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Title 40: Protection of Environment
PART 98—MANDATORY GREENHOUSE GAS REPORTING

Subpart W—Petroleum and Natural Gas Systems

Contents

SOURCE: 75 FR 74488, Nov. 30, 2010, unless otherwise noted.

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§98.230 Definition of the source category.

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

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

(2) *Onshore petroleum and natural gas production.* Onshore petroleum and natural gas production means all equipment on a single well-pad or associated with a single well-pad (including but not limited to compressors, generators, dehydrators, storage vessels, engines, boilers, heaters, flares, separation and processing equipment, and portable non-self-propelled equipment, which includes well drilling and completion equipment, workover 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, 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. Onshore petroleum and natural gas production also means all equipment on or associated with a single enhanced oil recovery (EOR) well pad using CO_2 or natural gas injection.

(3) *Onshore natural gas processing.* Natural gas processing means the separation of natural gas liquids (NGLs) or non-methane gases from produced natural gas, or the separation of NGLs into one or more component mixtures. 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 of 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 re-gasification 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. LNG export equipment means all onshore or offshore equipment that receives natural gas, liquefies natural gas, stores LNG, and transfers the LNG via ocean transportation to any location, including locations in the United States.

(8) *Natural gas distribution.* Natural gas distribution means the distribution pipelines and metering and regulating equipment at metering-regulating stations that are operated by a Local Distribution Company (LDC) within a single state that is regulated as a separate operating company 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.

(9) *Onshore petroleum and natural gas gathering and boosting.* Onshore petroleum and natural gas gathering and boosting means gathering pipelines and other equipment used to collect petroleum and/or natural gas from onshore production gas or oil wells and used to

compress, dehydrate, sweeten, or transport the petroleum and/or natural gas to a natural gas processing facility, a natural gas transmission pipeline or to a natural gas distribution pipeline. Gathering and boosting equipment includes, but is not limited to gathering pipelines, separators, compressors, acid gas removal units, dehydrators, pneumatic devices/pumps, storage vessels, engines, boilers, heaters, and flares. Gathering and boosting equipment does not include equipment reported under any other industry segment defined in this section. Gathering pipelines operating on a vacuum and gathering pipelines with a GOR) less than 300 standard cubic feet per stock tank barrel (scf/STB) are not included in this industry segment (oil here refers to hydrocarbon liquids of all API gravities).

(10) *Onshore natural gas transmission pipeline.* Onshore natural gas transmission pipeline means all natural gas transmission pipelines as defined in §98.238.

(b) [Reserved]

[75 FR 74488, Nov. 30, 2010, as amended at 76 FR 80574, Dec. 23, 2011; 79 FR 70385, Nov. 25, 2014; 80 FR 64283, Oct. 22, 2015]

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§98.231 Reporting threshold.

(a) You must report GHG emissions under this subpart if your facility contains petroleum and natural gas systems and the facility meets the requirements of §98.2(a)(2), except for the industry segments in paragraphs (a)(1) through (4) of this section.

(1) Facilities must report emissions from the onshore petroleum and natural gas production industry segment only if emission sources specified in §98.232(c) emit 25,000 metric tons of CO_2 equivalent or more per year.

(2) Facilities must report emissions from the natural gas distribution industry segment only if emission sources specified in §98.232(i) emit 25,000 metric tons of CO_2 equivalent or more per year.

(3) Facilities must report emissions from the onshore petroleum and natural gas gathering and boosting industry segment only if emission sources specified in §98.232(j) emit 25,000 metric tons of CO_2 equivalent or more per year.

(4) Facilities must report emissions from the onshore natural gas transmission pipeline industry segment only if emission sources specified in §98.232(m) emit 25,000 metric tons of CO_2 equivalent or more per year.

(b) For applying the threshold defined in §98.2(a)(2), natural gas processing facilities must also include owned or operated residue gas compression equipment.

[75 FR 74488, Nov. 30, 2010, as amended at 80 FR 64284, Oct. 22, 2015]

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§98.232 GHGs to report.

(a) You must report CO_2, CH_4, and N_2O emissions from each industry segment specified in paragraphs (b) through (j) and (m) of this section, CO_2, CH_4, and N_2O emissions from each flare as specified in paragraphs (b) through (j) of this section, and stationary and portable combustion emissions as applicable as specified in paragraph (k) of this section.

(b) For offshore petroleum and natural gas production, report CO_2, CH_4, and N_2O emissions from equipment leaks, vented emission, and flare emission source types as identified in the data collection and emissions estimation study conducted by BOEMRE in compliance with 30 CFR 250.302 through 304. Offshore platforms do not need to report portable emissions.

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

(1) Natural gas pneumatic device venting.

(2) [Reserved]

(3) Natural gas driven pneumatic pump venting.

(4) Well venting for liquids unloading.

(5) Gas well venting during well completions without hydraulic fracturing.

(6) Well venting during well completions with hydraulic fracturing that have a GOR of 300 scf/STB or greater (oil here refers to hydrocarbon liquids produced of all API gravities).

(7) Gas well venting during well workovers without hydraulic fracturing.

(8) Well venting during well workovers with hydraulic fracturing that have a GOR of 300 scf/STB or greater (oil here refers to hydrocarbon liquids produced of all API gravities).

(9) Flare stack emissions.

(10) Storage tanks vented emissions from produced hydrocarbons.

(11) Reciprocating compressor venting.

(12) Well testing venting and flaring.

(13) Associated gas venting and flaring from produced hydrocarbons.

(14) Dehydrator vents.

(15) [Reserved]

(16) EOR injection pump blowdown.

(17) Acid gas removal vents.

(18) EOR hydrocarbon liquids dissolved CO_2.

(19) Centrifugal compressor venting.

(20) [Reserved]

(21) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, pumps, flanges, and other components (such as instruments, loading arms, stuffing boxes, compressor seals, dump lever arms, and breather caps, but does not include components listed in paragraph (c)(11) or (19) of this section, and it does not include thief hatches or other openings on a storage vessel).

(22) You must use the methods in §98.233(z) and report under this subpart the emissions of CO_2, CH_4, and N_2O from stationary or portable fuel combustion equipment that cannot move on roadways under its own power and drive train, and that is located at an onshore petroleum and natural gas production facility as defined in §98.238. Stationary or portable equipment are the following equipment, which are integral to the extraction, processing, or movement of oil or natural gas: well drilling and completion equipment, workover equipment, natural gas dehydrators, natural gas compressors, electrical generators, steam boilers, and process heaters.

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

(1) Reciprocating compressor venting.

(2) Centrifugal compressor venting.

(3) Blowdown vent stacks.

(4) Dehydrator vents.

(5) Acid gas removal vents.

(6) Flare stack emissions.

(7) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, and meters.

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

(1) Reciprocating compressor venting.

(2) Centrifugal compressor venting.

(3) Transmission storage tanks.

(4) Blowdown vent stacks.

(5) Natural gas pneumatic device venting.

(6) Flare stack emissions.

(7) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, and meters.

(8) Equipment leaks from all other components that are not listed in paragraph (e)(1), (2), or (7) of this section and are either subject to the well site or compressor station fugitive emissions standards in §60.5397a of this chapter or you elect to survey using a leak detection method described in §98.234(a)(6) or (7). The other components subject to this paragraph (e)(8) also do not include thief hatches or other openings on a storage vessel. If these other components are not subject to the well site or compressor station fugitive emissions standards in §60.5397a of this chapter, you may also elect to report emissions from these other components if you elect to survey them using a leak detection method described in §98.234(a)(1) through (5).

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

(1) Reciprocating compressor venting.

(2) Centrifugal compressor venting.

(3) Natural gas pneumatic device venting.

(4) Flare stack emissions.

(5) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, and meters associated with storage stations.

(6) Equipment leaks from all other components that are associated with storage stations, are not listed in paragraph (f)(1), (2), or (5) of this section, and are either subject to the well site or compressor station fugitive emissions standards in §60.5397a of this chapter or you elect to survey using a leak detection method described in §98.234(a)(6) or (7). If these other components are not subject to the well site or compressor station fugitive emissions standards in §60.5397a of this chapter, you may also elect to report emissions from these other components if you elect to survey them using a leak detection method described in §98.234(a)(1) through (5).

(7) Equipment leaks from valves, connectors, open-ended lines, and pressure relief valves associated with storage wellheads.

(8) Equipment leaks from all other components that are associated with storage wellheads, are not listed in paragraph (f)(1), (2), or (7) of this section, and are either subject

wellheads, are not listed in paragraph (f)(1), (2), or (7) of this section, and are either subject to the well site or compressor station fugitive emissions standards in §60.5397a, of this chapter or you elect to survey using a leak detection method described in §98.234(a)(6) or (7). If these other components are not subject to the well site or compressor station fugitive emissions standards in §60.5397a of this chapter, you may also elect to report emissions from these other components if you elect to survey them using a leak detection method described in §98.234(a)(1) through (5).

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

(1) Reciprocating compressor venting.

(2) Centrifugal compressor venting.

(3) Flare stack emissions.

(4) Equipment leaks from valves, pump seals, connectors, and other equipment leak sources in LNG service.

(5) Equipment leaks from vapor recovery compressors, if you do not survey components associated with vapor recovery compressors in accordance with paragraph (g)(6) of this section.

(6) Equipment leaks from all components in gas service that are associated with a vapor recovery compressor, are not listed in paragraph (g)(1) or (2) of this section, and that are either subject to the well site or compressor station fugitive emissions standards in §60.5397a of this chapter or you elect to survey using a leak detection method described in §98.234(a).

(7) Equipment leaks from all components in gas service that are not associated with a vapor recovery compressor, are not listed in paragraph (g)(1) or (2) of this section, and are either subject to the well site or compressor station fugitive emissions standards in §60.5397a of this chapter or you elect to survey using a leak detection method described in §98.234(a)(6) or (7). If these components are not subject to the well site or compressor station fugitive emissions standards in §60.5397a of this chapter, you may also elect to report emissions from these components if you elect to survey them using a leak detection method described in §98.234(a)(1) through (5).

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

(1) Reciprocating compressor venting.

(2) Centrifugal compressor venting.

(3) Blowdown vent stacks.

(4) Flare stack emissions.

(5) Equipment leaks from valves, pump seals, connectors, and other equipment leak sources in LNG service.

(6) Equipment leaks from vapor recovery compressors, if you do not survey components associated with vapor recovery compressors in accordance with paragraph (h)(7) of this section.

(7) Equipment leaks from all components in gas service that are associated with a vapor recovery compressor, are not listed in paragraph (h)(1) or (2) of this section, and that are either subject to the well site or compressor station fugitive emissions standards in §60.5397a of this chapter or you elect to survey using a leak detection method described in §98.234(a).

(8) Equipment leaks from all components in gas service that are not associated with a vapor recovery compressor, are not listed in paragraph (h)(1) or (2) of this section, and that are either subject to the well site or compressor station fugitive emissions standards in §60.5397a of this chapter or you elect to survey using a leak detection method described in §98.234(a)(6) or (7). If these components are not subject to the well site or compressor station fugitive emissions standards in §60.5397a of this chapter, you may also elect to report emissions from these components if you elect to survey them using a leak detection method described in §98.234(a)(1) through (5).

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

(1) Equipment leaks from connectors, block valves, control valves, pressure relief valves, orifice meters, regulators, and open-ended lines at above grade transmission-distribution transfer stations.

(2) Equipment leaks at below grade transmission-distribution transfer stations.

(3) Equipment leaks at above grade metering-regulating stations that are not above grade transmission-distribution transfer stations.

(4) Equipment leaks at below grade metering-regulating stations.

(5) Distribution main equipment leaks.

(6) Distribution services equipment leaks.

(7) Report under subpart W of this part the emissions of CO_2, CH_4, and N_2O emissions from stationary fuel combustion sources following the methods in §98.233(z).

(j) For an onshore petroleum and natural gas gathering and boosting facility, report CO_2, CH_4, and N_2O emissions from the following source types:

(1) Natural gas pneumatic device venting.

(2) Natural gas driven pneumatic pump venting.

(3) Acid gas removal vents.

(4) Dehydrator vents.

(5) Blowdown vent stacks.

(6) Storage tank vented emissions.

(7) Flare stack emissions.

(8) Centrifugal compressor venting.

(9) Reciprocating compressor venting.

(10) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, pumps, flanges, and other components (such as instruments, loading arms, stuffing boxes, compressor seals, dump lever arms, and breather caps, but does not include components in paragraph (j)(8) or (9) of this section, and it does not include thief hatches or other openings on a storage vessel).

(11) Gathering pipeline equipment leaks.

(12) You must use the methods in §98.233(z) and report under this subpart the emissions of CO_2, CH_4, and N_2O from stationary or portable fuel combustion equipment that cannot move on roadways under its own power and drive train, and that is located at an onshore petroleum and natural gas gathering and boosting facility as defined in §98.238. Stationary or portable equipment includes the following equipment, which are integral to the movement of natural gas: Natural gas dehydrators, natural gas compressors, electrical generators, steam boilers, and process heaters.

(k) Report under subpart C of this part (General Stationary Fuel Combustion Sources) the emissions of CO_2, CH_4, and N_2O from each stationary fuel combustion unit by following the requirements of subpart C except for facilities under onshore petroleum and natural gas production, onshore petroleum and natural gas gathering and boosting, and natural gas distribution. 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. Onshore petroleum and natural gas gathering and boosting facilities must report stationary and portable combustion emissions as specified in paragraph (j) of this section.

(l) You must report under subpart PP of this part (Suppliers of Carbon Dioxide), CO_2 emissions captured and transferred off site by following the requirements of subpart PP.

(m) For onshore natural gas transmission pipeline, report pipeline blowdown CO_2 and CH_4 emissions from blowdown vent stacks.

[75 FR 74488, Nov. 30, 2010, as amended at 76 FR 80574, Dec. 23, 2011; 79 FR 70385, Nov. 25, 2014; 80 FR 64284, Oct. 22, 2015; 81 FR 86511, Nov. 30, 2016]

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§98.233 Calculating GHG emissions.

You must calculate and report the annual GHG emissions as prescribed in this section. For calculations that specify measurements in actual conditions, reporters may use a flow or volume measurement system that corrects to standard conditions and determine the flow or volume at standard conditions; otherwise, reporters must use average atmospheric conditions or typical operating conditions as applicable to the respective monitoring methods in this section.

(a) *Natural gas pneumatic device venting.* Calculate CH_4 and CO_2 volumetric emissions from continuous high bleed, continuous low bleed, and intermittent bleed natural gas pneumatic devices using Equation W-1 of this section.

$$E_{s,i} = \sum_{t=1}^{3} Count_t * EF_t * GHG_i * T_t \qquad \text{(Eq. W-1)}$$

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Where:

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions in standard cubic feet per year from natural gas pneumatic device vents, of types “t” (continuous high bleed, continuous low bleed, intermittent bleed), for GHG_i.

$Count_t$ = Total number of natural gas pneumatic devices of type “t” (continuous high bleed, continuous low bleed, intermittent bleed) as determined in paragraph (a)(1) or (a)(2) of this section.

EF_t = Population emission factors for natural gas pneumatic device vents (in standard cubic feet per hour per device) of each type “t” listed in Tables W-1A, W-3B, and W-4B to this subpart for onshore petroleum and natural gas production, onshore natural gas transmission compression, and underground natural gas storage facilities, respectively. Onshore petroleum and natural gas gathering and boosting facilities must use the population emission factors listed in Table W-1A to this subpart.

GHG_i = For onshore petroleum and natural gas production facilities, onshore petroleum and natural gas gathering and boosting facilities, onshore natural gas transmission compression facilities, and underground natural gas storage facilities, concentration of GHG_i, CH_4 or CO_2, in produced natural gas or processed natural gas for each facility as specified in paragraphs (u)(2)(i), (iii), and (iv) of this section.

T_t = Average estimated number of hours in the operating year the devices, of each type “t”, were operational using engineering estimates based on best available data. Default is 8,760 hours.

(1) For all industry segments, determine “$Count_t$” for Equation W-1 of this subpart for each type of natural gas pneumatic device (continuous high bleed, continuous low bleed, and intermittent bleed) by counting the devices, except as specified in paragraph (a)(2) of this section. The reported number of devices must represent the total number of devices for the reporting year.

(2) For the onshore petroleum and natural gas production industry segment, you have the option in the first two consecutive calendar years to determine "$Count_t$" for Equation W-1 of this section for each type of natural gas pneumatic device (continuous high bleed, continuous low bleed, and intermittent bleed) using engineering estimates based on best available data. For the onshore petroleum and natural gas gathering and boosting industry segment, you have the option in the first two consecutive calendar years to determine "$Count_t$" for Equation W-1 for each type of natural gas pneumatic device (continuous high bleed, continuous low bleed, and intermittent bleed) using engineering estimates based on best available data.

(3) For all industry segments, determine the type of pneumatic device using engineering estimates based on best available information.

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

(b) [Reserved]

(c) *Natural gas driven pneumatic pump venting.* (1) Calculate CH_4 and CO_2 volumetric emissions from natural gas driven pneumatic pump venting using Equation W-2 of this section. Natural gas driven pneumatic pumps covered in paragraph (e) of this section do not have to report emissions under this paragraph (c).

$$E_{s,i} = Count * EF * GHG_i * T \qquad \text{(Eq. W-2)}$$

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Where:

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions in standard cubic feet per year from all natural gas driven pneumatic pump venting, for GHG_i.

Count = Total number of natural gas driven pneumatic pumps.

EF = Population emissions factors for natural gas driven pneumatic pumps (in standard cubic feet per hour per pump) listed in Table W-1A of this subpart for onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting facilities.

GHG_i = Concentration of GHG_i, CH_4, or CO_2, in produced natural gas as defined in paragraph (u)(2)(i) of this section.

T = Average estimated number of hours in the operating year the pumps were operational using engineering estimates based on best available data. Default is 8,760 hours.

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

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

(1) *Calculation Method 1.* If you operate and maintain a continuous emissions monitoring system (CEMS) that has both a CO_2 concentration monitor and volumetric flow rate monitor, you must calculate CO_2 emissions under this subpart by following the Tier 4 Calculation Method and all associated calculation, quality assurance, reporting, and recordkeeping requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources). Alternatively, you may follow the manufacturer's instructions or industry standard practice. If a CO_2 concentration monitor and volumetric flow rate monitor are not available, you 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 Method in subpart C of this part (General 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 AGR units.

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

$$E_{a,CO_2} = V_s * Vol_{CO_2} \qquad \text{(Eq. W-3)}$$

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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 §98.234(b). Alternatively, you may follow the manufacturer's instructions or industry standard practice for calibration of the vent meter.

Vol_{CO2} = Annual average volumetric fraction of CO_2 content in vent gas flowing out of the AGR unit as determined in paragraph (d)(6) of this section.

(3) *Calculation Method 3.* If a CEMS or a vent meter is not installed, you may use the inlet or outlet gas flow rate of the acid gas removal unit to calculate emissions for CO_2 using Equations W-4A or W-4B of this section. If inlet gas flow rate is known, use Equation W-4A. If outlet gas flow rate is known, use Equation W-4B.

$$E_{a,CO2} = V_{in} * \left[\frac{Vol_I - Vol_O}{1 - Vol_O}\right] \qquad \text{(Eq. W-4A)}$$

$$E_{a,CO2} = V_{out} * \left[\frac{Vol_I - Vol_O}{1 - Vol_I}\right] \qquad \text{(Eq. W-4B)}$$

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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 as determined using methods specified in paragraph (d)(5) of this section.

V_{out} = Total annual volume of natural gas flow out of the AGR unit in cubic feet per year at actual conditions as determined using methods specified in paragraph (d)(5) of this section.

Vol_I = Annual average volumetric fraction of CO_2 content in natural gas flowing into the AGR unit as determined in paragraph (d)(7) of this section.

Vol_o = Annual average volumetric fraction of CO_2 content in natural gas flowing out of the AGR unit as determined in paragraph (d)(8) of this section.

(4) *Calculation Method 4.* If CEMS or a vent meter is not installed, you may calculate emissions using any standard simulation software package, such as AspenTech HYSYS®, or API 4679 AMINECalc, that uses the Peng-Robinson equation of state and speciates CO_2 emissions. A minimum of the following, determined for typical operating conditions over the calendar year by engineering estimate and process knowledge based on best available data, must be used to characterize emissions:

(i) Natural gas feed temperature, pressure, and flow rate.

(ii) Acid gas content of feed natural gas.

(iii) Acid gas content of outlet natural gas.

(iv) Unit operating hours, excluding downtime for maintenance or standby.

(v) Exit temperature of natural gas.

(vi) Solvent pressure, temperature, circulation rate, and weight.

(5) For Calculation Method 3, determine the gas flow rate of the inlet when using Equation W-4A of this section or the gas flow rate of the outlet when using Equation W-4B of this section for the natural gas stream of an AGR unit using a meter according to methods set forth in §98.234(b). If you do not have a continuous flow meter, either install a continuous flow meter or use an engineering calculation to determine the flow rate.

(6) For Calculation Method 2, 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 for each quarter that the AGR unit is operating to determine Vol_{CO2} in Equation W-3 of this section, according to the methods set forth in §98.234(b).

(7) For Calculation Method 3, 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 for each quarter that the AGR unit is operating to determine Vol_I in Equation W-4A or W-4B of this section, according to the methods set forth in §98.234(b).

(8) For Calculation Method 3, determine annual average volumetric fraction of CO_2 content in natural gas flowing out of the AGR unit using one of the methods specified in

paragraphs (d)(8)(i) through (d)(8)(iii) of this section.

(i) 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, you may install a continuous gas analyzer.

(ii) If a continuous gas analyzer is not available or installed, quarterly gas samples may be taken from the outlet gas stream for each quarter that the AGR unit is operating to determine Vol_O in Equation W-4A or W-4B of this section, according to the methods set forth in §98.234(b).

(iii) If a continuous gas analyzer is not available or installed, you may use the outlet pipeline quality specification for CO_2 in natural gas.

(9) Calculate annual volumetric CO_2 emissions at standard conditions using calculations in paragraph (t) of this section.

(10) Calculate annual mass CO_2 emissions using calculations in paragraph (v) of this section.

(11) Determine if CO_2 emissions from the AGR unit are recovered and transferred outside the facility. Adjust the CO_2 emissions estimated in paragraphs (d)(1) through (d)(10) of this section downward by the magnitude of CO_2 emissions recovered and transferred outside the facility.

(e) *Dehydrator vents.* For dehydrator vents, calculate annual CH_4 and CO_2 emissions using the applicable calculation methods described in paragraphs (e)(1) through (e)(4) of this section. If emissions from dehydrator vents are routed to a vapor recovery system, you must adjust the emissions downward according to paragraph (e)(5) of this section. If emissions from dehydrator vents are routed to a flare or regenerator fire-box/fire tubes, you must calculate CH_4, CO_2, and N_2O annual emissions as specified in paragraph (e)(6) of this section.

(1) *Calculation Method 1.* Calculate annual mass emissions from glycol dehydrators that have an annual average of daily natural gas throughput that is greater than or equal to 0.4 million standard cubic feet per day by using a software program, such as AspenTech HYSYS® or GRI-GLYCalc™, that uses the Peng-Robinson equation of state to calculate the equilibrium coefficient, speciates CH_4 and CO_2 emissions from dehydrators, and has provisions to include regenerator control devices, a separator flash tank, stripping gas and a gas injection pump or gas assist pump. The following parameters must be determined by engineering estimate based on best available data and must be used at a minimum to characterize emissions from dehydrators:

(i) Feed natural gas flow rate.

(ii) Feed natural gas water content.

(iii) Outlet natural gas water content.

(iv) Absorbent circulation pump type (*e.g.,* natural gas pneumatic/air pneumatic/electric).

(v) Absorbent circulation rate.

(vi) Absorbent type (*e.g.,* triethylene glycol (TEG), diethylene glycol (DEG) or ethylene glycol (EG)).

(vii) Use of stripping gas.

(viii) Use of flash tank separator (and disposition of recovered gas).

(ix) Hours operated.

(x) Wet natural gas temperature and pressure.

(xi) Wet natural gas composition. Determine this parameter using one of the methods described in paragraphs (e)(1)(xi)(A) through (D) of this section.

(A) Use the GHG mole fraction as defined in paragraph (u)(2)(i) or (ii) of this section.

(B) If the GHG mole fraction cannot be determined using paragraph (u)(2)(i) or (ii) of this section, select a representative analysis.

(C) You may use an appropriate standard method published by a consensus-based standards organization if such a method exists or you may use an industry standard practice as specified in §98.234(b) to sample and analyze wet natural gas composition.

(D) If only composition data for dry natural gas is available, assume the wet natural gas is saturated.

(2) *Calculation Method 2.* Calculate annual volumetric emissions from glycol dehydrators that have an annual average of daily natural gas throughput that is less than 0.4 million standard cubic feet per day using Equation W-5 of this section:

$$E_{s,i} = EF_i * Count * 1000 \qquad \text{(Eq. W-5)}$$

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Where:

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

EF_i = Population emission factors for glycol dehydrators in thousand standard cubic feet per dehydrator per year. Use 73.4 for CH_4 and 3.21 for CO_2 at 60 °F and 14.7 psia.

Count = Total number of glycol dehydrators that have an annual average of daily natural gas throughput that is less than 0.4 million standard cubic feet per day.

1000 = Conversion of EF_i in thousand standard cubic feet to standard cubic feet.

(3) *Calculation Method 3.* For dehydrators of any size that use desiccant, you must calculate emissions from the amount of gas vented from the vessel when it is depressurized for the desiccant refilling process using Equation W-6 of this section. Desiccant dehydrator emissions covered in this paragraph do not have to be calculated separately using the method specified in paragraph (i) of this section for blowdown vent stacks.

$$E_{s,n} = \frac{(H * D^2 * \pi * P_2 * \%G * N)}{(4 * P_1 * 100)} \qquad \text{(Eq. W-6)}$$

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Where:

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

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 (3.14).

%G = Percent of packed vessel volume that is gas.

N = Number of dehydrator openings in the calendar year.

100 = Conversion of %G to fraction.

(4) For glycol dehydrators that use the calculation method in paragraph (e)(2) of this section, calculate both CH_4 and CO_2 mass emissions from volumetric GHG_i emissions using calculations in paragraph (v) of this section. For desiccant dehydrators that use the calculation method in paragraph (e)(3) of this section, calculate both CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using calculations in paragraphs (u) and (v) of this section.

(5) Determine if the dehydrator unit has vapor recovery. Adjust the emissions estimated in paragraphs (e)(1), (2), and (3) of this section downward by the magnitude of emissions recovered using a vapor recovery system as determined by engineering estimate based on best available data.

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

(i) Use the dehydrator vent volume and gas composition as determined in paragraphs (e)(1) through (5) of this section, as applicable.

(ii) Use the calculation method of flare stacks in paragraph (n) of this section to determine dehydrator vent emissions from the flare or regenerator combustion gas vent.

(f) *Well venting for liquids unloadings.* Calculate annual volumetric natural gas emissions from well venting for liquids unloading using one of the calculation methods described in paragraphs (f)(1), (2), or (3) of this section. Calculate annual CH_4 and CO_2 volumetric and mass emissions using the method described in paragraph (f)(4) of this section.

(1) *Calculation Method 1.* Calculate emissions from wells with plunger lifts and wells without plunger lifts separately. For at least one well of each unique well tubing diameter group and pressure group combination in each sub-basin category (see §98.238 for the definitions of tubing diameter group, pressure group, and sub-basin category), where gas wells are vented to the atmosphere to expel liquids accumulated in the tubing, install a recording flow meter on the vent line used to vent gas from the well (*e.g.,* on the vent line off the wellhead separator or atmospheric storage tank) according to methods set forth in §98.234(b). Calculate the total emissions from well venting to the atmosphere for liquids unloading using Equation W-7A of this section. For any tubing diameter group and pressure group combination in a sub-basin where liquids unloading occurs both with and without plunger lifts, Equation W-7A will be used twice, once for wells with plunger lifts and once for wells without plunger lifts.

$$E_a = FR \sum_{p=1}^{h} T_p \qquad \text{(Eq. W-7A)}$$

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Where:

E_a = Annual natural gas emissions for all wells of the same tubing diameter group and pressure group combination in a sub-basin at actual conditions, a, in cubic feet. Calculate emission from wells with plunger lifts and wells without plunger lifts separately.

h = Total number of wells of the same tubing diameter group and pressure group combination in a sub-basin either with or without plunger lifts.

p = Wells 1 through h of the same tubing diameter group and pressure group combination in a sub-basin.

T_p = Cumulative amount of time in hours of venting for each well, p, of the same tubing diameter group and pressure group combination in a sub-basin during the year. If the available venting data do not contain a record of the date of the venting events and data are not available to provide the venting hours for the specific time period of January 1 to December 31, you may calculate an annualized vent time, T_p, using Equation W-7B of this section.

FR = Average flow rate in cubic feet per hour for all measured wells of the same tubing diameter group and pressure group combination in a sub-basin, over the duration of the liquids unloading, under actual conditions as determined in paragraph (f)(1)(i) of this section.

$$T_p = \frac{HR_p}{MP_p} \text{ x } D_p \qquad \text{(Eq. W-7B)}$$

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Where:

HR_p = Cumulative amount of time in hours of venting for each well, p, during the monitoring period.

MP_p = Time period, in days, of the monitoring period for each well, p. A minimum of 300 days in a calendar year are required. The next period of data collection must start immediately following the end of data year are required. The next period of data collection must start immediately following the end of data collection for the previous reporting year.

D_p = Time period, in days during which the well, p, was in production (365 if the well was in production for the entire year).

(i) Determine the well vent average flow rate ("FR" in Equation W-7A of this section) as specified in paragraphs (f)(1)(i)(A) through (C) of this section for at least one well in a unique well tubing diameter group and pressure group combination in each sub-basin category. Calculate emissions from wells with plunger lifts and wells without plunger lifts separately.

(A) Calculate the average flow rate per hour of venting for each unique tubing diameter group and pressure group combination in each sub-basin category by dividing the recorded total annual flow by the recorded time (in hours) for all measured liquid unloading events with venting to the atmosphere.

(B) Apply the average hourly flow rate calculated under paragraph (f)(1)(i)(A) of this section to all wells in the same pressure group that have the same tubing diameter group, for the number of hours of venting these wells.

(C) Calculate a new average flow rate every other calendar year starting with the first calendar year of data collection. For a new producing sub-basin category, calculate an average flow rate beginning in the first year of production.

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

(2) *Calculation Method 2.* Calculate the total emissions for each sub-basin from well venting to the atmosphere for liquids unloading without plunger lift assist using Equation W-8 of this section.

$$E_s = \sum_{p=1}^{W}\left[V_p \times \left(\left(0.37\times10^{-3}\right)\times CD_p^2 \times WD_p \times SP_p\right) + \sum_{q=1}^{V_p}\left(SFR_p \times \left(HR_{p,q} - 1.0\right)\times Z_{p,q}\right)\right] \qquad \text{(Eq. W-8)}$$

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Where:

E_s = Annual natural gas emissions for each sub-basin at standard conditions, s, in cubic feet per year.

W = Total number of wells with well venting for liquids unloading for each sub-basin.

p = Wells 1 through W with well venting for liquids unloading for each sub-basin.

V_p = Total number of unloading events in the monitoring period per well, p.

0.37×10^{-3} = {3.14 (pi)/4}/{14.7*144} (psia converted to pounds per square feet).

CD_p = Casing internal 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 = For each well, p, shut-in pressure or surface pressure for wells with tubing production, or casing pressure for each well with no packers, in pounds per square inch absolute (psia). If casing pressure

pressure for each well with no packers, in pounds per square inch absolute (psia). If casing pressure is not available for each well, you may determine the casing pressure by multiplying the tubing pressure of each well with a ratio of casing pressure to tubing pressure from a well in the same sub-basin for which the casing pressure is known. The tubing pressure must be measured during gas flow to a flow-line. The shut-in pressure, surface pressure, or casing pressure must be determined just prior to liquids unloading when the well production is impeded by liquids loading or closed to the flow-line by surface valves.

SFR_p = Average flow-line rate of gas for well, p, at standard conditions in cubic feet per hour. Use Equation W-33 of this section 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 event, q.

1.0 = Hours for average well to blowdown casing volume at shut-in pressure.

q = Unloading event.

$Z_{p,q}$ = 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.

(3) *Calculation Method 3.* Calculate the total emissions for each sub-basin from well venting to the atmosphere for liquids unloading with plunger lift assist using Equation W-9 of this section.

$$E_s = \sum_{p=1}^{W}\left[V_p \times \left(\left(0.37\times10^{-3}\right)\times TD_p^2 \times WD_p \times SP_p\right) + \sum_{q=1}^{V_p}\left(SFR_p \times \left(HR_{p,q} - 0.5\right)\times Z_{p,q}\right)\right] \qquad \text{(Eq. W-9)}$$

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Where:

E_s = Annual natural gas emissions for each sub-basin at standard conditions, s, in cubic feet per year.

W = Total number of wells with plunger lift assist and well venting for liquids unloading for each sub-basin.

p = Wells 1 through W with well venting for liquids unloading for each sub-basin.

V_p = Total number of unloading events in the monitoring period for each well, p.

0.37×10^{-3} = {3.14 (pi)/4}/{14.7*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), using engineering estimate based on best available data.

SFR_p = Average flow-line rate of gas for well, p, at standard conditions in cubic feet per hour. Use Equation W-33 of this section 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 event, q.

0.5 = Hours for average well to blowdown tubing volume at flow-line pressure.

q = Unloading event.

$Z_{p,q}$ = 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.

(4) Calculate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using calculations in paragraphs (u) and (v) of this section.

(g) *Well venting during completions and workovers with hydraulic fracturing.* Calculate annual volumetric natural gas emissions from gas well and oil well venting during completions and workovers involving hydraulic fracturing using Equation W-10A or Equation W-10B of this section. Equation W-10A applies to well venting when the gas flowback rate is measured from a specified number of example completions or workovers and Equation W-10B applies when the gas flowback vent or flare volume is measured for each completion or workover. Completion and workover activities are separated into two periods, an initial period when flowback is routed to open pits or tanks and a subsequent period when gas content is sufficient to route the flowback to a separator or when the gas content is sufficient to allow measurement by the devices specified in paragraph (g)(1) of this section, regardless of whether a separator is actually utilized. If you elect to use Equation W-10A, you must follow the procedures specified in paragraph (g)(1). If you elect to use Equation W-10B, you must use a recording flow meter installed on the vent line, downstream of a separator and ahead of a flare or vent, to measure the gas flowback. For either equation, emissions must be calculated separately for completions and workovers, for each sub-basin, and for each well type combination identified in paragraph (g)(2) of this section. You must calculate CH_4 and CO_2 volumetric and mass emissions as specified in paragraph (g)(3) of this section. If emissions from well venting during completions and workovers with hydraulic fracturing are routed to a flare, you must calculate CH_4, CO_2, and N_2O annual emissions as specified in paragraph (g)(4) of this section.

$$E_{s,n} = \sum_{p=1}^{W} \left[T_{p,s} \times FRM_s \times PR_{s,p} - EnF_{s,p} + \left[T_{p,i} \times FRM_i \div 2 \times PR_{s,p} \right] \right] \quad \text{(Eq. W-10A)}$$

$$E_{s,n} = \sum_{p=1}^{W} \left[FV_{s,p} - EnF_{s,p} + \left[T_{p,i} \times FR_{p,i} \div 2 \right] \right] \quad \text{(Eq. W-10B)}$$

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Where:

$E_{s,n}$ = Annual volumetric natural gas emissions in standard cubic feet from gas venting during well completions or workovers following hydraulic fracturing for each sub-basin and well type combination.

W = Total number of wells completed or worked over using hydraulic fracturing in a sub-basin and well type combination.

$T_{p,s}$ = Cumulative amount of time of flowback, after sufficient quantities of gas are present to enable separation, where gas vented or flared for the completion or workover, in hours, for each well, p, in a sub-basin and well type combination during the reporting year. This may include non-contiguous periods of venting or flaring.

$T_{p,i}$ = Cumulative amount of time of flowback to open tanks/pits, from when gas is first detected until sufficient quantities of gas are present to enable separation, for the completion or workover, in hours, for each well, p, in a sub-basin and well type combination during the reporting year. This may include non-contiguous periods of routing to open tanks/pits but does not include periods when the oil well ceases to produce fluids to the surface.

FRM_s = Ratio of average gas flowback, during the period when sufficient quantities of gas are present to enable separation, of well completions and workovers from hydraulic fracturing to 30-day production rate for the sub-basin and well type combination, calculated using procedures specified in paragraph (g)(1)(iii) of this section.

FRM_i = Ratio of initial gas flowback rate during well completions and workovers from hydraulic fracturing to 30-day gas production rate for the sub-basin and well type combination, calculated using procedures specified in paragraph (g)(1)(iv) of this section, for the period of flow to open tanks/pits.

$PR_{s,p}$ = Average gas production flow rate during the first 30 days of production after completions of newly drilled wells or well workovers using hydraulic fracturing in standard cubic feet per hour of each well p, that was measured in the sub-basin and well type combination. If applicable, $PR_{s,p}$ may be calculated for oil wells using procedures specified in paragraph (g)(1)(vii) of this section.

$EnF_{s,p}$ = Volume of N_2 injected gas in cubic feet at standard conditions that was injected into the reservoir during an energized fracture job or during flowback for each well, p, as determined by using an appropriate meter according to methods described in §98.234(b), or by using receipts of gas purchases that are used for the energized fracture job or injection during flowback. Convert to standard conditions using paragraph (t) of this section. If the fracture process did not inject gas into the reservoir or if the injected gas is CO_2 then $EnF_{s,p}$ is 0.

$FV_{s,p}$ = Flow volume of vented or flared gas for each well, p, in standard cubic feet measured using a recording flow meter (digital or analog) on the vent line to measure gas flowback during the separation period of the completion or workover according to methods set forth in §98.234(b).

$FR_{p,i}$ = Flow rate vented or flared of each well, p, in standard cubic feet per hour measured using a recording flow meter (digital or analog) on the vent line to measure the flowback, at the beginning of the period of time when sufficient quantities of gas are present to enable separation, of the completion or workover according to methods set forth in §98.234(b).

(1) If you elect to use Equation W-10A of this section on gas wells, you must use Calculation Method 1 as specified in paragraph (g)(1)(i) of this section, or Calculation Method 2 as specified in paragraph (g)(1)(ii) of this section, to determine the value of FRM_s and FRM_i. If you elect to use Equation W-10A of this section on oil wells, you must use Calculation Method 1 as specified in paragraph (g)(1)(i) to determine the value of FRM_s and FRM_i. These values must be based on the flow rate for flowback gases, once sufficient gas is present to enable separation. The number of measurements or calculations required to estimate FRM_s and FRM_i must be determined individually for completions and workovers per sub-basin and well type combination as follows: Complete measurements or calculations for at least one completion or workover for less than or equal to 25 completions or workovers for each well type combination within a sub-basin; complete measurements or calculations for at least two completions or workovers for 26 to 50 completions or workovers for each sub-basin and well type combination; complete measurements or calculations for at least three completions or workovers for 51 to 100 completions or workovers for each sub-basin and well type combination; complete measurements or calculations for at least four completions or workovers for 101 to 250 completions or workovers for each sub-basin and well type combination; and complete measurements or calculations for at least five completions or workovers for greater than 250 completions or workovers for each sub-basin and well type combination.

(i) *Calculation Method 1.* You must use Equation W-12A of this section as specified in paragraph (g)(1)(iii) of this section to determine the value of FRM_s. You must use Equation

W-12B of this section as specified in paragraph (g)(1)(iv) of this section to determine the value of FRM_i. The procedures specified in paragraphs (g)(1)(v) and (vi) of this section also apply. When making gas flowback measurements for use in Equations W-12A and W-12B of this section, you must use a recording flow meter (digital or analog) installed on the vent line, downstream of a separator and ahead of a flare or vent, to measure the gas flowback rates in units of standard cubic feet per hour according to methods set forth in §98.234(b).

(ii) *Calculation Method 2 (for gas wells).* You must use Equation W-12A as specified in paragraph (g)(1)(iii) of this section to determine the value of FRM_s. You must use Equation W-12B as specified in paragraph (g)(1)(iv) of this section to determine the value of FRM_i. The procedures specified in paragraphs (g)(1)(v) and (vi) also apply. When calculating the flowback rates for use in Equations W-12A and W-12B of this section based on well parameters, you must record the well flowing pressure immediately upstream (and immediately downstream in subsonic flow) of a well choke according to methods set forth in §98.234(b) to calculate the well flowback. The upstream pressure must be surface pressure and reservoir pressure cannot be assumed. The downstream pressure must be measured after the choke and atmospheric pressure cannot be assumed. Calculate flowback rate using Equation W-11A of this section for subsonic flow or Equation W-11B of this section for sonic flow. You must use best engineering estimates based on best available data along with Equation W-11C of this section to determine whether the predominant flow is sonic or subsonic. If the value of R in Equation W-11C of this section is greater than or equal to 2, then flow is sonic; otherwise, flow is subsonic. Convert calculated FR_a values from actual conditions upstream of the restriction orifice to standard conditions ($FR_{s,p}$ and $FR_{i,p}$) for use in Equations W-12A and W-12B of this section using Equation W-33 in paragraph (t) of this section.

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

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Where:

FR_a = Flowback rate in actual cubic feet per hour, under actual subsonic flow conditions.

A = Cross sectional open area of the restriction orifice (m^2).

P_1 = Pressure immediately upstream of the choke (psia).

T_u = Temperature immediately upstream of the choke (degrees Kelvin).

P_2 = Pressure immediately downstream of the choke (psia).

3430 = Constant with units of $m^2/(sec^2 * K)$.

$1.27*10^5$ = Conversion from m^3/second to ft^3/hour.

$$FR_a = 1.27*10^5 * A * \sqrt{187.08 * T_u} \quad \text{(Eq. W-11B)}$$

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Where:

FR_a = Flowback rate in actual cubic feet per hour, under actual sonic flow conditions.

A = Cross sectional open area of the restriction orifice (m^2).

T_u = Temperature immediately upstream of the choke (degrees Kelvin).

187.08 = Constant with units of $m^2/(sec^2 * K)$.

$1.27*10^5$ = Conversion from m^3/second to ft^3/hour.

$$R = P1/P2 \qquad \text{(Eq. W-11C)}$$

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Where:

R = Pressure ratio.

P_1 = Pressure immediately upstream of the choke (psia).

P_2 = Pressure immediately downstream of the choke (psia).

(iii) For Equation W-10A of this section, calculate FRM_s using Equation W-12A of this section.

$$FRM_s = \frac{\sum_{p=1}^{N} FR_{s,p}}{\sum_{p=1}^{N} PR_{s,p}} \qquad \text{(Eq. W-12A)}$$

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Where:

FRM_s = Ratio of average gas flowback rate, during the period of time when sufficient quantities of gas are present to enable separation, of well completions and workovers from hydraulic fracturing to 30-day gas production rate for each sub-basin and well type combination.

$FR_{s,p}$ = Measured average gas flowback rate from Calculation Method 1 described in paragraph (g)(1)(i) of this section or calculated average flowback rate from Calculation Method 2 described in paragraph (g)(1)(ii) of this section, during the separation period in standard cubic feet per hour for well(s) p for each sub-basin and well type combination. Convert measured and calculated FR_a values from actual conditions upstream of the restriction orifice (FR_a) to standard conditions ($FR_{s,p}$) for each well p using Equation W-33 in paragraph (t) of this section. You may not use flow volume as used in Equation W-10B of this section converted to a flow rate for this parameter.

$PR_{s,p}$ = Average gas production flow rate during the first 30 days of production after completions of newly drilled wells or well workovers using hydraulic fracturing, in standard cubic feet per hour for each well, p, that was measured in the sub-basin and well type combination. For oil wells for which production is not measured continuously during the first 30 days of production, the average flow rate may be based on individual well production tests conducted within the first 30 days of production. Alternatively, if applicable, $PR_{s,p}$ may be calculated for oil wells using procedures specified in paragraph (g)(1)(vii) of this section.

N = Number of measured or calculated well completions or workovers using hydraulic fracturing in a sub-basin and well type combination.

(iv) For Equation W-10A of this section, calculate FRM_i using Equation W-12B of this section.

$$FRMi = \frac{\sum_{p=1}^{N} FR_{i,p}}{\sum_{p=1}^{N} PR_{s,p}} \qquad \text{(Eq. W-12B)}$$

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Where:

FRM_i = Ratio of initial gas flowback rate during well completions and workovers from hydraulic fracturing to 30-day gas production rate for the sub-basin and well type combination, for the period of flow to open tanks/pits.

$FR_{i,p}$ = Initial measured gas flowback rate from Calculation Method 1 described in paragraph (g)(1)(i) of this section or initial calculated flow rate from Calculation Method 2 described in paragraph (g)(1)(ii) of this section in standard cubic feet per hour for well(s), p, for each sub-basin and well type combination. Measured and calculated $FR_{i,p}$ values must be based on flow conditions at the beginning of the separation period and must be expressed at standard conditions.

$PR_{s,p}$ = Average gas production flow rate during the first 30-days of production after completions of newly drilled wells or well workovers using hydraulic fracturing, in standard cubic feet per hour of each well, p, that was measured in the sub-basin and well type combination. For oil wells for which production is not measured continuously during the first 30 days of production, the average flow rate may be based on individual well production tests conducted within the first 30 days of production. Alternatively, if applicable, $PR_{s,p}$ may be calculated for oil wells using procedures specified in paragraph (g)(1)(vii) of this section.

N = Number of measured or calculated well completions or workovers using hydraulic fracturing in a sub-basin and well type combination.

(v) For Equation W-10A of this section, the ratio of gas flowback rate during well completions and workovers from hydraulic fracturing to 30-day gas production rate are applied to all well completions and well workovers, respectively, in the sub-basin and well type combination for the total number of hours of flowback and for the first 30 day average gas production rate for each of these wells.

(vi) For Equations W-12A and W-12B of this section, calculate new flowback rates for well completions and well workovers in each sub-basin and well type combination once every two years starting in the first calendar year of data collection.

(vii) For oil wells where the gas production rate is not metered and you elect to use Equation W-10A of this section, calculate the average gas production rate ($PR_{s,p}$) using Equation W-12C of this section. If GOR cannot be determined from your available data, then you must use one of the procedures specified in paragraph (g)(1)(vii)(A) or (B) of this section to determine GOR. If GOR from each well is not available, use the GOR from a cluster of wells in the same sub-basin category.

$$PR_{s,p} = GOR_p * \frac{V_p}{720} \qquad \text{(Eq. W-12C)}$$

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Where:

$PR_{s,p}$ = Average gas production flow rate during the first 30 days of production after completions of newly drilled wells or well workovers using hydraulic fracturing in standard cubic feet per hour of well p, in the sub-basin and well type combination.

GOR_p = Average gas to oil ratio during the first 30 days of production after completions of newly drilled wells or workovers using hydraulic fracturing in standard cubic feet of gas per barrel of oil for each well p, that was measured in the sub-basin and well type combination; oil here refers to hydrocarbon liquids produced of all API gravities.

V_p = Volume of oil produced during the first 30 days of production after completions of newly drilled wells or well workovers using hydraulic fracturing in barrels of each well p, that was measured in the sub-basin and well type combination.

720 = Conversion from 30 days of production to hourly production rate.

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

(B) You may use an industry standard practice as described in §98.234(b).

(2) For paragraphs (g) introductory text and (g)(1) of this section, measurements and calculations are completed separately for workovers and completions per sub-basin and well type combination. A well type combination is a unique combination of the parameters listed in paragraphs (g)(2)(i) through (iv) of this section.

(i) Vertical or horizontal (directional drilling).

(ii) With flaring or without flaring.

(iii) Reduced emission completion/workover or not reduced emission completion/workover.

(iv) Oil well or gas well.

(3) Calculate both CH_4 and CO_2 volumetric and mass emissions from total natural gas volumetric emissions using calculations in paragraphs (u) and (v) of this section.

(4) Calculate annual emissions from well venting during well completions and workovers from hydraulic fracturing where all or a portion of the gas is flared as specified in paragraphs (g)(4)(i) and (ii) of this section.

(i) Use the volumetric total natural gas emissions vented to the atmosphere during well completions and workovers as determined in paragraph (g) of this section to calculate volumetric and mass emissions using paragraphs (u) and (v) of this section.

(ii) Use the calculation method of flare stacks in paragraph (n) of this section to adjust emissions for the portion of gas flared during well completions and workovers using hydraulic fracturing. This adjustment to emissions from completions using flaring, versus completions without flaring, accounts for the conversion of CH_4 to CO_2 in the flare and for the formation on N_2O during flaring.

(h) *Gas well venting during completions and workovers without hydraulic fracturing.* Calculate annual volumetric natural gas emissions from each gas well venting during workovers without hydraulic fracturing using Equation W-13A of this section. Calculate annual volumetric natural gas emissions from each gas well venting during completions without hydraulic fracturing using Equation W-13B of this section. You must convert annual volumetric natural gas emissions to CH_4 and CO_2 volumetric and mass emissions as specified in paragraph (h)(1) of this section. If emissions from gas well venting during completions and workovers without hydraulic fracturing are routed to a flare, you must calculate CH_4, CO_2, and N_2O annual emissions as specified in paragraph (h)(2) of this section.

$$E_{s,wo} = N_{wo} * EF_{wo} \quad \text{(Eq. W-13A)}$$

$$E_{s,p} = \sum_{p=1}^{f} V_p * T_p \quad \text{(Eq. W-13B)}$$

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Where:

$E_{s,wo}$ = Annual volumetric natural gas emissions in standard cubic feet from gas well venting during well workovers without hydraulic fracturing.

N_{wo} = Number of workovers per sub-basin category that do not involve hydraulic fracturing in the reporting year.

EF_{wo} = Emission factor for non-hydraulic fracture well workover venting in standard cubic feet per workover. Use 3,114 standard cubic feet natural gas per well workover without hydraulic fracturing.

$E_{s,p}$ = Annual volumetric natural gas emissions in standard cubic feet from gas well venting during well completions without hydraulic fracturing.

p = Well completions 1 through f in a sub-basin.

f = Total number of well completions without hydraulic fracturing in a sub-basin category.

V_p = Average daily gas production rate in standard cubic feet per hour for each well, p, undergoing completion without hydraulic fracturing. This is the total annual gas production volume divided by total number of hours the wells produced to the flow-line. For completed wells that have not established a production rate, you may use the average flow rate from the first 30 days of production. In the event that the well is completed less than 30 days from the end of the calendar year, the first 30 days of the production straddling the current and following calendar years shall be used.

T_p = Time that gas is vented to either the atmosphere or a flare for each well, p, undergoing completion without hydraulic fracturing, in hours during the year.

(1) Calculate both CH_4 and CO_2 volumetric emissions from natural gas volumetric emissions using calculations in paragraph (u) of this section. Calculate both CH_4 and CO_2 mass emissions from volumetric emissions vented to atmosphere using calculations in paragraph (v) of this section.

(2) Calculate annual emissions of CH_4, CO_2, and N_2O from gas well venting to flares during well completions and workovers not involving hydraulic fracturing as specified in paragraphs (h)(2)(i) and (ii) of this section.

(i) Use the gas well venting volume and gas composition during well completions and workovers that are flared as determined using the methods specified in paragraphs (h) and (h)(1) of this section.

(ii) Use the calculation method of flare stacks in paragraph (n) of this section to determine emissions from the flare for gas well venting to a flare during completions and workovers without hydraulic fracturing.

(i) *Blowdown vent stacks.* Calculate CO_2 and CH_4 blowdown vent stack emissions from the depressurization of equipment to reduce system pressure for planned or emergency shutdowns resulting from human intervention or to take equipment out of service for maintenance as specified in either paragraph (i)(2) or (3) of this section. You may use the method in paragraph (i)(2) of this section for some blowdown vent stacks at your facility and the method in paragraph (i)(3) of this section for other blowdown vent stacks at your facility. Equipment with a unique physical volume of less than 50 cubic feet as determined in paragraph (i)(1) of this section are not subject to the requirements in paragraphs (i)(2) through (4) of this section. The requirements in this paragraph (i) do not apply to blowdown vent stack emissions from depressurizing to a flare, over-pressure relief, operating pressure control venting, blowdown of non-GHG gases, and desiccant dehydrator blowdown venting before reloading.

(1) *Method for calculating unique physical volumes.* You must calculate each unique physical volume (including pipelines, compressor case or cylinders, manifolds, suction bottles, discharge bottles, and vessels) between isolation valves, in cubic feet, by using engineering estimates based on best available data.

(2) *Method for determining emissions from blowdown vent stacks according to equipment or event type.* If you elect to determine emissions according to each equipment or event type, using unique physical volumes as calculated in paragraph (i)(1) of this section, you must calculate emissions as specified in paragraph (i)(2)(i) of this section and either paragraph (i)(2)(ii) or, if applicable, paragraph (i)(2)(iii) of this section for each equipment or event type. For industry segments other than onshore natural gas transmission pipeline, equipment or event types must be grouped into the following seven categories: Facility piping (*i.e.,* piping within the facility boundary other than physical volumes associated with distribution pipelines), pipeline venting (*i.e.,* physical volumes associated with distribution pipelines vented within the facility boundary), compressors, scrubbers/strainers, pig launchers and receivers, emergency shutdowns (this category includes emergency shutdown blowdown emissions regardless of equipment type), and all other equipment with a physical volume greater than or equal to 50 cubic feet. If a blowdown event resulted in emissions from multiple equipment types and the emissions cannot be apportioned to the different equipment types, then categorize the blowdown event as the equipment type that represented the largest portion of the emissions for the blowdown event. For the onshore natural gas transmission pipeline segment, pipeline segments or event types must be grouped into the

following eight categories: Pipeline integrity work (*e.g.,* the preparation work of modifying facilities, ongoing assessments, maintenance or mitigation), traditional operations or pipeline maintenance, equipment replacement or repair (*e.g.,* valves), pipe abandonment, new construction or modification of pipelines including commissioning and change of service, operational precaution during activities (*e.g.* excavation near pipelines), emergency shutdowns including pipeline incidents as defined in 49 CFR 191.3, and all other pipeline segments with a physical volume greater than or equal to 50 cubic feet. If a blowdown event resulted in emissions from multiple categories and the emissions cannot be apportioned to the different categories, then categorize the blowdown event in the category that represented the largest portion of the emissions for the blowdown event.

(i) Calculate the total annual natural gas emissions from each unique physical volume that is blown down using either Equation W-14A or W-14B of this section.

$$E_{s,n} = N * \left(V \left(\frac{(459.67 + T_s) P_a}{(459.67 + T_a) P_s Z_a} \right) - V * C \right) \quad \text{(Eq. W-14A)}$$

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Where:

$E_{s,n}$ = Annual natural gas emissions at standard conditions from each unique physical volume that is blown down, in cubic feet.

N = Number of occurrences of blowdowns for each unique physical volume in the calendar year.

V = Unique physical volume between isolation valves, in cubic feet, as calculated in paragraph (i)(1) of this section.

C = Purge factor is 1 if the unique physical volume is not purged, or 0 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). For emergency blowdowns at onshore petroleum and natural gas gathering and boosting facilities, engineering estimates based on best available information may be used to determine the temperature.

P_s = Absolute pressure at standard conditions (14.7 psia).

P_a = Absolute pressure at actual conditions in the unique physical volume (psia). For emergency blowdowns at onshore petroleum and natural gas gathering and boosting facilities, engineering estimates based on best available information may be used to determine the pressure.

Z_a = Compressibility factor at actual conditions for natural gas. You may use either a default compressibility factor of 1, or a site-specific compressibility factor based on actual temperature and pressure conditions.

$$E_{s,n} = \sum_{p=1}^{N} \left[V_p \left(\frac{(459.67 + T_s)(P_{a,b,p} - P_{a,e,p})}{(459.67 + T_{a,p}) P_s Z_a} \right) \right] \quad \text{(Eq. W-14B)}$$

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Where:

$E_{s,n}$ = Annual natural gas emissions at standard conditions from each unique physical volume that is blown down, in cubic feet.

p = Individual occurrence of blowdown for the same unique physical volume.

N = Number of occurrences of blowdowns for each unique physical volume in the calendar year.

V_p = Unique physical volume 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) for each blowdown "p".

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.

Z_a = Compressibility factor at actual conditions for natural gas. You may use either a default compressibility factor of 1, or a site-specific compressibility factor based on actual temperature and pressure conditions.

(ii) Except as allowed in paragraph (i)(2)(iii) of this section, calculate annual CH_4 and CO_2 volumetric and mass emissions from each unique physical volume that is blown down by using the annual natural gas emission value as calculated in either Equation W-14A or Equation W-14B of paragraph (i)(2)(i) of this section and the calculation method specified in paragraph (i)(4) of this section. Calculate the total annual CH_4 and CO_2 emissions for each equipment or event type by summing the annual CH_4 and CO_2 mass emissions for all unique physical volumes associated with the equipment or event type.

(iii) For onshore natural gas transmission compression facilities and LNG import and export equipment, as an alternative to using the procedures in paragraph (i)(2)(ii) of this section, you may elect to sum the annual natural gas emissions as calculated using either Equation W-14A or Equation W-14B of paragraph (i)(2)(i) of this section for all unique physical volumes associated with the equipment type or event type. Calculate the total annual CH_4 and CO_2 volumetric and mass emissions for each equipment type or event type using the sums of the total annual natural gas emissions for each equipment type and the calculation method specified in paragraph (i)(4) of this section.

(3) *Method for determining emissions from blowdown vent stacks using a flow meter.* In lieu of determining emissions from blowdown vent stacks as specified in paragraph (i)(2) of this section, you may use a flow meter and measure blowdown vent stack emissions for any unique physical volumes determined according to paragraph (i)(1) of this section to be greater than or equal to 50 cubic feet. If you choose to use this method, you must measure the natural gas emissions from the blowdown(s) through the monitored stack(s) using a flow meter according to methods in §98.234(b), and calculate annual CH_4 and CO_2 volumetric and mass emissions measured by the meters according to paragraph (i)(4) of this section.

(4) *Method for converting from natural gas emissions to GHG volumetric and mass emissions.* Calculate both CH_4 and CO_2 volumetric and mass emissions using the methods specified in paragraphs (u) and (v) of this section.

(j) *Onshore production and onshore petroleum and natural gas gathering and boosting storage tanks.* Calculate CH_4, CO_2, and N_2O (when flared) emissions from atmospheric pressure fixed roof storage tanks receiving hydrocarbon produced liquids from onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities (including stationary liquid storage not owned or operated by the reporter), as specified in this paragraph (j). For gas-liquid separators or onshore petroleum and natural gas gathering and boosting non-separator equipment (*e.g.,* stabilizers, slug catchers) with annual average daily throughput of oil greater than or equal to 10 barrels per day, calculate annual CH_4 and CO_2 using Calculation Method 1 or 2 as specified in paragraphs (j)(1) and (2) of this section. For wells flowing directly to atmospheric storage tanks without passing through a separator with throughput greater than or equal to 10 barrels per day, calculate annual CH_4 and CO_2 emissions using Calculation Method 2 as specified in paragraph (j)(2) of this section. For hydrocarbon liquids flowing to gas-liquid separators or non-separator equipment or directly to atmospheric storage tanks with throughput less than 10 barrels per day, use Calculation Method 3 as specified in paragraph (j)(3) of this section. If you use Calculation Method 1 or Calculation Method 2 for separators, you must also calculate emissions that may have occurred due to dump valves not closing properly using the method specified in paragraph (j)(6) of this section. If emissions from atmospheric pressure fixed roof storage tanks are routed to a vapor recovery system, you must adjust the emissions downward according to paragraph (j)(4) of this section. If emissions from atmospheric pressure fixed roof storage tanks are routed to a flare, you must calculate CH_4, CO_2, and N_2O annual emissions as specified in paragraph (j)(5) of this section.

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

(i) Separator or non-separator equipment temperature.

(ii) Separator or non-separator equipment pressure.

(iii) Sales oil or stabilized oil API gravity.

(iv) Sales oil or stabilized oil production rate.

(v) Ambient air temperature.

(vi) Ambient air pressure.

(vii) Separator or non-separator equipment oil composition and Reid vapor pressure. If this data is not available, determine these parameters by using one of the methods described in paragraphs (j)(1)(vii)(A) through (C) of this section.

(A) If separator or non-separator equipment oil composition and Reid vapor pressure default data are provided with the software program, select the default values that most closely match your separator or non-separator equipment pressure first, and API gravity secondarily.

(B) If separator or non-separator equipment oil composition and Reid vapor pressure data are available through your previous analysis, select the latest available analysis that is representative of produced crude oil or condensate from the sub-basin category for onshore petroleum and natural gas production or from the county for onshore petroleum and natural gas gathering and boosting.

(C) Analyze a representative sample of separator or non-separator equipment oil in each sub-basin category for onshore petroleum and natural gas production or each county for onshore petroleum and natural gas gathering and boosting for oil composition and Reid vapor pressure using an appropriate standard method published by a consensus-based standards organization.

(2) *Calculation Method 2.* Calculate annual CH_4 and CO_2 emissions using the methods in paragraph (j)(2)(i) of this section for gas-liquid separators with annual average daily throughput of oil greater than or equal to 10 barrels per day. Calculate annual CH_4 and CO_2 emissions using the methods in paragraph (j)(2)(ii) of this section for wells with annual average daily oil production greater than or equal to 10 barrels per day that flow directly to atmospheric storage tanks in onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting (if applicable). Calculate annual CH_4 and CO_2 emissions using the methods in paragraph (j)(2)(iii) of this section for non-separator equipment with annual average daily hydrocarbon liquids throughput greater than or equal to 10 barrels per day that flow directly to atmospheric storage tanks in onshore petroleum and natural gas gathering and boosting.

(i) *Flow to storage tank after passing through a separator.* Assume that all of the CH_4 and CO_2 in solution at separator temperature and pressure is emitted from oil sent to storage tanks. You may use an appropriate standard method published by a consensus-based standards organization if such a method exists or you may use an industry standard practice as described in §98.234(b) to sample and analyze separator oil composition at separator pressure and temperature.

(ii) *Flow to storage tank direct from wells.* Calculate CH_4 and CO_2 emissions using either of the methods in paragraph (j)(2)(ii)(A) or (B) of this section.

(A) If well production oil and gas compositions are available through a previous analysis, select the latest available analysis that is representative of produced oil and gas from the sub-basin category and assume all of the CH_4 and CO_2 in both oil and gas are emitted from the tank.

(B) If well production oil and gas compositions are not available, use default oil and gas compositions in software programs, such as API 4697 E&P Tank, that most closely match the well production gas/oil ratio and API gravity and assume all of the CH_4 and CO_2 in both oil and gas are emitted from the tank.

(iii) *Flow to storage tank direct from non-separator equipment.* Calculate CH_4 and CO_2 emissions using either of the methods in paragraph (j)(2)(iii)(A) or (B) of this section.

(A) If other non-separator equipment liquid and gas compositions are available through a previous analysis, select the latest available analysis that is representative of liquid and gas from non-separator equipment in the same county and assume all of the CH_4 and CO_2 in both hydrocarbon liquids and gas are emitted from the tank.

(B) If non-separator equipment liquid and gas compositions are not available, use default liquid and gas compositions in software programs, such as API 4697 E&P Tank, that most closely match the non-separator equipment gas/liquid ratio and API gravity and assume all of the CH_4 and CO_2 in both hydrocarbon liquids and gas are emitted from the tank.

(3) *Calculation Method 3.* Calculate CH_4 and CO_2 emissions using Equation W-15 of this section:

$$E_{s,i} = EF_i * Count * 1000 \qquad \text{(Eq. W-15)}$$

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Where:

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

EF_i = Population emission factor for separators, wells, or non-separator equipment in thousand standard cubic feet per separator, well, or non-separator equipment per year, for crude oil use 4.2 for CH_4 and 2.8 for CO_2 at 60 °F and 14.7 psia, and for gas condensate use 17.6 for CH_4 and 2.8 for CO_2 at 60 °F and 14.7 psia.

Count = Total number of separators, wells, or non-separator equipment with annual average daily throughput less than 10 barrels per day. Count only separators, wells, or non-separator equipment that feed oil directly to the storage tank.

1,000 = Conversion from thousand standard cubic feet to standard cubic feet.

(4) Determine if the storage tank receiving your separator oil has a vapor recovery system.

(i) Adjust the emissions estimated in paragraphs (j)(1) through (3) of this section downward by the magnitude of emissions recovered using a vapor recovery system as determined by engineering estimate based on best available data.

determined by engineering estimate based on best available data.

(ii) [Reserved]

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

(i) Use your separator flash gas volume and gas composition as determined in this section.

(ii) Use the calculation method of flare stacks in paragraph (n) of this section to determine storage tank emissions from the flare.

(6) If you use Calculation Method 1 or Calculation Method 2 in paragraph (j)(1) or (2) of this section, calculate emissions from occurrences of gas-liquid separator liquid dump valves not closing during the calendar year by using Equation W-16 of this section.

$$E_{s,i,o} = \left(CF_n * \frac{E_n}{8760} * T_n \right) \quad \text{(Eq. W-16)}$$

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Where:

$E_{s,i,o}$ = Annual volumetric GHG emissions at standard conditions from each storage tank in cubic feet that resulted from the dump valve on the gas-liquid separator not closing properly.

E_n = Storage tank emissions as determined in paragraphs (j)(1), (j)(2) and, if applicable, (j)(4) of this section in standard cubic feet per year.

T_n = Total time a dump valve is not closing properly in the calendar year in hours. Estimate T_n based on maintenance, operations, or routine separator inspections that indicate the period of time when the valve was malfunctioning in open or partially open position.

CF_n = Correction factor for tank emissions for time period T_n is 2.87 for crude oil production. Correction factor for tank emissions for time period T_n is 4.37 for gas condensate production.

8,760 = Conversion to hourly emissions.

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

(k) *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, calculate CH_4 and CO_2 annual emissions from compressor scrubber dump valve leakage as specified in paragraphs (k)(1) through (k)(4) of this section. If emissions from compressor scrubber dump valve leakage are routed to a flare, you must calculate CH_4, CO_2, and N_2O annual emissions as specified in paragraph (k)(5) of this section.

(1) Except as specified in paragraph (k)(1)(iv) of this section, you must monitor the tank vapor vent stack annually for emissions using one of the methods specified in paragraphs (k)(1)(i) through (iii) of this section.

(i) Use an optical gas imaging instrument according to methods set forth in §98.234(a)(1).

(ii) Measure the tank vent directly using a flow meter or high volume sampler according to methods in §98.234(b) or (d) for a duration of 5 minutes.

(iii) Measure the tank vent using a calibrated bag according to methods in §98.234(c) for a duration of 5 minutes or until the bag is full, whichever is shorter.

(iv) You may annually monitor leakage through compressor scrubber dump valve(s) into the tank using an acoustic leak detection device according to methods set forth in §98.234(a)(5).

(2) If the tank vapors from the vent stack are continuous for 5 minutes, or the optical gas imaging instrument or acoustic leak detection device detects a leak, then you must use one of the methods in either paragraph (k)(2)(i) or (ii) of this section.

(i) Use a flow meter, such as a turbine meter, calibrated bag, or high volume sampler to estimate tank vapor volumes from the vent stack according to methods set forth in §98.234(b) through (d). If you do not have a continuous flow measurement device, you may install a flow measuring device on the tank vapor vent stack. If the vent is directly measured for five minutes under paragraph (k)(1)(ii) or (iii) of this section to detect continuous leakage, this serves as the measurement.

(ii) Use an acoustic leak detection device on each scrubber dump valve connected to the tank according to the method set forth in §98.234(a)(5).

(3) If a leaking dump valve is identified, the leak must be counted as having occurred since the beginning of the calendar year, or from the previous test that did not detect leaking in the same calendar year. If the leaking dump valve is fixed following leak detection, the leak duration will end upon being repaired. If a leaking dump valve is identified and not repaired, the leak must be counted as having occurred through the rest of the calendar year.

(4) Use the requirements specified in paragraphs (k)(4)(i) and (ii) of this section to quantify annual emissions.

(i) Use the appropriate gas composition in paragraph (u)(2)(iii) of this section.

(ii) Calculate CH_4 and CO_2 volumetric and mass emissions at standard conditions using calculations in paragraphs (t), (u), and (v) of this section, as applicable to the monitoring equipment used.

(5) Calculate annual emissions from storage tanks to flares as specified in paragraphs (k)(5)(i) and (ii) of this section.

(i) Use the storage tank emissions volume and gas composition as determined in paragraphs (k)(1) through (4) of this section.

(ii) Use the calculation method of flare stacks in paragraph (n) of this section to determine storage tank emissions sent to a flare.

(l) *Well testing venting and flaring.* Calculate CH_4 and CO_2 annual emissions from well testing venting as specified in paragraphs (l)(1) through (5) of this section. If emissions from well testing venting are routed to a flare, you must calculate CH_4, CO_2, and N_2O annual emissions as specified in paragraph (l)(6) of this section.

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

(2) If GOR cannot be determined from your available data, then you must measure quantities reported in this section according to one of the procedures specified in paragraph (l)(2)(i) or (ii) of this section to determine GOR.

(i) You may use an appropriate standard method published by a consensus-based standards organization if such a method exists.

(ii) You may use an industry standard practice as described in §98.234(b).

(3) Estimate venting emissions using Equation W-17A (for oil wells) or Equation W-17B (for gas wells) of this section.

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

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

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Where:

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

GOR = Gas to oil ratio in cubic feet of gas per barrel of oil; oil here refers to hydrocarbon liquids produced of all API gravities.

FR = Average annual 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 calendar year that the well(s) is tested.

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

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

(6) Calculate emissions from well testing if emissions are routed to a flare as specified in paragraphs (l)(6)(i) and (ii) of this section.

(i) Use the well testing emissions volume and gas composition as determined in paragraphs (l)(1) through (4) of this section.

(ii) Use the calculation method of flare stacks in paragraph (n) of this section to determine well testing emissions from the flare.

(m) *Associated gas venting and flaring.* Calculate CH_4 and CO_2 annual emissions from associated gas venting not in conjunction with well testing (refer to paragraph (l): Well testing venting and flaring of this section) as specified in paragraphs (m)(1) through (4) of this section. If emissions from associated gas venting are routed to a flare, you must calculate CH_4, CO_2, and N_2O annual emissions as specified in paragraph (m)(5) of this section.

(1) Determine the GOR of the hydrocarbon production from each well whose associated natural gas is vented or flared. If GOR from each well is not available, use the GOR from a cluster of wells in the same sub-basin category.

(2) If GOR cannot be determined from your available data, then you must use one of the procedures specified in paragraphs (m)(2)(i) or (ii) of this section to determine GOR.

(i) You may use an appropriate standard method published by a consensus-based standards organization if such a method exists.

(ii) You may use an industry standard practice as described in §98.234(b).

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

$$E_{s,n} = \sum_{q=1}^{y} \sum_{p=1}^{x} \left[\left(GOR_{p,q} * V_{p,q} \right) - SG_{p,q} \right] \qquad \text{(Eq. W-18)}$$

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Where:

$E_{s,n}$ = Annual volumetric natural gas emissions, at the facility level, from associated gas venting at standard conditions, in cubic feet.

$GOR_{p,q}$ = Gas to oil ratio, for well p in sub-basin q, in standard 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 sub-basin q, in barrels in the calendar year during time periods in which associated gas was vented or flared.

$SG_{p,q}$ = Volume of associated gas sent to sales, for well p in sub-basin q, in standard cubic feet of gas in the calendar year during time periods in which associated gas was vented or flared.

x = Total number of wells in sub-basin that vent or flare associated gas.

y = Total number of sub-basins in a basin that contain wells that vent or flare associated gas.

(4) Calculate both CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using calculations in paragraphs (u) and (v) of this section.

(5) Calculate emissions from associated natural gas if emissions are routed to a flare as specified in paragraphs (m)(5)(i) and (ii) of this section.

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

(ii) Use the calculation method of flare stacks in paragraph (n) of this section to determine associated gas emissions from the flare.

(n) *Flare stack emissions.* Calculate CO_2, CH_4, and N_2O emissions from a flare stack as specified in paragraphs (n)(1) through (9) of this section.

(1) If you have a continuous flow measurement device on the flare, you must use the measured flow volumes to calculate the flare gas emissions. If all of the flare gas 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 you do not have a continuous flow measurement device on the flare, you can use engineering calculations based on process knowledge, company records, and best available data.

(2) If you have a continuous gas composition analyzer on gas to the flare, you must use these compositions in calculating emissions. If you do not have a continuous gas composition analyzer on gas to the flare, you must use the appropriate gas compositions for each stream of hydrocarbons going to the flare as specified in paragraphs (n)(2)(i) through (iii) of this section.

(i) For onshore natural gas production and onshore petroleum and natural gas gathering and boosting, determine the GHG mole fraction using paragraph (u)(2)(i) of this section.

(ii) For onshore natural gas processing, when the stream going to flare is natural gas, use the GHG mole fraction in feed natural gas for all streams upstream of the de-methanizer or dew point control, and GHG mole fraction in facility specific residue gas to transmission 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 fraction in feed natural gas liquid for all streams.

(iii) For any industry segment required to report to flare stack emissions under §98.232, 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 you may use a representative composition from the source for the stream determined by engineering calculation based on process knowledge and best available data.

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

(4) Convert GHG volumetric emissions to standard conditions using calculations in paragraph (t) of this section.

(5) Calculate GHG volumetric emissions from flaring at standard conditions using Equations W-19 and W-20 of this section.

$$E_{s,CH4} = V_s * X_{CH4} * \left[(1-\eta) * Z_L + Z_U\right] \qquad \text{(Eq. W-19)}$$

$$E_{s,CO2} = V_s * X_{CO2} + \sum_{j=1}^{5}\left(\eta * V_s * Y_j * R_j * Z_L\right) \qquad \text{(Eq. W-20)}$$

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Where:

$E_{s,CH4}$ = Annual CH_4 emissions from flare stack in cubic feet, at standard conditions.

$E_{s,CO2}$ = Annual CO_2 emissions from flare stack in cubic feet, at standard conditions.

V_s = Volume of gas sent to flare in standard cubic feet, during the year as determined in paragraph (n)(1) of this section.

η = Flare combustion efficiency, expressed as fraction of gas combusted by a burning flare (default is 0.98).

X_{CH4} = Mole fraction of CH_4 in the feed gas to the flare as determined in paragraph (n)(2) of this section.

X_{CO2} = Mole fraction of CO_2 in the feed gas to the flare as determined in paragraph (n)(2) of this section.

Z_U = Fraction of the feed gas sent to an un-lit flare determined by engineering estimate and process knowledge based on best available data and operating records.

Z_L = Fraction of the feed gas sent to a burning flare (equal to 1 − Z_U).

Y_j = Mole fraction of hydrocarbon constituents j (such as methane, ethane, propane, butane, and pentanes-plus) in the feed gas to the flare as determined in paragraph (n)(1) of this section.

R_j = Number of carbon atoms in the hydrocarbon constituent j in the feed gas to the flare: 1 for methane, 2 for ethane, 3 for propane, 4 for butane, and 5 for pentanes-plus).

(6) Calculate both CH_4 and CO_2 mass emissions from volumetric emissions using calculation in paragraph (v) of this section.

(7) Calculate N_2O emissions from flare stacks using Equation W-40 in paragraph (z) of this section.

(8) If you operate and maintain a CEMS that has both a CO_2 concentration monitor and volumetric flow rate monitor for the combustion gases from the flare, you must calculate only CO_2 emissions for the flare. You must follow the Tier 4 Calculation Method and all associated calculation, quality assurance, reporting, and recordkeeping requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources). If a CEMS is used to calculate flare stack emissions, the requirements specified in paragraphs (n)(1) through (7) of this section are not required.

(9) The flare emissions determined under this paragraph (n) must be corrected for flare emissions calculated and reported under other paragraphs of this section to avoid double counting of these emissions.

(o) *Centrifugal compressor venting.* If you are required to report emissions from centrifugal compressor venting as specified in §98.232(d)(2), (e)(2), (f)(2), (g)(2), and (h)(2), you must conduct volumetric emission measurements specified in paragraph (o)(1) of this section using methods specified in paragraphs (o)(2) through (5) of this section; perform calculations specified in paragraphs (o)(6) through (9) of this section; and calculate CH_4 and CO_2 mass emissions as specified in paragraph (o)(11) of this section. If emissions from a compressor source are routed to a flare, paragraphs (o)(1) through (11) do not apply and instead you must calculate CH_4, CO_2, and N_2O emissions as specified in paragraph (o)(12) of this section. If emissions from a compressor source are captured for fuel use or are routed to a thermal oxidizer, paragraphs (o)(1) through (12) do not apply and instead you must calculate and report emissions as specified in subpart C of this part. If emissions from a compressor source are routed to vapor recovery, paragraphs (o)(1) through (12) do not apply. If you are required to report emissions from centrifugal compressor venting at an onshore petroleum and natural gas production facility as specified in §98.232(c)(19) or an onshore petroleum and natural gas gathering and boosting facility as specified in §98.232(j)(8), you must calculate volumetric emissions as specified in paragraph (o)(10); and calculate CH_4 and CO_2 mass emissions as specified in paragraph (o)(11).

(1) *General requirements for conducting volumetric emission measurements.* You must conduct volumetric emission measurements on each centrifugal compressor as specified in this paragraph. Compressor sources (as defined in §98.238) without manifolded vents must use a measurement method specified in paragraph (o)(1)(i) or (ii) of this section. Manifolded compressor sources (as defined in §98.238) must use a measurement method specified in paragraph (o)(1)(i), (ii), (iii), or (iv) of this section.

(i) Centrifugal compressor source as found measurements. Measure venting from each compressor according to either paragraph (o)(1)(i)(A) or (B) of this section at least once annually, based on the compressor mode (as defined in §98.238) in which the compressor was found at the time of measurement, except as specified in paragraphs (o)(1)(i)(C) and (D) of this section. If additional measurements beyond the required annual testing are performed (including duplicate measurements or measurement of additional operating modes), then all measurements satisfying the applicable monitoring and QA/QC that is required by this paragraph (o) must be used in the calculations specified in this section.

(A) For a compressor measured in operating-mode, you must measure volumetric emissions from blowdown valve leakage through the blowdown vent as specified in either paragraph (o)(2)(i)(A) or (B) of this section and, if the compressor has wet seal oil degassing vents, measure volumetric emissions from wet seal oil degassing vents as specified in paragraph (o)(2)(ii) of this section.

(B) For a compressor measured in not-operating-depressurized-mode, you must measure volumetric emissions from isolation valve leakage as specified in either paragraph (o)(2)(i)(A), (B), or (C) of this section. If a compressor is not operated and has blind flanges in place throughout the reporting period, measurement is not required in this compressor mode.

(C) You must measure the compressor as specified in paragraph (o)(1)(i)(B) of this section at least once in any three consecutive calendar years, provided the measurement section at least once in any three consecutive calendar years, provided the measurement can be taken during a scheduled shutdown. If three consecutive calendar years occur without measuring the compressor in not-operating-depressurized-mode, you must measure the compressor as specified in paragraph (o)(1)(i)(B) of this section at the next scheduled depressurized shutdown. The requirement specified in this paragraph does not apply if the compressor has blind flanges in place throughout the reporting year. For purposes of this paragraph, a scheduled shutdown means a shutdown that requires a compressor to be taken off-line for planned or scheduled maintenance. A scheduled shutdown does not include instances when a compressor is taken offline due to a decrease in demand but must remain available.

(D) An annual as found measurement is not required in the first year of operation for any new compressor that begins operation after as found measurements have been conducted for all existing compressors. For only the first year of operation of new compressors, calculate emissions according to paragraph (o)(6)(ii) of this section.

(ii) Centrifugal compressor source continuous monitoring. Instead of measuring the compressor source according to paragraph (o)(1)(i) of this section for a given compressor, you may elect to continuously measure volumetric emissions from a compressor source as specified in paragraph (o)(3) of this section.

(iii) Manifolded centrifugal compressor source as found measurements. For a compressor source that is part of a manifolded group of compressor sources (as defined in §98.238), instead of measuring the compressor source according to paragraph (o)(1)(i), (ii), or (iv) of this section, you may elect to measure combined volumetric emissions from the manifolded group of compressor sources by conducting measurements at the common vent stack as specified in paragraph (o)(4) of this section. The measurements must be conducted at the frequency specified in paragraphs (o)(1)(iii)(A) and (B) of this section.

(A) A minimum of one measurement must be taken for each manifolded group of compressor sources in a calendar year.

(B) The measurement may be performed while the compressors are in any compressor mode.

(iv) Manifolded centrifugal compressor source continuous monitoring. For a compressor source that is part of a manifolded group of compressor sources, instead of measuring the compressor source according to paragraph (o)(1)(i), (ii), or (iii) of this section, you may elect to continuously measure combined volumetric emissions from the manifolded group of compressor sources as specified in paragraph (o)(5) of this section.

(2) *Methods for performing as found measurements from individual centrifugal compressor sources.* If conducting measurements for each compressor source, you must determine the volumetric emissions from blowdown valves and isolation valves as specified in paragraph (o)(2)(i) of this section, and the volumetric emissions from wet seal oil degassing vents as specified in paragraph (o)(2)(ii) of this section.

(i) For blowdown valves on compressors in operating-mode and for isolation valves on compressors in not-operating-depressurized-mode, determine the volumetric emissions compressors in not operating depressurized mode, determine the volumetric emissions using one of the methods specified in paragraphs (o)(2)(i)(A) through (D) of this section.

(A) Determine the volumetric flow at standard conditions from the blowdown vent using calibrated bagging or high volume sampler according to methods set forth in §98.234(c) and §98.234(d), respectively.

(B) Determine the volumetric flow at standard conditions from the blowdown vent using a temporary meter such as a vane anemometer according to methods set forth in §98.234(b).

(C) Use an acoustic leak detection device according to methods set forth in §98.234(a)(5).

(D) You may choose to use any of the methods set forth in §98.234(a) to screen for emissions. If emissions are detected using the methods set forth in §98.234(a), then you must use one of the methods specified in paragraph (o)(2)(i)(A) through (C) of this section. If emissions are not detected using the methods in §98.234(a), then you may assume that the volumetric emissions are zero. For the purposes of this paragraph, when using any of the methods in §98.234(a), emissions are detected whenever a leak is detected according to the methods.

(ii) For wet seal oil degassing vents in operating-mode, determine vapor volumes at standard conditions, using a temporary meter such as a vane anemometer or permanent flow meter according to methods set forth in §98.234(b).

(3) *Methods for continuous measurement from individual centrifugal compressor sources.* If you elect to conduct continuous volumetric emission measurements for an individual compressor source as specified in paragraph (o)(1)(ii) of this section, you must measure volumetric emissions as specified in paragraphs (o)(3)(i) and (ii) of this section.

(i) Continuously measure the volumetric flow for the individual compressor source at standard conditions using a permanent meter according to methods set forth in §98.234(b).

(ii) If compressor blowdown emissions are included in the metered emissions specified in paragraph (o)(3)(i) of this section, the compressor blowdown emissions may be included with the reported emissions for the compressor source and do not need to be calculated separately using the method specified in paragraph (i) of this section for blowdown vent stacks.

(4) *Methods for performing as found measurements from manifolded groups of centrifugal compressor sources.* If conducting measurements for a manifolded group of compressor sources, you must measure volumetric emissions as specified in paragraphs (o)(4)(i) and (ii) of this section.

(i) Measure at a single point in the manifold downstream of all compressor inputs and, if practical, prior to comingling with other non-compressor emission sources.

(ii) Determine the volumetric flow at standard conditions from the common stack using one of the methods specified in paragraphs (o)(4)(ii)(A) through (E) of this section.

(A) A temporary meter such as a vane anemometer according the methods set forth in §98.234(b).

(B) Calibrated bagging according to methods set forth in §98.234(c).

(C) A high volume sampler according to methods set forth §98.234(d).

(D) An acoustic leak detection device according to methods set forth in §98.234(a)(5).

(E) You may choose to use any of the methods set forth in §98.234(a) to screen for emissions. If emissions are detected using the methods set forth in §98.234(a), then you must use one of the methods specified in paragraph (o)(4)(ii)(A) through (o)(4)(ii)(D) of this section. If emissions are not detected using the methods in §98.234(a), then you may assume that the volumetric emissions are zero. For the purposes of this paragraph, when using any of the methods in §98.234(a), emissions are detected whenever a leak is detected according to the method.

(5) *Methods for continuous measurement from manifolded groups of centrifugal compressor sources.* If you elect to conduct continuous volumetric emission measurements for a manifolded group of compressor sources as specified in paragraph (o)(1)(iv) of this section, you must measure volumetric emissions as specified in paragraphs (o)(5)(i) through (iii) of this section.

(i) Measure at a single point in the manifold downstream of all compressor inputs and, if practical, prior to comingling with other non-compressor emission sources.

(ii) Continuously measure the volumetric flow for the manifolded group of compressor sources at standard conditions using a permanent meter according to methods set forth in §98.234(b).

(iii) If compressor blowdown emissions are included in the metered emissions specified in paragraph (o)(5)(ii) of this section, the compressor blowdown emissions may be included with the reported emissions for the manifolded group of compressor sources and do not need to be calculated separately using the method specified in paragraph (i) of this section for blowdown vent stacks.

(6) *Method for calculating volumetric GHG emissions from as found measurements for individual centrifugal compressor sources.* For compressor sources measured according to paragraph (o)(1)(i) of this section, you must calculate annual GHG emissions from the compressor sources as specified in paragraphs (o)(6)(i) through (iv) of this section.

(i) Using Equation W-21 of this section, calculate the annual volumetric GHG emissions for each centrifugal compressor mode-source combination specified in paragraphs (o)(1)(i)(A) and (B) of this section that was measured during the reporting year.

$$E_{s,i,m} = MT_{s,m} * T_m * GHG_{i,m} \qquad \text{(Eq. W-21)}$$

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Where:

$E_{s,i,m}$ = Annual volumetric GHG_i (either CH_4 or CO_2) emissions for measured compressor mode-source combination m, at standard conditions, in cubic feet.

$MT_{s,m}$ = Volumetric gas emissions for measured compressor mode-source combination m, in standard cubic feet per hour, measured according to paragraph (o)(2) of this section. If multiple measurements are performed for a given mode-source combination m, use the average of all measurements.

T_m = Total time the compressor is in the mode-source combination for which $E_{s,i,m}$ is being calculated in the reporting year, in hours.

$GHG_{i,m}$ = Mole fraction of GHG_i in the vent gas for measured compressor mode-source combination m; use the appropriate gas compositions in paragraph (u)(2) of this section.

m = Compressor mode-source combination specified in paragraph (o)(1)(i)(A) or (o)(1)(i)(B) of this section that was measured for the reporting year.

(ii) Using Equation W-22 of this section, calculate the annual volumetric GHG emissions from each centrifugal compressor mode-source combination specified in paragraph (o)(1)(i)(A) and (B) of this section that was not measured during the reporting year.

$$E_{s,i,m} = EF_{s,m} * T_m * GHG_{i,m} \qquad \text{(Eq. W-22)}$$

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Where:

$E_{s,i,m}$ = Annual volumetric GHG_i (either CH_4 or CO_2) emissions for unmeasured compressor mode-source combination m, at standard conditions, in cubic feet.

$EF_{s,m}$ = Reporter emission factor for compressor mode-source combination m, in standard cubic feet per hour, as calculated in paragraph (o)(6)(iii) of this section.

T_m = Total time the compressor was in the unmeasured mode-source combination m, for which $E_{s,i,m}$ is being calculated in the reporting year, in hours.

$GHG_{i,m}$ = Mole fraction of GHG_i in the vent gas for unmeasured compressor mode-source combination m; use the appropriate gas compositions in paragraph (u)(2) of this section.

m = Compressor mode-source combination specified in paragraph (o)(1)(i)(A) or (o)(1)(i)(B) of this section that was not measured in the reporting year.

(iii) Using Equation W-23 of this section, develop an emission factor for each compressor mode-source combination specified in paragraph (o)(1)(i)(A) and (B) of this section. These emission factors must be calculated annually and used in Equation W-22 of this section to determine volumetric emissions from a centrifugal compressor in the mode-source combinations that were not measured in the reporting year.

$$EF_{s,m} = \frac{\sum_{p=1}^{Count_m} MT_{s,m,p}}{Count_m} \qquad \text{(Eq. W-23)}$$

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Where:

$EF_{s,m}$ = Reporter emission factor to be used in Equation W-22 of this section for compressor mode-source combination m, in standard cubic feet per hour. The reporter emission factor must be based on all compressors measured in compressor mode-source combination m in the current reporting year and the preceding two reporting years.

$MT_{s,m,p}$ = Average volumetric gas emission measurement for compressor mode-source combination m, for compressor p, in standard cubic feet per hour, calculated using all volumetric gas emission measurements ($MT_{s,m}$ in Equation W-21 of this section) for compressor mode-source combination m for compressor p in the current reporting year and the preceding two reporting years.

$Count_m$ = Total number of compressors measured in compressor mode-source combination m in the current reporting year and the preceding two reporting years.

m = Compressor mode-source combination specified in paragraph (o)(1)(i)(A) or (o)(1)(i)(B) of this section.

(iv) The reporter emission factor in Equation W-23 of this section may be calculated by using all measurements from a single owner or operator instead of only using measurements from a single facility. If you elect to use this option, the reporter emission factor must be applied to all reporting facilities for the owner or operator.

(7) *Method for calculating volumetric GHG emissions from continuous monitoring of individual centrifugal compressor sources.* For compressor sources measured according to paragraph (o)(1)(ii) of this section, you must use the continuous volumetric emission measurements taken as specified in paragraph (o)(3) of this section and calculate annual volumetric GHG emissions associated with the compressor source using Equation W-24A of this section.

$$E_{s,i,v} = Q_{s,v} * GHG_{i,v} \quad \text{(Eq. W-24A)}$$

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Where:

$E_{s,i,v}$ = Annual volumetric GHG_i (either CH_4 or CO_2) emissions from compressor source v, at standard conditions, in cubic feet.

$Q_{s,v}$ = Volumetric gas emissions from compressor source v, for reporting year, in standard cubic feet.

$GHG_{i,v}$ = Mole fraction of GHG_i in the vent gas for compressor source v; use the appropriate gas compositions in paragraph (u)(2) of this section.

(8) *Method for calculating volumetric GHG emissions from as found measurements of manifolded groups of centrifugal compressor sources.* For manifolded groups of compressor sources measured according to paragraph (o)(1)(iii) of this section, you must calculate annual volumetric GHG emissions using Equation W-24B of this section. If the centrifugal compressors included in the manifolded group of compressor sources share the manifold with reciprocating compressors, you must follow the procedures in either this paragraph (o)(8) or paragraph (p)(8) of this section to calculate emissions from the manifolded group of compressor sources.

$$E_{s,i,g} = T_g * MT_{s,g,avg} * GHG_{i,g} \quad \text{(Eq. W-24B)}$$

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Where:

$E_{s,i,g}$ = Annual volumetric GHG_i (either CH_4 or CO_2) emissions for manifolded group of compressor sources g, at standard conditions, in cubic feet.

T_g = Total time the manifolded group of compressor sources g had potential for emissions in the reporting year, in hours. Include all time during which at least one compressor source in the manifolded group of compressor sources g was in a mode-source combination specified in either paragraph (o)(1)(i)(A), (o)(1)(i)(B), (p)(1)(i)(A), (p)(1)(i)(B), or (p)(1)(i)(C) of this section. Default of 8760 hours may be used.

$MT_{s,g,avg}$ = Average volumetric gas emissions of all measurements performed in the reporting year according to paragraph (o)(4) of this section for the manifolded group of compressor sources g, in standard cubic feet per hour.

$GHG_{i,g}$ = Mole fraction of GHG_i in the vent gas for manifolded group of compressor sources g; use the appropriate gas compositions in paragraph (u)(2) of this section.

(9) *Method for calculating volumetric GHG emissions from continuous monitoring of manifolded group of centrifugal compressor sources.* For a manifolded group of compressor sources measured according to paragraph (o)(1)(iv) of this section, you must use the continuous volumetric emission measurements taken as specified in paragraph (o)(5) of this section and calculate annual volumetric GHG emissions associated with each manifolded group of compressor sources using Equation W-24C of this section. If the centrifugal compressors included in the manifolded group of compressor sources share the manifold with reciprocating compressors, you must follow the procedures in either this paragraph (o)(9) or paragraph (p)(9) of this section to calculate emissions from the manifolded group of compressor sources.

$$E_{s,i,g}=Q_{s,g}*GHG_{i,g} \qquad \text{(Eq. W-24C)}$$

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Where:

$E_{s,i,g}$ = Annual volumetric GHG_i (either CH_4 or CO_2) emissions from manifolded group of compressor sources g, at standard conditions, in cubic feet.

$Q_{s,g}$ = Volumetric gas emissions from manifolded group of compressor sources g, for reporting year, in standard cubic feet.

$GHG_{i,g}$ = Mole fraction of GHG_i in the vent gas for measured manifolded group of compressor sources g; use the appropriate gas compositions in paragraph (u)(2) of this section.

(10) *Method for calculating volumetric GHG emissions from wet seal oil degassing vents at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility.* You must calculate emissions from centrifugal compressor wet seal oil degassing vents at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility using Equation W-25 of this section.

$$E_{s,i}=Count*EF_{i,s} \qquad \text{(Eq. W-25)}$$

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Where:

$E_{s,i}$ = Annual volumetric GHG_i (either CH_4 or CO_2) emissions from centrifugal compressor wet seals, at standard conditions, in cubic feet.

Count = Total number of centrifugal compressors that have wet seal oil degassing vents.

$EF_{i,s}$ = Emission factor for GHG_i. 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.

(11) *Method for converting from volumetric to mass emissions.* You must calculate both CH_4 and CO_2 mass emissions from volumetric emissions using calculations in paragraph (v) of this section.

(12) *General requirements for calculating volumetric GHG emissions from centrifugal compressors routed to flares.* You must calculate and report emissions from all centrifugal compressor sources that are routed to a flare as specified in paragraphs (o)(12)(i) through (iii) of this section.

(i) Paragraphs (o)(1) through (11) of this section are not required for compressor sources that are routed to a flare.

(ii) If any compressor sources are routed to a flare, calculate the emissions for the flare stack as specified in paragraph (n) of this section and report emissions from the flare as specified in §98.236(n), without subtracting emissions attributable to compressor sources from the flare.

(iii) Report all applicable activity data for compressors with compressor sources routed to flares as specified in §98.236(o).

(p) *Reciprocating compressor venting.* If you are required to report emissions from reciprocating compressor venting as specified in §98.232(d)(1), (e)(1), (f)(1), (g)(1), and (h)(1), you must conduct volumetric emission measurements specified in paragraph (p)(1) of this section using methods specified in paragraphs (p)(2) through (5) of this section; perform calculations specified in paragraphs (p)(6) through (9) of this section; and calculate CH_4 and CO_2 mass emissions as specified in paragraph (p)(11) of this section. If emissions from a compressor source are routed to a flare, paragraphs (p)(1) through (11) do not apply and instead you must calculate CH_4, CO_2, and N_2O emissions as specified in paragraph (p)(12) of this section. If emissions from a compressor source are captured for fuel use or are routed to a thermal oxidizer, paragraphs (p)(1) through (12) do not apply and instead you must calculate and report emissions as specified in subpart C of this part. If emissions from a compressor source are routed to vapor recovery, paragraphs (p)(1) through (12) do not apply. If you are required to report emissions from reciprocating compressor venting at an onshore petroleum and natural gas production facility as specified in §98.232(c)(11) or an onshore petroleum and natural gas gathering and boosting facility as specified in §98.232(j)(5), you must calculate volumetric emissions as specified in paragraph (p)(10); and calculate CH_4 and CO_2 mass emissions as specified in paragraph (p)(11).

(1) *General requirements for conducting volumetric emission measurements.* You must conduct volumetric emission measurements on each reciprocating compressor as specified in this paragraph. Compressor sources (as defined in §98.238) without manifolded vents must use a measurement method specified in paragraph (p)(1)(i) or (ii) of this section. Manifolded compressor sources (as defined in §98.238) must use a measurement method specified in paragraph (p)(1)(i), (ii), (iii), or (iv) of this section.

(i) Reciprocating compressor source as found measurements. Measure venting from each compressor according to either paragraph (p)(1)(i)(A), (B), or (C) of this section at least once annually, based on the compressor mode (as defined in §98.238) in which the compressor was found at the time of measurement, except as specified in paragraphs (p)(1)(i)(D) and (E) of this section. If additional measurements beyond the required annual testing are performed (including duplicate measurements or measurement of additional operating modes), then all measurements satisfying the applicable monitoring and QA/QC that is required by this paragraph (o) must be used in the calculations specified in this section.

(A) For a compressor measured in operating-mode, you must measure volumetric emissions from blowdown valve leakage through the blowdown vent as specified in either paragraph (p)(2)(i)(A) or (B) of this section, and measure volumetric emissions from reciprocating rod packing as specified in paragraph (p)(2)(ii) of this section.

(B) For a compressor measured in standby-pressurized-mode, you must measure volumetric emissions from blowdown valve leakage through the blowdown vent as specified in either paragraph (p)(2)(i)(A) or (B) of this section.

(C) For a compressor measured in not-operating-depressurized-mode, you must measure volumetric emissions from isolation valve leakage as specified in either paragraph (p)(2)(i)(A), (B), or (C) of this section. If a compressor is not operated and has blind flanges in place throughout the reporting period, measurement is not required in this compressor mode.

(D) You must measure the compressor as specified in paragraph (p)(1)(i)(C) of this section at least once in any three consecutive calendar years, provided the measurement can be taken during a scheduled shutdown. If there is no scheduled shutdown within three consecutive calendar years, you must measure the compressor as specified in paragraph (p)(1)(i)(C) of this section at the next scheduled depressurized shutdown. For purposes of this paragraph, a scheduled shutdown means a shutdown that requires a compressor to be taken off-line for planned or scheduled maintenance. A scheduled shutdown does not include instances when a compressor is taken offline due to a decrease in demand but must remain available.

(E) An annual as found measurement is not required in the first year of operation for any new compressor that begins operation after as found measurements have been conducted for all existing compressors. For only the first year of operation of new compressors, calculate emissions according to paragraph (p)(6)(ii) of this section.

(ii) Reciprocating compressor source continuous monitoring. Instead of measuring the compressor source according to paragraph (p)(1)(i) of this section for a given compressor, you may elect to continuously measure volumetric emissions from a compressor source as specified in paragraph (p)(3) of this section.

(iii) Manifolded reciprocating compressor source as found measurements. For a compressor source that is part of a manifolded group of compressor sources (as defined in §98.238), instead of measuring the compressor source according to paragraph (p)(1)(i), (ii), or (iv) of this section, you may elect to measure combined volumetric emissions from the manifolded group of compressor sources by conducting measurements at the common vent stack as specified in paragraph (p)(4) of this section. The measurements must be conducted at the frequency specified in paragraphs (p)(1)(iii)(A) and (B) of this section.

(A) A minimum of one measurement must be taken for each manifolded group of compressor sources in a calendar year.

(B) The measurement may be performed while the compressors are in any compressor mode.

(iv) Manifolded reciprocating compressor source continuous monitoring. For a compressor source that is part of a manifolded group of compressor sources, instead of measuring the compressor source according to paragraph (p)(1)(i), (ii), or (iii) of this section, you may elect to continuously measure combined volumetric emissions from the manifolded group of compressors sources as specified in paragraph (p)(5) of this section.

(2) *Methods for performing as found measurements from individual reciprocating compressor sources.* If conducting measurements for each compressor source, you must determine the volumetric emissions from blowdown valves and isolation valves as specified in paragraph (p)(2)(i) of this section. You must determine the volumetric emissions from reciprocating rod packing as specified in paragraph (p)(2)(ii) or (iii) of this section.

(i) For blowdown valves on compressors in operating-mode or standby-pressurized-mode, and for isolation valves on compressors in not-operating-depressurized-mode, determine the volumetric emissions using one of the methods specified in paragraphs (p)(2)(i)(A) through (D) of this section.

(A) Determine the volumetric flow at standard conditions from the blowdown vent using calibrated bagging or high volume sampler according to methods set forth in §98.234(c) and (d), respectively.

(B) Determine the volumetric flow at standard conditions from the blowdown vent using a temporary meter such as a vane anemometer, according to methods set forth in §98.234(b).

(C) Use an acoustic leak detection device according to methods set forth in §98.234(a)(5).

(D) You may choose to use any of the methods set forth in §98.234(a) to screen for emissions. If emissions are detected using the methods set forth in §98.234(a), then you must use one of the methods specified in paragraphs (p)(2)(i)(A) through (C) of this section. If emissions are not detected using the methods in §98.234(a), then you may assume that the volumetric emissions are zero. For the purposes of this paragraph, when using any of the methods in §98.234(a), emissions are detected whenever a leak is detected according to the method.

(ii) For reciprocating rod packing equipped with an open-ended vent line on compressors in operating-mode, determine the volumetric emissions using one of the methods specified in paragraphs (p)(2)(ii)(A) through (C) of this section.

(A) Determine the volumetric flow at standard conditions from the open-ended vent line using calibrated bagging or high volume sampler according to methods set forth in §98.234(c) and (d), respectively.

(B) Determine the volumetric flow at standard conditions from the open-ended vent line using a temporary meter such as a vane anemometer, according to methods set forth in §98.234(b).

(C) You may choose to use any of the methods set forth in §98.234(a) to screen for emissions. If emissions are detected using the methods set forth in §98.234(a), then you must use one of the methods specified in paragraph (p)(2)(ii)(A) and (p)(4)(ii)(B) of this section. If emissions are not detected using the methods in §98.234(a), then you may assume that the volumetric emissions are zero. For the purposes of this paragraph, when using any of the methods in §98.234(a), emissions are detected whenever a leak is detected according to the method.

(iii) For reciprocating rod packing not equipped with an open-ended vent line on compressors in operating-mode, you must determine the volumetric emissions using the method specified in paragraphs (p)(2)(iii)(A) and (B) of this section.

(A) You must use the methods described in §98.234(a) to conduct annual leak detection of equipment leaks from the packing case into an open distance piece, or for compressors with a closed distance piece, conduct annual detection of gas emissions from the rod packing vent, distance piece vent, compressor crank case breather cap, or other vent emitting gas from the rod packing.

(B) You must measure emissions found in paragraph (p)(2)(iii)(A) of this section using an appropriate meter, calibrated bag, or high volume sampler according to methods set forth in §98.234(b), (c), and (d), respectively.

(3) *Methods for continuous measurement from individual reciprocating compressor sources.* If you elect to conduct continuous volumetric emission measurements for an individual compressor source as specified in paragraph (p)(1)(ii) of this section, you must measure volumetric emissions as specified in paragraphs (p)(3)(i) and (p)(3)(ii) of this section.

(i) Continuously measure the volumetric flow for the individual compressor sources at standard conditions using a permanent meter according to methods set forth in §98.234(b).

(ii) If compressor blowdown emissions are included in the metered emissions specified in paragraph (p)(3)(i) of this section, the compressor blowdown emissions may be included with the reported emissions for the compressor source and do not need to be calculated separately using the method specified in paragraph (i) of this section for blowdown vent stacks.

(4) *Methods for performing as found measurements from manifolded groups of reciprocating compressor sources.* If conducting measurements for a manifolded group of compressor sources, you must measure volumetric emissions as specified in paragraphs (p)(4)(i) and (ii) of this section.

(i) Measure at a single point in the manifold downstream of all compressor inputs and, if practical, prior to comingling with other non-compressor emission sources.

(ii) Determine the volumetric flow at standard conditions from the common stack using one of the methods specified in paragraph (p)(4)(ii)(A) through (E) of this section.

(A) A temporary meter such as a vane anemometer according the methods set forth in §98.234(b).

(B) Calibrated bagging according to methods set forth in §98.234(c).

(C) A high volume sampler according to methods set forth §98.234(d).

(D) An acoustic leak detection device according to methods set forth in §98.234(a)(5).

(E) You may choose to use any of the methods set forth in §98.234(a) to screen for emissions. If emissions are detected using the methods set forth in §98.234(a), then you must use one of the methods specified in paragraph (p)(4)(ii)(A) through (D) of this section. If emissions are not detected using the methods in §98.234(a), then you may assume that the volumetric emissions are zero. For the purposes of this paragraph, when using any of the methods in §98.234(a), emissions are detected whenever a leak is detected according to the method.

(5) *Methods for continuous measurement from manifolded groups of reciprocating compressor sources.* If you elect to conduct continuous volumetric emission measurements for a manifolded group of compressor sources as specified in paragraph (p)(1)(iv) of this section, you must measure volumetric emissions as specified in paragraphs (p)(5)(i) through (iii) of this section.

(i) Measure at a single point in the manifold downstream of all compressor inputs and, if practical, prior to comingling with other non-compressor emission sources.

(ii) Continuously measure the volumetric flow for the manifolded group of compressor sources at standard conditions using a permanent meter according to methods set forth in §98.234(b).

(iii) If compressor blowdown emissions are included in the metered emissions specified in paragraph (p)(5)(ii) of this section, the compressor blowdown emissions may be included with the reported emissions for the manifolded group of compressor sources and do not need to be calculated separately using the method specified in paragraph (i) of this section for blowdown vent stacks.

(6) *Method for calculating volumetric GHG emissions from as found measurements for individual reciprocating compressor sources.* For compressor sources measured according to paragraph (p)(1)(i) of this section, you must calculate GHG emissions from the compressor sources as specified in paragraphs (p)(6)(i) through (iv) of this section.

(i) Using Equation W-26 of this section, calculate the annual volumetric GHG emissions for each reciprocating compressor mode-source combination specified in paragraphs (p)(1)(i)(A) through (C) of this section that was measured during the reporting year.

$$E_{s,i,m} = MT_{s,m} * T_m * GHG_{i,m} \qquad \text{(Eq. W-26)}$$

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Where:

$E_{s,i,m}$ = Annual volumetric GHG_i (either CH_4 or CO_2) emissions for measured compressor mode-source combination m, at standard conditions, in cubic feet.

$MT_{s,m}$ = Volumetric gas emissions for measured compressor mode-source combination m, in standard cubic feet per hour, measured according to paragraph (p)(2) of this section. If multiple measurements are performed for a given mode-source combination m, use the average of all measurements.

T_m = Total time the compressor is in the mode-source combination m, for which $E_{s,i,m}$ is being calculated in the reporting year, in hours.

$GHG_{i,m}$ = Mole fraction of GHG_i in the vent gas for measured compressor mode-source combination m; use the appropriate gas compositions in paragraph (u)(2) of this section.

m = Compressor mode-source combination specified in paragraph (p)(1)(i)(A), (B), or (C) of this section that was measured for the reporting year.

(ii) Using Equation W-27 of this section, calculate the annual volumetric GHG emissions from each reciprocating compressor mode-source combination specified in paragraph (p)(1)(i)(A), (B), and (C) of this section that was not measured during the reporting year.

$$E_{s,i,m} = EF_{s,m} * T_m * GHG_{i,m} \qquad \text{(Eq. W-27)}$$

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Where:

$E_{s,i,m}$ = Annual volumetric GHG_i (either CH_4 or CO_2) emissions for unmeasured compressor mode-source combination m, at standard conditions, in cubic feet.

$EF_{s,m}$ = Reporter emission factor for compressor mode-source combination m, in standard cubic feet per hour, as calculated in paragraph (p)(6)(iii) of this section.

T_m = Total time the compressor was in the unmeasured mode-source combination m, for which $E_{s,i,m}$ is being calculated in the reporting year, in hours.

$GHG_{i,m}$ = Mole fraction of GHG_i in the vent gas for unmeasured compressor mode-source combination m; use the appropriate gas compositions in paragraph (u)(2) of this section.

m = Compressor mode-source combination specified in paragraph (p)(1)(i)(A), (p)(1)(i)(B), or (p)(1)(i)(C) of this section that was not measured for the reporting year.

(iii) Using Equation W-28 of this section, develop an emission factor for each compressor mode-source combination specified in paragraph (p)(1)(i)(A), (B), and (C) of this section. These emission factors must be calculated annually and used in Equation W-27 of this section to determine volumetric emissions from a reciprocating compressor in the mode-source combinations that were not measured in the reporting year.

$$EF_{s,m} = \frac{\sum_{p=1}^{Count_m} MT_{s,m,p}}{Count_m} \qquad \text{(Eq. W-28)}$$

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Where:

$EF_{s,m}$ = Reporter emission factor to be used in Equation W-27 of this section for compressor mode-source combination m, in standard cubic feet per hour. The reporter emission factor must be based on all compressors measured in compressor mode-source combination m in the current reporting year and the preceding two reporting years.

$MT_{s,m,p}$ = Average volumetric gas emission measurement for compressor mode-source combination m, for compressor p, in standard cubic feet per hour, calculated using all volumetric gas emission measurements ($MT_{s,m}$ in Equation W-26 of this section) for compressor mode-source combination m for compressor p in the current reporting year and the preceding two reporting years.

$Count_m$ = Total number of compressors measured in compressor mode-source combination m in the current reporting year and the preceding two reporting years.

m = Compressor mode-source combination specified in paragraph (p)(1)(i)(A), (B), or (C) of this section.

(iv) The reporter emission factor in Equation W-28 of this section may be calculated by using all measurements from a single owner or operator instead of only using measurements from a single facility. If you elect to use this option, the reporter emission factor must be applied to all reporting facilities for the owner or operator.

(7) *Method for calculating volumetric GHG emissions from continuous monitoring of individual reciprocating compressor sources.* For compressor sources measured according to paragraph (p)(1)(ii) of this section, you must use the continuous volumetric emission measurements taken as specified in paragraph (p)(3) of this section and calculate annual volumetric GHG emissions associated with the compressor source using Equation W-29A of this section.

$$E_{s,i,v} = Q_{s,v} * GHG_{i,v} \qquad \text{(Eq. W-29A)}$$

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Where:

$E_{s,i,v}$ = Annual volumetric GHG_i (either CH_4 or CO_2) emissions from compressor source v, at standard conditions, in cubic feet.

$Q_{s,v}$ = Volumetric gas emissions from compressor source v, for reporting year, in standard cubic feet.

$GHG_{i,v}$ = Mole fraction of GHG_i in the vent gas for compressor source v; use the appropriate gas compositions in paragraph (u)(2) of this section.

(8) *Method for calculating volumetric GHG emissions from as found measurements of manifolded groups of reciprocating compressor sources.* For manifolded groups of compressor sources measured according to paragraph (p)(1)(iii) of this section, you must calculate annual GHG emissions using Equation W-29B of this section. If the reciprocating compressors included in the manifolded group of compressor sources share the manifold with centrifugal compressors, you must follow the procedures in either this paragraph (p)(8) or paragraph (o)(8) of this section to calculate emissions from the manifolded group of compressor sources.

$$E_{s,i,g} = T_g * MT_{s,g,avg} * GHG_{i,g} \qquad \text{(Eq. W-29B)}$$

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Where:

$E_{s,i,g}$ = Annual volumetric GHG_i (either CH_4 or CO_2) emissions for manifolded group of compressor sources g, at standard conditions, in cubic feet.

T_g = Total time the manifolded group of compressor sources g had potential for emissions in the reporting year, in hours. Include all time during which at least one compressor source in the manifolded group of compressor sources g was in a mode-source combination specified in either paragraph (o)(1)(i)(A), (o)(1)(i)(B), (p)(1)(i)(A), (p)(1)(i)(B), or (p)(1)(i)(C) of this section. Default of 8760 hours may be used.

$MT_{s,g,avg}$ = Average volumetric gas emissions of all measurements performed in the reporting year according to paragraph (p)(4) of this section for the manifolded group of compressor sources g, in standard cubic feet per hour.

$GHG_{i,g}$ = Mole fraction of GHG_i in the vent gas for manifolded group of compressor sources g; use the appropriate gas compositions in paragraph (u)(2) of this section.

(9) *Method for calculating volumetric GHG emissions from continuous monitoring of manifolded group of reciprocating compressor sources.* For a manifolded group of compressor sources measured according to paragraph (p)(1)(iv) of this section, you must use the continuous volumetric emission measurements taken as specified in paragraph (p)(5) of this section and calculate annual volumetric GHG emissions associated with each manifolded group of compressor sources using Equation W-29C of this section. If the reciprocating compressors included in the manifolded group of compressor sources share the manifold with centrifugal compressors, you must follow the procedures in either this paragraph (p)(9) or paragraph (o)(9) of this section to calculate emissions from the manifolded group of compressor sources.

$$E_{s,i,g} = Q_{s,g} * GHG_{i,g} \qquad \text{(Eq. W-29C)}$$

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Where:

$E_{s,i,g}$ = Annual volumetric GHG_i (either CH_4 or CO_2) emissions from manifolded group of compressor sources g, at standard conditions, in cubic feet.

$Q_{s,g}$ = Volumetric gas emissions from manifolded group of compressor sources g, for reporting year, in standard cubic feet.

$GHG_{i,g}$ = Mole fraction of GHG_i in the vent gas for measured manifolded group of compressor sources g; use the appropriate gas compositions in paragraph (u)(2) of this section.

(10) *Method for calculating volumetric GHG emissions from reciprocating compressor venting at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility.* You must calculate emissions from reciprocating compressor venting at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility using Equation W-29D of this section.

$$E_{s,i} = Count * EF_{i,s} \qquad \text{(Eq. W-29D)}$$

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Where:

$E_{s,i}$ = Annual volumetric GHG_i (either CH_4 or CO_2) emissions from reciprocating compressors, at standard conditions, in cubic feet.

Count = Total number of reciprocating compressors.

$EF_{i,s}$ = 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.

(11) *Method for converting from volumetric to mass emissions.* You must calculate both CH_4 and CO_2 mass emissions from volumetric emissions using calculations in paragraph (v) of this section.

(12) *General requirements for calculating volumetric GHG emissions from reciprocating compressors routed to flares.* You must calculate and report emissions from all reciprocating compressor sources that are routed to a flare as specified in paragraphs (p)(12)(i) through (iii) of this section.

(i) Paragraphs (p)(1) through (11) of this section are not required for compressor sources that are routed to a flare.

(ii) If any compressor sources are routed to a flare, calculate the emissions for the flare stack as specified in paragraph (n) of this section and report emissions from the flare as specified in §98.236(n), without subtracting emissions attributable to compressor sources from the flare.

(iii) Report all applicable activity data for compressors with compressor sources routed to flares as specified in §98.236(p).

(q) *Equipment leak surveys.* For the components identified in paragraphs (q)(1)(i) through (iii) of this section, you must conduct equipment leak surveys using the leak detection methods specified in paragraphs (q)(1)(i) through (iii) of this section. For the components identified in paragraph (q)(1)(iv) of this section, you may elect to conduct equipment leak surveys, and if you elect to conduct surveys, you must use a leak detection method specified in paragraph (q)(1)(iv) of this section. This paragraph (q) applies to components in streams with gas content greater than 10 percent CH_4 plus CO_2 by weight. Components in streams with gas content less than or equal to 10 percent CH_4 plus CO_2 by weight are exempt from the requirements of this paragraph (q) and 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 (q) and do not need to be reported.

(1) *Survey requirements.* (i) For the components listed in §98.232(e)(7), (f)(5), (g)(4), and (h)(5), that are not subject to the well site or compressor station fugitive emissions standards in §60.5397a of this chapter, you must conduct surveys using any of the leak detection methods listed in §98.234(a) and calculate equipment leak emissions using the procedures specified in paragraph (q)(2) of this section.

(ii) For the components listed in §98.232(d)(7) and (i)(1), you must conduct surveys using any of the leak detection methods listed in §98.234(a)(1) through (5) and calculate equipment leak emissions using the procedures specified in paragraph (q)(2) of this section.

(iii) For the components listed in §98.232(c)(21), (e)(7), (e)(8), (f)(5), (f)(6), (f)(7), (f)(8), (g)(4), (g)(6), (g)(7), (h)(5), (h)(7), (h)(8), and (j)(10) that are subject to the well site or compressor station fugitive emissions standards in §60.5397a of this chapter, you must conduct surveys using any of the leak detection methods in §98.234(a)(6) or (7) and calculate equipment leak emissions using the procedures specified in paragraph (q)(2) of this section.

(iv) For the components listed in §98.232(c)(21), (e)(8), (f)(6), (f)(7), (f)(8), (g)(6), (g)(7), (h)(7), (h)(8), or (j)(10), that are not subject to fugitive emissions standards in §60.5397a of this chapter, you may elect to conduct surveys according to this paragraph (q), and, if you elect to do so, then you must use one of the leak detection methods in §98.234(a).

(A) If you elect to use a leak detection method in §98.234(a)(1) through (5) for the surveyed component types in §98.232(c)(21), (f)(7), (g)(6), (h)(7), or (j)(10) in lieu of the population count methodology specified in paragraph (r) of this section, then you must calculate emissions for the surveyed component types in §98.232(c)(21), (f)(7), (g)(6), (h)(7), or (j)(10) using the procedures in paragraph (q)(2) of this section.

(B) If you elect to use a leak detection method in §98.234(a)(1) through (5) for the surveyed component types in §98.232(e)(8), (f)(6), (f)(8), (g)(7), and (h)(8), then you must use the procedures in paragraph (q)(2) of this section to calculate those emissions.

(C) If you elect to use a leak detection method in §98.234(a)(6) or (7) for any elective survey under this subparagraph (q)(1)(iv), then you must survey the component types in §98.232(c)(21), (e)(8), (f)(6), (f)(7), (f)(8), (g)(6), (g)(7), (h)(7), (h)(8), and (j)(10) that are not subject to fugitive emissions standards in §60.5397a of this chapter, and you must calculate emissions from the surveyed component types in §98.232(c)(21), (e)(8), (f)(6), (f)(7), (f)(8), (g)(6), (g)(7), (h)(7), (h)(8), and (j)(10) using the emission calculation requirements in paragraph (q)(2) of this section.

(2) *Emission calculation methodology.* For industry segments listed in §98.230(a)(2) through (9), if equipment leaks are detected during surveys required or elected for components listed in paragraphs (q)(1)(i) through (iv) of this section, then you must calculate equipment leak emissions per component type per reporting facility using Equation W-30 of this section and the requirements specified in paragraphs (q)(2)(i) through (xi) of this section. For the industry segment listed in §98.230(a)(8), the results from Equation W-30 are used to calculate population emission factors on a meter/regulator run basis using Equation W-31 of this section. If you chose to conduct equipment leak surveys at all above grade transmission-distribution transfer stations over multiple years, “n,” according to paragraph (q)(2)(x)(A) of this section, then you must calculate the emissions from all above grade transmission-distribution transfer stations as specified in paragraph (q)(2)(xi) of this section.

$$E_{s,p,i} = GHG_i * EF_{s,p} * \sum_{z=1}^{x_p} T_{p,z} \qquad \text{(Eq. W-30)}$$

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Where:

$E_{s,p,i}$ = Annual total volumetric emissions of GHGi from specific component type “p” (in accordance with paragraphs (q)(1)(i) through (iv) of this section) in standard (“s”) cubic feet, as specified in paragraphs (q)(2)(ii) through (x) of this section.

x_p = Total number of specific component type “p” detected as leaking in any leak survey during the year. A component found leaking in two or more surveys during the year is counted as one leaking component.

$EF_{s,p}$ = Leaker emission factor for specific component types listed in Tables W-1E, W-2, W-3A, W-4A, W-5A, W-6A, and W-7 to this subpart.

GHG_i = For onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities, concentration of GHG_i, CH_4, or CO_2, in produced natural gas as defined in paragraph (u)(2) of this section; 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} CO_2.

$T_{p,z}$ = The total time the surveyed component “z,” component type “p,” was assumed to be leaking and operational, in hours. If one leak detection survey is conducted in the calendar year, assume the component was leaking for the entire calendar year. If multiple leak detection surveys are conducted in the calendar year, assume a component found leaking in the first survey was leaking since the beginning of the year until the date of the survey; assume a component found leaking in the last survey of the year was leaking from the preceding survey through the end of the year; assume a component found leaking in a survey between the first and last surveys of the year was leaking since the preceding survey until the date of the survey; and sum times for all leaking periods. For each leaking component, account for time the component was not operational (*i.e.,* not operating under pressure) using an engineering estimate based on best available data.

(i) You must conduct at least one leak detection survey in a calendar year. The leak detection surveys selected must be conducted during the calendar year. If you conduct multiple complete leak detection surveys in a calendar year, you must use the results from each complete leak detection survey when calculating emissions using Equation W-30. For components subject to the well site and compressor station fugitive emissions standards in §60.5397a of this chapter, each survey conducted in accordance with §60.5397a of this chapter will be considered a complete leak detection survey for purposes of this section.

(ii) Calculate both CO_2 and CH_4 mass emissions using calculations in paragraph (v) of this section.

(iii) Onshore petroleum and natural gas production facilities must use the appropriate default whole gas leaker emission factors for components in gas service, light crude service, and heavy crude service listed in Table W-1E to this subpart.

(iv) Onshore petroleum and natural gas gathering and boosting facilities must use the appropriate default whole gas leaker factors for components in gas service listed in Table W-1E to this subpart.

(v) Onshore natural gas processing facilities must use the appropriate default total hydrocarbon leaker emission factors for compressor components in gas service and non-compressor components in gas service listed in Table W-2 to this subpart.

(vi) Onshore natural gas transmission compression facilities must use the appropriate default total hydrocarbon leaker emission factors for compressor components in gas service and non-compressor components in gas service listed in Table W-3A to this subpart.

(vii) Underground natural gas storage facilities must use the appropriate default total hydrocarbon leaker emission factors for storage stations or storage wellheads in gas service listed in Table W-4A to this subpart.

(viii) LNG storage facilities must use the appropriate default methane leaker emission factors for LNG storage components in LNG service or gas service listed in Table W-5A to this subpart.

(ix) LNG import and export facilities must use the appropriate default methane leaker emission factors for LNG terminals components in LNG service or gas service listed in Table W-6A to this subpart.

(x) Natural gas distribution facilities must use Equation W-30 of this section and the default methane leaker emission factors for transmission-distribution transfer station components in gas service listed in Table W-7 to this subpart to calculate component emissions from annual equipment leak surveys conducted at above grade transmission-distribution transfer stations. Natural gas distribution facilities are required to perform equipment leak surveys only at above grade stations that qualify as transmission-distribution equipment leak surveys only at above grade stations that qualify as transmission-distribution transfer stations. Below grade transmission-distribution transfer stations and all metering-regulating stations that do not meet the definition of transmission-distribution transfer stations are not required to perform equipment leak surveys under this section.

(A) Natural gas distribution facilities may choose to conduct equipment leak surveys at all above grade transmission-distribution transfer stations over multiple years "n," not exceeding a five year period to cover all above grade transmission-distribution transfer stations. If the facility chooses to use the multiple year option, then the number of transmission-distribution transfer stations that are monitored in each year should be approximately equal across all years in the cycle.

(B) Use Equation W-31 of this section to determine the meter/regulator run population emission factors for each GHG_i. As additional survey data become available, you must recalculate the meter/regulator run population emission factors for each GHG_i annually according to paragraph (q)(2)(x)(C) of this section.

$$EF_{s,MR,i} = \frac{\sum_{y=1}^{n}\sum_{p=1}^{7} E_{s,p,i,y}}{\sum_{y=1}^{n}\sum_{w=1}^{Count_{MR,y}} T_{w,y}} \quad \text{(Eq. W-31)}$$

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Where:

$EF_{s,MR,i}$ = Meter/regulator run population emission factor for GHG_i based on all surveyed above grade transmission-distribution transfer stations over "n" years, in standard cubic feet of GHG_i per operational hour of all meter/regulator runs.

$E_{s,p,i,y}$ = Annual total volumetric emissions at standard conditions of GHG_i from component type "p" during year "y" in standard ("s") cubic feet, as calculated using Equation W-30 of this section.

p = Seven component types listed in Table W-7 to this subpart for transmission-distribution transfer stations.

$T_{w,y}$ = The total time the surveyed meter/regulator run "w" was operational, in hours during survey year "y" using an engineering estimate based on best available data.

$Count_{MR,y}$ = Count of meter/regulator runs surveyed at above grade transmission-distribution transfer stations in year "y".

y = Year of data included in emission factor "$EF_{s,MR,i}$" according to paragraph (q)(2)(x)(C) of this section.

n = Number of years of data, according to paragraph (q)(2)(x)(A) of this section, whose results are used to calculate emission factor "$EF_{s,MR,i}$" according to paragraph (q)(2)(x)(C) of this section.

(C) The emission factor "EFs,$_{MR,i,}$" based on annual equipment leak surveys at above grade transmission-distribution transfer stations, must be calculated annually. If you chose to conduct equipment leak surveys at all above grade transmission-distribution transfer stations over multiple years, "n," according to paragraph (q)(2)(x)(A) of this section and you have submitted a smaller number of annual reports than the duration of the selected cycle period of 5 years or less, then all available data from the current year and previous years must be used in the calculation of the emission factor "$EF_{s,MR,i}$" from Equation W-31 of this section.

After the first survey cycle of “n” years is completed and beginning in calendar year (n+1), the survey will continue on a rolling basis by including the survey results from the current calendar year “y” and survey results from all previous (n−1) calendar years, such that each annual calculation of the emission factor “$EF_{s,MR,i}$” from Equation W-31 is based on survey results from “n” years. Upon completion of a cycle, you may elect to change the number of years in the next cycle period (to be 5 years or less). If the number of years in the new cycle is greater than the number of years in the previous cycle, calculate “$EF_{s,MR,i}$” from Equation W-31 in each year of the new cycle using the survey results from the current calendar year and the survey results from the preceding number years that is equal to the number of years in the previous cycle period. If the number of years, “n_{new},” in the new cycle is smaller than the number of years in the previous cycle, “n,” calculate “$EF_{s,MR,i}$” from Equation W-31 in each year of the new cycle using the survey results from the current calendar year and survey results from all previous (n_{new}−1) calendar years.

(xi) If you chose to conduct equipment leak surveys at all above grade transmission-distribution transfer stations over multiple years, “n,” according to paragraph (q)(2)(x)(A) of this section, you must use the meter/regulator run population emission factors calculated using Equation W-31 of this section and the total count of all meter/regulator runs at above grade transmission-distribution transfer stations to calculate emissions from all above grade transmission-distribution transfer stations using Equation W-32B in paragraph (r) of this section.

(r) *Equipment leaks by population count.* This paragraph (r) applies to emissions sources listed in §98.232(c)(21), (f)(7), (g)(5), (h)(6), and (j)(10) if you are not required to comply with paragraph (q) of this section and if you do not elect to comply with paragraph (q) of this section for these components in lieu of this paragraph (r). This paragraph (r) also applies to emission sources listed in §98.232(i)(2), (i)(3), (i)(4), (i)(5), (i)(6), and (j)(11). To be subject to the requirements of this paragraph (r), the listed emissions sources also must contact streams with gas content greater than 10 percent CH plus CO_2 by weight. Emissions sources that contact streams with gas content less than or equal to 10 percent CH_4 plus CO_2 by weight are exempt from the requirements of this paragraph (r) and do not need to be reported. Tubing systems equal to or less than one half inch diameter are exempt from the requirements of paragraph (r) of this section and do not need to be reported. You must calculate emissions from all emission sources listed in this paragraph using Equation W-32A of this section, except for natural gas distribution facility emission sources listed in §98.232(i)(3). Natural gas distribution facility emission sources listed in §98.232(i)(3) must calculate emissions using Equation W-32B of this section and according to paragraph (r)(6)(ii) of this section.

$$E_{s,e,i} = Count_e * EF_{s,e} * GHG_i * T_e \quad \text{(Eq. W-32A)}$$

$$E_{s,MR,i} = Count_{MR} * EF_{s,MR,i} * T_{w,avg} \quad \text{(Eq. W-32B)}$$

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Where:

$E_{s,e,i}$ = Annual volumetric emissions of GHG_i from the emission source type in standard cubic feet. The emission source type may be a component (*e.g.* connector, open-ended line, etc.), below grade metering-regulating station, below grade transmission-distribution transfer station, distribution main, distribution service, or gathering pipeline.

$E_{s,MR,i}$ = Annual volumetric emissions of GHG_i from all meter/regulator runs at above grade metering regulating stations that are not above grade transmission-distribution transfer stations or, when used to calculate emissions according to paragraph (q)(9) of this section, the annual volumetric emissions of GHG_i from all meter/regulator runs at above grade transmission-distribution transfer stations, in standard cubic feet.

$Count_e$ = Total number of the emission source type at the facility. For onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities, average component counts are provided by major equipment piece in Tables W-1B and Table W-1C to this subpart. Use average component counts as appropriate for operations in Eastern and Western U.S., according to Table W-1D to this subpart. Onshore petroleum and natural gas gathering and boosting facilities must also count the miles of gathering pipelines by material type (protected steel, unprotected steel, plastic, or cast iron). Underground natural gas storage facilities must count each component listed in Table W-4B to this subpart. LNG storage facilities must count the number of vapor recovery compressors. LNG import and export facilities must count the number of vapor recovery compressors. Natural gas distribution facilities must count: (1) The number of distribution services by material type; (2) miles of distribution mains by material type; and (3) number of below grade metering-regulating stations, by pressure type; as listed in Table W-7 to this subpart.

$Count_{MR}$ = Total number of meter/regulator runs at above grade metering-regulating stations that are not above grade transmission-distribution transfer stations or, when used to calculate emissions according to paragraph (q)(9) of this section, the total number of meter/regulator runs at above grade transmission-distribution transfer stations.

$EF_{s,e}$ = Population emission factor for the specific emission source type, as listed in Tables W-1A, W-4B, W-5B, W-6B, and W-7 to this subpart. Use appropriate population emission factor for operations in Eastern and Western U.S., according to Table W-1D to this subpart.

$EF_{s,MR,i}$ = Meter/regulator run population emission factor for GHG_i based on all surveyed above grade transmission-distribution transfer stations over "n" years, in standard cubic feet of GHG_i per operational hour of all meter/regulator runs, as determined in Equation W-31 of this section.

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

T_e = Average estimated time that each emission source type associated with the equipment leak emission was operational in the calendar year, in hours, using engineering estimate based on best available data.

$T_{w,avg}$ = Average estimated time that each meter/regulator run was operational in the calendar year, in hours per meter/regulator run, 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 (v) of this section.

(2) Onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities must use the appropriate default whole gas population emission factors listed in Table W-1A of this subpart. Major equipment and

components associated with gas wells and onshore petroleum and natural gas gathering and boosting systems are considered gas service components in reference to Table W-1A of this subpart and major natural gas equipment in reference to Table W-1B of this subpart. Major equipment and components associated with crude oil wells are considered crude service components in reference to Table W-1A of this subpart and major crude oil equipment in reference to Table W-1C of this subpart. Where facilities conduct EOR operations the emissions factor listed in Table W-1A of this subpart shall be used to estimate all streams of gases, including recycle CO_2 stream. The component count can be determined using either of the calculation methods described in this paragraph (r)(2), except for miles of gathering pipelines by material type, which must be determined using Component Count Method 2 in paragraph (r)(2)(ii) of this section. The same calculation method must be used for the entire calendar year.

(i) *Component Count Method 1.* For all onshore petroleum and natural gas production operations and onshore petroleum and natural gas gathering and boosting operations in the facility perform the following activities:

(A) Count all major equipment listed in Table W-1B and Table W-1C of this subpart. For meters/piping, use one meters/piping per well-pad for onshore petroleum and natural gas production operations and the number of meters in the facility for onshore petroleum and natural gas gathering and boosting operations.

(B) Multiply major equipment counts by the average component counts listed in Table W-1B of this subpart for onshore natural gas production and onshore petroleum and natural gas gathering and boosting; and Table W-1C of this subpart for onshore oil production. Use the appropriate factor in Table W-1A of this subpart for operations in Eastern and Western U.S. according to the mapping in Table W-1D of this subpart.

(ii) *Component Count Method 2.* Count each component individually for the facility. Use the appropriate factor in Table W-1A of this subpart for operations in Eastern and Western U.S. according to the mapping in Table W-1D of this subpart.

(3) Underground natural gas storage facilities must use the appropriate default total hydrocarbon population emission factors for storage wellheads in gas service listed in Table W-4B to this subpart.

(4) LNG storage facilities must use the appropriate default methane population emission factor for LNG storage compressors in gas service listed in Table W-5B to this subpart.

(5) LNG import and export facilities must use the appropriate default methane population emission factor for LNG terminal compressors in gas service listed in Table W-6B to this subpart.

(6) Natural gas distribution facilities must use the appropriate methane emission factors as described in paragraphs (r)(6)(i) and (ii) of this section.

(i) Below grade metering-regulating stations, distribution mains, and distribution services must use the appropriate default methane population emission factors listed in Table W-7 of must use the appropriate default methane population emission factors listed in Table W-7 of this subpart. Below grade transmission-distribution transfer stations must use the emission factor for below grade metering-regulating stations.

(ii) Above grade metering-regulating stations that are not above grade transmission-distribution transfer stations must use the meter/regulator run population emission factor calculated in Equation W-31. Natural gas distribution facilities that do not have above grade transmission-distribution transfer stations are not required to calculate emissions for above grade metering-regulating stations and are not required to report GHG emissions in §98.236(r)(2)(v).

(s) *Offshore petroleum and natural gas production facilities.* 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 estimation study conducted by BOEMRE in compliance with 30 CFR 250.302 through 304.

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

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

(ii) [Reserved]

(2) Offshore production facilities that are not under BOEMRE jurisdiction must use the most recent monitoring methods and calculation methods published by BOEMRE referenced in 30 CFR 250.302 through 250.304 to calculate and report annual emissions (GOADS).

(i) For any calendar year that does not overlap with the most recent BOEMRE emissions study publication, you may report the most recently reported emissions data submitted to demonstrate compliance with this subpart of part 98, with emissions adjusted based on the operating time for the facility relative to operating time in the previous reporting period.

(ii) [Reserved]

(3) If BOEMRE discontinues or delays their data collection effort by more than 4 years, then offshore reporters shall once in every 4 years use the most recent BOEMRE data collection and emissions estimation methods to estimate emissions. These emission estimates would be used to report emissions from the facility sources as required in paragraph (s)(1)(i) of this section.

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

must use the most recent BOEMRE data collection and emissions estimation methods published by BOEMRE referenced in 30 CFR 250.302 through 250.304 to calculate and report emissions.

(t) *GHG volumetric emissions using actual conditions.* If equation parameters in §98.233 are already determined at standard conditions as provided in the introductory text in §98.233, which results in volumetric emissions at standard conditions, then this paragraph does not apply. Calculate volumetric emissions at standard conditions as specified in paragraphs (t)(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 W-33 of this section for conversions of $E_{a,n}$ or conversions of FR_a (whether sub-sonic or sonic).

$$E_{s,n} = \frac{E_{a,n} * (459.67 + T_s) * P_a}{(459.67 + T_a) * P_s * Z_a} \qquad \text{(Eq. W-33)}$$

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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 flowrates under §98.233(g).

$E_{a,n}$ = Natural gas volumetric emissions at actual conditions in cubic feet, except $E_{a,n}$ equals $FR_{a,p}$ for each well p when calculating either subsonic or sonic flowrates under §98.233(g).

T_s = Temperature at standard conditions (60 °F).

T_a = Temperature at actual emission conditions (°F).

P_s = Absolute pressure at standard conditions (14.7 psia).

P_a = Absolute pressure at actual conditions (psia).

Z_a = Compressibility factor at actual conditions for natural gas. You may use either a default compressibility factor of 1, or a site-specific compressibility factor based on actual temperature and pressure conditions.

(2) Calculate GHG volumetric emissions at standard conditions using actual GHG emissions temperature and pressure, and Equation W-34 of this section.

$$E_{s,i} = \frac{E_{a,i} * (459.67 + T_s) * P_a}{(459.67 + T_a) * P_s * Z_a} \qquad \text{(Eq. W-34)}$$

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Where:

$E_{s,i}$ = GHG i volumetric emissions at standard temperature and pressure (STP) 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).

T_a = Temperature at actual emission conditions (°F).

P_s = Absolute pressure at standard conditions (14.7 psia).

P_a = Absolute pressure at actual conditions (psia).

Z_a = Compressibility factor at actual conditions for GHG i.

You may use either a default compressibility factor of 1, or a site-specific compressibility factor based on actual temperature and pressure conditions.

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

(u) *GHG volumetric emissions at standard conditions.* Calculate GHG volumetric emissions at standard conditions as specified in paragraphs (u)(1) and (2) of this section.

(1) Estimate CH_4 and CO_2 emissions from natural gas emissions using Equation W-35 of this section.

$$E_{s,i} = E_{s,n} * M_i \quad \text{(Eq. W-35)}$$

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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 W-35 of this section, the mole fraction, M_i, shall be the annual average mole fraction for each sub-basin category or facility, as specified in paragraphs (u)(2)(i) through (vii) of this section.

(i) *GHG mole fraction in produced natural gas for onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities.* If you have a continuous gas composition analyzer for produced natural gas, you must use an annual average of these values for determining the mole fraction. If you do not have a continuous gas composition analyzer, then you must use an annual average gas composition based on your most recent available analysis of the sub-basin category or facility, as applicable to the emission source.

(ii) 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 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. If you have a continuous gas composition analyzer on feed natural gas, you must use these values for determining the mole fraction. If you do not have a continuous gas composition analyzer, then annual samples must be taken according to methods set forth in §98.234(b).

(iii) *GHG mole fraction in transmission pipeline natural gas that passes through the facility for the onshore natural gas transmission compression industry segment and the onshore natural gas transmission pipeline industry segment.* You may use either a default 95 percent methane and 1 percent carbon dioxide fraction for GHG mole fraction in natural gas or site specific engineering estimates based on best available data.

(iv) *GHG mole fraction in natural gas stored in the underground natural gas storage industry segment.* You may use either a default 95 percent methane and 1 percent carbon dioxide fraction for GHG mole fraction in natural gas or site specific engineering estimates based on best available data.

(v) *GHG mole fraction in natural gas stored in the LNG storage industry segment.* You may use either a default 95 percent methane and 1 percent carbon dioxide fraction for GHG mole fraction in natural gas or site specific engineering estimates based on best available data.

(vi) *GHG mole fraction in natural gas stored in the LNG import and export industry segment.* For export facilities that receive gas from transmission pipelines, you may use either a default 95 percent methane and 1 percent carbon dioxide fraction for GHG mole fraction in natural gas or site specific engineering estimates based on best available data.

(vii) *GHG mole fraction in local distribution pipeline natural gas that passes through the facility for natural gas distribution facilities.* You may use either a default 95 percent methane and 1 percent carbon dioxide fraction for GHG mole fraction in natural gas or site specific engineering estimates based on best available data.

(v) *GHG mass emissions.* Calculate GHG mass emissions in metric tons by converting the GHG volumetric emissions at standard conditions into mass emissions using Equation W-36 of this section.

$$Mass_i = E_{s,i} * \rho_i * 10^{-3} \qquad \text{(Eq. W-36)}$$

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Where:

$Mass_i$ = GHG_i (either CH_4, CO_2, or N_2O) mass emissions in metric tons.

$E_{s,i}$ = GHG_i (either CH_4, CO_2, or N_2O) volumetric emissions at standard conditions, in cubic feet.

ρ_i = Density of GHG_i. Use 0.0526 kg/ft^3 for CO_2 and N_2O, and 0.0192 kg/ft^3 for CH_4 at 60 °F and 14.7 psia.

(w) *EOR injection pump blowdown.* Calculate CO_2 pump blowdown emissions from each EOR injection pump system as follows:

(1) Calculate the total injection pump system volume in cubic feet (including pipelines, manifolds and vessels) between isolation valves.

(2) Retain logs of the number of blowdowns per calendar year.

(3) Calculate the total annual CO_2 emissions from each EOR injection pump system using Equation W-37 of this section:

$$Mass_{CO2} = N * V_v * R_c * GHG_{CO2} * 10^{-3} \quad \text{(Eq. W-37)}$$

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Where:

$Mass_{CO2}$ = Annual EOR injection pump system emissions in metric tons from blowdowns.

N = Number of blowdowns for the EOR injection pump system in the calendar year.

V_v = Total volume in cubic feet of EOR injection pump system chambers (including pipelines, manifolds and vessels) between isolation valves.

R_c = Density of critical phase EOR injection gas in kg/ft^3. You may use an appropriate standard method published by a consensus-based standards organization if such a method exists or you may use an industry standard practice to determine density of super critical EOR injection gas.

GHG_{CO2} = Mass fraction of CO_2 in critical phase injection gas.

1×10^{-3} = Conversion factor from kilograms to metric tons.

(x) *EOR hydrocarbon liquids dissolved CO_2*. Calculate CO_2 emissions downstream of the storage tank from dissolved CO_2 in hydrocarbon liquids produced through EOR operations as follows:

(1) Determine the amount of CO_2 retained in hydrocarbon liquids after flashing in tankage at STP conditions. Annual samples of hydrocarbon liquids downstream of the storage tank must be taken according to methods set forth in §98.234(b) to determine retention of CO_2 in hydrocarbon liquids immediately downstream of the storage tank. Use the annual analysis for the calendar year.

(2) Estimate emissions using Equation W-38 of this section.

$$Mass_{CO2} = S_{hl} * V_{hl} \quad \text{(Eq. W-38)}$$

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Where:

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

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

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

(y) [Reserved]

(z) *Onshore petroleum and natural gas production, onshore petroleum and natural gas gathering and boosting, 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 paragraphs (z)(3) and (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 this part, or is a blend containing one or more fuels listed in Table C-1, calculate emissions according to paragraph (z)(1)(i) of this section. If the fuel combusted is natural gas and is of pipeline quality specification and has a minimum high heat value of 950 Btu per standard cubic foot, use the calculation method described in paragraph (z)(1)(i) of this section and you may use the emission factor provided for natural gas as listed in Table C-1. If the fuel is natural gas, and is not pipeline quality or has a high heat value of less than 950 Btu per standard cubic feet, calculate emissions according to paragraph (z)(2) of this section. If the fuel is field gas, process vent gas, or a blend containing field gas or process vent gas, calculate emissions according to paragraph (z)(2) of this section.

(i) For fuels listed in Table C-1 or a blend containing one or more fuels listed in Table C-1, calculate CO_2, CH_4, and N_2O emissions according to any Tier listed in subpart C of this part. You must follow all applicable calculation requirements for that tier listed in §98.33, any monitoring or QA/QC requirements listed for that tier in §98.34, any missing data procedures specified in §98.35, and any recordkeeping requirements specified in §98.37.

(ii) Emissions from fuel combusted in stationary or portable equipment at onshore petroleum and natural gas production facilities, at onshore petroleum and natural gas gathering and boosting facilities, and at natural gas distribution facilities will be reported according to the requirements specified in §98.236(z) and not according to the reporting requirements specified in subpart C of this part.

(2) For fuel combustion units that combust field gas, process vent gas, a blend containing field gas or process vent gas, or natural gas that is not of pipeline quality or that has a high heat value of less than 950 Btu per standard cubic feet, calculate combustion emissions as follows:

(i) You may use company records to determine the volume of fuel combusted in the unit during the reporting year.

(ii) If you have a continuous gas composition analyzer on fuel to the combustion unit, you must use these compositions for determining the concentration of gas hydrocarbon constituent in the flow of gas to the unit. If you do not have a continuous gas composition analyzer on gas to the combustion unit, you must use the appropriate gas compositions for each stream of hydrocarbons going to the combustion unit as specified in the applicable paragraph in (u)(2) of this section.

(iii) Calculate GHG volumetric emissions at actual conditions using Equations W-39A and W-39B of this section:

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

$$E_{a,CH4} = V_a * (1-\eta) * Y_{CH4} \qquad \text{(Eq. W-39B)}$$

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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 gas sent to combustion unit in actual cubic feet, during the year.

Y_{CO2} = Mole fraction of CO_2 constituent in gas sent to combustion unit.

$E_{a,CH4}$ = Contribution of annual CH_4 emissions from portable or stationary fuel combustion sources in cubic feet, under actual conditions.

η = Fraction of gas combusted for portable and stationary equipment determined using engineering estimation. For internal combustion devices, a default of 0.995 can be used.

Y_j = Mole fraction of gas hydrocarbon constituents 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} = Mole fraction of methane constituent in gas sent to combustion unit.

(iv) Calculate GHG volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(v) Calculate both combustion-related CH_4 and CO_2 mass emissions from volumetric CH_4 and CO_2 emissions using calculation in paragraph (v) of this section.

(vi) Calculate N_2O mass emissions using Equation W-40 of this section.

$$Mass_{N2O} = \left(1 \times 10^{-3}\right) \times Fuel \times HHV \times EF \qquad \text{(Eq. W-40)}$$

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Where:

$Mass_{N2O}$ = Annual N_2O emissions from the combustion of a particular type of fuel (metric tons).

Fuel = Annual mass or volume of the fuel combusted (mass or volume per year, choose appropriately to be consistent with the units of HHV).

HHV = Higher heating value of fuel, mmBtu/unit of fuel (in units consistent with the fuel quantity combusted). For field gas or process vent gas, you may use either a default higher heating value of 1.235×10^{-3} mmBtu/scf or a site-specific higher heating value. For natural gas that is not of pipeline quality or that has a high heat value less than 950 Btu per standard cubic foot, use a site-specific higher heating value.

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 §98.231(a). You 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 the equivalent of 130 horsepower), do not need to report combustion emissions or include these emissions for threshold determination in §98.231(a). You must report the type and number of each internal fuel combustion unit.

[75 FR 74488, Nov. 30, 2010, as amended at 76 FR 80575, Dec. 23, 2011; 77 FR 51490, Aug. 24, 2012; 78 FR 71960, Nov. 29, 2013; 79 FR 70408, Nov. 25, 2014; 80 FR 64284, Oct. 22, 2015; 81 FR 86511, Nov. 30, 2016]

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§98.234 Monitoring and QA/QC requirements.

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

(a) You must use any of the methods described in paragraphs (a)(1) through (5) of this section to conduct leak detection(s) of through-valve leakage from all source types listed in §98.233(k), (o), and (p) that occur during a calendar year. You must use any of the methods described in paragraphs (a)(1) through (7) of this section to conduct leak detection(s) of equipment leaks from components as specified in §98.233(q)(1)(i) that occur during a calendar year. You must use any of the methods described in paragraphs (a)(1) through (5) of this section to conduct leak detection(s) of equipment leaks from components as specified in §98.233(q)(1)(ii) that occur during a calendar year. You must use one of the methods described in paragraph (a)(6) or (7) of this section to conduct leak detection(s) of equipment leaks from components as specified in §98.233(q)(1)(iii). If electing to comply with §98.233(q) as specified in §98.233(q)(1)(iv), you must use any of the methods described in paragraphs (a)(1) through (7) of this section to conduct leak detection(s) of equipment leaks from component types as specified in §98.233(q)(1)(iv) that occur during a calendar year.

(1) *Optical gas imaging instrument as specified in §60.18 of this chapter.* Use an optical gas imaging instrument for equipment leak detection in accordance with 40 CFR part 60, subpart A, §60.18 of the *Alternative work practice for monitoring equipment leaks,* §60.18(i)

(1)(i); §60.18(i)(2)(i) except that the monitoring frequency shall be annual using the detection sensitivity level of 60 grams per hour as stated in 40 CFR Part 60, subpart A, Table 1: *Detection Sensitivity Levels;* §60.18(i)(2)(ii) and (iii) except the gas chosen shall be methane, and §60.18(i)(2)(iv) and (v); §60.18(i)(3); §60.18(i)(4)(i) and (v); including the requirements for daily instrument checks and distances, and excluding requirements for video records. Any emissions detected by the optical gas imaging instrument is a leak unless screened with Method 21 (40 CFR part 60, appendix A-7) monitoring, in which case 10,000 ppm or greater is designated a leak. In addition, you must operate the optical gas imaging instrument to image the source types required by this subpart in accordance with the instrument manufacturer's operating parameters. Unless using methods in paragraph (a)(2) of this section, an optical gas 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.

(2) *Method 21.* Use the equipment leak detection methods in 40 CFR part 60, appendix A-7, Method 21. If using Method 21 monitoring, if an instrument reading of 10,000 ppm or greater is measured, a leak is detected. Inaccessible emissions sources, as defined in 40 CFR part 60, are not exempt from this subpart. If the equipment leak detection methods in this paragraph cannot be used, you must use alternative leak detection devices as described in paragraph (a)(1) 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, you must operate the infrared laser beam illuminated instrument to detect the source types required by this subpart in accordance with the instrument manufacturer's operating parameters.

(4) [Reserved]

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

(6) Optical gas imaging instrument as specified in §60.5397a of this chapter. Use an optical gas imaging instrument for equipment leak detection in accordance with §60.5397a(b), (c)(3), (c)(7), and (e) of this chapter and paragraphs (a)(6)(i) through (iii) of this

section. Unless using methods in paragraph (a)(7) of this section, 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.

(i) For the purposes of this subpart, any visible emissions from a component listed in §98.232 observed by the optical gas imaging instrument is a leak.

(ii) For the purposes of this subpart, the term “fugitive emissions component” in §60.5397a of this chapter means “component.”

(iii) For the purpose of complying with §98.233(q)(1)(iv), the phrase “the collection of fugitive emissions components at well sites and compressor stations” in §60.5397a(b) of this chapter means “the collection of components for which you elect to comply with §98.233(q)(1)(iv).”

(7) Method 21 as specified in §60.5397a of this chapter. Use the equipment leak detection methods in appendix A-7 to part 60 of this chapter, Method 21, in accordance with §60.5397a(b), (c)(8), and (e) of this chapter and paragraphs (a)(7)(i) through (iii) of this section. Inaccessible emissions sources, as defined in part 60 of this chapter, are not exempt from this subpart. If the equipment leak detection methods in this paragraph cannot be used, you must use alternative leak detection devices as described in paragraph (a)(6) of this section to monitor inaccessible equipment leaks.

(i) For the purposes of this subpart, any instrument reading from a component listed in §98.232 of this chapter of 500 ppm or greater using Method 21 is a leak.

(ii) For the purposes of this subpart, the term “fugitive emissions component” in §60.5397a of this chapter means “component.”

(iii) For the purpose of complying with §98.233(q)(1)(iv), the phrase “the collection of fugitive emissions components at well sites and compressor stations” in §60.5397a(b) of this chapter means “the collection of components for which you elect to comply with §98.233(q)(1)(iv).”

(b) You must operate and calibrate all flow meters, composition analyzers and pressure gauges used to measure quantities reported in §98.233 according to the procedures in §98.3(i) and the procedures in paragraph (b) of this section. You may use an appropriate standard method published by a consensus-based standards organization if such a method exists or you may use an industry standard practice. Consensus-based standards organizations include, but are not limited to, the following: ASTM International, the American National Standards Institute (ANSI), the American Gas Association (AGA), the American Society of Mechanical Engineers (ASME), the American Petroleum Institute (API), and the North American Energy Standards Board (NAESB).

(c) Use calibrated bags (also known as vent bags) only where the emissions are at near-atmospheric pressures and below the maximum temperature specified by the vent bag manufacturer such that the 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 §98.233(t).

(4) Estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using the calculations in §98.233(u) and (v).

(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 operating procedures and measurement methods 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 §98.233(t). Estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using the calculations in §98.233(u) and (v).

(4) Calibrate the instrument at 2.5 percent methane with 97.5 percent air and 100 percent CH_4 by using calibrated gas samples and by following manufacturer's instructions for calibration.

(e) Peng Robinson Equation of State means the equation of state defined by Equation W-41 of this section:

$$p = \frac{RT}{V_m - b} - \frac{a\alpha}{V_m^2 + 2bV_m - b^2} \quad \text{(Eq. W-41)}$$

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Where:

p = Absolute pressure.

R = Universal gas constant.

T = Absolute temperature.

V_m = Molar volume.

$$a = \frac{0.45724 R^2 T_c^2}{p_c}$$

$$b = \frac{0.7780 R T_c}{p_c}$$

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

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Where:

ω = Acentric factor of the species.

T_c = Critical temperature.

P_c = Critical pressure.

(f) *Special reporting provisions for best available monitoring methods in reporting year 2015*—(1) *Best available monitoring methods.* From January 1, 2015 to March 31, 2015, for a facility subject to this subpart, you must use the calculation methodologies and equations in §98.233 “Calculating GHG Emissions”, but you may use the best available monitoring method for any parameter for which it is not reasonably feasible to acquire, install, and operate a required piece of monitoring equipment by January 1, 2015 as specified in paragraphs (f)(2) and (3) of this section. Starting no later than April 1, 2015, you must discontinue using best available methods and begin following all applicable monitoring and QA/QC requirements of this part, except as provided in paragraph (f)(4) of this section. Best available monitoring methods means any of the following methods:

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

(ii) Supplier data.

(iii) Engineering calculations.

(iv) Other company records.

(2) *Best available monitoring methods for well-related measurement data.* You may use best available monitoring methods for well-related measurement data identified in paragraphs (f)(2)(i) and (ii) of this section that cannot reasonably be measured according to the monitoring and QA/QC requirements of this subpart.

(i) If Calculation Method 1 for liquids unloading in §98.233(f)(1) was used in calendar year 2014 and will be used again in calendar year 2015, the vented natural gas flow rate for any well in a unique tubing diameter group and pressure group combination that has not been previously measured.

(ii) If using Equation W-10A of this subpart to determine natural gas emissions from completions and workovers for representative wells, the initial and average flowback rates (when using Calculation Method 1 in §98.233(g)(1)(i)) or pressures upstream and downstream of the choke (when using Calculation Method 2 in §98.233(g)(1)(ii)) for any well in a well type combination that has not been previously measured.

(3) *Best available monitoring methods for emissions measurement.* You may use best available monitoring methods for sources listed in paragraphs (f)(3)(i) and (ii) of this section if the required measurement data cannot reasonably be obtained according to the monitoring and QA/QC requirements of this part.

(i) Centrifugal compressor as found measurements of manifolded emissions from groups of centrifugal compressor sources according to §98.233(o)(4) and (5), 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 §98.232(d)(2), (e)(2), (f)(2), (g)(2), and (h)(2).

(ii) Reciprocating compressor as found measurements of manifolded emissions from groups of reciprocating compressor sources according to §98.233(p)(4) and (5), 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 §98.232(d)(1), (e)(1), (f)(1), (g)(1), and (h)(1).

(4) *Requests for extension of the use of best available monitoring methods beyond March 31, 2015.* You may submit a request to the Administrator to use one or more best available monitoring methods for sources listed in paragraphs (f)(2) and (3) of this section beyond March 31, 2015.

(i) *Timing of request.* The extension request must be submitted to EPA no later than January 31, 2015.

(ii) *Content of request.* Requests must contain the following information:

(A) A list of specific source types and parameters for which you are seeking use of best available monitoring methods.

(B) For each specific source type for which you are requesting use of best available monitoring methods, a description of the reasons that the needed equipment could not be obtained and installed before April 1, 2015.

(C) A description of the specific actions you will take to obtain and install the equipment as soon as reasonably feasible and the expected date by which the equipment will be installed and operating.

(iii) *Approval criteria.* To obtain approval to use best available monitoring methods after March 31, 2015, you must submit a request demonstrating to the Administrator's satisfaction that it is not reasonably feasible to acquire, install, and operate a required piece of monitoring equipment by April 1, 2015. The use of best available methods under paragraph (f) of this section will not be approved beyond December 31, 2015.

(g) *Special reporting provisions for best available monitoring methods in reporting year 2016*—(1) *Best available monitoring methods.* From January 1, 2016, to December 31, 2016, you must use the calculation methodologies and equations in §98.233 but you may use the best available monitoring method as described in paragraph (g)(2) of this section for any parameter specified in paragraphs (g)(3) through (6) of this section for which it is not reasonably feasible to acquire, install, and operate a required piece of monitoring equipment by January 1, 2016. Starting no later than January 1, 2017, you must discontinue using best available methods and begin following all applicable monitoring and QA/QC requirements of this part. For onshore petroleum and natural gas production, this paragraph (g)(1) only applies if emissions from well completions and workovers of oil wells with hydraulic fracturing cause your facility to exceed the reporting threshold in §98.231(a)(1).

(2) Best available monitoring methods means any of the following methods:

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

(ii) Supplier data.

(iii) Engineering calculations.

(iv) Other company records.

(3) *Best available monitoring methods for well-related measurement data for oil wells with hydraulic fracturing.* You may use best available monitoring methods for any well-related measurement data that cannot reasonably be measured according to the monitoring and QA/QC requirements of this subpart for venting during well completions and workovers of oil wells with hydraulic fracturing.

(4) *Best available monitoring methods for measurement data for onshore petroleum and natural gas gathering and boosting facilities.* You may use best available monitoring methods for any leak detection and/or measurement data that cannot reasonably be measured according to the monitoring and QA/QC requirements of this subpart for acid gas removal vents as specified in §98.233(d).

(5) *Best available monitoring methods for measurement data for natural gas transmission pipelines.* You may use best available monitoring methods for any measurement data for natural gas transmission pipelines that cannot reasonably be obtained according to the monitoring and QA/QC requirements of this subpart for blowdown vent stacks.

(6) *Best available monitoring methods for specified activity data.* You may use best available monitoring methods for activity data as listed in paragraphs (g)(6)(i) through (iii) of this section that cannot reasonably be obtained according to the monitoring and QA/QC requirements of this subpart for well completions and workovers of oil wells with hydraulic

fracturing, onshore petroleum and natural gas gathering and boosting facilities, or natural gas transmission pipelines.

(i) Cumulative hours of venting, days, or times of operation in §98.233(e), (g), (o), (p), and (r).

(ii) Number of blowdowns, completions, workovers, or other events in §98.233(g) and (i).

(iii) Cumulative volume produced, volume input or output, or volume of fuel used in paragraphs §98.233(d), (e), (j), (n), and (z).

(h) For well venting for liquids unloading, if a monitoring period other than the full calendar year is used to determine the cumulative amount of time in hours of venting for each well (the term "T_p" in Equation W-7A and W-7B of §98.233) or the number of unloading events per well (the term "V_p" in Equations W-8 and W-9 of §98.233), then the monitoring period must begin before February 1 of the reporting year and must not end before December 1 of the reporting year. The end of one monitoring period must immediately precede the start of the next monitoring period for the next reporting year. All production days must be monitored and all venting accounted for.

[75 FR 74488, Nov. 30, 2010, as amended at 76 FR 22827, Apr. 25, 2011; 76 FR 59540, Sept. 27, 2011; 76 FR 80586, Dec. 23, 2011; 78 FR 25395, May 1, 2013; 79 FR 70410, Nov. 25, 2014; 80 FR 64291, Oct. 22, 2015; 81 FR 86514, Nov. 30, 2016]

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§98.235 Procedures for estimating missing data.

Except as specified in §98.233, whenever a value of a parameter is unavailable for a GHG emission calculation required by this subpart (including, but not limited to, if a measuring device malfunctions during unit operation or activity data are not collected), you must follow the procedures specified in paragraphs (a) through (i) of this section, as applicable.

(a) For stationary and portable combustion sources that use the calculation methods of subpart C of this part, you must use the missing data procedures in subpart C of this part.

(b) For each missing value of a parameter that should have been measured quarterly or more frequently using equipment including, but not limited to, a continuous flow meter, composition analyzer, thermocouple, or pressure gauge, you must substitute the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident. If the "after" value is not obtained by the end of the reporting year, you may use the "before" value for the missing data substitution. If, for a particular parameter, no quality-assured data are available prior to the missing data incident, you must use the first quality-assured value obtained after the missing data period as the substitute data value. A value is quality-assured according to the procedures specified in §98.234.

(c) For each missing value of a parameter that should have been measured annually, you must repeat the estimation or measurement activity for those sources as soon as possible, including in the subsequent calendar year if missing data are not discovered until after December 31 of the year in which data are collected, until valid data for reporting are obtained. Data developed and/or collected in a subsequent calendar year to substitute for missing data cannot be used for that subsequent year's emissions estimation. Where missing data procedures are used for the previous year, at least 30 days must separate emissions estimation or measurements for the previous year and emissions estimation or measurements for the current year of data collection.

(d) For each missing value of a parameter that should have been measured biannually (every two years), you must conduct the estimation or measurement activity for those sources as soon as possible in the subsequent calendar year if the estimation or measurement was not made in the appropriate year (first year of data collection and every two years thereafter), until valid data for reporting are obtained. Data developed and/or collected in a subsequent calendar year to substitute for missing data cannot be used to alternate or postpone subsequent biannual emissions estimations or measurements.

(e) For the first 6 months of required data collection, facilities that become newly subject to this subpart W may use best engineering estimates for any data that cannot reasonably be measured or obtained according to the requirements of this subpart.

(f) For the first 6 months of required data collection, facilities that are currently subject to this subpart W and that acquire new sources from another facility that were not previously subject to this subpart W may use best engineering estimates for any data related to those newly acquired sources that cannot reasonably be measured or obtained according to the requirements of this subpart.

(g) Unless addressed in another paragraph of this section, for each missing value of any activity data, you must substitute data value(s) using the best available estimate(s) of the parameter(s), based on all applicable and available process or other data (including, but not limited to, processing rates, operating hours).

(h) You must report information for all measured and substitute values of a parameter, and the procedures used to substitute an unavailable value of a parameter per the requirements in §98.236(bb).

(i) You must follow recordkeeping requirements listed in §98.237(f).

[79 FR 70410, Nov. 25, 2014]

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§98.236 Data reporting requirements.

In addition to the information required by §98.3(c), each annual report must contain reported emissions and related information as specified in this section. Reporters that use a flow or volume measurement system that corrects to standard conditions as provided in the introductory text in §98.233 for data elements that are otherwise required to be determined at actual conditions, report gas volumes at standard conditions rather the gas volumes at actual conditions and report the standard temperature and pressure used by the measurement system rather than the actual temperature and pressure.

(a) The annual report must include the information specified in paragraphs (a)(1) through (10) of this section for each applicable industry segment. The annual report must also include annual emissions totals, in metric tons of each GHG, for each applicable industry segment listed in paragraphs (a)(1) through (10), and each applicable emission source listed in paragraphs (b) through (z) of this section.

(1) *Onshore petroleum and natural gas production.* For the equipment/activities specified in paragraphs (a)(1)(i) through (xvii) of this section, report the information specified in the applicable paragraphs of this section.

(i) *Natural gas pneumatic devices.* Report the information specified in paragraph (b) of this section.

(ii) *Natural gas driven pneumatic pumps.* Report the information specified in paragraph (c) of this section.

(iii) *Acid gas removal units.* Report the information specified in paragraph (d) of this section.

(iv) *Dehydrators.* Report the information specified in paragraph (e) of this section.

(v) *Liquids unloading.* Report the information specified in paragraph (f) of this section.

(vi) *Completions and workovers with hydraulic fracturing.* Report the information specified in paragraph (g) of this section.

(vii) *Completions and workovers without hydraulic fracturing.* Report the information specified in paragraph (h) of this section.

(viii) *Onshore production storage tanks.* Report the information specified in paragraph (j) of this section.

(ix) *Well testing.* Report the information specified in paragraph (l) of this section.

(x) *Associated natural gas.* Report the information specified in paragraph (m) of this section.

(xi) *Flare stacks.* Report the information specified in paragraph (n) of this section.

(xii) *Centrifugal compressors.* Report the information specified in paragraph (o) of this section.

(xiii) *Reciprocating compressors.* Report the information specified in paragraph (p) of this section.

(xiv) Equipment leak surveys. Report the information specified in paragraph (q) of this section.

(xv) *Equipment leaks by population count.* Report the information specified in paragraph (r) of this section.

(xvi) *EOR injection pumps.* Report the information specified in paragraph (w) of this section.

(xvii) *EOR hydrocarbon liquids.* Report the information specified in paragraph (x) of this section.

(xviii) *Combustion equipment.* Report the information specified in paragraph (z) of this section.

(2) *Offshore petroleum and natural gas production.* Report the information specified in paragraph (s) of this section.

(3) *Onshore natural gas processing.* For the equipment/activities specified in paragraphs (a)(3)(i) through (vii) of this section, report the information specified in the applicable paragraphs of this section.

(i) *Acid gas removal units.* Report the information specified in paragraph (d) of this section.

(ii) *Dehydrators.* Report the information specified in paragraph (e) of this section.

(iii) *Blowdown vent stacks.* Report the information specified in paragraph (i) of this section.

(iv) *Flare stacks.* Report the information specified in paragraph (n) of this section.

(v) *Centrifugal compressors.* Report the information specified in paragraph (o) of this section.

(vi) *Reciprocating compressors.* Report the information specified in paragraph (p) of this section.

(vii) *Equipment leak surveys.* Report the information specified in paragraph (q) of this section.

(4) *Onshore natural gas transmission compression.* For the equipment/activities specified in paragraphs (a)(4)(i) through (vii) of this section, report the information specified in the applicable paragraphs of this section.

(i) *Natural gas pneumatic devices.* Report the information specified in paragraph (b) of this section.

(ii) *Blowdown vent stacks.* Report the information specified in paragraph (i) of this section.

(iii) *Transmission storage tanks.* Report the information specified in paragraph (k) of this section.

(iv) *Flare stacks.* Report the information specified in paragraph (n) of this section.

(v) *Centrifugal compressors.* Report the information specified in paragraph (o) of this section.

(vi) *Reciprocating compressors.* Report the information specified in paragraph (p) of this section.

(vii) *Equipment leak surveys.* Report the information specified in paragraph (q) of this section.

(5) *Underground natural gas storage.* For the equipment/activities specified in paragraphs (a)(5)(i) through (vi) of this section, report the information specified in the applicable paragraphs of this section.

(i) *Natural gas pneumatic devices.* Report the information specified in paragraph (b) of this section.

(ii) *Flare stacks.* Report the information specified in paragraph (n) of this section.

(iii) *Centrifugal compressors.* Report the information specified in paragraph (o) of this section.

(iv) *Reciprocating compressors.* Report the information specified in paragraph (p) of this section.

(v) *Equipment leak surveys.* Report the information specified in paragraph (q) of this section.

(vi) *Equipment leaks by population count.* Report the information specified in paragraph (r) of this section.

(6) *LNG storage.* For the equipment/activities specified in paragraphs (a)(6)(i) through (v) of this section, report the information specified in the applicable paragraphs of this section.

(i) *Flare stacks.* Report the information specified in paragraph (n) of this section.

(ii) *Centrifugal compressors.* Report the information specified in paragraph (o) of this section.

(iii) *Reciprocating compressors.* Report the information specified in paragraph (p) of this section.

(iv) *Equipment leak surveys.* Report the information specified in paragraph (q) of this section.

(v) *Equipment leaks by population count.* Report the information specified in paragraph (r) of this section.

(7) *LNG import and export equipment.* For the equipment/activities specified in paragraphs (a)(7)(i) through (vi) of this section, report the information specified in the applicable paragraphs of this section.

(i) *Blowdown vent stacks.* Report the information specified in paragraph (i) of this section.

(ii) *Flare stacks.* Report the information specified in paragraph (n) of this section.

(iii) *Centrifugal compressors.* Report the information specified in paragraph (o) of this section.

(iv) *Reciprocating compressors.* Report the information specified in paragraph (p) of this section.

(v) *Equipment leak surveys.* Report the information specified in paragraph (q) of this section.

(vi) *Equipment leaks by population count.* Report the information specified in paragraph (r) of this section.

(8) *Natural gas distribution.* For the equipment/activities specified in paragraphs (a)(8)(i) through (iii) of this section, report the information specified in the applicable paragraphs of this section.

(i) *Combustion equipment.* Report the information specified in paragraph (z) of this section.

(ii) *Equipment leak surveys.* Report the information specified in paragraph (q) of this section.

(iii) *Equipment leaks by population count.* Report the information specified in paragraph (r) of this section.

(9) *Onshore petroleum and natural gas gathering and boosting.* For the equipment/activities specified in paragraphs (a)(9)(i) through (xi) of this section, report the information specified in the applicable paragraphs of this section.

(i) *Natural gas pneumatic devices.* Report the information specified in paragraph (b) of this section.

(ii) *Natural gas driven pneumatic pumps.* Report the information specified in paragraph (c) of this section.

(iii) *Acid gas removal units.* Report the information specified in paragraph (d) of this section.

(iv) *Dehydrators.* Report the information specified in paragraph (e) of this section.

(v) *Blowdown vent stacks.* Report the information specified in paragraph (i) of this section.

(vi) *Storage tanks.* Report the information specified in paragraph (j) of this section.

(vii) *Flare stacks.* Report the information specified in paragraph (n) of this section.

(viii) *Centrifugal compressors.* Report the information specified in paragraph (o) of this section.

(ix) *Reciprocating compressors.* Report the information specified in paragraph (p) of this section.

(x) Equipment leak surveys. Report the information specified in paragraph (q) of this section.

(xi) *Equipment leaks by population count.* Report the information specified in paragraph (r) of this section.

(xii) *Combustion equipment.* Report the information specified in paragraph (z) of this section.

(10) *Onshore natural gas transmission pipeline.* For blowdown vent stacks, report the information specified in paragraph (i) of this section.

(b) *Natural gas pneumatic devices.* You must indicate whether the facility contains the following types of equipment: Continuous high bleed natural gas pneumatic devices, continuous low bleed natural gas pneumatic devices, and intermittent bleed natural gas pneumatic devices. If the facility contains any continuous high bleed natural gas pneumatic devices, continuous low bleed natural gas pneumatic devices, or intermittent bleed natural gas pneumatic devices, then you must report the information specified in paragraphs (b)(1) through (b)(4) of this section.

(1) The number of natural gas pneumatic devices as specified in paragraphs (b)(1)(i) and (ii) of this section.

(i) The total number of devices of each type, determined according to §98.233(a)(1) and (2).

(ii) If the reported value in paragraph (b)(1)(i) of this section is an estimated value determined according to §98.233(a)(2), then you must report the information specified in paragraphs (b)(1)(ii)(A) through (C) of this section.

(A) The number of devices of each type reported in paragraph (b)(1)(i) of this section that are counted.

(B) The number of devices of each type reported in paragraph (b)(1)(i) of this section that are estimated (not counted).

(C) Whether the calendar year is the first calendar year of reporting or the second calendar year of reporting.

(2) For each type of pneumatic device, the estimated average number of hours in the calendar year that the natural gas pneumatic devices reported in paragraph (b)(1)(i) of this section were operating in the calendar year ("T_t" in Equation W-1 of this subpart).

(3) Annual CO_2 emissions, in metric tons CO_2, for the natural gas pneumatic devices combined, calculated using Equation W-1 of this subpart and §98.233(a)(4), and reported in paragraph (b)(1)(i) of this section.

(4) Annual CH_4 emissions, in metric tons CH_4, for the natural gas pneumatic devices combined, calculated using Equation W-1 of this subpart and §98.233(a)(4), and reported in paragraph (b)(1)(i) of this section.

(c) *Natural gas driven pneumatic pumps.* You must indicate whether the facility has any natural gas driven pneumatic pumps. If the facility contains any natural gas driven pneumatic pumps, then you must report the information specified in paragraphs (c)(1) through (4) of this section.

(1) Count of natural gas driven pneumatic pumps.

(2) Average estimated number of hours in the calendar year the pumps were operational ("T" in Equation W-2 of this subpart).

(3) Annual CO_2 emissions, in metric tons CO_2, for all natural gas driven pneumatic pumps combined, calculated according to §98.233(c)(1) and (2).

(4) Annual CH_4 emissions, in metric tons CH_4, for all natural gas driven pneumatic pumps combined, calculated according to §98.233(c)(1) and (2).

(d) *Acid gas removal units.* You must indicate whether your facility has any acid gas removal units that vent directly to the atmosphere, to a flare or engine, or to a sulfur recovery plant. If your facility contains any acid gas removal units that vent directly to the atmosphere, to a flare or engine, or to a sulfur recovery plant, then you must report the information specified in paragraphs (d)(1) and (2) of this section.

(1) You must report the information specified in paragraphs (d)(1)(i) through (vi) of this section for each acid gas removal unit.

(i) A unique name or ID number for the acid gas removal unit. For the onshore petroleum and natural gas production and the onshore petroleum and natural gas gathering and boosting industry segments, a different name or ID may be used for a single acid gas removal unit for each location it operates at in a given year.

(ii) Total feed rate entering 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.

(iii) The calculation method used to calculate CO_2 emissions from the acid gas removal unit, as specified in §98.233(d).

(iv) Whether any CO_2 emissions from the acid gas removal unit are recovered and transferred outside the facility, as specified in §98.233(d)(11). If any CO_2 emissions from the acid gas removal unit were recovered and transferred outside the facility, then you must report the annual quantity of CO_2, in metric tons CO_2, that was recovered and transferred outside the facility under subpart PP of this part.

(v) Annual CO_2 emissions, in metric tons CO_2, from the acid gas removal unit, calculated using any one of the calculation methods specified in §98.233(d) and as specified in §98.233(d)(10) and (11).

(vi) Sub-basin ID that best represents the wells supplying gas to the unit (for the onshore petroleum and natural gas production industry segment only) or name of the county that best represents the equipment supplying gas to the unit (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(2) You must report information specified in paragraphs (d)(2)(i) through (iii) of this section, applicable to the calculation method reported in paragraph (d)(1)(iii) of this section, for each acid gas removal unit.

(i) If you used Calculation Method 1 or Calculation Method 2 as specified in §98.233(d) to calculate CO_2 emissions from the acid gas removal unit, then you must report the information specified in paragraphs (d)(2)(i)(A) and (B) of this section.

(A) Annual average volumetric fraction of CO_2 in the vent gas exiting the acid gas removal unit.

(B) Annual volume of gas vented from the acid gas removal unit, in cubic feet.

(ii) If you used Calculation Method 3 as specified in §98.233(d) to calculate CO_2 emissions from the acid gas removal unit, then you must report the information specified in paragraphs (d)(2)(ii)(A) through (D) of this section.

(A) Indicate which equation was used (Equation W-4A or W-4B).

(B) Annual average volumetric fraction of CO_2 in the natural gas flowing out of the acid gas removal unit, as specified in Equation W-4A or Equation W-4B of this subpart.

(C) Annual average volumetric fraction of CO_2 content in natural gas flowing into the acid gas removal unit, as specified in Equation W-4A or Equation W-4B of this subpart.

(D) The natural gas flow rate used, as specified in Equation W-4A of this subpart, reported as either total annual volume of natural gas flow into the acid gas removal unit in cubic feet at actual conditions; or total annual volume of natural gas flow out of the acid gas removal unit, as specified in Equation W-4B of this subpart, in cubic feet at actual conditions.

(iii) If you used Calculation Method 4 as specified in §98.233(d) to calculate CO_2 emissions from the acid gas removal unit, then you must report the information specified in paragraphs (d)(2)(iii)(A) through (L) of this section, as applicable to the simulation software package used.

(A) The name of the simulation software package used.

(B) Natural gas feed temperature, in degrees Fahrenheit.

(C) Natural gas feed pressure, in pounds per square inch.

(D) Natural gas flow rate, in standard cubic feet per minute.

(E) Acid gas content of the feed natural gas, in mole percent.

(F) Acid gas content of the outlet natural gas, in mole percent.

(G) Unit operating hours, excluding downtime for maintenance or standby, in hours per year.

(H) Exit temperature of the natural gas, in degrees Fahrenheit.

(I) Solvent pressure, in pounds per square inch.

(J) Solvent temperature, in degrees Fahrenheit.

(K) Solvent circulation rate, in gallons per minute.

(L) Solvent weight, in pounds per gallon.

(e) *Dehydrators.* You must indicate whether your facility contains any of the following equipment: Glycol dehydrators with an annual average daily natural gas throughput greater than or equal to 0.4 million standard cubic feet per day, glycol dehydrators with an annual average daily natural gas throughput less than 0.4 million standard cubic feet per day, and dehydrators that use desiccant. If your facility contains any of the equipment listed in this paragraph (e), then you must report the applicable information in paragraphs (e)(1) through (3).

(1) For each glycol dehydrator that has an annual average daily natural gas throughput greater than or equal to 0.4 million standard cubic feet per day (as specified in §98.233(e)

(1)), you must report the information specified in paragraphs (e)(1)(i) through (xviii) of this section for the dehydrator.

(i) A unique name or ID number for the dehydrator. For the onshore petroleum and natural gas production and the onshore petroleum and natural gas gathering and boosting industry segments, a different name or ID may be used for a single dehydrator for each location it operates at in a given year.

(ii) Dehydrator feed natural gas flow rate, in million standard cubic feet per day, determined by engineering estimate based on best available data.

(iii) Dehydrator feed natural gas water content, in pounds per million standard cubic feet.

(iv) Dehydrator outlet natural gas water content, in pounds per million standard cubic feet.

(v) Dehydrator absorbent circulation pump type (*e.g.,* natural gas pneumatic, air pneumatic, or electric).

(vi) Dehydrator absorbent circulation rate, in gallons per minute.

(vii) Type of absorbent (*e.g.,* triethylene glycol (TEG), diethylene glycol (DEG), or ethylene glycol (EG)).

(viii) Whether stripper gas is used in dehydrator.

(ix) Whether a flash tank separator is used in dehydrator.

(x) Total time the dehydrator is operating, in hours.

(xi) Temperature of the wet natural gas, in degrees Fahrenheit.

(xii) Pressure of the wet natural gas, in pounds per square inch gauge.

(xiii) Mole fraction of CH_4 in wet natural gas.

(xiv) Mole fraction of CO_2 in wet natural gas.

(xv) Whether any dehydrator emissions are vented to a vapor recovery device.

(xvi) Whether any dehydrator emissions are vented to a flare or regenerator firebox/fire tubes. If any emissions are vented to a flare or regenerator firebox/fire tubes, report the information specified in paragraphs (e)(1)(xvi)(A) through (C) of this section for these emissions from the dehydrator.

(A) Annual CO_2 emissions, in metric tons CO_2, for the dehydrator, calculated according to §98.233(e)(6).

(B) Annual CH_4 emissions, in metric tons CH_4, for the dehydrator, calculated according to §98.233(e)(6).

(C) Annual N_2O emissions, in metric tons N_2O, for the dehydrator, calculated according to §98.233(e)(6).

(xvii) Whether any dehydrator emissions are vented to the atmosphere without being routed to a flare or regenerator firebox/fire tubes. If any emissions are not routed to a flare or regenerator firebox/fire tubes, then you must report the information specified in paragraphs (e)(1)(xvii)(A) and (B) of this section for those emissions from the dehydrator.

(A) Annual CO_2 emissions, in metric tons CO_2, for the dehydrator when not venting to a flare or regenerator firebox/fire tubes, calculated according to §98.233(e)(1), and, if applicable, (e)(5).

(B) Annual CH_4 emissions, in metric tons CH_4, for the dehydrator when not venting to a flare or regenerator firebox/fire tubes, calculated according to §98.233(e)(1) and, if applicable, (e)(5).

(xviii) Sub-basin ID that best represents the wells supplying gas to the dehydrator (for the onshore petroleum and natural gas production industry segment only) or name of the county that best represents the equipment supplying gas to the dehydrator (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(2) For glycol dehydrators with an annual average daily natural gas throughput less than 0.4 million standard cubic feet per day (as specified in §98.233(e)(2)), you must report the information specified in paragraphs (e)(2)(i) through (v) of this section for the entire facility.

(i) The total number of dehydrators at the facility.

(ii) Whether any dehydrator emissions were vented to a vapor recovery device. If any dehydrator emissions were vented to a vapor recovery device, then you must report the total number of dehydrators at the facility that vented to a vapor recovery device.

(iii) Whether any dehydrator emissions were vented to a control device other than a vapor recovery device or a flare or regenerator firebox/fire tubes. If any dehydrator emissions were vented to a control device(s) other than a vapor recovery device or a flare or regenerator firebox/fire tubes, then you must specify the type of control device(s) and the total number of dehydrators at the facility that were vented to each type of control device.

(iv) Whether any dehydrator emissions were vented to a flare or regenerator firebox/fire tubes. If any dehydrator emissions were vented to a flare or regenerator firebox/fire tubes, then you must report the information specified in paragraphs (e)(2)(iv)(A) through (D) of this section.

(A) The total number of dehydrators venting to a flare or regenerator firebox/fire tubes.

(B) Annual CO_2 emissions, in metric tons CO_2, for the dehydrators reported in paragraph (e)(2)(iv)(A) of this section, calculated according to §98.233(e)(6).

(C) Annual CH_4 emissions, in metric tons CH_4, for the dehydrators reported in paragraph (e)(2)(iv)(A) of this section, calculated according to §98.233(e)(6).

(D) Annual N_2O emissions, in metric tons N_2O, for the dehydrators reported in paragraph (e)(2)(iv)(A) of this section, calculated according to §98.233(e)(6).

(v) For dehydrator emissions that were not vented to a flare or regenerator firebox/fire tubes, report the information specified in paragraphs (e)(2)(v)(A) and (B) of this section.

(A) Annual CO_2 emissions, in metric tons CO_2, for emissions from all dehydrators reported in paragraph (e)(2)(i) of this section that were not vented to a flare or regenerator firebox/fire tubes, calculated according to §98.233(e)(2), (e)(4), and, if applicable, (e)(5), where emissions are added together for all such dehydrators.

(B) Annual CH_4 emissions, in metric tons CH_4, for emissions from all dehydrators reported in paragraph (e)(2)(i) of this section that were not vented to a flare or regenerator firebox/fire tubes, calculated according to §98.233(e)(2), (e)(4), and, if applicable, (e)(5), where emissions are added together for all such dehydrators.

(3) For dehydrators that use desiccant (as specified in §98.233(e)(3)), you must report the information specified in paragraphs (e)(3)(i) through (iii) of this section for the entire facility.

(i) The same information specified in paragraphs (e)(2)(i) through (iv) of this section for glycol dehydrators, and report the information under this paragraph for dehydrators that use desiccant.

(ii) Annual CO_2 emissions, in metric tons CO_2, for emissions from all desiccant dehydrators reported under paragraph (e)(3)(i) of this section that are not venting to a flare or regenerator firebox/fire tubes, calculated according to §98.233(e)(3), (e)(4), and, if applicable, (e)(5), and summing for all such dehydrators.

(iii) Annual CH_4 emissions, in metric tons CH_4, for emissions from all desiccant dehydrators reported in paragraph (e)(3)(i) of this section that are not venting to a flare or regenerator firebox/fire tubes, calculated according to §98.233(e)(3), (e)(4), and, if applicable, (e)(5), and summing for all such dehydrators.

(f) *Liquids unloading.* You must indicate whether well venting for liquids unloading occurs at your facility, and if so, which methods (as specified in §98.233(f)) were used to calculate emissions. If your facility performs well venting for liquids unloading and uses Calculation Method 1, then you must report the information specified in paragraph (f)(1) of this section. If the facility performs liquids unloading and uses Calculation Method 2 or 3, then you must report the information specified in paragraph (f)(2) of this section.

(1) For each sub-basin and well tubing diameter and pressure group for which you used Calculation Method 1 to calculate natural gas emissions from well venting for liquids unloading, report the information specified in paragraphs (f)(1)(i) through (xii) of this section. Report information separately for wells with plunger lifts and wells without plunger lifts.

(i) Sub-basin ID.

(ii) Well tubing diameter and pressure group ID and a list of the well ID numbers associated with each sub-basin and well tubing diameter and pressure group ID.

(iii) Plunger lift indicator.

(iv) Count of wells vented to the atmosphere for the sub-basin/well tubing diameter and pressure group.

(v) Percentage of wells for which the monitoring period used to determine the cumulative amount of time venting was not the full calendar year.

(vi) Cumulative amount of time wells were vented (sum of "T_p" from Equation W-7A or W-7B of this subpart), in hours.

(vii) Cumulative number of unloadings vented to the atmosphere for each well, aggregated across all wells in the sub-basin/well tubing diameter and pressure group.

(viii) Annual natural gas emissions, in standard cubic feet, from well venting for liquids unloading, calculated according to §98.233(f)(1).

(ix) Annual CO_2 emissions, in metric tons CO_2, from well venting for liquids unloading, calculated according to §98.233(f)(1) and (4).

(x) Annual CH_4 emissions, in metric tons CH_4, from well venting for liquids unloading, calculated according to §98.233(f)(1) and (4).

(xi) For each well tubing diameter group and pressure group combination, you must report the information specified in paragraphs (f)(1)(xi)(A) through (E) of this section for each individual well not using a plunger lift that was tested during the year.

(A) Well ID number of tested well.

(B) Casing pressure, in pounds per square inch absolute.

(C) Internal casing diameter, in inches.

(D) Measured depth of the well, in feet.

(E) Average flow rate of the well venting over the duration of the liquids unloading, in standard cubic feet per hour.

(xii) For each well tubing diameter group and pressure group combination, you must report the information specified in paragraphs (f)(1)(xii)(A) through (E) of this section for each individual well using a plunger lift that was tested during the year.

(A) Well ID number.

(B) The tubing pressure, in pounds per square inch absolute.

(C) The internal tubing diameter, in inches.

(D) Measured depth of the well, in feet.

(E) Average flow rate of the well venting over the duration of the liquids unloading, in standard cubic feet per hour.

(2) For each sub-basin for which you used Calculation Method 2 or 3 (as specified in §93.233(f)) to calculate natural gas emissions from well venting for liquids unloading, you must report the information in (f)(2)(i) through (x) of this section. Report information separately for each calculation method.

(i) Sub-basin ID and a list of the well ID numbers associated with each sub-basin.

(ii) Calculation method.

(iii) Plunger lift indicator.

(iv) Number of wells vented to the atmosphere.

(v) Cumulative number of unloadings vented to the atmosphere for each well, aggregated across all wells.

(vi) Annual natural gas emissions, in standard cubic feet, from well venting for liquids unloading, calculated according to §98.233(f)(2) or (3), as applicable.

(vii) Annual CO_2 emissions, in metric tons CO_2, from well venting for liquids unloading, calculated according to §98.233(f)(2) or (3), as applicable, and §98.233(f)(4).

(viii) Annual CH_4 emissions, in metric tons CH_4, from well venting for liquids unloading, calculated according to §98.233(f)(2) or (3), as applicable, and §98.233(f)(4).

(ix) For wells without plunger lifts, the average internal casing diameter, in inches.

(x) For wells with plunger lifts, the average internal tubing diameter, in inches.

(g) *Completions and workovers with hydraulic fracturing.* You must indicate whether your facility had any well completions or workovers with hydraulic fracturing during the calendar year. If your facility had well completions or workovers with hydraulic fracturing during the calendar year, then you must report information specified in paragraphs (g)(1) through (10) of this section, for each sub-basin and well type combination. Report information separately for completions and workovers.

(1) Sub-basin ID and a list of the well ID numbers associated with each sub-basin that had completions or workovers with hydraulic fracturing during the calendar year.

(2) Well type combination (horizontal or vertical, gas well or oil well).

(3) Number of completions or workovers in the sub-basin and well type combination category.

(4) Calculation method used.

(5) If you used Equation W-10A of §98.233 to calculate annual volumetric total gas emissions, then you must report the information specified in paragraphs (g)(5)(i) through (iii) of this section.

(i) Cumulative gas flowback time, in hours, from when gas is first detected until sufficient quantities are present to enable separation, and the cumulative flowback time, in hours, after sufficient quantities of gas are present to enable separation (sum of "$T_{p,i}$" and sum of "$T_{p,s}$" values used in Equation W-10A of §98.233). You may delay the reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells included in this number. If you elect to delay reporting of this data element, you must report by the date specified in §98.236(cc) the total number of hours of flowback from all wells during completions or workovers and the well ID number(s) for the well(s) included in the number.

(ii) For the measured well(s), the flowback rate, in standard cubic feet per hour (average of "$FR_{s,p}$" values used in Equation W-12A of §98.233), and the well ID numbers of the wells for which it is measured. You may delay the reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells that can be used for the measurement. If you elect to delay reporting of this data element, you must report by the date specified in §98.236(cc) the measured flowback rate during well completion or workover and the well ID number(s) for the well(s) included in the measurement.

(iii) If you used Equation W-12C of §98.233 to calculate the average gas production rate for an oil well, then you must report the information specified in paragraphs (g)(5)(iii)(A) and (B) of this section.

(A) Gas to oil ratio for the well in standard cubic feet of gas per barrel of oil ("GOR_p" in Equation W-12C of §98.233). You may delay the reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells that can be used for the measurement. If you elect to delay reporting of this data element, you must report by the date specified in §98.236(cc) the gas to oil ratio for the well and the well ID number for the well.

(B) Volume of oil produced during the first 30 days of production after completions of each newly drilled well or well workover using hydraulic fracturing, in barrels ("V_p" in Equation W-12C of §98.233). You may delay the reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells that can be used for the measurement. If you elect to delay reporting of this data element, you must report by the date specified in §98.236(cc) the volume of oil produced during the first 30 days of production after well completion or workover and the well ID number for the well.

(6) If you used Equation W-10B of §98.233 to calculate annual volumetric total gas emissions, then you must report the information specified in paragraphs (g)(6)(i) through (iii) of this section.

(i) Vented natural gas volume, in standard cubic feet, for each well in the sub-basin ("$FV_{s,p}$" in Equation W-10B of §98.233).

(ii) Flow rate at the beginning of the period of time when sufficient quantities of gas are present to enable separation, in standard cubic feet per hour, for each well in the sub-basin ("$FR_{p,i}$" in Equation W-10B of §98.233).

(iii) The well ID number for which vented natural gas volume was measured.

(7) Annual gas emissions, in standard cubic feet ("$E_{s,n}$" in Equation W-10A or W-10B).

(8) Annual CO_2 emissions, in metric tons CO_2.

(9) Annual CH_4 emissions, in metric tons CH_4.

(10) If the well emissions were vented to a flare, then you must report the total N_2O emissions, in metric tons N_2O.

(h) *Completions and workovers without hydraulic fracturing.* You must indicate whether the facility had any gas well completions without hydraulic fracturing or any gas well workovers without hydraulic fracturing, and if the activities occurred with or without flaring. If the facility had gas well completions or workovers without hydraulic fracturing, then you must report the information specified in paragraphs (h)(1) through (4) of this section, as applicable.

(1) For each sub-basin with gas well completions without hydraulic fracturing and without flaring, report the information specified in paragraphs (h)(1)(i) through (vi) of this section.

(i) Sub-basin ID and a list of the well ID numbers associated with each sub-basin for gas well completions without hydraulic fracturing and without flaring.

(ii) Number of well completions that vented gas directly to the atmosphere without flaring.

(iii) Total number of hours that gas vented directly to the atmosphere during venting for all completions in the sub-basin category (the sum of all "T_p" for completions that vented to the atmosphere as used in Equation W-13B).

the atmosphere as used in Equation W-13B).

(iv) Average daily gas production rate for all completions without hydraulic fracturing in the sub-basin without flaring, in standard cubic feet per hour (average of all "V_p" used in Equation W-13B of §98.233). You may delay reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells that can be used for the measurement. If you elect to delay reporting of this data element, you must report by the date specified in §98.236(cc) the measured average daily gas production rate for all wells during completions and the well ID number(s) for the well(s) included in the measurement.

(v) Annual CO_2 emissions, in metric tons CO_2, that resulted from completions venting gas directly to the atmosphere ("$E_{s,p}$" from Equation W-13B for completions that vented directly to the atmosphere, converted to mass emissions according to §98.233(h)(1)).

(vi) Annual CH_4 emissions, in metric tons CH_4, that resulted from completions venting gas directly to the atmosphere ("$E_{s,p}$" from Equation W-13B for completions that vented directly to the atmosphere, converted to mass emissions according to §98.233(h)(1)).

(2) For each sub-basin with gas well completions without hydraulic fracturing and with flaring, report the information specified in paragraphs (h)(2)(i) through (vii) of this section.

(i) Sub-basin ID and a list of the well ID numbers associated with each sub-basin for gas well completions without hydraulic fracturing and with flaring.

(ii) Number of well completions that flared gas.

(iii) Total number of hours that gas vented to a flare during venting for all completions in the sub-basin category (the sum of all "T_p" for completions that vented to a flare from Equation W-13B).

(iv) Average daily gas production rate for all completions without hydraulic fracturing in the sub-basin with flaring, in standard cubic feet per hour (the average of all "V_p" from Equation W-13B of §98.233). You may delay reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells that can be used for the measurement. If you elect to delay reporting of this data element, you must report by the date specified in §98.236(cc) the measured average daily gas production rate for all wells during completions and the well ID number(s) for the well(s) included in the measurement.

(v) Annual CO_2 emissions, in metric tons CO_2, that resulted from completions that flared gas calculated according to §98.233(h)(2).

(vi) Annual CH_4 emissions, in metric tons CH_4, that resulted from completions that flared gas calculated according to §98.233(h)(2).

(vii) Annual N_2O emissions, in metric tons N_2O, that resulted from completions that flared gas calculated according to §98.233(h)(2).

(3) For each sub-basin with gas well workovers without hydraulic fracturing and without flaring, report the information specified in paragraphs (h)(3)(i) through (iv) of this section.

(i) Sub-basin ID and a list of the well ID numbers associated with each sub-basin for gas well workovers without hydraulic fracturing and without flaring.

(ii) Number of workovers that vented gas to the atmosphere without flaring.

(iii) Annual CO_2 emissions, in metric tons CO_2 per year, that resulted from workovers venting gas directly to the atmosphere ("$E_{s,wo}$" in Equation W-13A for workovers that vented directly to the atmosphere, converted to mass emissions as specified in §98.233(h)(1)).

(iv) Annual CH_4 emissions, in metric tons CH_4 per year, that resulted from workovers venting gas directly to the atmosphere ("$E_{s,wo}$" in Equation W-13A for workovers that vented directly to the atmosphere, converted to mass emissions as specified in §98.233(h)(1)).

(4) For each sub-basin with gas well workovers without hydraulic fracturing and with flaring, report the information specified in paragraphs (h)(4)(i) through (v) of this section.

(i) Sub-basin ID and a list of well ID numbers associated with each sub-basin for gas well workovers without hydraulic fracturing and with flaring.

(ii) Number of workovers that flared gas.

(iii) Annual CO_2 emissions, in metric tons CO_2 per year, that resulted from workovers that flared gas calculated as specified in §98.233(h)(2).

(iv) Annual CH_4 emissions, in metric tons CH_4 per year, that resulted from workovers that flared gas, calculated as specified in §98.233(h)(2).

(v) Annual N_2O emissions, in metric tons N_2O per year, that resulted from workovers that flared gas calculated as specified in §98.233(h)(2).

(i) *Blowdown vent stacks.* You must indicate whether your facility has blowdown vent stacks. If your facility has blowdown vent stacks, then you must report whether emissions were calculated by equipment or event type or by using flow meters or a combination of both. If you calculated emissions by equipment or event type for any blowdown vent stacks, then you must report the information specified in paragraph (i)(1) of this section considering, in aggregate, all blowdown vent stacks for which emissions were calculated by equipment or event type. If you calculated emissions using flow meters for any blowdown vent stacks, then you must report the information specified in paragraph (i)(2) of this section considering, in aggregate, all blowdown vent stacks for which emissions were calculated using flow meters. For the onshore natural gas transmission pipeline segment, you must also report the information in paragraph (i)(3) of this section.

(1) *Report by equipment or event type.* If you calculated emissions from blowdown vent stacks by the seven categories listed in §98.233(i)(2) for industry segments other than the onshore natural gas transmission pipeline segment, then you must report the equipment or

onshore natural gas transmission pipeline segment, then you must report the equipment or event types and the information specified in paragraphs (i)(1)(i) through (iii) of this section for each equipment or event type. If a blowdown event resulted in emissions from multiple equipment types, and the emissions cannot be apportioned to the different equipment types, then you may report the information in paragraphs (i)(1)(i) through (iii) of this section for the equipment type that represented the largest portion of the emissions for the blowdown event. If you calculated emissions from blowdown vent stacks by the eight categories listed in §98.233(i)(2) for the onshore natural gas transmission pipeline segment, then you must report the pipeline segments or event types and the information specified in paragraphs (i)(1)(i) through (iii) of this section for each "equipment or event type" (*i.e.,* category). If a blowdown event resulted in emissions from multiple categories, and the emissions cannot be apportioned to the different categories, then you may report the information in paragraphs (i)(1)(i) through (iii) of this section for the "equipment or event type" (*i.e.,* category) that represented the largest portion of the emissions for the blowdown event.

(i) Total number of blowdowns in the calendar year for the equipment or event type (the sum of equation variable "N" from Equation W-14A or Equation W-14B of this subpart, for all unique physical volumes for the equipment or event type).

(ii) Annual CO_2 emissions for the equipment or event type, in metric tons CO_2, calculated according to §98.233(i)(2)(iii).

(iii) Annual CH_4 emissions for the equipment or event type, in metric tons CH_4, calculated according to §98.233(i)(2)(iii).

(2) *Report by flow meter.* If you elect to calculate emissions from blowdown vent stacks by using a flow meter according to §98.233(i)(3), then you must report the information specified in paragraphs (i)(2)(i) and (ii) of this section for the facility.

(i) Annual CO_2 emissions from all blowdown vent stacks at the facility for which emissions were calculated using flow meters, in metric tons CO_2 (the sum of all CO_2 mass emission values calculated according to §98.233(i)(3), for all flow meters).

(ii) Annual CH_4 emissions from all blowdown vent stacks at the facility for which emissions were calculated using flow meters, in metric tons CH_4, (the sum of all CH_4 mass emission values calculated according to §98.233(i)(3), for all flow meters).

(3) *Onshore natural gas transmission pipeline segment.* Report the information in paragraphs (i)(3)(i) through (iii) of this section for each state.

(i) Annual CO_2 emissions in metric tons CO_2.

(ii) Annual CH_4 emissions in metric tons CH_4.

(iii) Annual number of blowdown events.

(j) *Onshore production and onshore petroleum and natural gas gathering and boosting storage tanks.* You must indicate whether your facility sends produced oil to atmospheric tanks. If your facility sends produced oil to atmospheric tanks, then you must indicate which Calculation Method(s) you used to calculate GHG emissions, and you must report the information specified in paragraphs (j)(1) and (2) of this section as applicable. If you used Calculation Method 1 or Calculation Method 2 of §98.233(j), and any atmospheric tanks were observed to have malfunctioning dump valves during the calendar year, then you must indicate that dump valves were malfunctioning and you must report the information specified in paragraph (j)(3) of this section.

(1) If you used Calculation Method 1 or Calculation Method 2 of §98.233(j) to calculate GHG emissions, then you must report the information specified in paragraphs (j)(1)(i) through (xvi) of this section for each sub-basin (for onshore production) or county (for onshore petroleum and natural gas gathering and boosting) and by calculation method. Onshore petroleum and natural gas gathering and boosting facilities do not report the information specified in paragraphs (j)(1)(ix) and (xi) of this section.

(i) Sub-basin ID (for onshore production) or county name (for onshore petroleum and natural gas gathering and boosting).

(ii) Calculation method used, and name of the software package used if using Calculation Method 1.

(iii) The total annual oil volume from gas-liquid separators and direct from wells or non-separator equipment that is sent to applicable onshore production and onshore petroleum and natural gas gathering and boosting storage tanks, in barrels. You may delay reporting of this data element for onshore production if you indicate in the annual report that wildcat wells and delineation wells are the only wells in the sub-basin with oil production greater than or equal to 10 barrels per day and flowing to gas-liquid separators or direct to storage tanks. If you elect to delay reporting of this data element, you must report by the date specified in §98.236(cc) the total volume of oil from all wells and the well ID number(s) for the well(s) included in this volume.

(iv) The average gas-liquid separator or non-separator equipment temperature, in degrees Fahrenheit.

(v) The average gas-liquid separator or non-separator equipment pressure, in pounds per square inch gauge.

(vi) The average sales oil or stabilized oil API gravity, in degrees.

(vii) The minimum and maximum concentration (mole fraction) of CO_2 in flash gas from onshore production and onshore natural gas gathering and boosting storage tanks.

(viii) The minimum and maximum concentration (mole fraction) of CH_4 in flash gas from onshore production and onshore natural gas gathering and boosting storage tanks.

(ix) The number of wells sending oil to gas-liquid separators or directly to atmospheric tanks.

(x) The number of atmospheric tanks.

(xi) An estimate of the number of atmospheric tanks, not on well-pads, receiving your oil.

(xii) If any emissions from the atmospheric tanks at your facility were controlled with vapor recovery systems, then you must report the information specified in paragraphs (j)(1)(xii)(A) through (E) of this section.

(A) The number of atmospheric tanks that control emissions with vapor recovery systems.

(B) Total CO_2 mass, in metric tons CO_2, that was recovered during the calendar year using a vapor recovery system.

(C) Total CH_4 mass, in metric tons CH_4, that was recovered during the calendar year using a vapor recovery system.

(D) Annual CO_2 emissions, in metric tons CO_2, from atmospheric tanks equipped with vapor recovery systems.

(E) Annual CH_4 emissions, in metric tons CH_4, from atmospheric tanks equipped with vapor recovery systems.

(xiii) If any atmospheric tanks at your facility vented gas directly to the atmosphere without using a vapor recovery system or without flaring, then you must report the information specified in paragraphs (j)(1)(xiii)(A) through (C) of this section.

(A) The number of atmospheric tanks that vented gas directly to the atmosphere without using a vapor recovery system or without flaring.

(B) Annual CO_2 emissions, in metric tons CO_2, that resulted from venting gas directly to the atmosphere.

(C) Annual CH_4 emissions, in metric tons CH_4, that resulted from venting gas directly to the atmosphere.

(xiv) If you controlled emissions from any atmospheric tanks at your facility with one or more flares, then you must report the information specified in paragraphs (j)(1)(xiv)(A) through (D) of this section.

(A) The number of atmospheric tanks that controlled emissions with flares.

(B) Annual CO_2 emissions, in metric tons CO_2, from atmospheric tanks that controlled emissions with one or more flares.

(C) Annual CH_4 emissions, in metric tons CH_4, from atmospheric tanks that controlled emissions with one or more flares.

(D) Annual N_2O emissions, in metric tons N_2O, from atmospheric tanks that controlled emissions with one or more flares.

(2) If you used Calculation Method 3 to calculate GHG emissions, then you must report the information specified in paragraphs (j)(2)(i) through (iii) of this section.

(i) Report the information specified in paragraphs (j)(2)(i)(A) through (F) of this section, at the basin level, for atmospheric tanks where emissions were calculated using Calculation Method 3 of §98.233(j). Onshore gathering and boosting facilities do not report the information specified in paragraphs (j)(2)(i)(E) and (F) of this section.

(A) The total annual oil/condensate throughput that is sent to all atmospheric tanks in the basin, in barrels. You may delay reporting of this data element for onshore production if you indicate in the annual report that wildcat wells and delineation wells are the only wells in the sub-basin with oil/condensate production less than 10 barrels per day and that send oil/condensate to atmospheric tanks. If you elect to delay reporting of this data element, you must report by the date specified in §98.236(cc) the total annual oil/condensate throughput from all wells and the well ID number(s) for the well(s) included in this volume.

(B) An estimate of the fraction of oil/condensate throughput reported in paragraph (j)(2)(i)(A) of this section sent to atmospheric tanks in the basin that controlled emissions with flares.

(C) An estimate of the fraction of oil/condensate throughput reported in paragraph (j)(2)(i)(A) of this section sent to atmospheric tanks in the basin that controlled emissions with vapor recovery systems.

(D) The number of atmospheric tanks in the basin.

(E) The number of wells with gas-liquid separators (“Count” from Equation W-15 of this subpart) in the basin.

(F) The number of wells without gas-liquid separators (“Count” from Equation W-15 of this subpart) in the basin.

(ii) Report the information specified in paragraphs (j)(2)(ii)(A) through (D) of this section for each sub-basin (for onshore production) or county (for onshore petroleum and natural gas gathering and boosting) with atmospheric tanks whose emissions were calculated using Calculation Method 3 of §98.233(j) and that did not control emissions with flares.

(A) Sub-basin ID (for onshore production) or county name (for onshore petroleum and natural gas gathering and boosting).

(B) The number of atmospheric tanks in the sub-basin (for onshore production) or county (for onshore petroleum and natural gas gathering and boosting) that did not control emissions with flares.

(C) Annual CO_2 emissions, in metric tons CO_2, from atmospheric tanks in the sub-basin (for onshore production) or county (for onshore petroleum and natural gas gathering and boosting) that did not control emissions with flares, calculated using Equation W-15 of §98.233(j) and adjusted for vapor recovery, if applicable.

(D) Annual CH_4 emissions, in metric tons CH_4, from atmospheric tanks in the sub-basin (for onshore production) or county (for onshore petroleum and natural gas gathering and boosting) that did not control emissions with flares, calculated using Equation W-15 of §98.233(j) and adjusted for vapor recovery, if applicable.

(iii) Report the information specified in paragraphs (j)(2)(iii)(A) through (E) of this section for each sub-basin (for onshore production) or county (for onshore petroleum and natural gas gathering and boosting) with atmospheric tanks whose emissions were calculated using Calculation Method 3 of §98.233(j) and that controlled emissions with flares.

(A) Sub-basin ID (for onshore production) or county name (for onshore petroleum and natural gas gathering and boosting).

(B) The number of atmospheric tanks in the sub-basin (for onshore production) or county (for onshore petroleum and natural gas gathering and boosting) that controlled emissions with flares.

(C) Annual CO_2 emissions, in metric tons CO_2, from atmospheric tanks that controlled emissions with flares.

(D) Annual CH_4 emissions, in metric tons CH_4, from atmospheric tanks that controlled emissions with flares.

(E) Annual N_2O emissions, in metric tons N_2O, from atmospheric tanks that controlled emissions with flares.

(3) If you used Calculation Method 1 or Calculation Method 2 of §98.233(j), and any gas-liquid separator liquid dump values did not close properly during the calendar year, then you must report the information specified in paragraphs (j)(3)(i) through (iv) of this section for each sub-basin (for onshore production) or county (for onshore petroleum and natural gas gathering and boosting).

(i) The total number of gas-liquid separators whose liquid dump valves did not close properly during the calendar year.

(ii) The total time the dump valves on gas-liquid separators did not close properly in the calendar year, in hours (sum of the "T_n" values used in Equation W-16 of this subpart).

(iii) Annual CO_2 emissions, in metric tons CO_2, that resulted from dump valves on gas-liquid separators not closing properly during the calendar year, calculated using Equation W-16 of this subpart.

(iv) Annual CH_4 emissions, in metric tons CH_4, that resulted from the dump valves on gas-liquid separators not closing properly during the calendar year, calculated using Equation W-16 of this subpart.

(k) *Transmission storage tanks.* You must indicate whether your facility contains any transmission storage tanks. If your facility contains at least one transmission storage tank, then you must report the information specified in paragraphs (k)(1) through (3) of this section for each transmission storage tank vent stack.

(1) For each transmission storage tank vent stack, report the information specified in (k)(1)(i) through (iv) of this section.

(i) The unique name or ID number for the transmission storage tank vent stack.

(ii) Method used to determine if dump valve leakage occurred.

(iii) Indicate whether scrubber dump valve leakage occurred for the transmission storage tank vent according to §98.233(k)(2).

(iv) Indicate if there is a flare attached to the transmission storage tank vent stack.

(2) If scrubber dump valve leakage occurred for a transmission storage tank vent stack, as reported in paragraph (k)(1)(iii) of this section, and the vent stack vented directly to the atmosphere during the calendar year, then you must report the information specified in paragraphs (k)(2)(i) through (v) of this section for each transmission storage vent stack where scrubber dump valve leakage occurred.

(i) Method used to measure the leak rate.

(ii) Measured leak rate (average leak rate from a continuous flow measurement device), in standard cubic feet per hour.

(iii) Duration of time that the leak is counted as having occurred, in hours, as determined in §98.233(k)(3) (may use best available data if a continuous flow measurement device was used).

(iv) Annual CO_2 emissions, in metric tons CO_2, that resulted from venting gas directly to the atmosphere, calculated according to §98.233(k)(1) through (4).

(v) Annual CH_4 emissions, in metric tons CH_4, that resulted from venting gas directly to the atmosphere, calculated according to §98.233(k)(1) through (4).

(3) If scrubber dump valve leakage occurred for a transmission storage tank vent stack, as reported in paragraph (k)(1)(iii), and the vent stack vented to a flare during the calendar year, then you must report the information specified in paragraphs (k)(3)(i) through (vi) of this section.

(i) Method used to measure the leak rate.

(ii) Measured leakage rate (average leak rate from a continuous flow measurement device) in standard cubic feet per hour.

(iii) Duration of time that flaring occurred in hours, as defined in §98.233(k)(3) (may use best available data if a continuous flow measurement device was used).

(iv) Annual CO_2 emissions, in metric tons CO_2, that resulted from flaring gas, calculated according to §98.233(k)(5).

(v) Annual CH_4 emissions, in metric tons CH_4, that resulted from flaring gas, calculated according to §98.233(k)(5).

(vi) Annual N_2O emissions, in metric tons N_2O, that resulted from flaring gas, calculated according to §98.233(k)(5).

(l) *Well testing.* You must indicate whether you performed gas well or oil well testing, and if the testing of gas wells or oil wells resulted in vented or flared emissions during the calendar year. If you performed well testing that resulted in vented or flared emissions during the calendar year, then you must report the information specified in paragraphs (l)(1) through (4) of this section, as applicable.

(1) If you used Equation W-17A of §98.233 to calculate annual volumetric natural gas emissions at actual conditions from oil wells and the emissions are not vented to a flare, then you must report the information specified in paragraphs (l)(1)(i) through (vii) of this section.

(i) Number of wells tested in the calendar year.

(ii) Well ID numbers for the wells tested in the calendar year.

(iii) Average number of well testing days per well for well(s) tested in the calendar year.

(iv) Average gas to oil ratio for well(s) tested, in cubic feet of gas per barrel of oil.

(v) Average flow rate for well(s) tested, in barrels of oil per day. You may delay reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells that are tested. If you elect to delay reporting of this data element, you must report by the date specified in §98.236(cc) the measured average flow rate for well(s) tested and the well ID number(s) for the well(s) included in the measurement.

(vi) Annual CO_2 emissions, in metric tons CO_2, calculated according to §98.233(l).

(vii) Annual CH_4 emissions, in metric tons CH_4, calculated according to §98.233(l).

(2) If you used Equation W-17A of §98.233 to calculate annual volumetric natural gas emissions at actual conditions from oil wells and the emissions are vented to a flare, then you must report the information specified in paragraphs (l)(2)(i) through (viii) of this section.

(i) Number of wells tested in the calendar year.

(ii) Well ID numbers for the wells tested in the calendar year.

(iii) Average number of well testing days per well for well(s) tested in the calendar year.

(iv) Average gas to oil ratio for well(s) tested, in cubic feet of gas per barrel of oil.

(v) Average flow rate for well(s) tested, in barrels of oil per day. You may delay reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells that are tested. If you elect to delay reporting of this data element, you must report by the date specified in §98.236(cc) the measured average flow rate for well(s) tested and the well ID number(s) for the well(s) included in the measurement.

(vi) Annual CO_2 emissions, in metric tons CO_2, calculated according to §98.233(l).

(vii) Annual CH_4 emissions, in metric tons CH_4, calculated according to §98.233(l).

(viii) Annual N_2O emissions, in metric tons N_2O, calculated according to §98.233(l).

(3) If you used Equation W-17B of §98.233 to calculate annual volumetric natural gas emissions at actual conditions from gas wells and the emissions were not vented to a flare, then you must report the information specified in paragraphs (l)(3)(i) through (vi) of this section.

(i) Number of wells tested in the calendar year.

(ii) Well ID numbers for the wells tested in the calendar year.

(iii) Average number of well testing days per well for well(s) tested in the calendar year.

(iv) Average annual production rate for well(s) tested, in actual cubic feet per day. You may delay reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells that are tested. If you elect to delay reporting of this data element, you must report by the date specified in §98.236(cc) the measured average annual production rate for well(s) tested and the well ID number(s) for the well(s) included in the measurement.

(v) Annual CO_2 emissions, in metric tons CO_2, calculated according to §98.233(l).

(vi) Annual CH_4 emissions, in metric tons CH_4, calculated according to §98.233(l).

(4) If you used Equation W-17B of §98.233 to calculate annual volumetric natural gas emissions at actual conditions from gas wells and the emissions were vented to a flare, then you must report the information specified in paragraphs (l)(4)(i) through (vii) of this section.

(i) Number of wells tested in calendar year.

(ii) Well ID numbers for the wells tested in the calendar year.

(iii) Average number of well testing days per well for well(s) tested in the calendar year.

(iii) Average number of well testing days per well for well(s) tested in the calendar year.

(iv) Average annual production rate for well(s) tested, in actual cubic feet per day. You may delay reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells that are tested. If you elect to delay reporting of this data element, you must report by the date specified in §98.236(cc) the measured average annual production rate for well(s) tested and the well ID number(s) for the well(s) included in the measurement.

(v) Annual CO_2 emissions, in metric tons CO_2, calculated according to §98.233(l).

(vi) Annual CH_4 emissions, in metric tons CH_4, calculated according to §98.233(l).

(vii) Annual N_2O emissions, in metric tons N_2O, calculated according to §98.233(l).

(m) *Associated natural gas.* You must indicate whether any associated gas was vented or flared during the calendar year. If associated gas was vented or flared during the calendar year, then you must report the information specified in paragraphs (m)(1) through (8) of this section for each sub-basin.

(1) Sub-basin ID and a list of well ID numbers for wells for which associated gas was vented or flared.

(2) Indicate whether any associated gas was vented directly to the atmosphere without flaring.

(3) Indicate whether any associated gas was flared.

(4) Average gas to oil ratio, in standard cubic feet of gas per barrel of oil (average of the “GOR” values used in Equation W-18 of this subpart).

(5) Volume of oil produced, in barrels, in the calendar year during the time periods in which associated gas was vented or flared (the sum of “$V_{p,q}$” used in Equation W-18 of §98.233). You may delay reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells from which associated gas was vented or flared. If you elect to delay reporting of this data element, you must report by the date specified in §98.236(cc) the volume of oil produced for well(s) with associated gas venting and flaring and the well ID number(s) for the well(s) included in the measurement.

(6) Total volume of associated gas sent to sales, in standard cubic feet, in the calendar year during time periods in which associated gas was vented or flared (the sum of “SG” values used in Equation W-18 of §98.233(m)). You may delay reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells from which associated gas was vented or flared. If you elect to delay reporting of this data element, you must report by the date specified in §98.236(cc) the measured total volume of associated gas sent to sales for well(s) with associated gas venting and flaring and the well ID number(s) for the well(s) included in the measurement.

(7) If you had associated gas emissions vented directly to the atmosphere without flaring, then you must report the information specified in paragraphs (m)(7)(i) through (iii) of

this section for each sub-basin.

(i) Total number of wells for which associated gas was vented directly to the atmosphere without flaring and a list of their well ID numbers.

(ii) Annual CO_2 emissions, in metric tons CO_2, calculated according to §98.233(m)(3) and (4).

(iii) Annual CH_4 emissions, in metric tons CH_4, calculated according to §98.233(m)(3) and (4).

(8) If you had associated gas emissions that were flared, then you must report the information specified in paragraphs (m)(8)(i) through (iv) of this section for each sub-basin.

(i) Total number of wells for which associated gas was flared and a list of their well ID numbers.

(ii) Annual CO_2 emissions, in metric tons CO_2, calculated according to §98.233(m)(5).

(iii) Annual CH_4 emissions, in metric tons CH_4, calculated according to §98.233(m)(5).

(iv) Annual N_2O emissions, in metric tons N_2O, calculated according to §98.233(m)(5).

(n) *Flare stacks.* You must indicate if your facility contains any flare stacks. You must report the information specified in paragraphs (n)(1) through (12) of this section for each flare stack at your facility, and for each industry segment applicable to your facility.

(1) Unique name or ID for the flare stack. For the onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting industry segments, a different name or ID may be used for a single flare stack for each location where it operates at in a given calendar year.

(2) Indicate whether the flare stack has a continuous flow measurement device.

(3) Indicate whether the flare stack has a continuous gas composition analyzer on feed gas to the flare.

(4) Volume of gas sent to the flare, in standard cubic feet ("V_s" in Equations W-19 and W-20 of this subpart).

(5) Fraction of the feed gas sent to an un-lit flare ("Z_u" in Equation W-19 of this subpart).

(6) Flare combustion efficiency, expressed as the fraction of gas combusted by a burning flare.

(7) Mole fraction of CH_4 in the feed gas to the flare ("X_{CH4}" in Equation W-19 of this subpart).

(8) Mole fraction of CO_2 in the feed gas to the flare ("X_{CO2}" in Equation W-20 of this subpart).

(9) Annual CO_2 emissions, in metric tons CO_2 (refer to Equation W-20 of this subpart).

(10) Annual CH_4 emissions, in metric tons CH_4 (refer to Equation W-19 of this subpart).

(11) Annual N_2O emissions, in metric tons N_2O (refer to Equation W-40 of this subpart).

(12) Indicate whether a CEMS was used to measure emissions from the flare. If a CEMS was used to measure emissions from the flare, then you are not required to report N_2O and CH_4 emissions for the flare stack.

(o) *Centrifugal compressors.* You must indicate whether your facility has centrifugal compressors. You must report the information specified in paragraphs (o)(1) and (2) of this section for all centrifugal compressors at your facility. For each compressor source or manifolded group of compressor sources that you conduct as found leak measurements as specified in §98.233(o)(2) or (4), you must report the information specified in paragraph (o)(3) of this section. For each compressor source or manifolded group of compressor sources that you conduct continuous monitoring as specified in §98.233(o)(3) or (5), you must report the information specified in paragraph (o)(4) of this section. Centrifugal compressors in onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting are not required to report information in paragraphs (o)(1) through (4) of this section and instead must report the information specified in paragraph (o)(5) of this section.

(1) *Compressor activity data.* Report the information specified in paragraphs (o)(1)(i) through (xiv) of this section for each centrifugal compressor located at your facility.

(i) Unique name or ID for the centrifugal compressor.

(ii) Hours in operating-mode.

(iii) Hours in not-operating-depressurized-mode.

(iv) Indicate whether the compressor was measured in operating-mode.

(v) Indicate whether the compressor was measured in not-operating-depressurized-mode.

(vi) Indicate which, if any, compressor sources are part of a manifolded group of compressor sources.

(vii) Indicate which, if any, compressor sources are routed to a flare.

(viii) Indicate which, if any, compressor sources have vapor recovery.

(ix) Indicate which, if any, compressor source emissions are captured for fuel use or are routed to a thermal oxidizer.

(x) Indicate whether the compressor has blind flanges installed and associated dates.

(xi) Indicate whether the compressor has wet or dry seals.

(xii) If the compressor has wet seals, the number of wet seals.

(xiii) Power output of the compressor driver (hp).

(xiv) Indicate whether the compressor had a scheduled depressurized shutdown during the reporting year.

(2) *Compressor source.* (i) For each compressor source at each compressor, report the information specified in paragraphs (o)(2)(i)(A) through (C) of this section.

(A) Centrifugal compressor name or ID. Use the same ID as in paragraph (o)(1)(i) of this section.

(B) Centrifugal compressor source (wet seal, isolation valve, or blowdown valve).

(C) Unique name or ID for the leak or vent. If the leak or vent is connected to a manifolded group of compressor sources, use the same leak or vent ID for each compressor source in the manifolded group. If multiple compressor sources are released through a single vent for which continuous measurements are used, use the same leak or vent ID for each compressor source released via the measured vent. For a single compressor using as found measurements, you must provide a different leak or vent ID for each compressor source.

(ii) For each leak or vent, report the information specified in paragraphs (o)(2)(ii)(A) through (E) of this section.

(A) Indicate whether the leak or vent is for a single compressor source or manifolded group of compressor sources and whether the emissions from the leak or vent are released to the atmosphere, routed to a flare, combustion (fuel or thermal oxidizer), or vapor recovery.

(B) Indicate whether an as found measurement(s) as identified in §98.233(o)(2) or (4) was conducted on the leak or vent.

(C) Indicate whether continuous measurements as identified in §98.233(o)(3) or (5) were conducted on the leak or vent.

(D) Report emissions as specified in paragraphs (o)(2)(ii)(D)(*1*) and (*2*) of this section for the leak or vent. If the leak or vent is routed to a flare, combustion, or vapor recovery, you are not required to report emissions under this paragraph.

(*1*) Annual CO_2 emissions, in metric tons CO_2.

(*2*) Annual CH_4 emissions, in metric tons CH_4.

(E) If the leak or vent is routed to flare, combustion, or vapor recovery, report the percentage of time that the respective device was operational when the compressor source emissions were routed to the device.

(3) *As found measurement sample data.* If the measurement methods specified in §98.233(o)(2) or (4) are conducted, report the information specified in paragraph (o)(3)(i) of this section. If the calculation specified in §98.233(o)(6)(ii) is performed, report the information specified in paragraph (o)(3)(ii) of this section.

(i) For each as found measurement performed on a leak or vent, report the information specified in paragraphs (o)(3)(i)(A) through (F) of this section.

(A) Name or ID of leak or vent. Use same leak or vent ID as in paragraph (o)(2)(i)(C) of this section.

(B) Measurement date.

(C) Measurement method. If emissions were not detected when using a screening method, report the screening method. If emissions were detected using a screening method, report only the method subsequently used to measure the volumetric emissions.

(D) Measured flow rate, in standard cubic feet per hour.

(E) For each compressor attached to the leak or vent, report the compressor mode during which the measurement was taken.

(F) If the measurement is for a manifolded group of compressor sources, indicate whether the measurement location is prior to or after comingling with non-compressor emission sources.

(ii) For each compressor mode-source combination where a reporter emission factor as calculated in Equation W-23 was used to calculate emissions in Equation W-22, report the information specified in paragraphs (o)(3)(ii)(A) through (D) of this section.

(A) The compressor mode-source combination.

(B) The compressor mode-source combination reporter emission factor, in standard cubic feet per hour ($EF_{s,m}$ in Equation W-23).

(C) The total number of compressors measured in the compressor mode-source combination in the current reporting year and the preceding two reporting years ($Count_m$ in Equation W-23).

(D) Indicate whether the compressor mode-source combination reporter emission factor is facility-specific or based on all of the reporter's applicable facilities.

(4) *Continuous measurement data.* If the measurement methods specified in §98.233(o)(3) or (5) are conducted, report the information specified in paragraphs (o)(4)(i) through (iv) of this section for each continuous measurement conducted on each leak or vent associated with each compressor source or manifolded group of compressor sources.

(i) Name or ID of leak or vent. Use same leak or vent ID as in paragraph (o)(2)(i)(C) of this section.

(ii) Measured volume of flow during the reporting year, in million standard cubic feet.

(iii) Indicate whether the measured volume of flow during the reporting year includes compressor blowdown emissions as allowed for in §98.233(o)(3)(ii) and (o)(5)(iii).

(iv) If the measurement is for a manifolded group of compressor sources, indicate whether the measurement location is prior to or after comingling with non-compressor emission sources.

(5) *Onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting.* Centrifugal compressors with wet seal degassing vents in onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting must report the information specified in paragraphs (o)(5)(i) through (iii) of this section.

(i) Number of centrifugal compressors that have wet seal oil degassing vents.

(ii) Annual CO_2 emissions, in metric tons CO_2, from centrifugal compressors with wet seal oil degassing vents.

(iii) Annual CH_4 emissions, in metric tons CH_4, from centrifugal compressors with wet seal oil degassing vents.

(p) *Reciprocating compressors.* You must indicate whether your facility has reciprocating compressors. You must report the information specified in paragraphs (p)(1) and (2) of this section for all reciprocating compressors at your facility. For each compressor source or manifolded group of compressor sources that you conduct as found leak measurements as specified in §98.233(p)(2) or (4), you must report the information specified in paragraph (p)(3) of this section. For each compressor source or manifolded group of compressor sources that you conduct continuous monitoring as specified in §98.233(p)(3) or (5), you must report the information specified in paragraph (p)(4) of this section. Reciprocating compressors in onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting are not required to report information in paragraphs (p)(1) through (4) of this section and instead must report the information specified in paragraph (p)(5) of this section.

(1) *Compressor activity data.* Report the information specified in paragraphs (p)(1)(i) through (xiv) of this section for each reciprocating compressor located at your facility.

(i) Unique name or ID for the reciprocating compressor.

(ii) Hours in operating-mode.

(iii) Hours in standby-pressurized-mode.

(iv) Hours in not-operating-depressurized-mode.

(v) Indicate whether the compressor was measured in operating-mode.

(vi) Indicate whether the compressor was measured in standby-pressurized-mode.

(vii) Indicate whether the compressor was measured in not-operating-depressurized-mode.

(viii) Indicate which, if any, compressor sources are part of a manifolded group of compressor sources.

(ix) Indicate which, if any, compressor sources are routed to a flare.

(x) Indicate which, if any, compressor sources have vapor recovery.

(xi) Indicate which, if any, compressor source emissions are captured for fuel use or are routed to a thermal oxidizer.

(xii) Indicate whether the compressor has blind flanges installed and associated dates.

(xiii) Power output of the compressor driver (hp).

(xiv) Indicate whether the compressor had a scheduled depressurized shutdown during the reporting year.

(2) *Compressor source.* (i) For each compressor source at each compressor, report the information specified in paragraphs (p)(2)(i)(A) through (C) of this section.

(A) Reciprocating compressor name or ID. Use the same ID as in paragraph (p)(1)(i) of this section.

(B) Reciprocating compressor source (isolation valve, blowdown valve, or rod packing).

(C) Unique name or ID for the leak or vent. If the leak or vent is connected to a manifolded group of compressor sources, use the same leak or vent ID for each compressor source in the manifolded group. If multiple compressor sources are released through a single vent for which continuous measurements are used, use the same leak or vent ID for each compressor source released via the measured vent. For a single compressor using as found measurements, you must provide a different leak or vent ID for each compressor source.

(ii) For each leak or vent, report the information specified in paragraphs (p)(2)(ii)(A) through (E) of this section.

(A) Indicate whether the leak or vent is for a single compressor source or manifolded group of compressor sources and whether the emissions from the leak or vent are released to the atmosphere, routed to a flare, combustion (fuel or thermal oxidizer), or vapor recovery.

(B) Indicate whether an as found measurement(s) as identified in §98.233(p)(2) or (4) was conducted on the leak or vent.

(C) Indicate whether continuous measurements as identified in §98.233(p)(3) or (5) were conducted on the leak or vent.

(D) Report emissions as specified in paragraphs (p)(2)(ii)(D)(*1*) and (*2*) of this section for the leak or vent. If the leak or vent is routed to flare, combustion, or vapor recovery, you are not required to report emissions under this paragraph.

(*1*) Annual CO_2 emissions, in metric tons CO_2.

(*2*) Annual CH_4 emissions, in metric tons CH_4.

(E) If the leak or vent is routed to flare, combustion, or vapor recovery, report the percentage of time that the respective device was operational when the compressor source emissions were routed to the device.

(3) *As found measurement sample data.* If the measurement methods specified in §98.233(p)(2) or (4) are conducted, report the information specified in paragraph (p)(3)(i) of this section. If the calculation specified in §98.233(p)(6)(ii) is performed, report the information specified in paragraph (p)(3)(ii) of this section.

(i) For each as found measurement performed on a leak or vent, report the information specified in paragraphs (p)(3)(i)(A) through (F) of this section.

(A) Name or ID of leak or vent. Use same leak or vent ID as in paragraph (p)(2)(i)(C) of this section.

(B) Measurement date.

(C) Measurement method. If emissions were not detected when using a screening method, report the screening method. If emissions were detected using a screening method, report only the method subsequently used to measure the volumetric emissions.

(D) Measured flow rate, in standard cubic feet per hour.

(E) For each compressor attached to the leak or vent, report the compressor mode during which the measurement was taken.

(F) If the measurement is for a manifolded group of compressor sources, indicate whether the measurement location is prior to or after comingling with non-compressor emission sources.

(ii) For each compressor mode-source combination where a reporter emission factor as calculated in Equation W-28 was used to calculate emissions in Equation W-27, report the information specified in paragraphs (p)(3)(ii)(A) through (D) of this section

(A) The compressor mode-source combination.

(A) The compressor mode-source combination.

(B) The compressor mode-source combination reporter emission factor, in standard cubic feet per hour ($EF_{s,m}$ in Equation W-28).

(C) The total number of compressors measured in the compressor mode-source combination in the current reporting year and the preceding two reporting years ($Count_m$ in Equation W-28).

(D) Indicate whether the compressor mode-source combination reporter emission factor is facility-specific or based on all of the reporter's applicable facilities.

(4) *Continuous measurement data.* If the measurement methods specified in §98.233(p)(3) or (5) are conducted, report the information specified in paragraphs (p)(4)(i) through (iv) of this section for each continuous measurement conducted on each leak or vent associated with each compressor source or manifolded group of compressor sources.

(i) Name or ID of leak or vent. Use same leak or vent ID as in paragraph (p)(2)(i)(C) of this section.

(ii) Measured volume of flow during the reporting year, in million standard cubic feet.

(iii) Indicate whether the measured volume of flow during the reporting year includes compressor blowdown emissions as allowed for in §98.233(p)(3)(ii) and (p)(5)(iii).

(iv) If the measurement is for a manifolded group of compressor sources, indicate whether the measurement location is prior to or after comingling with non-compressor emission sources.

(5) *Onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting.* Reciprocating compressors in onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting must report the information specified in paragraphs (p)(5)(i) through (iii) of this section.

(i) Number of reciprocating compressors.

(ii) Annual CO_2 emissions, in metric tons CO_2, from reciprocating compressors.

(iii) Annual CH_4 emissions, in metric tons CH_4, from reciprocating compressors.

(q) Equipment leak surveys. For any components subject to or complying with the requirements of §98.233(q), you must report the information specified in paragraphs (q)(1) and (2) of this section. Natural gas distribution facilities with emission sources listed in §98.232(i)(1) must also report the information specified in paragraph (q)(3) of this section.

(1) You must report the information specified in paragraphs (q)(1)(i) through (v) of this section.

(i) Except as specified in paragraph (q)(1)(ii) of this section, the number of complete equipment leak surveys performed during the calendar year.

(ii) Natural gas distribution facilities performing equipment leak surveys across a multiple year leak survey cycle must report the number of years in the leak survey cycle.

(iii) Except for onshore natural gas processing facilities and natural gas distribution facilities, indicate whether any equipment components at your facility are subject to the well site or compressor station fugitive emissions standards in §60.5397a of this chapter. Report the indication per facility, not per component type.

(iv) For facilities in onshore petroleum and natural gas production, onshore petroleum and natural gas gathering and boosting, onshore natural gas transmission compression, underground natural gas storage, LNG storage, and LNG import and export equipment, indicate whether you elected to comply with §98.233(q) according to §98.233(q)(1)(iv) for any equipment components at your facility.

(v) Report each type of method described in §98.234(a) that was used to conduct leak surveys.

(2) You must indicate whether your facility contains any of the component types subject to or complying with §98.233(q) that are listed in §98.232(c)(21), (d)(7), (e)(7), (e)(8), (f)(5), (f)(6), (f)(7), (f)(8), (g)(4), (g)(6), (g)(7), (h)(5), (h)(7), (h)(8), (i)(1), or (j)(10) for your facility's industry segment. For each component type that is located at your facility, you must report the information specified in paragraphs (q)(2)(i) through (v) of this section. If a component type is located at your facility and no leaks were identified from that component, then you must report the information in paragraphs (q)(2)(i) through (v) of this section but report a zero ("0") for the information required according to paragraphs (q)(2)(ii) through (v) of this section.

(i) Component type.

(ii) Total number of the surveyed component type that were identified as leaking in the calendar year ("x_p" in Equation W-30 of this subpart for the component type).

(iii) Average time the surveyed components are assumed to be leaking and operational, in hours (average of "$T_{p,z}$" from Equation W-30 of this subpart for the component type).

(iv) Annual CO_2 emissions, in metric tons CO_2, for the component type as calculated using Equation W-30 (for surveyed components only).

(v) Annual CH_4 emissions, in metric tons CH_4, for the component type as calculated using Equation W-30 (for surveyed components only).

(3) Natural gas distribution facilities with emission sources listed in §98.232(i)(1) must also report the information specified in paragraphs (q)(3)(i) through (viii) and, if applicable, (q)(3)(ix) of this section.

(i) Number of above grade transmission-distribution transfer stations surveyed in the calendar year.

(ii) Number of meter/regulator runs at above grade transmission-distribution transfer stations surveyed in the calendar year ("$Count_{MR,y}$" from Equation W-31 of this subpart, for the current calendar year).

(iii) Average time that meter/regulator runs surveyed in the calendar year were operational, in hours (average of "$T_{w,y}$" from Equation W-31 of this subpart, for the current calendar year).

(iv) Number of above grade transmission-distribution transfer stations surveyed in the current leak survey cycle.

(v) Number of meter/regulator runs at above grade transmission-distribution transfer stations surveyed in current leak survey cycle (sum of "$Count_{MR,y}$" from Equation W-31 of this subpart, for all calendar years in the current leak survey cycle).

(vi) Average time that meter/regulator runs surveyed in the current leak survey cycle were operational, in hours (average of "$T_{w,y}$" from Equation W-31 of this subpart, for all years included in the leak survey cycle).

(vii) Meter/regulator run CO_2 emission factor based on all surveyed transmission-distribution transfer stations in the current leak survey cycle, in standard cubic feet of CO_2 per operational hour of all meter/regulator runs ("$EF_{s,MR,i}$" for CO_2 calculated using Equation W-31 of this subpart).

(viii) Meter/regulator run CH_4 emission factor based on all surveyed transmission-distribution transfer stations in the current leak survey cycle, in standard cubic feet of CH_4 per operational hour of all meter/regulator runs ("$EF_{s,MR,i}$" for CH_4 calculated using Equation W-31 of this subpart).

(ix) If your natural gas distribution facility performs equipment leak surveys across a multiple year leak survey cycle, you must also report:

(A) The total number of meter/regulator runs at above grade transmission-distribution transfer stations at your facility ("$Count_{MR}$" in Equation W-32B of this subpart).

(B) Average estimated time that each meter/regulator run at above grade transmission-distribution transfer stations was operational in the calendar year, in hours per meter/regulator run ("$T_{w,avg}$" in Equation W-32B of this subpart).

(C) Annual CO_2 emissions, in metric tons CO_2, for all above grade transmission-distribution transfer stations at your facility.

(D) Annual CH_4 emissions, in metric tons CH_4, for all above grade transmission-distribution transfer stations at your facility.

(r) *Equipment leaks by population count.* If your facility is subject to the requirements of §98.233(r), then you must report the information specified in paragraphs (r)(1) through (3) of this section, as applicable.

(1) You must indicate whether your facility contains any of the emission source types required to use Equation W-32A of §98.233. You must report the information specified in paragraphs (r)(1)(i) through (v) of this section separately for each emission source type required to use Equation W-32A that is located at your facility. Onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities must report the information specified in paragraphs (r)(1)(i) through (v) separately by component type, service type, and geographic location (*i.e.,* Eastern U.S. or Western U.S.).

(i) Emission source type. Onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities must report the component type, service type and geographic location.

(ii) Total number of the emission source type at the facility ("$Count_e$" in Equation W-32A of this subpart).

(iii) Average estimated time that the emission source type was operational in the calendar year, in hours ("T_e" in Equation W-32A of this subpart).

(iv) Annual CO_2 emissions, in metric tons CO_2, for the emission source type.

(v) Annual CH_4 emissions, in metric tons CH_4, for the emission source type.

(2) Natural gas distribution facilities must also report the information specified in paragraphs (r)(2)(i) through (v) of this section.

(i) Number of above grade transmission-distribution transfer stations at the facility.

(ii) Number of above grade metering-regulating stations that are not transmission-distribution transfer stations at the facility.

(iii) Total number of meter/regulator runs at above grade metering-regulating stations that are not above grade transmission-distribution transfer stations ("$Count_{MR}$" in Equation W-32B of this subpart).

(iv) Average estimated time that each meter/regulator run at above grade metering-regulating stations that are not above grade transmission-distribution transfer stations was operational in the calendar year, in hours per meter/regulator run ("$T_{w,avg}$" in Equation W-32B of this subpart).

(v) If your facility has above grade metering-regulating stations that are not above grade transmission-distribution transfer stations and your facility also has above grade transmission-distribution transfer stations, you must also report:

(A) Annual CO_2 emissions, in metric tons CO_2, from above grade metering-regulating stations that are not above grade transmission-distribution transfer stations.

(B) Annual CH_4 emissions, in metric tons CH_4, from above grade metering regulating stations that are not above grade transmission-distribution transfer stations.

(3) Onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities must also report the information specified in paragraphs (r)(3)(i) and (ii) of this section.

(i) Calculation method used.

(ii) Onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities must report the information specified in paragraphs (r)(3)(ii)(A) and (B) of this section, for each major equipment type, production type (*i.e.,* natural gas or crude oil), and geographic location combination in Tables W-1B and W-1C to this subpart for which equipment leak emissions are calculated using the methodology in §98.233(r).

(A) An indication of whether the facility contains the major equipment type.

(B) If the facility does contain the equipment type, the count of the major equipment type.

(s) *Offshore petroleum and natural gas production.* You must report the information specified in paragraphs (s)(1) through (3) of this section for each emission source type listed in the most recent BOEMRE study.

(1) Annual CO_2 emissions, in metric tons CO_2.

(2) Annual CH_4 emissions, in metric tons CH_4.

(3) Annual N_2O emissions, in metric tons N_2O.

(t) [Reserved]

(u) [Reserved]

(v) [Reserved]

(w) *EOR injection pumps.* You must indicate whether CO_2 EOR injection was used at your facility during the calendar year and if any EOR injection pump blowdowns occurred during the year. If any EOR injection pump blowdowns occurred during the calendar year, then you must report the information specified in paragraphs (w)(1) through (8) of this section for each EOR injection pump system.

(1) Sub-basin ID.

(2) EOR injection pump system identifier.

(3) Pump capacity, in barrels per day.

(4) Total volume of EOR injection pump system equipment chambers, in cubic feet ("V_v" in Equation W-37 of this subpart).

(5) Number of blowdowns for the EOR injection pump system in the calendar year.

(6) Density of critical phase EOR injection gas, in kilograms per cubic foot ("R_c" in Equation W-37 of this subpart).

(7) Mass fraction of CO_2 in critical phase EOR injection gas ("GHG_{CO2}" in Equation W-37 of this subpart).

(8) Annual CO_2 emissions, in metric tons CO_2, from EOR injection pump system blowdowns.

(x) *EOR hydrocarbon liquids.* You must indicate whether hydrocarbon liquids were produced through EOR operations. If hydrocarbon liquids were produced through EOR operations, you must report the information specified in paragraphs (x)(1) through (4) of this section for each sub-basin category with EOR operations.

(1) Sub-basin ID.

(2) Total volume of hydrocarbon liquids produced through EOR operations in the calendar year, in barrels ("V_{hl}" in Equation W-38 of this subpart).

(3) Average CO_2 retained in hydrocarbon liquids downstream of the storage tank, in metric tons per barrel under standard conditions ("S_{hl}" in Equation W-38 of this subpart).

(4) Annual CO_2 emissions, in metric tons CO_2, from CO_2 retained in hydrocarbon liquids produced through EOR operations downstream of the storage tank ("$Mass_{CO2}$" in Equation W-38 of this subpart).

(y) [Reserved]

(z) *Combustion equipment at onshore petroleum and natural gas production facilities, onshore petroleum and natural gas gathering and boosting facilities, and natural gas distribution facilities.* If your facility is required by §98.232(c)(22), (i)(7), or (j)(12) to report emissions from combustion equipment, then you must indicate whether your facility has any combustion units subject to reporting according to paragraph (a)(1)(xvii), (a)(8)(i), or (a)(9)(xi) of this section. If your facility contains any combustion units subject to reporting according to paragraph (a)(1)(xviii), (a)(8)(i), or (a)(9)(xii) of this section, then you must report the information specified in paragraphs (z)(1) and (2) of this section, as applicable.

(1) Indicate whether the combustion units include: External fuel combustion units with a rated heat capacity less than or equal to 5 million Btu per hour; or, internal fuel combustion units that are not compressor-drivers, with a rated heat capacity less than or equal to 1 mmBtu/hr (or the equivalent of 130 horsepower). If the facility contains external fuel combustion units with a rated heat capacity less than or equal to 5 million Btu per hour or

internal fuel combustion units that are not compressor-drivers, with a rated heat capacity less than or equal to 1 million Btu per hour (or the equivalent of 130 horsepower), then you must report the information specified in paragraphs (z)(1)(i) and (ii) of this section for each unit type.

(i) The type of combustion unit.

(ii) The total number of combustion units.

(2) Indicate whether the combustion units include: External fuel combustion units with a rated heat capacity greater than 5 million Btu per hour; internal fuel combustion units that are not compressor-drivers, with a rated heat capacity greater than 1 million Btu per hour (or the equivalent of 130 horsepower); or, internal fuel combustion units of any heat capacity that are compressor-drivers. If your facility contains: External fuel combustion units with a rated heat capacity greater than 5 mmBtu/hr; internal fuel combustion units that are not compressor-drivers, with a rated heat capacity greater than 1 million Btu per hour (or the equivalent of 130 horsepower); or internal fuel combustion units of any heat capacity that are compressor-drivers, then you must report the information specified in paragraphs (z)(2)(i) through (vi) of this section for each combustion unit type and fuel type combination.

(i) The type of combustion unit.

(ii) The type of fuel combusted.

(iii) The quantity of fuel combusted in the calendar year, in thousand standard cubic feet, gallons, or tons.

(iv) Annual CO_2 emissions, in metric tons CO_2, calculated according to §98.233(z)(1) and (2).

(v) Annual CH_4 emissions, in metric tons CH_4, calculated according to §98.233(z)(1) and (2).

(vi) Annual N_2O emissions, in metric tons N_2O, calculated according to §98.233(z)(1) and (2).

(aa) Each facility must report the information specified in paragraphs (aa)(1) through (11) of this section, for each applicable industry segment, by using best available data. If a quantity required to be reported is zero, you must report zero as the value.

(1) For onshore petroleum and natural gas production, report the data specified in paragraphs (aa)(1)(i) and (ii) of this section.

(i) Report the information specified in paragraphs (aa)(1)(i)(A) through (C) of this section for the basin as a whole.

(A) The quantity of gas produced in the calendar year from wells, in thousand standard cubic feet. This includes gas that is routed to a pipeline, vented or flared, or used in field operations. This does not include gas injected back into reservoirs or shrinkage resulting from lease condensate production.

(B) The quantity of gas produced in the calendar year for sales, in thousand standard cubic feet.

(C) The quantity of crude oil and condensate produced in the calendar year for sales, in barrels.

(ii) Report the information specified in paragraphs (aa)(1)(ii)(A) through (M) of this section for each unique sub-basin category.

(A) State.

(B) County.

(C) Formation type.

(D) The number of producing wells at the end of the calendar year and a list of the well ID numbers (exclude only those wells permanently taken out of production, *i.e.,* plugged and abandoned).

(E) The number of producing wells acquired during the calendar year and a list of the well ID numbers.

(F) The number of producing wells divested during the calendar year and a list of the well ID numbers.

(G) The number of wells completed during the calendar year and a list of the well ID numbers.

(H) The number of wells permanently taken out of production (*i.e.,* plugged and abandoned) during the calendar year and a list of the well ID numbers.

(I) Average mole fraction of CH_4 in produced gas.

(J) Average mole fraction of CO_2 in produced gas.

(K) If an oil sub-basin, report the average GOR of all wells, in thousand standard cubic feet per barrel.

(L) If an oil sub-basin, report the average API gravity of all wells.

(M) If an oil sub-basin, report average low pressure separator pressure, in pounds per square inch gauge.

(2) For offshore production, report the quantities specified in paragraphs (aa)(2)(i) and (ii) of this section.

(i) The total quantity of gas handled at the offshore platform in the calendar year, in thousand standard cubic feet, including production volumes and volumes transferred via pipeline from another location.

(ii) The total quantity of oil and condensate handled at the offshore platform in the calendar year, in barrels, including production volumes and volumes transferred via pipeline from another location.

(3) For natural gas processing, report the information specified in paragraphs (aa)(3)(i) through (vii) of this section.

(i) The quantity of natural gas received at the gas processing plant in the calendar year, in thousand standard cubic feet.

(ii) The quantity of processed (residue) gas leaving the gas processing plant in the calendar year, in thousand standard cubic feet.

(iii) The cumulative quantity of all NGLs (bulk and fractionated) received at the gas processing plant in the calendar year, in barrels.

(iv) The cumulative quantity of all NGLs (bulk and fractionated) leaving the gas processing plant in the calendar year, in barrels.

(v) Average mole fraction of CH_4 in natural gas received.

(vi) Average mole fraction of CO_2 in natural gas received.

(vii) Indicate whether the facility fractionates NGLs.

(4) For natural gas transmission compression, report the quantity specified in paragraphs (aa)(4)(i) through (v) of this section.

(i) The quantity of gas transported through the compressor station in the calendar year, in thousand standard cubic feet.

(ii) Number of compressors.

(iii) Total compressor power rating of all compressors combined, in horsepower.

(iv) Average upstream pipeline pressure, in pounds per square inch gauge.

(v) Average downstream pipeline pressure, in pounds per square inch gauge.

(5) For underground natural gas storage, report the quantities specified in paragraphs (aa)(5)(i) through (iii) of this section.

(i) The quantity of gas injected into storage in the calendar year, in thousand standard cubic feet.

(ii) The quantity of gas withdrawn from storage in the calendar year, in thousand standard cubic feet.

(iii) Total storage capacity, in thousand standard cubic feet.

(6) For LNG import equipment, report the quantity of LNG imported in the calendar year, in thousand standard cubic feet.

(7) For LNG export equipment, report the quantity of LNG exported in the calendar year, in thousand standard cubic feet.

(8) For LNG storage, report the quantities specified in paragraphs (aa)(8)(i) through (iii) of this section.

(i) The quantity of LNG added into storage in the calendar year, in thousand standard cubic feet.

(ii) The quantity of LNG withdrawn from storage in the calendar year, in thousand standard cubic feet.

(iii) Total storage capacity, in thousand standard cubic feet.

(9) For natural gas distribution, report the quantities specified in paragraphs (aa)(9)(i) through (vii) of this section.

(i) The quantity of natural gas received at all custody transfer stations in the calendar year, in thousand standard cubic feet. This value may include meter corrections, but only for the calendar year covered by the annual report.

(ii) The quantity of natural gas withdrawn from in-system storage in the calendar year, in thousand standard cubic feet.

(iii) The quantity of natural gas added to in-system storage in the calendar year, in thousand standard cubic feet.

(iv) The quantity of natural gas delivered to end users, in thousand standard cubic feet. This value does not include stolen gas, or gas that is otherwise unaccounted for.

(v) The quantity of natural gas transferred to third parties such as other LDCs or pipelines, in thousand standard cubic feet. This value does not include stolen gas, or gas that is otherwise unaccounted for.

(vi) The quantity of natural gas consumed by the LDC for operational purposes, in thousand standard cubic feet.

(vii) The estimated quantity of gas stolen in the calendar year, in thousand standard cubic feet.

(10) For onshore petroleum and natural gas gathering and boosting facilities, report the quantities specified in paragraphs (aa)(10)(i) through (iv) of this section.

(i) The quantity of gas received by the gathering and boosting facility in the calendar year, in thousand standard cubic feet.

(ii) The quantity of gas transported to a natural gas processing facility, a natural gas transmission pipeline, a natural gas distribution pipeline, or another gathering and boosting facility in the calendar year, in thousand standard cubic feet.

(iii) The quantity of all hydrocarbon liquids received by the gathering and boosting facility in the calendar year, in barrels.

(iv) The quantity of all hydrocarbon liquids transported to a natural gas processing facility, a natural gas transmission pipeline, a natural gas distribution pipeline, or another gathering and boosting facility in the calendar year, in barrels.

(11) For onshore natural gas transmission pipeline facilities, report the quantities specified in paragraphs (aa)(11)(i) through (vi) of this section.

(i) The quantity of natural gas received at all custody transfer stations in the calendar year, in thousand standard cubic feet. This value may include meter corrections, but only for the calendar year covered by the annual report.

(ii) The quantity of natural gas withdrawn from in-system storage in the calendar year, in thousand standard cubic feet.

(iii) The quantity of natural gas added to in-system storage in the calendar year, in thousand standard cubic feet.

(iv) The quantity of natural gas transferred to third parties such as LDCs or other transmission pipelines, in thousand standard cubic feet.

(v) The quantity of natural gas consumed by the transmission pipeline facility for operational purposes, in thousand standard cubic feet.

(vi) The miles of transmission pipeline for each state in the facility.

(bb) For any missing data procedures used, report the information in §98.3(c)(8) except as provided in paragraphs (bb)(1) and (2) of this section.

(1) For quarterly measurements, report the total number of quarters that a missing data procedure was used for each data element rather than the total number of hours.

(2) For annual or biannual (once every two years) measurements, you do not need to report the number of hours that a missing data procedure was used for each data element.

(cc) If you elect to delay reporting the information in paragraph (g)(5)(i), (g)(5)(ii), (g)(5)(iii)(A), (g)(5)(iii)(B), (h)(1)(iv), (h)(2)(iv), (j)(1)(iii), (j)(2)(i)(A), (l)(1)(iv), (l)(2)(iv), (l)(3)(iii), (l)(4) (iii), (m)(5), or (m)(6) of this section, you must report the information required in that paragraph no later than the date 2 years following the date specified in §98.3(b) introductory text.

[79 FR 70411, Nov. 24, 2014, as amended at 80 FR 64291, Oct. 22, 2015; 81 FR 86515, Nov. 30, 2016]

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§98.237 Records that must be retained.

Monitoring Plans, as described in §98.3(g)(5), must be completed by April 1, 2011. In addition to the information required by §98.3(g), you must retain the following records:

(a) Dates on which measurements were conducted.

(b) Results of all emissions detected and measurements.

(c) Calibration reports for detection and measurement instruments used.

(d) Inputs and outputs of calculations or emissions computer model runs used for engineering estimation of emissions.

(e) The records required under §98.3(g)(2)(i) shall include an explanation of how company records, engineering estimation, or best available information are used to calculate each applicable parameter under this subpart.

(f) For each time a missing data procedure was used, keep a record listing the emission source type, a description of the circumstance that resulted in the need to use missing data procedures, the missing data provisions in §98.235 that apply, the calculation or analysis used to develop the substitute value, and the substitute value.

[75 FR 74488, Nov. 30, 2010, as amended at 76 FR 80590, Dec. 23, 2011; 79 FR 70424, Nov. 25, 2014]

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§98.238 Definitions.

Except as provided in this section, all terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Acid gas means hydrogen sulfide (H_2S) and/or carbon dioxide (CO_2) contaminants that are separated from sour natural gas by an acid gas removal unit.

Acid gas removal unit (AGR) means a process unit that separates hydrogen sulfide and/or carbon dioxide from sour natural gas using liquid or solid absorbents or membrane separators.

Acid gas removal vent emissions mean the acid gas separated from the acid gas absorbing medium (*e.g.,* an amine solution) and released with methane and other light hydrocarbons to the atmosphere or a flare.

Associated gas venting or flaring means the venting or flaring of natural gas which originates at wellheads that also produce hydrocarbon liquids and occurs either in a discrete gaseous phase at the wellhead or is released from the liquid hydrocarbon phase by separation. This does not include venting or flaring resulting from activities that are reported elsewhere, including tank venting, well completions, and well workovers.

Associated with a single well-pad means associated with the hydrocarbon stream as produced from one or more wells located on that single well-pad. The association ends where the stream from a single well-pad is combined with streams from one or more additional single well-pads, where the point of combination is located off that single well-pad. Onshore production storage tanks on or associated with a single well-pad are considered a part of the onshore production facility.

Basin means geologic provinces as defined by the American Association of Petroleum Geologists (AAPG) Geologic Note: AAPG-CSD Geologic Provinces Code Map: AAPG Bulletin, Prepared by Richard F. Meyer, Laure G. Wallace, and Fred J. Wagner, Jr., Volume 75, Number 10 (October 1991) (incorporated by reference, see §98.7) and the Alaska Geological Province Boundary Map, Compiled by the American Association of Petroleum Geologists Committee on Statistics of Drilling in Cooperation with the USGS, 1978 (incorporated by reference, see §98.7).

Compressor means any machine for raising the pressure of a natural gas or CO_2 by drawing in low pressure natural gas or CO_2 and discharging significantly higher pressure natural gas or CO_2.

Compressor mode means the operational and pressurized status of a compressor. For a centrifugal compressor, “mode” refers to either operating-mode or not-operating-depressurized-mode. For a reciprocating compressor, “mode” refers to either: Operating-mode, standby-pressurized-mode, or not-operating-depressurized-mode.

Compressor source means the source of certain venting or leaking emissions from a centrifugal or reciprocating compressor. For centrifugal compressors, “source” refers to blowdown valve leakage through the blowdown vent, unit isolation valve leakage through an open blowdown vent without blind flanges, and wet seal oil degassing vents. For reciprocating compressors, “source” refers to blowdown valve leakage through the blowdown vent, unit isolation valve leakage through an open blowdown vent without blind flanges, and rod packing emissions.

Condensate means hydrocarbon and other liquid, including both water and hydrocarbon liquids, separated from natural gas that condenses due to changes in the temperature, pressure, or both, and remains liquid at storage conditions.

Delineation well means a well drilled in order to determine the boundary of a field or producing reservoir.

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

Engineering estimation, for purposes of subpart W, means an estimate of emissions based on engineering principles applied to measured and/or approximated physical parameters such as dimensions of containment, actual pressures, actual temperatures, and compositions.

Enhanced oil recovery (EOR) means the use of certain methods such as water flooding or gas injection into existing wells to increase the recovery of crude oil from a reservoir. In the context of this subpart, EOR applies to injection of critical phase or immiscible carbon dioxide into a crude oil reservoir to enhance the recovery of oil.

External combustion means fired combustion in which the flame and products of combustion are separated from contact with the process fluid to which the energy is delivered. Process fluids may be air, hot water, or hydrocarbons. External combustion equipment may include fired heaters, industrial boilers, and commercial and domestic combustion units.

Facility with respect to natural gas distribution for purposes of reporting under this subpart and for the corresponding subpart A requirements means the collection of all distribution pipelines and metering-regulating stations that are operated by a Local Distribution Company (LDC) within a single state that is regulated as a separate operating company by a public utility commission or that are operated as an independent municipally-owned distribution system.

Facility with respect to natural gas distribution for purposes of reporting under this subpart and for the corresponding subpart A requirements means the collection of all distribution pipelines and metering-regulating stations that are operated by a Local Distribution Company (LDC) within a single state that is regulated as a separate operating company by a public utility commission or that are operated as an independent municipally-owned distribution system.

Facility with respect to onshore petroleum and natural gas gathering and boosting for purposes of reporting under this subpart and for the corresponding subpart A requirements means all gathering pipelines and other equipment located along those pipelines that are under common ownership or common control by a gathering and boosting system owner or operator and that are located in a single hydrocarbon basin as defined in this section. Where a person owns or operates more than one gathering and boosting system in a basin (for example, separate gathering lines that are not connected), then all gathering and boosting equipment that the person owns or operates in the basin would be considered one facility. Any gathering and boosting equipment that is associated with a single gathering and boosting system, including leased, rented, or contracted activities, is considered to be under common control of the owner or operator of the gathering and boosting system that contains the pipeline. The facility does not include equipment and pipelines that are part of any other industry segment defined in this subpart.

Facility with respect to onshore petroleum and natural gas production for purposes of reporting under this subpart and for the corresponding subpart A requirements means all petroleum or natural gas equipment on a single well-pad or associated with a single 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 §98.238. 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.

Facility with respect to the onshore natural gas transmission pipeline segment means the total U.S. mileage of natural gas transmission pipelines, as defined in this section, owned and operated by an onshore natural gas transmission pipeline owner or operator as defined in this section. The facility does not include pipelines that are part of any other industry segment defined in this subpart.

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

Field 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) (incorporated by reference, see §98.7).

Flare, for the purposes of subpart W, means a combustion device, whether at ground level or elevated, that uses an open or closed flame to combust waste gases without energy recovery.

Flare combustion efficiency means the fraction of hydrocarbon gas, on a volume or mole basis, that is combusted at the flare burner tip.

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 flares.

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

Gathering and boosting system means a single network of pipelines, compressors and process equipment, including equipment to perform natural gas compression, dehydration, and acid gas removal, that has one or more connection points to gas and oil production and a downstream endpoint, typically a gas processing plant, transmission pipeline, LDC pipeline, or other gathering and boosting system.

Gathering and boosting system owner or operator means any person that holds a contract in which they agree to transport petroleum or natural gas from one or more onshore petroleum and natural gas production wells to a natural gas processing facility, another gathering and boosting system, a natural gas transmission pipeline, or a distribution pipeline, or any person responsible for custody of the petroleum or natural gas transported.

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

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 -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.

Liquefied natural gas (LNG) means natural gas (primarily methane) that has been liquefied by reducing its temperature to −260 degrees Fahrenheit at atmospheric pressure.

LNG boil-off gas means natural gas in the gaseous phase that vents from LNG storage tanks due to ambient heat leakage through the tank insulation and heat energy dissipated in the LNG by internal pumps.

Manifolded compressor source means a compressor source (as defined in this section) that is manifolded to a common vent that routes gas from multiple compressors.

Manifolded group of compressor sources means a collection of any combination of manifolded compressor sources (as defined in this section) that are manifolded to a common vent.

Meter/regulator run means a series of components used in regulating pressure or metering natural gas flow, or both, in the natural gas distribution industry segment. At least one meter, at least one regulator, or any combination of both on a single run of piping is considered one meter/regulator run.

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.

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, but are not limited to, methane, heavier hydrocarbons and carbon dioxide. Natural gas may be field quality, pipeline quality, or process gas.

Offshore means seaward of the terrestrial borders of the United States, including waters subject to the ebb and flow of the tide, as well as adjacent bays, lakes or other normally standing waters, and extending to the outer boundaries of the jurisdiction and control of the United States under the Outer Continental Shelf Lands Act.

Onshore natural gas transmission pipeline owner or operator means, for interstate pipelines, the person identified as the transmission pipeline owner or operator on the Certificate of Public Convenience and Necessity issued under 15 U.S.C. 717f, or, for intrastate pipelines, the person identified as the owner or operator on the transmission pipeline's Statement of Operating Conditions under section 311 of the Natural Gas Policy Act, or for pipelines that fall under the “Hinshaw Exemption” as referenced in section 1(c) of the Natural Gas Act, 15 U.S.C. 717-717 (w)(1994), the person identified as the owner or operator on blanket certificates issued under 18 CFR 284.224. If an intrastate pipeline is not subject to section 311 of the Natural Gas Policy Act (NGPA), the onshore natural gas transmission pipeline owner or operator is the person identified as the owner or operator on reports to the state regulatory body regulating rates and charges for the sale of natural gas to consumers.

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 §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.

Operating pressure means the containment pressure that characterizes the normal state of gas or liquid inside a particular process, pipeline, vessel or tank.

Pressure groups as applicable to each sub-basin are defined as follows: Less than or equal to 25 psig; greater than 25 psig and less than or equal to 60 psig; greater than 60 psig and less than or equal to 110 psig; greater than 110 psig and less than or equal to 200 psig; and greater than 200 psig. The pressure in the context of pressure groups is either the well shut-in pressure; well casing pressure; or you may use the casing-to-tubing pressure of one well from the same sub-basin multiplied by the tubing pressure for each well in the sub-basin.

Pump means a device used to raise pressure, drive, or increase flow of liquid streams in closed or open conduits.

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

Pump seal emissions means hydrocarbon gas released from the seal face between the pump internal chamber and the atmosphere.

Reduced emissions completion means a well completion following hydraulic fracturing where gas flowback emissions from the gas outlet of the separator that are otherwise vented are captured, cleaned, and routed to the flow line or collection system, re-injected into the well or another well, used as an on-site fuel source, or used for other useful purpose that a purchased fuel or raw material would serve, with de minimis direct venting to the atmosphere. Short periods of flaring during a reduced emissions completion may occur.

Reduced emissions workover means a well workover with hydraulic fracturing (*i.e.,* refracturing) where gas flowback emissions from the gas outlet of the separator that are otherwise vented are captured, cleaned, and routed to the flow line or collection system, re-injected into the well or another well, used as an on-site fuel source, or used for other useful purpose that a purchased fuel or raw material would serve, with de minimis direct venting to the atmosphere. Short periods of flaring during a reduced emissions workover may occur.

Reservoir means a porous and permeable underground natural formation containing significant quantities of hydrocarbon liquids and/or gases.

Residue Gas and *Residue Gas Compression* mean, respectively, production lease natural gas from which gas liquid products and, in some cases, non-hydrocarbon components have been extracted such that it meets the specifications set by a pipeline transmission company, and/or a distribution company; and the compressors operated by the processing facility, whether inside the processing facility boundary fence or outside the fence-line, that deliver the residue gas from the processing facility to a transmission pipeline.

Separator means a vessel in which streams of multiple phases are gravity separated into individual streams of single phase.

Sub-basin category, for onshore natural gas production, means a subdivision of a basin into the unique combination of wells with the surface coordinates within the boundaries of an individual county and subsurface completion in one or more of each of the following five formation types: Oil, high permeability gas, shale gas, coal seam, or other tight gas reservoir rock. The distinction between high permeability gas and tight gas reservoirs shall be designated as follows: High permeability gas reservoirs with >0.1 millidarcy permeability, and tight gas reservoirs with ≤0.1 millidarcy permeability. Permeability for a reservoir type shall be determined by engineering estimate. Wells that produce only from high permeability gas, shale gas, coal seam, or other tight gas reservoir rock are considered gas wells; gas wells producing from more than one of these formation types shall be classified into only one type based on the formation with the most contribution to production as determined by engineering knowledge. All wells that produce hydrocarbon liquids (with or without gas) and do not meet the definition of a gas well in this sub-basin category definition are considered to be in the oil formation. All emission sources that handle condensate from gas wells in high permeability gas, shale gas, or tight gas reservoir rock formations are considered to be in the formation that the gas well belongs to and not in the oil formation.

Transmission-distribution (T-D) transfer station means a metering-regulating station where a local distribution company takes part or all of the natural gas from a transmission pipeline and puts it into a distribution pipeline.

Transmission pipeline means a Federal Energy Regulatory Commission rate-regulated Interstate pipeline, a state rate-regulated Intrastate pipeline, or a pipeline that falls under the “Hinshaw Exemption” as referenced in section 1(c) of the Natural Gas Act, 15 U.S.C. 717-717 (w)(1994).

Tubing diameter groups are defined as follows: Outer diameter less than or equal to 1 inch; outer diameter greater than 1 inch and less than 2.375 inch; and outer diameter greater than or equal to 2.375 inch.

Tubing systems means piping equal to or less than one half inch diameter as per nominal pipe size.

Turbine meter means a flow meter in which a gas or liquid flow rate through the calibrated tube spins a turbine from which the spin rate is detected and calibrated to measure the fluid flow rate.

Vented emissions means intentional or designed releases of CH_4 or CO_2 containing natural gas or hydrocarbon gas (not including stationary combustion flue gas), including process designed flow to the atmosphere through seals or vent pipes, equipment blowdown for maintenance, and direct venting of gas used to power equipment (such as pneumatic devices).

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

Well identification (ID) number means the unique and permanent identification number assigned to a petroleum or natural gas well. If the well has been assigned a US Well Number, the well ID number required in this subpart is the US Well Number. If a US Well Number has not been assigned to the well, the well ID number is the identifier established by the well's permitting authority.

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 well completion or workover, then it is considered part of well completion or workover.

Wildcat well means a well outside known fields or the first well drilled in an oil or gas field where no other oil and gas production exists.

[75 FR 74488, Nov. 30, 2010, as amended at 76 FR 80590, Dec. 23, 2011; 79 FR 63794, Oct. 24, 2014; 79 FR 70424, Nov. 25, 2014; 80 FR 64296, Oct. 22, 2015]

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Table W-1A to Subpart W of Part 98—Default Whole Gas Emission Factors for Onshore Petroleum and Natural Gas Production Facilities and Onshore Petroleum and Natural Gas Gathering and Boosting Facilities

Table W-1A to Subpart W of Part 98—Default Whole Gas Emission Factors for Onshore Petroleum and Natural Gas Production Facilities and Onshore Petroleum and Natural Gas Gathering and Boosting Facilities

Onshore petroleum and natural gas production and Onshore petroleum and natural gas gathering and boosting	Emission factor (scf/hour/component)
Eastern U.S.	
Population Emission Factors—All Components, Gas Service[1]	
Valve	0.027
Connector	0.003
Open-ended Line	0.061
Pressure Relief Valve	0.040
Low Continuous Bleed Pneumatic Device Vents[2]	1.39
High Continuous Bleed Pneumatic Device Vents[2]	37.3
Intermittent Bleed Pneumatic Device Vents[2]	13.5
Pneumatic Pumps[3]	13.3
Population Emission Factors—All Components, Light Crude Service[4]	
Valve	0.05
Flange	0.003
Connector	0.007
Open-ended Line	0.05
Pump	0.01
Other[5]	0.30
Population Emission Factors—All Components, Heavy Crude Service[6]	
Valve	0.0005
Flange	0.0009
Connector (other)	0.0003
Open-ended Line	0.006
Other[5]	0.003
Population Emission Factors—Gathering Pipelines, by Material Type[7]	
Protected Steel	0.47
Unprotected Steel	16.59
Plastic/Composite	2.50
Cast Iron	27.60
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 (other)	0.007
Open-ended Line	0.05
Pump	0.01
Other[5]	0.30
Population Emission Factors—All Components, Heavy Crude Service[6]	
Valve	0.0005
Flange	0.0009
Connector (other)	0.0003
Open-ended Line	0.006
Other[5]	0.003
Population Emission Factors—Gathering Pipelines by Material Type[7]	
Protected Steel	0.47
Unprotected Steel	16.59
Plastic/Composite	2.50
Cast Iron	27.60

[1]For multi-phase flow that includes gas, use the gas service emissions factors.

[2]Emission 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]“Others” 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.”

[7]Emission factors are in units of “scf/hour/mile of pipeline.”

[80 FR 64297, Oct. 22, 2015]

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Table W-1B to Subpart W of Part 98—Default Average Component Counts for Major Onshore Natural Gas Production Equipment and Onshore Petroleum and Natural Gas Gathering and Boosting Equipment

Major equipment	Valves	Connectors	Open-ended lines	Pressure relief valves
Eastern U.S.				
Wellheads	8	38	0.5	0
Separators	1	6	0	0
Meters/piping	12	45	0	0
Compressors	12	57	0	0
In-line heaters	14	65	2	1
Dehydrators	24	90	2	2
Western U.S.				

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

[75 FR 74488, Nov. 30, 2010, as amended at 80 FR 64298, Oct. 22, 2015]

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Table W-1C to Subpart W of Part 98—Default Average Component Counts For Major Crude Oil Production Equipment

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

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Table W-1D to Subpart W of Part 98—Designation Of Eastern And Western U.S.

Eastern U.S.	Western U.S.
Connecticut	Alabama
Delaware	Alaska
Florida	Arizona
Georgia	Arkansas
Illinois	California
Indiana	Colorado
Kentucky	Hawaii
Maine	Idaho
Maryland	Iowa
Massachusetts	Kansas
Michigan	Louisiana
New Hampshire	Minnesota
New Jersey	Mississippi
New York	Missouri
North Carolina	Montana
Ohio	Nebraska
Pennsylvania	Nevada
Rhode Island	New Mexico
South Carolina	North Dakota
Tennessee	Oklahoma
Vermont	Oregon
Virginia	South Dakota
West Virginia	Texas
Wisconsin	Utah

	Washington
	Wyoming

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Table W-1E to Subpart W of Part 98—Default Whole Gas Leaker Emission Factors for Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting

Equipment components	Emission factor (scf/hour/component)	
	If you survey using any of the methods in §98.234(a)(1) through (6)	If you survey using Method 21 as specified in §98.234(a)(7)
Leaker Emission Factors—All Components, Gas Service[1]		
Valve	4.9	3.5
Flange	4.1	2.2
Connector (other)	1.3	0.8
Open-Ended Line[2]	2.8	1.9
Pressure Relief Valve	4.5	2.8
Pump Seal	3.7	1.4
Other[3]	4.5	2.8
Leaker Emission Factors—All Components, Light Crude Service[1]		
Valve	3.2	2.2
Flange	2.7	1.4
Connector (other)	1.0	0.6
Open-Ended Line	1.6	1.1
Pump	3.7	2.6
Agitator Seal	3.7	2.6
Other[3]	3.1	2.0
Leaker Emission Factors—All Components, Heavy Crude Service[1]		
Valve	3.2	2.2
Flange	2.7	1.4
Connector (other)	1.0	0.6
Open-Ended Line	1.6	1.1
Pump	3.7	2.6
Agitator Seal	3.7	2.6
Other[3]	3.1	2.0

[1]For multi-phase flow that includes gas, use the gas service emission factors.

[2]The open-ended lines component type includes blowdown valve and isolation valve leaks emitted through the blowdown vent stack for centrifugal and reciprocating compressors.

[3]"Others" category includes any equipment leak emission point not specifically listed in this table, as specified in §98.232(c)(21) and (j)(10).

[4]Hydrocarbon liquids greater than or equal to 20°API are considered "light crude."

[5]Hydrocarbon liquids less than 20°API are considered "heavy crude."

[81 FR 86515, Nov. 30, 2016]

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Table W-2 to Subpart W of Part 98—Default Total Hydrocarbon Emission Factors for Onshore Natural Gas Processing

Onshore natural gas processing plants	**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.

[76 FR 80592, Dec. 23, 2011]

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Table W-3A to Subpart W of Part 98—Default Total Hydrocarbon Leaker Emission Factors for Onshore Natural Gas Transmission Compression

Onshore natural gas transmission compression	**Emission factor (scf/hour/component)**	
	If you survey using any of the methods in §98.234(a)(1) through (6)	**If you survey using Method 21 as specified in §98.234(a)(7)**
Leaker Emission Factors—Compressor Components, Gas Service		
Valve[1]	14.84	9.51
Connector	5.59	3.58
Open-Ended Line	17.27	11.07
Pressure Relief Valve	39.66	25.42
Meter or Instrument	19.33	12.39
Other[2]	4.1	2.63
Leaker Emission Factors—Non-Compressor Components, Gas Service		
Valve[1]	6.42	4.12
Connector	5.71	3.66
Open-Ended Line	11.27	7.22
Pressure Relief Valve	2.01	1.29
Meter or Instrument	2.93	1.88
Other[2]	4.1	2.63

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

[2]Other includes any potential equipment leak emission point in gas service that is not specifically listed in this table, as specified in §98.232(e)(8).

[81 FR 86516, Nov. 30, 2016]

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Table W-3B to Subpart W of Part 98—Default Total Hydrocarbon Population Emission Factors for Onshore Natural Gas Transmission Compression

Table W-3B to Subpart W of Part 98—Default Total Hydrocarbon Population Emission Factors for Onshore Natural Gas Transmission Compression

Population emission factors—gas service onshore natural gas transmission compression	Emission factor (scf/hour/component)
Low Continuous Bleed Pneumatic Device Vents[1]	1.37
High Continuous Bleed Pneumatic Device Vents[1]	18.20
Intermittent Bleed Pneumatic Device Vents[1]	2.35

[1]Emission Factor is in units of "scf/hour/device."

[81 FR 86516, Nov. 30, 2016]

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Table W-4A to Subpart W of Part 98—Default Total Hydrocarbon Leaker Emission Factors for Underground Natural Gas Storage

Underground natural gas storage	Emission factor (scf/hour/component)	
	If you survey using any of the methods in §98.234(a)(1) through (6)	If you survey using Method 21 as specified in §98.234(a)(7)
Leaker Emission Factors—Storage Station, Gas Service		
Valve[1]	14.84	9.51
Connector (other)	5.59	3.58
Open-Ended Line	17.27	11.07
Pressure Relief Valve	39.66	25.42
Meter and Instrument	19.33	12.39
Other[2]	4.1	2.63
Leaker Emission Factors—Storage Wellheads, Gas Service		
Valve[1]	4.5	3.2
Connector (other than flanges)	1.2	0.7
Flange	3.8	2.0
Open-Ended Line	2.5	1.7
Pressure Relief Valve	4.1	2.5
Other[2]	4.1	2.5

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

[2]Other includes any potential equipment leak emission point in gas service that is not specifically listed in this table, as specified in §98.232(f)(6) and (8).

[81 FR 86517, Nov. 30, 2016]

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Table W-4B to Subpart W of Part 98—Default Total Hydrocarbon Population Emission Factors for Underground Natural Gas Storage

Table W-4B to Subpart W of Part 98—Default Total Hydrocarbon Population Emission Factors for Underground Natural Gas Storage

Underground natural gas storage	Emission factor (scf/hour/component)
Population Emission Factors—Storage Wellheads, Gas Service	
Connector	0.01
Valve	0.1
Pressure Relief Valve	0.17
Open-Ended Line	0.03
Population Emission Factors—Other Components, Gas Service	
Low Continuous Bleed Pneumatic Device Vents[1]	1.37
High Continuous Bleed Pneumatic Device Vents[1]	18.20
Intermittent Bleed Pneumatic Device Vents[1]	2.35

[1]Emission Factor is in units of "scf/hour/device."

[81 FR 86517, Nov. 30, 2016]

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Table W-5A to Subpart W of Part 98—Default Methane Leaker Emission Factors for Liquefied Natural Gas (LNG) Storage

LNG storage	Emission factor (scf/hour/component)	
	If you survey using any of the methods in §98.234(a)(1) through (6)	If you survey using Method 21 as specified in §98.234(a)(7)
Leaker Emission Factors—LNG Storage Components, LNG Service		
Valve	1.19	0.23
Pump Seal	4.00	0.73
Connector	0.34	0.11
Other[1]	1.77	0.99
Leaker Emission Factors—LNG Storage Components, Gas Service		
Valve[2]	14.84	9.51
Connector	5.59	3.58
Open-Ended Line	17.27	11.07
Pressure Relief Valve	39.66	25.42
Meter and Instrument	19.33	12.39
Other[3]	4.1	2.63

[1]"Other" equipment type for components in LNG service should be applied for any equipment type other than connectors, pumps, or valves.

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

[3]"Other" equipment type for components in gas service should be applied for any equipment type other than valves, connectors, flanges, open-ended lines, pressure relief valves, and meters and instruments, as specified in §98.232(g)(6) and (7).

[81 FR 86518, Nov. 30, 2016]

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Table W-5B to Subpart W of Part 98—Default Methane Population Emission Factors for Liquefied Natural Gas (LNG) Storage

LNG storage	Emission factor (scf/hour/component)
Population Emission Factors—LNG Storage Compressor, Gas Service	
Vapor Recovery Compressor[1]	4.17

[1]Emission Factor is in units of "scf/hour/device."

[81 FR 86518, Nov. 30, 2016]

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Table W-6A to Subpart W of Part 98—Default Methane Leaker Emission Factors for LNG Import and Export Equipment

LNG import and export equipment	Emission factor (scf/hour/component)	
	If you survey using any of the methods in §98.234(a)(1) through (6)	If you survey using Method 21 as specified in §98.234(a)(7)
Leaker Emission Factors—LNG Terminals Components, LNG Service		
Valve	1.19	0.23
Pump Seal	4.00	0.73
Connector	0.34	0.11
Other[1]	1.77	0.99
Leaker Emission Factors—LNG Terminals Components, Gas Service		
Valve[2]	14.84	9.51
Connector	5.59	3.58
Open-Ended Line	17.27	11.07
Pressure Relief Valve	39.66	25.42
Meter and Instrument	19.33	12.39
Other[3]	4.1	2.63

[1]"Other" equipment type for components in LNG service should be applied for any equipment type other than connectors, pumps, or valves.

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

[3]"Other" equipment type for components in gas service should be applied for any equipment type other than valves, connectors, flanges, open-ended lines, pressure relief valves, and meters and instruments, as specified in §98.232(h)(7) and (8).

[81 FR 86518, Nov. 30, 2016]

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Table W-6B to Subpart W of Part 98—Default Methane Population Emission Factors for LNG Import and Export Equipment

Table W-6B to Subpart W of Part 98—Default Methane Population Emission Factors for LNG Import and Export Equipment

LNG import and export equipment	Emission factor (scf/hour/component)
Population Emission Factors—LNG Terminals Compressor, Gas Service	
Vapor Recovery Compressor[1]	4.17

[1]Emission Factor is in units of "scf/hour/compressor."

[81 FR 86518, Nov. 30, 2016]

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Table W-7 to Subpart W of Part 98—Default Methane Emission Factors for Natural Gas Distribution

Natural gas distribution	Emission factor (scf/hour/component)
Leaker Emission Factors—Transmission-Distribution Transfer Station[1] Components, Gas Service	
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 Metering-Regulating station[1] Components, Gas Service[2]	
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[3]	
Unprotected Steel	12.58
Protected Steel	0.35
Plastic	1.13
Cast Iron	27.25
Population Emission Factors—Distribution Services, Gas Service[4]	
Unprotected Steel	0.19

Protected Steel	0.02
Plastic	0.001
Copper	0.03

[1]Excluding customer meters.

[2]Emission Factor is in units of “scf/hour/station.”

[3]Emission Factor is in units of “scf/hour/mile.”

[4]Emission Factor is in units of “scf/hour/number of services.”

[76 FR 80594, Dec. 23, 2011]

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