This redline/strikeout document represents select corrections to 40 CFR part 98 regulatory text in the final action:

Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems; Final Rule

Originally signed by the EPA Administrator Michael Regan on April 22, 2024

This redline/strikeout document shows the corrections that are effective January 1, 2025, specifically:

- § 98.233 (amendatory instruction 2)
- § 98.236 (amendatory instruction 4)

Subpart W—Petroleum and Natural Gas Systems

§ 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*. Onshore natural gas processing means the forced extraction of natural gas liquids (NGLs) from field gas, fractionation of mixed NGLs to natural gas products, or both. Natural gas processing does not include a Joule-Thomson valve, a dew point depression valve, or an isolated or standalone Joule-Thomson skid. This segment also includes all residue gas compression equipment owned or operated by the natural gas processing plant.

(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 downstream endpoint, typically a natural gas processing facility, a natural gas transmission pipeline or 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]

§ 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.

§ 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. You must also report the information specified in paragraph (l) of this section, as applicable.

(b) For offshore petroleum and natural gas production, report CO_2, CH_4, and N_2O emissions from the following sources. Offshore platforms do not need to report emissions from portable equipment.

(1) Equipment leaks (*i.e.*, fugitives), vented emission, and flare emission source types as identified by Bureau of Ocean Energy Management (BOEM) in compliance with 30 CFR 550.302 through 304.

(2) Other large release events.

(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) Blowdown vent stacks.

(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) Hydrocarbon liquids and produced water storage tank emissions.

(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 unit vents and nitrogen removal unit vents.

(18) EOR hydrocarbon liquids dissolved CO_2.

(19) Centrifugal compressor venting.

(20) [Reserved]

(21) Equipment leaks listed in paragraph (c)(21)(i) or (ii) of this section, as applicable:

(i) Equipment leaks from components including 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).

(ii) Equipment leaks from major equipment including wellheads, separators, meters/piping, compressors, dehydrators, heaters, and storage vessels.

(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.

(23) Other large release events.

(24) Drilling mud degassing.

(25) Crankcase vents.

(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 unit vents and nitrogen removal unit vents.

(6) Flare stack emissions.

(7) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, and meters, and equipment leaks from all other components in gas service (not including thief hatches or other openings on storage vessels) that either are subject to equipment leak standards for onshore natural gas processing plants in § 60.5400b or § 60.5401b of this chapter, or an applicable approved state plan or applicable Federal plan in part 62 of this chapter or that you elect to survey using a leak detection method described in § 98.234(a).

(8) Natural gas pneumatic device venting.

(9) Other large release events.

(10) Hydrocarbon liquids and produced water storage tank emissions.

(11) Crankcase vents.

(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) Condensate 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 either are subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter, the fugitive emissions standards for well sites, centralized production facilities, and compressor stations in § 60.5397b or § 60.5398b of this chapter, or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, or that you elect to survey using a leak detection method described in § 98.234(a). The other components subject to this paragraph (e)(8) also do not include thief hatches or other openings on a storage vessel.

(9) Other large release events.

(10) Dehydrator vents.

(11) Crankcase vents.

(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 either are subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter, the fugitive emissions standards for well sites, centralized production facilities, and compressor stations in § 60.5397b or § 60.5398b of this chapter, or an applicable approved state plan or applicable Federal plan in part 62 of this chapter or that you elect to survey using a leak detection method described in § 98.234(a). The other components subject to this paragraph (f)(6) do not include thief hatches or other openings on a storage vessel.

(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 either are subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter, the fugitive emissions standards for well sites, centralized production facilities, and compressor stations in § 60.5397b or § 60.5398b of this chapter, or an applicable approved state plan or applicable Federal plan in part 62 of this chapter or that you elect to survey using a leak detection method described in § 98.234(a).

(9) Other large release events.

(10) Dehydrator vents.

(11) Blowdown vent stacks.

(12) Condensate storage tanks.

(13) Crankcase vents.

(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 either are subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter, the fugitive emissions standards for well sites, centralized production facilities, and compressor stations in § 60.5397b or § 60.5398b of this chapter, or an applicable approved state plan or applicable Federal plan in part 62 of this chapter or that 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 either are subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter, the fugitive emissions standards for well sites, centralized production facilities, and compressor stations in § 60.5397b or § 60.5398b of this chapter, or an applicable approved state plan or applicable Federal plan in part 62 of this chapter or that you elect to survey using a leak detection method described in § 98.234(a).

(8) Other large release events.

(9) Blowdown vent stacks.

(10) Acid gas removal unit vents and nitrogen removal unit vents.

(11) Crankcase vents.

(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 either are subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter, the fugitive emissions standards for well sites, centralized production facilities, and compressor stations in § 60.5397b or § 60.5398b of this chapter, or an applicable approved state plan or applicable Federal plan in part 62 of this chapter or that 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 either are

subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter, the fugitive emissions standards for well sites, centralized production facilities, and compressor stations in § 60.5397b or § 60.5398b of this chapter, or an applicable approved state plan or applicable Federal plan in part 62 of this chapter or that you elect to survey using a leak detection method described in § 98.234(a).

(9) Acid gas removal unit vents and nitrogen removal unit vents.

(10) Other large release events.

(11) Crankcase vents.

(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).

(8) Other large release events.

(9) Blowdown vent stacks.

(10) Natural gas pneumatic device venting.

(11) Crankcase vents.

(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 unit vents and nitrogen removal unit vents.

(4) Dehydrator vents.

(5) Blowdown vent stacks.

(6) Hydrocarbon liquids and produced water storage tank emissions.

(7) Flare stack emissions.

(8) Centrifugal compressor venting.

(9) Reciprocating compressor venting.

(10) Equipment leaks listed in paragraph (j)(10)(i) or (ii) of this section, as applicable:

(i) Equipment leaks from components including 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).

(ii) Equipment leaks from major equipment including wellheads, separators, meters/piping, compressors, dehydrators, heaters, and storage vessels.

(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.

(13) Other large release events.

(14) Crankcase vents.

(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 CO_2, CH_4, and N_2O emissions from the following source types:

(1) Blowdown vent stacks.

(2) Other large release events.

(3) Equipment leaks listed in paragraph (m)(3)(i) or (ii) of this section, as applicable:

(i) Equipment leaks at transmission company interconnect metering-regulating stations.

(ii) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, and meters at transmission company interconnect metering-regulating stations.

(4) Equipment leaks listed in paragraph (m)(4)(i) or (ii) of this section, as applicable:

(i) Equipment leaks at farm tap and/or direct sale metering-regulating stations.

(ii) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, and meters at farm tap and/or direct sale metering-regulating stations.

(5) Transmission pipeline equipment leaks.

§ 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 emissions from natural gas pneumatic device venting using the applicable provisions as specified in this paragraph (a) of this section. If you have a continuous flow meter on the natural gas supply line dedicated to any one or combination of natural gas pneumatic devices or natural gas driven pneumatic pumps vented directly to the atmosphere for any portion of the year, you must use the method specified in paragraph (a)(1) of this section to calculate CH_4 and CO_2 emissions from those devices. For natural gas pneumatic devices vented directly to the atmosphere for which the natural gas supply rate is not continuously measured, use the applicable methods specified in paragraphs (a)(2) through (7) of this section to calculate CH_4 and CO_2 emissions. For natural gas pneumatic devices that are routed to flares, combustion, or vapor recovery systems, use the applicable provisions specified in paragraphs (a)(8) of this section. All references to natural gas pneumatic devices for Calculation Method 1 in this paragraph (a) also apply to combinations of natural gas pneumatic devices and natural gas driven pneumatic pumps that are served by a common natural gas supply line.

(1) *Calculation Method 1*. If you have or elect to install a continuous flow meter that is capable of meeting the requirements of § 98.234(b) on the natural gas supply line dedicated to any one or combination of natural gas pneumatic devices and natural gas driven pneumatic pumps that are vented directly to the atmosphere, you must use the applicable methods specified in paragraph (a)(1)(i) through (iv) of this section to calculate CH_4 and CO_2 emissions from those devices.

(i) For volumetric flow monitors:

(A) Determine the cumulative annual volumetric flow, in standard cubic feet, as measured by the flow monitor in the reporting year. If all natural gas pneumatic devices supplied by the measured natural gas supply line are routed to the atmosphere for only a portion of the year and are routed to a flare, combustion, or vapor recovery system for the remaining portion of the year, determine the cumulative annual volumetric flow considering only those times when one or more of the natural gas pneumatic devices were vented directly to the atmosphere. If the flow meter was installed during the year, calculate the total volumetric flow for the year based on the measured volumetric flow times the total hours in the calendar year the devices were in service (*i.e.*, supplied with natural gas) divided by the number of hours the devices were in service (*i.e.*, supplied with natural gas) and the volumetric flow was being measured.

(B) Convert the natural gas volumetric flow from paragraph (a)(1)(i)(A) of this section to CH_4 and CO_2 volumetric emissions following the provisions in paragraph (u) of this section.

(C) Convert the CH_4 and CO_2 volumetric emissions from paragraph (a)(1)(i)(B) of this section to CH_4 and CO_2 mass emissions using calculations in paragraph (v) of this section.

(ii) For mass flow monitors:

(A) Determine the cumulative annual mass flow, in metric tons, as measured by the flow monitor in the reporting year. If all natural gas pneumatic devices supplied by the measured natural gas supply line are vented directly to the atmosphere for only a portion of the year and are routed to a flare, combustion, or vapor recovery system for the remaining portion of the year, determine the cumulative annual mass flow considering only those times when one or more of the natural gas pneumatic devices were vented directly to the atmosphere. If the flow meter was installed during the year, calculate the total mass flow for the year based on the measured mass flow times the total hours in the calendar year the devices were in service (*i.e.*, supplied with natural gas) divided by the number of hours the devices were in service (*i.e.*, supplied with natural gas) and the mass flow was being measured.

(B) Convert the cumulative mass flow from paragraph (a)(1)(ii)(A) of this section to CH_4 and CO_2 mass emissions by multiplying by the mass fraction of CH_4 and CO_2 in the supplied natural gas. You must follow the provisions in paragraph (u) of this section for determining the mole fraction of CH_4 and CO_2 and use molecular weights of 16 kg/kg-mol and 44 kg/kg-mol for CH_4 and CO_2, respectively. You may assume unspecified components have an average molecular weight of 28 kg/kg-mol.

(iii) If the flow meter on the natural gas supply line serves both natural gas pneumatic devices and natural gas driven pneumatic pumps, disaggregate the total measured amount of natural gas to pneumatic devices and natural gas driven pneumatic pumps based on engineering calculations and best available data.

(iv) The flow meter must be operated and calibrated according to the methods set forth in § 98.234(b).

(2) *Calculation Method 2.* Except as provided in paragraph (a)(1) of this section, you may elect to measure the volumetric flow rate of each natural gas pneumatic device vent that vents directly to the atmosphere at your well-pad site, gathering and boosting site, or facility, as applicable, as specified in paragraphs (a)(2)(i) through (ix) of this section. You must exclude the counts of devices measured according to paragraph (a)(1) of this section from the counts of devices to be measured or for which emissions are calculated according to the requirements in this paragraph (a)(2).

(i) For facilities in the onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting industry segments, you may elect to measure your pneumatic devices according to this Calculation Method 2 for some well-pad sites or gathering and boosting sites and use other methods for other sites. When you elect to measure the emissions from natural gas pneumatic devices according to this Calculation Method 2 at a well-pad site or gathering and boosting site, you must measure all natural gas pneumatic devices that are vented directly to the atmosphere at the well-pad site or gathering and boosting site during the same calendar year and you must measure and calculate emissions according to the provisions in paragraphs (a)(2)(iii) through (viii) of this section.

(ii) For facilities in the onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, or natural gas distribution industry segments electing to use this Calculation Method 2, you must measure all natural gas pneumatic devices vented directly to the atmosphere at your facility each year or, if your facility has 26 or more pneumatic devices, over multiple years, not to exceed the number of years as specified in paragraphs (a)(2)(ii)(A) through (D) of this section. If you elect to measure your pneumatic devices over multiple years, you must measure approximately the same number of devices each year. You must measure and calculate emissions for natural gas pneumatic devices at your facility according to the provisions in paragraphs (a)(2)(iii) through (ix), as applicable.

(A) If your facility has at least 26 but not more than 50 natural gas pneumatic devices vented directly to the atmosphere, the maximum number of years to measure all devices at your facility is 2 years.

(B) If your facility has at least 51 but not more than 75 natural gas pneumatic devices vented directly to the atmosphere, the maximum number of years to measure all devices at your facility is 3 years.

(C) If your facility has at least 76 but not more than 100 natural gas pneumatic devices vented directly to the atmosphere, the maximum number of years to measure all devices at your facility is 4 years.

(D) If your facility has 101 or more natural gas pneumatic devices vented directly to the atmosphere, the maximum number of years to measure all devices at your facility is 5 years.

(iii) For all industry segments, determine the volumetric flow rate of each natural gas pneumatic device vent (in standard cubic feet per hour) using one of the methods specified in § 98.234(b) through (d), as appropriate, according to the requirements specified in paragraphs (a)(2)(iii)(A) through (E) of this section. You must measure the emissions under~~ representative~~ conditions representative of normal operations, which excludes periods immediately after conducting maintenance on the device or manually actuating the device.

(A) If you use a temporary meter, such as a vane anemometer, according to the methods set forth in § 98.234(b) or a high volume sampler according to methods set forth in § 98.234(d), you must measure the emissions from each device for a minimum of 15 minutes while the device is in service (*i.e.*, supplied with natural gas), except for natural gas pneumatic isolation valve actuators. For natural gas pneumatic isolation valve actuators, you must measure the emissions from each device for a minimum of 5 minutes while the device is in service (*i.e.*, supplied with natural gas). If there is no measurable flow from the natural gas pneumatic device after the minimum sampling period, you can discontinue monitoring and follow the applicable methods in paragraph (a)(2)(v) of this section.

(B) If you use calibrated bagging, follow the methods set forth in § 98.234(c) except you need only fill one bag to have a valid measurement. You must collect sample for a minimum of 5 minutes for natural gas pneumatic isolation valve actuators or 15 minutes for other natural gas pneumatic devices. If no gas is collected in the calibrated bag during the minimum sampling period, you can discontinue monitoring and follow the applicable methods in paragraph (a)(2)(v) of this section. If gas is collected in the bag during the minimum sampling period, you must either continue sampling until you fill the calibrated bag or you may elect to remeasure the vent according to paragraph (a)(2)(iii)(A) of this section.

(C) You do not need to use the same measurement method for each natural gas pneumatic device vent.

(D) If the measurement method selected measures the volumetric flow rate in actual cubic feet, convert the measured flow to standard cubic feet following the methods specified in paragraph (t)(1) of this section.

(E) If there is measurable flow from the device vent, calculate the volumetric flow rate of each natural gas pneumatic device vent (in standard cubic feet per hour) by dividing the cumulative volume of natural gas measured during the measurement period (in standard cubic feet) by the duration of the measurement (in hours).

(iv) For all industry segments, if there is measurable flow from the device vent, calculate the volume of natural gas emitted from each natural gas pneumatic device vent as the product of the natural gas flow rate measured in paragraph (a)(2)(iii) of this section and the number of hours the pneumatic device was in service (*i.e.*, supplied with natural gas) in the calendar year.

(v) For all industry segments, if there is no measurable flow from the device vent, estimate the emissions from the device according to the methods in paragraphs (a)(2)(v)(A) through (C) of this section, as applicable.

(A) For continuous high bleed pneumatic devices:

(*1*) Confirm that the device is in-service. If not, remeasure the device according to paragraph (a)(2)(iii) of this section at a time the device is in-service and calculate natural gas emissions from the device according to paragraph (a)(2)(iv) of this section.

(*2*) Confirm that the device is correctly characterized as a continuous high bleed pneumatic device according to the provisions in paragraph (a)(~~6~~7) of this section. If the device type was mischaracterized, recharacterize the device type and use the appropriate methods in paragraph (a)(2)(v)(B) or (C) of this section, as applicable.

(*3*) Upon confirmation of the items in paragraphs (a)(2)(v)(A)(*1*) and (*2*) of this section, remeasure the device vent using a different measurement method specified in § 98.234(b) through (d) or longer monitoring duration until there is a measurable flow from the device and calculate the natural gas emissions from the device according to paragraph (a)(2)(iv) of this section.

(B) For continuous low bleed pneumatic devices:

(*1*) Confirm that the device is in-service. If not, remeasure the device according to paragraph (a)(2)(iii) of this section at a time the device is in-service and calculate natural gas emissions from the device according to paragraph (a)(2)(iv) of this section.

(*2*) Determine natural gas bleed rate (in standard cubic feet per hour) at the supply pressure used for the pneumatic device based on the manufacturer's steady state natural gas bleed rate reported for the device. If the steady state bleed rate is reported in terms of air consumption, multiply the air consumption rate by 1.29 to calculate the steady state natural gas bleed rate. If a steady state bleed rate is not reported, follow the requirements in paragraph (a)(2)(v)(B)(*4*) of this section.

(*3*) Calculate the volume of natural gas emitted from the natural gas pneumatic device vent as the product of the natural gas steady state bleed rate determined in paragraph (a)(2)(v)(B)(*2*) of this section and number of hours the pneumatic device was in service (*i.e.*, supplied with natural gas) in the calendar year.

(*4*) If a steady state bleed rate is not reported, reassess whether the device is correctly characterized as a continuous low bleed pneumatic device according to the provisions in paragraph (a)(7) of this section. If the device is confirmed to be a continuous low bleed pneumatic device, you must remeasure the device vent using a different measurement method specified in § 98.234(b) through (d) or longer monitoring duration until there is a measurable flow from the device and calculate natural gas emissions from the device according to paragraph (a)(2)(iv) of this section. If the device type was mischaracterized, recharacterize the device type and use the appropriate methods in paragraph (a)(2)(v)(A) or (C) of this section, as applicable.

(C) For intermittent bleed pneumatic devices:

(*1*) Confirm that the device is in-service. If not, remeasure the device according to paragraph (a)(2)(iii) of this section at a time the device is in-service and calculate natural gas emissions according to paragraph (a)(2)(iv) of this section. For devices confirmed to be in-service during the measurement period, calculate natural gas emissions according to paragraphs (a)(2)(v)(C)(*2*) through (*5*) of this section.

(*2*) Calculate the volume of the controller, tubing and actuator (in actual cubic feet) based on the device and tubing size.

(*3*) Sum the volumes in paragraph (a)(2)(v)(C)(*2*) of this section and convert the volume to standard cubic feet following the methods specified in paragraph (t)(1) of this section based on the natural gas supply pressure.

(*4*) Estimate the number of actuations during the year based on company records, if available, or best engineering estimates. For isolation valve actuators, you may multiply the number of valve closures during the year by 2 (one actuation to close the valve; one actuation to open the valve).

(*5*) Calculate the volume of natural gas emitted from the natural gas pneumatic device vent as the product of the per actuation volume in standard cubic feet determined in paragraph (a)(2)(v)(C)(*3*) of this section, the number of actuations during the year as determined in paragraph (a)(2)(v)(C)(*4*) of this section, and the relay correction factor. Use 1 for the relay correction factor if there is no relay; use 3 for the relay correction factor if there is a relay.

(vi) For each pneumatic device, convert the volumetric emissions of natural gas at standard conditions determined in paragraph (a)(2)(iv) or (v) of this section, as applicable, to CO_2 and CH_4 volumetric emissions at standard conditions using the methods specified in paragraph (u) of this section.

(vii) For each pneumatic device, convert the GHG volumetric emissions at standard conditions determined in paragraph (a)(2)(vi) of this section to GHG mass emissions using the methods specified in paragraph (v) of this section.

(viii) Sum the CO_2 and CH_4 mass emissions determined in paragraph (a)(2)(vii) of this section separately for each type of natural gas pneumatic device (continuous high bleed, continuous low bleed, and intermittent bleed).

(ix) For facilities in the onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, or natural gas distribution industry segments, if you chose to conduct natural gas pneumatic device measurements over multiple years, “n,” according to paragraph (a)(2)(ii) of this section, then you must calculate the emissions from all pneumatic devices at your facility as specified in paragraph (a)(2)(ix)(A) through (E) of this section.

(A) Use the emissions calculated in (a)(2)(viii) of this section for the devices measured during the reporting year.

(B) Calculate the whole gas emission factor for each type of pneumatic device at the facility using equation W-1A to this section and all available data from the current year and the previous years in your monitoring cycle (n-1 years) for which natural gas pneumatic device vent measurements were made according to Calculation Method 2 in paragraph (a)(2) of this section (*e.g.*, if your monitoring cycle is 3 years, then use measured data from the current year and the two previous years). This emission factor must be updated annually.

$$EF_t = \frac{\sum_{y=1}^{n} MT_{s,t,y}}{\sum_{y=1}^{n} Count_{t,y}} \qquad \text{(Eq. W-1A)}$$

Where:

EF_t = Whole gas population emission factor for natural gas pneumatic device vents of type "t" (continuous high bleed, continuous low bleed, intermittent bleed), in standard cubic feet per hour per device.

$MT_{s,t,y}$ = Volumetric whole gas emissions rate measurement at standard ("s") conditions from component type "t" during year "y" in standard cubic feet per hour, as calculated in paragraph (a)(2)(iii) [if there was measurable flow from the device vent], (a)(2)(v)(B)(*2*), or (a)(2)(v)(C)(*6*) of this section, as applicable.

$Count_{t,y}$ = Count of natural gas pneumatic device vents of type "t" measured according to Calculation Method 2 in year "y."

n = Number of years of data to include in the emission factor calculation according to the number of years used to monitor all natural gas pneumatic device vents at the facility.

(C) Calculate CH_4 and CO_2 volumetric emissions from continuous high bleed, continuous low bleed, and intermittent bleed natural gas pneumatic devices that were not measured during the reporting year using equation W-1B to this section.

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

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 paragraphs (a)(5) through (7) of this section that vent directly to the atmosphere and that were not directly measured according to the requirements in paragraph (a)(1) or (a)(2)(iii) 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" (continuous high bleed, continuous low bleed, intermittent bleed) as calculated using equation W-1A to this section.
GHG_i	=	Concentration of GHG_i, CH_4 or CO_2, in produced natural gas or processed natural gas for each facility as specified in paragraph (u)(2) of this section.
T_t	=	Average estimated number of hours in the operating year the devices, of each type "t", were in service (*i.e.*, supplied with natural gas) using engineering estimates based on best available data. Default is 8,760 hours.

(D) Convert the volumetric emissions calculated using equation W-1B to this section to CH_4 and CO_2 mass emissions using the methods specified in paragraph (v) of this section.

(E) Sum the CH_4 and CO_2 mass emissions calculated in paragraphs (a)(2)(ix)(A) and (D) of this section separately for each type of pneumatic device (continuous high bleed, continuous low bleed, intermittent bleed) to calculate the total CH_4 and CO_2 mass emissions by device type for Calculation Method 2.

(3) *Calculation Method 3*. For facilities in the onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting industry segments, you may elect to use the applicable methods specified in paragraphs (a)(3)(i) through (iv) of this section, as applicable, to calculate CH_4 and CO_2 emissions from your natural gas pneumatic devices that are vented directly to the atmosphere at your site except those that are measured according to paragraph (a)(1) or (2) of this section. You must exclude the counts of devices measured according to paragraph (a)(1) of this section from the counts of devices to be monitored or for which emissions are calculated according to the requirements in this paragraph (a)(3). You may not use this Calculation Method 3 for those well-pad sites or gathering and

boosting sites for which you elected to measure emissions according to paragraph (a)(2) of this section.

(i) For continuous high bleed and continuous low bleed natural gas pneumatic devices vented directly to the atmosphere, you must calculate CH_4 and CO_2 volumetric emissions using either the methods in paragraph (a)(3)(i)(A) or (B) of this section.

(A) Measure all continuous high bleed and continuous low bleed pneumatic devices at your well-pad site or gathering and boosting site, as applicable, according to the provisions in paragraphs (a)(2) of this section.

(B) Use equation W-1B to this section, except use the appropriate default whole gas population emission factors for natural gas pneumatic device vents (in standard cubic feet per hour per device) of each type “t” (continuous high bleed and continuous low bleed) as listed in table W-1 to this subpart.

(ii) For intermittent bleed pneumatic devices, you must monitor each intermittent bleed pneumatic device at your well-pad site or gathering and boosting site as specified in paragraphs (a)(3)(ii)(A) through (C) of this section, as applicable.

(A) You must use one of the monitoring methods specified in § 98.234(a)(1) through (3) except that the monitoring dwell time for each device vent must be at least 2 minutes or until a malfunction is identified, whichever is shorter. A device is considered malfunctioning if any leak is observed when the device is not actuating or if a leak is observed for more than 5 seconds, or the extended duration as specified in paragraph (a)(3)(ii)(C) of this section if applicable, during a device actuation. If you cannot tell when a device is actuating, any observed leak from the device indicates a malfunctioning device.

(B) If you elect to monitor emissions from natural gas pneumatic devices at a well-pad site or gathering and boosting site according to this Calculation Method 3, you must monitor all natural gas intermittent bleed pneumatic devices that are vented directly to the atmosphere at the well-pad site or gathering and boosting site during the same calendar year. You must monitor the natural gas intermittent bleed pneumatic devices under conditions representative of normal operations, which excludes periods immediately after conducting maintenance on the device or manually actuating the device.

(C) For certain throttling pneumatic devices or isolation valve actuators on pipes greater than 5 inches in diameter, that may actuate for more than 5 seconds under normal conditions, you may elect to identify individual devices for which longer bleed periods may be allowed as specified in paragraphs (a)(3)(ii)(C)(*1*) and (*2*) of this section prior to monitoring these devices for the first time.

(*1*) You must identify the devices for which extended actuations are considered normal operations. For each device identified, you must determine the typical actuation time and maintain documentation and rationale for the extended actuation duration value.

(*2*) You must clearly and permanently tag the device vent for each natural gas pneumatic device that has an extended actuation duration. The tag must include the device ID and the normal duration period (in seconds) as determined and documented for the device as specified in paragraph (a)(3)(ii)(C)(*1*) of this section.

(iii) For intermittent bleed pneumatic devices that are monitored according to paragraph (a)(3)(ii) of this section during the reporting year, you must calculate CH_4 and CO_2 volumetric emissions from intermittent bleed natural gas pneumatic devices vented directly to the atmosphere using equation W-1C to this section.

$$E_i = GHG_i \times \left[\sum_{z=1}^{x}\{K_1 \times T_{mal,z} + K_2 \times (T_{t,z} - T_{mal,z})\} + (K_2 \times Count \times T_{avg})\right] \quad \text{(Eq. W-1C)}$$

Where:

E_i = Annual total volumetric emissions of GHG_i from intermittent bleed natural gas pneumatic devices in standard cubic feet.

GHG_i = Concentration of GHG_i, CH_4 or CO_2, in natural gas supplied to the intermittent bleed natural gas pneumatic device as defined in paragraph (u)(2) of this section.

x = Total number of intermittent bleed natural gas pneumatic devices detected as malfunctioning in any pneumatic device monitoring survey during the year. A component found as malfunctioning in two or more surveys during the year is counted as one malfunctioning component.

K_1 = Whole gas emission factor for malfunctioning intermittent bleed natural gas pneumatic devices, in standard cubic feet per hour per device. Use 24.1 for well-pad sites in the onshore petroleum and natural gas production industry segment and use 16.1 for gathering and boosting sites in the onshore petroleum and natural gas gathering and boosting industry segment.

$T_{mal,z}$ = The total time the surveyed pneumatic device "z" was in service (*i.e.*, supplied with natural gas) and assumed to be malfunctioning, in hours. If one pneumatic device monitoring survey is conducted in the calendar year, assume the device found malfunctioning was malfunctioning for the entire calendar year. If multiple pneumatic device monitoring surveys are conducted in the calendar year, assume a device found malfunctioning in the first survey was malfunctioning since the beginning of the year until the date of the survey; assume a device found malfunctioning in the last survey of the year was malfunctioning from the preceding survey through the end of the year; assume a device found malfunctioning in a survey between the first and last surveys of the year was malfunctioning since the preceding survey until the date of the survey; and sum times for all malfunctioning periods.

$T_{t,z}$ = The total time the surveyed natural gas pneumatic device "z" was in service (*i.e.*, supplied with natural gas) during the year. Default is 8,760 hours for non-leap years and 8,784 hours for leap years.

K_2 = Whole gas emission factor for properly operating intermittent bleed natural gas pneumatic devices, in standard cubic feet per hour per device. Use 0.3 for well-pad sites in the onshore petroleum and natural gas production industry segment and use 2.8 for gathering and boosting sites in the onshore petroleum and natural gas gathering and boosting industry segment.

Count	=	Total number of intermittent bleed natural gas pneumatic devices that were never observed to be malfunctioning during any monitoring survey during the year.
T_{avg}	=	The average time the intermittent bleed natural gas pneumatic devices that were never observed to be malfunctioning during any monitoring survey were in service (*i.e.*, supplied with natural gas) using engineering estimates based on best available data. Default is 8,760 hours for non-leap years and 8,784 hours for leap years.

(A) You must conduct at least one complete pneumatic device monitoring survey in a calendar year. If you conduct multiple complete pneumatic device monitoring surveys in a calendar year, you must use the results from each complete pneumatic device monitoring survey when calculating emissions using equation W-1C to this section.

(B) For the purposes of paragraph (a)(3)(iii)(A) of this section, a complete monitoring survey is a survey of all intermittent bleed natural gas pneumatic devices vented directly to the atmosphere at a well-pad site for onshore petroleum and natural gas production facilities (except those measured according to paragraph (a)(1) of this section) or all intermittent bleed pneumatic devices vented directly to the atmosphere at a gathering and boosting site for onshore petroleum and natural gas gathering and boosting facilities (except those measured according to paragraph (a)(1) of this section).

(iv) You must convert the CH_4 and CO_2 volumetric emissions as determined according to paragraphs (a)(3)(i) and (iii) of this section and calculate both CO_2 and CH_4 mass emissions using calculations in paragraph (v) of this section for each type of natural gas pneumatic device (continuous high bleed, continuous low bleed, and intermittent bleed).

(4) *Calculation Method 4*. For well-pads in the onshore petroleum and natural gas production industry segment, gathering and boosting sites in the onshore petroleum and natural gas gathering and boosting industry segments, or for facilities in the onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, or

natural gas distribution industry segments, you may elect to calculate CH_4 and CO_2 emissions from your natural gas pneumatic devices that are vented directly to the atmosphere at your site using the methods specified in paragraphs (a)(4)(i) and (ii) of this section except those that are measured according to paragraphs (a)(1) through (3) of this section. You must exclude the counts of devices measured according to paragraph (a)(1) of this section from the counts of devices to be monitored or for which emissions are calculated according to the requirements in this paragraph (a)(4). You may not use this Calculation Method 4 for those devices for which you elected to measure emissions according to paragraph (a)(1), (2), or (3) of this section.

(i) You must calculate CH_4 and CO_2 volumetric emissions using equation W-1B to this section, except use the appropriate default whole gas population emission factors for natural gas pneumatic device vents (in standard cubic feet per hour per device) of each type “t” (continuous high bleed, continuous low bleed, and intermittent bleed) as listed in table W-1 to this subpart.

(ii) You must convert the CH_4 and CO_2 volumetric emissions as determined according to paragraphs (a)(4)(i) of this section and calculate both CO_2 and CH_4 mass emissions using calculations in paragraph (v) of this section for each type of natural gas pneumatic device (continuous high bleed, continuous low bleed, and intermittent bleed).

(5) *Counts of natural gas pneumatic devices.* For all industry segments, determine “$Count_t$” for equation W-1A, W-1B, or W-1C to this section for each type of natural gas pneumatic device (continuous high bleed, continuous low bleed, and intermittent bleed) by counting the total number of devices at the well-pad site, gathering and boosting site, or facility, as applicable, the number of devices that are vented directly to the atmosphere and the number of those devices that were measured or monitored during the reporting year, as applicable, except as specified in paragraph (a)(6) of this section.

(6) *Counts of onshore petroleum and natural gas production industry segment or the onshore petroleum and natural gas gathering and boosting natural gas pneumatic devices*. For facilities in the onshore petroleum and natural gas production industry segment or the onshore petroleum and natural gas gathering and boosting industry segment, you have the option in the first two consecutive calendar years to determine the total number of natural gas pneumatic devices at the facility and the number of devices that are vented directly to the atmosphere for each type of natural gas pneumatic device (continuous high bleed, continuous low bleed, and intermittent bleed), as applicable, using engineering estimates based on best available data. Counts of natural gas pneumatic devices measured or monitored during the reporting year must be made based on actual counts.

(7) *Type of natural gas pneumatic devices*. For all industry segments, determine the type of natural gas pneumatic device using engineering estimates based on best available information.

(8) *Routing to flares, combustion, or vapor recovery systems*. Calculate emissions from natural gas pneumatic devices routed to flares, combustion, or vapor recovery systems as specified in paragraph (a)(8)(i) or (ii) of this section, as applicable. If a device was vented directly to the atmosphere for part of the year and routed to a flare, combustion unit, or vapor recovery system during another part of the year, then calculate emissions from the time the device vents directly to the atmosphere as specified in paragraph (a)(1), (2), (3) or (4) of this section, as applicable, and calculate emissions from the time the device was routed to a flare or combustion as specified in paragraph (a)(8)(i) or (ii) of this section, as applicable. During periods when natural gas pneumatic device emissions are collected in a vapor recovery system that is not routed to combustion, paragraphs (a)(1) through (4) and (a)(8)(i) and (ii) of this section do not apply and no emissions calculations are required. Notwithstanding the calculation and emissions

reporting requirements as specified in this paragraph (a)(8) of this section, the number of natural gas pneumatic devices routed to flares, combustion, or vapor recovery systems, by type, must be reported as specified in § 98.236(b)(2)(iii).

(i) If any natural gas pneumatic devices were routed to a flare, you must calculate CH_4, CO_2, and N_2O 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).

(ii) If emissions from any natural gas pneumatic devices were routed to combustion units, you must calculate and report emissions as specified in subpart C of this part or calculate emissions as specified in paragraph (z) of this section and report emissions from the combustion equipment as specified in § 98.236(z), as applicable.

(b) [Reserved]

(c) *Natural gas driven pneumatic pump venting*. Calculate CH_4 and CO_2 emissions from natural gas driven pneumatic pumps venting directly to the atmosphere as specified in paragraph (c)(1), (2), or (3) of this section, as applicable. If you have a continuous flow meter on the natural gas supply line that is dedicated to any one or more natural gas driven pneumatic pumps, each of which only vents directly to the atmosphere, you must use Calculation Method 1 as specified in paragraph (c)(1) of this section to calculate vented CH_4 and CO_2 emissions from those pumps. Use Calculation Method 1 for any portion of a year when all of the pumps on the continuously measured natural gas supply line were vented directly to atmosphere. For natural gas driven pneumatic pumps vented directly to the atmosphere for which the natural gas supply rate is not continuously measured or the continuously measured natural gas supply line supplies some natural gas driven pneumatic pumps that vent emissions directly to the atmosphere and others that route emissions to flares, combustion or vapor recovery, use either the method specified in paragraph (c)(2) or (3) of this section to calculate vented CH_4 and CO_2 emissions for all of the natural gas driven pneumatic pumps at your facility that are not subject to Calculation Method 1; you may not use Calculation Method 2 for some vented natural gas driven pneumatic pumps and Calculation Method 3 for other natural gas driven pneumatic pumps. Calculate emissions from natural gas driven pneumatic pumps routed to flares or combustion as specified in paragraph (c)(4) of this section. All references to natural gas driven pneumatic pumps for Calculation Method 1 in this paragraph (c) also apply to combinations of natural gas pneumatic devices and natural gas driven pneumatic pumps that are served by a common natural gas supply line. You do not have to calculate emissions from natural gas driven pneumatic pumps covered in paragraph (e) of this section under this paragraph (c).

(1) *Calculation Method 1*. If you have or elect to install a continuous flow meter that is capable of meeting the requirements of § 98.234(b)~~ of this subpart~~ on a supply line to natural gas driven pneumatic pumps, then for the period of the year when the natural gas supply line is dedicated to any one or more natural gas driven pneumatic pumps, and each of the pumps is vented directly to the atmosphere, you must use the applicable methods specified in paragraphs (c)(1)(i) or (ii) of this section to calculate vented CH_4 and CO_2 emissions from those pumps.

(i) For volumetric flow monitors:

(A) Determine the cumulative annual volumetric flow, in standard cubic feet, as measured by the flow monitor in the reporting year. If the flow meter was installed during the year, calculate the total volumetric flow for the year based on the measured volumetric flow times the total hours in the calendar year in which at least one of the pumps connected to the supply line was pumping liquid divided by the number of hours in the year when at least one of pumps connected to the supply line was pumping liquid and the volumetric flow was being measured.

(B) Convert the natural gas volumetric flow from paragraph (c)(1)(i)(A) of this section to CH_4 and CO_2 volumetric emissions following the provisions in paragraph (u) of this section.

(C) Convert the CH_4 and CO_2 volumetric emissions from paragraph (c)(1)(i)(B) of this section to CH_4 and CO_2 mass emissions using calculations in paragraph (v) of this section.

(ii) For mass flow monitors:

(A) Determine the cumulative annual mass flow, in metric tons, as measured by the flow monitor in the reporting year. If the flow meter was installed during the year, calculate the total mass flow of vented natural gas emissions for the year based on the measured mass flow times the total hours in the calendar year in which at least one of the pumps connected to the supply line was pumping liquid divided by the number of hours in the year when at least one of pumps connected to the supply line was pumping liquid and the mass flow was being measured.

(B) Convert the cumulative mass flow from paragraph (c)(1)(ii)(A) of this section to CH_4 and CO_2 mass emissions by multiplying by the mass fraction of CH_4 and CO_2 in the supplied natural gas. You must follow the provisions in paragraph (u) of this section for determining the mole fraction of CH_4 and CO_2 and use molecular weights of 16 kg/kg-mol and 44 kg/kg-mol for CH_4 and CO_2, respectively. You may assume unspecified components have an average molecular weight of 28 kg/kg-mol.

(iii) If the supply line serves both natural gas pneumatic devices and natural gas driven pneumatic pumps, disaggregate the total measured amount of natural gas to natural gas pneumatic devices and natural gas driven pneumatic pumps based on engineering calculations and best available data.

(iv) The flow meter must be operated and calibrated according to the methods set forth in § 98.234(b).

(2) *Calculation Method 2.* Except as provided in paragraph (c)(1) of this section, you may elect to measure the volumetric flow rate of each natural gas driven pneumatic pump at your facility that vents directly to the atmosphere as specified in paragraphs (c)(2)(i) through (vii) of this section. You must exclude the counts of pumps measured according to paragraph (c)(1) of this section from the counts of pumps to be measured and for which emissions are calculated according to the requirements in this paragraph (c)(2).

(i) Measure all natural gas driven pneumatic pumps at your facility at least once every 5 years. If you elect to measure your pneumatic pumps over multiple years, you must measure approximately the same number of pumps each year. When you measure the emissions from natural gas driven pneumatic pumps at a well-pad site or gathering and boosting site, you must measure all pneumatic pumps that are vented directly to the atmosphere at the well-pad site or gathering and boosting site during the same calendar year.

(ii) Determine the volumetric flow rate of each natural gas driven pneumatic pump (in standard cubic feet per hour) using one of the methods specified in § 98.234(b) through (d), as appropriate, according to the requirements specified in paragraphs (c)(2)(ii)(A) through (D) of this section. You must measure the emissions under ~~representative~~ conditions representative of normal operations, which excludes periods immediately after conducting maintenance on the pump.

(A) If you use a temporary meter, such as a vane anemometer, according to the methods set forth in § 98.234(b) or a high volume sampler according to methods set forth in § 98.234(d), you must measure the emissions from each pump for a minimum of 5 minutes, during a period when the pump is continuously pumping liquid.

(B) If you use calibrated bagging, follow the methods set forth in § 98.234(c), except under § 98.234(c)(2), only one bag must be filled to have a valid measurement. You must collect sample for a minimum of 5 minutes, or until the bag is full, whichever is shorter, during a period when the pump is continuously pumping liquid. If the bag is not full after 5 minutes, you must either continue sampling until you fill the calibrated bag or you may elect to remeasure the vent according to paragraph (c)(2)(ii)(A) of this section.

(C) You do not need to use the same measurement method for each natural gas driven pneumatic pump vent.

(D) If the measurement method selected measures the volumetric flow rate in actual cubic feet, convert the measured flow to standard cubic feet following the methods specified in paragraph (t)(1) of this section. Convert the measured flow during the test period to standard cubic feet per hour, as appropriate.

(iii) Calculate the volume of natural gas emitted from each natural gas driven pneumatic pump vent as the product of the natural gas emissions flow rate measured in paragraph (c)(2)(ii) of this section and the number of hours that liquid was pumped by the pneumatic pump in the calendar year.

(iv) For each pneumatic pump, convert the volumetric emissions of natural gas at standard conditions determined in paragraph (c)(2)(iii) of this section to CO_2 and CH_4 volumetric emissions at standard conditions using the methods specified in paragraph (u) of this section.

(v) For each pneumatic pump, convert the GHG volumetric emissions at standard conditions determined in paragraph (c)(2)(iv) of this section to GHG mass emissions using the methods specified in paragraph (v) of this section.

(vi) Sum the CO_2 and CH_4 mass emissions determined in paragraph (c)(2)(v) of this section.

(vii) If you chose to conduct natural gas pneumatic pump measurements over multiple years, "n," according to paragraph (c)(2)(i) of this section, then you must calculate the emissions from all pneumatic pumps at your facility as specified in paragraph (c)(2)(vii)(A) through (D) of this section.

(A) Use the emissions calculated in paragraph (c)(2)(vi) of this section for the pumps measured during the reporting year.

(B) Calculate the whole gas emission factor for pneumatic pumps at the facility using equation W-2A to this section and all available data from the current year and the previous years in your monitoring cycle (n-1 years) for which natural gas pneumatic pump vent measurements were made according to Calculation Method 2 in paragraph (c)(2) of this section (*e.g.*, if your monitoring cycle is 3 years, then use measured data from the current year and the two previous years). This emission factor must be updated annually.

$$EF_s = \frac{\sum_{y=1}^{n} MT_{s,y}}{\sum_{y=1}^{n} Count_y} \qquad \text{(Eq. W-2A)}$$

Where:

EF_s = Whole gas population emission factor for natural gas pneumatic pump vents, in standard cubic feet per hour per pump.

$MT_{s,y}$ = Volumetric whole gas emissions rate measurement at standard ("s") conditions during year "y" in standard cubic feet per hour, as calculated in paragraph (c)(2)(iii) of this section.

$Count_y$ = Count of natural gas driven pneumatic pump vents measured according to Calculation Method 2 in year "y."

n = Number of years of data to include in the emission factor calculation according to the number of years used to monitor all natural gas pneumatic pump vents at the facility.

(C) Calculate CH_4 and CO_2 volumetric emissions from natural gas driven pneumatic pumps per well-pad site or gathering and boosting site that were not measured during the reporting year using equation W-2B to this section.

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

Where:

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

Count = Total number of natural gas driven pneumatic pumps that vented directly to the atmosphere and that were not directly measured according to the requirements in paragraphs (c)(1) or (c)(2)(ii) of this section.

EF_s = Population emission factors for natural gas driven pneumatic pumps (in standard cubic feet per hour per pump) as calculated using equation W-2A to this section.

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 that vented directly to the atmosphere were pumping liquid using engineering estimates based on best available data. Default is 8,760 hours for pumps that only vented directly to the atmosphere.

(D) Calculate both CH_4 and CO_2 mass emissions from volumetric emissions calculated using equation W-2B to this section using calculations in paragraph (v) of this section.

(E) Sum the CH_4 and CO_2 mass emissions calculated in paragraphs (c)(2)(vii)(A) and (D) of this section to calculate the total CH_4 and CO_2 mass emissions for Calculation Method 2 per well-pad site or gathering and boosting site.

(3) *Calculation Method 3*. If you elect not to measure emissions as specified in Calculation Method 2, then you must use the applicable method specified in paragraphs (c)(3)(i) and (ii) of this section to calculate CH_4 and CO_2 emissions from all natural gas driven pneumatic pumps that are vented directly to the atmosphere at each well-pad site or gathering and boosting site at your facility and that are not measured according to paragraph (c)(1) of this section. You must exclude the counts of devices measured according to paragraph (c)(1) of this section from the counts of pumps for which emissions are calculated according to the requirements in this paragraph (c)(3).

(i) Calculate CH_4 and CO_2 volumetric emissions from natural gas driven pneumatic pumps using equation W-2B to this section, except use the appropriate default whole gas population emission factor for natural gas pneumatic pump vents (in standard cubic feet per hour per device) as provided in table W-1 to this subpart.

(ii) Convert the CH_4 and CO_2 volumetric emissions determined according to paragraph (c)(3)(i) of this section to CO_2 and CH_4 mass emissions using calculations in paragraph (v) of this section.

(4) *Routing to flares, combustion, or vapor recovery systems*. Calculate emissions from natural gas driven pneumatic pumps for periods when they are routed to flares or combustion as specified in paragraph (c)(4)(i) or (ii) of this section, as applicable. If emissions from a natural gas driven pneumatic pump were vented directly to the atmosphere for part of the year and routed to a flare, combustion, or vapor recovery for another part of the year, then calculate

vented emissions for the portion of the year when venting occurs using the applicable method in paragraph (c)(1), (2), or (3) of this section for the period when venting occurs (including periods when emissions bypassed a flare), and calculate emissions for the portion of the year when the emissions are routed to a flare or combustion unit using the method in paragraph (c)(4) of this section. During periods when emissions from a pump are routed to a vapor recovery system without subsequently being routed to combustion, paragraphs (c)(1) through (3) and (c)(4)(i) and (ii) of this section do not apply and no emissions calculations are required. Notwithstanding the calculation and emissions reporting requirements as specified in this paragraph (c)(4) of this section, the number of natural gas pneumatic pumps routed to flares, combustion, or vapor recovery systems must be reported as specified in § 98.236(c)(2)(iii) and (iv).

(i) If any natural gas driven pneumatic pumps were routed to a flare, you must calculate CH_4, CO_2, and N_2O 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).

(ii) If emissions from any natural gas driven pneumatic pumps were routed to combustion, you must calculate emissions for the combustion equipment as specified in paragraph (z) of this section and report emissions from the combustion equipment as specified in § 98.236(z).

(d) *Acid gas removal unit (AGR) vents and Nitrogen removal unit (NRU) vents*. For AGR vents (including processes such as amine, membrane, molecular sieve or other absorbents and adsorbents), calculate emissions for CH_4 and CO_2 vented directly to the atmosphere or emitted through a sulfur recovery plant, using any of the calculation methods described in paragraphs (d)(1) through (4) of this section, and also comply with paragraphs (d)(5) through (12) of this section, as applicable. For NRU vents, calculate emissions for CH_4 vented directly to the atmosphere using any of the calculation methods described in paragraphs (d)(1) through (4) of this section, and also comply with paragraphs (d)(5) through (~~11~~12) of this section, as applicable. If any AGR vents or NRU vents are routed to a flare, you must calculate CH_4, CO_2, and N_2O 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). If any AGR vents or NRU vents are routed through an engine (*e.g.*, permeate from a membrane or de-adsorbed gas from a pressure swing adsorber used as fuel supplement) (*i.e.*, routed to combustion), you must calculate CH_4, CO_2, and N_2O emissions as specified in subpart C of this part or as specified in paragraph (z) of this section, 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).

(2) *Calculation Method 2*. Except as specified in paragraph (d)(4) of this section, for CO_2 emissions, 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 to this section. Except as specified in paragraph (d)(4) of this section, for CH_4 emissions, if a vent meter is installed,

including the volumetric flow rate monitor on a CEMS for CO_2, use the CH_4 composition and annual volume of vent gas to calculate emissions using equation W-3 to this section.

$$E_{a,i} = V_a \times Vol_i \qquad \text{(Eq. W-3)}$$

Where:

$E_{a,i}$	=	Annual total volumetric GHG_i (either CO_2 or CH_4) emissions at actual conditions, in cubic feet per year.
V_a	=	Total annual volume of vent gas flowing out of the AGR or NRU 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_i	=	Annual average volumetric fraction of GHG_i (either CO_2 or CH_4) content in vent gas flowing out of the AGR or NRU as determined in paragraph (d)(7) of this section.

(3) *Calculation Method 3*. If a CEMS for CO_2 or a vent meter is not installed, you may use the inlet and/or outlet gas flow rate of the AGR or NRU to calculate emissions for CH_4 and CO_2 using equation W-4A, W-4B, or W-4C to this section. If inlet gas flow rate and CH_4 and CO_2 content of the vent gas are known, use equation W-4A to this section. If outlet gas flow rate and CH_4 and CO_2 content of the vent gas are known, use equation W-4B to this section. If inlet gas flow rate and outlet gas flow rate are known, use equation W-4C to this section. If the calculated annual total volumetric emissions ($E_{a,i}$) are less than or equal to 0 cubic feet per year, you may not use this calculation method for either CH_4 or CO_2.

$$E_{a,i} = V_{in} \times \left[\frac{Vol_{I,i} - Vol_{O,i}}{Vol_{EM,i} - Vol_{O,i}}\right] \times Vol_{EM,i} \qquad \text{(Eq. W-4A)}$$

$$E_{a,i} = V_{out} \times \left[\frac{Vol_{I,i} - Vol_{O,i}}{Vol_{EM,i} - Vol_{I,i}}\right] \times Vol_{EM,i} \qquad \text{(Eq. W-4B)}$$

$$E_{a,i} = \left(V_{in} \times Vol_{I,i}\right) - \left(V_{out} \times Vol_{O,i}\right) \qquad \text{(Eq. W-4C)}$$

Where:

$E_{a,i}$	=	Annual total volumetric GHG_i (either CH_4 or CO_2) emissions at actual conditions, in cubic feet per year.
V_{in}	=	Total annual volume of natural gas flow into the AGR or NRU 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 or NRU in cubic feet per year at actual conditions as determined using methods specified in paragraph (d)(5) of this section.
$Vol_{I,i}$	=	Annual average volumetric fraction of GHG_i (either CH_4 or CO_2) content in natural gas flowing into the AGR or NRU as determined in paragraph (d)(7) of this section.
$Vol_{O,i}$	=	Annual average volumetric fraction of GHG_i (either CH_4 or CO_2) content in natural gas flowing out of the AGR or NRU as determined in paragraph (d)(8) of this section.
$Vol_{EM,i}$	=	Annual average volumetric fraction of GHG_i (either CH_4 or CO_2) content in the vent gas flowing out of the AGR or NRU as determined in paragraph (d)(6) of this section.

(4) *Calculation Method 4*. If CEMS for CO_2 or a vent meter is not installed, you may calculate CH_4 and CO_2 emissions from an AGR or NRU using any standard simulation software package, such as AspenTech HYSYS®, or API 4679 AMINECalc, that uses the Peng-Robinson equation of state and speciates CH_4 and CO_2 emissions. A minimum of the parameters listed in paragraph (d)(4)(i) through (x) of this section, as applicable, must be used to characterize emissions. If paragraph (d)(4)(i) through (x) of this section indicates that an applicable parameter must be measured, collect measurements reflective of representative operating conditions over the time period covered by the simulation. Determine all other applicable parameters in paragraph (d)(4)(i) through (x) of this section by engineering estimate and process knowledge based on best available data and, if necessary, adjust parameters to represent the operating

conditions over the time period covered by the simulation. Determine the number of simulations and associated time periods such that the simulations cover the entire reporting year (*i.e.*, if you calculate emissions using one simulation, use representative parameters for the operating conditions over the calendar year; if you use periodic simulations to cover the calendar year, use parameters for the operating conditions over each corresponding appropriate portion of the calendar year). You may also use this method for CO_2 emissions from an AGR if a vent meter is installed but a CEMS is not, or for CH_4 emissions from an AGR if a vent meter is installed (including the volumetric flow rate monitor on a CEMS for CO_2), in which case you must determine the difference between the annual volume of vent gas measured by the vent meter and the simulated annual volume of vent gas according to paragraph (d)(9) of this section.

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

(ii) Acid gas content of feed natural gas (must be measured).

(iii) Acid gas content of outlet natural gas.

(iv) CH_4 content of feed natural gas (must be measured).

(v) CH_4 content of outlet natural gas.

(vi) For NRU, nitrogen content of feed natural gas (must be measured).

(vii) For NRU, nitrogen content of outlet natural gas.

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

(ix) Exit temperature of natural gas.

(x) For AGR, solvent type, pressure, temperature, circulation rate, and composition.

(5) *Flow rate of inlet or outlet*. For Calculation Method 3, determine the gas flow rate of the inlet when using equation W-4A or W-4C to this section or the gas flow rate of the outlet when using equation W-4B or W-4C to this section for the natural gas stream of an AGR or

NRU 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) *Composition of vent gas*. For Calculation Method 2 or Calculation Method 3 when using equation W-4A or W-4B to this section, 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 or NRU is operating to determine Vol_i in equation W-3 to this section or $Vol_{EM,i}$ in equation W-4A or W-4B to this section, according to the methods set forth in § 98.234(b).

(7) *Composition of inlet gas stream*. 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 or NRU is operating to determine $Vol_{I,i}$ in equation W-4A, W-4B, or W-4C to this section, according to the methods set forth in § 98.234(b).

(8) *Composition of outlet gas stream.* For Calculation Method 3, determine annual average volumetric fraction of GHG_i (either CH_4 or CO_2) content in natural gas flowing out of the AGR or NRU using one of the methods specified in paragraphs (d)(8)(i) through (iii) of this section.

(i) If a continuous gas analyzer is installed on the outlet natural 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 natural gas stream for each quarter that the AGR or NRU is operating to determine $Vol_{O,i}$ in equation W-4A, W-4B, or W-4C to 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 and the outlet quality specification for CH_4 in natural gas.

(9) *Comparison of annual volume of vent gas*. If a vent meter is installed but you wish to use Calculation Method 4 rather than Calculation Method 2 for an AGR, use equation W-4D to this section to determine the difference between the annual volume of vent gas measured by the vent meter and the simulated annual volume of vent gas.

$$PD = \frac{\left|V_{a,meter} - V_{a,sim}\right|}{\left(\frac{V_{a,meter} + V_{a,sim}}{2}\right)} \times 100\% \qquad \text{(Eq. W-4D)}$$

Where:

PD	=	Percent difference between vent gas volumes, %.
$V_{a,meter}$	=	Total annual volume of vent gas flowing out of the AGR 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.
$V_{a,sim}$	=	Total annual volume of vent gas flowing out of the AGR in cubic feet per year at actual conditions as determined by a standard simulation software package consistent with paragraph (d)(4) of this section.

(10) *Volumetric emissions*. Calculate annual volumetric CH_4 and CO_2 emissions at standard conditions using calculations in paragraph (t) of this section.

(11) *Emissions vented directly to atmosphere from AGRs or NRUs routed to vapor recovery systems or flares*. If the AGR vent or NRU vent has a vapor recovery system or routes emissions to a flare, calculate annual emissions vented directly to atmosphere from the AGR vent or NRU vent during periods of time when emissions were not routed to the vapor recovery system or flare as specified in paragraph (d)(11)(i) and (ii) of this section. If emissions are routed to a flare but the flare is unlit, calculate emissions in accordance with the methodology specified in paragraph (n) of this section and report emissions from the flare as specified in § 98.236(n).

(i) Calculate vented emissions as specified in paragraph (d)(1), (2), (3), or (4) of this section, which represents the emissions from the AGR vent or NRU vent prior to the vapor recovery system or flare. Calculate an average hourly vented emissions rate by dividing the vented emissions by the number of hours that the AGR or NRU was in operation.

(ii) To calculate vented emissions during periods when the AGR vent or NRU vent was not routing emissions to a vapor recovery system or a flare, multiply the average hourly vented emissions rate determined in paragraph (d)(11)(i) of this section by the number of hours that the AGR or NRU vented directly to the atmosphere. Determine the number of hours that the AGR or NRU vented directly to atmosphere by subtracting the hours that the AGR or NRU was connected to a vapor recovery system or flare (based on engineering estimate and best available data) from the total operating hours for the AGR or NRU in the calendar year. You must take into account periods with reduced capture efficiency of the vapor recovery system or flare.

(12) *Mass emissions*. Calculate annual mass CH_4 and CO_2 emissions using calculations in paragraph (v) of this section.

(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 (5) of this section. For glycol dehydrators that have an annual average daily natural gas throughput that is greater than or equal to 0.4 million standard cubic feet per day, use Calculation Method 1 in paragraph (e)(1) of this section. For glycol dehydrators that have an annual average of daily natural gas throughput that is greater than 0 million standard cubic feet per day and less than 0.4 million standard cubic feet per day, use either Calculation Method 1 in paragraph (e)(1) of this section or Calculation Method 2 in paragraph (e)(2) of this section. If you are required to use a software program consistent with the requirements of paragraph (e)(1) of this section for compliance with federal or state regulations, air permit requirements, or annual emissions inventory reporting for the current reporting year, you must use Calculation Method 1 to calculate annual CH_4 and CO_2 emissions. If emissions from dehydrator vents are routed to a vapor recovery system, you must calculate the emissions according to paragraph (e)(4) of this section. If emissions from dehydrator vents are routed to a regenerator firebox/fire tubes or to other non-flare combustion units, you must calculate CH_4, CO_2, and N_2O annual emissions as specified in paragraph (e)(5) of this section. If any dehydrator vents are routed to a flare, you must calculate CH_4, CO_2, and N_2O 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).

(1) *Calculation Method 1*. Calculate annual mass emissions from glycol dehydrators by using a software program, such as AspenTech HYSYS®, Bryan Research & Engineering ProMax®, 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. If you elect to use ProMax®, you must use version 5.0 or above. Emissions must be modeled from both the still vent and, if applicable, the flash tank vent. A

minimum of the parameters listed in paragraph (e)(1)(i) through (xi) of this section, as applicable, must be used to characterize emissions. If paragraph (e)(1)(i) through (xi) of this section indicates that an applicable parameter must be measured, collect measurements reflective of representative operating conditions for the time period covered by the simulation. Sample and analyze composition at least once every five years. Samples must be collected within six months of the startup or by January 1, 2030, whichever date is later. Until such a time that a sample is collected, determine composition by using one of the existing methods. Determine all other applicable parameters in paragraph (e)(1)(i) through (xi) of this section by engineering estimate and process knowledge based on best available data and, if necessary, adjust parameters to represent the operating conditions over the time period covered by the simulation. Determine the number of simulations and associated time periods such that the simulations cover the entire reporting year (*i.e.*, if you calculate emissions using one simulation, use representative parameters for the operating conditions over the calendar year; if you use periodic simulations to cover the calendar year, use parameters for the operating conditions over each corresponding appropriate portion of the calendar year). If more than one simulation is performed, input parameters should be remeasured if no longer representative of operating conditions.

(i) Feed natural gas flow rate (based on measured data).

(ii) Feed natural gas water content (must be measured).

(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 at the absorber inlet (must be measured).

(xi) Wet natural gas composition. Measure this parameter using one of the methods described in paragraphs (e)(1)(xi)(A) and (B) of this section.

(A) 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.

(B) 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 using equation W-5 to this section, and then calculate the collective CH_4 and CO_2 mass emissions from the volumetric emissions using the procedures in paragraph (v) of this section:

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

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 daily natural gas throughput that is greater than 0 million standard cubic feet per day and less than 0.4 million standard cubic feet per day for which you elect to use this Calculation Method 2.

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 to this section. From volumetric natural gas emissions, calculate both CH_4 and CO_2 volumetric and mass emissions using the procedures in paragraphs (u) and (v) 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.

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

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) *Emissions vented directly to atmosphere from dehydrators routed to a vapor recovery system, flare, or regenerator firebox/fire tubes*. If the dehydrator(s) has a vapor recovery system, routes emissions to a flare, or routes emissions to a regenerator firebox/fire tubes and you use Calculation Method 1 or Calculation Method 2 in paragraph (e)(1) or (2) of this section, calculate

annual emissions vented directly to atmosphere from the dehydrator(s) during periods of time when emissions were not routed to the vapor recovery system, flare, or regenerator firebox/fire tubes as specified in paragraphs (e)(4)(i) and (ii) of this section. If the dehydrator(s) has a vapor recovery system or routes emissions to a flare or other non-flare combustion unit and you use Calculation Method 3 in paragraph (e)(3) of this section, calculate annual emissions vented directly to atmosphere from the dehydrator(s) during periods of time when emissions were not routed to the vapor recovery system, ~~or~~ flare, or other non-flare combustion unit as specified in paragraph (e)(4)(iii) of this section.

(i) When emissions from dehydrator(s) are calculated using Calculation Method 1 or 2, calculate vented emissions as specified in paragraph (e)(1) or (2) of this section, which represents the emissions from the dehydrator prior to the vapor recovery system, ~~or~~ flare, or regenerator firebox/fire tubes. Calculate an average hourly vented emissions rate by dividing the vented emissions by the number of hours that the dehydrator was in operation.

(ii) To calculate total emissions vented directly to atmosphere during periods when the dehydrator was not routing emissions to a vapor recovery system, flare, or regenerator firebox/fire tubes for dehydrator(s) with emissions calculated using Calculation Method 1 or 2, multiply the average hourly vented emissions rate determined in paragraph (e)(4)(i) of this section by the number of hours that the dehydrator vented directly to the atmosphere. Determine the number of hours that the dehydrator vented directly to atmosphere by subtracting the hours that the dehydrator was connected to a vapor recovery system, flare, or regenerator firebox/fire tubes (based on engineering estimate and best available data) from the total operating hours for the dehydrator in the calendar year. You must take into account periods with reduced capture efficiency of the vapor recovery system, flare, or regenerator firebox/fire tubes. If emissions are routed to a flare but the flare is unlit, calculate emissions in accordance with the methodology specified in paragraph (n) of this section and report emissions from the flare as specified in § 98.236(n).

(iii) When emissions from dehydrator(s) are calculated using Calculation Method 3, calculate total annual emissions vented directly to atmosphere from the dehydrator(s) during periods of time when emissions were not routed to the vapor recovery system, flare, or other non-flare combustion unit~~regenerator firebox/fire tubes~~ by determining of the number of depressurization events (including portions of an event) that vented to atmosphere based on engineering estimate and best available data. You must take into account periods with reduced capture efficiency of the vapor recovery system,~~, or~~ flare, or other non-flare combustion unit. If emissions are routed to a flare but the flare is unlit, calculate emissions in accordance with the methodology specified in paragraph (n) of this section and report emissions from the flare as specified in § 98.236(n).

(5) *Combustion emissions from routing to regenerator firebox/fire tubes or other non-flare combustion unit.* If any glycol dehydrator emissions are routed to a regenerator firebox/fire tubes~~ or other non-flare combustion unit~~, calculate emissions from these devices attributable to dehydrator flash tank vents or still vents as specified in paragraphs (e)(5)(i) through (iii) of this section. If any desiccant dehydrator emissions are routed to a non-flare combustion unit, calculate combusted emissions as specified in paragraphs (e)(5)(i) through (iii) of this section. If you operate a CEMS to monitor the emissions from the regenerator firebox/fire tubes or other non-flare combustion unit, calculate emissions as specified in paragraph (e)(5)(iv) of this section.

(i) Determine the volume of the total emissions that is routed to a regenerator firebox/fire tubes or other non-flare combustion unit as specified in paragraph (e)(5)(i)(A) or (B) of this section.

(A) Measure the flow from the dehydrator(s) to the regenerator firebox/fire tubes or other non-flare combustion unit using a continuous flow measurement device. If you continuously measure flow to the regenerator firebox/fire tubes or other non-flare combustion unit, you must use the measured volumes to calculate emissions from the regenerator firebox/fire tubes or other non-flare combustion unit.

(B) Using engineering estimates based on best available data, determine the volume of the total emissions estimated in paragraph (e)(1), (2), or (3) of this section, as applicable, that is routed to the regenerator firebox/fire tubes or other non-flare combustion unit.

(ii) Determine composition of the gas routed to a regenerator firebox/fire tubes or other non-flare combustion unit as specified in paragraph (e)(5)(ii)(A) or (B) of this section.

(A) Use the appropriate vent emissions as determined in paragraph (e)(1) or (2) of this section.

(B) Measure the composition of the gas from the dehydrator(s) to the regenerator firebox/fire tubes or other non-flare combustion unit using a continuous composition analyzer. If you continuously measure gas composition, then those measured data must be used to calculate dehydrator emissions from the regenerator firebox/fire tubes or other non-flare combustion unit.

(iii) Determine GHG volumetric emissions at actual conditions from the regenerator firebox/fire tubes or other non-flare combustion unit using equations W-39A, W-39B, and W-40 to this section. Calculate GHG volumetric emissions at standard conditions using calculations in paragraph (t) of this section. Calculate both GHG mass emissions from volumetric emissions using calculations in paragraph (v) of this section.

(iv) 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 regenerator firebox/fire tubes or other non-flare combustion unit, you must calculate only CO_2 emissions for the regenerator firebox/fire tubes or other non-flare combustion unit. 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 emissions from a regenerator firebox/fire tubes or other non-flare combustion unit, the requirements specified in paragraphs (e)(5)(ii) and (iii) of this section are not required.

(f) *Well venting for liquids unloadings*. Calculate annual volumetric natural gas emissions from well venting for liquids unloading when the well is unloaded to the atmosphere using one of the calculation methods described in paragraph (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. If emissions from well venting for liquids unloading are routed to a flare, you must calculate CH_4, CO_2, and N_2O annual emissions as specified in paragraph (n) of this section and report emissions from the flare as specified in § 98.236(n).

(1) *Calculation Method 1*. Calculate emissions from manual and automated unloadings at 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 directly 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 to this section. Equation W-7A to this section must be used for each unloading type combination (automated plunger lift unloadings, manual plunger lift unloadings, automated unloadings without plunger lifts and manual unloadings without plunger lifts) for any tubing diameter group and pressure group combination in each sub-basin.

$$E_a = FR \times T_p \qquad \text{(Eq. W-7A)}$$

Where:

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

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 = 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 to this section.

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

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 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 to 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 automated plunger lift unloadings, wells with manual plunger lift unloadings, wells with automated unloadings without plunger lifts and wells with manual unloadings 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 each well in the same pressure group that have the same tubing diameter group, for the number of hours ~~of~~that each well is ~~venting~~vented to the atmosphere.

(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 well from manual and automated well venting to the atmosphere for liquids unloading without plunger lift assist using equation W-8 to this section.

$$E_s = N_p \times \left(\left(0.37 \times 10^{-3}\right) \times CD_p^2 \times WD_p \times SP_p\right) + \sum_{q=1}^{N_p}\left(SFR_p \times \left(HR_{p,q} - 1.0\right) \times Z_{p,q}\right) \quad \text{(Eq. W-8)}$$

Where:

E_s	=	Annual natural gas emissions for each well at standard conditions, s, in cubic feet per year.
N_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 well, p, in inches or the tubing diameter for well, p, when stoppage packers are used in the annulus to restrict flow of gas up the annulus to the surface.
WD_p	=	Vertical well depth from either the top of the well or the lowest packer to the bottom of the well or the top of the fluid column, for well, p, in feet. For horizontal wells the bottom of the well is the point at which the vertical borehole pivots to a horizontal direction.
SP_p	=	For 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 is not available for the well, you may determine the casing pressure by multiplying the tubing pressure of the 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 to this section to calculate the average flow-line rate at standard conditions.
$HR_{p,q}$	=	Hours that 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 to this section.

$$E_s = N_p \times \left(\left(0.37 \times 10^{-3}\right) \times TD_p^2 \times WD_p \times SP_p\right) + \sum_{q=1}^{N_p}\left(SFR_p \times \left(HR_{p,q} - 0.5\right) \times Z_{p,q}\right) \quad \text{(Eq. W-9)}$$

Where:

E_s	=	Annual natural gas emissions for each well at standard conditions, s, in cubic feet per year.
N_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).
TD_p	=	Tubing internal diameter for well, p, in inches.
WD_p	=	Tubing depth to plunger bumper or to the top of the fluid column for well, p, in feet.
SP_p	=	Flow-line pressure for 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 to this section to calculate the average flow-line rate at standard conditions.
$HR_{p,q}$	=	Hours that 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) *Volumetric and mass emissions*. 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 to this section. Equation W-10A to this section applies to well venting when the gas flowback rate is measured from a specified number of example completions or workovers in a sub-basin and well type combination and equation W-10B to this section applies when the gas flowback vent volume is measured for each completion or workover in a sub-basin and well type combination. 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 to this section, you must follow the procedures specified in paragraph (g)(1) of this section. If you elect to use equation W-10B to this section, 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. To calculate emissions during the initial period, you must calculate the gas flowback rate in the initial flowback period as described in equation W-10B to this section. Alternatively, you may use a multiphase flow meter placed on the flow line downstream of the wellhead and ahead of the separator to directly measure gas flowback during the initial period when flowback is routed to open pits or tanks. If you use a multiphase flow meter, measurements must be taken from initiation of flowback to the beginning of the period of time when sufficient quantities of gas are present to enable separation. 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 (n) of this section, report emissions from the flare as specified in § 98.236(n), and report additional information specified in § 98.236(g), as applicable.

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

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

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 well.

CW = Total number of completions or workovers using hydraulic fracturing.

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

$T_{p,i}$ = 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 each completion or workover, in hours, 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 each completion of a newly drilled well or well workover using hydraulic fracturing in standard cubic feet per hour 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 during each completion or workover, 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 gas for each completion or workover, 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 of each completion or workover, in standard cubic feet per hour during the initial period when flowback is routed to open pits or tanks from initiation of flowback to the beginning of the period of time when sufficient quantities of gas are present to enable separation, 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). Alternatively, flow rate during the initial period may be measured using a multiphase flow meter installed upstream of the separator capable of accurately measuring gas flow prior to separation.

$Z_{p,i}$ = If a multiphase flow meter is used to measure flowback during the initial period, then $Z_{p,i}$ is equal to 1. If flowback is 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, then $Z_{p,i}$ is equal to 0.5.

(1) If you elect to use equation W-10A to this section on gas wells, you must use Calculation Method 1 as specified in paragraph (g)(1)(i) of this section. If you are unable to measure the gas flowback rates using a recording flow meter for gas well completions or workovers as described in Calculation Method 1, for example due to field conditions, operating conditions, or health and safety considerations, you may use Calculation Method 2 as specified in paragraph (g)(1)(ii) of this section 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 to 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 to 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 to 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). Alternatively, you may use a multiphase flow meter placed on the flow line downstream of the wellhead and ahead of the separator to directly measure gas flowback during the initial period when flowback is routed to open pits or tanks. If you use a multiphase flow meter, measurements must be taken from initiation of flowback to the beginning of the period of time when sufficient quantities of gas are present to enable separation.

(ii) *Calculation Method 2 (for gas wells)*. You must use equation W-12A to 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 to 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) also apply. When calculating the flowback rates for use in equations W-12A and W-12B to 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 to this section for subsonic flow or equation W-11B to this section for sonic flow. You must use best engineering estimates based on best available data along with equation W-11C to this section to determine whether the predominant flow is sonic or subsonic. If the value of R in equation W-11C to 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 to this section using equation W-33 to this section.

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

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.

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

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.

$$R = {}^{P1}\!/_{P2} \quad \text{(Eq. W-11C)}$$

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 to this section, calculate FRM_s using equation W-12A to this section.

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

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 to this section. You may not use flow volume as used in equation W-10B to 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 to this section, calculate FRM_i using equation W-12B to this section.

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

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 or measured using a multiphase flow meter installed upstream of the separator capable of accurately measuring gas flow prior to separation.
$PR_{s,p}$	=	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 to 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 to 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 to this section, calculate the average gas production rate ($PR_{s,p}$) using equation W-12C to 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.

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

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.

(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 to this section. Calculate annual volumetric natural gas emissions from each gas well venting during completions without hydraulic fracturing using equation W-13B to 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 (n) of this section, report emissions from the flare as specified in § 98.236(n), and report additional information specified in § 98.236(h), as applicable.

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

$$E_{s,p} = V_p \times T_p \qquad \text{(Eq. W-13B)}$$

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 well 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.
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 well 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 directly to the atmosphere 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) [Reserved]

(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. For industry segments other than natural gas distribution, 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. Natural gas distribution blowdowns with a unique physical volume of less than 500 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. If emissions from blowdown vent stacks are routed to a flare, you must calculate CH_4, CO_2, and N_2O annual emissions as specified in paragraph (n) of this section and report emissions from the flare as specified in § 98.236(n).

(1) *Method for calculating unique physical volumes or distribution pipeline 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. For natural gas distribution pipelines without isolation valves, calculate the unique physical volume of the distribution pipeline section that was isolated from operation by methods other than isolation

valves, in cubic feet, by using engineering estimates based on best available data (*e.g.*, diameter of the pipeline and length of isolated section).

(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) of this section or, if applicable, paragraph (i)(2)(iii) of this section for each equipment or event type. Categorize equipment and event types for each industry segment as specified in paragraph (i)(2)(iv) of this section.

(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 to this section.

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

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, 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 production, onshore petroleum and natural gas gathering and boosting facilities, onshore natural gas transmission pipeline facilities, and natural gas distribution

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 production, onshore petroleum and natural gas gathering and boosting facilities, onshore natural gas transmission pipeline facilities, and natural gas distribution 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.

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

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, 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". For emergency blowdowns at onshore petroleum and natural gas production, onshore petroleum and natural gas gathering and boosting facilities, onshore natural gas transmission pipeline facilities, and natural gas distribution 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).

$P_{a,b,p}$ = Absolute pressure at actual conditions in the unique physical volume (psia) at the beginning of the blowdown "p". For emergency blowdowns at onshore petroleum and natural gas production, onshore petroleum and natural gas gathering and boosting facilities, onshore natural gas transmission pipeline facilities, and natural gas distribution facilities, engineering estimates based on best available information may be used to determine the pressure at the beginning of the blowdown.

$P_{a,e,p}$ = 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. For emergency blowdowns at onshore petroleum and natural gas production, onshore petroleum and natural gas gathering and boosting facilities, onshore natural gas transmission pipeline facilities, and natural gas distribution facilities, engineering estimates based on best available information may be used to determine the pressure at the end of the blowdown.

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 to 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 to 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.

(iv) Categorize blowdown vent stack emission events as specified in paragraphs (i)(2)(iv)(A) and (B) of this section, as applicable.

(A) For the onshore petroleum and natural gas production, onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, LNG storage, LNG import and export equipment, and onshore petroleum and natural gas gathering and boosting industry segments, equipment or event types must be grouped into the following seven categories: Facility piping (*i.e.*, physical volumes associated with piping for which the entire physical volume is located within the facility boundary), pipeline venting (*i.e.*, physical volumes associated with pipelines for which a portion of the physical volume is located outside the facility boundary and the remainder, including the blowdown vent stack, is located 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.

(B) For the onshore natural gas transmission pipeline and natural gas distribution industry segments, 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.

(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) *Hydrocarbon liquids and produced water storage tanks*. Calculate CH_4 and CO_2 emissions from atmospheric pressure storage tanks receiving hydrocarbon liquids and CH_4 emissions from atmospheric pressure storage tanks receiving produced water, from onshore petroleum and natural gas production facilities, onshore petroleum and natural gas gathering and boosting facilities (including stationary liquid storage not owned or operated by the reporter), and onshore natural gas processing facilities as specified in this paragraph (j). For wells, gas-liquid separators, or onshore petroleum and natural gas gathering and boosting or onshore natural gas processing non-separator equipment (*e.g.*, stabilizers, slug catchers) with annual average daily throughput of hydrocarbon liquids 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, gas-liquid separators, or non-separator equipment with annual average daily throughput of hydrocarbon liquids greater than 0 barrels per day and less than 10 barrels per day, calculate annual CH_4 and CO_2 emissions using Calculation Method 1, 2, or 3 as specified in paragraphs (j)(1) through (3) of this section. Annual average daily throughput of hydrocarbon liquids should be calculated using the flow out of the separator, well, or non-separator equipment determined over the actual days of operation. For atmospheric pressure storage tanks receiving produced water, calculate annual CH_4 emissions using Calculation Method 1, 2, or 3 as specified in paragraphs (j)(1) through (3) of this section. If you are required to use the flash emissions modeling software in paragraph (j)(1) of this section for compliance with federal or state regulations, air permit requirements, or annual inventory reporting for the current reporting year, you must use Calculation Method 1 to calculate annual CH_4 and, if applicable, CO_2 emissions. For atmospheric pressure storage tanks routing emissions to a vapor recovery system or a flare, calculate annual emissions vented directly to atmosphere as specified in paragraph (j)(4) of this section. If you use Calculation Method 1 or Calculation Method 2 for gas-liquid separators sending hydrocarbon liquids to atmospheric pressure storage tanks, you must also calculate emissions that may have occurred due to hydrocarbon liquid dump valves not closing properly using the method specified in paragraph (j)(5) of this section. If emissions from atmospheric pressure storage tanks are routed to a flare, you must calculate CH_4, CO_2, and N_2O

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).

(1) *Calculation Method 1*. For atmospheric pressure storage tanks receiving hydrocarbon liquids, calculate annual CH_4 and CO_2 emissions, and for atmospheric pressure tanks receiving produced water, calculate annual CH_4 emissions, using operating conditions in the well, last gas-liquid separator, or last non-separator equipment before liquid transfer to storage tanks. Calculate flashing emissions with a software program, such as AspenTech HYSYS®, Bryan Research & Engineering ProMax®, or, for atmospheric pressure storage tanks receiving hydrocarbon liquids from gas-liquid separator or non-separator equipment, 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 hydrocarbon liquids or produced water from the well, separator, or non-separator equipment enter an atmospheric pressure storage tank. If you elect to use ProMax®, you must use version 5.0 or above. A minimum of the parameters listed in paragraphs (j)(1)(i) through (vii) of this section, as applicable, must be used to characterize emissions. If paragraphs (j)(1)(i) through (vii) of this section indicate that an applicable parameter must be measured, collect measurements reflective of representative operating conditions for the time period covered by the simulation and at least at the frequency specified. Determine all other applicable parameters in paragraphs (j)(1)(i) through (vii) of this section by engineering estimate and process knowledge based on best available data and, if necessary, adjust parameters to represent the operating conditions over the time period covered by the simulation. Determine the number of simulations and associated time periods such that the simulations cover the entire reporting year (*i.e.*, if you calculate emissions using one simulation, use representative parameters for the operating conditions over the calendar year; if you use periodic simulations to cover the calendar

year, use parameters for the operating conditions over each corresponding appropriate portion of the calendar year). If more than one simulation is performed, input parameters should be remeasured if no longer representative of operating conditions.

(i) Well, separator, or non-separator equipment temperature (must be measured at least annually if required as an input for the model).

(ii) Well, separator, or non-separator equipment pressure (must be measured at least annually if required as an input for the model).

(iii) [Reserved]

(iv) Sales or stabilized hydrocarbon liquids or produced water production rate (must be measured at least annually if required as an input for the model).

(v) Ambient air temperature.

(vi) Ambient air pressure.

(vii) Sales or stabilized hydrocarbon liquids API gravity, and well, separator, or non-separator equipment hydrocarbon liquids or produced water composition and Reid vapor pressure (must be measured if required as an input for the model). 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 sales or stabilized hydrocarbon liquids for API gravity, and hydrocarbon liquids or produced water composition and Reid vapor pressure. You must sample and analyze sales or stabilized oil for API gravity, and hydrocarbon liquids or produced water for composition and Reid vapor pressure within six months of equipment start-up or by January 1, 2030, whichever is later, and at least once every five years thereafter. Until such time that a sample is collected, determine API gravity by engineering estimate and process knowledge based on best available data, and determine composition and Reid vapor pressure by using one of the methods described in paragraphs (j)(1)(vii)(A) through (C) of this section. For produced water, you may instead elect to use a representative sales oil or stabilized hydrocarbon liquid API gravity and a hydrocarbon liquid composition and Reid vapor pressure, and assume oil entrainment of 1 percent or greater.

(A) If separator or non-separator equipment hydrocarbon liquids 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 hydrocarbon liquids composition and Reid vapor pressure data are available through your previous analysis, select the latest available analysis that is representative of hydrocarbon liquids 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 hydrocarbon liquids 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 hydrocarbon liquids composition and Reid vapor pressure using an appropriate standard method published by a consensus-based standards organization.

(2) *Calculation Method 2*. For atmospheric pressure storage tanks receiving hydrocarbon liquids, calculate annual CH_4 and CO_2 emissions and for atmospheric pressure tanks receiving produced water, calculate annual CH_4 emissions, using operating conditions in the well, last gas-liquid separator, or last non-separator equipment before liquid transfer to storage tanks and the methods in paragraph (j)(2)(i) of this section.

(i) Assume that all of the CH_4 and, if applicable, CO_2 in solution at well, separator, or non-separator equipment temperature and pressure is emitted from hydrocarbon liquids or produced water sent to atmospheric pressure 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 hydrocarbon liquids or produced water composition at well, separator, or non-separator pressure and temperature. You must sample and analyze hydrocarbon liquids or produced water composition within six months of equipment start-up or by January 1, 2030, whichever is later, and at least once every five years thereafter. Until such time that a sample is collected, determine produced water composition by engineering estimate and process knowledge based on best available data, and determine hydrocarbon liquids composition by using one of the methods described in paragraphs (j)(1)(vii)(A) through (C) of this section. For produced water, you may instead elect to use a representative hydrocarbon liquid composition and assume oil entrainment of 1 percent or greater.

(ii) [Reserved]

(3) *Calculation Method 3*. Calculate CH_4 and CO_2 emissions from atmospheric pressure storage tanks receiving hydrocarbon liquids as specified in paragraph (j)(3)(i) of this section. Calculate CH_4 emissions from atmospheric pressure storage tanks receiving produced water as specified in paragraph (j)(3)(ii) of this section.

(i) Calculate CH_4 and CO_2 emissions from atmospheric pressure storage tanks receiving hydrocarbon liquids using equation W-15A to this section:

$$E_{s,i} = EF_i \times Count \times 1{,}000 \qquad \text{(Eq. W-15A)}$$

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 greater than 0 barrels per day and less than 10 barrels per day. Count only separators, wells, or non-separator equipment that feed hydrocarbon liquids directly to the atmospheric pressure storage tank for which you elect to use this Calculation Method 3.

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

(ii) Calculate CH_4 emissions from atmospheric pressure storage tanks receiving produced water using equation W-15B to this section:

$$Mass_{CH_4} = EF_{CH_4} \times FR \times 0.001 \qquad \text{(Eq. W-15B)}$$

Where:

$Mass_{CH4}$ = Annual total CH_4 emissions in metric tons.

EF_{CH4} = Population emission factor for produced water in metric tons CH_4 per thousand barrels produced water per year. For produced water streams from separators, wells, or non-separator equipment with pressure less than or equal to 50 psi, use 0.0015. For produced water streams from separators, wells, or non-separator equipment with pressure greater than 50 but less than or equal to 250 psi, use 0.0142. For produced water streams from separators, wells, or non-separator equipment with pressure greater than 250 psi, use 0.0508. Pressure should be representative of separators, wells, or non-separator equipment that feed produced water directly to the atmospheric pressure storage tank.

FR = Annual flow rate of produced water to atmospheric pressure storage tanks, in barrels.

0.001 = Conversion from barrels to thousand barrels.

(4) *Emissions vented directly to atmosphere from atmospheric pressure storage tanks routed to vapor recovery systems or flares.* If the atmospheric pressure storage tank receiving your hydrocarbon liquids or produced water has a vapor recovery system or routes emissions to a flare, calculate annual emissions vented directly to atmosphere from the storage tank during periods of time when emissions were not routed to the vapor recovery system or flare as specified in paragraph (j)(4)(i) of this section. Determine recovered mass as specified in paragraph (j)(4)(ii) of this section.

(i) For an atmospheric pressure storage tank that routes any emissions to a vapor recovery system or a flare, calculate vented emissions as specified in paragraphs (j)(4)(i)(A) through (E) of this section.

(A) Calculate vented emissions as specified in paragraph (j)(1), (2), or (3) of this section, which represents the emissions from the atmospheric storage tank prior to the vapor recovery system or flare. Calculate an average hourly vented emissions rate by dividing the vented emissions by the number of hours that the tank was in operation.

(B) To calculate vented emissions during periods when the tank was not routing emissions to a vapor recovery system or a flare, multiply the average hourly vented emissions rate determined in paragraph (j)(4)(i)(A) of this section by the number of hours that the tank vented directly to the atmosphere. Determine the number of hours that the tank vented directly to atmosphere by subtracting the hours that the tank was connected to a vapor recovery system or flare (based on engineering estimate and best available data) from the total operating hours for the tank in the calendar year. If emissions are routed to a flare but the flare is unlit, calculate emissions in accordance with the methodology specified in paragraph (n) of this section and report emissions from the flare as specified in § 98.236(n).

(C) During periods when a thief hatch is open and emissions from the tank are routed to a vapor recovery system or a flare, assume the capture efficiency of the vapor recovery system or a flare is 0 percent. A thief hatch is open if it is fully or partially open such there is a visible gap between the hatch cover and the hatch portal. To calculate vented emissions during such periods, multiply the average hourly vented emissions rate determined in paragraph (j)(4)(i)(A) of this section by the number of hours that the thief hatch is open. Determine the number of hours that the thief hatch is open~~ or not properly seated~~ as specified in paragraph (j)(7) of this section.

(D) Calculate vented emissions not captured by the vapor recovery system or a flare due to causes other than open thief hatches based on best available data, including any data from operating pressure sensors on atmospheric pressure storage tanks.

(E) Calculate total emissions vented directly to atmosphere as the sum of the emissions calculated as specified in paragraphs (j)(4)(i)(B) through (D) of this section.

(ii) Using engineering estimates based on best available data, determine the portion of the total emissions estimated in paragraphs (j)(1) through (3) of this section that is recovered using a vapor recovery system. You must take into account periods with reduced capture efficiency of the vapor recovery system (*e.g.*, when a thief hatch is open) when calculating mass recovered as specified in paragraphs (j)(4)(i)(C) and (D) of this section.

(5) *Gas-liquid separator dump valves*. 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 that did not close properly during the calendar year by using equation W-16 to this section. Determine the total time a dump valve did not close properly in the calendar year (T_{dv}) as specified in paragraph (j)(5)(i) of this section.

$$E_{s,i,dv} = CF_{dv} \times \frac{E_{s,i}}{8{,}760} \times T_{dv} \qquad \text{(Eq. W-16)}$$

Where:

$E_{s,i,dv}$	=	Annual volumetric GHG emissions (either CO_2 or CH_4) at standard conditions in cubic feet from atmospheric pressure storage tanks that resulted from the dump valve on an associated gas-liquid separator that did not close properly.
CF_{dv}	=	Correction factor for tank emissions for time period T_{dv} is 2.87 for crude oil production. Correction factor for tank emissions for time period T_{dv} is 4.37 for gas condensate production.
$E_{s,i}$	=	Annual volumetric GHG emissions (either CO_2 or CH_4) as determined in paragraphs (j)(1) and (2) and, if applicable, (j)(4) of this section, in standard cubic feet per year, from atmospheric pressure storage tanks with dump valves on an associated gas-liquid separator that did not close properly.
8,760	=	Conversion to hourly emissions.
T_{dv}	=	Total time a dump valve did not close properly in the calendar year as determined in paragraph (j)(5)(i) of this section, in hours.

(i) If a parametric monitor is operating on a controlled atmospheric pressure storage tank or gas-liquid separator, you must use data obtained from the parametric monitor to determine periods when the gas-liquid separator liquid dump valve is stuck in an open or partially open position. An applicable operating parametric monitor must be capable of logging data whenever a gas-liquid separator liquid dump valve is stuck in an open or partially open position, as well as when the gas-liquid separator liquid dump valve is subsequently closed. If an applicable parametric monitor is not operating, including during periods of time when the parametric monitor is malfunctioning, you must perform an audio, visual, and olfactory inspection of each gas-liquid separator liquid dump valve to determine if the valve is stuck in an open or partially open position, in accordance with paragraph (j)(5)(i)(A) and (B) of this section.

(A) Audio, visual and olfactory inspections must be conducted at least once in a calendar year.

(B) If stuck gas-liquid separator liquid dump valve is identified, the dump valve must be counted as being open since the beginning of the calendar year, or from the previous audio, visual, and olfactory inspection that did not identify the dump valve as being stuck in the open position in the same calendar year. If the dump valve is fixed following audio, visual, and olfactory inspection, the time period for which the dump valve was stuck open will end upon being repaired. If a stuck dump valve is identified and not repaired, the time period for which the dump valve was stuck open must be counted as having occurred through the rest of the calendar year.

(ii) [Reserved]

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

(7) *Thief hatches*. If a thief hatch sensor is operating on a controlled atmospheric pressure storage tank, you must use data obtained from the thief hatch sensor to determine periods when the thief hatch is open. An applicable operating thief hatch sensor must be capable of logging data whenever a thief hatch is open, as well as when the thief hatch is subsequently closed. If a thief hatch sensor is not operating but a tank pressure sensor is operating on a controlled atmospheric pressure storage tank, you must use data obtained from the pressure sensor to determine periods when the thief hatch is open. An applicable operating pressure sensor must be capable of logging tank pressure data. If neither an applicable thief hatch sensor nor an applicable pressure sensor is operating, including during periods of time when the sensors are malfunctioning, for longer than 30 days, you must perform a visual inspection of each thief hatch

on a controlled atmospheric pressure storage tank in accordance with paragraph (j)(7)(i) through (iii) of this section.

(i) For thief hatches on controlled atmospheric pressure storage tanks subject to the standards in § 60.5395b of this chapter, or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, visual inspections must be conducted at least as frequent as the required audio, visual, and olfactory inspections described in § 60.5416b or the applicable approved state plan or applicable Federal plan in part 62. If the time between required audio, visual, and olfactory inspections described in § 60.5416b or the applicable approved state plan or applicable Federal plan in part 62 is greater than one year, visual inspections must be conducted at least annually.

(ii) For thief hatches on controlled atmospheric pressure storage tanks not subject to the standards in § 60.5395b of this chapter, or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, visual inspections must be conducted at least once in a calendar year.

(iii) If one visual inspection is conducted in the calendar year and an open thief hatch is found, assume the thief hatch was open for the entire calendar year or the entire period that the sensor(s) was not operating or malfunctioning. If multiple visual inspections are conducted in the calendar year, assume a thief hatch found open in the first visual inspection was open since the beginning of the year until the date of the visual inspection; assume a thief hatch found open in the last visual inspection of the year was open from the preceding visual inspection through the end of the year; assume a thief hatch found open in a visual inspection between the first and last visual inspections of the year was open since the preceding visual inspection until the date of the visual inspection.

(k) *Condensate storage tanks*. For vent stacks connected to one or more condensate storage tanks, either water or hydrocarbon, without vapor recovery, flares, or other controls, in onshore natural gas transmission compression or underground natural gas storage, calculate CH_4 and CO_2 annual emissions from compressor scrubber dump valve leakage as specified in paragraphs (k)(1) through (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 (n) of this section and report emissions from the flare as specified in § 98.236(n).

(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.

(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 (n) of this section, report emissions from the flare as specified in § 98.236(n), and report additional information specified in § 98.236(l), as applicable.

(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 to this section (for oil wells) or equation W-17B to this section (for gas wells) for each well tested during the reporting year.

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

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

Where:

$E_{a,n}$	=	Annual volumetric natural gas emissions from well testing for each well being tested in cubic feet under actual conditions.
GOR	=	Gas to oil ratio in cubic feet of gas per barrel of oil for each well being tested; 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 being tested.
PR	=	Average annual production rate in actual cubic feet per day for the gas well being tested.
D	=	Number of days during the calendar year that the well 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.

(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) of this section) as specified in paragraphs (m)(1) through (3) 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 (n) of this section, report emissions from the flare as specified in § 98.236(n), and report additional information specified in § 98.236(m), as applicable.

(1) If you measure the gas flow to a vent using a continuous flow measurement device, you must use the measured flow volumes to calculate vented associated gas emissions.

(2) If you do not measure the gas flow to a vent using a continuous flow measurement device, you must follow the procedures in paragraphs (m)(2)(i) through (iii) of this section.

(i) 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.

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

(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).

(iii) Estimate venting emissions using equation W-18 to this section.

$$E_{s,n,p} = \left(GOR_p \times V_p\right) - SG_p \qquad \text{(Eq. W-18)}$$

Where:

$E_{s,n,p}$	=	Annual volumetric natural gas emissions at each well from associated gas venting at standard conditions, in cubic feet.
GOR_p	=	Gas to oil ratio, for well p, in standard cubic feet of gas per barrel of oil determined according to paragraphs (m)(2)(i) through (iii) of this section; oil here refers to hydrocarbon liquids produced of all API gravities.
V_p	=	Volume of oil produced, for well p, in barrels in the calendar year only during time periods in which associated gas was vented or flared.
SG_p	=	Volume of associated gas sent to sales and volume of associated gas used for other purposes at the facility site, including powering engines, separators, safety systems and/or combustion equipment and not flared or vented, for well p, in standard cubic feet of gas in the calendar year only during time periods in which associated gas was vented or flared.

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

(n) *Flare stack emissions*. Except as specified in paragraph (n)(9) of this section, calculate CO_2, CH_4, and N_2O emissions from each flare stack as specified in paragraphs (n)(1) through (8) of this section. For each flare, disaggregate the total flared emissions to applicable source types as specified in paragraph (n)(10) of this section.

(1) *Destruction efficiency and combustion efficiency*. To calculate CH_4 emissions for flares, use the applicable default destruction and combustion efficiencies specified in paragraphs (n)(1)(i) through (iii) of this section or alternative destruction and combustion efficiencies determined in accordance with paragraph (n)(1)(v) of this section. If you change the method with which you determine the default destruction and combustion efficiencies during a year, then use the applicable destruction and combustion efficiencies in paragraphs (n)(1)(i) through (iii) and paragraph (n)(1)(v) of this section for each portion of the year during which a different default

destruction and combustion efficiency was used, and calculate an annual time-weighted average destruction and combustion efficiency to report for the flare.

(i) *Tier 1*. Use a default destruction efficiency of 98 percent and a default combustion efficiency of 96.5 percent if you follow the performance test requirements specified in paragraph (n)(1)(i)(A) of this section and the operating limit requirements specified in paragraph (n)(1)(i)(B) of this section, or the operating limit requirements specified in paragraph (n)(1)(i)(C) of this section, as applicable. You must also keep the applicable records in § 63.655(i)(2), (3), and (9) of this chapter. If you fail to fully conform with all cited provisions for a period of 15 consecutive days, you must utilize the Tier 3 default destruction and combustion efficiency values until such time that full conformance is achieved. You must document these periods and maintain records as specified in § 98.237 of the date when the non-conformance began, and the date when full conformance is re-established.

(A) The applicable testing requirements in § 63.645(a), (b), (c), (d), and (i) of this chapter, including § 63.116 (a)(2), (3), (b), and (c) of this chapter. When § 63.645 refers to “organic HAP,” the terms “methane” and “CO_2” shall apply for the purposes of this subpart.

(B) The applicable monitoring requirements in § 63.644(a), (b), (d), and (e) of this chapter. The data to submit in a Notification of Compliance Status report in § 63.644(d) of this chapter shall be maintained as records for the purposes of this section (n)(1)(i), and references to violations in § 63.644(e) of this chapter do not apply for the purposes of this section (n)(1)(i).

(C) The requirements in § 63.670 (a) through (n), § 63.670(p), and § 63.671 of this chapter.

(ii) *Tier 2*. Use a default destruction efficiency of 95 percent and a default combustion efficiency of 93.5 percent if you follow the requirements specified in either paragraph (n)(1)(ii)(A), (B), (C), or (D) of this section. If you fail to fully conform with all cited provisions for a period of 15 consecutive days, you must utilize the Tier 3 default destruction and combustion efficiency values until such time that full conformance is achieved. You must document these periods and maintain records as specified in § 98.237 of the date when the non-conformance began, and the date when full conformance is re-established.

(A) The requirements in § 60.5412b(a)(1) of this chapter, along with the applicable testing requirements in § 60.5413b(b) of this chapter, the applicable continuous compliance requirements in § 60.5415b(f) of this chapter, and the applicable continuous monitoring requirements in § 60.5417b of this chapter. You must also keep the applicable records in § 60.5420b(c)(11) of this chapter.

(B) The requirements in § 60.5412b(a)(3) of this chapter, the applicable continuous compliance requirements in § 60.5415b(f) of this chapter, and the applicable continuous monitoring requirements in § 60.5417b~~(b)~~ of this chapter. You must also keep the applicable records in § 60.5420b(c)(11) of this chapter.

(C) If using an enclosed combustion device tested by the manufacturer in accordance with § 60.5413b(d) of this chapter, the requirements in § 60.5413b(b)(5)(iii) and (e) of this chapter, the applicable continuous compliance requirements in § 60.5415b(f) of this chapter, and the applicable continuous monitoring requirements in § 60.5417b of this chapter. You must also keep the applicable records in § 60.5420b(c)(11) of this chapter.

(D) If you are subject to an approved state plan or applicable Federal plan in part 62 of this chapter that requires the reduction of methane by 95 percent, you may follow all applicable requirements of the approved state plan or applicable Federal plan in part 62 of this chapter, including the testing, continuous compliance, continuous monitoring, and recordkeeping requirements.

(iii) *Tier 3*. Use a default destruction efficiency of 92 percent and a default combustion efficiency of 90.5 percent if you do not meet the requirements specified in either paragraph (n)(1)(i) or (ii) of this section.

(iv) *Alternative test method*. If you are utilizing the tier 2 default efficiencies in paragraph (n)(2)(ii) of this section and are not subject to 40 CFR subpart OOOOb or an applicable approved state or applicable federal plan under part 62 of this chapter that requires 95 percent reduction in methane emissions, you may conduct a performance test using EPA OTM-52 (incorporated by reference, see § 98.7) as an alternative to conducting a performance test using the methods specified in § 60.5413b of this chapter, or in an applicable approved state plan or applicable Federal plan in part 62 of this chapter. If the combustion efficiency obtained using OTM-52 is equal to or greater than 93.5 percent, then use a default destruction efficiency of 95 percent and a default combustion efficiency of 93.5 percent. If you utilize OTM-52 for the testing, you must comply with all the applicable monitoring, compliance, and recordkeeping requirements identified in paragraph (n)(1)(ii) of this section.

(v) *Alternative destruction and combustion efficiencies*. You may use a directly measured combustion efficiency instead of the default combustion efficiencies specified in paragraphs (n)(1)(i) through (iii) of this section if you follow the provisions of paragraph (n)(1)(v)(A) through (E) of this section.

(A) Measure the combustion efficiency in accordance with an alternative test method approved in accordance with § 60.5412b(d) of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter.

(B) Conduct monitoring as specified in §§ 60.5415b(f)(1)(x) and (xi) and 60.5417b(i) of this chapter, or an applicable approved state plan or applicable Federal plan in part 62 of this chapter.

(C) Adhere to all conditions in the monitoring plan you prepare as specified in § 60.5417b(i)(2) of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter at all times.

(D) You must use a destruction efficiency equal to the combustion efficiency plus 1.5.

(E) If you fail to fully conform with your plan for a period of 15 or more consecutive days, you must utilize the Tier 3 default destruction and combustion efficiency values until such time that full conformance is achieved. You must document these periods and maintain records as specified in § 98.237 of the date when the non-conformance began, and the date when full conformance is re-established.

(2) *Pilot*. Continuously monitor for the presence of a pilot flame or combustion flame as specified in paragraph (n)(2)(i) of this section or visually inspect for the presence of a pilot flame or combustion flame as specified in paragraph (n)(2)(ii) of this section, as applicable. If you comply with tier 2, you must also use data collected according to paragraph (n)(2)(iii) of this section in your calculations of time the flare was unlit and the fraction of gas routed to the flare during periods when the flare was unlit. If you continuously monitor, then periods when the flare is unlit must be determined based on those data, except when contradicted by data collected according to paragraph (n)(2)(iii) of this section. Determine the fraction of the total volume that is routed to the flare during unlit periods as specified in paragraph (n)(2)(iv) of this section.

(i) At least once every five minutes monitor for the presence of a pilot flame or combustion flame using a device (including, but not limited to, a thermocouple, ultraviolet beam sensor, infrared sensor, video surveillance system, or advanced remote monitoring method) capable of detecting that the pilot or combustion flame is present at all times.

(A) Monitoring for the presence of a flare flame in accordance with § 60.5417b satisfies the requirement of this paragraph (n)(2).

(B) You may use multiple or redundant monitoring devices. When a discrepancy occurs between multiple devices, you must either visually confirm or use video surveillance output to confirm that the flame is present as soon as practicable after detecting the discrepancy to ensure that at least one device is operating properly. If you confirm that at least one device is operating properly, you may rely on the properly operating device(s) to monitor the flame.

(C) Continuous monitoring systems used for the presence of a pilot flame or combustion flame are not subject to a minimum accuracy requirement beyond being able to detect the presence or absence of a flame and are exempt from the calibration requirements of this part 98.

(D) Track the length of time over all periods when the flare is unlit and calculate the fraction of the total flow to the flare that was routed to the flare when the flare was unlit as specified in paragraph (n)(2)(iv) of this section.

(E) If all continuous monitoring devices are out of service for more than one week, then visually inspect for the presence of a pilot flame or combustion flame at least once per week for the first 4 weeks that the monitoring devices are out of service or until at least one repaired or new device is operational, whichever period is shorter. If all continuous monitoring devices are out of service for less than one week, then at least one visual inspection must be conducted during the outage. If a flame is not detected during a weekly visual inspection, assume the pilot has been unlit since the previous inspection or the last time the continuous monitoring device detected a flame, and assume that the pilot remains unlit until a subsequent inspection or continuous monitoring device detects a flame. If the monitoring device outage lasts more than 4 weeks, then you may switch to conducting inspections at least once per month in accordance with paragraph (n)(2)(ii) of this section.

(ii) As an alternative to continuous monitoring as specified in paragraph (n)(2)(i) of this section, if you comply with tier 3 in paragraph (n)(1)(iii) of this section, at least once per month visually inspect for the presence of a pilot flame or combustion flame. You may also conduct visual inspections when using an alternative test method in accordance with paragraph (n)(1)(iv) of this section that allows visual inspections. If a flame is not detected, track the time since the previous inspection until a subsequent inspection detects a flame, and use this time in your calculation of the fraction of the total flow to the flare that was routed to the flare when the flare was unlit as specified in paragraph (n)(2)(iv) of this section. Use the sum of the measured flows, as determined from measurements obtained under paragraph (n)(1) of this section, during all time periods when the pilot was determined to be unlit, to calculate the fraction of the total annual volume that is routed to the flare when it is unlit.

(iii) For a flare subject to 40 CFR part 60 subpart OOOOb, or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, a flare inspection conducted using an OGI camera during a fugitive emissions survey in accordance with § 60.5415b(f)(1)(x) constitutes a pilot flame inspection under this subpart. If a flame is not detected, track the time from the previous inspection until a subsequent inspection or continuous monitoring device detects a flame and use this time in your calculation of the fraction of the total flow to the flare that was routed to the flare when the flare was unlit as specified in paragraph (n)(2)(iv) of this section.

(iv) If you measure total flow to the flare in accordance with paragraph (n)(3)(i) of this section, calculate the fraction of the total annual volume that is routed to the flare when it is unlit using the actual flow during the unlit time periods that are tracked according to paragraph (n)(2)(i)(D), (ii), or (iii) of this section. If you determine flows of individual streams routed to the flare in accordance with paragraph (n)(3)(ii) of this section, use the stream-specific average flow rates for the streams routed to the flare during unlit times to calculate the fraction of the total annual volume that is routed to the flare when it is unlit.

(3) *Flow determination*. Calculate total flow to the flare as specified in paragraph (n)(3)(i) of this section or determine flow of each individual stream that is routed to the flare as specified in paragraph (n)(3)(ii) of this section. Use engineering calculations based on best available data and company records to calculate pilot gas flow to add to the total gas flow to the flare.

(i) Use a continuous parameter monitoring system to measure flow of gas to the flare downstream of any sweep, purge, or auxiliary gas addition. You may use either flow meters or indirectly calculate flow using other parameter monitoring systems combined with engineering calculations, such as line pressure, line size, and burner nozzle dimensions. If you use a continuous parameter monitoring system, you must use the measured flow in calculating the total flow volume to the flare. The continuous parameter monitoring system must measure data values at least once every hour.

(ii) Determine flow to the flare from individual sources, including sweep, purge, auxiliary fuel, and collective flow from offsite sources that route gas to the flare using any combination of the methods in paragraphs (n)(3)(ii)(A) and (B) of this section, as applicable. Adjust the volumes determined as specified in paragraphs (n)(3)(ii)(A) and (B) of this section by any estimated bypass volumes diverted from entering the flare and leaks from the closed vent system in accordance with paragraphs (n)(3)(ii)(C) and (D) of this section. Do not adjust the volumes routed to the flare for volumes diverted through bypass lines located upstream of the flow measurement or determination location.

(A) Use a continuous flow meter to measure the flow of gas from individual sources (or combination of sources) that route gas to the flare. If the emission streams for multiple sources are routed to a manifold before being combined with other emission streams, you may conduct the measurement in the manifold instead of from each source that is routed to the manifold. If you use a continuous flow meter, you must use the measured flow in calculating the total flow volume to the flare. The continuous flow meter must measure data values at least once every hour.

(B) If flow from a source is not measured using a continuous flow meter, then use methods specified in paragraphs (n)(3)(ii)(B)(*1*) through (*8*) of this section, as applicable.

(*1*) Determine flow of emission streams routed to flares from acid gas removal units using Calculation Method 3 or Calculation Method 4 as specified in paragraph (d)(3) or (4) of this section. Use the method specified in paragraph (n)(3)(ii)(B)(*8*) of this section to determine the volume of non-GHG constituents in a stream from an acid gas removal unit or nitrogen removal unit and add to the volume of GHGs to determine the total volume to the flare.

(*2*) Determine flow of emission streams routed to flares from dehydrators using an applicable method specified in paragraph (e) of this section. When using Calculation Method 2 to determine volume of GHGs from small glycol dehydrators, also use the method specified in paragraph (n)(3)(ii)(B)(*8*) of this section to determine the volume of non-GHG constituents in the stream to the flare and add to the volume of GHGs to determine the total volume to the flare.

(*3*) Determine flow of emission streams routed to flares from completions and workovers with hydraulic fracturing using a method specified in paragraph (g) of this section.

(*4*) Determine flow of emission streams routed to flares from completions and workovers without hydraulic fracturing using a method specified in paragraph (h) of this section.

(*5*) Determine flow of emission streams routed to flares from hydrocarbon liquids and produced water storage tanks using a method specified in paragraph (j) of this section. When using Calculation Method 2 or Calculation Method 3 to calculate the volume of GHGs, use the method specified in paragraph (n)(3)(ii)(B)(*8*) of this section to determine the volume of non-GHG constituents in the stream to the flare and add to the volume of GHGs to determine the total volume to the flare.

(*6*) Determine flow of emission streams routed to flares from well testing using an applicable method specified in paragraph (l) of this section.

(*7*) Determine flow of associated gas emission streams routed to flares using the method specified in paragraph (m)(2) of this section.

(*8*) Use engineering calculations based on process knowledge, company records, and best available data to calculate flow for sources other than those described in paragraphs (n)(3)(ii)(B)(*1*) through (*7*) of this section and to calculate volume of non-GHG constituents in streams for which the method used in paragraphs (n)(3)(ii)(B)(*1*), (*2*), and (5) of this section calculates only the GHG flow.

(C) If the closed vent system that routes emissions to the flare contains one or more bypass devices that could be used to divert all or a portion of the gases from entering the flare, then you must determine when flow is diverted through the bypass and estimate the volume that bypasses the flare. The bypass volume may be determined based on engineering calculations, process knowledge, and best available data. Use the estimated bypass volume to adjust the volumes determined in accordance with paragraph (n)(3)(ii)(A) or (B) of this section to determine the flow to the flare. For bypass volumes that are diverted directly to atmosphere, use the estimated volume in the calculation and reporting of vented emissions from the applicable source(s).

(D) If you determine a component in the closed vent system is leaking, you must adjust the flow determined in accordance with paragraph (n)(3)(ii)(A) or (B) of this section by the estimated volume of the leak to determine the flow to the flare. Estimate the leak volume based on engineering calculations, process knowledge, and best available data. Report the estimated leak volume as vented emissions from the applicable source(s).

(4) *Gas composition*. Determine the composition of the inlet gas to the flare as specified in either paragraph (n)(4)(i) or (ii) of this section, or determine composition of the individual streams that are combined and routed to the flare as specified in paragraph (n)(4)(iii) of this section. Use representative compositions of pilot gas determined by engineering calculation based on process knowledge and best available data.

(i) Use a continuous gas composition analyzer on the inlet gas to the flare burner downstream of any purge, sweep, or auxiliary fuel addition to measure annual average mole fractions of methane, ethane, propane, butane, pentanes plus, and CO_2. If you use a continuous gas composition analyzer on the total inlet stream to the flare, you must use the measured annual average mole fractions to calculate total emissions from the flare. The continuous gas composition analyzer must measure data values at least once every hour.

(ii) Take samples of the inlet gas to the flare burner downstream of any purge, sweep, or auxiliary fuel addition at least annually in which gas is routed to the flare and analyze for methane, ethane, propane, butane, pentanes plus, and CO_2 constituents. Determine the annual average concentration of each constituent as the annual average of all valid measurements for that constituent during the year and you must use those data to calculate flared emissions.

(iii) When composition is not determined at the inlet to the flare as specified in either paragraph (i) or (ii) of this section, then determine annual average compositions for streams from individual sources (or combinations of sources), including sweep, purge, and auxiliary fuel, routed to the flare using any combination of the methods specified in paragraphs (n)(4)(iii)(A) and (B) of this section, as applicable.

(A) Use a continuous gas composition analyzer to measure annual average mole fractions of methane, ethane, propane, butane, pentanes plus, and CO_2 constituents. If emission streams for multiple sources are routed to a manifold before being combined with other emission streams, you may measure gas composition in the manifold instead of from each source that is routed to the manifold. If you use a continuous gas composition analyzer, you must use the measured annual average mole fractions to calculate flared emissions for the stream. The continuous gas composition analyzer must measure data values at least once every hour.

(B) If composition is not measured in accordance with paragraph (n)(4)(iii)(A) of this section, then use methods specified in paragraphs (n)(4)(iii)(B)(*1*) through (*7*) of this section to determine composition, as applicable. When paragraphs (n)(4)(iii)(B)(*1*) through (*5*) reference continuous gas composition analyzer requirements in paragraph (u)(2) of this section, the requirements in paragraph (n)(4)(iii)(A) apply for the purposes of this paragraph (n)(4)(iii)(B). When paragraphs (n)(4)(iii)(B)(*1*) through (*5*) reference paragraph (u)(2) of this section, the language “your most recent available analysis” in paragraph (u)(2)(i) of this section means “annual samples” for the purposes of this paragraph (n)(4)(iii)(B).

(*1*) Determine the total annual average GHG composition of streams from acid gas removal units based on either process simulation as specified in paragraph (d)(4) of this section or quarterly sampling in accordance with paragraphs (d)(6) and (10) of this section, and determine the composition of ethane, propane, butane, and pentanes plus as specified in paragraph (n)(4)(iii)(B)(*5*) of this section.

(*2*) Determine the total annual average composition of streams from glycol dehydrators using Calculation Method 1 as specified in paragraph (e)(1) of this section or determine the annual average GHG composition as specified in paragraph (u)(2) of this section for the applicable industry segment. Determine annual average GHG composition of streams from desiccant dehydrators as specified in paragraph (u)(2) of this section. If you determine GHG composition in accordance with paragraph (u)(2) of this section, also determine the composition of ethane, propane, butane, and pentanes plus as specified in paragraph (n)(4)(iii)(B)(*5*) of this section.

(*3*) Determine the total annual average composition of streams from hydrocarbon liquids and produced water storage tanks using Calculation Method 1 in accordance with paragraph (j)(1) of this section or determine the annual average GHG composition as specified in paragraph (u)(2)(i) of this section. If you determine annual average GHG composition as specified in paragraph (u)(2)(i) of this section, then also determine the composition of ethane, propane, butane, and pentanes plus as specified in paragraph (n)(4)(iii)(B)(*5*) of this section.

(*4*) For onshore natural gas processing facilities, determine GHG mole fractions for all emission sources downstream of the de-methanizer overhead or dew point control based on samples of facility-specific residue gas to transmission pipeline systems taken at least once per year according to methods set forth in § 98.234(b), and determine GHG mole fractions for all emission sources upstream of the de-methanizer or dew point control based on samples of feed natural gas taken at least once per year according to methods set forth in § 98.234(b). For onshore natural gas processing plants that solely fractionate a liquid stream, use the GHG mole fraction in feed natural gas liquid streams as determined from samples taken at least once per year. If multiple samples of a stream are taken in a year, use the arithmetic average GHG composition.

(*5*) Except as specified in paragraph (n)(4)(iii)(B)(*6*) of this section, for streams from any source type other than those identified in paragraphs (n)(4)(iii)(B)(*1*) through (*4*) of this section, and for purge gas, sweep gas, and auxiliary fuel, determine the annual average GHG composition as specified in paragraph (u)(2) of this section for the applicable industry segment, and determine the composition of ethane, propane, butane, and pentanes plus as specified in paragraph (n)(4)(iii)(B)(*7*) of this section.

(*6*) When the stream going to the flare is a hydrocarbon product stream, such as methane, ethane, propane, butane, pentanes-plus, or mixed light hydrocarbons, you may use a representative composition from the source for the stream determined by engineering calculation based on process knowledge and best available data.

(7) When only the GHG composition is determined in accordance with paragraph (u)(2) of this section, determine the annual average composition of ethane, propane, butane, and pentanes plus in the stream using a representative composition based on process knowledge and best available data.

(5) *Calculate CH_4 and CO_2 emissions*. Calculate GHG volumetric emissions from flaring at standard conditions using equations W-19 and W-20 to this section and as specified in paragraphs (n)(5)(i) through (iv) of this section.

$$E_{s,CH_4} = V_s \times X_{CH_4} \times \left[\left(1 - \eta_D\right) \times Z_L + Z_U\right] \qquad \text{(Eq. W-19)}$$

$$E_{s,CO_2} = V_s \times X_{CO_2} + \sum_{j=1}^{5} \left(\eta_C \times V_s \times Y_j \times R_j \times Z_L\right) \qquad \text{(Eq. W-20)}$$

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)(3) of this section.
η_D	=	Flare destruction efficiency, expressed as fraction of hydrocarbon compounds in gas that is destroyed by a burning flare, but may or may not be completely oxidized to CO_2.
η_C	=	Flare combustion efficiency, expressed as fraction of hydrocarbon compounds in gas that is oxidized to CO_2 by a burning flare.
X_{CH4}	=	Annual average mole fraction of CH_4 in the feed gas to the flare or in each of the streams routed to the flare as determined in paragraph (n)(4) of this section.
X_{CO2}	=	Annual average mole fraction of CO_2 in the feed gas to the flare or in each of the streams routed to the flare as determined in paragraph (n)(4) of this section.
Z_U	=	Fraction of the feed gas sent to an un-lit flare determined from both the total time the flare was unlit as determined by monitoring the pilot flame or combustion flame as specified in paragraph (n)(2) of this section and the volume of gas routed to the flare during periods when the flare was unlit based on the flow determined in accordance with paragraph (n)(3) of this section.
Z_L	=	Fraction of the feed gas sent to a burning flare (equal to 1 – Z_U).
Y_j	=	Annual average mole fraction of hydrocarbon constituents j (such as methane, ethane, propane, butane, and pentanes-plus) in the feed gas to the flare or in each of the streams routed to the flare as determined in paragraph (n)(4) 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).

(i) If you measure the gas flow at the flare inlet as specified in paragraph (n)(3)(i) of this section and you measure gas composition for the inlet gas to the flare as specified in paragraph (n)(4)(i) or (ii) of this section, then use those data in equations W-19 and W-20 to this section to calculate total emissions from the flare.

(ii) If you determine the flow from each source as specified in paragraph (n)(3)(ii) of this section and you measure gas composition for the inlet gas to the flare as specified in paragraph (n)(4)(i) or (ii) of this section, then sum the flows for each stream to calculate the total annual gas flow to the flare. Use that total annual flow with the annual average concentration of each constituent as calculated in paragraph (n)(4)(i) or (ii) of this section in equations W-19 and W-20 to this section to calculate total emissions from the flare.

(iii) If you determine the flow from each source as specified in paragraph (n)(3)(ii) of this section and you determine gas composition for the emission stream from each source as specified in paragraph (n)(4)(iii) of this section, then calculate total emissions from the flare as specified in either paragraph (n)(5)(iii)(A) or (B) of this section.

(A) Use each set of stream-specific flow and annual average concentration data in equations W-19 and W-20 to this section to calculate stream-specific flared emissions for each stream, and then sum the results from each stream-specific calculation to calculate the total emissions from the flare.

(B) Sum the flows from each source to calculate the total gas flow into the flare and use the source-specific flows and source-specific annual average concentrations to determine flow-weighted annual average concentrations of CO_2 and hydrocarbon constituents in the combined gas stream into the flare. Use the calculated total gas flow and the calculated flow-weighted annual average concentrations for the inlet gas stream to the flare in equations W-19 and W-20 to this section to calculate the total emissions from the flare.

(iv) You may not combine measurement of the inlet gas flow to the flare as specified in paragraph (n)(3)(i) of this section with measurement of the gas composition of the streams from each source as specified in paragraph (n)(4)(iii) of this section.

(6) *Convert volume at actual conditions to volume at standard conditions*. Convert GHG volumetric emissions to standard conditions using calculations in paragraph (t) of this section.

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

(8) *Calculate N_2O emissions*. Calculate N_2O emissions from flare stacks using equation W-40 to this section. Determine the values of parameters "HHV" and "Fuel" in equation W-40 to this section as specified in paragraphs (n)(8)(i) through (iv) of this section, as applicable.

(i) Directly measure the annual average higher heating value in the inlet stream to the flare using either a continuous gas composition analyzer or a calorimeter. Use this flare-specific annual average higher heating value for the parameter "HHV" in equation W-40 to this section, and use either the total inlet flow to the flare measured as specified in paragraph (n)(3)(i) of this section or the sum of the flows of individual streams routed to the flare as determined in paragraph (n)(3)(ii) of this section for the parameter "Fuel" in equation W-40 to this section to calculate the total N_2O emissions from the flare.

(ii) Calculate the annual average higher heating value in the inlet stream to the flare using annual average gas compositions of the inlet stream measured in accordance with paragraph (n)(4)(i) or (ii) of this section. Use this flare-specific annual average higher heating value for the parameter “HHV” in equation W-40 to this section, and use either the total inlet flow to the flare measured as specified in paragraph (n)(3)(i) of this section or the sum of the flows of individual streams routed to the flare as determined in paragraph (n)(3)(ii) of this section for the parameter “Fuel” in equation W-40 to this section to calculate the total N_2O emissions from the flare.

(iii) Directly measure the annual average higher heating values in the individual streams routed to the flare using either a continuous gas composition analyzer or a calorimeter. Calculate the total N_2O emissions from the flare as specified in either paragraph (n)(8)(iii)(A) or (B) of this section.

(A) Use the stream-specific annual average higher heating values for the parameter “HHV” in equation W-40 to this section, use the stream-specific flows as determined in paragraph (n)(3)(ii) of this section for the parameter “Fuel” in equation W-40 to this section in separate stream-specific calculations of N_2O emissions using equation W-40 to this section, and sum the resulting values to calculate the total N_2O emissions from the flare.

(B) Use the stream-specific annual average higher heating values and flows to calculate a flow-weighted annual average higher heating value to use as the parameter “HHV” in equation W-40 to this section and the sum of the individual stream flows routed to the flare as determined in paragraph (n)(3)(ii) of this section for the parameter “Fuel” in equation W-40 to this section to calculate total N_2O emissions from the flare.

(iv) Calculate annual average higher heating values for the individual streams routed to the flare using gas compositions determined in accordance with paragraph (n)(4)(iii) of this section. Calculate the total N_2O emissions from the flare as specified in either paragraph (n)(8)(iv)(A) or (B) of this section.

(A) Use the stream-specific annual average higher heating values and the stream-specific flows in separate stream-specific calculations of N_2O emissions using equation W-40 to this section and sum the resulting values to calculate the total N_2O emissions from the flare.

(B) Use the stream-specific annual average higher heating values and flows to calculate a flow-weighted annual average higher heating value to use as the parameter "HHV" in equation W-40 to this section and the sum of the individual stream flows routed to the flare as determined in paragraph (n)(3)(ii) of this section for the parameter "Fuel" in equation W-40 to this section to calculate total N_2O emissions from the flare.

(9) *CEMS*. 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 CO_2 emissions for the flare using the CEMS. 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 CO_2 emissions, you must also comply with all other requirements specified in paragraphs (n)(1) through (8) of this section, except that calculation of CO_2 emissions using equation W-20 to this section is not required.

(10) *Disaggregation*. Disaggregate the total emissions from the flare as calculated in paragraphs (n)(7) and (8) of this section or paragraph (n)(9) of this section, as applicable, to each source type listed in paragraphs (n)(10)(i) through (viii) of this section, as applicable to the industry segment, that routed emissions to the flare. If emissions from the flare are calculated in accordance with paragraph (n)(5)(iii) of this section using stream-specific flow and composition, including combined streams that contain emissions from only a single source type, use the source-specific emissions calculated using these data to calculate the disaggregated emissions

per source type. If the total emissions from the flare are calculated using total flow and/or total annual average composition of the total inlet stream to the flare, or if flow or composition are determined for a combined stream that contains emissions from more than one source type, then use engineering calculations and best available data to disaggregate the total emissions to the applicable source types.

(i) Acid gas removal units.

(ii) Dehydrators.

(iii) Completions and workovers with hydraulic fracturing.

(iv) Completions and workovers without hydraulic fracturing.

(v) Hydrocarbon liquids and produced water storage tanks.

(vi) Well testing.

(vii) Associated gas.

(viii) Other (collectively).

(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 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) 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) of this section do not apply and instead you must calculate CH_4, CO_2, and N_2O emissions as specified in paragraph (n) of this section and report emissions from the flare as specified in § 98.236(n). If emissions from a compressor source are routed to combustion, paragraphs (o)(1) through (11) of this section do not apply and instead you must calculate and report emissions as specified in subpart C of this part or paragraph (z) of this section, as applicable. If emissions from a compressor source are routed to a vapor recovery system, paragraphs (o)(1) through (11) of this section do not apply.

(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), (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 paragraph (o)(1)(i)(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 paragraph (o)(2)(i) of this section, measure volumetric emissions from wet seal oil degassing vents as specified in paragraph (o)(2)(ii) of this section if the compressor has wet seal oil degassing vents, and measure volumetric emissions from dry seal vents as specified in paragraph (o)(2)(iii) of this section if the compressor has dry seals.

(B) For a compressor measured in not-operating-depressurized-mode, you must measure volumetric emissions from isolation valve leakage as specified in paragraph (o)(2)(i) 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) For a compressor measured in standby-pressurized-mode, you must measure volumetric emissions from blowdown valve leakage through the blowdown vent as specified in paragraph (o)(2)(i) of this section, measure volumetric emissions from wet seal oil degassing vents as specified in paragraph (o)(2)(ii) of this section if the compressor has wet seal oil degassing vents, and measure volumetric emissions from dry seal vents as specified in paragraph (o)(2)(iii) of this section if the compressor has dry seals.

(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, the volumetric emissions from wet seal oil degassing vents as

specified in paragraph (o)(2)(ii) of this section, and the volumetric emissions from dry seal vents as specified in paragraph (o)(2)(iii) of this section.

(i) For blowdown valves on compressors in operating-mode or in 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 (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 or in standby-pressurized-mode, determine volumetric flow at standard conditions, using one of the methods specified in paragraphs (o)(2)(ii)(A) through (C) of this section. You must quantitatively measure the volumetric flow for wet seal oil degassing vent; you may not use screening methods set forth in § 98.234(a) to screen for emissions for the wet seal oil degassing vent.

(A) Use a temporary meter such as a vane anemometer or permanent flow meter according to methods set forth in § 98.234(b).

(B) Use calibrated bags according to methods set forth in § 98.234(c).

(C) Use a high volume sampler according to methods set forth in § 98.234(d).

(iii) For dry seal vents in operating-mode or in standby-pressurized-mode, determine volumetric flow at standard conditions from each dry seal vent using one of the methods specified in paragraphs (o)(2)(iii)(A) through (D) of this section. The measurement should be conducted on the compressor side dry seal. If a compressor has more than one dry seal vent, determine the aggregate dry seal vent volumetric flow for the compressor as the sum of the volumetric flows determined for each dry seal vent on the compressor.

(A) Use a temporary meter such as a vane anemometer or permanent flow meter according to methods set forth in § 98.234(b).

(B) Use calibrated bags according to methods set forth in § 98.234(c).

(C) Use a high volume sampler according to methods set forth in § 98.234(d).

(D) You may choose to use any of the methods set forth in § 98.234(a)(1) through (3) to screen for emissions. If emissions are detected using one of these specified methods, then you must use one of the methods specified in paragraph (o)(2)(iii)(A) through (C) of this section. If emissions are not detected using the methods in § 98.234(a)(1) through (3), 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. Acoustic leak detection is only applicable for through-valve leakage and is not applicable for screening dry seal vents.

(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 (F) 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) [Reserved]

(E) You may choose to use any of the methods set forth in § 98.234(a)(1) through (3) to screen for emissions. If emissions are detected using one of these methods, then you must use one of the methods specified in paragraph (o)(4)(ii)(A) through (D) of this section. If emissions are not detected using the methods in § 98.234(a)(1) through (3), 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. Acoustic leak detection is only applicable for through-valve leakage and is not applicable for screening a manifolded group of compressor sources.

(F) If one of the screening methods specified in § 98.234(a)(1) through (3) identifies a leak in a manifolded group of centrifugal compressor sources, you may use acoustic leak detection, according to § 98.234(a)(5), to identify the source of the leak. You must use one of the methods specified in paragraphs (o)(4)(ii)(A) through (D) of this section to quantify emissions from the identified source.

(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 to this section, calculate the annual volumetric GHG emissions for each centrifugal compressor mode-source combination specified in paragraphs (o)(1)(i)(A) through (C) of this section that was measured during the reporting year.

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

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), (B), or (C) of this section that was measured for the reporting year.

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

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

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), (B), or (C) of this section that was not measured in the reporting year.

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

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

Where:

$EF_{s,m}$	=	Reporter emission factor to be used in equation W-22 to 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 to 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), (B), or (C) of this section.

(iv) The reporter emission factor in equation W-23 to 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 to this section.

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

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 to 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.

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

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), (o)(1)(i)(C), (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 to 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.

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

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 volumetric emissions from centrifugal compressors at an onshore petroleum and natural gas production facility or an

onshore petroleum and natural gas gathering and boosting facility as specified in paragraphs (o)(10)(i) through (iv), as applicable.

(i) For all centrifugal compressors at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility that are subject to the centrifugal compressor standards in § 60.5380b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter for dry seals and self-contained wet seals, you must conduct the volumetric emission measurements as required by § 60.5380b(a)(5) of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, conduct all additional volumetric emission measurements specified in paragraph (o)(1) of this section using methods specified in paragraphs (o)(2) through (5) of this section (based on the compressor mode (as defined in § 98.238) in which the compressor was found at the time of measurement), and calculate emissions as specified in paragraphs (o)(6) through (9) of this section. Conduct all measurements required by this paragraph (o)(10)(i) at the frequency specified by § 60.5380b(a)(4) of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter. For any reporting year in which measuring at the frequency specified by § 60.5380b(a)(4) of this chapter results in measurement not being required for a subject compressor, calculate emissions for all mode-source combinations as specified in paragraph (o)(6)(ii) of this section.

(ii) For all centrifugal compressors at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility that are not subject to the centrifugal compressor standards in § 60.5380b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter for dry seals and self-contained wet seals, you may elect to conduct the volumetric emission measurements specified in paragraph (o)(1) of this section using methods specified in paragraphs (o)(2) through (5) of this section (based on the compressor mode (as defined in § 98.238) in which the compressor was found at the time of measurement), and calculate emissions as specified in paragraphs (o)(6) through (9) of this section.

(iii) For all centrifugal compressors at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility for which paragraph (o)(10)(i) of this section does not apply and you do not elect to conduct the volumetric measurements specified in paragraph (o)(1) of this section, you must calculate total atmospheric wet seal oil degassing vent emissions from all centrifugal compressors at either an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility using equation W-25A to this section. Emissions from centrifugal compressor wet seal oil degassing vents that are routed to a flare, combustion, or vapor recovery system are not required to be determined under this paragraph (o).

$$E_{s,i} = \sum_{p=1}^{Count} E_{s,i,p} \qquad \text{(Eq. W-25A)}$$

Where:

$E_{s,i}$	=	Annual volumetric GHG_i (either CH_4 or CO_2) emissions from all centrifugal compressors, at standard conditions, in cubic feet.
Count	=	Total number of centrifugal compressors with wet seal oil degassing vents that are vented directly to the atmosphere.
$E_{s,i,p}$	=	Annual volumetric GHGi (either CH_4 or CO_2) emissions for centrifugal compressor p, at standard conditions, in cubic feet, calculated using equation W-25B to this section.

(iv) For all centrifugal compressors at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility for which paragraph (o)(10)(i) of this section does not apply, and you do not elect to conduct the volumetric measurements specified in paragraph (o)(1) of this section, you must calculate wet seal oil degassing vent emissions from each centrifugal compressor using equation W-25B to this section. Emissions from centrifugal compressor wet seal oil degassing vents that are routed to a flare, combustion, or vapor recovery system are not required to be determined under this paragraph (o).

$$E_{s,i,p} = EF_{s,p} \times \frac{T_p}{T_{total}} \times \frac{GHG_{i,p}}{GHG_{EF}} \qquad \text{(Eq. W-25B)}$$

Where:

$E_{s,i,p}$	=	Annual volumetric GHG_i (either CH_4 or CO_2) emissions for centrifugal compressor p, at standard conditions, in cubic feet.
$EF_{s,p}$	=	Emission factor for centrifugal compressor p, in standard cubic feet per year. 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.
T_p	=	Total time centrifugal compressor p was in operating mode, for which $E_{s,i,p}$ is being calculated in the reporting year, in hours.
T_{total}	=	Total hours per year. Use 8784 in leap years and use 8760 in all other years.
$GHG_{i,p}$	=	Mole fraction of GHG (either CH_4 or CO_2) in the vent gas for centrifugal compressor p in operating mode; use the appropriate gas compositions in paragraph (u)(2) of this section.
GHG_{EF}	=	Mole fraction of GHG (either CH_4 or CO_2) used in the determination of $EF_{s,p}$. Use 0.95 for CH_4 and 0.05 for CO_2.

(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.

(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 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)(9), you must calculate volumetric emissions as specified in paragraph (p)(10) 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) of this section do not apply and instead you must calculate CH_4, CO_2, and N_2O emissions as specified in paragraph (n) of this section and report emissions from the flare as specified in § 98.236(n). If emissions from a compressor source are routed to combustion, paragraphs (p)(1) through (11) of this section do not apply and instead you must calculate and report emissions as specified in subpart C of this part or paragraph (z) of this section, as applicable. If emissions from a compressor source are routed to a vapor recovery system, paragraphs (p)(1) through (11) of this section do not apply.

(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 paragraph (p)(1)(i)(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 (p) 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 paragraph (p)(2)(i) of this section, and measure volumetric emissions from reciprocating rod packing as specified in paragraph (p)(2)(ii) or (iii) of this section, as applicable.

(B) For a compressor measured in not-operating-depressurized-mode, you must measure volumetric emissions from isolation valve leakage as specified in paragraph (p)(2)(i) 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) For a compressor measured in standby-pressurized-mode, you must measure volumetric emissions from blowdown valve leakage through the blowdown vent as specified in paragraph (p)(2)(i) of this section and measure volumetric emissions from reciprocating rod packing as specified in paragraph (p)(2)(ii) or (iii) of this section, as applicable.

(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 (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, as applicable.

(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 or standby-pressurized-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)(1) through (3) to screen for emissions. If emissions are detected using one of these specified methods, then you must use one of the methods specified in paragraphs (p)(2)(ii)(A) and (B) of this section. If emissions are not detected using the methods in § 98.234(a)(1) through (3), then you may assume that the volumetric emissions are zero. For the purposes of this paragraph (p)(2)(ii)(C), when using any of the methods in § 98.234(a), emissions are detected whenever a leak is detected according to the method. Acoustic leak detection is only applicable for through-valve leakage and is not applicable for screening or measuring rod packing emissions.

(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)(1) through (3) 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. Acoustic leak detection is only applicable for through-valve leakage and is not applicable for screening rod packing emissions.

(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 (F) of this section.

(A) A temporary meter such as a vane anemometer according to 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 in § 98.234(d).

(D) [Reserved]

(E) You may choose to use any of the methods set forth in § 98.234(a)(1) through (3) to screen for emissions. If emissions are detected using one of these specified methods, then you must use one of the methods specified in paragraphs (p)(4)(ii)(A) through (D) of this section. If emissions are not detected using the methods in § 98.234(a)(1) through (3), 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. Acoustic leak detection is only applicable for through-valve leakage and is not applicable for screening a manifolded group of compressor sources.

(F) If one of the screening methods specified in § 98.234(a)(1) through (3) identifies a leak in a manifolded group of reciprocating compressor sources, you may use acoustic leak detection, according to § 98.234(a)(5), to identify the source of the leak. You must use one of the methods specified in paragraphs (p)(4)(ii)(A) through (D) of this section to quantify the emissions from the identified source.

(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 to 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.

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

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 to this section, calculate the annual volumetric GHG emissions from each reciprocating compressor mode-source combination specified in paragraphs (p)(1)(i)(A) through (C) of this section that was not measured during the reporting year.

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

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

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

Where:

$EF_{s,m}$ = Reporter emission factor to be used in equation W-27 to 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 to 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 to 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 to this section.

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

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 to 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.

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

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), (o)(1)(i)(C), (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 to 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.

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

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 volumetric emissions from reciprocating compressors at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility as specified in paragraphs (p)(10)(i) through (iv) of this section, as applicable.

(i) For all reciprocating compressors at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility that are subject to the reciprocating compressor standards in § 60.5385b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, you must conduct the volumetric emission measurements as required by § 60.5385b(b) and (c) of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, conduct any additional volumetric emission measurements specified in paragraph (p)(1) of this section using methods specified in paragraphs (p)(2) through (5) of this section (based on the compressor mode (as defined in § 98.238) in which the compressor was found at the time of measurement), and calculate emissions as specified in paragraphs (p)(6) through (9) of this section. Conduct all measurements required by this paragraph (p)(10)(i) at the frequency specified by § 60.5385b(a) of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter. For any reporting year in which measuring at the frequency specified by § 60.5385b(a) of this chapter results in measurement not being required for a subject compressor, calculate emissions for all mode-source combinations as specified in paragraph (p)(6)(ii) of this section.

(ii) For all reciprocating compressors at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility that are not subject to the reciprocating compressor standards in § 60.5385b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, you may elect to conduct volumetric emission measurements specified in paragraph (p)(1) of this section using methods specified in paragraphs (p)(2) through (5) of this section (based on the compressor mode (as defined in § 98.238) in which the compressor was found at the time of measurement), and calculate emissions as specified in paragraphs (p)(6) through (9) of this section.

(iii) For all reciprocating compressors at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility for which paragraph (p)(10)(i) of this section does not apply, and you do not elect to conduct volumetric emission measurements specified in paragraph (p)(1) of this section, you must calculate total atmospheric rod packing emissions from all reciprocating compressors at either an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility using equation W-29D to this section. Reciprocating compressor rod packing emissions that are routed to a flare, combustion, or vapor recovery system are not required to be determined under this paragraph (p).

$$E_{s,i} = \sum_{p=1}^{Count} E_{s,i,p} \qquad \text{(Eq. W-29D)}$$

Where:

$E_{s,i}$	=	Annual volumetric GHG_i (either CH_4 or CO_2) emissions from all reciprocating compressors, at standard conditions, in cubic feet.
Count	=	Total number of reciprocating compressors with rod packing emissions vented directly to the atmosphere.
$E_{s,i,p}$	=	Annual volumetric GHG_i (either CH_4 or CO_2) emissions for reciprocating compressor p, at standard conditions, in cubic feet, calculated using equation W-29E to this section.

(iv) For all reciprocating compressors at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility for which paragraph (p)(10)(i) of this section does not apply, you must calculate rod packing vent emissions from each reciprocating compressor using equation W-29E to this section. Reciprocating compressor rod packing emissions that are routed to a flare, combustion, or vapor recovery system are not required to be determined under this paragraph (p).

$$E_{s,i,p} = EF_{s,p} \times \frac{T_p}{T_{total}} \times \frac{GHG_{i,p}}{GHG_{EF}} \qquad \text{(Eq. W-29E)}$$

Where:

$E_{s,i,p}$	=	Annual volumetric GHG_i (either CH_4 or CO_2) emissions for reciprocating compressor p, at standard conditions, in cubic feet.
$EF_{s,p}$	=	Emission factor for reciprocating compressor p, in standard cubic feet per year. Use 2.13×10^5 standard cubic feet per year per compressor for CH_4 and 1.18×10^4 standard cubic feet per year per compressor for CO_2 at 60 °F and 14.7 psia.
T_p	=	Total time reciprocating compressor p was in operating mode, for which $E_{s,i,p,}$is being calculated in the reporting year, in hours.
T_{total}	=	Total hours per year. Use 8784 in leap years and use 8760 in all other years.
$GHG_{i,p}$	=	Mole fraction of GHG (either CH_4 or CO_2) in the vent gas for reciprocating compressor p in operating mode; use the appropriate gas compositions in paragraph (u)(2) of this section.
GHG_{EF}	=	Mole fraction of GHG (either CH_4 or CO_2) used in the determination of $EF_{s,p}$. Use 0.98 for CH_4 and 0.02 for CO_2.

(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.

(q) *Equipment leak surveys*. For the components identified in paragraphs (q)(1)(i) through (iii) and (v) of this section, you must conduct equipment leak surveys using the leak detection methods specified in paragraphs (q)(1)(i) through (iii) and (v) of this section. For the components identified in paragraph (q)(1)(iv) and (vi) 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) and (vi) 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. Equipment leak components in vacuum service are exempt from the survey and emission estimation requirements of this paragraph (q) and only the count of these equipment must 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, the fugitive emissions standards for well sites, centralized production facilities, and compressor stations in § 60.5397b or 60.5398b of this chapter, or an applicable approved state plan or applicable Federal plan in part 62 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 either paragraph (q)(2) or (3) of this section.

(ii) For the components listed in § 98.232(i)(1), you must conduct surveys using any of the leak detection methods listed in § 98.234(a) except § 98.234(a)(2)(ii) and calculate equipment leak emissions using the procedures specified in either paragraph (q)(2) or (3) of this section.

(iii) For the components listed in § 98.232(c)(21)(i), (e)(7) and (8), (f)(5) through (8), (g)(4), (g)(6) and (7), (h)(5), (h)(7) and (8), and (j)(10)(i) that are subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter, the fugitive emissions standards for well sites, centralized production facilities, and compressor stations in § 60.5397b or 60.5398b of this chapter, or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, and are required to conduct surveys using any of the leak detection methods in § 98.234(a)(1)(ii) or (iii) or (a)(2)(ii), as applicable, you must use the results of those surveys to calculate equipment leak emissions using the procedures specified in either paragraph (q)(2) or (3) of this section.

(iv) For the components listed in § 98.232(c)(21)(i), (e)(8), (f)(6) through (8), (g)(6) or (7), (h)(7) or (8), or (j)(10)(i), that are not subject to or are not required to conduct surveys using the methods in § 98.234(a) in accordance with the fugitive emissions standards in § 60.5397a of this chapter, the fugitive emissions standards for well sites, centralized production facilities, and compressor stations in § 60.5397b or 60.5398b of this chapter, or an applicable approved state plan or applicable Federal plan in part 62 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) for the surveyed component types in § 98.232(c)(21)(i), (f)(7), (g)(6), (h)(7), or (j)(10)(i) 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)(i), (f)(7), (g)(6), (h)(7), or (j)(10)(i) using the procedures in either paragraph (q)(2) or (3) of this section.

(B) If you elect to use a leak detection method in § 98.234(a) for the surveyed component types in § 98.232(e)(8), (f)(6) and (8), (g)(7), and (h)(8), then you must use the procedures in either paragraph (q)(2) or (3) of this section to calculate those emissions.

(C) If you elect to use a leak detection method in § 98.234(a)(1)(ii) or (iii) or (a)(2)(ii), as applicable, for any elective survey under paragraph (q)(1)(iv) of this section, then you must survey the component types in § 98.232(c)(21)(i), (e)(8), (f)(6) through (8), (g)(6) and (7), (h)(7) and (8), and (j)(10)(i) that are not subject to or are not required to conduct surveys using the methods in § 98.234(a) in accordance with the fugitive emissions standards in § 60.5397a of this chapter, the fugitive emissions standards for well sites, centralized production facilities, and compressor stations in § 60.5397b or 60.5398b of this chapter, or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, and you must calculate emissions from the surveyed component types in § 98.232(c)(21)(i), (e)(8), (f)(6) through (8), (g)(6) and (7), (h)(7) and (8), and (j)(10)(i) using the emission calculation requirements in either paragraph (q)(2) or (3) of this section.

(v) For the components listed in § 98.232(d)(7), you must conduct surveys as specified in paragraphs (q)(1)(v)(A) and (B) of this section and you must calculate equipment leak emissions using the procedures specified in either paragraph (q)(2) or (3) of this section.

(A) For the components listed in § 98.232(d)(7) that are not subject to the equipment leak standards for onshore natural gas processing plants in § 60.5400b or § 60.5401b of this chapter, or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, you may use any of the leak detection methods listed in § 98.234(a).

(B) For the components listed in § 98.232(d)(7) that are subject to the equipment leak standards for onshore natural gas processing plants in § 60.5400b or § 60.5401b of this chapter, or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, you must use either of the leak detection methods in § 98.234(a)(1)(iii) or (a)(2)(ii).

(vi) For the components listed in § 98.232(m)(3)(ii) and (m)(4)(ii), 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). If you elect to use a leak detection method in § 98.234(a) for the surveyed component types in § 98.232(m)(3)(ii) and (m)(4)(ii) 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(m)(3)(ii) and (m)(4)(ii) using the procedures in either paragraph (q)(2) or (3) of this section.

(vii) Except as provided in paragraph (q)(1)(viii) of this section, you must conduct at least one complete leak detection survey in a 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 the procedures specified in either paragraph (q)(2) or (3) of this section. Except as provided in paragraphs (q)(1)(vii)(A) through (H) of this section, a complete leak detection survey is a survey in which all equipment components required to be surveyed as specified in paragraphs (q)(1)(i) through (vi) of this section are surveyed.

(A) 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 using one of the methods in § 98.234(a) will be considered a complete leak detection survey for purposes of this section.

(B) For components subject to the well site, centralized production facility, and compressor station fugitive emissions standards in § 60.5397b or 60.5398b of this chapter, each survey conducted in accordance with the fugitive emissions standards for well sites, centralized production facilities, and compressor stations in § 60.5397b, 60.5398b(b)(4) or 60.5398b(b)(5)(ii) of this chapter using one of the methods in § 98.234(a) will be considered a complete leak detection survey for purposes of this section.

(C) For components subject to the well site, centralized production facility, and compressor station fugitive emissions standards in an applicable approved state plan or applicable Federal plan in part 62 of this chapter, each survey conducted in accordance with the applicable approved state plan or applicable Federal plan in part 62 of this chapter using one of the methods in § 98.234(a) will be considered a complete leak detection survey for purposes of this section.

(D) For an onshore petroleum and natural gas production facility electing to conduct leak detection surveys according to paragraph (q)(1)(iv) of this section, a survey of all required components at a single well-pad site, as defined in § 98.238, will be considered a complete leak detection survey for purposes of this section.

(E) For an onshore petroleum and natural gas gathering and boosting facility electing to conduct leak detection surveys according to paragraph (q)(1)(iv) of this section, a survey of all required components at a gathering and boosting site, as defined in § 98.238, will be considered a complete leak detection survey for purposes of this section.

(F) For an onshore natural gas processing facility subject to the equipment leak standards for onshore natural gas processing plants in § 60.5400b or § 60.5401b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, each survey conducted in accordance with the equipment leak standards for onshore natural gas processing plants in § 60.5400b or § 60.5401b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter will be considered a complete leak detection survey for the purposes of calculating emissions using the procedures specified in either paragraph (q)(2) or (3) of this section. At least one complete leak detection survey conducted during the reporting year must include all components listed in § 98.232(d)(7) and subject to this paragraph (q), including components which are considered difficult-to-monitor emission sources as specified in §98.234(a). Inaccessible components as provided in §§ 60.5401b(h)(3) and 60.5401c(h)(3) of this chapter are exempt from the monitoring requirements in this subpart.

(G) For natural gas distribution facilities that choose to conduct equipment leak surveys at all above grade transmission-distribution transfer stations over multiple years as provided in paragraph (q)(1)(~~vii~~viii) of this section, a survey of all required components at the above grade transmission-distribution transfer stations monitored during the calendar year will be considered a complete leak detection survey for purposes of this section.

(H) For onshore natural gas transmission pipeline facilities that conduct leak detection surveys according to paragraph (q)(1)(vi) of this section, a survey of all required components at a transmission company interconnect metering-regulating station or a farm tap/direct sale metering-regulating station, will be considered a complete leak detection survey for purposes of this section.

(viii) Natural gas distribution facilities are required to perform 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. 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.

(2) *Calculation Method 1: Leaker emission factor calculation methodology*. If you elect not to measure leaks according to Calculation Method 2 as specified in paragraph (q)(3) of this section, you must use this Calculation Method 1 for all components included in a complete leak survey. For industry segments listed in § 98.230(a)(2) through (10), if equipment leaks are detected during surveys required or elected for components listed in paragraphs (q)(1)(i) through (vi) of this section, then you must calculate equipment leak emissions per component type per reporting facility, well-pad site, or gathering and boosting site, as applicable, using equation W-30 to this section and the requirements specified in paragraphs (q)(2)(i) through (x) and (xii) of this section. For the industry segment listed in § 98.230(a)(8), the results from equation W-30 to this section are used to calculate population emission factors on a meter/regulator run basis using equation W-31 to 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)(1)(viii) 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.

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

Where:

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

k = Factor to adjust for undetected leaks by respective leak detection method, where k equals 1.25 for the methods in § 98.234(a~~q~~)(1), (3) and (5); k equals 1.55 for the method in § 98.234(a~~q~~)(2)(i); and k equals 1.27 for the method in § 98.234(a~~q~~)(2)(ii).

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 or concentration of GHG_i, CH_4 or CO_2, in the total hydrocarbon of the feed natural gas; for LNG storage and LNG import and export equipment~~ and onshore natural gas transmission pipeline~~, GHG_i equals 1 for CH_4 and 0 for CO_2; and for natural gas distribution and onshore natural gas transmission pipeline, GHG_i equals 1 for CH_4 and 1.1×10^{-2} for 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) The leak detection surveys selected for use in equation W-30 to this section must be conducted during the calendar year as indicated in paragraph (q)(1)(vii) and (viii) of this section, as applicable.

(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, if available, use the facility-specific leaker emission factor calculated in accordance with paragraph (q)(4) of section or use the appropriate default whole gas leaker emission factors consistent with the well type, where components associated with gas wells are considered to be in gas service and components associated with oil wells are considered to be in oil service as listed in table W-2 to this subpart.

(iv) Onshore petroleum and natural gas gathering and boosting facilities must, if available, use the facility-specific leaker emission factor calculated in accordance with paragraph (q)(4) of section or use the appropriate default whole gas leaker factors for components in gas service listed in table W-2 to this subpart.

(v) Onshore natural gas processing facilities must, if available, use the facility-specific leaker emission factor calculated in accordance with paragraph (q)(4) of section or 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-4 to this subpart.

(vi) Onshore natural gas transmission compression facilities must, if available, use the facility-specific leaker emission factor calculated in accordance with paragraph (q)(4) of section or 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-4 to this subpart.

(vii) Underground natural gas storage facilities must, if available, use the facility-specific leaker emission factor calculated in accordance with paragraph (q)(4) of section or use the appropriate default total hydrocarbon leaker emission factors for storage stations or storage wellheads in gas service listed in table W-4 to this subpart.

(viii) LNG storage facilities must, if available, use the facility-specific leaker emission factor calculated in accordance with paragraph (q)(4) of section or use the appropriate default methane leaker emission factors for LNG storage components in LNG service or gas service listed in table W-6 to this subpart.

(ix) LNG import and export facilities must, if available, use the facility-specific leaker emission factor calculated in accordance with paragraph (q)(4) of section or use the appropriate default methane leaker emission factors for LNG terminals components in LNG service or gas service listed in table W-6 to this subpart.

(x) Except as provided in paragraph (q)(3)(viii) of this section, natural gas distribution facilities must use equation W-30 to this section and the default methane leaker emission factors for transmission-distribution transfer station components in gas service listed in table W-6 to this subpart to calculate component emissions from annual equipment leak surveys conducted at above grade transmission-distribution transfer stations.

(A) Use equation W-31 to 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)(B) of this section.

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

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 to this section.
p	=	Seven component types listed in table W-6 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)(B) of this section.
n	=	Number of years of data, according to paragraph (q)(1)(~~vii~~viii) of this section, whose results are used to calculate emission factor "$EF_{s,MR,i}$" according to paragraph (q)(2)(x)(B) of this section.

(B) 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)(1)(viii) 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 to 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 to this section 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 to this section 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 to this section 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)(1)(viii) of this section, you must use the meter/regulator run population emission factors calculated using equation W-31 to 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 to this section.

(xii) Onshore natural gas transmission pipeline facilities must use the facility-specific leaker emission factor calculated in accordance with paragraph (q)(4) of this section.

(3) *Calculation Method 2: Leaker measurement methodology.* For industry segments listed in § 98.230(a)(2) through (10), if equipment leaks are detected during surveys required or elected for components listed in paragraphs (q)(1)(i) through (vi) of this section, you may elect to measure the volumetric flow rate of each natural gas leak identified during a complete leak survey. If you elect to use this method, you must use this method for all components included in a complete leak survey and you must determine the volumetric flow rate of each natural gas leak identified during the leak survey and aggregate the emissions by the method of leak detection and component type as specified in paragraphs (q)(3)(i) through (vii) of this section.

(i) Determine the volumetric flow rate of each natural gas leak identified during the leak survey following the methods § 98.234(b) through (d), as appropriate for each leak identified. You do not need to use the same measurement method for each leak measured. If you are unable to measure the natural gas leak because it would require elevating the measurement personnel more than 2 meters above the surface and a lift is unavailable at the site or it would pose immediate danger to measurement personnel, then you must substitute the default leak rate for the component and site type from tables W-2, W-4, or W-6 to this subpart, as applicable, as the measurement for this leak.

(ii) For each leak, calculate the volume of natural gas emitted as the product of the natural gas flow rate measured in paragraph (q)(3)(i) of this section and the duration of the leak. 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. 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.

(iii) For each leak, convert the volumetric emissions of natural gas determined in paragraph (q)(3)(ii) of this section to standard conditions using the method specified in paragraph (t)(1) of this section.

(iv) For each leak, convert the volumetric emissions of natural gas at standard conditions determined in paragraph (q)(3)(iii) of this section to CO_2 and CH_4 volumetric emissions at standard conditions using the methods specified in paragraph (u) of this section.

(v) For each leak, convert the GHG volumetric emissions at standard conditions determined in paragraph (q)(3)(iv) of this section to GHG mass emissions using the methods specified in paragraph (v) of this section.

(vi) Sum the CO_2 and CH_4 mass emissions determined in paragraph (q)(3)(v) of this section separately for each type of component required to be surveyed by the method used for the survey for which a leak was detected.

(vii) Multiply the total CO_2 and CH_4 mass emissions by survey method and component type determined in paragraph (q)(3)(vi) by the survey specific value for “k”, the factor adjustment for undetected leaks, where k equals 1.25 for the methods in § 98.234(a~~q~~)(1), (3) and (5); k equals 1.55 for the method in § 98.234(a~~q~~)(2)(i); and k equals 1.27 for the method in § 98.234(a~~q~~)(2)(ii).

(viii) For natural gas distribution facilities:

(A) Use equation W-31 to this section to determine the meter/regulator run population emission factors for each GHG_i using the methods as specified in paragraphs (q)(2)(x)(A) and (B) of this section, except use the sum of the GHG volumetric emissions for each type of component required to be surveyed by the method used for the survey for which a leak was detected calculated in paragraph (q)(3)(iv) of this section rather than the emissions calculated using equation W-30 to this section.

(B) If you chose to conduct equipment leak surveys at all above grade transmission-distribution transfer stations over multiple years, "n," according to paragraph (q)(1)(~~vii~~viii) of this section, you must use the meter/regulator run population emission factors calculated according to paragraph (q)(3)(~~vii~~viii)(A) 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 to this section.

(4) *Development of facility-specific component-level leaker emission factors by leak detection method.* If you elect to measure leaks according to Calculation Method 2 as specified in paragraph (q)(3) of this section, you must use the measurement values determined in accordance with paragraph (q)(3) of this section to calculate a facility-specific component-level leaker emission factor by leak detection method as provided in paragraphs (q)(4)(i) through (iv) of this section.

(i) You must track the leak measurements made separately for each of the applicable components listed in paragraphs (q)(1)(i) through (vi) of this section and by the leak detection method according to the following three bins.

(A) Method 21 as specified in § 98.234(a)(2)(i).

(B) Method 21 as specified in § 98.234(a)(2)(ii).

(C) Optical gas imaging (OGI) and other leak detection methods as specified in § 98.234(a)(1), (3), or (5).

(ii) You must accumulate a minimum of 50 leak measurements total for a given component type and leak detection method combination before you can develop and use a facility-specific component-level leaker emission factor for use in calculating emissions according to paragraph (q)(2) of this section (Calculation Method 1: Leaker emission factor calculation methodology).

(iii) Sum the volumetric flow rate of natural gas determined in accordance with paragraph (q)(3)(i) of this section for each leak by component type and leak detection method as specified in paragraph (q)(4)(i) of this section meeting the minimum number of measurement requirement in paragraph (q)(4)(ii) of this section.

(iv) Convert the volumetric flow rate of natural gas determined in paragraph (q)(4)(iii) of this section to standard conditions using the method specified in paragraph (t)(1) of this section.

(v) Determine the emission factor in units of standard cubic feet per hour component (scf/hr-component) by dividing the sum of the volumetric flow rate of natural gas determined in paragraph (q)(4)(iv) of this section by the total number of leak measurements for that component type and leak detection method combination.

(vi) You must update the emission factor determined in (q)(4)(v) of this section annually to include the results from all complete leak surveys for which leak measurement was performed during the reporting year in accordance with paragraph (q)(3) of this section.

(r) *Equipment leaks by population count*. This paragraph (r) applies to emissions sources listed in § 98.232(c)(21)(ii), (f)(7), (g)(5), (h)(6), (j)(10)(ii), (m)(3)(i), and (m)(4)(i) 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) through (6), (j)(11), and (m)(5). 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_4 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 this paragraph (r) and do not need to be reported. Equipment leak components in vacuum service are exempt from the survey and emission estimation requirements of this paragraph (r) and only the count of these equipment must be reported. You must calculate emissions from all emission sources listed in this paragraph (r) using equation W-32A to 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 to this section and according to paragraph (r)(6)(ii) of this section.

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

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

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 major equipment (*e.g.*, wellhead, separator), component (*e.g.*, connector, open-ended line), below grade metering-regulating station, below grade transmission-distribution transfer station, distribution main, distribution service, gathering pipeline, transmission company interconnect metering-regulating station, farm tap and/or direct sale metering-regulating station, or transmission 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)(2)(xi) or (q)(3)(~~vii~~viii)(B) of this section, the annual volumetric emissions of GHG_i from all meter/regulator runs at above grade transmission-distribution transfer stations.

$Count_e$ = Total number of the emission source type at the facility. Onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities must count each major equipment piece listed in table W-1 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-3 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 the: (1) Number of distribution services by material type; (2) miles of distribution mains by material type; (3) number of below grade transmission-distribution transfer stations; and (4) number of below grade metering-regulating stations; as listed in table W-5 to this subpart. Onshore natural gas transmission pipeline facilities must count the following, as listed in table W-5 to this subpart: (1) Miles of transmission pipelines by material type; (2) number of transmission company interconnect metering-regulating stations; and (3) number of farm tap and/or direct sale metering-regulating stations.

$Count_{MR}$ = 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)(2)(xi) or (q)(3)(~~vii~~viii)(B) 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 specified in paragraphs (r)(2) through (7) of this section.

$EF_{s,MR,i}$ = 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 to 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 or concentration of GHGi, CH_4 or CO_2, in the total hydrocarbon of the feed natural gas; 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 and onshore natural gas transmission pipeline, 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-1 to this subpart. Major equipment associated with gas wells are considered gas service equipment in table W-1 to this subpart. Onshore petroleum and natural gas gathering and boosting facilities shall use the gas service equipment emission factors in table W-1 to this subpart. Major equipment associated with crude oil wells are considered crude service equipment in table W-1 to this subpart. Where facilities conduct EOR operations, the emission factor listed in table W-1 to this subpart shall be used to estimate all streams of gases, including recycle CO_2 stream. 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.

(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-3 to this subpart.

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

(5) LNG import and export facilities must use the appropriate default methane population emission factors for LNG terminal compressors in gas service listed in table W-5 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 transmission-distribution transfer stations, below grade metering-regulating stations, distribution mains, and distribution services must use the appropriate default methane population emission factors listed in table W-5 to this subpart to estimate emissions from components listed in § 98.232(i)(2), (4), (5), and (6), respectively.

(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 to this section in accordance with paragraph (q)(2)(x) or (q)(3)(viii)(A) of this section for the components listed in § 98.232(i)(3). 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).

(7) Onshore natural gas transmission pipeline facilities must use the appropriate default methane population emission factors listed in table W-5 to this subpart to estimate emissions from components listed in § 98.232(m)(3)(i), (4)(i) and (5).

(s) *Offshore petroleum and natural gas production facilities*. Calculate CO_2, CH_4, and N_2O emissions for offshore petroleum and natural gas production from all equipment leaks (*i.e.*, fugitives), vented emission, and flare emission source types as identified by BOEM in the most recent monitoring and calculation methods published by BOEM referenced in 30 CFR 550.302 through 304.

(1) Offshore production facilities that report to BOEM's emissions inventory must calculate emissions as specified in paragraph (s)(1)(i) or (ii) of this section, as applicable.

(i) Report the same annual emissions calculated using the most recent monitoring and calculation methods published by BOEM as referenced in 30 CFR 550.302 through 304 for any reporting year that overlaps with a BOEM emissions inventory year and any other reporting year in which the BOEM's emissions reporting system is available and the facility has the data needed to use BOEM's emissions reporting system.

(ii) If BOEM's emissions reporting system is not available or if the facility does not have the data needed to use BOEM's emissions reporting system, adjust emissions from the most recent emissions calculated in accordance with paragraph (s)(1)(i), (s)(3), or (s)(4) of this section, as applicable, by using a ratio of the operating time for the facility in the current reporting year relative to the operating time for the facility during the reporting year for which emissions were calculated as specified in paragraph (s)(1)(i), (s)(3), or (s)(4) of this section, as applicable.

(2) Offshore production facilities that do not report to BOEM's emissions inventory must calculate emissions as specified in paragraph (s)(2)(i) or (ii) of this section, as applicable.

(i) Use the most recent monitoring and calculation methods published by BOEM as referenced in 30 CFR 550.302 through 304 to calculate ~~and report~~ annual emissions for any reporting year that overlaps with a BOEM emissions inventory year and any other reporting year in which the facility has the data needed to use BOEM's emissions calculation methods.

(ii) If the facility does not have the data needed to use BOEM's calculation methods, adjust emissions from the facility's most recent emissions calculated in accordance with paragraph (s)(2)(i), (s)(3), or (s)(4) of this section, as applicable, by using a ratio of the operating time for the facility in the current reporting year relative to the operating time for the facility in the reporting year for which the emissions were calculated as specified in paragraph (s)(2)(i), (s)(3), or (s)(4) of this section, as applicable.

(3) If BOEM's emissions inventory is discontinued or delayed for more than 3 consecutive years, then offshore production facilities shall once in every 3 years use the most recent monitoring and calculation methods published by BOEM referenced in 30 CFR 550.302 through 304 to calculate annual emissions for each of the emission source types covered in BOEM's most recently published calculation methods.

(4) For the first year of reporting, offshore production facilities must use the most recent monitoring and calculation methods published by BOEM referenced in 30 CFR 550.302 through 304 to calculate and report annual 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 paragraph (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 to this section for conversions of $E_{a,n}$ or conversions of FR_a (whether sub-sonic or sonic).

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

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 to this section.

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

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 to this section.

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

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 to 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 to this section.

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

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 to this section:

$$Mass_{CO_2} = N * V_v * R_c * GHG_{CO_2} * 10^{-3} \qquad \text{(Eq. W-37)}$$

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 to this section.

$$Mass_{CO_2} = S_{hl} * V_{hl} \qquad \text{(Eq. W-38)}$$

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) *Other large release events*. Calculate CO_2 and CH_4 emissions from other large release events as specified in paragraphs (y)(2) through (5) of this section for each release that meets or exceeds the applicable criteria in paragraph (y)(1) of this section. You are not required to measure every release from your facility, but if you have EPA-provided notification(s) under the super emitter program in § 60.5371, 60.5371a, or 60.5371b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter or if EPA- or facility-funded monitoring or measurement data that demonstrate the release meets or exceeds one of the thresholds or may reasonably be anticipated to meet or exceed (or to have met or exceeded) one of the thresholds in paragraph (y)(1) of this section, then you must calculate the event emissions and, if the thresholds are confirmed to be exceeded, report the emissions as an other large release event. If you receive an EPA-provided notification under the super emitter program in § 60.5371, 60.5371a, or 60.5371b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, you must comply with the requirements in paragraph (y)(6) of this section.

(1) You must report emissions for other large release events that emit GHG at or above any applicable threshold listed in paragraphs (y)(1)(i) or (ii) of this section. You must report the emissions for the entire duration of the event, not just those time periods of the event emissions exceed the thresholds in paragraphs (y)(1)(i) or (ii) of this section.

(i) For sources not subject to reporting under paragraphs (a) through (s), (w), (x), (dd), or (ee) of this section (such as but not limited to a fire, explosion, well blowout, or pressure relief), a release that emits methane at any point in time at a rate of 100 kg/hr or greater.

(ii) For sources subject to reporting under paragraphs (a) through (h), (j) through (s), (w), (x), (dd), or (ee) of this section, a release that emits methane at any point in time at a rate of 100 kg/hr or greater in excess of the emissions calculated from the source using the applicable methods under paragraphs (a) through (h), (j) through (s), (w), (x), (dd), or (ee) of this section. For a release meeting the criteria in this paragraph (y)(1)(ii), you must report the emissions as an other large release event and exclude the emissions that would have been calculated for that source during the timespan of the event in the source-specific emissions calculated under paragraphs (a) through (h), (j) through (s), (w), (x), (dd), or (ee) of this section, as applicable.

(2) Estimate the total volume of gas released during the event in standard cubic feet and the methane emission rate at any point in time during the event in kilograms per hour using measurement data according to § 98.234(b), if available, or a combination of process knowledge, engineering estimates, and best available data when measurement data are not available according to paragraphs (y)(2)(i) through (v) of this section.

(i) The total volume of gas released must be estimated as the product of the measured or estimated average flow or release rate and the estimated event duration. For events for which information is available showing variable or decaying flow rates, you must calculate the maximum natural gas flow or release rate during the event and either determine a representative average release rate across the entire event or determine representative release rates for specific time periods within the event duration. If you elect to determine representative release rates for specific time periods within the event duration, calculate the volume of gas released for each time period within the event duration as the product of the representative release rate and the length of the corresponding time period and sum the volume of gas released across each of the time periods for the full duration of the event. For events that have releases from multiple release points but have a common root cause (*e.g.*, over-pressuring of a system causes releases from multiple pressure relief devices), you must report the event as a single other large release event considering the cumulative volume of gas released across all release points.

(ii) The start time of the event must be determined based on monitored process parameters and sound engineering principles. If monitored process parameters cannot identify the start of the event, the event must be assumed to start on the date of the most recent monitoring or measurement survey that confirms the source was not emitting at or above the rates specified in paragraph (y)(1) of this section or assumed to have started 91 days prior to the date the event was first identified, whichever start date is most recent.

(iii) The end time of the event must be the date of the confirmed repair or confirmed cessation of emissions.

(iv) For the purposes of paragraph (y)(2)(ii) of this section, “monitoring or measurement survey” includes any monitoring or measurement method in § 98.234(a) through (d) as well as advanced screening methods such as monitoring systems mounted on vehicles, drones, helicopters, airplanes, or satellites capable of identifying emissions at the thresholds specified in paragraph (y)(1) of this section at a 90 percent probability of detection as demonstrated by controlled release tests. Audio, visual, and olfactory inspections are considered monitoring surveys if and only if the event was identified via an audio, visual, and olfactory inspection.

(v) For events that span two different reporting years, calculate the portion of the event’s volumetric emissions calculated according to paragraph (y)(2)(i) of this section that occurred in each reporting year considering only reporting year 2025 and later reporting years. For events with consistent flow or for which one average emissions rate is used, use the relative duration of the event within each reporting year to apportion the volume of gas released for each reporting year. For variable flow events for which the volume of gas released is estimated for separate time periods, sum the volume of gas released across each of the time periods within a given reporting year separately. If one of the time periods span two different reporting years, calculate the portion of the volumetric emissions calculated for that time period that applies to each reporting year based on the number of hours in that time period within each reporting year.

(3) Determine the composition of the gas released to the atmosphere using measurement data, if available, or a combination of process knowledge, engineering estimates, and best available data when measurement data are not available. In the event of an explosion or fire, where a portion of the natural gas may be combusted, estimate the composition of the gas released to the atmosphere considering the fraction of natural gas released directly to the atmosphere and the fraction of natural gas that was combusted by the explosion or fire during the release event. Assume combustion efficiency equals destruction efficiency and assume a maximum combustion efficiency of 92 percent for natural gas that is combusted in an explosion or fire when estimating the CO_2 and CH_4 composition of the release. You may use different compositions for different periods within the duration if available information suggests composition varied during the release (*e.g.*, if a portion of the release occurred while fire was present and a portion of the release occurred when no fire was present).

(4) Calculate the GHG volumetric emissions using equation W-35 to this section.

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

(6) If you receive an EPA-provided notification under the super emitter program in § 60.5371, 60.5371a, or 60.5371b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, you must include the emissions from that source or event within your subpart W report unless you can provide certification as specified in either paragraph (y)(6)(i) or (ii) of this section, as applicable, or unless the EPA has determined that the notification has a demonstrable error, as specified in paragraph (y)(6)(iii) of this section.

(i) If you do not own or operate any petroleum and natural gas system equipment within 50 meters of the location identified in the notification, you may prepare and submit the certification that the facility does not own or operate the equipment at the location identified in the notification.

(ii) If you own or operate petroleum and natural gas system equipment within 50 meters of the location identified in the notification, but there are also other petroleum and natural gas system equipment within 50 meters of the location identified in the notification owned and operated by a different facility, you may prepare and submit the certification that the facility does not own or operate the emitting equipment at the location identified in the notification if and only if you comply with all of the following requirements.

(A) Within 5 days of receiving the notification, complete an investigation of available data as specified in § 60.5371b(d)(2)(i) through (iv) of this chapter to identify the emissions source related to the event notification.

(B) If the data investigation in paragraph (y)(6)(ii)(A) of this section does not identify the emissions source related to the event notification, you must conduct a complete survey of equipment at your facility that is within 50 meters of the location identified in the notification following any one of the methods provided in § 98.234(a)(1) through (3) within 15 days of receiving the notification.

(C) The investigations and surveys conducted in paragraphs (y)(6)(ii)(A) and (B) of this section verify that none of the equipment that you own or operate at the location identified in the notification were responsible for the high emissions event.

(iii) For consideration of demonstrable error, you must submit a statement of demonstrable error as specified by § 60.5371, 60.5371a, or 60.5371b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter. You must report emissions associated with the notification unless the EPA has determined that the notification contained a demonstrable error.

(z) *Combustion equipment*. Except as specified in paragraphs (z)(6) and (7) of this section, calculate CO_2, CH_4, and N_2O combustion-related emissions from stationary or portable equipment using the applicable method in paragraphs (z)(1) through (3) of this section according to the fuel combusted as specified in those paragraphs:

(1) If a fuel combusted in the stationary or portable equipment meets the specifications of paragraph (z)(1)(i) of this section, then calculate emissions according to paragraph (z)(1)(ii) of this section.

(i) The fuel combusted in the stationary or portable equipment is listed in table C-1 to subpart C of this part or is a blend in which all fuels are listed in table C-1. If the fuel is natural gas or the blend contains natural gas, the natural gas must also meet the criteria of paragraphs (z)(1)(i)(A) and (B) of this section.

(A) The natural gas must be of pipeline quality specification.

(B) The natural gas must have a minimum higher heating value of 950 Btu per standard cubic foot.

(ii) For fuels listed in paragraph (z)(1)(i) of this section, calculate CO_2, CH_4, and N_2O emissions for each unit or group of units combusting the same fuel according to any Tier listed in subpart C of this part, except that each natural gas-fired reciprocating internal combustion engine or gas turbine must use one of the methods in paragraph (z)(4) of this section to quantify a CH_4 emission factor instead of using the CH_4 emission factor in table C-2 to 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. You must report emissions according to paragraph (z)(5) of this section.

(2) If a fuel combusted in the stationary or portable equipment meets the specifications of paragraph (z)(2)(i) of this section, then calculate emissions according to paragraph (z)(2)(ii) of this section.

(i) The fuel combusted in the stationary or portable equipment is natural gas that is not pipeline quality or it is a blend containing natural gas that is not pipeline quality with only fuels that are listed in table C-1. The natural gas must meet the criteria of paragraphs (z)(2)(i)(A) through (C) of this section.

(A) The natural gas must have a minimum higher heating value of 950 Btu per standard cubic foot.

(B) The natural gas must have a maximum ~~CO_2 content of~~ higher heating value of 1,100 Btu per standard cubic foot.

(C) The natural gas must have a minimum CH_4 content of 70 percent by volume.

(ii) For fuels listed in paragraph (z)(2)(i) of this section, calculate CO_2, CH_4, and N_2O emissions for each unit or group of units combusting the same fuel according to Tier 2, Tier 3, or Tier 4 listed in subpart C of this part, except that each natural gas-fired reciprocating engine or gas turbine must use one of the methods in paragraph (z)(4) of this section to quantify a CH_4 emission factor instead of using the CH_4 emission factor in table C-2 to 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. You must report emissions according to paragraph (z)(5) of this section.

(3) If a fuel combusted in the stationary or portable equipment meets the specifications of paragraph (z)(3)(i) of this section, then calculate emissions according to paragraph (z)(3)(ii) of this section.

(i) The fuel combusted in the stationary or portable equipment does not meet the criteria of either paragraph (z)(1)(i) or (z)(2)(i) of this section. Examples include natural gas that is not of pipeline quality, natural gas that has a higher heating value of less than 950 Btu per standard cubic feet, and natural gas that is not pipeline quality and does not meet the criteria of either paragraph (z)(2)(i)(B) or (C) of this section. Other examples include field gas that does not meet the definition of natural gas in § 98.238 and blends containing field gas that does not meet the definition of natural gas in § 98.238.

(ii) For fuels listed in paragraph (z)(3)(i) of this section, calculate combustion emissions for each unit or group of units combusting the same fuel using the applicable steps from paragraphs (z)(3)(ii)(A) through (G) of this section:

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

(B) If you have a continuous gas composition analyzer on fuel to the combustion unit(s), you must use these compositions for determining the concentration of each constituent in the flow of gas to the unit or group of units. If you do not have a continuous gas composition analyzer on gas to the combustion unit(s), you may use engineering estimates based on best available data to determine the concentration of each constituent in the flow of gas to the unit or group of units. Otherwise, you must use the appropriate gas compositions for each stream going to the combustion unit(s) as specified in paragraph (u)(2) of this section.

(C) For reciprocating internal combustion engines or gas turbines, you may conduct a performance test following the applicable procedures in § 98.234(i) and calculate CH_4 emissions in accordance with paragraph (z)(3)(ii)(G) of this section. Otherwise, you must calculate CH_4 emissions in accordance with paragraphs (z)(3)(ii)(D) through (F) of this section.

(D) Calculate GHG volumetric emissions at actual conditions using equations W-39A and W-39B to this section:

$$E_{a,CO_2} = (V_a * Y_{CO_2}) \quad + \quad \eta * \sum_{j=1}^{5} V_a * Y_j * R_j \qquad \text{(Eq. W-39A)}$$

$$E_{a,CH_4} = V_a * (1 - \eta) * Y_{CH_4} \qquad \text{(Eq. W-39B)}$$

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 the combustion unit or group of units in actual cubic feet, during the year.

Y_{CO2} = Mole fraction of CO_2 in gas sent to the combustion unit or group of units.

η = Fraction of gas combusted for portable and stationary equipment determined using engineering estimation. For internal combustion devices that are not reciprocating internal combustion engines or gas turbines, a default of 0.995 can be used. For two-stroke lean-burn reciprocating internal combustion engines, a default of 0.953 must be used; for four-stroke lean-burn reciprocating internal combustion engines, a default of 0.962 must be used; for four-stroke rich-burn reciprocating internal combustion engines, a default of 0.997 must be used, and for gas turbines, a default of 0.999 must be used.

Y_j = Mole fraction of hydrocarbon constituent j (such as methane, ethane, propane, butane, and pentanes plus) in gas sent to the combustion unit or group of units.

R_j = Number of carbon atoms in the hydrocarbon constituent j in gas sent to the combustion unit or group of units; 1 for methane, 2 for ethane, 3 for propane, 4 for butane, and 5 for pentanes plus.

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

Y_{CH4} = Mole fraction of methane in gas sent to the combustion unit or group of units.

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

(F) 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.

(G) Calculate CH_4 and N_2O mass emissions, as applicable, using equation W-40 to this section.

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

Where:

$Mass_i$ = Annual N_2O or CH_4 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	=	Site-specific higher heating value of the fuel, mmBtu/unit of the fuel (in units consistent with the fuel quantity combusted).
EF_i	=	For N_2O, use 1.0×10^{-4} kg N_2O/mmBtu; for CH_4, use the CH_4 EF (kg CH_4/MMBtu) determined from your performance test according to paragraph (z)(4)(i) of this section.
1×10^{-3}	=	Conversion factor from kilograms to metric tons.

(4) For each natural gas-fired reciprocating internal combustion engine or gas turbine calculating emissions according to paragraph (z)(1)(ii) or (z)(2)(ii) of this section, you must determine a CH_4 emission factor (kg CH_4/MMBtu) using one of the methods provided in paragraphs (z)(4)(i) through (iii) of this section. For each reciprocating internal combustion engine or gas turbine calculating CH_4 emissions according to paragraph (z)(3)(ii)(G) of this section, you must determine a CH_4 emission factor (kg CH_4/MMBtu) using the method provided in paragraph (z)(4)(i).

(i) Conduct a performance test following the applicable procedures in § 98.234(i). If you are required or elect to conduct a performance test for any reason, you must use that result to determine the CH_4 emission factors. If multiple performance tests are conducted in the same reporting year, the arithmetic average of all performance tests completed that year must be used to determine the CH_4 emission factor.

(ii) Original equipment manufacturer information, which may include manufacturer specification sheets, emissions certification data, or other manufacturer data providing expected emission rates from the reciprocating internal combustion engine or gas turbine.

(iii) Applicable equipment type-specific emission factor from table W-7 to this subpart.

(5) 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 that are calculated according to

the procedures in either paragraph (z)(1)(ii) or (z)(2)(ii) of this section must be reported according to the requirements specified in § 98.236(z) rather than the reporting requirements specified in subpart C of this part.

(6) 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.

(7) 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.

(aa) through (cc) [Reserved]

(dd) *Drilling mud degassing*. Calculate annual volumetric CH_4 emissions from the degassing of drilling mud using one of the calculation methods described in paragraphs (dd)(1), (2), or (3) of this section. If you have taken mudlogging measurements from the penetration of the first hydrocarbon bearing zone until drilling mud ceases to be circulated in the wellbore, including mud pumping rate and gas trap-derived gas concentration that is reported in parts per million (ppm) or is reported in units from which ppm can be derived, you must use Calculation Method 1 as described in paragraph (dd)(1) of this section. If you have not taken mudlogging measurements, you must use Calculation Method 2 as described in paragraph (dd)(2) of this section. If you have taken mudlogging measurements for some, but not all, of the time the well bore has penetrated the first hydrocarbon bearing zone until drilling mud ceases to be circulated in the wellbore including mud pumping rate and gas trap-derived gas concentration that is reported in parts per million (ppm) or is reported in units from which ppm can be derived, you must use Calculation Method 3 as described in paragraph (dd)(3) of this section.

(1) *Calculation Method 1*. For each well in the sub-basin in which drilling mud was used during well drilling, you must calculate CH_4 emissions from drilling mud degassing by applying an emissions rate derived from a representative well in the same sub-basin and within the equivalent stratigraphic interval. You must follow the procedures specified in paragraph (dd)(1)(i) of this section to calculate CH_4 emissions for the representative well and follow the procedures in paragraphs (dd)(1)(ii) through (iv) of this section to calculate CH_4 emissions for every well drilled in the sub-basin and within the equivalent stratigraphic interval.

(i) Calculate CH_4 emissions from mud degassing for one representative well in each sub-basin and within the equivalent stratigraphic interval. For the representative well, you must use mudlogging measurements, including gas trap derived gas concentration and mud pumping rate, taken during the reporting year. In the first year of reporting, you may use measurements from the prior reporting year if measurements from the current reporting year are not available. Use equation W-41 to this section to calculate natural gas emissions from mud degassing at the representative well. You must identify and calculate CH_4 emissions for a representative well for the sub-basin and within the equivalent stratigraphic interval every 2 calendar years or on a more frequent basis. If a representative well is not available in the same sub-basin and within the equivalent stratigraphic interval, you may choose a well within the facility that is drilled into the same formation and within the equivalent stratigraphic interval.

$$E_{s,CH_4,r} = MR_r \times T_r \times \frac{X_n}{1{,}000{,}000} \times GHG_{CH_4} \times 0.1337 \qquad \text{(Eq. W-41)}$$

Where:

$E_{s,CH4,r}$ = Annual total volumetric CH_4 emissions from mud degassing for the representative well, r, in standard cubic feet.

MR_r = Average mud rate for the representative well, r, in gallons per minute.

T_r = Total time that drilling mud is circulated in the representative well, r, in minutes beginning with initial penetration of the first hydrocarbon-bearing zone until drilling mud ceases to be circulated in the wellbore.

X_n = Average concentration of natural gas in the drilling mud as measured by the gas trap, in parts per million.

GHG_{CH4} = Measured mole fraction of CH_4 in natural gas entrained in the drilling mud.

0.1337 = Conversion from gallons to standard cubic feet.

(ii) Calculate the emissions rate of CH_4 in standard cubic feet per minute from the representative well using equation W-42 to this section.

$$ER_{s,CH_4,r} = \frac{E_{s,CH_4,r}}{T_r} \qquad \text{(Eq. W-42)}$$

Where:

$ER_{s,CH4,r}$ = Volumetric CH_4 emission rate from mud degassing for the representative well, r, in standard cubic feet per minute.

$E_{s,CH4,r}$ = Annual total volumetric CH_4 emissions from mud degassing for the representative well, r, in standard cubic feet.

T_r = Total time that drilling mud is circulated in the representative well, r, in minutes beginning with initial penetration of the first hydrocarbon-bearing zone until drilling mud ceases to be circulated in the wellbore.

(iii) Use equation W-43 to this section to calculate emissions for any wells drilled in the same sub-basin and within the equivalent stratigraphic interval in the reporting year.

$$E_{s,CH_4,p} = ER_{s,CH_4,r} \times T_p \qquad \text{(Eq. W-43)}$$

Where:

$E_{s,CH4,p}$ = Annual total CH_4 emissions from mud degassing for the well, p, in standard cubic feet.

$ER_{s,CH4,r}$ = Volumetric CH_4 emission rate from mud degassing for the representative well, r, in standard cubic feet per minute.

T_p = Total time that drilling mud is circulated in the well, p, during the reporting year, in minutes beginning with initial penetration of the first hydrocarbon-bearing zone until drilling mud ceases to be circulated in the wellbore.

(iv) Calculate CH_4 mass emissions using calculations in paragraph (v) of this section.

(2) *Calculation Method 2*. If you did not take mudlogging measurements, calculate emissions from mud degassing for each well using equation W-44 to this section:

$$Mass_{CH_4,p} = EF_{CH_4} \times DD_p \times \frac{X_{CH_4}}{83.85} \quad \text{(Eq. W-44)}$$

Where:

$Mass_{CH4,p}$ = Annual total CH_4 emissions for the well, p, in metric tons.

EF_{CH4} = Emission factor in metric tons CH_4 per drilling day. Use 0.2605 for water-based drilling muds, 0.0586 for oil-based drilling muds, and 0.0586 for synthetic drilling muds.

DD_p = Total number of drilling days for the well, p, when drilling mud is circulated in the wellbore. The first drilling day is the day that the borehole penetrated the first hydrocarbon-bearing zone and the last drilling day is the day drilling mud ceases to be circulated in the wellbore.

X_{CH4} = The mole percent of methane in gas vented during mud degassing in the sub-basin in which the well is located and derived from the average mole fraction of CH_4 in produced gas for the sub-basin as reported in § 98.236(aa)(1)(ii)(I).

83.85 = The mole percent of methane from the vented gas used to derive the emission factor (EF).

(3) *Calculation Method 3*. If you have taken mudlogging measurements at intermittent time intervals for some, but not all, of the time the well bore has penetrated the first hydrocarbon bearing zone until drilling mud ceases to be circulated in the wellbore, you must use Calculation Method 1 to calculate emissions for the cumulative amount of time mudlogging measurements were taken and Calculation Method 2 for the cumulative amount of time mudlogging

measurements were not taken. To determine total annual CH_4 emissions for the well, add $Mass_{CH4,p}$ calculated using Calculation Method 2 to $E_{s,CH4,r}$, if the well is a representative well, or $E_{s,CH4,p}$, if the well is not a representative well, calculated using Calculation Method 1.

(ee) *Crankcase venting*. For each reciprocating internal combustion engine with a rated heat capacity greater than 1 mmBtu/hr (or the equivalent of 130 horsepower), calculate annual CH_4 mass emissions from crankcase venting using one of the methods provided in paragraphs (ee)(1) and (2) of this section. If you elect to use the method in paragraph (ee)(1) of this section, you must use the results of the direct measurement to determine the CH_4 emissions. If any crankcase vents are routed to a flare, you must calculate CH_4, CO_2, and N_2O 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). Notwithstanding the calculation and emissions reporting requirements as specified in this paragraph (ee) of this section, the number of reciprocating internal combustion engines with crankcase vents routed to flares must be reported as specified in § 98.236(ee)(1).

(1) *Calculation Method 1*. Determine the CH_4 mass emissions from reciprocating internal combustion engines annually using the method provided in paragraphs (ee)(1)(i) through (iv) of this section. If you choose to use this method you must use it for all reciprocating internal combustion engines at the facility, well-pad site, or gathering and boosting site, except that if you choose to perform the screening specified in paragraph (ee)(1)(ii) of this section, you must use the method in paragraph (ee)(2) of this section to determine emissions from each reciprocating internal combustion engine that is not operating at the facility, well-pad site, or gathering and boosting site at the time of the screening.

(i) Determine the volumetric flow from the crankcase vent at standard conditions using an appropriate meter, calibrated bag, or high volume sampler according to methods set forth in § 98.234(b), (c), and (d), respectively. Each measurement must be conducted within 10 percent of 100 percent peak load. You may not measure during period of startup, shutdown, or malfunction.

(ii) You may choose to use any of the methods set forth in § 98.234(a)(1) through (3) to screen for emissions. If emissions are detected using the methods set forth in § 98.234(a)(1) through (3), then you must use one of the methods specified in paragraphs (ee)(1)(i) of this section to determine the volumetric flow from the crank case vent at standard conditions. If emissions are not detected using the methods in § 98.234(a)(1) through (3), then you may assume that the emissions are zero. For the purposes of this paragraph, when using any of the methods in § 98.234(a)(1) through (3), emissions are detected whenever a leak is detected according to the method.

(iii) If conducting measurements for a manifolded group of crankcase vent sources, you must measure at a single point in the manifold downstream of all crankcase vent inputs and, if practical, prior to comingling with other non-compressor emission sources. Determine the volumetric flow at standard conditions from the common stack using one of the methods specified in paragraph (ee)(1)(i) of this section. If the manifolded group contains only crankcase vent sources, divide the measured volumetric flow equally between all operating reciprocating internal combustion engines. If the manifolded group contains crankcase vent sources and compressor vent sources, follow the methods for manifolded sources provided in paragraphs (o) or (p) of this section, as applicable, and report emissions from the crankcase vent as specified in § 98.236(o) or (p), as applicable.

(iv) Using equation W-45 to this section, calculate the annual volumetric CH_4 emissions for each reciprocating internal combustion engine that was measured during the reporting year.

$$E_{CH_4} = MT_{s,CCV} \times GHG_{CH_4} \times T \qquad \text{(Eq. W-45)}$$

Where:

E_{CH4}	=	Annual total volumetric emissions of CH_4 from crankcase venting on the reciprocating internal combustion engine, in standard cubic feet.
$MT_{s,CCV}$	=	Volumetric gas emissions for measured crankcase vent, in standard cubic feet per hour, measured according to paragraph (ee)(1)(i) of this section.
GHG_{CH4}	=	Concentration of CH_4 in the gas stream entering reciprocating internal combustion engine. If the concentration of CH_4 is unknown, use the concentration of CH_4 in the gas stream either using engineering estimates based on best available data or as defined in paragraph (u)(2) of this section.
T	=	Total operating hours per year for the reciprocating internal combustion engine.

(v) You must calculate CH_4 mass emissions from volumetric emissions using calculations in paragraph (v) of this section.

(2) *Calculation Method 2*. Calculate annual CH_4 mass emissions from crankcase venting for each reciprocating internal combustion engine using equation W-46 to this section:

$$E_{CH_4} = EF \times 0.001 \times T \qquad \text{(Eq. W-46)}$$

Where:

E_{CH4}	=	Annual total mass emissions of CH_4 from crankcase venting on the reciprocating internal combustion engine, in metric tons.
EF	=	Emission factor for crankcase venting on the reciprocating internal combustion engine, in kilograms CH_4 per hour per reciprocating internal combustion engine. Use 0.083 kilograms CH_4 per hour per reciprocating internal combustion engine for sources in the onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting industry segments. Use 0.11 kilograms CH_4 per hour per reciprocating

		internal combustion engine for sources in all other applicable industry segments.
0.001	=	Conversion from kilograms to metric tons.
T	=	Total operating hours per year for the reciprocating internal combustion engine.

§ 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 part 550.

(a) You must use any of the applicable methods described in paragraphs (a)(1) through (5) of this section to conduct leak detection(s) or screening survey(s) as specified in § 98.233(k), (o), (p), and (ee) 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)(i) or (ii) or (q)(1)(v)(A) that occur during a calendar year. You must use one of the methods described in paragraph (a)(1)(ii) or (iii) or (a)(2)(ii) of this section, as applicable, to conduct leak detection(s) of equipment leaks from components as specified in § 98.233(q)(1)(iii) or (q)(1)(v)(B). 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 (5) 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. Difficult-to-monitor emissions sources are not exempt from this subpart. If the primary leak detection method employed cannot be used to monitor difficult-to-monitor components without elevating the monitoring personnel more than 2 meters above a support surface, you must use alternative leak detection devices as described in paragraph (a)(1) or (3) of this section to monitor difficult-to-monitor equipment leaks or vented emissions at least once per calendar year.

(1) *Optical gas imaging instrument.* Use an optical gas imaging instrument for equipment leak detection as specified in either paragraph (a)(1)(i), (ii), or (iii) of this section. You may use any of the methods as specified in paragraphs (a)(1)(i) through (iii) of this section unless you are required to use a specific method in § 98.233(q)(1).

(i) *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 minimum 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 from an applicable component is 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.

(ii) *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 (c)(3) and (7), and (e) of this chapter and paragraphs (a)(1)(ii)(A) through (C) of this section.

(A) For the purposes of this subpart, any visible emissions observed by the optical gas imaging instrument from a component required or elected to be monitored as specified in § 98.233(q)(1) is a leak.

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

(C) 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 of this chapter means "the collection of components for which you elect to comply with § 98.233(q)(1)(iv)."

(iii) *Optical gas imaging instrument as specified in appendix K to part 60 of this chapter*. Use an optical gas imaging instrument for equipment leak detection in accordance with appendix K to part 60, *Determination of Volatile Organic Compound and Greenhouse Gas Leaks Using Optical Gas Imaging*. Any emissions detected by the optical gas imaging instrument from an applicable component is a leak.

(2) *Method 21*. Use the equipment leak detection methods in Method 21 in appendix A-7 to part 60 of this chapter as specified in paragraph (a)(2)(i) or (ii) of this section. You may use either of the methods as specified in paragraphs (a)(2)(i) and (ii) of this section unless you are required to use a specific method in § 98.233(q)(1). You must survey all applicable source types at the facility needed to conduct a complete equipment leak survey as defined in § 98.233(q)(1). For the purposes of this subpart, the term "fugitive emissions component" in § 60.5397a of this chapter and § 60.5397b of this chapter means "component."

(i) *Method 21 with a leak definition of 10,000 ppm*. Use the equipment leak detection methods in Method 21 in appendix A-7 to part 60 of this chapter using methane as the reference compound. If an instrument reading of 10,000 ppm or greater is measured for any applicable component, a leak is detected.

(ii) *Method 21 with a leak definition of 500 ppm*. Use the equipment leak detection methods in Method 21 in appendix A-7 to part 60 of this chapter using methane as the reference compound. If an instrument reading of 500 ppm or greater is measured for any applicable component, a leak is detected.

(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. 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 through-valve leakage. For these acoustic stethoscope type devices, a leak is detected if an audible leak signal is observed or registered by the device. If the acoustic stethoscope type device is used as a screening to a measurement method and a leak is detected, the leak must be measured using any one of the methods specified in paragraphs (b) through (d) of this section.

(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) For high volume samplers that output methane mass emissions, you must use the calculations in § 98.233(u) and (v) in reverse to determine the natural gas volumetric emissions at standard conditions. For high volume samplers that output methane volumetric flow in actual conditions, divide the volumetric methane flow rate by the mole fraction of methane in the natural gas according to the provisions in § 98.233(u) and 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.

(5) If the measured methane flow exceeds the manufacturer's reported quantitation limit or if the measured natural gas flow determined as specified in paragraph (d)(3) of this section

exceeds 70 percent of the manufacturer's reported maximum sampling flow rate, then the flow exceeds the capacity of the instrument and you must either use a temporary or permanent flow meter according to paragraph (b) of this section or use calibrated bags according to paragraph (c) of this section to determine the leak or flow rate. If you elect to use OGI to demonstrate that 100 percent of the flow is captured by the high volume sampler throughout the measurement period, then the measured flow rate above the 70 percent maximum sampling rate provision can be used. However, if any emissions are observed via OGI escaping capture of the high volume sampler during a measurement period, then that measurement is considered invalid (*i.e.*, considered to be exceeding the quantitation capacity of the device) even if the measured flow rate is less than 70 percent of the sampling rate and you must either use a temporary or permanent flow meter according to paragraph (b) of this section or use calibrated bags according to paragraph (c) of this section to determine the leak or flow rate.

(e) Peng Robinson Equation of State means the equation of state defined by equation W-47 to this section:

$$p = \frac{RT}{V_m - b} - \frac{a\alpha}{V_m^2 + 2bV_m - b^2} \qquad \text{(Eq. W-47)}$$

Where:

p	=	Absolute pressure.
R	=	Universal gas constant.
T	=	Absolute temperature.
V_m	=	Molar volume.
a	=	$\frac{0.45724R^2T_c^2}{p_c}$

b = $\dfrac{0.7780RT_c}{p_c}$

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

Where:

ω = Acentric factor of the species.

T_c = Critical temperature.

P_c = Critical pressure.

(f) [Reserved]

(g) [Reserved]

(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.

(i) You must use any of the applicable methods described in paragraphs (i)(1) through (4) of this section to conduct a performance test to determine the concentration of CH_4 in the exhaust gas. This concentration must be used to develop a CH_4 emission factor (kg/MMBtu) for estimating combustion slip from reciprocating internal combustion engines or gas turbines as specified in § 98.233(z)(4). You may not conduct performance tests during period of startup, shutdown or malfunction. You must conduct three separate test runs for each performance test.

Each test run must be conducted within 10 percent of 100 percent peak (or the highest achievable) load and last at least 1 hour.

(1) EPA Method 18 in appendix A-6 to part 60 of this chapter.

(2) EPA Method 320 in appendix A to part 63 of this chapter.

(3) ASTM D6348-12 (Reapproved 2020) (incorporated by reference, see § 98.7).

(4) EPA Method 25A in appendix A-7 to part 60 of this chapter, with the use of nonmethane cutter as described in § 1065.265 of this chapter.

§ 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 start up new emission sources or 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 operating or 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).

§ 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 than 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) of this section, and each applicable emission source listed in paragraphs (b) through (z), (dd) and (ee) of this section.

(1) *Onshore petroleum and natural gas production*. For the equipment/activities specified in paragraphs (a)(1)(i) through (xxii) 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 and nitrogen 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) *Blowdown vent stacks*. Report the information specified in paragraph (i) of this section.

(ix) *Hydrocarbon liquids and produced water storage tanks*. Report the information specified in paragraph (j) of this section.

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

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

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

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

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

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

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

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

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

(xix) *Other large release events*. Report the information specified in paragraph (y) of this section.

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

(xxi) *Drilling mud degassing*. Report the information specified in paragraph (dd) of this section.

(xxii) *Crankcase vents*. Reporting the information specified in paragraph (ee) of this section.

(2) *Offshore petroleum and natural gas production*. For the equipment/activities specified in paragraphs (a)(2)(i) and (ii) of this section, report the information specified in the applicable paragraphs of this section.

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

(ii) *Other large release events*. Report the information specified in paragraph (y) of this section.

(3) *Onshore natural gas processing*. For the equipment/activities specified in paragraphs (a)(3)(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) *Acid gas removal units and nitrogen removal units*. Report the information specified in paragraph (d) of this section.

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

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

(v) *Hydrocarbon liquids and produced water storage tanks*. Report the information specified in paragraph (j) of this section.

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

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

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

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

(x) *Other large release events*. Report the information specified in paragraph (y) of this section.

(xi) *Crankcase vents*. Report the information specified in paragraph (ee) of this section.

(4) *Onshore natural gas transmission compression*. For the equipment/activities specified in paragraphs (a)(4)(i) through (x) 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) *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) *Condensate storage tanks*. Report the information specified in paragraph (k) of this section.

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

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

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

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

(ix) *Other large release events*. Report the information specified in paragraph (y) of this section.

(x) *Crankcase vents*. Reporting the information specified in paragraph (ee) of this section.

(5) *Underground natural gas storage*. For the equipment/activities specified in paragraphs (a)(5)(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) *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) *Condensate storage tanks*. Report the information specified in paragraph (k) of this section.

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

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

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

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

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

(x) *Other large release events*. Report the information specified in paragraph (y) of this section.

(xi) *Crankcase vents*. Reporting the information specified in paragraph (ee) of this section.

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

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

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

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

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

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

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

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

(viii) *Other large release events*. Report the information specified in paragraph (y) of this section.

(ix) *Crankcase vents*. Reporting the information specified in paragraph (ee) of this section.

(7) *LNG import and export equipment*. For the equipment/activities specified in paragraphs (a)(7)(i) through (ix) of this section, report the information specified in the applicable paragraphs of this section.

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

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

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

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

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

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

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

(viii) *Other large release events*. Report the information specified in paragraph (y) of this section.

(ix) *Crankcase vents*. Reporting the information specified in paragraph (ee) of this section.

(8) *Natural gas distribution*. For the equipment/activities specified in paragraphs (a)(8)(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) *Equipment leak surveys*. Report the information specified in paragraph (q) of this section.

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

(v) *Other large release events*. Report the information specified in paragraph (y) of this section.

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

(vii) *Crankcase vents*. Reporting the information specified in paragraph (ee) of this section.

(9) *Onshore petroleum and natural gas gathering and boosting*. For the equipment/activities specified in paragraphs (a)(9)(i) through (xiv) 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 and nitrogen 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) *Hydrocarbon liquids and produced water 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) *Other large release events*. Report the information specified in paragraph (y) of this section.

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

(xiv) *Crankcase vents*. Reporting the information specified in paragraph (ee) of this section.

(10) *Onshore natural gas transmission pipeline*. For the equipment/activities specified in paragraphs (a)(10)(i) through (iii) 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) *Equipment leaks by population count*. Report the information specified in paragraph (r) of this section.

(iii) *Other large release events*. Report the information specified in paragraph (y) 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 (6) of this section, as applicable. You must report the information specified in paragraphs (b)(1) through (6) of this section, as applicable, for each well-pad site (for onshore petroleum and natural gas production), each gathering and boosting site (for onshore petroleum and natural gas gathering and boosting), or facility (for all other applicable industry segments).

(1) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(2) The number of natural gas pneumatic devices as specified in paragraphs (b)(2)(i) through (viii) of this section, as applicable. If a natural gas pneumatic device was vented directly to the atmosphere for part of the year and routed to a flare, combustion unit, or vapor recovery

system during another part of the year, then include the device in each of the applicable counts specified in paragraphs (b)(2)(ii) through (vii) of this section.

(i) The total number of natural gas pneumatic devices of each type (continuous low bleed, continuous high bleed, and intermittent bleed), determined according to § 98.233(a)(5) through (7).

(ii) The total number of natural gas pneumatic devices of each type (continuous low bleed, continuous high bleed, and intermittent bleed) vented directly to the atmosphere, determined according to § 98.233(a)(5) through (7).

(iii) The total number of natural gas pneumatic devices of each type (continuous low bleed, continuous high bleed, and intermittent bleed) routed to a flare, combustion, or vapor recovery system.

(iv) The total number of natural gas pneumatic devices of each type (continuous low bleed, continuous high bleed, and intermittent bleed) vented directly to the atmosphere for which emissions were calculated using Calculation Method 1 according to § 98.233(a)(1).

(v) The total number of natural gas pneumatic devices of each type (continuous low bleed, continuous high bleed, and intermittent bleed) vented directly to the atmosphere for which emissions were calculated using Calculation Method 2 according to § 98.233(a)(2).

(vi) The total number of natural gas pneumatic devices of each type (continuous low bleed, continuous high bleed, and intermittent bleed) vented directly to the atmosphere for which emissions were calculated using Calculation Method 3 according to § 98.233(a)(3).

(vii) The total number of natural gas pneumatic devices of each type (continuous low bleed, continuous high bleed, and intermittent bleed) vented directly to the atmosphere for which emissions were calculated using Calculation Method 4 according to § 98.233(a)(4).

(viii) If the reported values in paragraphs (b)(2)(i) through (vii) of this section are estimated values determined according to § 98.233(a)(6), then you must report the information specified in paragraphs (b)(2)(viii)(A) through (C) of this section.

(A) The number of natural gas pneumatic devices of each type reported in paragraphs (b)(2)(i) through (vii) of this section that are counted.

(B) The number of natural gas pneumatic devices of each type reported in paragraphs (b)(2)(i) through (vii) 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.

(3) For natural gas pneumatic devices vented directly to the atmosphere for which emissions were calculated using Calculation Method 1 according to § 98.233(a)(1), report the information in paragraphs (b)(3)(i) through (vi) of this section for each measurement location.

(i) Unique measurement location identification number.

(ii) Type of flow monitor (volumetric flow monitor; mass flow monitor).

(iii) Number of natural gas pneumatic devices of each type (continuous low bleed, continuous high bleed, and intermittent bleed) downstream of the flow monitor.

(iv) An indication of whether a natural gas driven pneumatic pump is also downstream of the flow monitor.

(v) Annual CO_2 emissions, in metric tons CO_2, for the natural gas pneumatic devices calculated according to § 98.233(a)(1) for the measurement location.

(vi) Annual CH_4 emissions, in metric tons CH_4, for the natural gas pneumatic devices calculated according to § 98.233(a)(1) for the measurement location.

(4) For natural gas pneumatic devices vented directly to the atmosphere for which emissions were calculated using Calculation Method 2 according to § 98.233(a)(2), report the information in paragraphs (b)(4)(i) through (ii) of this section, as applicable.

(i) For onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting facilities:

(A) Indicate the primary measurement method used (temporary flow meter, calibrated bagging, or high volume sampler).

(B) The average number of hours each type of the natural gas pneumatic device (continuous low bleed, continuous high bleed, and intermittent bleed) was in service (*i.e.*, supplied with natural gas) in the calendar year.

(C) Annual CO_2 emissions, in metric tons CO_2, cumulative by type of natural gas pneumatic device for which emissions were directly measured and calculated as specified in § 98.233(a)(2)(iii) through (viii).

(D) Annual CH_4 emissions, in metric tons CH_4, cumulative by type of natural gas pneumatic device for which emissions were directly measured and calculated as specified in § 98.233(a)(2)(iii) through (viii).

(ii) For onshore natural gas processing facilities, onshore natural gas transmission compression facilities, underground natural gas storage facilities, and natural gas distribution facilities:

(A) The number of years used in the current measurement cycle.

(B) Indicate the primary measurement method used (temporary flow meter, calibrated bagging, or high volume sampler) to measure the emissions from natural gas pneumatic devices at this facility.

(C) Indicate whether the emissions from any natural gas pneumatic devices at this facility were calculated using equation W-1B to § 98.233.

(D) If the emissions from any natural gas pneumatic devices at this facility were calculated using equation W-1B to § 98.233, report the following information for each type of natural gas pneumatic device (continuous low bleed, continuous high bleed, and intermittent bleed).

(*1*) The value of the emission factor for the reporting year as calculated using equation W-1A to § 98.233 (in scf/hour/device).

(*2*) The total number of natural gas pneumatic devices measured across all years upon which the emission factor is based (*i.e.*, the cumulative value of " $\sum_{y=1}^{n} Count_{t,y}$ " in equation W-1A to § 98.233).

(*3*) Total number of natural gas pneumatic devices that vent directly to the atmosphere and that were not directly measured according to the requirements in § 98.233(a)(1) or (a)(2)(iii) (*i.e.*, "$Count_t$" in equation W-1B to § 98.233).

(*4*) The average estimated number of hours in the operating year the natural gas pneumatic devices were in service (*i.e.*, supplied with natural gas) ("T_t" in equation W-1B to § 98.233).

(E) Annual CO_2 emissions, in metric tons CO_2, cumulative by type of natural gas pneumatic device for which emissions were directly measured and calculated as specified in § 98.233(a)(2)(iii) through (viii).

(F) Annual CH_4 emissions, in metric tons CH_4, cumulative by type of natural gas pneumatic device for which emissions were directly measured and calculated as specified in § 98.233(a)(2)(iii) through (viii).

(G) Annual CO_2 emissions, in metric tons CO_2, cumulative by type of natural gas pneumatic device for which emissions were calculated according to § 98.233(a)(2)(ix). Enter 0 if all devices at this facility were monitored during the reporting year.

(H) Annual CH_4 emissions, in metric tons CH_4, cumulative by type of natural gas pneumatic device for which emissions were calculated according to § 98.233(a)(2)(ix). Enter 0 if all devices at this facility were monitored during the reporting year.

(5) For natural gas pneumatic devices vented directly to the atmosphere for which emissions were calculated using Calculation Method 3 according to § 98.233(a)(3), report the information in paragraphs (b)(5)(i) through (iv) of this section.

(i) For continuous high bleed and continuous low bleed natural gas pneumatic devices:

(A) Indicate whether you measured emissions according to § 98.233(a)(3)(i)(A) or used default emission factors according to § 98.233(a)(3)(i)(B) to calculate emissions from your continuous high bleed and continuous low bleed natural gas pneumatic devices vented directly to the atmosphere at this well-pad site, gathering and boosting site, or facility, as applicable.

(B) If measurements were made according to § 98.233(a)(3)(i)(A), indicate the primary measurement method used (temporary flow meter, calibrated bagging, or high volume sampler).

(C) If default emission factors were used according to § 98.233(a)(3)(i)(B) to calculate emissions, report the following information for each type of applicable natural gas pneumatic device (continuous low bleed and continuous high bleed).

(*1*) Total number of natural gas pneumatic devices that vent directly to the atmosphere and that were not directly measured according to the requirements in § 98.233(a)(1) or (a)(2)(iii) ("$Count_t$" in equation W-1B to § 98.233).

(*2*) The average estimated number of hours in the operating year that the natural gas pneumatic devices were in service (*i.e.*, supplied with natural gas) (“T_t” in equation W-1B to § 98.233).

(ii) For intermittent bleed natural gas pneumatic devices:

(A) Indicate the primary monitoring method used (OGI; Method 21 at 10,000 ppm; Method 21 at 500 ppm; or infrared laser beam) and the number of complete monitoring surveys conducted at the well-pad site or gathering and boosting site.

(B) The total number of intermittent bleed natural gas pneumatic devices detected as malfunctioning in any pneumatic device monitoring survey during the calendar year (“x” in equation W-1C to § 98.233).

(C) Average time the intermittent bleed natural gas pneumatic devices were in service (*i.e.*, supplied with natural gas) and assumed to be malfunctioning in the calendar year (average value of “$T_{\cancel{m.z}\underline{mal,z}}$” in equation W-1C to § 98.233).

(D) The total number of intermittent bleed natural gas pneumatic devices that were monitored but were not detected as malfunctioning in any pneumatic device monitoring survey during the calendar year (“Count” in equation W-1C to § 98.233).

(E) Average time the intermittent bleed natural gas pneumatic devices that were monitored but were not detected as malfunctioning in any pneumatic device monitoring survey during the calendar year were in service (*i.e.*, supplied with natural gas) during the calendar year (“T_{avg}” in equation W-1C to § 98.233).

(iii) Annual CO_2 emissions, in metric tons CO_2, for each type of natural gas pneumatic device calculated according to Calculation Method 3 in § 98.233(a)(3).

(iv) Annual CH_4 emissions, in metric tons CH_4, for each type of natural gas pneumatic device calculated according to Calculation Method 3 in § 98.233(a)(3).

(6) For natural gas pneumatic devices vented directly to the atmosphere for which emissions were calculated using Calculation Method 4 according to § 98.233(a)(4), report the following information for each type of applicable natural gas pneumatic device (continuous low bleed, continuous high bleed, and intermittent bleed).

(i) Total number of natural gas pneumatic devices that vent directly to the atmosphere and that were not directly measured according to the requirements in § 98.233(a)(1) (*i.e.*, "$Count_t$" in equation W-1B to § 98.233).

(ii) The average estimated number of hours in the operating year that the natural gas pneumatic devices were in service (*i.e.*, supplied with natural gas) ("T_t" in equation W-1B to § 98.233).

(iii) Annual CO_2 emissions, in metric tons CO_2, for each type of natural gas pneumatic device calculated according to Calculation Method 4 in § 98.233(a)(4).

(iv) Annual CH_4 emissions, in metric tons CH_4, for each type of natural gas pneumatic device calculated according to Calculation Method 4 in § 98.233(a)(4).

(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 (5) of this section. You must report the information specified in paragraphs (c)(1) through (5) of this section, as applicable, for each well-pad site (for onshore petroleum and natural gas production) and each gathering and boosting site (for onshore petroleum and natural gas gathering and boosting).

(1) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(2) The number of natural gas driven pneumatic pumps as specified in paragraphs (c)(2)(i) through (iv) of this section, as applicable. If a natural gas driven pneumatic pump was vented directly to the atmosphere for part of the year and routed to a flare, combustion, or vapor recovery system during another part of the year, then include the device in each of the applicable counts specified in paragraphs (c)(2)(ii) through (iv) of this section.

(i) The total number of natural gas driven pneumatic pumps.

(ii) The total number of natural gas driven pneumatic pumps vented directly to the atmosphere at any point during the year (including pumps that normally routed emissions to a flare but flow bypassed the flare for part of the year).

(iii) The total number of natural gas driven pneumatic pumps routed to a flare at any point during the year.

(iv) The total number of natural gas driven pneumatic pumps routed to combustion or a vapor recovery system at any point during the year.

(3) For natural gas driven pneumatic pumps for which vented emissions were calculated using Calculation Method 1 according to § 98.233(c)(1), report the information in paragraphs (c)(3)(i) through (vi) of this section for each measurement location.

(i) Unique measurement location identification number.

(ii) Type of flow monitor (volumetric flow monitor; mass flow monitor).

(iii) Number of natural gas driven pneumatic pumps downstream of the flow monitor.

(iv) An indication of whether any natural gas pneumatic devices are also downstream of the monitoring location.

(v) Annual CO_2 emissions, in metric tons CO_2, for the pneumatic pump(s) calculated according to § 98.233(c)(1) for the measurement location.

(vi) Annual CH_4 emissions, in metric tons CH_4, for the pneumatic pump(s) calculated according to § 98.233(c)(1) for the measurement location.

(4) If you used Calculation Method 2 according to § 98.233(c)(2) to calculate vented emissions, report the information in paragraphs (c)(4)(i) through (ix) of this section, as applicable.

(i) The number of years used in the current measurement cycle.

(ii) The total number of natural gas driven pneumatic pumps for which emissions were measured or calculated using Calculation Method 2.

(iii) Indicate whether the emissions from the natural gas driven pneumatic pumps at this well-pad site or gathering and boosting site, as applicable, were measured during the reporting year or if the emissions were calculated using equation W-2B to § 98.233.

(iv) If the natural gas driven pneumatic pumps at this well-pad site or gathering and boosting site, as applicable, were measured during the reporting year, indicate the primary measurement method used (temporary flow meter, calibrated bagging, or high volume sampler).

(v) If the emissions from natural gas driven pneumatic pumps at this well-pad site or gathering and boosting site, as applicable, were calculated using equation W-2B to § 98.233, report the following information:

(A) The value of the emission factor for the reporting year as calculated using equation W-2A to § 98.233 (in scf/hour/pump).

(B) The total number of natural gas driven pneumatic pumps measured across all years upon which the emission factor is based (*i.e.*, the cumulative value of "$\sum_{y=1}^{n} Count_y$" term used in equation W-2A to § 98.233).

(C) Total number of natural gas driven pneumatic pumps that vent directly to the atmosphere and that were not directly measured according to the requirements in § 98.233(c)(1) or (c)(2)(iii) (*i.e.*, "Count" in equation W-2B to § 98.233).

(D) The average estimated number of hours in the operating year the pumps were pumping liquid (*i.e.*, "T" in equation W-2B to § 98.233).

(vi) Annual CO_2 emissions, in metric tons CO_2, cumulative for all natural gas driven pneumatic pumps for which emissions were directly measured and calculated as specified in § 98.233(c)(2)(ii) through (vi). Enter 0 if emissions from none of the natural gas driven pneumatic pumps at this well-pad site or gathering and boosting site were measured during the reporting year.

(vii) Annual CH_4 emissions, in metric tons CH_4, cumulative for all natural gas driven pneumatic pumps for which emissions were directly measured and calculated as specified in § 98.233(c)(2)(ii) through (vi). Enter 0 if emissions from none of the natural gas driven pneumatic pumps at this well-pad site or gathering and boosting site were measured during the reporting year.

(viii) Annual CO_2 emissions, in metric tons CO_2, cumulative for all natural gas driven pneumatic pumps for which emissions were calculated according to § 98.233(c)(2)(vii)(B) through (D). Enter 0 if emissions from all natural gas driven pneumatic pumps at this well-pad site or gathering and boosting site were measured during the reporting year.

(ix) Annual CH_4 emissions, in metric tons CH_4, cumulative for all natural gas driven pneumatic pumps for which emissions were calculated according to § 98.233(c)(2)(vii)(B) through (D). Enter 0 if emissions from all natural gas driven pneumatic pumps at this well-pad site or gathering and boosting site were measured during the reporting year.

(5) If you used Calculation Method 3 according to § 98.233(c)(3) to calculate vented emissions, report the information in paragraphs (c)(5)(i) through (iv) of this section for the natural gas driven pneumatic pumps subject to Calculation Method 3.

(i) Number of pumps that vent directly to the atmosphere (*i.e.*, "Count" in equation W-2B to § 98.233).

(ii) Average estimated number of hours in the calendar year that natural gas driven pneumatic pumps that vented directly to atmosphere were pumping liquid ("T" in equation W-2B to § 98.233).

(iii) Annual CO_2 emissions, in metric tons CO_2, for all natural gas driven pneumatic pumps vented directly to the atmosphere combined, calculated according to § 98.233(c)(3).

(iv) Annual CH_4 emissions, in metric tons CH_4, for all natural gas driven pneumatic pumps vented directly to the atmosphere combined, calculated according to § 98.233(c)(3).

(d) *Acid gas removal units and nitrogen removal units*. You must indicate whether your facility has any acid gas removal units or nitrogen removal units that vent directly to the atmosphere, to a flare or engine, or to a sulfur recovery plant. For any acid gas removal units or nitrogen removal units that vent directly to the atmosphere or to a sulfur recovery plant, you must report the information specified in paragraphs (d)(1) and (2) of this section. If the acid gas removal units or nitrogen removal units that vent directly to the atmosphere for only part of the year, report the information specified in paragraph (d)(2) if this section for the part of the year that the units vent directly to the atmosphere. For acid gas removal units or nitrogen removal units that were routed to an engine or routed to a vapor recovery system for the entire year, you must only report the information specified in paragraphs (d)(1)(i) through (v) and (x) of this section. For acid gas removal units or nitrogen removal units that were routed to flares for which you calculated natural gas emissions routed to the flare using continuous parameter monitoring systems as specified in § 98.233(n)(3)(i) and 98.233(n)(3)(ii)(A) and continuous gas composition analyzers or sampling as specified in § 98.233(n)(4), you must report the information specified in paragraphs (d)(1)(i) through (v) and (x) of this section, as applicable. For acid gas removal units that were routed to flares for which you calculated natural gas emissions routed to the flare using the calculation methods in § 98.233(d) to determine natural gas volumes as specified in § 98.233(n)(3)(ii)(B), then you must report the information specified in paragraphs (d)(1)(i) through (vii) and (x) of this section and paragraph (d)(2) of this section.

(1) You must report the information specified in paragraphs (d)(1)(i) through (xi) of this section for each acid gas removal unit or nitrogen removal unit, as applicable.

(i) A unique name or ID number for the acid gas removal unit or nitrogen 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 or nitrogen removal unit for each location it operates at in a given year.

(ii) Whether the acid gas removal unit or nitrogen removal unit vent was routed to a flare. If so, report the information specified in paragraphs (d)(1)(ii)(A) through (D) of this section for acid gas removal units and the information specified in paragraph (d)(1)(ii)(B) of this section for nitrogen removal units.

(A) Indicate whether you calculated natural gas emissions routed to the flare using continuous parameter monitoring systems as specified in § 98.233(n)(3)(i) and (ii)(A) and continuous gas composition analyzers or sampling as specified in § 98.233(n)(4), or you calculated natural gas emissions routed to the flare using the calculation methods in § 98.233(d) as specified in § 98.233(n)(3)(ii)(B).

(B) Indicate whether natural gas emissions were routed to a flare for the entire year or only part of the year.

(C) The unique name or ID for the flare stack as specified in paragraph (n)(1) of this section to which the acid gas removal unit or nitrogen removal unit vent was routed.

(D) The unique ID for the stream routed to the flare as specified in paragraph (n)(3) of this section from the acid gas removal unit or nitrogen removal unit vent.

(iii) Whether the acid gas removal unit or nitrogen removal unit vent was routed to combustion, and if so, whether it was routed for the entire year or only part of the year.

(iv) Whether the acid gas removal unit or nitrogen removal unit vent was routed to a vapor recovery system, and if so, whether it was routed for the entire year or only part of the year.

(v) Total feed rate entering the acid gas removal unit or nitrogen removal unit, using a meter or engineering estimate based on process knowledge or best available data, in million standard cubic feet per year.

(vi) If the acid gas removal unit or nitrogen removal unit was routed to a flare, to combustion, or to vapor recovery for only part of the year, the feed rate entering the acid gas removal unit or nitrogen removal unit during the portion of the year that the emissions were vented directly to the atmosphere, using a meter or engineering estimate based on process knowledge or best available data, in million standard cubic feet per year.

(vii) The calculation method used to calculate CO_2 and CH_4 emissions from the acid gas removal unit or to calculate CH_4 emissions from the nitrogen removal unit, as specified in § 98.233(d).

(viii) Annual CO_2 emissions, in metric tons CO_2, vented directly to the atmosphere 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)(11) and (12).

(ix) Annual CH_4 emissions, in metric tons CH_4, vented directly to the atmosphere from the acid gas removal unit or nitrogen removal unit, calculated using any one of the calculation methods specified in § 98.233(d) and as specified in § 98.233(d)(11) and (12).

(x) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (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 or nitrogen 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 and Calculation Method 2 as specified in § 98.233(d) to calculate CH_4 emissions from the acid gas removal unit or nitrogen removal unit, then you must report the information specified in paragraphs (d)(2)(i)(A) through (C) of this section, as applicable.

(A) Annual average volumetric fraction of CO_2 in the vent gas exiting the acid gas removal unit.

(B) Annual average volumetric fraction of CH_4 in the vent gas exiting the acid gas removal unit or nitrogen removal unit.

(C) Annual volume of gas vented from the acid gas removal unit or nitrogen removal unit, in cubic feet.

(D) The temperature that corresponds to the reported annual volume of gas vented from the unit, in degrees Fahrenheit. If the annual volume of gas vented is reported in actual cubic feet, report the actual temperature; if it is reported in standard cubic feet, report 60 °F.

(E) The pressure that corresponds to the reported annual volume of gas vented from the unit, in pounds per square inch absolute. If the annual volume of gas vented is reported in actual cubic feet, report the actual pressure; if it is reported in standard cubic feet, report 14.7 psia.

(ii) If you used Calculation Method 3 as specified in § 98.233(d) to calculate CO_2 or CH_4 emissions from the acid gas removal unit or nitrogen removal unit, then you must report the information specified in paragraphs (d)(2)(ii)(A) through (M) of this section, as applicable depending on the equation used.

(A) Indicate which equation was used (equation W-4A, W-4B, or W-4C to § 98.233).

(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, equation W-4B, or equation W-4C to § 98.233.

(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, equation W-4B, or equation W-4C to § 98.233.

(D) Annual average volumetric fraction of CO_2 in the vent gas exiting the acid gas removal unit, as specified in equation W-4A or equation W-4B to § 98.233.

(E) Annual average volumetric fraction of CH_4 in the natural gas flowing out of the acid gas removal unit or nitrogen removal unit, as specified in equation W-4A, equation W-4B, or equation W-4C to § 98.233.

(F) Annual average volumetric fraction of CH_4 content in natural gas flowing into the acid gas removal unit or nitrogen removal unit, as specified in equation W-4A, equation W-4B, or equation W-4C to § 98.233.

(G) Annual average volumetric fraction of CH_4 in the vent gas exiting the acid gas removal unit or nitrogen removal unit, as specified in equation W-4A or equation W-4B to § 98.233.

(H) The total annual volume of natural gas flow into the acid gas removal unit or nitrogen removal unit, as specified in equation W-4A or equation W-4C to § 98.233, in cubic feet at actual conditions.

(I) The temperature that corresponds to the reported total annual volume of natural gas flow into the acid gas removal unit or nitrogen removal unit, as specified in equation W-4A or equation W-4C to § 98.233, in degrees Fahrenheit. If the total annual volume of natural gas flow is reported in actual cubic feet, report the actual temperature; if it is reported in standard cubic feet, report 60 °F.

(J) The pressure that corresponds to the reported total annual volume of natural gas flow into the acid gas removal unit or nitrogen removal unit, as specified in equation W-4A or equation W-4C to § 98.233, in pounds per square inch absolute. If the total annual volume of natural gas flow is reported in actual cubic feet, report the actual pressure; if it is reported in standard cubic feet, report 14.7 psia.

(K) The total annual volume of natural gas flow out of the acid gas removal unit or nitrogen removal unit, as specified in equation W-4B or equation W-4C to § 98.233, in cubic feet at actual conditions.

(L) The temperature that corresponds to the reported total annual volume of natural gas flow out of the acid gas removal unit or nitrogen removal unit, as specified in equation W-4B or equation W-4C to § 98.233, in degrees Fahrenheit. If the total annual volume of natural gas flow is reported in actual cubic feet, report the actual temperature; if it is reported in standard cubic feet, report 60 °F.

(M) The pressure that corresponds to the reported total annual volume of natural gas flow out of the acid gas removal unit or nitrogen removal unit, as specified in equation W-4B or equation W-4C to § 98.233, in pounds per square inch absolute. If the total annual volume of natural gas flow is reported in actual cubic feet, report the actual pressure; if it is reported in standard cubic feet, report 14.7 psia.

(iii) If you used Calculation Method 4 as specified in § 98.233(d) to calculate CO_2 or CH_4 emissions from the acid gas removal unit or nitrogen removal unit, then you must report the information specified in paragraphs (d)(2)(iii)(A) through (O) of this section, as applicable to the simulation software package used.

(A) The name of the simulation software package used.

(B) Annual average natural gas feed temperature, in degrees Fahrenheit.

(C) Annual average natural gas feed pressure, in pounds per square inch.

(D) Annual average natural gas feed flow rate, in standard cubic feet per minute.

(E) Annual average acid gas content of the feed natural gas, in mole percent.

(F) Annual average acid gas content of the outlet natural gas, in mole percent.

(G) Annual average methane content of the feed natural gas, in mole percent.

(H) Annual average methane content of the outlet natural gas, in mole percent

(I) Total annual unit operating hours, excluding downtime for maintenance or standby, in hours per year.

(J) Annual average exit temperature of the natural gas, in degrees Fahrenheit.

(K) Annual average solvent pressure, in pounds per square inch.

(L) Annual average solvent temperature, in degrees Fahrenheit.

(M) Annual average solvent circulation rate, in gallons per minute.

(N) Solvent type used for the majority of the year, from one of the following options: Selexol™, Rectisol®, Purisol™, Fluor Solvent℠, Benfield™, 20 wt% MEA, 30 wt% MEA, 40 wt% MDEA, 50 wt% MDEA, and other (specify).

(O) If a vent meter is installed and you elected to use Calculation Method 4 for an AGR, report the information in paragraphs (d)(2)(iii)(O)(*1*) through (*3*) of this section.

(*1*) The total annual volume of vent gas flowing out of the AGR in cubic feet per year at actual conditions as determined by flow meter ("$V_{a,meter}$" from equation W-4D to § 98.233).

(*2*) The total annual volume of vent gas flowing out of the AGR in cubic feet per year at actual conditions as determined the standard simulation software package ("$V_{a,sim}$" from equation W-4D to § 98.233).

(*3*) If the calculated percent difference between the vent volumes ("PD" from equation W-4D to § 98.233) is greater than 20 percent, provide a brief description of the reason for the difference.

(e) *Dehydrators*. You must indicate whether your facility contains any of the following equipment: Glycol dehydrators for which you calculated emissions using Calculation Method 1 according to § 98.233(e)(1), glycol dehydrators for which you calculated emissions using Calculation Method 2 according to § 98.233(e)(2), 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) of this section. For dehydrators that were routed to flares for which you calculated natural gas emissions routed to the flare using continuous parameter monitoring systems as specified in § 98.233(n)(3)(i) and (ii)(A) and continuous gas composition analyzers or sampling as specified in § 98.233(n)(4), you must report the information specified in paragraph (e)(4) of this section. For dehydrators that were routed to flares for which you calculated natural gas emissions routed to the flare using the calculation methods in § 98.233(e) to determine natural gas volumes as specified in § 98.233(n)(3)(ii)(B), then you must report the applicable information in paragraphs (e)(1) through (3) of this section and the information specified in paragraph (e)(4) of this section.

(1) For each glycol dehydrator for which you calculated emissions using Calculation Method 1 (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. If reported emissions are based on more than one simulation, you must report the average of the simulation inputs.

(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.

(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 stripping gas is used in dehydrator.

(ix) Whether a flash tank separator is used in dehydrator.

(x) Total time the dehydrator is operating during the year, in hours.

(xi) Temperature of the wet natural gas at the absorber inlet, in degrees Fahrenheit.

(xii) Pressure of the wet natural gas at the absorber inlet, 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) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(xvi) If a flash tank separator is used in the dehydrator, then you must report the information specified in paragraphs (e)(1)(xvi)(A) through (F) of this section for the emissions from the flash tank vent, as applicable. If flash tank emissions were routed to a regenerator firebox/fire tubes, then you must also report the information specified in paragraphs (e)(1)(xvi)(G) through (I) of this section for the combusted emissions from the flash tank vent.

(A) Whether any flash gas emissions are vented directly to the atmosphere, routed to a flare, routed to the regenerator firebox/fire tubes, routed to a vapor recovery system, used as stripping gas, or any combination.

(B) Annual CO_2 emissions, in metric tons CO_2, from the flash tank when not routed to a flare or regenerator firebox/fire tubes, calculated according to § 98.233(e)(1) and, if applicable, (e)(4).

(C) Annual CH_4 emissions, in metric tons CH_4, from the flash tank when not routed to a flare or regenerator firebox/fire tubes, calculated according to § 98.233(e)(1) and, if applicable, ~~paragraph~~ (e)(4) ~~of this section~~.

(D) Annual CO_2 emissions, in metric tons CO_2, that resulted from routing flash gas to a regenerator firebox/fire tubes, calculated according to § 98.233(e)(5).

(E) Annual CH_4 emissions, in metric tons CH_4, that resulted from routing flash gas to a regenerator firebox/fire tubes, calculated according to § 98.233(e)(5).

(F) Annual N_2O emissions, in metric tons N_2O, that resulted from routing flash gas to a regenerator firebox/fire tubes, calculated according to § 98.233(e)(5).

(G) Indicate whether the regenerator firebox/fire tubes was monitored with a CEMS. If a CEMS was used, then paragraphs (e)(1)(xvi)(E) and (F) and (e)(1)(xvi)(H) and (I) of this section do not apply.

(H) Total volume of gas from the flash tank to a regenerator firebox/fire tubes, in standard cubic feet.

(I) Average combustion efficiency, expressed as a fraction of gas from the flash tank combusted by a burning regenerator firebox/fire tubes.

(xvii) Report the information specified in paragraphs (e)(1)(xvii)(A) through (F) of this section for the emissions from the still vent, as applicable. If still vent emissions were routed to a regenerator firebox/fire tubes, then you must also report the information specified in paragraphs (e)(1)(xvii)(G) through (I) of this section for the combusted emissions from the still vent.

(A) Whether any still vent emissions are vented directly to the atmosphere, routed to a flare, routed to the regenerator firebox/fire tubes, routed to a vapor recovery system, used as stripping gas, or any combination.

(B) Annual CO_2 emissions, in metric tons CO_2, from the still vent when not routed to a flare or regenerator firebox/fire tubes, calculated according to § 98.233(e)(1), and, if applicable, (e)(4).

(C) Annual CH_4 emissions, in metric tons CH_4, from the still vent when not routed to a flare or regenerator firebox/fire tubes, calculated according to § 98.233(e)(1) and, if applicable, (e)(4).

(D) Annual CO_2 emissions, in metric tons CO_2, that resulted from routing still vent gas to a regenerator firebox/fire tubes, calculated according to § 98.233(e)(5).

(E) Annual CH_4 emissions, in metric tons CH_4, that resulted from routing still vent gas to a regenerator firebox/fire tubes, calculated according to § 98.233(e)(5).

(F) Annual N_2O emissions, in metric tons N_2O, that resulted from routing still vent gas to a regenerator firebox/fire tubes, calculated according to § 98.233(e)(5).

(G) Indicate whether the regenerator firebox/fire tubes were monitored with a CEMS. If a CEMS was used, then paragraphs (e)(1)(xvii)(E) and (F) and (e)(1)(xvii)(H) and (I) of this section do not apply.

(H) Total volume of gas from the still vent to a regenerator firebox/fire tubes, in standard cubic feet.

(I) Average combustion efficiency, expressed as a fraction of gas from the still vent combusted by a burning regenerator firebox/fire tubes.

(xviii) Name of the software package used.

(2) You must report the information specified in paragraphs (e)(2)(i) through (vi) of this section for all glycol dehydrators with an annual average daily natural gas throughput greater than 0 million standard cubic feet per day and less than 0.4 million standard cubic feet per day for which you calculated emissions using Calculation Method 2 (as specified in § 98.233(e)(2)) at the facility, well-pad site, or gathering and boosting site.

(i) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(ii) The total number of dehydrators at the facility, well-pad site, or gathering and boosting site for which you calculated emissions using Calculation Method 2.

(iii) Whether any dehydrator emissions were routed to a vapor recovery system. If any dehydrator emissions were routed to a vapor recovery system, then you must report the total number of dehydrators at the facility that routed to a vapor recovery system.

(iv) Whether any dehydrator emissions were routed to a control device that reduces CO_2 and/or CH_4 emissions other than a vapor recovery system or a flare or regenerator firebox/fire tubes. If any dehydrator emissions were routed to a control device that reduces CO_2 and/or CH_4 emissions other than a vapor recovery system 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 routed to each type of control device.

(v) Whether any dehydrator emissions were routed to a flare or regenerator firebox/fire tubes. If any dehydrator emissions were routed to a flare or regenerator firebox/fire tubes, then you must report the information specified in paragraphs (e)(2)(v)(A) through (E) of this section.

(A) The total number of dehydrators routed to a flare and the total number of dehydrators routed to regenerator firebox/fire tubes.

(B) Total volume of gas from the flash tank to a regenerator firebox/fire tubes, in standard cubic feet.

(C) Annual CO_2 emissions, in metric tons CO_2, for the dehydrators routed to a regenerator firebox/fire tubes reported in paragraph (e)(2)(v)(A) of this section, calculated according to § 98.233(e)(5).

(D) Annual CH_4 emissions, in metric tons CH_4, for the dehydrators routed to a regenerator firebox/fire tubes reported in paragraph (e)(2)(v)(A) of this section, calculated according to § 98.233(e)(5).

(E) Annual N_2O emissions, in metric tons N_2O, for the dehydrators routed to a regenerator firebox/fire tubes reported in paragraph (e)(2)(v)(A) of this section, calculated according to § 98.233(e)(5).

(vi) For dehydrator emissions that were not routed to a flare or regenerator firebox/fire tubes, report the information specified in paragraphs (e)(2)(vi)(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)(ii) of this section that were not routed to a flare or regenerator firebox/fire tubes, calculated according to § 98.233(e)(2) and, if applicable, (e)(4), 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)(ii) of this section that were not routed to a flare or regenerator firebox/fire tubes, calculated according to § 98.233(e)(2) and, if applicable, (e)(4), 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 (viii) of this section for each well-pad site, gathering and boosting site, or facility, as applicable.

(i) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(ii) Count of desiccant dehydrators as specified in paragraphs (e)(3)(ii)(A) and (B) of this section that had one or more openings during the calendar year at the facility, well-pad site, or gathering and boosting site for which you calculated emissions using Calculation Method 3.

(A) The number of opened desiccant dehydrators that used deliquescing desiccant (*e.g.*, calcium chloride or lithium chloride).

(B) The number of opened desiccant dehydrators that used regenerative desiccant (*e.g.*, molecular sieves, activated alumina, or silica gel).

(iii) For desiccant dehydrators at the facility, well-pad site, or gathering and boosting site identified in paragraph (e)(3)(ii) of this section, total physical volume of all opened dehydrator vessels.

(iv) For desiccant dehydrators at the facility, well-pad site, or gathering and boosting site identified in paragraph (e)(3)(ii) of this section, total number of dehydrator openings in the calendar year.

(v) For desiccant dehydrators at the facility, well-pad site, or gathering and boosting site identified in paragraph (e)(3)(ii) of this section, whether any dehydrator emissions were routed to a vapor recovery system. If any dehydrator emissions were routed to a vapor recovery system, then you must report the total number of dehydrators at the facility that routed to a vapor recovery system.

(vi) For desiccant dehydrators at the facility, well-pad site, or gathering and boosting site identified in paragraph (e)(3)(ii) of this section, whether any dehydrator emissions were routed to a control device that reduces CO_2 and/or CH_4 emissions other than a vapor recovery system or a flare or a non-flare combustion unit. If any dehydrator emissions were routed to a control device that reduces CO_2 and/or CH_4 emissions other than a vapor recovery system or a flare or a non-flare combustion unit, then you must specify the type of control device(s) and the total number of dehydrators at the facility that were routed to each type of control device.

(vii) For desiccant dehydrators at the facility, well-pad site, or gathering and boosting site identified in paragraph (e)(3)(ii) of this section, whether any dehydrator emissions were routed to a flare or a non-flare combustion unit. If any dehydrator emissions were routed to a flare or a non-flare combustion unit, then you must report the information specified in paragraphs (e)(3)(vii)(A) through (E) of this section.

(A) The total number of dehydrators routed to a flare and the total number of dehydrators routed to a non-flare combustion unit.

(B) Total volume of gas ~~from the flash tank~~routed to non-flare combustion units, in standard cubic feet.

(C) Annual CO_2 emissions, in metric tons CO_2, for the dehydrators routed to non-flare combustion units reported in paragraph (e)(3)(vii)(A) of this section, calculated according to § 98.233(e)(5).

(D) Annual CH_4 emissions, in metric tons CH_4, for the dehydrators routed to non-flare combustion units reported in paragraph (e)(3)(vii)(A) of this section, calculated according to § 98.233(e)(5).

(E) Annual N_2O emissions, in metric tons N_2O, for the dehydrators routed to non-flare combustion units reported in paragraph (e)(3)(vii)(A) of this section, calculated according to § 98.233(e)(5).

(viii) For desiccant dehydrators at the facility, well-pad site, or gathering and boosting site identified in paragraph (e)(3)(ii) of this section that were not routed to a flare or a non-flare combustion unit, report the information specified in paragraphs (e)(3)(viii)(A) and (B) of this section.

(A) Annual CO_2 emissions, in metric tons CO_2, for emissions from all desiccant dehydrators reported under paragraph (e)(3)(ii) of this section that are not venting to a flare or non-flare combustion unit~~s~~, calculated according to § 98.233(e)(3) and, if applicable, (e)(4), and summing for all such dehydrators.

(B) Annual CH_4 emissions, in metric tons CH_4, for emissions from all desiccant dehydrators reported in paragraph (e)(3)(ii) of this section that are not venting to a flare or non-flare combustion unit, calculated according to § 98.233(e)(3), and, if applicable, (e)(4), and summing for all such dehydrators.

(4) For dehydrators that were routed to flares, report the information specified in paragraphs (e)(4)(i) through (iv) of this section.

(i) Indicate whether you calculated natural gas emissions routed to the flare using continuous parameter monitoring systems as specified in § 98.233(n)(3)(i) and 98.233(n)(3)(ii)(A) and continuous gas composition analyzers or sampling as specified in § 98.233(n)(4), or you calculated natural gas emissions routed to the flare using the calculation methods in § 98.233(e) as specified in § 98.233(n)(3)(ii)(B).

(ii) Indicate whether natural gas emissions were routed to a flare for the entire year or only part of the year.

(iii) The unique name or ID for the flare stack as specified in paragraph (n)(1) of this section to which the dehydrator vent was routed.

(iv) The unique ID for the stream routed to the flare as specified in paragraph (n)(3) of this section from the dehydrator.

(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 venting to the atmosphere 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 venting to the atmosphere and uses Calculation Method 2 or 3, then you must report the information specified in paragraph (f)(2) of this section.

(1) For each well for which you used Calculation Method 1 to calculate natural gas emissions from well venting for liquids unloading vented to the atmosphere, 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 by unloading type combination (with or without plunger lifts, automated or manual unloading).

(i) Well ID number.

(ii) Well tubing diameter and pressure group ID.

(iii) Unloading type combination (with or without plunger lifts, automated or manual unloading).

(iv) [Reserved]

(v) Indicate whether the monitoring period used to determine the cumulative amount of time venting to the atmosphere was not the full calendar year.

(vi) Cumulative amount of time the well was vented directly to the atmosphere ("T_p" from equation W-7A or W-7B to § 98.233), in hours.

(vii) Cumulative number of unloadings vented directly to the atmosphere for the well.

(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 (F) 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.

(F) Unloading type (automated or manual).

(xii) For each well tubing diameter group and pressure group combination, you must report the information specified in paragraphs (f)(1)(xii)(A) through (F) 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.

(F) Unloading type (automated or manual).

(2) For each well 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 vented to the atmosphere, you must report the information in paragraphs (f)(2)(i) through (xii) of this

section. Report information separately for each calculation method and unloading type combination (with or without plunger lifts, automated or manual unloadings).

(i) Well ID number.

(ii) Calculation method.

(iii) Unloading type combination (with or without plunger lifts, automated or manual unloadings).

(iv) [Reserved]

(v) Cumulative number of unloadings venting directly to the atmosphere for the well.

(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) Average flow-line rate of gas (average of "SFR_p" from equation W-8 or W-9 to § 98.233, as applicable), at standard conditions in cubic feet per hour.

(x) Cumulative amount of time that wells were left open to the atmosphere during unloading events (sum of "$HR_{p,q}$" from equation W-8 or W-9 to § 98.233, as applicable), in hours.

(xi) For each well without plunger lifts, the information in paragraphs (f)(2)(xi)(A) through (C) of this section.

(A) Internal casing diameter ("CD_p" from equation W-8 to § 98.233), in inches.

(B) Well depth ("WD_p" from equation W-8 to § 98.233), in feet.

(C) Shut-in pressure, surface pressure, or casing pressure ("SP_p" from equation W-8 to § 98.233), in pounds per square inch absolute.

(xii) For each well with plunger lifts, the information in paragraphs (f)(2)(xiii)(A) through (C) of this section.

(A) Internal tubing diameter ("TD_p" from equation W-9 to § 98.233), in inches.

(B) Tubing depth ("WD_p" from equation W-9 to § 98.233), in feet.

(C) Flow line pressure ("SP_p" from equation W-9 to § 98.233), in pounds per square inch absolute.

(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 that vented directly to the atmosphere, then you must report information specified in paragraphs (g)(1) through (10) of this section, for each well. If your facility had well completions or workovers with hydraulic fracturing during the year that routed to flares and you calculated natural gas emissions routed to the flare using continuous parameter monitoring systems as specified in § 98.233(n)(3)(i) and 98.233(n)(3)(ii)(A) and continuous gas composition analyzers or sampling as specified in § 98.233(n)(4), then you must report the information specified in paragraphs (g)(1) through (3) and (10) of this section, for each well. If your facility had well completions or workovers with hydraulic fracturing during the year that routed to flares and you calculated natural gas emissions routed to the flare using the calculation methods in § 98.233(g) to determine natural gas volumes as specified in § 98.233(n)(3)(ii)(B), then you must report the information specified in paragraphs (g)(1) through (6) and (10) of this section, for each well. Report information separately for completions and workovers.

(1) Well ID number.

(2) Well type combination (horizontal or vertical, flared or vented, reduced emission completion or not a reduced emission completion, gas well or oil well).

(3) Number of completions or workovers for each well.

(4) Calculation method used.

(5) If you used equation W-10A to § 98.233 to calculate annual volumetric total gas emissions, then you must report the information specified in paragraphs (g)(5)(i) through (v) of this section.

(i) Cumulative gas flowback time, in hours, for all completions or workovers at the well 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 to § 98.233). You may delay the reporting of this data element if you indicate in the annual report that the well is a wildcat well or delineation well. If you elect to delay reporting of this data element, you must report by the date specified in paragraph (cc) of this section the total number of hours of flowback from the well during completions or workovers.

(ii) If the well is a measured well for the sub-basin and well-type combination, the flowback rate, in standard cubic feet per hour (average of "$FR_{s,p}$" values used in equation W-12A to § 98.233). You may delay the reporting of this data element if you indicate in the annual report that the well is a wildcat well or delineation well. If you elect to delay reporting of this data element, you must report by the date specified in paragraph (cc) of this section the measured flowback rate(s) during well completion or workover for the well.

(iii) If you used equation W-12C to § 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 to § 98.233). You may delay the reporting of this data element if you indicate in the annual report that the well is a wildcat well or delineation well. If you elect to delay reporting of this data element, you must report by the date specified in paragraph (cc) of this section the gas to oil ratio for the well.

(B) Volume of oil produced during the first 30 days of production after completion of the newly drilled well or well workover using hydraulic fracturing, in barrels ("V_p" in equation W-12C to § 98.233). You may delay the reporting of this data element if you indicate in the annual report that the well is a wildcat well or delineation well. If you elect to delay reporting of this data element, you must report by the date specified in paragraph (cc) of this section the volume of oil produced during the first 30 days of production after well completion or workover for the well.

(iv) Whether the flow rate during the initial flowback period was determined using:

(A) A recording flow meter (digital or analog) installed on the vent line, downstream of a separator.

(B) A multiphase flow meter upstream of the separator.

(C) Equation W-11A or W-11B to § 98.233.

(v) Whether the flow rate when sufficient quantities are present to enable separation was determined using:

(A) A recording flow meter (digital or analog) installed on the vent line, downstream of a separator.

(B) Equation W-11A or W-11B to § 98.233.

(6) If you used equation W-10B to § 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 ("$FV_{s,p}$" in equation W-10B to § 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 ("$FR_{p,i}$" in equation W-10B to § 98.233).

(iii) If a multiphase flowmeter was used to measure the flow rate during the initial flowback period, report the average flow rate measured by the multiphase flow meter from the initiation of flowback to the beginning of the period of time when sufficient quantities of gas present to enable separation in standard cubic feet per hour.

(7) Annual gas emissions, in standard cubic feet ("$E_{s,n}$" in equation W-10A or W-10B to § 98.233).

(8) Annual CO_2 emissions, in metric tons CO_2.

(9) Annual CH_4 emissions, in metric tons CH_4.

(10) Indicate whether natural gas emissions from completion(s) or workover(s) with hydraulic fracturing were routed to a flare and emissions are reported according to paragraph (n) of this section, and if so, provide the information specified in paragraphs (g)(10)(i) through (iv) of this section.

(i) Indicate whether you calculated natural gas emissions routed to the flare using continuous parameter monitoring systems as specified in § 98.233(n)(3)(i) and (n)(3)(ii)(A) and continuous gas composition analyzers or sampling as specified in § 98.233(n)(4), or you calculated natural gas emissions routed to the flare using the calculation methods in § 98.233(g) as specified in § 98.233(n)(3)(ii)(B).

(ii) Indicate whether natural gas emissions were routed to a flare for the entire year or only part of the year.

(iii) The unique name or ID for the flare stack as specified in paragraph (n)(1) of this section.

(iv) The unique ID for each stream routed to the flare as specified in paragraph (n)(3) of this section.

(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 well with one or more gas well completions without hydraulic fracturing and without flaring, report the information specified in paragraphs (h)(1)(i) through (vi) of this section.

(i) Well ID number.

(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 without hydraulic fracturing ("T_p" for completions that vented directly to the atmosphere as used in equation W-13B to § 98.233). You may delay reporting of this data element if you indicate in the annual report that the well is a wildcat well or delineation well. If you elect to delay reporting of this data element, you must report by the date specified in paragraph (cc) of this section the total number of hours that gas vented directly to the atmosphere during completions for the well.

(iv) Average daily gas production rate for all completions without hydraulic fracturing without flaring, in standard cubic feet per hour ("V_p" in equation W-13B to § 98.233). You may delay reporting of this data element if you indicate in the annual report that the well is a wildcat well or delineation well. If you elect to delay reporting of this data element, you must report by the date specified in paragraph (cc) of this section the measured average daily gas production rate during completions for the well.

(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 to § 98.233 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 to § 98.233 for completions that vented directly to the atmosphere, converted to mass emissions according to § 98.233(h)(1)).

(2) If your facility had well completions without hydraulic fracturing and with flaring during the year and you calculated natural gas emissions routed to the flare using continuous parameter monitoring systems as specified in § 98.233(n)(3)(i) and (ii)(A) and continuous gas composition analyzers or sampling as specified in § 98.233(n)(4), then you must report the

information specified in paragraphs (h)(2)(i) through (ii) and (viii) of this section, for each well. If your facility had well completions without hydraulic fracturing during the year that routed to flares and you calculated natural gas emissions routed to the flare using the calculation methods in § 98.233(h) to determine natural gas volumes as specified in § 98.233(n)(3)(ii)(B), then you must report the information specified in paragraphs (h)(2)(i) through (iv) and (viii) of this section, for each well.

(i) Well ID number.

(ii) Number of well completions that flared gas.

(iii) Total number of hours that gas routed to a flare during venting for all completions without hydraulic fracturing ("T_p" for completions that vented to a flare from equation W-13B to § 98.233). You may delay reporting of this data element if you indicate in the annual report that the well is a wildcat well or delineation well. If you elect to delay reporting of this data element, you must report by the date specified in paragraph (cc) of this section the total number of hours that gas vented to the flare during completions for the well.

(iv) Average daily gas production rate for all completions without hydraulic fracturing with flaring, in standard cubic feet per hour ("V_p" from equation W-13B to § 98.233). You may delay reporting of this data element if you indicate in the annual report that the well is a wildcat well or delineation well. If you elect to delay reporting of this data element, you must report by the date specified in paragraph (cc) of this section the measured average daily gas production rate during completions for the well.

(v) [Reserved]

(vi) [Reserved]

(vii) [Reserved]

(viii) Report the information specified in paragraphs (h)(2)(viii)(A) through (D).

(A) Indicate whether you calculated natural gas emissions routed to the flare using continuous parameter monitoring systems as specified in § 98.233(n)(3)(i) and (ii)(A) and continuous gas composition analyzers or sampling as specified in § 98.233(n)(4), or you calculated natural gas emissions routed to the flare using the calculation methods in § 98.233(h) as specified in § 98.233(n)(3)(ii)(B).

(B) Indicate whether natural gas emissions were routed to a flare for the entire year or only part of the year.

(C) The unique name or ID for the flare stack as specified in paragraph (n)(1) of this section.

(D) The unique ID for each stream routed to the flare as specified in paragraph (n)(3) of this section.

(3) For each well with one or more gas well workovers without hydraulic fracturing and without flaring, report the information specified in paragraphs (h)(3)(i) through (iv) of this section.

(i) Well ID number.

(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 to § 98.233 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 to § 98.233 for workovers that vented directly to the atmosphere, converted to mass emissions as specified in § 98.233(h)(1)).

(4) If your facility had well workovers without hydraulic fracturing and with flaring during the year and you calculated natural gas emissions routed to the flare using continuous parameter monitoring systems as specified in § 98.233(n)(3)(i) and (ii)(A) and continuous gas composition analyzers or sampling as specified in § 98.233(n)(4), then you must report the information specified in paragraphs (h)(4)(i) through (ii) and (vi) of this section, for each well. If your facility had well workovers without hydraulic fracturing during the year that routed to flares and you calculated natural gas emissions routed to the flare using the calculation methods in § 98.233(h) to determine natural gas volumes as specified in § 98.233(n)(3)(ii)(B), then you must report the information specified in paragraphs (h)(4)(i) through (ii) and (vi) of this section, for each well.

(i) Well ID number.

(ii) Number of workovers that flared gas.

(iii) [Reserved]

(iv) [Reserved]

(v) [Reserved]

(vi) Report the information specified in paragraphs (h)(4)(vi)(A) through (D).

(A) Indicate whether you calculated natural gas emissions routed to the flare using continuous parameter monitoring systems as specified in § 98.233(n)(3)(i) and (ii)(A) and continuous gas composition analyzers or sampling as specified in § 98.233(n)(4), or you calculated natural gas emissions routed to the flare using the calculation methods in § 98.233(h) as specified in § 98.233(n)(3)(ii)(B).

(B) Indicate whether natural gas emissions were routed to a flare for the entire year or only part of the year.

(C) The unique name or ID for the flare stack as specified in paragraph (n)(1) of this section.

(D) The unique ID for each stream routed to the flare as specified in paragraph (n)(3) of this section.

(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. You must report the information specified in paragraphs (i)(1) through (3) of this section, as applicable, for each well-pad site (for onshore production), each gathering and boosting site (for onshore petroleum and natural gas gathering and boosting), or facility (for all other applicable industry segments).

(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)(iv)(A) for onshore petroleum and natural gas production, onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, LNG storage, LNG import and export equipment, or onshore petroleum and natural gas gathering and boosting industry segments, then you must report the

information specified in paragraphs (i)(1)(i) through (v) of this section, as applicable. If a blowdown event resulted in emissions from multiple equipment or event types, and the emissions cannot be apportioned to the different equipment or event types, then you may report the information in paragraphs (i)(1)(ii) through (v) of this section for the equipment or event type that represented the largest portion of the emissions for the blowdown event. For the onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting industry segments, if a blowdown event is not directly associated with a specific well-pad site or gathering and boosting site (*e.g.*, a mid-field pipeline blowdown) or could be associated with multiple well-pad or gathering and boosting sites, then you may report the information in paragraphs (i)(1)(i) through (v) of this section for either the nearest well-pad site or gathering and boosting site upstream from the blowdown event or the well-pad site or gathering and boosting site that represented the largest portion of the emissions for the blowdown event, as appropriate. If you calculated emissions from blowdown vent stacks by the eight categories listed in § 98.233(i)(2)(iv)(B) for the natural gas distribution or onshore natural gas transmission pipeline industry segments, then you must report the information specified in paragraphs (i)(1)(ii) through (v) of this section, as applicable. If a blowdown event resulted in emissions from multiple equipment or event types, and the emissions cannot be apportioned to the different equipment or event types, then you may report the information in paragraphs (i)(1)(ii) through (v) of this section for the equipment or event type that represented the largest portion of the emissions for the blowdown event.

(i) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(ii) Equipment or event type. For the onshore petroleum and natural gas production, onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, LNG storage, LNG import and export equipment, or onshore petroleum and natural gas gathering and boosting industry segments, use the seven categories listed in § 98.233(i)(2)(iv)(A). For the natural gas distribution or onshore natural gas transmission pipeline industry segments, use the eight categories listed in § 98.233(i)(2)(iv)(B).

(iii) 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 to § 98.233, for all unique physical volumes for the equipment or event type).

(iv) Annual CO_2 emissions for the equipment or event type, in metric tons CO_2, calculated according to § 98.233(i)(2)(iii).

(v) 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) through (iii) of this section, as applicable. For the onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting industry segments, if a blowdown event is not directly associated with a specific well-pad site or gathering and boosting site (*e.g.*, a mid-field pipeline blowdown) or could be associated with multiple well-pad sites or gathering and boosting sites, then you may report the information in paragraphs (i)(2)(i) through (iii) of this section for either the nearest well-pad site or gathering and boosting site upstream from the blowdown event or the well-pad site or gathering and

boosting site that represented the largest portion of the emissions for the blowdown event, as appropriate.

(i) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(ii) Annual CO_2 emissions from all blowdown vent stacks at the facility, well-pad site, or gathering and boosting site 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).

(iii) Annual CH_4 emissions from all blowdown vent stacks at the facility, well-pad site, or gathering and boosting site 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) *Hydrocarbon liquids and produced water storage tanks*. You must indicate whether your facility sends hydrocarbon produced liquids and/or produced water to atmospheric pressure storage tanks. If your facility sends hydrocarbon produced liquids and/or produced water to atmospheric pressure storage 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 pressure storage tanks were observed to have malfunctioning dump valves during the calendar year, then you must indicate that dump valves were malfunctioning and must report the information specified in paragraph (j)(3) of this section. For hydrocarbon liquids and produced water storage tanks that were routed to flares for which you calculated natural gas emissions routed to the flare using continuous parameter monitoring systems as specified in § 98.233(n)(3)(i) and (ii)(A) and continuous gas composition analyzers or sampling as specified in § 98.233(n)(4), you must report the information specified in paragraph (j)(4) of this section. For hydrocarbon liquids and produced water storage tanks that were routed to flares for which you calculated natural gas emissions routed to the flare using the calculation methods in § 98.233(j) to determine natural gas volumes as specified in § 98.233(n)(3)(ii)(B), then you must report the applicable information in paragraphs (j)(1) through (3) of this section and the information specified in paragraph (j)(4) 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 well-pad site (for onshore petroleum and natural gas production), gathering and boosting site (for onshore petroleum and natural gas gathering and boosting), or facility (for all other applicable industry segments) and by calculation method and liquid type, as applicable. Onshore petroleum and natural gas gathering and boosting and onshore natural gas processing facilities do not report the information specified in paragraph (j)(1)(ix) of this section.

(i) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(ii) Calculation method used, and name of the software package used if using Calculation Method 1.

(iii) The total annual hydrocarbon liquids or produced water volume from gas-liquid separators and direct from wells or non-separator equipment that is sent to applicable atmospheric pressure 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/or delineation wells are the only wells at the well-pad site with hydrocarbon liquids or produced water production flowing to gas-liquid separators or direct to atmospheric pressure storage tanks for which you used the same calculation method. If you elect to delay reporting of this data element, you must report by the date specified in paragraph (cc) of this section the total volume of hydrocarbon liquids or produced water from all wells and the well ID number(s) for the well(s) included in this volume.

(iv) The average well, gas-liquid separator, or non-separator equipment temperature, in degrees Fahrenheit.

(v) The average well, gas-liquid separator, or non-separator equipment pressure, in pounds per square inch gauge.

(vi) For atmospheric pressure storage tanks receiving hydrocarbon liquids, the average sales oil or stabilized hydrocarbon liquids API gravity, in degrees.

(vii) If you used Calculation Method 1 of § 98.233(j) to calculate GHG emissions for atmospheric pressure storage tanks receiving hydrocarbon liquids, the flow-weighted average concentration (mole fraction) of CO_2 in flash gas from atmospheric pressure storage tanks (calculated as the sum of all products of the concentration of CO_2 in the flash gas for each storage tank times the total quantity of flash gas for that storage tank, divided by the sum of all flash gas emissions from storage tanks).

(viii) If you used Calculation Method 1 of § 98.233(j) to calculate GHG emissions for atmospheric pressure storage tanks receiving hydrocarbon liquids, the flow-weighted average concentration (mole fraction) of CH_4 in flash gas from atmospheric pressure storage tanks (calculated as the sum of all products of the concentration of CH_4 in the flash gas for each storage tank times the total quantity of flash gas for that storage tank, divided by the sum of all flash gas emissions from storage tanks).

(ix) The number of wells sending hydrocarbon liquids or produced water to gas-liquid separators or directly to atmospheric pressure storage tanks.

(x) Count of atmospheric pressure storage tanks specified in paragraphs (j)(1)(x)(A) through (F) of this section.

(A) The number of fixed roof atmospheric pressure storage tanks.

(B) The number of floating roof atmospheric pressure storage tanks.

(C) The number of atmospheric pressure storage tanks that vented gas directly to the atmosphere and did not control emissions using a vapor recovery system or one or more flares at any point during the reporting year.

(D) The number of atmospheric pressure storage tanks that routed emissions to a vapor recovery system at any point during the reporting year.

(E) The number of atmospheric pressure storage tanks that routed emissions to one or more flares at any point during the reporting year.

(F) The number of atmospheric pressure storage tanks in paragraph (j)(1)(x)(D) or (E) of this section that had an open ~~or not properly seated~~ thief hatch at some point during the year while the storage tank was also routing emissions to a vapor recovery system and/or a flare.

(xi) For atmospheric pressure storage tanks receiving hydrocarbon liquids, annual CO_2 emissions, in metric tons CO_2, that resulted from venting gas directly to the atmosphere, calculated according to § 98.233(j)(1) and (2).

(xii) Annual CH_4 emissions, in metric tons CH_4, that resulted from venting gas directly to the atmosphere, calculated according to § 98.233(j)(1) and (2).

(xiii) For the atmospheric pressure storage tanks receiving hydrocarbon liquids identified in paragraphs (j)(1)(x)(D) of this section, total CO_2 mass, in metric tons CO_2, that was recovered during the calendar year using a vapor recovery system.

(xiv) For the atmospheric pressure storage tanks identified in paragraphs (j)(1)(x)(D) of this section, total CH_4 mass, in metric tons CH_4, that was recovered during the calendar year using a vapor recovery system.

(xv) For the atmospheric pressure storage tanks identified in paragraph (j)(1)(x)(F) of this section, the total volume of gas vented through open thief hatches, in scf, during periods while the storage tanks were also routing emissions to vapor recovery systems and/or 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 (H) of this section, at the facility level, for atmospheric pressure storage tanks where emissions were calculated using Calculation Method 3 of § 98.233(j).

(A) The total annual hydrocarbon liquids throughput that is sent to all atmospheric pressure storage tanks in the facility with emissions calculated using Calculation Method 3, in barrels. You may delay reporting of this data element for onshore production if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells at the facility with hydrocarbon liquids production that send hydrocarbon liquids to atmospheric pressure storage tanks for which emissions were calculated using Calculation Method 3. If you elect to delay reporting of this data element, you must report by the date specified in paragraph (cc) of this section the total annual hydrocarbon liquids throughput from all wells and the well ID number(s) for the well(s) included in this volume.

(B) The total annual produced water throughput that is sent to all atmospheric pressure storage tanks in the facility with emissions calculated using Calculation Method 3, in barrels, specified in paragraphs (j)(2)(i)(B)(*1*) through (*3*) of this section.

(*1*) Total volume of produced water with pressure less than or equal to 50 psi.

(*2*) Total volume of produced water with pressure greater than 50 psi and less than or equal to 250 psi.

(*3*) Total volume of produced water with pressure greater than 250 psi.

(C) An estimate of the fraction of hydrocarbon liquids throughput reported in paragraph (j)(2)(i)(A) of this section sent to atmospheric pressure storage tanks in the facility that controlled emissions with flares.

(D) An estimate of the fraction of hydrocarbon liquids throughput reported in paragraph (j)(2)(i)(A) of this section sent to atmospheric pressure storage tanks in the facility that controlled emissions with vapor recovery systems.

(E) An estimate of the fraction of total produced water throughput reported in paragraph (j)(2)(i)(B) of this section sent to atmospheric pressure storage tanks in the facility that controlled emissions with flares.

(F) An estimate of the fraction of total produced water throughput reported in paragraph (j)(2)(i)(B) of this section sent to atmospheric pressure storage tanks in the facility that controlled emissions with vapor recovery systems.

(G) The number of fixed roof atmospheric pressure storage tanks in the facility.

(H) The number of floating roof atmospheric pressure storage tanks in the facility.

(ii) Report the information specified in paragraphs (j)(2)(ii)(A) through (H) of this section for each well-pad site (for onshore production), gathering and boosting site (for onshore petroleum and natural gas gathering and boosting), or facility (for all other applicable industry segments) with atmospheric pressure storage tanks receiving hydrocarbon liquids whose emissions were calculated using § 98.233(j)(3)(i).

(A) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(B) The number of atmospheric pressure storage tanks that did not control emissions with flares and for which emissions were calculated using Calculation Method 3.

(C) The number of atmospheric pressure storage tanks that controlled emissions with flares and for which emissions were calculated using Calculation Method 3.

(D) The number of atmospheric pressure storage tanks that had an open thief hatch at some point during the year while the storage tank was also routing emissions to a vapor recovery system and/or a flare.

(E) The total number of separators, wells, or non-separator equipment with annual average daily hydrocarbon liquids throughput greater than 0 barrels per day and less than 10 barrels per day for which you used Calculation Method 3 ("Count" from equation W-15A to § 98.233).

(F) Annual CO_2 emissions, in metric tons CO_2, that resulted from venting gas directly to the atmosphere, calculated using equation W-15A to § 98.233 and adjusted using the requirements described in § 98.233(j)(4), if applicable.

(G) Annual CH_4 emissions, in metric tons CH_4, that resulted from venting gas directly to the atmosphere, calculated using equation W-15A to § 98.233 and adjusted using the requirements described in § 98.233(j)(4), if applicable.

(H) The total volume of gas vented through open thief hatches, in scf, during periods while the atmospheric pressure storage tanks were also routing emissions to vapor recovery systems and/or flares.

(iii) Report the information specified in paragraphs (j)(2)(iii)(A) through (F) of this section for each well-pad site (for onshore production), gathering and boosting site (for onshore petroleum and natural gas gathering and boosting), or facility (for onshore natural gas processing) with atmospheric pressure storage tanks receiving produced water whose emissions were calculated using § 98.233(j)(3)(ii).

(A) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(B) The number of atmospheric pressure storage tanks that did not control emissions with flares and for which emissions were calculated using Calculation Method 3.

(C) The number of atmospheric pressure storage tanks that controlled emissions with flares and for which emissions were calculated using Calculation Method 3.

(D) The number of atmospheric pressure storage tanks that had an open thief hatch at some point during the year while the storage tank was also routing emissions to a vapor recovery system and/or a flare.

(E) Annual CH_4 emissions, in metric tons CH_4, that resulted from venting gas directly to the atmosphere, calculated using equation W-15B to § 98.233 and adjusted using the requirements described in § 98.233(j)(4), if applicable.

(F) The total volume of gas vented through open thief hatches, in scf, during periods while the atmospheric pressure storage tanks were also routing emissions to vapor recovery systems and/or 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 (v) of this section for each well-pad site (for onshore production), gathering and boosting site (for onshore petroleum and natural gas gathering and boosting), or facility (for all other applicable industry segments) by liquid type.

(i) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(ii) The total number of gas-liquid separators whose liquid dump valves did not close properly during the calendar year.

(iii) The total time the dump valves on gas-liquid separators did not close properly in the calendar year, in hours (sum of the "T_{dv}" values used in equation W-16 to § 98.233).

(iv) For atmospheric pressure storage tanks receiving hydrocarbon liquids, 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 to § 98.233.

(v) 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 to § 98.233.

(4) For atmospheric pressure storage tanks that were routed to flares, report the information specified in paragraphs (j)(4)(i) through (iv) of this section.

(i) Indicate whether you calculated natural gas emissions routed to the flare using continuous parameter monitoring systems as specified in § 98.233(n)(3)(i) and 98.233(n)(3)(ii)(A) and continuous gas composition analyzers or sampling as specified in § 98.233(n)(4), or you calculated natural gas emissions routed to the flare using the calculation methods in § 98.233(j) as specified in § 98.233(n)(3)(ii)(B).

(ii) Indicate whether natural gas emissions were routed to a flare for the entire year or only part of the year.

(iii) The unique name or ID for the flare stack as specified in paragraph (n)(1) of this section to which the atmospheric pressure storage tank vent was routed.

(iv) The unique ID for the stream routed to the flare as specified in paragraph (n)(3) of this section from the atmospheric pressure storage tank.

(k) *Condensate storage tanks*. You must indicate whether your facility contains any condensate storage tanks. If your facility contains at least one condensate storage tank, then you must report the information specified in paragraphs (k)(1) and (2) of this section for each condensate storage tank vent stack.

(1) For each condensate 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 condensate storage tank vent stack.

(ii) Indicate if a flare is attached to the condensate storage tank vent stack.

(iii) Indicate whether scrubber dump valve leakage occurred for the condensate storage tank vent according to § 98.233(k)(1).

(iv) Which method specified in § 98.233(k)(1) was used to determine if dump valve leakage occurred.

(2) If scrubber dump valve leakage occurred for a condensate 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 condensate storage vent stack where scrubber dump valve leakage occurred.

(i) Which method specified in § 98.233(k)(2) was 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).

(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) For oil wells not routed to a flare, you must report the information specified in paragraphs (l)(1)(i) through (vii) of this section for each well tested.

(i) [Reserved]

(ii) Well ID number.

(iii) Number of well testing days for the tested well in the calendar year.

(iv) Average gas to oil ratio for the tested well, in cubic feet of gas per barrel of oil. You may delay reporting of this data element if you indicate in the annual report that the well is a wildcat well or delineation well. If you elect to delay reporting of this data element, you must report by the date specified in paragraph (cc) of this section the average gas to oil ratio for the tested well.

(v) Average flow rate for the tested well, in barrels of oil per day. You may delay reporting of this data element if you indicate in the annual report that the well is a wildcat well or delineation well. If you elect to delay reporting of this data element, you must report by the date specified in paragraph (cc) of this section the measured average flow rate for the tested well.

(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) For oil wells routed to a flare and where you calculated natural gas emissions routed to the flare using continuous parameter monitoring systems as specified in § 98.233(n)(3)(i) and 98.233(n)(3)(ii)(A) and continuous gas composition analyzers or sampling as specified in § 98.233(n)(4), then you must report the information specified in paragraphs (l)(2)(i) through (ii) and (ix) of this section, for each well tested. For oil wells routed to a flare and where you calculated natural gas emissions routed to the flare using the calculation methods in § 98.233(l) to determine natural gas volumes as specified in § 98.233(n)(3)(ii)(B), then you must report the information specified in paragraphs (l)(2)(i) through (v) and (ix) of this section. All reported data elements should be specific to the well for which equation W-17A to § 98.233 was used and for which well testing emissions were routed to flares.

(i) [Reserved]

(ii) Well ID number.

(iii) Number of well testing days for the tested well in the calendar year.

(iv) Average gas to oil ratio for the tested well, in cubic feet of gas per barrel of oil. You may delay reporting of this data element if you indicate in the annual report that the well is a wildcat well or delineation well. If you elect to delay reporting of this data element, you must report by the date specified in paragraph (cc) of this section the average gas to oil ratio for the tested well.

(v) Average flow rate for the tested well, in barrels of oil per day. You may delay reporting of this data element if you indicate in the annual report that the well is a wildcat well or delineation well. If you elect to delay reporting of this data element, you must report by the date specified in paragraph (cc) of this section the measured average flow rate for the tested well.

(vi) [Reserved]

(vii)[Reserved]

(viii) [Reserved]

(ix) Indicate whether natural gas emissions from well testing were routed to a flare and emissions are reported according to paragraph (n) of this section, and if so, provide the information specified in paragraphs (l)(2)(ix)(A) through (D).

(A) Indicate whether you calculated natural gas emissions routed to the flare using continuous parameter monitoring systems as specified in § 98.233(n)(3)(i) and 98.233(n)(3)(ii)(A) and continuous gas composition analyzers or sampling as specified in § 98.233(n)(4), or you calculated natural gas emissions routed to the flare using the calculation methods in § 98.233(l) as specified in § 98.233(n)(3)(ii)(B).

(B) Indicate whether natural gas emissions were routed to a flare for the entire year or only part of the year.

(C) The unique name or ID for the flare stack as specified in paragraph (n)(1) of this section.

(D) The unique ID for each stream routed to the flare as specified in paragraph (n)(3) of this section.

(3) For gas wells not routed to a flare, you must report the information specified in paragraphs (l)(3)(i) through (vi) of this section for each well tested.

(i) [Reserved]

(ii) Well ID number.

(iii) Number of well testing days for the tested well~~(s)~~ in the calendar year. You may delay reporting of this data element if you indicate in the annual report that the well is a wildcat well or delineation well. If you elect to delay reporting of this data element, you must report by the date specified in paragraph (cc) of this section the number of well testing days for the tested well.

(iv) Average annual production rate for the tested well, in actual cubic feet per day. You may delay reporting of this data element if you indicate in the annual report that the well is a wildcat well or delineation well. If you elect to delay reporting of this data element, you must report by the date specified in paragraph (cc) of this section the measured average annual production rate for the tested well.

(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) For gas wells routed to a flare and where you calculated natural gas emissions routed to the flare using continuous parameter monitoring systems as specified in § 98.233(n)(3)(i) and 98.233(n)(3)(ii)(A) and continuous gas composition analyzers or sampling as specified in § 98.233(n)(4), then you must report the information specified in paragraphs (l)(4)(i) through (ii) and (viii) of this section, for each well tested. For gas wells routed to a flare and where you calculated natural gas emissions routed to the flare using the calculation methods in § 98.233(l) to determine natural gas volumes as specified in § 98.233(n)(3)(ii)(B), then you must report the information specified in paragraphs (l)(4)(i) through (iv) and (viii) of this section for each well tested. All reported data elements should be specific to the well for which equation W-17B to § 98.233 was used and for which well testing emissions were routed to flares.

(i) [Reserved]

(ii) Well ID number.

(iii) Number of well testing days for the tested well in the calendar year. You may delay reporting of this data element if you indicate in the annual report that the well is a wildcat well or delineation well. If you elect to delay reporting of this data element, you must report by the date specified in paragraph (cc) of this section the number of well testing days for the tested well.

(iv) Average annual production rate for the tested well, in actual cubic feet per day. You may delay reporting of this data element if you indicate in the annual report that the well is a wildcat well ~~and/~~or delineation well~~ and the only wells that are tested in the same basin are wildcat wells and/or delineation wells~~. If you elect to delay reporting of this data element, you must report by the date specified in paragraph (cc) of this section the measured average annual production rate for the tested well.

(v) [Reserved]

(vi)[Reserved]

(vii) [Reserved]

(viii) Indicate whether natural gas emissions from well testing were routed to a flare and emissions are reported according to paragraph (n) of this section, and if so, provide the information specified in paragraphs (l)(4)(viii)(A) through (D).

(A) Indicate whether you calculated natural gas emissions routed to the flare using continuous parameter monitoring systems as specified in § 98.233(n)(3)(i) and 98.233(n)(3)(ii)(A) and continuous gas composition analyzers or sampling as specified in § 98.233(n)(4), or you calculated natural gas emissions routed to the flare using the calculation methods in § 98.233(l) as specified in § 98.233(n)(3)(ii)(B).

(B) Indicate whether natural gas emissions were routed to a flare for the entire year or only part of the year.

(C) The unique name or ID for the flare stack as specified in paragraph (n)(1) of this section.

(D) The unique ID for each stream routed to the flare as specified in paragraph (n)(3) of this section.

(m) *Associated natural gas*. You must indicate whether any associated gas was vented or flared during the calendar year. If associated gas was vented during the calendar year, then you must report the information specified in paragraphs (m)(1) through (7) of this section for each well for which associated gas was vented. If associated gas was flared during the calendar year and you calculated natural gas emissions routed to the flare using continuous parameter monitoring systems as specified in § 98.233(n)(3)(i) and 98.233(n)(3)(ii)(A) and continuous gas composition analyzers or sampling as specified in § 98.233(n)(4), then you must report the information specified in paragraphs (m)(1) through (3) of this section, for each well. If associated gas was flared and you calculated natural gas emissions routed to the flare using the calculation methods in § 98.233(m) to determine natural gas volumes as specified in § 98.233(n)(3)(ii)(B), then you must report the information specified in paragraphs (m)(1) through (6) of this section for each well.

(1) Well ID number.

(2) Indicate whether any associated gas was vented directly to the atmosphere without flaring.

(3) Indicate whether any associated gas was flared and emissions are reported according to paragraph (n) of this section, and, if so, provide the information specified in paragraphs (m)(3)(i) through (iv).

(i) Indicate whether you calculated natural gas emissions routed to the flare using continuous parameter monitoring systems as specified in § 98.233(n)(3)(i) and 98.233(n)(3)(ii)(A) and continuous gas composition analyzers or sampling as specified in §

98.233(n)(4), or you calculated natural gas emissions routed to the flare using the calculation methods in § 98.233(m) as specified in § 98.233(n)(3)(ii)(B).

(ii) Indicate whether natural gas emissions were routed to a flare for the entire year or only part of the year.

(iii) The unique name or ID for the flare stack to which associated natural gas is routed as specified in paragraph (n)(1) of this section.

(iv) The unique ID for each associated natural gas stream routed to the flare as specified in paragraph (n)(3) of this section.

(4) Average gas to oil ratio, in standard cubic feet of gas per barrel of oil during the reporting year. Do not report the GOR if you vented or flared associated gas and used a continuous flow monitor to determine the total volume of associated gas vented or routed to the flare (*i.e.*, if you did not use equation W-18 to § 98.233 for the well with associated gas venting or flaring emissions).

(5) Volume of oil produced by the well, in barrels, in the calendar year only during the time periods in which associated gas was vented or flared ("V_p" used in equation W-18 to § 98.233). You may delay reporting of this data element if you indicate in the annual report that the well is a wildcat well or delineation well. If you elect to delay reporting of this data element, you must report by the date specified in paragraph (cc) of this section the volume of oil produced by the well during the time periods in which associated gas venting and flaring was occurring. Do not report the volume of oil produced if you vented or flared associated gas and used a continuous flow monitor to determine the total volume of associated gas vented or routed to the flare (*i.e.*, if you did not use equation W-18 to § 98.233 for the well with associated gas venting or flaring emissions).

(6) Total volume of associated gas sent to sales or used on site and not sent to a vent or flare, in standard cubic feet, in the calendar year only during time periods in which associated gas was vented or flared ("SG" value used in equation W-18 to § 98.233). You may delay reporting of this data element if you indicate in the annual report that the well is a wildcat well or delineation well. If you elect to delay reporting of this data element, you must report by the date specified in paragraph (cc) of this section the measured total volume of associated gas sent to sales for the well during the time periods in which associated gas venting and flaring was occurring. Do not report the volume of gas sent to sales if you vented or flared associated gas and used a continuous flow monitor to determine the total volume of associated gas vented or routed to the flare (*i.e.*, if you did not use equation W-18 to § 98.233).

(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 (viii) of this section for each well.

(i) [Reserved]

(ii) Indicate whether the associated gas volume vented from the well was measured using a continuous flow monitor.

(iii) Indicate whether associated gas streams vented from the well were measured with a continuous gas composition analyzer~~s~~.

(iv) Total volume of associated gas vented from the well, in standard cubic feet.

(v) Flow-weighted average mole fraction of CH_4 in associated gas vented from the well.

(vi) Flow-weighted average mole fraction of CO_2 in associated gas vented from the well.

(vii) Annual CO_2 emissions, in metric tons CO_2, calculated according to § 98.233(m)(3) and (4).

(viii) Annual CH_4 emissions, in metric tons CH_4, calculated according to § 98.233(m)(3) and (4).

(n) *Flare stacks*. You must indicate if your facility has any flare stacks. You must report the information specified in paragraphs (n)(1) through (20) of this section for each flare stack at 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) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(3) Unique IDs for each stream routed to the flare and the source type that generated the stream, if you determine the flow of each stream that is routed to the flare as specified in § 98.233(n)(3)(ii) and/or you determine the gas composition for each stream routed to the flare as specified in § 98.233(n)(4)(iii). If you determine flow or composition for a combined stream from multiple source types, then report the source type that provides the most gas to the combined stream. For source types not listed in § 98.233(n)(3)(ii)(B)(*1*) through (*7*), report collectively as "other."

(4) Indicate the type of flare (*i.e.*, open ground-level flare, enclosed ground-level flare, open elevated flare, or enclosed elevated flare).

(5) Indicate the type of flare assist (*i.e.*, unassisted, air-assisted with single speed fan/blower, air-assisted with dual speed fan/blower, air-assisted with variable speed fan/blower, steam-assisted, or pressure-assisted).

(6) Indicate whether the pilot flame or combustion flame was monitored continuously, visually inspected, or both. If visually inspected, report the number of inspections during the year. If the pilot flame was monitored continuously, report the number of times all continuous monitoring devices were out of service or otherwise inoperable for a period of more than one week.

(7) Indicate whether you measured total flow at the inlet to the flare as specified in § 98.233(n)(3)(i) or whether you determined flow for individual streams routed to the flare as specified in § 98.233(n)(3)(ii). If you measured total flow, indicate whether the volume of gas was determined using a continuous flow measurement device or whether it was determined using parameter monitoring and engineering calculations. If you determined flow for individual streams, indicate for each stream whether flow was determined using a continuous flow measurement device, parameter monitoring and engineering calculations, or other simulation or engineering calculation methods. If you switched from one method to another during the year, then indicate multiple methods were used.

(8) Indicate whether a continuous gas composition analyzer was used at the inlet to the flare as specified in § 98.233(n)(4)(i), whether composition at the inlet to the flare was determined based on sampling and analysis as specified in § 98.233(n)(4)(ii), or if composition was determined for individual streams as specified in § 98.233(n)(4)(iii). If you determined composition for individual streams, indicate for each stream whether composition was determined using a continuous gas composition analyzer, sampling and analysis, or other

simulation or engineering calculation methods. If you switched from one method to another during the year, then indicate multiple methods were used.

(9) Indicate whether you directly measured annual average HHV of the inlet stream to the flare as specified in § 98.233(n)(8)(i), calculated the annual average HHV of the inlet stream to the flare based on composition of the inlet stream as specified in § 98.233(n)(8)(ii), directly measured the annual average HHV of individual streams routed to the flare as specified in § 98.233(n)(8)(iii), or calculated the annual average HHV of individual streams based on their composition as specified in § 98.233(n)(8)(iv).

(10) Annual average HHV of the inlet stream to the flare determined as specified in § 98.233(n)(8)(i) or (ii); both the calculated flow-weighted annual average HHV of the inlet stream to the flare and each individual stream HHV determined as specified in § 98.233(n)(8)(iii)(B) or (iv)(B); or each individual stream HHV, if you determined HHVs for each individual stream routed to the flare and you used these HHVs to calculate N_2O emissions for each stream as specified in § 98.233(n)(8)(iii)(A) or (iv)(A).

(11) Volume of gas sent to the flare, in standard cubic feet ("V_s" in equations W-19 and W-20 to § 98.233, where V_s is the total flow at the flare inlet if you measure inlet flow to the flare in accordance with § 98.233(n)(3)(i) or the sum of the V_s values for individual streams if you measure or determine flow of individual streams in accordance with § 98.233(n)(3)(ii)). If you measure or determine the volume of gas for each stream routed to the flare as specified in § 98.233(n)(3)(ii), then also report the annual volume of each stream, adjusted to exclude any estimated volume that bypassed the flare or determined to have leaked from the closed vent system, and indicate that the flow has been adjusted to account for bypass volume or leaks.

(12) Fraction of the feed gas sent to an un-lit flare based on total time when continuous monitoring of the pilot or periodic inspections indicated the flare was not lit and measured or calculated flow during the times when the flare was not lit (“Z_U” in equation W-19 to § 98.233).

(13) Flare destruction efficiency, expressed as the fraction of hydrocarbon compounds in gas that is destroyed by a burning flare, but may or may not be completely oxidized to CO_2 (§ 98.233(n)(1)). If you used multiple methods during the year, report the flow-weighted average destruction efficiency based on each tier that applied. Report the efficiency fraction to three decimal places.

(i) If you use tier 1, report the following:

(A) Number of days in periods of 15 or more consecutive days when you did not conform with all cited provisions in § 98.233(n)(1)(i).

(B) [Reserved]

(ii) If you use tier 2, report the following:

(A) Indicate if you are subject to part 60, subpart OOOOb of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter or if you are electing to comply with the flare monitoring requirements in part 60, subpart OOOOb of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter.

(B) If you are not required to comply with part 60, subpart OOOOb of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, indicate whether you are electing to comply with § 98.233(n)(1)(ii)(A), (B), (C), or (D).

(C) If you are not required to comply with part 60, subpart OOOOb of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter and the flare is an enclosed ground level flare or an enclosed elevated flare, indicate if your most recent performance test was conducted using the method in § 60.5413b(b) of this chapter (as specified in § 98.233(n)(1)(ii)(A)), the method in § 60.5413b(d) of this chapter (as specified in § 98.233(n)(1)(ii)(C)), or if it was conducted using OTM-52.

(D) Number of days in periods of 15 or more consecutive days when you did not conform with all cited provisions in § 98.233(n)(1)(ii).

(iii) Indicate if you use an alternative test method approved under § 60.5412b(d) of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter. If you use an approved alternative test method, indicate the approved destruction efficiency for the method, the date when you started to use the method, and the name or ID of the method.

(14) Annual average mole fraction of CH_4 in the feed gas to the flare if you measure composition of the inlet gas as specified in § 98.233(n)(~~3~~4)(i) or (ii) ("X_{CH4}" in equation W-19 to § 98.233), or the annual average CH_4 mole fractions for each stream if you determine composition of each stream routed to the flare as specified in § 98.233(n)(4)(iii).

(15) Except as specified in paragraph (n)(20) of this section, annual average mole fraction of CO_2 in the feed gas to the flare if you measure composition of the inlet gas as specified in § 98.233(n)(4)(i) or (ii) ("X_{CO2}" in equation W-20 to § 98.233), or the annual average CO_2 mole fractions for each stream if you determine composition of each stream routed to the flare as specified in § 98.233(n)(4)(iii).

(16) Annual CO_2 emissions, in metric tons CO_2 (refer to equation W-20 to § 98.233).

(17) Annual CH_4 emissions, in metric tons CH_4 (refer to equation W-19 to § 98.233).

(18) Annual N_2O emissions, in metric tons N_2O (refer to equation W-40 to § 98.233).

(19) Estimated disaggregated CH_4, CO_2, and N_2O emissions attributed to each source type as determined in § 98.233(n)(10) (*i.e.*, AGR vents, dehydrator vents, well venting during

completions and workovers with hydraulic fracturing, gas well venting during completions and workovers without hydraulic fracturing, hydrocarbon liquids and produced water storage tanks, well testing venting and flaring, associated gas venting and flaring, other flared sources).

(20) Indicate whether a CEMS was used to measure emissions from the flare. If a CEMS was used, then you are not required to report the CO_2 mole fraction in paragraph (n)(15) of this section.

(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 that calculate emissions according to § 98.233(o)(10)(iii) 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 (xi) of this section, as applicable, for each centrifugal compressor located at your facility.

(i) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(ii) Unique name or ID for the centrifugal compressor.

(iii) Hours in operating-mode.

(iv) Hours in standby-pressurized-mode.

(v) Hours in not-operating-depressurized-mode.

(vi) If you conducted volumetric emission measurements as specified in § 98.233(o)(1):

(A) Indicate whether the compressor was measured in operating-mode.

(B) Indicate whether the compressor was measured in standby-pressurized-mode.

(C) Indicate whether the compressor was measured in not-operating-depressurized-mode.

(vii) Indicate whether the compressor has blind flanges installed and associated dates.

(viii) Indicate whether the compressor has wet or dry seals.

(ix) If the compressor has wet seals, the number of wet seals.

(x) If the compressor has dry seals, the number of dry seals.

(xi) Power output of the compressor driver (hp).

(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)(ii) of this section.

(B) Centrifugal compressor source (wet seal, dry 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, or vapor recovery system.

(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 system, 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 system, 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 to § 98.233 was used to calculate emissions in equation W-22 to § 98.233, 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 to § 98.233).

(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 to § 98.233).

(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 that calculate emissions according to § 98.233(o)(10)(iii) must report the information specified in paragraphs (o)(5)(i) through (iv) of this section. You must report the information specified in paragraphs (o)(5)(i) through (iv) of this section, as applicable, for each well-pad site

(for onshore petroleum and natural gas production) or each gathering and boosting site (for onshore petroleum and natural gas gathering and boosting).

(i) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(ii) Report the following activity data.

(A) Total number of centrifugal compressors at the facility.

(B) Number of centrifugal compressors that have wet seals.

(C) Number of centrifugal compressors that have atmospheric wet seal oil degassing vents (*i.e.*, wet seal oil degassing vents where the emissions are released to the atmosphere rather than being routed to flares, combustion, or vapor recovery systems).

(iii) Annual CO_2 emissions, in metric tons CO_2, from centrifugal compressors with atmospheric wet seal oil degassing vents.

(iv) Annual CH_4 emissions, in metric tons CH_4, from centrifugal compressors with atmospheric 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 that calculate emissions according to § 98.233(p)(10)(iii) 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 (viii) of this section, as applicable, for each reciprocating compressor located at your facility.

(i) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(ii) Unique name or ID for the reciprocating compressor.

(iii) Hours in operating-mode.

(iv) Hours in standby-pressurized-mode.

(v) Hours in not-operating-depressurized-mode.

(vi) If you conducted volumetric emission measurements as specified in § 98.233(p)(1):

(A) Indicate whether the compressor was measured in operating-mode.

(B) Indicate whether the compressor was measured in standby-pressurized-mode.

(C) Indicate whether the compressor was measured in not-operating-depressurized-mode.

(vii) Indicate whether the compressor has blind flanges installed and associated dates.

(viii) Power output of the compressor driver (hp).

(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, or vapor recovery system.

(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 a flare, combustion, or vapor recovery system, 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 a flare, combustion, or vapor recovery system, 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 to § 98.233 was used to calculate emissions in equation W-27 to § 98.233, report the information specified in paragraphs (p)(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-28 to § 98.233).

(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 to § 98.233).

(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 that calculate

emissions according to § 98.233(p)(10)(iii) must report the information specified in paragraphs (p)(5)(i) through (iv) of this section. You must report the information specified in paragraphs (p)(5)(i) through (iv) of this section, as applicable, for each well-pad site (for onshore petroleum and natural gas production) or each gathering and boosting site (for onshore petroleum and natural gas gathering and boosting).

(i) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(ii) Report the following activity data.

(A) Total number of reciprocating compressors at the facility.

(B) Number of reciprocating compressors that have rod packing emissions vented directly to the atmosphere (*i.e.*, rod packing vents where the emissions are released to the atmosphere rather than being routed to flares, combustion, or vapor recovery systems).

(iii) Annual CO_2 emissions, in metric tons CO_2, from reciprocating compressors with rod packing emissions vented directly to the atmosphere.

(iv) Annual CH_4 emissions, in metric tons CH_4, from reciprocating compressors with rod packing emissions vented directly to the atmosphere.

(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. You must report the information specified in paragraphs (q)(1) and (2) of this section, as applicable, for each well-pad site (for onshore production), gathering and boosting site (for onshore petroleum and natural gas gathering and boosting), or facility (for all other applicable industry segments). 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 (ix) of this section.

(i) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(ii) Except as specified in paragraph (q)(1)(iii) of this section, the number of complete equipment leak surveys performed during the calendar year.

(iii) 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.

(iv) Except for natural gas distribution facilities and onshore natural gas transmission pipeline facilities, indicate whether any of the leak detection surveys used in calculating emissions per § 98.233(q)(2) were conducted for compliance with any of the standards in paragraphs (q)(1)(iv)(A) through (E) of this section. Report the indication per well-pad site, gathering and boosting site, or facility, not per component type, as applicable.

(A) The well site or compressor station fugitive emissions standards in § 60.5397a of this chapter.

(B) The well site, centralized production facility, or compressor station fugitive emissions standards in § 60.5397b or § 60.5398b of this chapter.

(C) The well site, centralized production facility, or compressor station fugitive emissions standards in an applicable approved state plan or applicable Federal plan in part 62 of this chapter.

(D) The standards for equipment leaks at onshore natural gas processing plants in § 60.5400b or § 60.5401b of this chapter.

(E) The standards for equipment leaks at onshore natural gas processing plants in an applicable approved state plan or applicable Federal plan in part 62 of this chapter.

(v) 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 well-pad site, gathering and boosting site, or facility.

(vi) Report each type of method described in § 98.234(a) that was used to conduct leak surveys.

(vii) Report whether emissions were calculated using Calculation Method 1 (leaker factor emission calculation methodology) and/or using Calculation Method 2 (leaker measurement methodology).

(viii) For facilities in onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting, report the number of major equipment (as listed in table W-1 to this subpart) by service type for which leak detection surveys were conducted and emissions calculated according to § 98.233(q).

(ix) For facilities in onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting, report the number of major equipment (as listed in table W-1 to this subpart) in vacuum service as defined in § 98.238.

(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) or (8), (f)(5)

through (8), (g)(4), (g)(6) or (7), (h)(5), (h)(7) or (8), (i)(1), (j)(10), (m)(3)(ii) or (m)(4)(ii) for your facility's industry segment. For each component type and leak detection method combination that is located at your well-pad site, gathering and boosting site, or facility, you must report the information specified in paragraphs (q)(2)(i) through (ix) of this section. If a component type is located at your well-pad site, gathering and boosting site, or facility and no leaks were identified from that component, then you must report the information in paragraphs (q)(2)(i) through (ix) of this section but report a zero ("0") for the information required according to paragraphs (q)(2)(vi) through (ix) of this section. If you used Calculation Method 1 (leaker factor emission calculation methodology) for some complete leak surveys and used Calculation Method 2 (leaker measurement methodology) for some complete leak surveys, you must report the information specified in paragraphs (q)(2)(i) through (ix) of this section separately for component surveys using Calculation Method 1 and Calculation Method 2.

(i) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(ii) Component type.

(iii) Leak detection method used for the screening survey (*e.g.*, Method 21 as specified in § 98.234(a)(2)(i); Method 21 as specified in § 98.234(a)(2)(ii); and OGI and other leak detection methods as specified in § 98.234(a)(1), (3), or (5)).

(iv) Emission factor or measurement method used (*e.g.*, default emission factor; facility~~site~~-specific emission factor developed according to § 98.233(q)(4); or direct measurement according to § 98.233(q)(3)).

(v) Total number of components surveyed by type and leak detection method in the calendar year.

(vi) Total number of the surveyed component types by leak detection method that were identified as leaking in the calendar year ("x_p" in equation W-30 to § 98.233 for the component type or the number of leaks measured for the specified component type according to the provisions in § 98.233(q)(3)).

(vii) Average time the surveyed components are assumed to be leaking and operational, in hours (average of "$T_{p,z}$" from equation W-30 to § 98.233 for the component type or average duration of leaks for the specified component type determined according to the provisions in § 98.233(q)(3)(ii)).

(viii) Annual CO_2 emissions, in metric tons CO_2, for the component type as calculated using equation W-30 to § 98.233 or § 98.233(q)(3)(vii) (for surveyed components only).

(ix) Annual CH_4 emissions, in metric tons CH_4, for the component type as calculated using equation W-30 to § 98.233 or § 98.233(q)(3)(vii) (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 to § 98.233, 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 to § 98.233, 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 to § 98.233, 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 to § 98.233, 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 to § 98.233).

(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 to § 98.233).

(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 to § 98.233).

(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 to § 98.233).

(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. You must report the information specified in paragraphs (r)(1) through (3) of this section, as applicable, for each well-pad site (for onshore petroleum and natural gas production), gathering and boosting site (for onshore petroleum and natural gas gathering and boosting), or facility (for all other applicable industry segments).

(1) You must indicate whether your facility contains any of the emission source types required to use equation W-32A to § 98.233. You must report the information specified in paragraphs (r)(1)(i) through (vi) of this section separately for each emission source type required to use equation W-32A to § 98.233 that is located at your facility. For each well-pad site and gathering and boosting site at onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities, you must report the information specified in paragraphs (r)(1)(i) through (vi) of this section separately by equipment type and service type.

(i) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(ii) Emission source type. Onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities must report the equipment type and service type.

(iii) Total number of the emission source type at the well-pad site, gathering and boosting site, or facility, as applicable (“$Count_e$” in equation W-32A to § 98.233).

(iv) Average estimated time that the emission source type was operational in the calendar year, in hours (“T_e” in equation W-32A to § 98.233).

(v) Annual CO_2 emissions, in metric tons CO_2, for the emission source type.

(vi) 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 to § 98.233).

(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 to § 98.233).

(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) You must indicate whether your facility contains any emission source types in vacuum service as defined in § 98.238. If your facility contains equipment in vacuum service, you must report the information specified in paragraphs (r)(3)(i) through (iii) of this section separately for each emission source type in vacuum service that is located at your well-pad site, gathering and boosting site, or facility, as applicable.

(i) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(ii) Emission source type.

(iii) Total number of the emission source type at the well-pad site, gathering and boosting site, or facility, as applicable.

(s) *Offshore petroleum and natural gas production*. You must report the information specified in paragraphs (s)(1) through (3) of this section for your facility.

(1) The BOEM Facility ID(s) that correspond(s) to your facility, if applicable.

(2) If you adjusted emissions according to § 98.233(s)(1)(ii) or (s)(2)(ii), report the information specified in paragraphs (s)(2)(i) and (ii) of this section.

(i) Facility operating hours for the year of the most recent emissions calculated according to § 98.233(s)(1)(ii) or § 98.233(s)(2)(ii) prior to the current reporting year.

(ii) Facility operating hours for the current reporting year.

(3) For each emission source type listed in the most recent monitoring and calculation methods published by BOEM as referenced in 30 CFR 550.302 through 304, report the information specified in paragraphs (s)(3)(i) through (iii) of this section.

(i) Annual CO_2 emissions, in metric tons CO_2.

(ii) Annual CH_4 emissions, in metric tons CH_4.

(iii) 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 to § 98.233).

(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 to § 98.233).

(7) Mass fraction of CO_2 in critical phase EOR injection gas ("GHG_{CO2}" in equation W-37 to § 98.233).

(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 to § 98.233).

(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 to § 98.233).

(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 to § 98.233).

(y) *Other large release events*. You must indicate whether there were any other large release events from your facility during the reporting year and indicate whether your facility was notified of a potential super-emitter release under the provisions of § 60.5371, 60.5371a, or 60.5371b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter. If there were any other large release events, you must report the total number of other large release events from your facility that occurred during the reporting year and, for each other large release event, report the information specified in paragraphs (y)(1) through (10) of this section. If you received a super-emitter release notification under the provisions of § 60.5371, 60.5371a, or 60.5371b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter that the EPA has not determined to contain a demonstrable error according to the provisions in § 98.233(y)(6), you must include the emissions from that source or event within your subpart W report unless you can provide certification that the facility does not own or operate the equipment at the location identified in the notification using the methods specified in § 98.233(y)(6). Regardless, if you received a super-emitter release notification under the provisions of §§ 60.5371, 60.5371a, or 60.5371b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, you must also report the information specified in paragraph (y)(11) of this section.

(1) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(2) Unique release event identification number (*e.g.*, Event 1, Event 2).

(3) The latitude and longitude of the release in decimal degrees to at least four digits to the right of the decimal point.

(4) The approximate start date, start time, and duration (in hours) of the release event, and an indication of how the start date and time were determined (determined based on pressure

monitor, temperature monitor, other monitored process parameter (specify), assigned based on last monitoring or measurement survey showing no large release (specify monitoring or measurement survey method), or used the 91-day default start date).

(5) A general description of the event. Include:

(i) Identification of the equipment involved in the release.

(ii) A description of how the release occurred, from one of the following categories: maintenance event, fire/explosion, gas well blowout, oil well blowout, gas well release, oil well release, pressure relief, large leak, and other (specify).

(iii) An indication of whether the release exceeded a threshold in § 98.233(y)(1)(i) or in § 98.233(y)(1)(ii).

(iv) A description of the technology or method used to identify the release.

(v) An indication of whether the release was identified under the provisions of § 60.5371, 60.5371a, or 60.5371b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter and, if the release was identified under the provisions of §§ 60.5371, 60.5371a, or 60.5371b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, a unique notification ID number for the notification as assigned in paragraph (y)(11)(i) of this section.

(vi) An indication of whether a portion of the natural gas released was combusted during the release, and if so, the fraction of the natural gas released that was estimated to be combusted and the assumed combustion efficiency for the combusted natural gas.

(6) The total volume of gas released during the event in standard cubic feet.

(7) The volume fraction of CO_2 in the gas released during the event.

(8) The volume fraction of CH_4 in the gas released during the event.

(9) Annual CO_2 emissions, in metric tons CO_2, from the release event that occurred during the reporting year.

(10) Annual CH_4 emissions, in metric tons CH_4, from the release event that occurred during the reporting year and the maximum CH_4 emissions rate, in kilograms per hour, determined for any period of the event according to the provisions § 98.233(y)(2)(i).

(11) Report the total number of super-emitter release notifications received from the EPA under the provisions of §§ 60.5371, 60.5371a, or 60.5371b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter for this facility for events that occurred during the reporting year that were not determined by the EPA to have a demonstratable error in the notification and, for each such super-emitter release notification, report the information specified in paragraphs (y)(11)(i) through (v) of this section.

(i) Unique notification identification number (*e.g.*, Notification_01, Notification_02). If a unique notification number was provided with a notification received under the provisions of § 60.5371, 60.5371a, or 60.5371b of this chapter, an applicable approved state plan, or applicable Federal plan in part 62 of this chapter, report the number associated with the event provided in the notification.

(ii) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only) to which the notification was attributed.

(iii) Based on any assessment or investigation triggered by the notification, indicate if the emissions were from normal operations, a planned maintenance event, leaking equipment, malfunctioning equipment or device, or undetermined cause.

(iv) An indication of whether the emissions identified via the notification are included in annual emissions reported under this subpart and, if so, the source type under which the emissions identified via the notification are reported (from the list of source types required to be reported as specified in § 98.232 for the facility's applicable industry segment). If the emissions were reported following the requirements of § 98.233(y) as an other large release event, report the unique release event identification number assigned to the other large release event as reported in paragraph (y)(2) of this section. If the emissions identified via the notification are not included in the annual emissions reported under this subpart, you must provide certification that the facility does not own or operate the equipment at the location identified in the notification as specified in § 98.233(y)(6)(i) or provide certification that the facility conducted a complete investigation of the site as specified in § 98.233(y)(6)(ii) and does not own or operate the emitting equipment at the location identified in the notification.

(v) Provide an indication if you received a super-emitter release notification from the EPA after December 31 of the reporting year for which investigations are on-going such that the annual report that has been submitted may be revised and resubmitted pending the outcome of the super-emitter investigation.

(z) *Combustion equipment*. 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)(xx), (a)(8)(vi), or (a)(9)(xiii) of this section. If your facility contains any combustion units subject to reporting according to paragraph (a)(1)(xx), (a)(8)(vi), or (a)(9)(xiii) of this section, then you must report the information specified in paragraphs (z)(1) and (2) of this section, as applicable. You must report the information specified in paragraphs (z)(1) and (2) of this section, as applicable, for each well-pad site (for onshore petroleum and natural gas production), gathering and boosting site (for onshore petroleum and natural gas gathering and boosting), or facility (for all other applicable industry segments).

(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) through (iii) of this section for each unit type.

(i) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(ii) The type of combustion unit.

(iii) 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. For each type of combustion unit at your facility, you must report the information specified in paragraphs (z)(2)(i) through (iv) and (z)(2)(viii) through (x) of this section, except for 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 that combust natural gas meeting the criteria in § 98.233(z)(1) or (2) or a fuel meeting the criteria in § 98.233(z)(3), which must report the information specified in paragraphs (z)(2)(i) through (x) of this section. Information must be reported for each combustion unit type, fuel type, and method for determining the CH_4 emission factor combination, as applicable.

(i) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(ii) The type of combustion unit including 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.

(iii) The type of fuel combusted.

(iv) The quantity of fuel combusted in the calendar year, in thousand standard cubic feet, gallons, or tons.

(v) The equipment type, including reciprocating 2-stroke-lean burn, reciprocating 4-stroke lean-burn, reciprocating 4-stroke rich-burn, and gas turbine.

(vi) The method used to determine the methane emission factor, including the default emission factor from table W-7 to this subpart, OEM data, or performance tests in § 98.234(i) for natural gas described in § 98.233(z)(1) or (2), or performance tests in § 98.234(i) or default combustion efficiency for fuels described in section § 98.233(z)(3).

(vii) The value of the CH_4 emission factor (kg CH_4/mmBtu). If multiple performance tests were performed in the same reporting year, the arithmetic average value of CH_4 emission factor (kg CH_4/mmBtu). This information is not required if CH_4 emissions were calculated per § 98.233(z)(3)(ii)(D).

(viii) Annual CO_2 emissions, in metric tons CO_2, calculated according to § 98.233(z)(1) through (3).

(ix) Annual CH_4 emissions, in metric tons CH_4, calculated according to § 98.233(z)(1) through (3).

(x) Annual N_2O emissions, in metric tons N_2O, calculated according to § 98.233(z)(1) through (3).

(aa) *Industry segment-specific information*. Each facility must report the information specified in paragraphs (aa)(1) through (11) of this section, for each applicable industry segment, determined using a flow meter that meets the requirements of § 98.234(b) for quantities that are sent to sale or through the facility and determined by using best available data for other quantities. 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 (iv) 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, unless otherwise specified.

(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 natural gas produced from producing wells that is sent to sale in the calendar year, in thousand standard cubic feet.

(C) The quantity of crude oil and condensate produced from producing wells that is sent to sale in the calendar year, 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 (exclude only those wells permanently shut-in and plugged).

(E) The number of producing wells acquired during the calendar year.

(F) The number of producing wells divested during the calendar year.

(G) The number of wells completed during the calendar year.

(H) The number of wells permanently shut-in and plugged during the calendar year.

(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.

(iii) Report the information specified in paragraphs (aa)(1)(iii)(A) through (D) of this section for each well located in the facility.

(A) Well ID number.

(B) Well-pad ID.

(C) For each well permanently shut-in and plugged during the calendar year, the quantity of natural gas produced that is sent to sale in the calendar year, in thousand standard cubic feet.

(D) For each well permanently shut-in and plugged during the calendar year, the quantity of crude oil and condensate produced that is sent to sale in the calendar year, in barrels.

(iv) Report the information specified in paragraphs (aa)(1)(iv)(A) through (C) of this section for each well-pad site located in the facility.

(A) A unique name or ID number for the well-pad.

(B) Sub-basin ID.

(C) The latitude and longitude of the well-pad representing the geographic centroid or center point of the well-pad in decimal degrees to at least four digits to the right of the decimal point.

(2) For offshore production, report the quantities specified in paragraphs (aa)(2)(i) through (iv) of this section.

(i) The quantity of natural gas produced from producing wells that is sent to sale in the calendar year, in thousand standard cubic feet.

(ii) The quantity of crude oil and condensate produced from producing wells that is sent to sale in the calendar year, in barrels.

(iii) For each well permanently shut-in and plugged during the calendar year, the quantity of natural gas produced that is sent to sale in the calendar year, in thousand standard cubic feet.

(iv) For each well permanently shut-in and plugged during the calendar year, the quantity of crude oil and condensate produced that is sent to sale in the calendar year, in barrels.

(3) For natural gas processing, if your facility fractionates NGLs and also reported as a supplier to subpart NN of this part under the same e-GGRT identification number in the calendar year, you must report the information specified in paragraphs (aa)(3)(ii) and (aa)(3)(v) through (ix) of this section. Otherwise, report the information specified in paragraphs (aa)(3)(i) through (ix) of this section.

(i) The quantity of natural gas received at the gas processing plant for processing 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.

(viii) Indicate whether the facility reported as a supplier to subpart NN of this part under the same e-GGRT identification number in the calendar year.

(ix) The quantity of residue gas leaving that has been processed by the facility and any gas that passes through the facility to sales without being processed by the facility.

(4) For natural gas transmission compression, report the quantity specified in paragraphs (aa)(4)(i) through (v) of this section.

(i) The quantity of natural 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 natural gas withdrawn from storage and sent to sale 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 that is sent to sale in the calendar year, in thousand standard cubic feet.

(7) For LNG export equipment, report the quantity of LNG exported that is sent to sale 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 and sent to sale in the calendar year, in thousand standard cubic feet.

(iii) Total storage capacity, in thousand standard cubic feet.

(9) [Reserved]

(10) For onshore petroleum and natural gas gathering and boosting facilities, report the quantities specified in paragraphs (aa)(10)(i) through (v) 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 natural gas transported from the 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 from the gathering and boosting facility in the calendar year, in barrels.

(v) Report the information specified in paragraphs (aa)(10)(v)(A) through (E) of this section for each gathering and boosting site located in the facility for which there were emissions in the calendar year.

(A) A unique name or ID number for the gathering and boosting site.

(B) Gathering and boosting site type (gathering compressor station, centralized oil production site, gathering pipeline, or other fence-line site).

(C) State.

(D) For gathering compressor stations, centralized oil production sites, and other fence-line sites, county.

(E) For gathering compressor stations, centralized oil production sites, and other fence-line sites, the latitude and longitude of the gathering and boosting site representing the geographic centroid or center point of the site in decimal degrees to at least four digits to the right of the decimal point.

(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 underground natural gas storage and LNG storage (regasification) facilities owned and operated by the onshore natural gas transmission pipeline owner or operator that are not subject to this subpart in the calendar year, in thousand standard cubic feet.

(iii) The quantity of natural gas added to underground natural gas storage and LNG storage (liquefied) facilities owned and operated by the onshore natural gas transmission pipeline owner or operator that are not subject to this subpart in the calendar year, in thousand standard cubic feet.

(iv) The quantity of natural gas transported through the facility and 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) *Missing data*. For any missing data procedures used, report the information in § 98.3(c)(8) and the procedures used to substitute an unavailable value of a parameter, 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) *Delay in reporting for* w*ildcat wells and delineation wells*. If you elect to delay reporting the information in paragraph (g)(5)(i) or (ii), (g)(5)(iii)(A) or (B), (h)(1)(iv), (h)(2)(iv), (j)(1)(iii), (j)(2)(i)(A), (l)(1)(v), (l)(2)(v), (l)(3)(iv), (l)(4)(iv), (m)(5) or (6), (dd)(1)(iii), (dd)(1)(vi)(A), (B), or (C), (dd)(3)(iii)(A), or (dd)(3)(iii)(D)(*1*), (*2*), or (*3*) 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.

(dd) *Drilling mud degassing*. You must indicate whether there were mud degassing operations at your facility, and if so, which methods (as specified in § 98.233(dd)) were used to calculate emissions. For wells for which your facility performed mud degassing operations and used Calculation Method 1, then you must report the information specified in paragraph (dd)(1) of this section. For wells for which your facility performed mud degassing operations and used Calculation Method 2, then you must report the information specified in paragraph (dd)(2) of this section. For wells for which your facility performed mud degassing operations and used Calculation Method 3, then you must report the information specified in paragraph (dd)(3) of this section.

(1) For each well for which you used Calculation Method 1 to calculate natural gas emissions from mud degassing, report the information specified in paragraphs (dd)(1)(i) through (viii) of this section.

(i) Well ID number.

(ii) Approximate total depth below surface, in feet.

(iii) Target hydrocarbon-bearing stratigraphic formation to which the well is drilled.

(iv) Total time that drilling mud is circulated in the well (T_r in equation W-41 to § 98.233 and T_p in equation W-43 to § 98.233), in minutes, beginning with initial penetration of the first hydrocarbon-bearing zone until drilling mud ceases to be circulated in the wellbore. You may delay reporting of this data element for a representative well if you indicate in the annual report that one or more wells to which the calculated CH_4 emissions rate for the representative well ($ER_{s,CH4,r}$ in equation W-42 to § 98.233) is applied is a wildcat well or delineation well. You may delay reporting of this data element for any well if you indicate in the annual report that the well is a wildcat or delineation well. If you elect to delay reporting of this data element, you must report by the date specified in paragraph (cc) of this section the total time that drilling mud is circulated in the well, in minutes.

(v) The composition of the drilling mud: water-based, oil-based, or synthetic.

(vi) If the well is not a representative well, Well ID number of the representative well used to derive the CH_4 emission rate used to calculate CH_4 emissions for this well.

(vii) If the well is a representative well, report the information specified in paragraphs (dd)(1)(vi)(A) through (D) of this section.

(A) Average mud rate (MR_r in equation W-41 to § 98.233), in gallons per minute. You may delay reporting of this data element if you indicate in the annual report that one or more wells to which the calculated CH_4 emissions rate for the representative well ($ER_{s,CH4,r}$ in equation W-42 to § 98.233) is applied is a wildcat well or delineation well. If you elect to delay reporting of this data element, you must report by the date specified in paragraph (cc) of this section the average mud rate, in gallons per minute.

(B) Average concentration of natural gas in the drilling mud (X_n in equation W-41 to § 98.233), in parts per million. You may delay reporting of this data element if you indicate in the annual report that the well is a wildcat well or delineation well. If you elect to delay reporting of this data element, you must report by the date specified in paragraph (cc) of this section the average concentration of natural gas in the drilling mud in parts per million.

(C) Measured mole fraction for CH_4 in natural gas entrained in the drilling mud (GHG_{CH4} in equation W-41 to § 98.233). You may delay reporting of this data element if you indicate in the annual report that the well is a wildcat well or delineation well. If you elect to delay reporting of this data element, you must report by the date specified in paragraph (cc) of this section the measured mole fraction for CH_4 in natural gas entrained in the drilling mud.

(D) Calculated CH_4 emissions rate in standard cubic feet per minute ($ER_{s,CH4,r}$ in equation W-42 to § 98.233). You may delay reporting of this data element if you indicate in the annual report that that one or more wells to which the calculated CH_4 emissions rate for the representative well ($ER_{s,CH4,r}$ in equation W-42 to § 98.233) is applied is a wildcat or delineation well. If you elect to delay reporting of this data element, you must report by the date specified in paragraph (cc) of this section the calculated CH_4 emissions rate in standard cubic feet per minute.

(viii) Annual CH_4 emissions, in metric tons CH_4, from well drilling mud degassing, calculated according to § 98.233(dd)(1).

(2) For each well for which you used Calculation Method 2 to calculate natural gas emissions from mud degassing, report the information specified in paragraphs (dd)(2)(i) through (iv) of this section.

(i) Well ID number.

(ii) Total number of drilling days (DD_p in equation W-44 to § 98.233).

(iii) The composition of the drilling mud: water-based, oil-based, or synthetic.

(iv) Annual CH_4 emissions, in metric tons CH_4, from drilling mud degassing, calculated according to § 98.233(dd)(2).

(3) For each well for which you used Calculation Method 3 to calculate natural gas emissions from mud degassing, report the information specified in paragraphs (dd)(3)(i) through (iv) of this section.

(i) Well ID number.

(ii) For the time periods you used Calculation Method 1 to calculate natural gas emissions from mud degassing, report the information specified in paragraphs (dd)(3)(ii)(A) through (G) of this section.

(A) Approximate total depth below surface, in feet.

(B) Target hydrocarbon-bearing stratigraphic formation to which the well is drilled.

(C) Total time that drilling mud is circulated in the well (Tr in equation W-41 to § 98.233 and T_p in equation W-43 to § 98.233), in minutes, beginning with initial penetration of the first hydrocarbon-bearing zone until drilling mud ceases to be circulated in the wellbore. You may delay reporting of this data element for a representative well if you indicate in the annual report that that one or more wells to which the calculated CH_4 emissions rate for the representative well ($ER_{s,CH4,r}$ in equation W-42 to § 98.233) is applied is a wildcat well or delineation well. You may delay reporting of this data element for any well if you indicate in the annual report that the well is a wildcat well or delineation well. If you elect to delay reporting of this data element, you must report by the date specified in paragraph (cc) of this section the total time that drilling mud is circulated in the well, in minutes.

(D) The composition of the drilling mud: water-based, oil-based, or synthetic.

(E) If the well is not a representative well, Well ID number of the representative well used to derive the CH_4 emission rate used to calculate CH_4 emissions for this well.

(F) If the well is a representative well, report the information specified in paragraphs (dd)(3)(ii)(F)(*1*) through (*4*) of this section.

(*1*) Average mud rate (MR_r in equation W-41 to § 98.233), in gallons per minute. You may delay reporting of this data element if you indicate in the annual report that one or more wells to which the calculated CH_4 emissions rate for the representative well ($ER_{s,CH4,r}$ in equation W-42 to § 98.233) is applied is a wildcat well or delineation well. If you elect to delay reporting of this data element, you must report by the date specified in paragraph (cc) of this section the average mud rate, in gallons per minute.

(*2*) Average concentration of natural gas in the drilling mud (X_n in equation W-41 to § 98.233), in parts per million. You may delay reporting of this data element if you indicate in the annual report that the well is a wildcat well or delineation well. If you elect to delay reporting of this data element, you must report by the date specified in paragraph (cc) of this section the average concentration of natural gas in the drilling mud in parts per million.

(*3*) Measured mole fraction for CH_4 in natural gas entrained in the drilling mud (GHG_{CH4} in equation W-41 to § 98.233). You may delay reporting of this data element if you indicate in the annual report that the well is a wildcat well or delineation well. If you elect to delay reporting of this data element, you must report by the date specified in paragraph (cc) of this section the measured mole fraction for CH_4 in natural gas entrained in the drilling mud.

(*4*) Calculated CH_4 emissions rate in standard cubic feet per minute ($ER_{s,CH4,r}$ in equation W-42 to § 98.233). You may delay reporting of this data element if you indicate in the annual report that one or more wells to which the calculated CH_4 emissions rate for the representative well ($ER_{s,CH4,r}$ in equation W-42 to § 98.233) is applied is a wildcat well or delineation well. If you elect to delay reporting of this data element, you must report by the date specified in paragraph (cc) of this section the calculated CH_4 emissions rate in standard cubic feet per minute.

(G) Annual CH_4 emissions, in metric tons CH_4, from well drilling mud degassing, calculated according to § 98.233(dd)(1).

(iii) For the time periods for each well for which you used Calculation Method 2 to calculate natural gas emissions from mud degassing, report the information specified in paragraphs (dd)(3)(iii)(A) through (C) of this section.

(A) Total number of drilling days (DD_p in equation W-44 to § 98.233).

(B) The composition of the drilling mud: water-based, oil-based, or synthetic.

(C) Annual CH_4 emissions, in metric tons CH_4, from drilling mud degassing, calculated according to § 98.233(dd)(2).

(iv) Total annual CH_4 emissions, in metric tons CH_4, from drilling mud degassing, calculated from summing the annual CH_4 emissions calculated from § 98.233(dd)(3)(iii)(E) and § 98.233(dd)(3)(iv)(C)

(ee) *Crankcase vents*. You must indicate whether your facility performs any crankcase venting from reciprocating internal combustion engines. For all reciprocating internal combustion engines with crankcase vents, you must report the information specified in paragraph (ee)(1) of this section for each well-pad site (for onshore petroleum and natural gas production), gathering and boosting site (for onshore petroleum and natural gas gathering and boosting), or facility (for all other applicable industry segments). For each reciprocating internal combustion engine that you conduct measurements as specified in § 98.233(ee)(1), you must report the information specified in paragraph (ee)(2) of this section. For reciprocating internal combustion engines with CH_4 emissions calculated as specified in § 98.233(ee)(2), you must report the information specified in paragraph (ee)(3) of this section for each well-pad site (for onshore petroleum and natural gas production), gathering and boosting site (for onshore petroleum and natural gas gathering and boosting), or facility (for all other applicable industry segments).

(1) The information and number of reciprocating internal combustion engines with crankcase vents as specified in paragraphs (ee)(1)(i) through (v) of this section, as applicable. If a reciprocating internal combustion engine with crankcase vents was vented directly to the atmosphere for part of the year and routed to a flare during another part of the year, then include the engine in each of the applicable counts specified in paragraphs (ee)(1)(iii) and (iv) of this section.

(i) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(ii) The total number of reciprocating internal combustion engines with crankcase vents.

(iii) The total number of reciprocating internal combustion engines with crankcase vents that operated and were vented directly to the atmosphere.

(iv) The total number of reciprocating internal combustion engines with crankcase vents that operated and were routed to a flare.

(v) The total number of reciprocating internal combustion engines with crankcase vents that were in a manifolded group containing a compressor vent source with emissions reported under paragraph (o) or (p) of this section.

(2) Reciprocating internal combustion engines with crankcase vents that calculate emissions according to § 98.233(ee)(1) must report the information specified in paragraphs (ee)(2)(i) and (ii) of this section, as applicable.

(i) For each measurement performed on a crankcase vent, report the information specified in paragraphs (ee)(2)(i)(A) through (F) of this section.

(A) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(B) Unique name or ID for the reciprocating internal combustion engine.

(C) Measurement date.

(D) 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.

(E) Measured flow rate, in standard cubic feet per hour.

(F) If the measurement is for a manifolded group of crankcase vent sources, indicate the number of reciprocating internal compressor engines that were operating during measurement.

(ii) Annual CH_4 emissions from the reciprocating internal combustion engine crankcase vent, in metric tons CH_4.

(3) Reciprocating internal combustion engines with crankcase vents that calculate emissions according to § 98.233(ee)(2) must report the information specified in paragraphs (ee)(3)(i) through (iv) of this section.

(i) Well-pad ID (for the onshore petroleum and natural gas production industry segment only) or gathering and boosting site ID (for the onshore petroleum and natural gas gathering and boosting industry segment only).

(ii) Total number of reciprocating internal combustion engines with crankcase vents that were operational at some point in the calendar year at the well-pad site, gathering and boosting site, or facility, as applicable.

(iii) Total time that the reciprocating internal combustion engines with crankcase venting were operational in the calendar year, in hours ("T" in equation W-46 to § 98.233).

(iv) Annual CH_4 emissions, in metric tons CH_4, calculated according to § 98.233(ee)(2).

§ 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.

(g) For each situation when you fail to fully conform with all cited provisions in either § 98.233(n)(1)(i) or (ii) for a period of 15 consecutive days and you utilized the Tier 3 default destruction and combustion efficiency values, you must document these periods when the non-conformance began, and the date when full conformance was re-established.

§ 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 unit (AGR) 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.

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.

Atmospheric pressure storage tank means a vessel (excluding sumps) operating at atmospheric pressure that is designed to contain an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water and that is constructed entirely of non-earthen materials (*e.g.*, wood, concrete, steel, plastic) that provide structural support. Atmospheric pressure storage tanks include both fixed roof tanks and floating roof tanks. Floating roof tanks include tanks with either an internal floating roof or an external floating roof.

Automated liquids unloading means an unloading that is performed without manual interference. Examples of automated liquids unloadings include a timing and/or pressure device used to optimize intermittent shut-in of the well before liquids choke off gas flow or to open and close valves, continually operating equipment that does not require presence of an operator such as rod pumping units, automated and unmanned plunger lifts, or other unloading activities that do not entail a physical presence at the well-pad.

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).

Centralized oil production site means any permanent combination of one or more hydrocarbon liquids storage tanks located on one or more contiguous or adjacent properties that does not also contain a permanent combination of one or more compressors that are part of the onshore petroleum and natural gas gathering and boosting facility that gathers hydrocarbon liquids from multiple well-pads. A *centralized oil production site* is a type of gathering and boosting site for purposes of this subpart.

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 both centrifugal compressors and reciprocating compressors, “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, wet seal oil degassing vents, and dry seal 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.

Crankcase venting means the process of venting or removing blow-by from the void spaces of an internal combustion engine outside of the combustion cylinders to prevent excessive pressure build-up within the engine. This does not include ingestive systems that vent blow-by into the engine where it is returned to the combustion process (*e.g.*, closed crankcase ventilation system, closed breather system) or if the vent blow-by is routed to another closed vent system.

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.

Drilling mud means a mixture of clays and additives with water, oil, or synthetic materials. While drilling, the drilling mud is continuously pumped through the drill string and out the bit to cool and lubricate the drill bit, and move cuttings through the wellbore to the surface.

Drilling mud degassing means the practice of safely removing pockets of free gas entrained in the drilling mud once it is outside of the wellbore.

Enclosed combustion device means a flare that uses a closed flame.

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.

Equivalent stratigraphic interval means the depth of the same stratum of rock in the Earth's subsurface.

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 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 in gas routed to a flare, CO_2 from partial combustion of hydrocarbons in gas routed to a flare, CH_4 emissions resulting from the incomplete combustion of hydrocarbons in gas routed to a flare, and N_2O resulting from operation of a flare.

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, the collection or gravity separation of water or hydrocarbon liquids from natural gas at ambient temperature or heated above ambient temperatures, the condensation of water or hydrocarbon liquids through passive reduction in pressure or temperature, a Joule-Thomson valve, a dew point depression valve, or an isolated or standalone Joule-Thomson skid.

Gathering and boosting site means a single gathering compressor station as defined in this section, centralized oil production site as defined in this section, gathering pipeline site as defined in this section, or other fence-line site within the onshore petroleum and natural gas gathering and boosting industry segment.

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 or one or more other gathering and boosting systems 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 or one or more other gathering and boosting systems to a downstream endpoint, typically 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.

Gathering compressor station means any permanent combination of one or more compressors located on one or more contiguous or adjacent properties that are part of the onshore petroleum and natural gas gathering and boosting facility that move natural gas at increased pressure through gathering pipelines or into or out of storage. A *gathering compressor station* is a type of gathering and boosting site for purposes of this subpart.

Gathering pipeline site means all of the gathering pipelines within a single state. A *gathering pipeline site* is a type of gathering and boosting site for purposes of this subpart.

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.

In vacuum service means equipment operating at an internal pressure which is at least 5 kilopascals (kPa) (0.7 psia) below ambient pressure.

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.

Manual liquids unloading means an unloading when field personnel attend to the well at the well-pad, for example to manually plunge a well at the site using a rig or other method, to open a valve to direct flow to an atmospheric tank to clear the well, or to manually shut-in the well to allow pressure to build in the well-bore. Manual unloadings may be performed on a routine schedule or on “as needed” basis.

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.

Mud rate means the pumping rate of the mud by the mud pumps, usually measured in gallons per minute (gpm).

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.

Nitrogen removal unit (NRU) means a process unit that separates nitrogen from natural gas using various separation processes (*e.g.*, cryogenic units, membrane units).

Nitrogen removal unit vent emissions means the nitrogen gas separated from the natural gas and released with methane and other gases to the atmosphere.

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.

Other large release event means any planned or unplanned uncontrolled release to the atmosphere of gas, liquids, or mixture thereof, from wells and/or other equipment that result in emissions for which there are no methodologies in § 98.233 other than under § 98.233(y) to appropriately estimate these emissions. *Other large release events* include, but are not limited to, well blowouts, well releases, pressure relief valve releases from process equipment other than hydrocarbon liquids storage tanks, storage tank cleaning and other maintenance activities, and releases that occur as a result of an accident, equipment rupture, fire, or explosion. *Other large release events* also include failure of equipment or equipment components such that a single equipment leak or release has emissions that exceed the emissions calculated for that source using applicable methods in § 98.233(a) through (h), (j) through (s), (w), (x), (dd), or (ee) by the threshold in § 98.233(y)(1)(ii). *Other large release events* do not include blowdowns for which emissions are calculated according to the provisions in § 98.233(i).

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.

Produced water means the water (brine) brought up from the hydrocarbon-bearing strata during the extraction of oil and gas, and can include formation water, injection water, and any chemicals added downhole or during the oil/water separation process.

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.

Routed to combustion means, for onshore petroleum and natural gas production facilities, natural gas distribution facilities, and onshore petroleum and natural gas gathering and boosting facilities, that emissions are routed to stationary or portable fuel combustion equipment specified in § 98.232(c)(22), (i)(7), or (j)(12), as applicable. For all other industry segments in this subpart, *routed to combustion* means that emissions are routed to a stationary fuel combustion unit subject to subpart C of this part (General Stationary Fuel Combustion Sources).

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.

Target hydrocarbon-bearing stratigraphic formation means the stratigraphic interval intended to be the primary hydrocarbon producing formation.

Transmission company interconnect M&R station means a metering and pressure regulating stations with an inlet pressure above 100 psig located at a point of transmission pipeline to transmission pipeline interconnect.

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 blowout means a complete loss of well control for a long duration of time resulting in an emissions release.

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-pad site means all equipment on or associated with a single well-pad. Specifically, the *well-pad site* includes all equipment on a single well-pad plus all equipment associated with that single well-pad.

Well release means a short duration of uncontrolled emissions release from a well followed by a period of controlled emissions release in which control techniques were successfully implemented.

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.

Table W-1 to Subpart W of Part 98—Default Whole Gas Population Emission Factors

Industry Segment	Source Type/Component	Emission factor (scf whole gas/hour/unit)
Population Emission Factors—Pneumatic Device Vents and Pneumatic Pumps, Gas Service[1]		
• Onshore petroleum and natural gas production • Onshore petroleum and natural gas gathering and boosting	Continuous Low Bleed Pneumatic Device Vents[2]	6.8
	Continuous High Bleed Pneumatic Device Vents[2]	21
	Intermittent Bleed Pneumatic Device Vents[2]	8.8
	Pneumatic Pumps[3]	13.3
• Onshore natural gas processing • Onshore natural gas transmission compression • Underground natural gas storage • Natural gas distribution	Continuous Low Bleed Pneumatic Device Vents[2]	6.8
	Continuous High Bleed Pneumatic Device Vents[2]	30
	Intermittent Bleed Pneumatic Device Vents[2]	2.3
Population Emission Factors—Major Equipment, Gas Service[1]		
• Onshore petroleum and natural gas production • Onshore petroleum and natural gas gathering and boosting	Wellhead	8.87
	Separator	9.65
	Meters/Piping	7.04
	Compressor	13.8
	Dehydrator	8.09
	Heater	5.22
	Storage Vessel	1.83
Population Emission Factors—Major Equipment, Crude Service		
Onshore petroleum and natural gas production	Wellhead	4.13
	Separator	4.77
	Meters/Piping	12.4
	Compressor	13.8
	Dehydrator	8.09
	Heater	3.2
	Storage Vessel	1.91
Population Emission Factors—Gathering Pipelines, by Material Type[4]		
Onshore petroleum and natural gas gathering and boosting	Protected Steel	0.93
	Unprotected Steel	8.2
	Plastic/Composite	0.28
	Cast Iron	8.4

[1] For multi-phase flow that includes gas, use the gas service emission factors.

[2] Emission factor is in units of “scf whole gas/hour/device.”

[3] Emission factor is in units of “scf whole gas/hour/pump.”

[4] Emission factors are in units of "scf whole gas/hour/mile of pipeline."

Table W-2 to Subpart W of Part 98—Default Whole Gas Leaker Emission Factors

Equipment components	Emission factor (scf whole gas/hour/component)		
	If you survey using Method 21 as specified in § 98.234(a)(2)(i)	**If you survey using Method 21 as specified in § 98.234(a)(2)(ii)**	**If you survey using any of the methods in § 98.234(a)(1), (3), or (5)**
Leaker Emission Factors—Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting—All Components, Gas Service			
Valve	9.6	5.5	16
Flange	6.9	4.0	11
Connector (other)	4.9	2.8	7.9
Open-Ended Line[1]	6.3	3.6	10
Pressure Relief Valve	7.8	4.5	13
Pump Seal	14	8.3	23
Other[2]	9.1	5.3	15
Leaker Emission Factors—Onshore Petroleum and Natural Gas Production—All Components, Oil Service			
Valve	5.6	3.3	9.2
Flange	2.7	1.6	4.4
Connector (other)	5.6	3.2	9.1
Open-Ended Line	1.6	0.93	2.6
Pump[3]	3.7	2.2	6.0
Other[2]	2.2	1.0	2.9

[1] The open-ended lines component type includes blowdown valve and isolation valve leaks emitted through the blowdown vent stack for centrifugal and reciprocating compressors when using the population emission factor approach as specified in § 98.233(o)(10)(iv) or (p)(10)(iv).

[2] "Others" category includes any equipment leak emission point not specifically listed in this table, as specified in § 98.232(c)(21) and (j)(10).

[3] The pumps component type in oil service includes agitator seals.

Table W-3 to Subpart W of Part 98—Default Total Hydrocarbon Population Emission Factors

Industry Segment	Source Type/Component	Emission factor (scf total hydrocarbon/hour/component)
Population Emission Factors—Storage Wellheads, Gas Service		
Underground natural gas storage	Connector	0.01
	Valve	0.1
	Pressure Relief Valve	0.17

	Open-Ended Line	0.03

Table W-4 to Subpart W of Part 98—Default Total Hydrocarbon Leaker Emission Factors

Equipment components	Emission factor (scf total hydrocarbon/hour/component)		
	If you survey using Method 21 as specified in § 98.234(a)(2)(i)	**If you survey using Method 21 as specified in § 98.234(a)(2)(ii)**	**If you survey using any of the methods in § 98.234(a)(1), (3), or (5)**
Leaker Emission Factors—Onshore Natural Gas Processing, Onshore Natural Gas Transmission Compression—Compressor Components, Gas Service			
Valve[1]	14.84	9.51	24.2
Connector	5.59	3.58	9.13
Open-Ended Line	17.27	11.07	28.2
Pressure Relief Valve	39.66	25.42	64.8
Meter	19.33	12.39	31.6
Other[2]	4.1	2.63	6.70
Leaker Emission Factors—Onshore Natural Gas Processing, Onshore Natural Gas Transmission Compression—Non-Compressor Components, Gas Service			
Valve[1]	6.42	4.12	10.5
Connector	5.71	3.66	9.3
Open-Ended Line	11.27	7.22	18.4
Pressure Relief Valve	2.01	1.29	3.28
Meter	2.93	1.88	4.79
Other[2]	4.1	2.63	6.70
Leaker Emission Factors—Underground Natural Gas Storage—Storage Station, Gas Service			
Valve[1]	14.84	9.51	24.2
Connector (other)	5.59	3.58	9.13
Open-Ended Line	17.27	11.07	28.2
Pressure Relief Valve	39.66	25.42	64.8
Meter and Instrument	19.33	12.39	31.6
Other[2]	4.1	2.63	6.70
Leaker Emission Factors—Underground Natural Gas Storage—Storage Wellheads, Gas Service			
Valve[1]	4.5	3.2	7.35
Connector (other than flanges)	1.2	0.7	1.96
Flange	3.8	2.0	6.21
Open-Ended Line	2.5	1.7	4.08
Pressure Relief Valve	4.1	2.5	6.70
Other[2]	4.1	2.5	6.70

[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(d)(7) for onshore natural gas processing, § 98.232(e)(8) for onshore natural gas transmission compression, and as specified in § 98.232(f)(6) and (8) for underground natural gas storage.

Table W-5 to Subpart W of Part 98—Default Methane Population Emission Factors

Industry Segment	Source Type/Component	Emission factor (scf methane/hour/component)
Population Emission Factors—LNG Storage Compressor, Gas Service		
LNG storage LNG import and export equipment	Vapor Recovery Compressor[1]	4.17
Population Emission Factors—Below Grade Transmission-Distribution Transfer Station Components and Below Grade Metering-Regulating Station[2] Components, Gas Service[3]		
Natural gas distribution	Below Grade T-D Transfer Station	0.30
	Below Grade M&R Station	0.30
Population Emission Factors—Distribution Mains, Gas Service[4]		
Natural gas distribution	Unprotected Steel	5.1
	Protected Steel	0.57
	Plastic	0.17
	Cast Iron	6.9
Population Emission Factors—Distribution Services, Gas Service[5]		
Natural gas distribution	Unprotected Steel	0.086
	Protected Steel	0.0077
	Plastic	0.0016
	Copper	0.03
Population Emission Factors—Interconnect, Direct Sale, or Farm Tap Stations[2,3]		
Onshore natural gas transmission pipeline	Transmission Company Interconnect M&R Station	166
	Direct Sale or Farm Tap Station	1.3
Population Emission Factors—Transmission Pipelines, Gas Service[4]		
Onshore natural gas transmission pipeline	Unprotected Steel	0.74
	Protected Steel	0.041
	Plastic	0.061
	Cast Iron	27

[1] Emission Factor is in units of "scf methane/hour/compressor."

[2] Excluding customer meters.

[3] Emission Factor is in units of "scf methane/hour/station."

[4] Emission Factor is in units of "scf methane/hour/mile."

[5] Emission Factor is in units of "scf methane/hour/number of services."

Table W-6 to Subpart W of Part 98—Default Methane Leaker Emission Factors

Equipment components	Emission factor (scf methane/hour/component)		
	If you survey using Method 21 as specified in § 98.234(a)(2)(i)	If you survey using Method 21 as specified in § 98.234(a)(2)(ii)	If you survey using any of the methods in § 98.234(a)(1), (3), or (5)
Leaker Emission Factors—LNG Storage and LNG Import and Export Equipment—Storage Components and Terminals Components, LNG Service			
Valve	1.19	0.23	1.94
Pump Seal	4.00	0.73	6.54
Connector	0.34	0.11	0.56
Other[1]	1.77	0.99	2.9
Leaker Emission Factors—LNG Storage and LNG Import and Export Equipment—Storage Components and Terminals Components, Gas Service			
Valve[2]	14.84	9.51	24.2
Connector	5.59	3.58	9.13
Open-Ended Line	17.27	11.07	28.2
Pressure Relief Valve	39.66	25.42	64.8
Meter and Instrument	19.33	12.39	31.6
Other[3]	4.1	2.63	6.70
Leaker Emission Factors— Natural Gas Distribution— Transmission-Distribution Transfer Station[4] Components, Gas Service			
Connector	1.69	--	2.76
Block Valve	0.557	--	0.91
Control Valve	9.34	--	15.3
Pressure Relief Valve	0.27	--	0.44
Orifice Meter	0.212	--	0.35
Regulator	0.772	--	1.26
Open-ended Line	26.131	--	42.7

[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) and § 98.232(h)(7) and (8).

[4] Excluding customer meters.

Table W-7 to Subpart W of Part 98—Default Methane Emission Factors for Internal Combustion Equipment

Internal Combustion Equipment Type	Emission factor (kg CH_4/mmBtu)
Reciprocating Engine, 2-stroke lean-burn	0.658
Reciprocating Engine, 4-stroke lean-burn	0.522
Reciprocating Engine, 4-stroke rich-burn	0.045
Gas Turbine	0.004