transactions, the verification team shall develop a sampling plan that meets the following requirements:

***

(B) The verification team shall include in the sampling plan a ranking of emissions sources by amount of contribution to total CO_2 equivalent emissions for the reporting entity, and a ranking of emissions sources with the largest calculation uncertainty. The verification team shall also include in the sampling plan a ranking of the ~~single~~ product data ~~components~~ by units specified in the appropriate section of this article and a ranking of the ~~single~~ product data ~~components~~ with the largest uncertainty. As applicable and deemed appropriate by the verification team, fuel and electricity transactions shall also be ranked or evaluated relative to the amount of fuel or power exchanged and uncertainties that may apply to data provided by the reporting entity.

***

(9) *Emissions Data Report Modifications.* As a result of data checks by the verification team and prior to completion of a verification statement(s), the reporting entity must make any possible improvements or corrections to the submitted emissions data report, and submit a revised emissions data report to ARB. Failure to do so will result in an adverse verification statement. The reporting entity shall maintain documentation to support any revisions made to the initial emissions data report. Documentation for all emissions data report submittals shall be retained by the reporting entity for ten years pursuant to section 95105.

(10) *Findings.* To verify that the emissions data report is free of material misstatements, the verification team shall make its own determination of emissions for checked sources and product data for checked data and shall determine whether there is reasonable assurance that the emissions data report does not contain a material misstatement in GHG emissions reported for the reporting entity, on a CO_2 equivalent basis and/or a material misstatement in product data for the reporting entity, using the units required by the applicable parts of this article. ~~For product data, a material misstatement on a single product data component, except as otherwise specified in this article, will lead to an adverse product data verification statement.~~ To assess conformance with this article the verification team shall review the methods and factors used to develop the emissions data report for adherence to the requirements of this article and ensure that other requirements of this article are met.

***

(12) *Material Misstatement Assessment.* Assessments of material misstatement are conducted independently on total reported covered emissions and total

reported ~~single~~ covered product data ~~components~~ (units from the applicable parts of this article).

(A) In assessing whether an emissions data report contains a material misstatement, the verification team must separately determine whether the total reported covered emissions and total reported ~~single~~ covered product data ~~components~~ contain a material misstatement using the following equation:

$$\cancel{Percent\ error} = \sum \frac{[Discrepancies + Omissions + Misreporting]\ x\ 100\%}{\text{Total reported covered emissions/ or covered product data}}$$

$$Percent\ error\ (emissions) = \sum \frac{[Discrepancies + Omissions + Misreporting\ ]x\ 100\%}{Total\ reported\ covered\ emissions}$$

or

$$Percent\ error\ (product\ data) = \sum \frac{[Discrepancies + Omissions + Misreporting\ ]x\ 100\%}{Total\ covered\ product\ data}$$

Where:
“Discrepancies” means any differences between the reported covered emissions or~~/~~ covered product data and the verifier’s review of ~~calculated~~ covered emissions~~/~~ or covered product data for a data source or product data subject to data checks in section 95131(b)(8).

“Omissions” means any covered emissions or covered product data the verifier concludes must be part of the emissions data report, but were not included by the reporting entity in the emissions data report.

“Misreporting” means duplicate, incomplete or other covered emissions the verifier concludes should, or should not, be part of the emissions data report or duplicate or other product data the verifier concludes should not be part of the emissions data report.

“Total reported covered emissions~~/~~ or covered product data” means the total annual reporting entity covered emissions or total reported ~~single~~ covered product data ~~components~~ for which the verifier is conducting a material misstatement assessment.

***

(i) *Verifying Biomass-derived Fuels.* In the absence of certification of the biomass-derived fuel by an accredited certifier of biomass-derived fuels, the verification body is subject to the requirements of subarticle 4 of this article as modified below when verifying biomass-derived fuel:

(1) *General biomass-derived fuel verification requirements.*

***

(C) *Completion of Verification Services for Biomass-derived Fuels.*

1. All information used for the verification of biomass-derived fuels must be included in the independent review as required in section 93131(c)(2) of this article.
2. Conformance for biomass-derived fuels is evaluated against the requirements of this article and sections 95852.1.1 and 95852.2 of the cap-and-trade regulation.
3. <u>Reported c</u>~~C~~arbon dioxide emissions from biomass-derived fuels are ~~included in the reporting entity's overall~~ <u>considered an omission in the</u> evaluation for material misstatement<u> when</u>~~.~~<u>:</u>
   <u>a.</u> A~~ny~~<u>The</u> fuel ~~that~~ does not conform with sections 95852.1.1 and 95852.2 of the cap-and-trade regulation and
   <u>b.</u> ~~it's~~ <u>The</u> emissions are ~~not~~ listed as ~~non-~~exempt biomass-derived CO_2.~~will be considered an omission when evaluating for material misstatement under 95131(b)(12)(A) 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.

§ 95132. Accreditation Requirements for Verification Bodies, Lead Verifiers, and Verifiers of Emissions Data Reports and Offset Project Data Reports.

***

(b) The Executive Officer may issue accreditation to verification bodies, lead verifiers, and verifiers that meet the requirements specified in this section.

***

(5) Sector Specific and Offset Project Specific Verifiers.

***

(B) *Offset Project Specific Verifier*. The applicant seeking to be accredited as an offset project specific verifier as specified in section 95977<u>.1(b)</u>~~(e)(4)(A)(iii)~~ of the cap-and-trade regulation must, in addition to meeting the requirements for accredited lead verifier or verifier qualification, meet one of the following requirements:

***

(c) *ARB Accreditation.*

(1) Within 90 days of receiving an application for accreditation as a verification body, lead verifier, verifier, sector specific verifier, or offset project specific verifier, the Executive Officer shall inform the applicant in writing either that the application is complete or that additional specific information is required to make the application complete.

(2) Upon a finding by the Executive Officer that an application for accreditation as a verification body, verifier, lead verifier, sector specific verifier, or offset project specific verifier is complete, meets all applicable regulatory requirements, and passes a performance review as defined in section 95102(a), the prescreening requirement is met and the applicant will be eligible to attend the verification training required by this section.

(3) Within 45 days following completion of the application process and all applicable training and examination requirements, the Executive Officer shall act to issue an Executive Order to grant or withhold accreditation for the verification body, lead verifier, sector specific verifier, offset project specific verifier or verifier.

(4) The Executive Order for accreditation is valid for a period of three years, whereupon the applicant may re-apply for accreditation as a verifier, lead verifier, sector specific verifier, offset project specific verifier, or verification body if the applicant has not been subject to ARB enforcement action under this article. All ARB approved general, sector specific, or offset project specific verification training and examination requirements applicable at the time of re-application must be met for accreditation to be renewed by the Executive Officer. In addition, the performance review requirement set forth in section 95132(c)(2) must be met for accreditation to be renewed by the Executive Officer.

***

(7) Within 15 working days of being notified of any corrective action in another voluntary or mandatory GHG program, an ARB accredited verification body, lead verifier, sector specific verifier, offset project specific verifier, or verifier shall provide written notice to the Executive Officer of the corrective action. That notification shall include reasons for the corrective action and the type of corrective action. The verification body or verifier must provide additional information to the Executive Officer upon request.

***

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.

§ 95133. Conflict of Interest Requirements for Verification Bodies.

***

(b) The potential for a conflict of interest must be deemed to be high where:

(1) The verification body and reporting entity share any management staff or board of directors membership, or any of the senior management staff of the reporting entity have been employed by the verification body, or vice versa, within the previous ~~three~~ five years; or

(2) Within the previous five years, any staff member of the verification body or any related entity has provided to the reporting entity any of the following ~~non-verification~~ services:

***

(c) The potential for a conflict of interest shall be deemed to be low where the following conditions are met:

(1) N~~n~~o potential for a high conflict of interest is found ~~under~~ pursuant to section 95133(b); and

(2) A~~a~~ny non-verification services provided by any member of the verification body or verification team to the reporting entity within the last five years are valued at less than 20 percent of the fee for the proposed verification services. Any independent greenhouse gas emissions verification provided by the verification body or verification team outside the jurisdiction of ARB is excluded from this financial assessment.

***

(e) *Conflict of Interest Submittal Requirements for Accredited Verification Bodies.*

(1) Before the start of any work related to providing verification services to a reporting entity, a verification body must first be authorized in writing by the Executive Officer to provide verification services. To obtain authorization the verification body shall submit to the Executive Officer a self-evaluation of the potential for any conflict of interest that the verification body, related entities ~~its ners~~, or any subcontractors performing verification services may have with the reporting entity for which it will perform verification services. The submittal shall include the following:

(A) Identification of whether the potential for conflict of interest is high, low, or medium based on factors specified in sections 95133(b), (c), and (d);

(B) Identification of whether the verification body, related entities, or any member of the verification team has previously provided verification services for the reporting entity or related entities and, if so, provide a description of such services and the years in which such ~~verification~~ services were provided;

(C) Identification of whether any member of the verification team, verification body, or related entity has engaged in ~~any non-verification~~ services of any nature, other than ARB verification services, with the reporting entity or related entities either within or outside California, during the previous ~~three~~ five years. If ~~non-verification~~ services other than ARB verification services have previously been provided, the following information shall also be submitted:

1. Identification of the nature and location of the work performed for the reporting entity or related entity and whether the work is similar to the type of work to be performed during verification, such as emissions inventory, auditing, energy efficiency, renewable energy, or other work with implications for the reporting entity's greenhouse gas emissions pursuant to this article ~~or the accounting of greenhouse gas emissions or electricity or fuel transactions~~;

2. The nature of past, present or future relationships of any member of the verification team, verification body, or related entities with the reporting entity or related entities including:

   a. Instances when any member of the verification team, verification body, or related entities has performed or intends to perform work for the reporting entity or related entities;
   b. Identification of whether work is currently being performed for the reporting entity or related entities, and if so, the nature of the work;
   c. How much work was performed for the reporting entity or related entities in the last ~~three~~ five years, in dollars;
   d. Whether any member of the verification team, verification body, or related entities has ~~any~~ contracts or other arrangements to perform work for the reporting entity or a related entity;
   e. How much work related to greenhouse gases ~~or electricity transactions~~ the verification team has performed for the reporting entity or related entities in the last ~~three~~five years, in dollars.

***

(f) *Conflict of Interest Determinations.* The Executive Officer must review the self-evaluation submitted by the verification body and determine whether the verification body is authorized to perform verification services for the reporting entity.

***

(4) If the Executive Officer determines that the verification body and verification team have a medium potential for a conflict of interest, the Executive Officer shall evaluate the conflict of interest mitigation plan submitted pursuant to section 95133(d), and may request additional information from the applicant to complete the determination. In determining whether verification services may

proceed, the Executive Officer may consider factors including, but not limited to, the nature of previous work performed, the current and past relationships between the verification body, related entities, and its subcontractors with the reporting entity and related entities, and the cost of the verification services to be performed. If the Executive Officer determines that these factors when considered in combination demonstrate an acceptable level of potential conflict of interest, the Executive Officer will authorize the verification body to provide verification services

***

(g) *Monitoring Conflict of Interest Situations.*

***

(2) The verification body shall continue to monitor arrangements or relationships that may be present for a period of one year after the completion of verification services. During that period, within 30 days of the verification body or any verification team member entering into any contract with the reporting entity or related entity for which the body has provided verification services, the verification body shall notify the Executive Officer of the contract and the nature of the work to be performed, and revenue received. The Executive Officer, within 30 working days, will determine the level or conflict using the criteria in section 95133(a)-(d), if the reporting entity must reverify their emissions data report, and if accreditation revocation is warranted.

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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.

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

§95150. Definition of the Source Category.

(a) This source category consists of the following industry segments~~ specified in 40 CFR §98.230(a)(1) through (a)(8) with the following additional source types~~:

(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 emissions from offshore drilling and exploration that is not conducted on production platforms.~~ The onshore natural gas processing segment includes boosting stations;~~

(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 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.~~The onshore natural gas transmission compression segment includes boosting stations.~~

(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 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 California.

(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.

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.

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

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

(b) For applying the threshold defined in section 95101(b), natural gas processing facilities must also include owned or operated residue gas compression equipment. ~~In determining whether a facility in 95150 meets the reporting threshold defined in 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.

§95152. ~~GHGs~~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 paragraphs (b) through (i) of this section, CO_2, CH_4, and N_2O emissions from each flare as specified in paragraphs (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 the Bureau of Ocean Energy Management (BOEM) in compliance with 30 CFR §§250.302 through 304 (July 1, 2011), which is hereby incorporated by reference. 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 of 40 CFR Part 98.

(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;
(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) Crude oil and condensate 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 subarticle 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; and
(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; and
(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; and
(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; and
(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; and
(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 section 95150 of this article the emissions of CO_2, CH_4, and N_2O emissions from stationary combustion sources following the methods in 95153(y); and
(8) Flare stack emissions.

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

~~(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 s 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 95153. Additional data must be reported in aggregated and disaggregated form as specified in 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 of a facility must calculate and report 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 sections 95153(a) and (b) must calculate emissions from a 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 of 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). 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:

$E_{nm,i,x}$ = 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 Appendix A 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 vents (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 the applicable calculation methodologies described in paragraphs (c)(1)-(c)(10) below.

(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 subarticle by following the Tier 4 Calculation Methodology and all associated calculation, quality assurance, reporting, and recordkeeping requirements for Tier 4 in section 95115 (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 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 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.

$E_{CO2} = V_{in} * [Y_{CO2-in} * (1 - Y_{H2S-spec}) - Y_{CO2-out} * (1 - Y_{H2S-in})]/(1 - Y_{H2S-spec} - Y_{CO2-out})$ (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 CO_2 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 a 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 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 monthly in natural gas or acid gas into the AGR unit using continuous gas analyzer data (if available), or other known 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 which applies the Peng-Robinson equation of state (Equation 38 of section 95154) 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 in subparagraphs (1) – (4) below.

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.

$$E_{S,n} = \sum_{p=1}^{W}\left[V_p * \left((0.37 * 10^{-3}) * CD_p^2 * WD_p * SP_p\right) + \sum_{p=1}^{V_p}\left(SFR_p * \left(HR_{p,q} - 1.0\right) * Z_{p,q}\right)\right] \qquad \text{(Eq. 6)}$$

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 basin.
$0.37x10^{-3}$ = {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 29 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.

$$E_{S,n} = \sum_{p=1}^{W}\left[V_p * \left((0.37 * 10^{-3}) * TD_p^2 * WD_p * SP_p\right) + \sum_{q=1}^{V_p}\left(SFR_p * \left(HR_{p,q} - 0.5\right) * Z_{p,q}\right)\right] \quad \text{(Eq. 7)}$$

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 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 29 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:

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

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 x 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 x 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 paragraph (r) of this section.

(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 or 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).

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

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 by Equation 13 or 14 and paragraph (g)(3) of this section.

(h) *Onshore production storage tanks*. Calculate emissions from occurrences of gas-liquid separator liquid dump valves not closing during the calendar year by using the method found in 95153(i).

(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 five 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 five 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; or

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

(3) Estimate venting emissions using Equation 15 or Equation 16 of this section.

$$E_{a,n} = GOR * FR * D \qquad \text{(Eq. 15)}$$

$$E_{a,n} = PR * D \qquad \text{(Eq. 16)}$$

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 from 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.

(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; or

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

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

$$E_{a,n} = \sum_{q=1}^{y} \sum_{p=1}^{x} GOR_{p,q} * V_{p,q} \qquad \text{(Eq.17)}$$

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 or company records.
(3) 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 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.
(B) 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 specifications. If not available, assume that flare combustion efficiency is 98 percent.

(5) Calculate GHG volumetric emissions at actual conditions using Equations 18, 19, and 20 of this section.

$$E_{a,CH4}(uncombusted) = V_a * (1 - \eta) * X_{CH4} \quad \text{(Eq. 18)}$$
$$E_{a,CO2}(uncombusted) = V_a * X_{CO2} \quad \text{(Eq. 19)}$$
$$E_{a,CO2}(combusted) = \sum_{j=1}^{5}\left(\eta * V_a * Y_j * R_j\right) \quad \text{(Eq. 20)}$$

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 37 in paragraph (y) 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 article (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 18 through 20 of this section, use volume 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 sections 95152(c)(12), (d)(5), (e)(6), (f)(5), (g)(3), and (h)(3) 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 three 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 three year period, it must be measured in the standby depressurized mode.

(D) An engineering estimate approach based on similar equipment specifications and operating conditions may be used to determine the MT_m variable in place of actual measured values for centrifugal compressors that are operated for no more than 200 hours in a calendar year and used for peaking purposes in place of metered gas emissions if an applicable meter is not present on the compressor.

(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 sections 95154(c) and 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 21 of this section.

$$E_{s,i,m} = \sum_m MT_m * T_m * Y_i * (1 - CF) \qquad \text{(Eq. 21)}$$

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)(A) through (m)(1)(C).

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 sections 95152(c)(12), (d)(5), (e)(6), (f)(5), (g)(3), and (h)(3), the operator must calculate annual emissions from both wet seal and dry seal centrifugal compressor vents using Equation 22 of this section.

$$E_{s,i} = Count * EF_i \qquad \text{(Eq. 22)}$$

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 degassing 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)(13), (d)(6), (e)(7), (f)(6), (g)(4), and (h)(4) 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:
(A) Operating or standby pressurized mode, blowdown vent leakage through the blowdown vent stack.
(B) Operating mode, reciprocating rod packing emissions.
(C) Not operating depressurized mode, unit isolation valve leakage through the blowdown vent stack, without blind flanges.

1. 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 three 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 three year period, it must be measured in the standby depressurized mode.
2. An engineering estimate approach based on similar equipment specifications and operating conditions may be used to determine the MT_m variable in place of actual measured values for reciprocating compressors that are operated for no more than 200 hours in a calendar year and used for peaking purposes in place of metered gas emissions if an applicable meter is not present on the compressor.

(2) 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 sections 95154(c) and 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).

(3) If reciprocating rod packing is not equipped with a vent line use the following method to 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)(2)(A) of this section using an appropriate meter, or calibrated bag, or high volume sampler according to the methods set forth in sections 95154(b), (c), and (d) respectively.

(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 23 of this section.

$$E_{s,i,m} = \sum_m MT_m * T_m * Y_i * (1 - CF) \qquad \text{(Eq. 23)}$$

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.

(6) For each reciprocating compressors with a rated horsepower of less than 250hp, the operator must calculate annual emissions using Equation 24 of this section.

$$E_{s,i} = Count * EF_i \qquad \text{(Eq. 24)}$$

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.

(7) 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)(17), (d)(7), (e)(8), (f)(7), (g)(5), (h)(5), 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 25 or 26 of this section for each component type. Use Equation 25 for industry segments listed in section 95150(a)(1) – (a)(7). Use Equation 26 for natural gas distribution facilities as defined in section 95150(a)(8).

$$E_{s,i} = GHG_i * \sum_{p=1}^{x} \left(EF * T_p\right) \qquad \text{(Eq. 25)}$$

$$E_{s,i} = GHG_i * \sum_{q=t-n+1}^{t} \sum_{p=1}^{x} \left(EF * T_{p,q}\right) \qquad \text{(Eq. 26)}$$

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 1A and 2 through 7 of Appendix A.

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 1.1×10^{-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 1.1×10^{-2} for CO_2 or use the experimentally determined gas composition for CO_2 and CH_4.

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 Transmission – Distribution (T-D) transfer stations in a natural gas distribution facility; $0 < n \leq 5$. For the first (n-1) calendar years of reporting the summation in Equation 26 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 petroleum and natural gas production facilities must use the appropriate default leaker emissions factors listed in Table 1A of Appendix A for all leaks from equipment types in the table.
(3) Onshore natural gas processing facilities must use the appropriate default leaker emission factors listed in Table 2 of Appendix A for equipment leaks detected from valves, connectors, open ended lines, pressure relief valves, and meters.
(4) Onshore natural gas transmission facilities shall use the appropriate default leaker emission factors listed in Table 3 of Appendix A for equipment leaks detected from valves, connectors, open ended lines, pressure relief valves, and meters.
(5) Underground natural gas storage facilities for storage stations shall use the appropriate default leaker emission factors listed in Table 4 of Appendix A for equipment leaks detected from valves, connectors, open ended lines, pressure relief valves, and meters.

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

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

(8) Natural gas distribution facilities for above ground transmission-distribution transfer stations, shall use the appropriate default leak emission factors listed in Table 7 of Appendix A 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 27 of this section.

$$E_{s,i} = Count_s * EF_s * GHG_i * T_s \qquad \text{(Eq. 27)}$$

Where:

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

$Count_s$ = 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 Appendix A. Use average component counts as appropriate for operations in Western U.S., according to Table 1B of Appendix A 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_s = Population emission factor for the specific component type, as listed in Table 1A and Tables 3 through Table 7 of Appendix A. Use appropriate emission factor for operations in Western U.S., according to Table 1(A) – 1(C) of Appendix A. EF for meter/regulator runs at above grade metering-regulator stations is determined in Equation 28 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 ; 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 or use the experimentally determined gas composition for CO_2 and CH_4.

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 must use the appropriate default population emission factors listed in Table 1A of Appendix A 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 Appendix A and major natural gas equipment in reference to Table 1B of Appendix A. Major equipment and components associated with crude oil wells are considered crude service components in reference to Table 1A of Appendix A and major crude oil equipment in reference to Table 1C of Appendix A. Where facilities conduct EOR operations the emissions factor listed in Table 1A of Appendix A 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 Appendix A. 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 Appendix A for onshore natural gas production and onshore oil production, respectively. Use the appropriate factor in Table 1A of Appendix A for operations in Eastern and Western U.S. according to the mapping in Table 1B of Appendix A.

(B) *Component Count Methodology 2*. Count each component individually for the facility. Use the appropriate factor in Table 1A of Appendix A for operations in the 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 Appendix A 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 Appendix A for equipment leak from vapor recovery compressors.

(5) LNG import and export facilities must use the appropriate emission factor listed in Table 6 of Appendix A 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, must use the appropriate default population emission factors listed in Table 7 of Appendix A. Below grade T-D transfer stations must use the emission factor for below grade metering-regulating stations.

(B) Emissions from all above grade metering-regulating stations (including above grade T-D transfer stations) must be calculated by applying the emission factor calculated in Equation 28 and the total count of metering/regulator runs at all above grade metering-regulating stations (inclusive of T-D transfer stations) to Equation 27. The facility wide emission factor in Equation 28 will be calculated by using the total volumetric GHG emissions at standard conditions for all equipment leak sources calculated in Equation 26 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)(1) 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).

$$EF = E_{s,i}/(8760 * Count) \qquad \text{(Eq. 28)}$$

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 T-D transfer stations, from Equation 27.

Count = Total number of meter/regulator runs at all T-D transfer stations that were monitored over the years that constitute one complete cycle as per paragraph (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 BOEM in compliance with 30 CFR §§250.302 through 304 (July 1, 2011), which is hereby incorporated by reference.

(1) Offshore production facilities under BOEM jurisdiction must report the same annual emissions as calculated and reported by BOEM in data collection and emissions estimate study published by BOEM and referenced in 30 CFR §§250.302 through 304 (July 1, 2011) Gulfwide Offshore Activities Data System (GOADS).

(A) The BOEM data is collected and reported every other year. In years where the BOEM data is not available, use the previous year's BOEM data and adjust the emissions based on the operating time for the facility relative to the operating time in the previous year's BOEM data.

(2) Offshore production facilities that are not under BOEM jurisdiction must use monitoring methods and calculation methodologies published by BOEM and referenced in 30 CFR §§250.302 through 304 (July 1, 2011) to calculate and report emissions (GOADS).

(A) The BOEM data is collected and reported every other year. In years where the BOEM data is not available, use the previous year's BOEM data and adjust the emissions based on the operating time for the facility relative to the operating time in the previous year's BOEM data.

(3) If BOEM 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 BOEM data collection and emissions estimation methods to report emission from the facility sources.

(4) For either the first or subsequent year of reporting, offshore facilities either within or outside of BOEM jurisdiction that were not covered in the previous

BOEM data collection cycle must use the BOEM data collection and emissions estimation methods published by BOEM and referenced in 30 CFR §§250.302 through 304 (July 1, 2011) (GOADS) to report.

(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 29 of this section.

$$E_{s,n} = E_{a,n} * (459.67 + T_s) * P_a / ((459.67 + T_a) * P_s) \quad \text{(Eq. 29)}$$

Where:

$E_{s,n}$ = Natural gas 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 section 95153(f).
$E_{a,n}$ = 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 30 of this section.

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

Where:

$E_{s,i}$ = GHG i volumetric emissions at standard 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 31 of this section.

$$E_{s,i} = E_{s,n} * M_i \qquad \text{(Eq. 31)}$$

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

(A) GHG mole fraction in produced pipeline quality 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. The composition of non-pipeline quality natural gas must be determined as specified in section 95115(c)(4).

(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 section 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 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).

(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 32 of this section.

$$Mass_i = E_{s,i} * \rho_i * 10^{-3} \qquad \text{(Eq. 32)}$$

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:

$$Mass_{CO2} = N * V_v * R_c * GHG_i * 10^{-3} \qquad \text{(Eq. 33)}$$

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) *Crude Oil and Condensate Dissolved CO_2 and CH_4*. The operator must calculate dissolved CO_2 and CH_4 in crude oil and condensate. Emissions must be reported for crude oil and condensate sent to a storage tank or ponds and holding facilities.

(1) Calculate CO_2 and CH_4 emissions from crude oil and condensate using Equation 33A:

$$E_{CO2/CH4} = (S_{cc} * V_{cc})(1 - (VR * CE)) \qquad \text{(Eq. 33A)}$$

Where:

$E_{CO2/CH4}$ = Annual CO_2 or CH_4 emissions in metric tons.
S_{cc} = Mass of CO_2 or CH_4 liberated in a flash liberation test per barrel of produced water (as determined in paragraph (v)(1)(A)1. or mass of CO_2 or CH_4 recovered in a VRU per barrel of crude oil and condensate (as determined in paragragh (v)(1)(A)2.
V_{cc} = Barrels of crude oil or condensate 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 crude oil and condensate) shall be determined using one of the following methods:

1. Flash liberation test. Measure the amount of CO_2 and CH_4 liberated from crude oil and condensate when the crude oil or condensate 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 crude oil and condensate.

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 crude oil and condensate by sampling (under representative operating conditions) and analysis of the vapor recovery unit (VRU) gas stream to determine the mass of CO_2 and CH_4 captured by the vapor recovery system per barrel of crude oil or condensate 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. Vapor recovery system measurements may include gases from crude oil and condensate and produced water.

(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.

(w) *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 Equation 34:

$$E_{CO2/CH4} = (S_{pw} * V_{pw})(1 - VR * CE) \qquad \text{(Eq. 34)}$$

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 paragraph (w)(1)(A)1. or mass of CO_2 or CH_4 recovered in a VRU per barrel of produced water (as determined in paragragh (w)(1)(A)2.

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. Vapor recovery system measurements may include gases from produced water and crude oil and condensate.

(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 .

(x) ***Reserved***

(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 Subpart C of 40 CFR Part 98, or is a blend containing one or more fuels listed in Table C-1, calculate emissions according to paragraph (y)(1)(A). 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 paragraph (y)(1)(A) and the facility operator may use the emission factor provided for natural gas as listed in Subpart C, Table C-1. If the fuel is natural gas, and is not pipeline quality calculate emissions according to paragraph (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 paragraph (y)(2).

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

(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 paragraph (s)(2) of this section.

(C) Calculate GHG volumetric emissions at actual conditions using Equations 35 and 36 of this section:

$$E_{a,CO2} = (V_a * Y_{CO2}) + \eta * \sum_{j=1}^{5} V_a * Y_j * R_j \qquad \text{(Eq. 35)}$$

$$E_{a,CH4} = V_a * (1 - \eta) * Y_{CH4} \qquad \text{(Eq. 36)}$$

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 an 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.

(D) Calculate N_2O mass emissions using Equation 37 of this section.

$$Mass_{N2O} = (1\ x\ 10^{-3}) * Fuel * HHV * EF \qquad \text{(Eq. 37)}$$

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 1.235×10^{-3} mmBtu/scf for HHV.

EF = Use 1.0×10^{-4} kg N_2O/mmBtu.

1×10^{-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 95101(e). The operator must report the type and number of each internal fuel combustion unit.

~~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 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:~~

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

~~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:~~

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

~~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:~~

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

~~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~~ $\cancel{CO_2}$ ~~and~~ $\cancel{CH_4}$ ~~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~~ ~~(~~$\cancel{P_1}$~~) and downstream pressure (~~$\cancel{P_2}$~~) 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~~ $\cancel{P_2/P_1 \leq 0.542}$~~. Subsonic flow is defined as the flow regime where~~ $\cancel{P_2/P_1 > 0.542}$~~. 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:~~

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

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

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

$$\cancel{V_s = T_s * FR_s}$$

~~Where:~~
$\cancel{V_s}$ ~~= Volume of gas vented during sonic flow conditions (scf).~~
$\cancel{T_s}$ ~~= Total time the specific source associated with the equipment leak emission was operational in the calendar year, in hours.~~
$\cancel{FR_s}$ ~~= 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:~~

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

~~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 al 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:~~

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

~~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).~~

~~(w) *Stationary and Portable Equipment Combustion Emissions.* The operator must use the methods in 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.

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 (July 1, 2011), which is hereby incorporated by reference.

(a) ~~The operator must conform with the monitoring and QA/QC requirements of 40 CFR §98.234.~~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 sections 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 imaging instrument*. Use an optical gas imaging instrument for equipment leak detection in accordance with 40 CFR Part 60, subarticle 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, subarticle 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 (July 1, 2011, which is hereby incorporated by reference). Any emissions detected by the optical gas imagining instrument is a leak unless screened with Method 21 (40 CFR Part 60, appendix A-7 (July 1, 2011), which is hereby incorporated by reference) 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 subarticle 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 two meters above a support surface.

(2) *Method 21.* Use the equipment leak detection methods in 40 CFR Part 60, appendix A-7, Method 21 (July 1, 2011). 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 subarticle. 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 subarticle in accordance with the instrument manufacturer's operating instructions.

(4) *Optical gas imaging instrument.* An optical gas imaging 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 subarticle 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 subarticle 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. Pursuant to section 95109 of this article, 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.

(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 38 of this section.

$$p = \frac{RT}{(V_m - b)} - a\alpha/(V_m^2 + 2bV_m - b^2) \qquad \text{(Eq. 38)}$$

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.

(f) *Special reporting provisions: best available monitoring methods*. Best available monitoring methods will be allowed for the reporting of 2012 data as described in paragraphs (1)-(4). Beginning with collection of data on January 1, 2013, best available monitoring methods will no longer be allowed.

(1) ARB will allow owners or operators to use best available monitoring methods for certain parameters in section 95153 as specified in paragraphs (f)(2), (f)(3), and (f)(4) of this section. Best available monitoring methods means any of the following methods specified in paragraph (f)(1) of this section:

(A) Monitoring methods currently used by the facility that do not meet the specifications of this subarticle.

(B) Supplier data.

(C) Engineering calculations.

(D) Other company records.

(2) Operators may use best available monitoring methods for any well-related data that cannot reasonably be measured according to the monitoring and QA/QC requirements of this subarticle, and only where required measurements cannot be duplicated due to technical limitations after December 31, 2012. These well-related sources are:

(A) Gas well venting during well completions and workovers as specified in section 95153(f).

(B) Well testing venting and flaring as specified in section 95153(e).

(3) Operators may use best available monitoring methods for activity data as listed below that cannot reasonably be obtained according to the monitoring and QA/QC requirements of this subarticle, specifically for events that generate data that can be collected in 2012 and cannot be duplicated after December 31, 2012. These sources are:

(A) Cumulative hours of venting, days, or times of operation in sections 95153 (d), (e), (f), (j), (m), (n), (o), and (p).

(B) Number of blowdowns, completions, workovers, or other events in sections 95153(e), (f), (g), and (u).

(C) Cumulative volume produced, volume input or output, or volume of fuel used in sections 95153(c), (d), (h), (i), (j), (k), (l), and (y).

(4) Operators may use best available monitoring methods for sources requiring leak detection and/or measurement. These sources include:

(A) Reciprocating compressor rod packing venting in onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, LNG storage, and LNG import and export equipment as specified in sections 95152 (d)(6), (e)(7), (f)(6), (g)(4), and (h)(4).

(B) Centrifugal compressor wet seal oil degassing venting in onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, LNG storage, and LNG import and

export equipment as specified in sections 95152(d)(5), (e)(6), (f)(5), (g)(3), and (h)(3).
(C) Acid gas removal vent stacks in onshore petroleum and natural gas production and onshore natural gas processing as specified in sections 95152(c)(3) and (d)(4).
(D) Equipment leak emissions from valves, connectors, open ended lines, pressure relief valves, block valves, control valves, compressor blowdown valves, orifice meters, other meters, regulators, vapor recovery compressors, centrifugal compressor dry seals, and/or other equipment leaks in onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, LNG storage, LNG import and export equipment, and natural gas distribution as specified in sections 95152(c)(17) (d)(7), (e)(8), (f)(7), (g)(5), (h)(5), and (i)(1).

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.

§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.~~

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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~~ section 95157 except as specified below.

(a) In addition to the data required by section 95157,~~40 CFR §98.236 (a)-(c),~~ the operator of an onshore and offshore 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;
(3) For cogeneration sources:

(A) Total thermal output (MMBtu) and the portion of CO_2e emissions associated with this output;
(B) Net electricity generation (MWh) and the portion of CO_2e emissions associated with this generation;
(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 CO2e emissions associated with this production~~;
~~(4)~~(8) Barrels of crude oil produced using methods other than thermal enhanced oil recovery, ~~and the portion of CO2e emissions associated with this production.~~;
(9) MMBtu of associated gas produced using thermal enhanced oil recovery;
(10) MMBtu of associated gas produced using methods other than thermal enhanced oil recovery.
(11) The operator of an onshore petroleum and natural gas production facility may voluntarily report the annual product data information in sections 95156(a)(9)-(10) for calendar years 2011 and 2012. If the operator chooses to report the 2011 and 2012 product data, then they must submit the data to ARB by April 10, 2013 and follow the verification requirements of this article. For emissions data reports submitted in 2014

and any subsequent year, the operator must report and verify the annual product data listed in section 95156(a)(9)-(10).

~~(b) In lieu of the requirements of 40 CFR §98.236(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.~~

(b) For dry gas production, the operator of an onshore petroleum and natural gas production facility may voluntarily report its annual volume of dry gas produced (Mscf) for calendar years 2011 and 2012. If the operator chooses to report the 2011 and 2012 dry gas produced, then they must submit the data to ARB by April 10, 2013 and follow the verification requirements of this article. For emissions data reports submitted in 2014 and any subsequent year, the operator must report and verify the volume of dry natural gas produced (Mscf).

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

(d) The operator of a natural gas liquid fractionating facility or a natural gas processing facility must report the annual production of the following natural gas liquids in barrels corrected to 60 degrees Fahrenheit:

(1) Ethane
(2) Ethylene
(3) Propane
(4) Propylene
(5) Butane
(6) Butylene
(7) Isobutane
(8) Isobutylene
(9) Pentanes plus
(10) Natural gasoline
(11) Liquefied petroleum gas
(12) Bulk natural gas liquids not included in 95156(d)(1)-(11)

(e) The operator of a natural gas liquid fractionating facility may voluntarily report the annual product data information in sections 95156(d)(1)-(12) for calendar years 2011 and 2012. If the operator chooses to report the 2011 and 2012 product data, then they must submit the data to ARB by April 10, 2013 and follow the verification requirements of this article. For emissions data reports submitted in 2014 and any subsequent year, the operator must report and verify the annual product data listed in section 95156(d)(1)-(12).

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.

§95157. Activity 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 BOEM study.

(c) Report the information listed in this paragraph for each applicable source type in metric tons for each GHG type. 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 section 95153(c), annual fraction of CO_2 content in the vent from acid gas removal unit (refer to section 95153(c)(6)).
(C) For Calculation Methodology 3 of section 95153(c), annual average volume fraction of CO_2 content of natural gas into and out of the acid gas removal unit (refer to section 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 section 95153.
(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 sections 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(e)), 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 7 of section 95153(e)), report the following for each basin:

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) Total count of completions in calendar year.
(B) Total count of workovers in calendar year.
(C) 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.
(D) 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.
(E) Annual CO_2 and CH_4 emissions that resulted from venting gas directly to the atmosphere, expressed in metric tons for each gas.
(F) 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(g)), 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) If a wellhead separator dump valve is functioning improperly during the calendar year (refer to section 95153 (i)), 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 section 95153(i).

(10) For well testing venting and flaring (refer to Equation 15 or 16 of section 95153(j)), 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 17 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 18, 19, and 20 of section 95153(l)), 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 18 of section 95153).
(G) Report uncombusted CO_2 emissions, in metric tons (refer to Equation 19 of section 95153).
(H) Report combusted CO_2 emissions, in metric tons (refer to Equation 20 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 21 and 22 of section 95153(m)), 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 21 of section 95153) and for compressors not measured (refer to Equation 22 of section 95153).

(B) For wet and dry seal centrifugal compressors in operating mode, (refer to Equation 21 and 22 of section 95153(m)), 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 21 and 22 of section 95153).

(C) For wet and dry seal centrifugal compressors in not operating, depressurized mode (refer to Equations 21 and 22 of section 95153(m)), 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 21 and 22 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 23 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 section 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 Appendix A.
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 sections 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 Appendix A 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 Appendix A, 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 28 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 33 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 (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 basin category.

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.

§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.

Appendix A

to the Regulation for the Mandatory Reporting
of Greenhouse Gas Emissions

**Emission Factors and Calculation Data
for Petroleum and Natural Gas Systems Reporting**

Table 1A
Default Whole Gas Emission Factors for Onshore Petroleum and Natural Gas Production

Onshore petroleum and natural gas production	Emission factor (scf/hour/ component)
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
Default Average Component Counts for Major Onshore Natural Gas Production Equipment

Major equipment	Valves	Connectors	Open-ended lines	Pressure relief valves
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
Default Average Component Counts for Major Crude Oil Production Equipment

Major equipment	Valves	Flanges	Connectors	Open-ended lines	Other components
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
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
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
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
Default Methane Emission Factors for Liquefied 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
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
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."