

**Appendix B. Greenhouse Gas Reporting Program:
Reporting Requirements (as of July 9, 2015)**

Subpart	Reporting Threshold	Reporting and Verification
C—General Stationary Combustion (§98.36)	25,000 metric tons CO ₂ e/year	<p>(a) In addition to the facility-level information required under §98.3, the annual GHG emissions report shall contain the unit-level or process-level data specified in paragraphs (b) through (f) of this section, as applicable, for each stationary fuel combustion source (e.g., individual unit, aggregation of units, common pipe, or common stack) except as otherwise provided in this paragraph (a). For the data specified in paragraphs (b)(9)(iii), (c)(2)(ix), (e)(2)(i), (e)(2)(ii)(A), (e)(2)(ii)(C), (e)(2)(ii)(D), (e)(2)(iv)(A), (e)(2)(iv)(C), (e)(2)(iv)(F), and (e)(2)(ix)(D) through (F) of this section, the owner or operator of a stationary fuel combustion source that does not meet the criteria specified in paragraph (f) of this section may elect either to report the data specified in this sentence in the annual report or to use verification software according to §98.5(b) in lieu of reporting these data. If you elect to use this verification software, you must use the verification software according to §98.5(b) for all of these data that apply to the stationary fuel combustion source.</p> <p>(b) <i>Units that use the four tiers.</i> You shall report the following information for stationary combustion units that use the Tier 1, Tier 2, Tier 3, or Tier 4 methodology in §98.33(a) to calculate CO₂ emissions, except as otherwise provided in paragraphs (c) and (d) of this section:</p> <ol style="list-style-type: none"> (1) The unit ID number. (2) A code representing the type of unit. (3) Maximum rated heat input capacity of the unit, in mmBtu/hr. (4) Each type of fuel combusted in the unit during the report year. (5) The methodology (<i>i.e.</i>, tier) used to calculate the CO₂ emissions for each type of fuel combusted (<i>i.e.</i>, Tier 1, 2, 3, or 4). (6) The methodology start date, for each fuel type. (7) The methodology end date, for each fuel type. (8) For a unit that uses Tiers 1, 2, or 3: <ol style="list-style-type: none"> (i) The annual CO₂ mass emissions (including biogenic CO₂), and the annual CH₄, and N₂O mass emissions for each type of fuel combusted during the reporting year, expressed in metric tons of each gas and in metric tons of CO₂e; and (ii) Metric tons of biogenic CO₂ emissions (if applicable). (9) For a unit that uses Tier 4: <ol style="list-style-type: none"> (i) If the total annual CO₂ mass emissions measured by the CEMS consists entirely of non-biogenic CO₂ (<i>i.e.</i>, CO₂ from fossil fuel combustion plus, if applicable, CO₂ from sorbent and/or process CO₂), report the total annual CO₂ mass emissions, expressed in metric tons. You are not required to report the combustion CO₂ emissions by fuel type. (ii) Report the total annual CO₂ mass emissions measured by the CEMS. If this total includes both biogenic and non-biogenic CO₂, separately report the annual non-

biogenic CO₂ mass emissions and the annual CO₂ mass emissions from biomass combustion, each expressed in metric tons. You are not required to report the combustion CO₂ emissions by fuel type.

(iii) An estimate of the heat input from each type of fuel listed in Table C-2 of this subpart that was combusted in the unit during the report year.

(iv) The annual CH₄ and N₂O emissions for each type of fuel listed in Table C-2 of this subpart that was combusted in the unit during the report year, expressed in metric tons of each gas and in metric tons of CO₂e.

(10) Annual CO₂ emissions from sorbent (if calculated using Equation C-11 of this subpart), expressed in metric tons.

(11) If applicable, the plant code (as defined in §98.6).

(c) *Reporting alternatives for units using the four Tiers.* You may use any of the applicable reporting alternatives of this paragraph to simplify the unit-level reporting required under paragraph (b) of this section:

(1) *Aggregation of units.* If a facility contains two or more units (e.g., boilers or combustion turbines), each of which has a maximum rated heat input capacity of 250 mmBtu/hr or less, you may report the combined GHG emissions for the group of units in lieu of reporting GHG emissions from the individual units, provided that the use of Tier 4 is not required or elected for any of the units and the units use the same tier for any common fuels combusted. If this option is selected, the following information shall be reported instead of the information in paragraph (b) of this section:

(i) Group ID number, beginning with the prefix "GP".

(ii)-(iii) [Reserved]

(iv) The highest maximum rated heat input capacity of any unit in the group (mmBtu/hr).

(v) Each type of fuel combusted in the group of units during the reporting year.

(vi) Annual CO₂ mass emissions and annual CH₄, and N₂O mass emissions, aggregated for each type of fuel combusted in the group of units during the report year, expressed in metric tons of each gas and in metric tons of CO₂e. If any of the units burn both fossil fuels and biomass, report also the annual CO₂ emissions from combustion of all fossil fuels combined and annual CO₂ emissions from combustion of all biomass fuels combined, expressed in metric tons.

(vii) The methodology (*i.e.*, tier) used to calculate the CO₂ mass emissions for each type of fuel combusted in the units (*i.e.*, Tier 1, Tier 2, or Tier 3).

(viii) The methodology start date, for each fuel type.

(ix) The methodology end date, for each fuel type.

(x) The calculated CO₂ mass emissions (if any) from sorbent expressed in metric tons.

(xi) If applicable, the plant code (as defined in §98.6).

(2) *Monitored common stack or duct configurations.* When the flue gases from two or more stationary fuel combustion units at a facility are combined together in a common stack or duct before exiting to the atmosphere and if CEMS are used to continuously monitor CO₂ mass emissions at the common stack or duct according to the Tier 4 Calculation Methodology, you may report the combined emissions from the units sharing the common stack or duct, in lieu of separately reporting the GHG emissions from the individual units. This monitoring and reporting alternative may also be used when process off-gases or a mixture of combustion products and process gases are combined together in a common stack or duct before exiting to the atmosphere. Whenever the common stack or duct monitoring option is applied, the following information shall be reported instead of the information in paragraph (b) of this section:

(i) Common stack or duct identification number, beginning with the prefix "CS".

(ii) Number of units sharing the common stack or duct. Report "1" when the flue gas flowing through the common stack or duct includes combustion products and/or process off-gases, and all of the effluent comes from a single unit (e.g., a furnace, kiln, petrochemical production unit, or smelter).

(iii) Combined maximum rated heat input capacity of the units sharing the common stack or duct (mmBtu/hr). This data element is required only when all of the units sharing the common stack are stationary fuel combustion units.

(iv) Each type of fuel combusted in the units during the year.

(v) The methodology (tier) used to calculate the CO₂ mass emissions, i.e., Tier 4.

(vi) The methodology start date.

(vii) The methodology end date.

(viii) Total annual CO₂ mass emissions measured by the CEMS, expressed in metric tons. If any of the units burn both fossil fuels and biomass, separately report the annual non-biogenic CO₂ mass emissions (i.e., CO₂ from fossil fuel combustion plus, if applicable, CO₂ from sorbent and/or process CO₂) and the annual CO₂ mass emissions from biomass combustion, each expressed in metric tons.

(ix) An estimate of the heat input from each type of fuel listed in Table C-2 of this subpart that was combusted in the units sharing the common stack or duct during the report year.

(x) For each type of fuel listed in Table C-2 of this subpart that was combusted during the report year in the units sharing the common stack or duct during the report year, the annual CH₄ and N₂O mass emissions from the units sharing the common stack or duct, expressed in metric tons of each gas and in metric tons of CO₂e.

(xi) If applicable, the plant code (as defined in §98.6).

(3) *Common pipe configurations.* When two or more stationary combustion units at a facility combust the same type of liquid or gaseous fuel and the fuel is fed to the individual units through a common supply line or pipe, you may report the combined emissions from the units served by the common supply line, in lieu of separately reporting the GHG emissions from the individual units, provided that the total amount of fuel combusted by the units is accurately measured at the common pipe or supply line

using a fuel flow meter, or, for natural gas, the amount of fuel combusted may be obtained from gas billing records. For Tier 3 applications, the flow meter shall be calibrated in accordance with §98.34(b). If a portion of the fuel measured (or obtained from gas billing records) at the main supply line is diverted to either: A flare; or another stationary fuel combustion unit (or units), including units that use a CO₂ mass emissions calculation method in part 75 of this chapter; or a chemical or industrial process (where it is used as a raw material but not combusted), and the remainder of the fuel is distributed to a group of combustion units for which you elect to use the common pipe reporting option, you may use company records to subtract out the diverted portion of the fuel from the fuel measured (or obtained from gas billing records) at the main supply line prior to performing the GHG emissions calculations for the group of units using the common pipe option. If the diverted portion of the fuel is combusted, the GHG emissions from the diverted portion shall be accounted for in accordance with the applicable provisions of this part. When the common pipe option is selected, the applicable tier shall be used based on the maximum rated heat input capacity of the largest unit served by the common pipe configuration, except where the applicable tier is based on criteria other than unit size. For example, if the maximum rated heat input capacity of the largest unit is greater than 250 mmBtu/hr, Tier 3 will apply, unless the fuel transported through the common pipe is natural gas or distillate oil, in which case Tier 2 may be used, in accordance with §98.33(b)(2)(ii). As a second example, in accordance with §98.33(b)(1)(v), Tier 1 may be used regardless of unit size when natural gas is transported through the common pipe, if the annual fuel consumption is obtained from gas billing records in units of therms or mmBtu. When the common pipe reporting option is selected, the following information shall be reported instead of the information in paragraph (b) of this section:

(i) Common pipe identification number, beginning with the prefix "CP".

(ii) [Reserved]

(iii) The highest maximum rated heat input capacity of any unit served by the common pipe (mmBtu/hr).

(iv) The fuels combusted in the units during the reporting year.

(v) The methodology used to calculate the CO₂ mass emissions (i.e., Tier 1, Tier 2, or Tier 3).

(vi) If the any of the units burns both fossil fuels and biomass, the annual CO₂ mass emissions from combustion of all fossil fuels and annual CO₂ emissions from combustion of all biomass fuels from the units served by the common pipe, expressed in metric tons.

(vii) Annual CO₂ mass emissions and annual CH₄ and N₂O emissions from each fuel type for the units served by the common pipe, expressed in metric tons of each gas and in metric tons of CO₂e.

(viii) Methodology start date.

(ix) Methodology end date.

(x) If applicable, the plant code (as defined in §98.6).

(4) The following alternative reporting option applies to facilities at which a common liquid or gaseous fuel supply is shared between one or more large combustion units, such as boilers or combustion turbines (including units subject to subpart D of this part and other units subject to part 75 of this chapter) and small combustion sources,

including, but not limited to, space heaters, hot water heaters, and lab burners. In this case, you may simplify reporting by attributing all of the GHG emissions from combustion of the shared fuel to the large combustion unit(s), provided that:

(i) The total quantity of the fuel combusted during the report year in the units sharing the fuel supply is measured, either at the "gate" to the facility or at a point inside the facility, using a fuel flow meter, billing meter, or tank drop measurements (as applicable);

(ii) On an annual basis, at least 95 percent (by mass or volume) of the shared fuel is combusted in the large combustion unit(s), and the remainder is combusted in the small combustion sources. Company records may be used to determine the percentage distribution of the shared fuel to the large and small units; and

(iii) The use of this reporting option is documented in the Monitoring Plan required under §98.3(g)(5). Indicate in the Monitoring Plan which units share the common fuel supply and the method used to demonstrate that this alternative reporting option applies. For the small combustion sources, a description of the types of units and the approximate number of units is sufficient.

(d) *Units subject to part 75 of this chapter.* (1) For stationary combustion units that are subject to subpart D of this part, you shall report the following unit-level information:

(i) Unit or stack identification numbers. Use exact same unit, common stack, common pipe, or multiple stack identification numbers that represent the monitored locations (*e.g.*, 1, 2, CS001, MS1A, CP001, *etc.*) that are reported under §75.64 of this chapter.

(ii) Annual CO₂ emissions at each monitored location, expressed in both short tons and metric tons. Separate reporting of biogenic CO₂ emissions under §98.3(c)(4)(ii) and §98.3(c)(4)(iii)(A) is optional only for the 2010 reporting year, as provided in §98.3(c)(12).

(iii) Annual CH₄ and N₂O emissions at each monitored location, for each fuel type listed in Table C-2 that was combusted during the year (except as otherwise provided in §98.33(c)(4)(ii)(B)), expressed in metric tons of CO₂e.

(iv) The total heat input from each fuel listed in Table C-2 that was combusted during the year (except as otherwise provided in §98.33(c)(4)(ii)(B)), expressed in mmBtu.

(v) Identification of the Part 75 methodology used to determine the CO₂ mass emissions.

(vi) Methodology start date.

(vii) Methodology end date.

(viii) Acid Rain Program indicator.

(ix) Annual CO₂ mass emissions from the combustion of biomass, expressed in metric tons of CO₂e, except where the reporting provisions of §§98.3(c)(12)(i) through (c)(12)(iii) are implemented for the 2010 reporting year.

(x) If applicable, the plant code (as defined in §98.6).

(2) For units that use the alternative CO₂ mass emissions calculation methods provided in §98.33(a)(5), you shall report the following unit-level information:

(i) Unit, stack, or pipe ID numbers. Use exact same unit, common stack, common pipe, or multiple stack identification numbers that represent the monitored locations (e.g., 1, 2, CS001, MS1A, CP001, etc.) that are reported under §75.64 of this chapter.

(ii) For units that use the alternative methods specified in §98.33(a)(5)(i) and (ii) to monitor and report heat input data year-round according to appendix D to part 75 of this chapter or §75.19 of this chapter:

(A) Each type of fuel combusted in the unit during the reporting year.

(B) The methodology used to calculate the CO₂ mass emissions for each fuel type.

(C) Methodology start date.

(D) Methodology end date.

(E) A code or flag to indicate whether heat input is calculated according to appendix D to part 75 of this chapter or §75.19 of this chapter.

(F) Annual CO₂ emissions at each monitored location, across all fuel types, expressed in metric tons of CO₂e.

(G) Annual heat input from each type of fuel listed in Table C-2 of this subpart that was combusted during the reporting year, expressed in mmBtu.

(H) Annual CH₄ and N₂O emissions at each monitored location, from each fuel type listed in Table C-2 of this subpart that was combusted during the reporting year (except as otherwise provided in §98.33(c)(4)(ii)(D)), expressed in metric tons CO₂e.

(I) Annual CO₂ mass emissions from the combustion of biomass, expressed in metric tons CO₂e, except where the reporting provisions of §§98.3(c)(12)(i) through (c)(12)(iii) are implemented for the 2010 reporting year.

(J) If applicable, the plant code (as defined in §98.6).

(iii) For units with continuous monitoring systems that use the alternative method for units with continuous monitoring systems in §98.33(a)(5)(iii) to monitor heat input year-round according to part 75 of this chapter:

(A) Each type of fuel combusted during the reporting year.

(B) Methodology used to calculate the CO₂ mass emissions.

(C) Methodology start date.

(D) Methodology end date.

(E) A code or flag to indicate that the heat input data is derived from CEMS measurements.

(F) The total annual CO₂ emissions at each monitored location, expressed in

metric tons of CO₂e.

(G) Annual heat input from each type of fuel listed in Table C-2 of this subpart that was combusted during the reporting year, expressed in mmBtu.

(H) Annual CH₄ and N₂O emissions at each monitored location, from each fuel type listed in Table C-2 of this subpart that was combusted during the reporting year (except as otherwise provided in §98.33(c)(4)(ii)(B)), expressed in metric tons CO₂e.

(I) Annual CO₂ mass emissions from the combustion of biomass, expressed in metric tons CO₂e, except where the reporting provisions of §§98.3(c)(12)(i) through (c)(12)(iii) are implemented for the 2010 reporting year.

(J) If applicable, the plant code (as defined in §98.6).

(e) *Verification data.* You must keep on file, in a format suitable for inspection and auditing, sufficient data to verify the reported GHG emissions. This data and information must, where indicated in this paragraph (e), be included in the annual GHG emissions report.

(1) The applicable verification data specified in this paragraph (e) are not required to be kept on file or reported for units that meet any one of the three following conditions:

(i) Are subject to the Acid Rain Program.

(ii) Use the alternative methods for units with continuous monitoring systems provided in §98.33(a)(5).

(iii) Are not in the Acid Rain Program, but are required to monitor and report CO₂ mass emissions and heat input data year-round, in accordance with part 75 of this chapter.

(2) For stationary combustion sources using the Tier 1, Tier 2, Tier 3, and Tier 4 Calculation Methodologies in §98.33(a) to quantify CO₂ emissions, the following additional information shall be kept on file and included in the GHG emissions report, where indicated:

(i) For the Tier 1 Calculation Methodology, report the total quantity of each type of fuel combusted in the unit or group of aggregated units (as applicable) during the reporting year, in short tons for solid fuels, gallons for liquid fuels and standard cubic feet for gaseous fuels, or, if applicable, therms or mmBtu for natural gas.

(ii) For the Tier 2 Calculation Methodology, report:

(A) The total quantity of each type of fuel combusted in the unit or group of aggregated units (as applicable) during each month of the reporting year. Express the quantity of each fuel combusted during the measurement period in short tons for solid fuels, gallons for liquid fuels, and scf for gaseous fuels.

(B) The frequency of the HHV determinations (e.g., once a month, once per fuel lot).

(C) The high heat values used in the CO₂ emissions calculations for each type of fuel combusted during the reporting year, in mmBtu per short ton for solid fuels, mmBtu per gallon for liquid fuels, and mmBtu per scf for gaseous fuels. Report a HHV value for

each calendar month in which HHV determination is required. If multiple values are obtained in a given month, report the arithmetic average value for the month.

(D) If Equation C-2c of this subpart is used to calculate CO₂ mass emissions, report the total quantity (*i.e.*, pounds) of steam produced from MSW or solid fuel combustion during each month of the reporting year, and the ratio of the maximum rate heat input capacity to the design rated steam output capacity of the unit, in mmBtu per lb of steam.

(E) For each HHV used in the CO₂ emissions calculations for each type of fuel combusted during the reporting year, indicate whether the HHV is a measured value or a substitute data value.

(iii) For the Tier 2 Calculation Methodology, keep records of the methods used to determine the HHV for each type of fuel combusted and the date on which each fuel sample was taken, except where fuel sampling data are received from the fuel supplier. In that case, keep records of the dates on which the results of the fuel analyses for HHV are received.

(iv) For the Tier 3 Calculation Methodology, report:

(A) The quantity of each type of fuel combusted in the unit or group of units (as applicable) during each month of the reporting year, in short tons for solid fuels, gallons for liquid fuels, and scf for gaseous fuels.

(B) The frequency of carbon content and, if applicable, molecular weight determinations for each type of fuel for the reporting year (e.g., daily, weekly, monthly, semiannually, once per fuel lot).

(C) The carbon content and, if applicable, gas molecular weight values used in the emission calculations (including both valid and substitute data values). For each calendar month of the reporting year in which carbon content and, if applicable, molecular weight determination is required, report a value of each parameter. If multiple values of a parameter are obtained in a given month, report the arithmetic average value for the month. Express carbon content as a decimal fraction for solid fuels, kg C per gallon for liquid fuels, and kg C per kg of fuel for gaseous fuels. Express the gas molecular weights in units of kg per kg-mole.

(D) The total number of valid carbon content determinations and, if applicable, molecular weight determinations made during the reporting year, for each fuel type.

(E) The number of substitute data values used for carbon content and, if applicable, molecular weight used in the annual GHG emissions calculations.

(F) The annual average HHV, when measured HHV data, rather than a default HHV from Table C-1 of this subpart, are used to calculate CH₄ and N₂O emissions for a Tier 3 unit, in accordance with §98.33(c)(1).

(G) The value of the molar volume constant (MVC) used in Equation C-5 (if applicable).

(v) For the Tier 3 Calculation Methodology, keep records of the following:

(A) For liquid and gaseous fuel combustion, the dates and results of the initial calibrations and periodic recalibrations of the required fuel flow meters.

(B) For fuel oil combustion, the method from §98.34(b) used to make tank drop measurements (if applicable).

(C) The methods used to determine the carbon content and (if applicable) the molecular weight of each type of fuel combusted.

(D) The methods used to calibrate the fuel flow meters).

(E) The date on which each fuel sample was taken, except where fuel sampling data are received from the fuel supplier. In that case, keep records of the dates on which the results of the fuel analyses for carbon content and (if applicable) molecular weight are received.

(vi) For the Tier 4 Calculation Methodology, report:

(A) The total number of source operating hours in the reporting year.

(B) The cumulative CO₂ mass emissions in each quarter of the reporting year, i.e., the sum of the hourly values calculated from Equation C-6 or C-7 of this subpart (as applicable), in metric tons.

(C) For CO₂ concentration, stack gas flow rate, and (if applicable) stack gas moisture content, the percentage of source operating hours in which a substitute data value of each parameter was used in the emissions calculations.

(vii) For the Tier 4 Calculation Methodology, keep records of:

(A) Whether the CEMS certification and quality assurance procedures of part 75 of this chapter, part 60 of this chapter, or an applicable State continuous monitoring program were used.

(B) The dates and results of the initial certification tests of the CEMS.

(C) The dates and results of the major quality assurance tests performed on the CEMS during the reporting year, i.e., linearity checks, cylinder gas audits, and relative accuracy test audits (RATAs).

(viii) If CO₂ emissions that are generated from acid gas scrubbing with sorbent injection are not captured using CEMS, report:

(A) The total amount of sorbent used during the report year, in short tons.

(B) The molecular weight of the sorbent.

(C) The ratio ("R") in Equation C-11 of this subpart.

(ix) For units that combust both fossil fuel and biomass, when biogenic CO₂ is determined according to §98.33(e)(2), you shall report the following additional information, as applicable:

(A) The annual volume of CO₂ emitted from the combustion of all fuels, i.e., V_{total} , in scf.

(B) The annual volume of CO₂ emitted from the combustion of fossil fuels, i.e., V_{ff} ,

in scf. If more than one type of fossil fuel was combusted, report the combustion volume of CO₂ for each fuel separately as well as the total.

(C) The annual volume of CO₂ emitted from the combustion of biomass, *i.e.*, V_{bio} , in scf.

(D) The carbon-based F-factor used in Equation C-13 of this subpart, for each type of fossil fuel combusted, in scf CO₂ per mmBtu.

(E) The annual average HHV value used in Equation C-13 of this subpart, for each type of fossil fuel combusted, in Btu/lb, Btu/gal, or Btu/scf, as appropriate.

(F) The total quantity of each type of fossil fuel combusted during the reporting year, in lb, gallons, or scf, as appropriate.

(G) Annual biogenic CO₂ mass emissions, in metric tons.

(x) When ASTM methods D7459-08 (incorporated by reference, see §98.7) and D6866-08 (incorporated by reference, see §98.7) are used to determine the biogenic portion of the annual CO₂ emissions from MSW combustion, as described in §98.34(d), report:

(A) The results of each quarterly sample analysis, expressed as a decimal fraction (e.g., if the biogenic fraction of the CO₂ emissions from MSW combustion is 30 percent, report 0.30).

(B) The annual biogenic CO₂ mass emissions from MSW combustion, in metric tons.

(xi) When ASTM methods D7459-08 (incorporated by reference, see §98.7) and D6866-08 (incorporated by reference, see §98.7) are used in accordance with §98.34(e) to determine the biogenic portion of the annual CO₂ emissions from a unit that co-fires biogenic fuels (or partly-biogenic fuels, including tires if you are electing to report biogenic CO₂ emissions from tire combustion) and non-biogenic fuels, you shall report the results of each quarterly sample analysis, expressed as a decimal fraction (e.g., if the biogenic fraction of the CO₂ emissions is 30 percent, report 0.30).

(3) Within 30 days of receipt of a written request from the Administrator, you shall submit explanations of the following:

(i) An explanation of how company records are used to quantify fuel consumption, if the Tier 1 or Tier 2 Calculation Methodology is used to calculate CO₂ emissions.

(ii) An explanation of how company records are used to quantify fuel consumption, if solid fuel is combusted and the Tier 3 Calculation Methodology is used to calculate CO₂ emissions.

(iii) An explanation of how sorbent usage is quantified.

(iv) An explanation of how company records are used to quantify fossil fuel consumption in units that uses CEMS to quantify CO₂ emissions and combusts both fossil fuel and biomass.

(v) An explanation of how company records are used to measure steam production, when it is used to calculate CO₂ mass emissions under §98.33(a)(2)(iii) or to

		<p>quantify solid fuel usage under §98.33(c)(3).</p> <p>(4) Within 30 days of receipt of a written request from the Administrator, you shall submit the verification data and information described in paragraphs (e)(2)(iii), (e)(2)(v), and (e)(2)(vii) of this section.</p> <p>(f) Each stationary fuel combustion source (e.g., individual unit, aggregation of units, common pipe, or common stack) subject to reporting under paragraph (b) or (c) of this section must indicate if both of the following two conditions are met:</p> <p>(1) The stationary fuel combustion source contains at least one combustion unit connected to a fuel-fired electric generator owned or operated by an entity that is subject to regulation of customer billing rates by the public utility commission (excluding generators that are connected to combustion units that are subject to subpart D of this part).</p> <p>(2) The stationary fuel combustion source is located at a facility for which the sum of the nameplate capacities for all electric generators specified in paragraph (f)(1) of this section is greater than or equal to 1 megawatt electric output.</p>
D—Electricity Generation (§98.46)	All In	The annual report shall comply with the data reporting requirements specified in §98.36(d)(1).
E—Adipic Acid Production (§98.56)	All In	<p>In addition to the information required by §98.3(c), each annual report must contain the information specified in paragraphs (a) through (n) of this section at the facility level.</p> <p>(a) Annual process N₂O emissions from adipic acid production (metric tons).</p> <p>(b)-(c) [Reserved]</p> <p>(d) Annual process N₂O emissions from adipic acid production facility that is sold or transferred off site (metric tons).</p> <p>(e) Number of abatement technologies (if applicable).</p> <p>(f) Types of abatement technologies used (if applicable).</p> <p>(g) Abatement technology destruction efficiency for each abatement technology (percent destruction).</p> <p>(h) Abatement utilization factor for each abatement technology (fraction of annual production that abatement technology is operating).</p> <p>(i) Number of times in the reporting year that missing data procedures were followed to measure adipic acid production (months).</p> <p>(j) If you conducted a performance test and calculated a site-specific emissions factor according to §98.53(a)(1), each annual report must also contain the information specified in paragraphs (j)(1) through (7) of this section for each adipic acid production unit.</p> <p>(1) [Reserved]</p> <p>(2) Test method used for performance test.</p>

		<p>(3) [Reserved]</p> <p>(4) N₂O concentration per test run during performance test (ppm N₂O).</p> <p>(5) Volumetric flow rate per test run during performance test (dscf/hr).</p> <p>(6) Number of test runs.</p> <p>(7) Number of times in the reporting year that a performance test had to be repeated (number).</p> <p>(k) If you requested Administrator approval for an alternative method of determining N₂O emissions under §98.53(a)(2), each annual report must also contain the information specified in paragraphs (k)(1) through (4) of this section for each adipic acid production facility.</p> <p>(1) Name of alternative method.</p> <p>(2) Description of alternative method.</p> <p>(3) Request date.</p> <p>(4) Approval date.</p> <p>(l) Fraction control factor for each abatement technology (percent of total emissions from the production unit that are sent to the abatement technology) if equation E-3c is used.</p> <p>(m) If only cyclohexane is oxidized to produce adipic acid and the quantity is known, report the information specified in paragraph (m)(1) of this section. If materials other than cyclohexane are oxidized to produce adipic acid, report the information specified in paragraph (m)(2) of this section.</p> <p>(1) Annual quantity of cyclohexane (tons) used to produce adipic acid.</p> <p>(2) Annual quantity of cyclohexanone and cyclohexanol mixture (tons) used to produce adipic acid.</p> <p>(n) Annual percent N₂O emission reduction for all production units combined.</p>
<p>F—Aluminum Production (§98.66)</p>	<p>All In</p>	<p>In addition to the information required by §98.3(c), you must report the following information at the facility level:</p> <p>(a) [Reserved]</p> <p>(b) Type of smelter technology used.</p> <p>(c) The following PFC-specific information on an annual basis:</p> <p>(1) Perfluoromethane emissions and perfluoroethane emissions from anode effects in all prebake and all Søderberg electrolysis cells combined.</p>

		<p>(2) [Reserved]</p> <p>(3) The last date when the smelter-specific-slope coefficients (or overvoltage emission factors) were measured.</p> <p>(d) Method used to measure the frequency and duration of anode effects (or overvoltage).</p> <p>(e) The following CO₂-specific information for prebake cells:</p> <p>(1) Annual anode consumption if using the method in §98.63(g).</p> <p>(2) Annual CO₂ emissions from the smelter.</p> <p>(f) The following CO₂-specific information for Söderberg cells:</p> <p>(1) Annual paste consumption if using the method in §98.63(g).</p> <p>(2) Annual CO₂ emissions from the smelter.</p> <p>(g) [Reserved]</p> <p>(h) Exact data elements required will vary depending on smelter technology (e.g., point-feed prebake or Söderberg) and process control technology (e.g., Pechiney or other).</p>
<p>G—Ammonia Manufacturing (§98.76)</p>	<p>All In</p>	<p>In addition to the information required by §98.3(c), each annual report must contain the information specified in paragraphs (a) and (b) of this section, as applicable for each ammonia manufacturing process unit.</p> <p>(a) If a CEMS is used to measure CO₂ emissions, then you must report the relevant information required under §98.36 for the Tier 4 Calculation Methodology and the information in paragraphs (a)(1) and (2) of this section:</p> <p>(1) Annual quantity of each type of feedstock consumed for ammonia manufacturing (scf of feedstock or gallons of feedstock or kg of feedstock).</p> <p>(2) Method used for determining quantity of feedstock used.</p> <p>(b) If a CEMS is not used to measure emissions, then you must report all of the following information in this paragraph (b):</p> <p>(1) Annual CO₂ process emissions (metric tons) for each ammonia manufacturing process unit.</p> <p>(2) [Reserved]</p> <p>(3) Method used for determining quantity of monthly feedstock used.</p> <p>(4) Whether carbon content for each feedstock for month n is based on reports from the supplier or analysis of carbon content.</p> <p>(5) If carbon content of feedstock for month n is based on analysis, the test method used.</p>

		<p>(6) Sampling analysis results of carbon content of feedstock as determined for QA/QC of supplier data under §98.74(e).</p> <p>(7)-(11) [Reserved]</p> <p>(12) Annual urea production (metric tons) and method used to determine urea production.</p> <p>(13) Annual CO₂ emissions (metric tons) from the steam reforming of a hydrocarbon or the gasification of solid and liquid raw material at the ammonia manufacturing process unit used to produce urea and the method used to determine the CO₂ consumed in urea production.</p> <p>(14) Annual ammonia production (metric tons, sum of all process units reported within subpart G).</p> <p>(15) Annual methanol production for each process unit (metric tons).</p>
H—Cement Production (§98.86)	All In	<p>In addition to the information required by §98.3(c), each annual report must contain the information specified in paragraphs (a) and (b) of this section, as appropriate.</p> <p>(a) If a CEMS is used to measure CO₂ emissions, then you must report under this subpart the relevant information required by §98.36(e)(2)(vi) and the information listed in this paragraph(a):</p> <ol style="list-style-type: none"> (1) Monthly clinker production from each kiln at the facility. (2) Annual facility cement production. (3) Number of kilns and number of operating kilns. <p>(b) If a CEMS is not used to measure CO₂ emissions, then you must report the information listed in this paragraph (b) for each kiln:</p> <ol style="list-style-type: none"> (1) Kiln identification number. (2) [Reserved] (3) Annual cement production at the facility. (4) Number of kilns and number of operating kilns. (5)-(6) [Reserved] (7) Method used to determine non-calcined CaO and non-calcined MgO in clinker. (8) [Reserved] (9) Method used to determine non-calcined CaO and non-calcined MgO in CKD. (10) [Reserved] (11) Quarterly kiln-specific CKD CO₂ emission factors for each kiln (metric tons CO₂/metric ton CKD produced). (12) [Reserved] (13) Name of raw kiln feed or raw material. (14) Number of times missing data procedures were used to determine the following information: <ol style="list-style-type: none"> (i) Clinker production (number of months). (ii) Carbonate contents of clinker (number of months). (iii) Non-calcined content of clinker (number of months). (iv) CKD not recycled to kiln (number of quarters). (v) Non-calcined content of CKD (number of quarters) (vi) Organic carbon contents of raw materials (number of times). (vii) Raw material consumption (number of months). (15) Method used to determine the monthly clinker production from each kiln. (16) Annual clinker production (metric tons). (17) Annual average clinker CO₂ emission factor for the facility, averaged across all kilns (metric tons CO₂/metric ton clinker produced). (18) Annual average CKD CO₂ emission factor for the facility, averaged across all kilns (metric tons CO₂/metric ton CKD produced).
I—Electronics Manufacturing	25,000 metric tons	In addition to the information required by §98.3(c), you must include in each annual

(§98.96)	CO ₂ e/year	<p>report the following information for each electronics manufacturing facility:</p> <p>(a) Annual manufacturing capacity of each fab at your facility used to determine the annual manufacturing capacity of your facility in Equation I-5 of this subpart.</p> <p>(b) For facilities that manufacture semiconductors, the diameter of wafers manufactured at each fab at your facility (mm).</p> <p>(c) Annual emissions, on a fab basis as described in paragraph (c)(1) through (5) of this section.</p> <p>(1) When you use the procedures specified in §98.93(a) of this subpart, each fluorinated GHG emitted from each process type for which your fab is required to calculate emissions as calculated in Equations I-6 and I-7 of this subpart.</p> <p>(2) Each fluorinated GHG emitted from each process type or process sub-type as calculated in Equations I-8 and I-9 of this subpart, as applicable.</p> <p>(3) N₂O emitted from all chemical vapor deposition processes and N₂O emitted from the aggregate of other N₂O-using manufacturing processes as calculated in Equation I-10 of this subpart.</p> <p>(4) Each fluorinated heat transfer fluid emitted as calculated in Equation 1-16 of this subpart.</p> <p>(5) When you use the procedures specified in §98.93(i) of this subpart, annual emissions of each fluorinated GHG, on a fab basis.</p> <p>(d) The method of emissions calculation used in §98.93.</p> <p>(e) Annual production in terms of substrate surface area (e.g., silicon, PV-cell, glass).</p> <p>(f)-(l) [Reserved]</p> <p>(m) For the fab-specific apportioning model used to apportion fluorinated GHG and N₂O consumption under §98.94(c), the following information to determine it is verified in accordance with procedures in §98.94(c)(1) and (2):</p> <p>(1) Identification of the quantifiable metric used in your fab-specific engineering model to apportion gas consumption for each fab, and/or an indication if direct measurements were used in addition to, or instead of, a quantifiable metric.</p> <p>(2) The start and end dates selected under §98.94(c)(2)(i).</p> <p>(3) Certification that the gas(es) you selected under §98.94(c)(2)(ii) for each fab corresponds to the largest quantity(ies) consumed, on a mass basis, of fluorinated GHG used at your fab during the reporting year for which you are required to apportion.</p> <p>(4) The result of the calculation comparing the actual and modeled gas consumption under §98.94(c)(2)(iii) and (iv), as applicable.</p> <p>(5) If you are required to apportion fluorinated GHG consumption between fabs as required by §98.94(c)(2)(v), certification that the gas(es) you selected under §98.94(c)(2)(ii) corresponds to the largest quantity(ies) consumed on a mass basis, of fluorinated GHG used at your facility during the reporting year for which you are required to</p>
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		<p>apportion.</p> <p>(n)-(o) [Reserved]</p> <p>(p) Inventory and description of all abatement systems through which fluorinated GHGs or N₂O flow at your facility and for which you are claiming destruction or removal efficiency, including:</p> <p>(1) The number of abatement systems controlling emissions for each process sub-type, or process type, as applicable, for each gas used in the process sub-type or process type.</p> <p>(2) The basis of the destruction or removal efficiency being used (default or site specific measurement according to §98.94(f)(4)(i)) for each process sub-type or process type and for each gas.</p> <p>(q) For all abatement systems through which fluorinated GHGs or N₂O flow at your facility, for which you are reporting controlled emissions, the following:</p> <p>(1) Certification that all abatement systems at the facility have been installed, maintained, and operated in accordance with the site maintenance plan for abatement systems that is developed and maintained in your records as specified in §98.97(d)(9).</p> <p>(2) If you use default destruction or removal efficiency values in your emissions calculations under §98.93(a), (b), or (i), certification that the site maintenance plan for abatement systems for which emissions are being reported contains manufacturer's recommendations and specifications for installation, operation, and maintenance for each abatement system.</p> <p>(3) If you use default destruction or removal efficiency values in your emissions calculations under §98.93(a), (b), and/or (i), certification that the abatement systems for which emissions are being reported were specifically designed for fluorinated GHG or N₂O abatement, as applicable. You must support this certification by providing abatement system supplier documentation stating that the system was designed for fluorinated GHG or N₂O abatement, as applicable.</p> <p>(4) For all stack systems for which you calculate fluorinated GHG emissions according to the procedures specified in §98.93(i)(3), certification that you have included and accounted for all abatement systems and any respective downtime in your emissions calculations under §98.93(i)(3).</p> <p>(r) You must report an effective fab-wide destruction or removal efficiency value for each fab at your facility calculated using Equation I-26, I-27, and I-28 of this subpart, as appropriate.</p> <p>(1) Use Equation I-27 of this subpart to calculate total unabated emissions, in metric tons CO₂e, of all fluorinated GHG emitted from electronics manufacturing processes whose emissions of fluorinated GHG you calculated according to the default utilization and by-product formation rate procedures in §98.93(a) or §98.93(i)(4). For each fluorinated GHG i in process j, use the same consumption (C_{ij}), emission factors ($1-U_{ij}$), and by-product formation rates (B_{ijk}) to calculate unabated emissions as you used to calculate emissions in §98.93(a) or §98.93(i)(4).</p> <p>(2) Use Equation I-28 to calculate total unabated emissions, in metric ton CO₂e, of all fluorinated GHG emitted from electronics manufacturing processes whose emissions of fluorinated GHG you calculated according to the stack testing procedures in §98.93(i)(3).</p>
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		<p>tested platforms.</p> <p>(iii) It must describe the status of implementing 450 mm wafer technology and the potential need to create or update default emission factors compared to 300 mm technology.</p> <p>(iv) It must provide any utilization and by-product formation rates and/or destruction or removal efficiency data that have been collected in the previous 3 years that support the changes in semiconductor manufacturing processes described in the report.</p> <p>(v) It must describe the use of a new gas, use of an existing gas in a new process type or sub-type, or a fundamental change in process technology.</p> <p>(3) If, on the basis of the information reported in paragraph (y)(2) of this section, the report indicates that GHG emissions from semiconductor manufacturing may have changed from those represented by the default utilization and by-product formation rates in Tables I-3 or I-4, or the default destruction or removal efficiency values in Table I-16 of this subpart, the report must lay out a data gathering and analysis plan focused on the areas of potential change. The plan must describe the elements in paragraphs (y)(3)(i) and (ii).</p> <p>(i) The testing of tools to determine the potential effect on current utilization and by-product formation rates and destruction or removal efficiency values under the new conditions.</p> <p>(ii) A planned analysis of the effect on overall facility emissions using a representative gas-use profile for a 200 mm, 300 mm, or 450 mm fab (depending on which technology is under consideration).</p> <p>(4) Multiple semiconductor manufacturing facilities may submit a single consolidated 3-year report as long as the facility identifying information in §98.3(c)(1) and the certification statement in §98.3(c)(9) is provided for each facility for which the consolidated report is submitted.</p> <p>(5) The Administrator will review the report received and determine whether it is necessary to update the default utilization rates and by-product formation rates in Tables I-3, I-4, I-11, and I-12 of this subpart and default destruction or removal efficiency values in Table I-16 of this subpart based on the following:</p> <p>(i) Whether the revised default utilization and by-product formation rates and destruction or removal efficiency values will result in a projected shift in emissions of 10 percent or greater.</p> <p>(ii) Whether new platforms, processes, or facilities that are not captured in current default utilization and by-product formation rates and destruction or removal efficiency values should be included in revised values.</p> <p>(iii) Whether new data are available that could expand the existing data set to include new gases, tools, or processes not included in the existing data set (i.e. gases, tools, or processes for which no data are currently available).</p> <p>(6) The Administrator will review the reports within 120 days and will notify you of a determination whether it is necessary to update any default utilization and by-product formation rates and/or destruction or removal efficiency values. If the Administrator determines it is necessary to update default utilization and by-product formation rates and/or destruction or removal efficiency values, you will then have 180 days from the</p>
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		<p>date you receive notice of the determination to execute the data collection and analysis plan described in the report and submit those data to the Administrator.</p>
<p>Subpart K – Ferroalloy production (§98.116)</p>	<p>25,000 metric tons CO₂e/year</p>	<p>In addition to the information required by §98.3(c), each annual report must contain the information specified in paragraphs (a) through (e) of this section, as applicable:</p> <p>(a) Annual facility ferroalloy product production capacity (tons).</p> <p>(b) If a CEMS is used to measure CO₂ emissions, report the annual production for each ferroalloy product identified in §98.110, from each EAF (tons).</p> <p>(c) Total number of EAFs at facility used for production of ferroalloy products.</p> <p>(d) If a CEMS is used to measure CO₂ emissions, then you must report under this subpart the relevant information required by §98.36 for the Tier 4 Calculation Methodology and the following information specified in paragraphs (d)(1) through (d)(3) of this section.</p> <p>(1) Annual process CO₂ emissions (in metric tons) from each EAF used for the production of any ferroalloy product identified in §98.110.</p> <p>(2) Annual process CH₄ emissions (in metric tons) from each EAF used for the production of any ferroalloy listed in Table K-1 of this subpart (metric tons).</p> <p>(3) Identification number of each EAF.</p> <p>(e) If a CEMS is not used to measure CO₂ process emissions, and the carbon mass balance procedure is used to determine CO₂ emissions according to the requirements in §98.113(b), then you must report the following information specified in paragraphs (e)(1) through (e)(7) of this section.</p> <p>(1) Annual process CO₂ emissions (in metric tons) from each EAF used for the production of any ferroalloy identified in §98.110 (metric tons).</p> <p>(2) Annual process CH₄ emissions (in metric tons) from each EAF used for the production of any ferroalloy listed in Table K-1 of this subpart.</p> <p>(3) Identification number for each material.</p> <p>(4)-(5) [Reserved]</p> <p>(6) List the method used for the determination of carbon content for each material included for the calculation of annual process CO₂ emissions for each EAF (e.g., supplier provided information, analyses of representative samples you collected).</p> <p>(7) If you use the missing data procedures in §98.115(b), you must report how monthly mass of carbon-containing inputs and outputs with missing data was determined and the number of months the missing data procedures were used.</p>
<p>Subpart L – Fluorinated Gas</p>	<p>25,000 metric tons CO₂e/year</p>	<p>(a) <i>All facilities.</i> In addition to the information required by §98.3(c), you must report the information in paragraphs (a)(2) through (6) of this section according to the schedule in paragraph (a)(1) of this section, except as otherwise provided in paragraph (j) of this</p>

<p>Production (§98.126)</p>	<p>section or in §98.3(c)(4)(vii) and Table A-7 of subpart A of this part.</p> <p>(1) <i>Frequency of reporting under paragraph (a) of this section.</i> The information in paragraphs (a)(2) through (6) of this section must be reported annually.</p> <p>(2) <i>Generically-identified process.</i> For each production and transformation process at the facility, you must:</p> <p>(i) Provide a number, letter, or other identifier for the process. This identifier must be consistent from year to year.</p> <p>(ii) Indicate whether the process is a fluorinated gas production process, a fluorinated gas transformation process where no fluorinated GHG reactant is produced at another facility, or a fluorinated gas transformation process where one or more fluorinated GHG reactants are produced at another facility.</p> <p>(iii) Indicate whether the process could be characterized as reaction, distillation, or packaging (include all that apply).</p> <p>(iv) For each generically-identified process and each fluorinated GHG group, report the method(s) used to determine the mass emissions of that fluorinated GHG group from that process from vents (<i>i.e.</i>, mass balance (for reporting years 2011, 2012, 2013, and 2014 only), process-vent-specific emission factor, or process-vent-specific emission calculation factor).</p> <p>(v) For each generically-identified process and each fluorinated GHG group, report the method(s) used to determine the mass emissions of that fluorinated GHG group from that process from equipment leaks, unless you used the mass balance method (for reporting years 2011, 2012, 2013, and 2014 only) for that process.</p> <p>(3) <i>Emissions from production and transformation processes, process level, multiple products.</i> If your facility produces more than one fluorinated gas product, for each generically-identified process and each fluorinated GHG group, you must report the total GWP-weighted emissions of all fluorinated GHGs in that group from the process, in metric tons CO₂e.</p> <p>(4) <i>Emissions from production and transformation processes, facility level, multiple products.</i> If your facility produces more than one fluorinated gas product, you must report the information in paragraphs (a)(4)(i) and (ii) of this section, as applicable, for emissions from production and transformation processes.</p> <p>(i) For each fluorinated GHG with emissions of 1,000 metric tons of CO₂e or more from production and transformation processes, summed across the facility as a whole, you must report the total mass in metric tons of the fluorinated GHG emitted from production and transformation processes, summed across the facility as a whole. If the fluorinated GHG does not have a chemical-specific GWP in Table A-1 of subpart A, identify the fluorinated GHG group of which that fluorinated GHG is a member.</p> <p>(ii) For all other fluorinated GHGs emitted from production and transformation processes, you must report the total GWP-weighted emissions from production and transformation processes of those fluorinated GHGs by fluorinated GHG group, summed across the facility as a whole, in metric tons of CO₂e.</p> <p>(5) <i>Emissions from production and transformation processes, facility level, one product only.</i> If your facility produces only one fluorinated gas product, aggregate and report the total GWP-weighted emissions from production and transformation processes of fluorinated GHGs by fluorinated GHG group for the facility as a whole, in metric tons of CO₂e, with the following exception: Where emissions consist of a major fluorinated</p>
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GHG constituent of a fluorinated gas product, and the product is sold or transferred to another person, report the total mass in metric tons of each fluorinated GHG that is emitted from production and transformation processes and that is a major fluorinated GHG constituent of the product. If the fluorinated GHG does not have a chemical-specific GWP in Table A-1 of subpart A, identify the fluorinated GHG group of which that fluorinated GHG is a member.

(6) *Effective destruction efficiency.* For each generically-identified process, use Table L-1 of this subpart to report the range that encompasses the effective destruction efficiency, $DE_{\text{effective}}$, calculated for that process using Equation L-35 of this subpart. The effective destruction efficiency must be reported on a CO_2e basis.

(b) *Reporting for mass balance method for reporting years 2011, 2012, 2013, and 2014.* If you used the mass balance method to calculate emissions for any of the reporting years 2011, 2012, 2013, or 2014, you must conduct mass balance reporting for that reporting year. For processes whose emissions were determined using the mass balance method under the former §98.123(b), as included in paragraph 1 of Appendix A of this subpart, you must report the information listed in paragraphs (b)(1) and (b)(2) of this section for each process on an annual basis.

(1) If you calculated the relative and absolute errors under the former §98.123(b)(1), the overall absolute and relative errors calculated for the process under the former §98.123(b)(1), in metric tons CO_2e and decimal fraction, respectively.

(2) The method used to estimate the total mass of fluorine in destroyed or recaptured streams (specify the former §98.123(b)(4) or (15), as included in paragraph 1 of Appendix A of this subpart).

(c) *Reporting for emission factor and emission calculation factor approach.* For processes whose emissions are determined using the emission factor approach under §98.123(c)(3) or the emission calculation factor under §98.123(c)(4), you must report the following for each generically-identified process.

(1) [Reserved]

(2) [Reserved]

(3) For each fluorinated GHG group, the total GWP-weighted mass of all fluorinated GHGs in that group emitted from all process vents combined, in metric tons of CO_2e .

(4) For each fluorinated GHG group, the total GWP-weighted mass of all fluorinated GHGs in that group emitted from equipment leaks, in metric tons of CO_2e .

(d) *Reporting for missing data.* Where missing data have been estimated pursuant to §98.125, you must report:

(1) The generically-identified process for which the data were missing.

(2) The reason the data were missing, the length of time the data were missing, and the method used to estimate the missing data.

(3) Estimates of the missing data for all missing data associated with data elements required to be reported in this section.

(e) *Reporting of destruction device excess emissions data.* Each fluorinated gas

production facility that destroys fluorinated GHGs must report the excess emissions that result from malfunctions of the destruction device, and these excess emissions must be reflected in the fluorinated GHG estimates in the former §98.123(b) as included in paragraph 1 of Appendix A of this subpart for the former mass balance method, and in §98.123(c). Such excess emissions would occur if the destruction efficiency was reduced due to the malfunction.

(f) *Reporting of destruction device testing.* By March 31, 2012 or by March 31 of the year immediately following the year in which it begins fluorinated GHG destruction, each fluorinated gas production facility that destroys fluorinated GHGs must submit a report containing the information in paragraphs (f)(1) through (f)(4) of this section. This report is one-time unless you make a change to the destruction device that would be expected to affect its destruction efficiencies.

(1) [Reserved]

(2) Chemical identity of the fluorinated GHG(s) used in the performance test conducted to determine destruction efficiency, including surrogates, and information on why the surrogate is sufficient to demonstrate the destruction efficiency for each fluorinated GHG, consistent with requirements in §98.124(g)(1), vented to the destruction device.

(3) Date of the most recent destruction device test.

(4) Name of all applicable Federal or State regulations that may apply to the destruction process.

(5) [Reserved]

(g) *Reporting for destruction of previously produced fluorinated GHGs.* Each fluorinated gas production facility that destroys fluorinated GHGs must report, separately from the fluorinated GHG emissions reported under paragraphs (b) or (c) of this section, the following for each previously produced fluorinated GHG destroyed:

(1) [Reserved]

(2) The mass of the fluorinated GHG emitted from the destruction device (metric tons).

(h) *Reporting of emissions from venting of residual fluorinated GHGs from containers.* Each fluorinated gas production facility that vents residual fluorinated GHGs from containers must report the following for each fluorinated GHG vented:

(1) The mass of the residual fluorinated GHG vented from containers annually (metric tons).

(2) [Reserved]

(i) *Reporting of fluorinated GHG products of incomplete combustion (PICs) of fluorinated gases.* Each fluorinated gas production facility that destroys fluorinated gases must submit a one-time report by June 30, 2011, that describes any measurements, research, or analysis that it has performed or obtained that relate to the formation of products of incomplete combustion that are fluorinated GHGs during the destruction of fluorinated gases. The report must include the methods and results of any measurement or modeling studies, including the products of incomplete combustion for which the exhaust stream was analyzed, as well as copies of relevant scientific papers, if available,

		<p>or citations of the papers, if they are not. No new testing is required to fulfill this requirement.</p> <p>(j) <i>Special provisions for reporting years 2011, 2012, and 2013 only.</i> For reporting years 2011, 2012, and 2013, the owner or operator of a facility must comply with paragraphs (j)(1), (j)(2), and (j)(3) of this section.</p> <p>(1) <i>Timing.</i> The owner or operator of a facility is not required to report the data elements at §98.3(c)(4)(iii) and paragraphs (a)(2), (a)(3), (a)(4), (a)(6), (b), (c), (d), (e), (f), (g), and (h) of this section until the later of March 31, 2015 or the date set forth for that data element at §98.3(c)(4)(vii) and Table A-7 of Subpart A of this part.</p> <p>(2) <i>Excess emissions.</i> Excess emissions of fluorinated GHGs resulting from destruction device malfunctions must be reflected in the reported facility-wide CO₂e emissions but are not required to be reported separately.</p> <p>(3) <i>Calculation and reporting of CO₂e.</i> You must report the total fluorinated GHG emissions covered by this subpart, expressed in metric tons of CO₂e. This includes emissions from all fluorinated gas production processes, all fluorinated gas transformation processes that are not part of a fluorinated gas production process, all fluorinated gas destruction processes that are not part of a fluorinated gas production process or a fluorinated gas transformation process, and venting of residual fluorinated GHGs from containers returned from the field. To convert fluorinated GHG emissions to CO₂e for reporting under this section, use Equation A-1 of §98.2. For fluorinated GHGs whose GWPs are not listed in Table A-1 of Subpart A of this part, use either the default GWP specified below or your best estimate of the GWP based on the information described in §98.123(c)(1)(vi)(A)(3). Use of quantitative structure activity relationships (QSARs) is an acceptable method for determining GWPs in situations where pure standards of the “target” fluorinated GHG are not available, the “target” fluorinated GHG cannot be isolated from gas streams, and FTIR spectra for the impurities are not available.</p> <p>(i) If you choose to use a default GWP rather than your best estimate of the GWP for fluorinated GHGs whose GWPs are not listed in Table A-1 of Subpart A of this part, use a default GWP of 10,000 for fluorinated GHGs that are fully fluorinated GHGs and use a default GWP of 2000 for other fluorinated GHGs.</p> <p>(ii) Provide the total annual emissions across fluorinated GHGs for the entire facility, in metric tons of CO₂e, that were calculated using the default GWP of 2000.</p> <p>(iii) Provide the total annual emissions across fluorinated GHGs for the entire facility, in metric tons of CO₂e, that were calculated using the default GWP of 10,000.</p> <p>(iv) Provide the total annual emissions across fluorinated GHGs for the entire facility, in metric tons of CO₂e, that were calculated using your best estimate of the GWP.</p> <p>(k) <i>Submission of complete reporting year 2011, 2012, and 2013 GHG reports.</i> By March 31, 2015, you must submit annual GHG reports for reporting years 2011, 2012, and 2013 that contain the information specified in paragraphs (a) through (i) of this section. The reports must calculate CO₂e using the GWPs in Table A-1 of subpart A of this part (as in effect on January 1, 2015). Prior submission of partial reports for these reporting years under paragraph (j) of this section does not affect your obligation to submit complete reports under this paragraph.</p>
Subpart N –	25,000	In addition to the information required by §98.3(c), each annual report must

<p>Glass Production (§98.146)</p>	<p>metric tons CO₂e/year</p>	<p>contain the information specified in paragraphs (a) and (b) of this section, as applicable.</p> <p>(a) If a CEMS is used to measure CO₂ emissions, then you must report under this subpart the relevant information required under §98.36 for the Tier 4 Calculation Methodology and the following information specified in paragraphs (a)(1) and (2) of this section:</p> <p>(1) Annual quantity of each carbonate-based raw material charged to each continuous glass melting furnace and for all furnaces combined (tons).</p> <p>(2) Annual quantity of glass produced by each glass melting furnace and by all furnaces combined (tons).</p> <p>(b) If a CEMS is not used to determine CO₂ emissions from continuous glass melting furnaces, and process CO₂ emissions are calculated according to the procedures specified in §98.143(b), then you must report the following information as specified in paragraphs (b)(1) through (b)(9) of this section:</p> <p>(1) Annual process emissions of CO₂ (metric tons) for each continuous glass melting furnace and for all furnaces combined.</p> <p>(2) Annual quantity of each carbonate-based raw material charged (tons) to all furnaces combined.</p> <p>(3) Annual quantity of glass produced (tons) from each continuous glass melting furnace and from all furnaces combined.</p> <p>(4) [Reserved]</p> <p>(5) Results of all tests used to verify the carbonate-based mineral mass fraction for each carbonate-based raw material charged to a continuous glass melting furnace, as specified in paragraphs (b)(5)(i) through (b)(5)(iii) of this section.</p> <p>(i) Date of test.</p> <p>(ii) Method(s) and any variations used in the analyses.</p> <p>(iii) Mass fraction of each sample analyzed.</p> <p>(6) [Reserved]</p> <p>(7) Method used to determine decimal fraction of calcination.</p> <p>(8) Total number of continuous glass melting furnaces.</p> <p>(9) The number of times in the reporting year that missing data procedures were followed to measure monthly quantities of carbonate-based raw materials or mass fraction of the carbonate-based minerals for any continuous glass melting furnace (months).</p>
<p>Subpart O – HCFC-22 Production and HFC-23 Destruction</p>	<p>HCFC-22: All In HFC-23 destruction</p>	<p>(a) In addition to the information required by §98.3(c), the HCFC-22 production facility shall report the following information at the facility level:</p>

<p>(§98.156)</p>	<p>processes that are not collocated with a HCFC-22 production and that destroy more than 2.14 metric tons HFC-23 per year: All In</p>	<p>(1) Annual mass of HCFC-22 produced in metric tons.</p> <p>(2) [Reserved]</p> <p>(3) Annual mass of reactants fed into the process in metric tons of reactant.</p> <p>(4) The mass (in metric tons) of materials other than HCFC-22 and HFC-23 (i.e., unreacted reactants, HCl and other by-products) that occur in more than trace concentrations and that are permanently removed from the process.</p> <p>(5) The method for tracking startups, shutdowns, and malfunctions and HFC-23 generation/emissions during these events.</p> <p>(6) The names and addresses of facilities to which any HFC-23 was sent for destruction, and the quantities of HFC-23 (metric tons) sent to each.</p> <p>(7)-(10) [Reserved]</p> <p>(11) Annual mass of HFC-23 emitted in metric tons.</p> <p>(12) Annual mass of HFC-23 emitted from equipment leaks in metric tons.</p> <p>(13) Annual mass of HFC-23 emitted from process vents in metric tons.</p> <p>(b) In addition to the information required by §98.3(c), facilities that destroy HFC-23 shall report the following for each HFC-23 destruction process:</p> <p>(1)-(2) [Reserved]</p> <p>(3) Annual mass of HFC-23 emitted from the destruction device.</p> <p>(c) Each HFC-23 destruction facility shall report the concentration (mass fraction) of HFC-23 measured at the outlet of the destruction device during the facility's annual HFC-23 concentration measurements at the outlet of the device. If the concentration of HFC-23 is below the detection limit of the measuring device, report the detection limit and that the concentration is below the detection limit.</p> <p>(d) If the HFC-23 concentration measured pursuant to §98.154(l) is greater than that measured during the performance test that is the basis for the destruction efficiency (DE), the facility shall report the following:</p> <p>(1) [Reserved]</p> <p>(2) Concentration (mass fraction) of HFC-23 at the outlet of the destruction device.</p> <p>(3) Flow rate at the outlet of the destruction device in kg/hr.</p> <p>(4) Emission rate (in kg/hr) calculated from paragraphs (d)(2) and (d)(3) of this section.</p> <p>(5) [Reserved]</p> <p>(e) By March 31, 2011 or within 60 days of commencing HFC-23 destruction, HFC-23 destruction facilities shall submit a one-time report including the following information</p>
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		<p>for each destruction process:</p> <p>(1) [Reserved]</p> <p>(2) The methods used to determine destruction efficiency.</p> <p>(3) The methods used to record the mass of HFC-23 destroyed.</p> <p>(4) The name of other relevant federal or state regulations that may apply to the destruction process.</p> <p>(5) If any changes are made that affect HFC-23 destruction efficiency or the methods used to record volume destroyed, then these changes must be reflected in a revision to this report. The revised report must be submitted to EPA within 60 days of the change</p>
<p>Subpart P – Hydrogen Production (§98.166)</p>	<p>25,000 metric tons CO₂e/year</p>	<p>In addition to the information required by §98.3(c), each annual report must contain the information specified in paragraphs (a) or (b) of this section, as appropriate, and paragraphs (c) through (e) of this section:</p> <p>(a) If a CEMS is used to measure CO₂ emissions, then you must report the relevant information required under §98.36 for the Tier 4 Calculation Methodology and the following information in this paragraph (a):</p> <p>(1) Unit identification number and annual CO₂ emissions.</p> <p>(2) Annual quantity of hydrogen produced (metric tons) for each process unit.</p> <p>(3) Annual quantity of ammonia produced (metric tons), if applicable, for each process unit.</p> <p>(b) If a CEMS is not used to measure CO₂ emissions, then you must report the following information for each hydrogen production process unit:</p> <p>(1) Unit identification number and annual CO₂ emissions.</p> <p>(2) [Reserved]</p> <p>(3) Annual quantity of hydrogen produced (metric tons).</p> <p>(4) Annual quantity of ammonia produced, if applicable (metric tons).</p> <p>(5)-(6) [Reserved]</p> <p>(7) Name and annual quantity (metric tons) of each carbon-containing fuel and feedstock.</p> <p>(c) Quantity of CO₂ collected and transferred off site in either gas, liquid, or solid forms, following the requirements of subpart PP of this part.</p> <p>(d) Annual quantity of carbon other than CO₂ collected and transferred off site in either gas, liquid, or solid forms (kg carbon).</p> <p>(e) Annual methanol production (metric tons) for each process unit.</p>

<p>Subpart Q – Iron and Steel Production (§98.176)</p>	<p>25,000 metric tons CO₂e/year</p>	<p>In addition to the information required by §98.3(c), each annual report must contain the information required in paragraphs (a) through (h) of this section for each coke pushing operation; taconite indurating furnace; basic oxygen furnace; non-recovery coke oven battery; sinter process; EAF; decarburization vessel; direct reduction furnace; and flare burning coke oven gas or blast furnace gas. For reporting year 2010, the information required in paragraphs (a) through (h) of this section is not required for decarburization vessels that are not argon-oxygen decarburization vessels. For reporting year 2011 and each subsequent reporting year, the information in paragraphs (a) through (h) of this section must be reported for all decarburization vessels.</p> <p>(a) Unit identification number and annual CO₂ emissions (in metric tons).</p> <p>(b) If a CEMS is used to measure CO₂ emissions, then you must report the annual production quantity for the production unit (in metric tons) for taconite pellets, coke, sinter, iron, and raw steel.</p> <p>(c) If a CEMS is used to measure CO₂ emissions, then you must report the relevant information required under §98.36 for the Tier 4 Calculation Methodology.</p> <p>(d) If a CEMS is not used to measure CO₂ emissions, then you must report for each process whether the emissions were determined using the carbon mass balance method in §98.173(b)(1) or the site-specific emission factor method in §98.173(b)(2).</p> <p>(e) If you use the carbon mass balance method in §98.173(b)(1) to determine CO₂ emissions, you must, except as provided in §98.174(b)(4), report the following information for each process:</p> <p>(1) [Reserved]</p> <p>(2) Whether the carbon content was determined from information from the supplier or by laboratory analysis, and if by laboratory analysis, the method used.</p> <p>(3)-(4) [Reserved]</p> <p>(5) If you used the missing data procedures in §98.175(b), you must report how the monthly mass for each process input or output with missing data was determined and the number of months the missing data procedures were used.</p> <p>(6) The information specified in paragraphs (e)(6)(i) through (vi) of this section aggregated for all process units for which CO₂ emissions were determined using the mass balance method in §98.173(b)(1), except as provided in §98.174(b)(4).</p> <p>(i) The annual mass (metric tons) of all gaseous, liquid, and solid fuels (combined) used in process units for which CO₂ emissions were determined using Equations Q-1 through Q-7 of §98.173, calculated as specified in Equation Q-9 of this section.</p> <p>(ii) The annual mass (metric tons) of all non-fuel material inputs (combined) specified in Equations Q-1 through Q-7 of §98.173, calculated as specified in Equation Q-10 of this section.</p> <p>(iii) The annual mass (metric tons) of all solid and liquid products and byproducts (combined) specified in Equations Q-1 through Q-7 of §98.173, calculated as specified in Equation Q-11 of <i>this section</i>.</p> <p>(iv) The weighted average carbon content of all gaseous, liquid, and solid fuels (combined) included in Equation Q-9 of this section, calculated as specified in Equation</p>
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		<p>Q-12 of this section.</p> <p>(v) The weighted average carbon content of all non-fuel inputs to all process units (combined) included in Equation Q-10 of this section, calculated as specified in Equation Q-13 of this section.</p> <p>(vi) The weighted average carbon content of all solid and liquid products and byproducts from all process units (combined) included in Equation Q-11 of this section, calculated as specified in Equation Q-14 of this section.</p> <p>(f) If you used the site-specific emission factor method in §98.173(b)(2) to determine CO₂ emissions, you must report the following information for each process:</p> <p>(1) The measured average hourly CO₂ emission rate during the test (in metric tons per hour).</p> <p>(2)-(4) [Reserved]</p> <p>(g) [Reserved]</p> <p>(h) For flares burning coke oven gas or blast furnace gas, the information specified in §98.256(e) of subpart Y (Petroleum Refineries) of this part.</p>
<p>Subpart R – Lead Production (§98.186)</p>	<p>25,000 metric tons CO₂e/year</p>	<p>In addition to the information required by §98.3(c), each annual report must contain the information specified in paragraphs (a) or (b) of this section, as applicable.</p> <p>(a) If a CEMS is used to measure CO₂ emissions according to the requirements in §98.183(a) or (b)(1), then you must report under this subpart the relevant information required by §98.36 and the information specified in paragraphs (a)(1) through (a)(4) of this section.</p> <p>(1) Identification number of each smelting furnace.</p> <p>(2) Annual lead product production capacity (tons).</p> <p>(3) Annual production for each lead product (tons).</p> <p>(4) Total number of smelting furnaces at facility used for lead production.</p> <p>(b) If a CEMS is not used to measure CO₂ emissions, and you measure CO₂ emissions according to the requirements in §98.183(b)(2)(i) and (b)(2)(ii), then you must report the information specified in paragraphs (b)(1) through (b)(9) of this section.</p> <p>(1) Identification number of each smelting furnace. (2) Annual process CO₂ emissions (in metric tons) from each smelting furnace as determined by Equation R-1 of this subpart.</p> <p>(3) Annual lead product production capacity for the facility and each smelting furnace(tons).</p> <p>(4) Annual production for each lead product (tons).</p> <p>(5) Total number of smelting furnaces at facility used for production of lead</p>

		<p>products reported in paragraph (b)(4) of this section.</p> <p>(6)-(7) [Reserved]</p> <p>(8) List the method used for the determination of carbon content for each material used for the calculation of annual process CO₂ emissions using Equation R-1 of §98.183 for each smelting furnace (e.g., supplier provided information, analyses of representative samples you collected).</p> <p>(9) If you use the missing data procedures in §98.185(b), you must report how the monthly mass of carbon-containing materials with missing data was determined and the number of months the missing data procedures were used.</p>
<p>Subpart S – Lime Production (§98.196)</p>	<p>All In</p>	<p>In addition to the information required by §98.3(c), each annual report must contain the information specified in paragraphs (a) or (b) of this section, as applicable.</p> <p>(a) If a CEMS is used to measure CO₂ emissions, then you must report under this subpart the relevant information required by §98.36 and the information listed in paragraphs (a)(1) through (8) of this section.</p> <p>(1) Method used to determine the quantity of lime that is produced and quantity of lime that is sold.</p> <p>(2) Method used to determine the quantity of calcined lime byproduct or waste sold.</p> <p>(3) Beginning and end of year inventories for each lime product that is produced, by type.</p> <p>(4) Beginning and end of year inventories for calcined lime byproducts or wastes sold, by type.</p> <p>(5) Annual amount of calcined lime byproduct or waste sold, by type (tons).</p> <p>(6) Annual amount of lime product sold, by type (tons).</p> <p>(7) Annual amount of calcined lime byproduct or waste that is not sold, by type (tons).</p> <p>(8) Annual amount of lime product not sold, by type (tons).</p> <p>(b) If a CEMS is not used to measure CO₂ emissions, then you must report the information listed in paragraphs (b)(1) through (18) of this section.</p> <p>(1) Annual CO₂ process emissions from all lime kilns combined (metric tons).</p> <p>(2)-(3) [Reserved]</p> <p>(4) Standard method used (ASTM or NLA testing method) to determine chemical compositions of each lime type produced and each calcined lime byproduct or waste type.</p> <p>(5)-(6) [Reserved]</p>

		<p>(7) Method used to determine the quantity of lime produced and/or lime sold.</p> <p>(8) [Reserved]</p> <p>(9) Method used to determine the quantity of calcined lime byproduct or waste sold.</p> <p>(10)-(12) [Reserved]</p> <p>(13) Beginning and end of year inventories for each lime product that is produced.</p> <p>(14) Beginning and end of year inventories for calcined lime byproducts or wastes sold.</p> <p>(15) Annual lime production capacity (tons) per facility.</p> <p>(16) Number of times in the reporting year that missing data procedures were followed to measure lime production (months) or the chemical composition of lime products sold (months).</p> <p>(17) Indicate whether CO₂ was used on-site (i.e. for use in a purification process). If CO₂ was used on-site, provide the information in paragraphs (b)(17)(i) and (ii) of this section.</p> <p>(i) The annual amount of CO₂ captured for use in the on-site process.</p> <p>(ii) The method used to determine the amount of CO₂ captured.</p> <p>(18) Annual quantity (tons) of lime product sold, by type.</p>
<p>Subpart T – Magnesium Production (§98.206)</p>	<p>25,000 metric tons CO₂e/year</p>	<p>In addition to the information required by §98.3(c), each annual report must include the following information at the facility level:</p> <p>(a) Emissions of each cover or carrier gas in metric tons.</p> <p>(b) Types of production processes at the facility (e.g., primary, secondary, die casting).</p> <p>(c) Amount of magnesium produced or processed in metric tons for each process type. This includes the output of primary and secondary magnesium production processes and the input to magnesium casting processes.</p> <p>(d) Cover and carrier gas flow rate (e.g., standard cubic feet per minute) for each production unit and composition in percent by volume.</p> <p>(e) For any missing data, you must report the length of time the data were missing for each cover gas or carrier gas, the method used to estimate emissions in their absence, and the quantity of emissions thereby estimated.</p> <p>(f) The annual cover gas usage rate for the facility for each cover gas, excluding the carrier gas (kg gas/metric ton Mg).</p> <p>(g) If applicable, an explanation of any change greater than 30 percent in the facility's cover gas usage rate (e.g., installation of new melt protection technology or leak</p>

		<p>discovered in the cover gas delivery system that resulted in increased emissions).</p> <p>(h) A description of any new melt protection technologies adopted to account for reduced or increased GHG emissions in any given year.</p>
Subpart U – Miscellaneous Uses of Carbonate (§98.216)	25,000 metric tons CO ₂ e/year	<p>In addition to the information required by §98.3(c), each annual report must contain the information specified in paragraphs (a) through (g) of this section at the facility level, as applicable.</p> <p>(a) Annual CO₂ emissions from miscellaneous carbonate use (metric tons).</p> <p>(b) [Reserved]</p> <p>(c) Measurement method used to determine the mass of carbonate.</p> <p>(d) Method used to calculate emissions.</p> <p>(e) If you followed the calculation method of §98.213(b)(1)(i), you must report the information in paragraphs (e)(1) through (e)(3) of this section.</p> <p>(1)-(2) [Reserved]</p> <p>(3) If you determined the calcination fraction, indicate which standard method was used.</p> <p>(f) [Reserved]</p> <p>(g) Number of times in the reporting year that missing data procedures were followed to measure carbonate consumption, carbonate input or carbonate output (months).</p>
Subpart V – Nitric Acid Production (§98.226)	All In	<p>In addition to the information required by §98.3(c), each annual report must contain the information specified in paragraphs (a) through (q) of this section.</p> <p>(a) Nitric Acid train identification number.</p> <p>(b) Annual process N₂O emissions from each nitric acid train (metric tons).</p> <p>(c) [Reserved]</p> <p>(d) [Reserved]</p> <p>(e) Annual nitric acid production from the nitric acid facility (tons, 100 percent acid basis).</p> <p>(f) Number of nitric acid trains.</p> <p>(g) Number of different N₂O abatement technologies per nitric acid train “t”.</p> <p>(h) Abatement technologies used (if applicable).</p> <p>(i) [Reserved]</p> <p>(j) [Reserved]</p>

		<p>(k) Type of nitric acid process used for each nitric acid train (low, medium, high, or dual pressure).</p> <p>(l) Number of times in the reporting year that missing data procedures were followed to measure nitric acid production (months).</p> <p>(m) If you conducted a performance test and calculated a site-specific emissions factor according to §98.223(a)(1), each annual report must also contain the information specified in paragraphs (m)(1) through (7) of this section.</p> <p>(1) [Reserved]</p> <p>(2) Test method used for performance test.</p> <p>(3)-(6) [Reserved]</p> <p>(7) Number of times in the reporting year that a performance test had to be repeated (number).</p> <p>(n) If you requested Administrator approval for an alternative method of determining N₂O emissions under §98.223(a)(2), each annual report must also contain the information specified in paragraphs (n)(1) through (4) of this section.</p> <p>(1) Name of alternative method.</p> <p>(2) Description of alternative method.</p> <p>(3) Request date.</p> <p>(4) Approval date.</p> <p>(o) [Reserved]</p> <p>(p) [Reserved]</p> <p>(q) Annual percent N₂O emission reduction for all nitric acid trains combined.</p>
<p>Subpart W – Petroleum and Natural Gas Systems (§98.236)</p>	<p>25,000 metric tons CO₂e/year</p>	<p>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.</p> <p>(a) The annual report must include the information specified in paragraphs (a)(1) through (8) 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 (8) of this section, and each applicable emission source listed in paragraphs (b) through (z) of this section.</p> <p>(1) <i>Onshore petroleum and natural gas production.</i> For the equipment/activities specified in paragraphs (a)(1)(i) through (xvii) of this section, report the information specified in the applicable paragraphs of this section.</p> <p>(i) <i>Natural gas pneumatic devices.</i> Report the information specified in paragraph</p>

(b) of this section.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

this section.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(8) *Natural gas distribution*. For the equipment/activities specified in paragraphs (a)(8)(i) through (iii) of this section, report the information specified in the applicable paragraphs of this section.

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

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

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

(b) *Natural gas pneumatic devices*. You must indicate whether the facility contains the following types of equipment: Continuous high bleed natural gas pneumatic devices, continuous low bleed natural gas pneumatic devices, and intermittent bleed natural gas pneumatic devices. If the facility contains any continuous high bleed natural gas pneumatic devices, continuous low bleed natural gas pneumatic devices, or intermittent bleed natural gas pneumatic devices, then you must report the information specified in paragraphs (b)(1) through (b)(4) of this section.

(1) The number of natural gas pneumatic devices as specified in paragraphs (b)(1)(i) and (ii) of this section.

(i) The total number of devices of each type, determined according to §98.233(a)(1) and (2).

(ii) If the reported value in paragraph (b)(1)(i) of this section is an estimated value determined according to §98.233(a)(2), then you must report the information specified in paragraphs (b)(1)(ii)(A) through (C) of this section.

(A) The number of devices of each type reported in paragraph (b)(1)(i) of this section that are counted.

(B) The number of devices of each type reported in paragraph (b)(1)(i) of this section that are estimated (not counted).

(C) Whether the calendar year is the first calendar year of reporting or the second calendar year of reporting.

(2) For each type of pneumatic device, the estimated average number of hours in the calendar year that the natural gas pneumatic devices reported in paragraph (b)(1)(i) of this section were operating in the calendar year (“ T_i ” in Equation W-1 of this subpart).

(3) Annual CO₂ emissions, in metric tons CO₂, for the natural gas pneumatic devices combined, calculated using Equation W-1 of this subpart and §98.233(a)(4), and reported in paragraph (b)(1)(i) of this section.

(4) Annual CH₄ emissions, in metric tons CH₄, for the natural gas pneumatic devices combined, calculated using Equation W-1 of this subpart and §98.233(a)(4), and reported in paragraph (b)(1)(i) of this section.

(c) *Natural gas driven pneumatic pumps*. You must indicate whether the facility has any natural gas driven pneumatic pumps. If the facility contains any natural gas driven pneumatic pumps, then you must report the information specified in paragraphs (c)(1) through (4) of this section.

(1) Count of natural gas driven pneumatic pumps.

(2) Average estimated number of hours in the calendar year the pumps were operational ("T" in Equation W-2 of this subpart).

(3) Annual CO₂ emissions, in metric tons CO₂, for all natural gas driven pneumatic pumps combined, calculated according to §98.233(c)(1) and (2).

(4) Annual CH₄ emissions, in metric tons CH₄, for all natural gas driven pneumatic pumps combined, calculated according to §98.233(c)(1) and (2).

(d) *Acid gas removal units.* You must indicate whether your facility has any acid gas removal units that vent directly to the atmosphere, to a flare or engine, or to a sulfur recovery plant. If your facility contains any acid gas removal units that vent directly to the atmosphere, to a flare or engine, or to a sulfur recovery plant, then you must report the information specified in paragraphs (d)(1) and (2) of this section.

(1) You must report the information specified in paragraphs (d)(1)(i) through (vi) of this section for each acid gas removal unit.

(i) A unique name or ID number for the acid gas removal unit. For the onshore petroleum and natural gas production industry segment, a different name or ID may be used for a single acid gas removal unit for each location it operates at in a given year.

(ii) Total feed rate entering the acid gas removal unit, using a meter or engineering estimate based on process knowledge or best available data, in million cubic feet per year.

(iii) The calculation method used to calculate CO₂ emissions from the acid gas removal unit, as specified in §98.233(d).

(iv) Whether any CO₂ emissions from the acid gas removal unit are recovered and transferred outside the facility, as specified in §98.233(d)(11). If any CO₂ emissions from the acid gas removal unit were recovered and transferred outside the facility, then you must report the annual quantity of CO₂, in metric tons CO₂, that was recovered and transferred outside the facility under subpart PP of this part.

(v) Annual CO₂ emissions, in metric tons CO₂, from the acid gas removal unit, calculated using any one of the calculation methods specified in §98.233(d) and as specified in §98.233(d)(10) and (11).

(vi) Sub-basin ID that best represents the wells supplying gas to the unit (for the onshore petroleum and natural gas production industry segment only).

(2) You must report information specified in paragraphs (d)(2)(i) through (iii) of this section, applicable to the calculation method reported in paragraph (d)(1)(iii) of this section, for each acid gas removal unit.

(i) If you used Calculation Method 1 or Calculation Method 2 as specified in §98.233(d) to calculate CO₂ emissions from the acid gas removal unit, then you must report the information specified in paragraphs (d)(2)(i)(A) and (B) of this section.

(A) Annual average volumetric fraction of CO₂ in the vent gas exiting the acid gas removal unit.

(B) Annual volume of gas vented from the acid gas removal unit, in cubic feet.

(ii) If you used Calculation Method 3 as specified in §98.233(d) to calculate CO₂ emissions from the acid gas removal unit, then you must report the information specified in paragraphs (d)(2)(ii)(A) through (D) of this section.

(A) Indicate which equation was used (Equation W-4A or W-4B).

(B) Annual average volumetric fraction of CO₂ in the natural gas flowing out of the acid gas removal unit, as specified in Equation W-4A or Equation W-4B of this subpart.

(C) Annual average volumetric fraction of CO₂ content in natural gas flowing into the acid gas removal unit, as specified in Equation W-4A or Equation W-4B of this subpart.

(D) The natural gas flow rate used, as specified in Equation W-4A of this subpart, reported as either total annual volume of natural gas flow into the acid gas removal unit in cubic feet at actual conditions; or total annual volume of natural gas flow out of the acid gas removal unit, as specified in Equation W-4B of this subpart, in cubic feet at actual conditions.

(iii) If you used Calculation Method 4 as specified in §98.233(d) to calculate CO₂ emissions from the acid gas removal unit, then you must report the information specified in paragraphs (d)(2)(iii)(A) through (L) of this section, as applicable to the simulation software package used.

(A) The name of the simulation software package used.

(B) Natural gas feed temperature, in degrees Fahrenheit.

(C) Natural gas feed pressure, in pounds per square inch.

(D) Natural gas flow rate, in standard cubic feet per minute.

(E) Acid gas content of the feed natural gas, in mole percent.

(F) Acid gas content of the outlet natural gas, in mole percent.

(G) Unit operating hours, excluding downtime for maintenance or standby, in hours per year.

(H) Exit temperature of the natural gas, in degrees Fahrenheit.

(I) Solvent pressure, in pounds per square inch.

(J) Solvent temperature, in degrees Fahrenheit.

(K) Solvent circulation rate, in gallons per minute.

(L) Solvent weight, in pounds per gallon.

(e) *Dehydrators*. You must indicate whether your facility contains any of the following equipment: Glycol dehydrators with an annual average daily natural gas throughput greater than or equal to 0.4 million standard cubic feet per day, glycol dehydrators with an annual average daily natural gas throughput less than 0.4 million standard cubic feet per day, and dehydrators that use desiccant. If your facility contains

any of the equipment listed in this paragraph (e), then you must report the applicable information in paragraphs (e)(1) through (3).

(1) For each glycol dehydrator that has an annual average daily natural gas throughput greater than or equal to 0.4 million standard cubic feet per day (as specified in §98.233(e)(1)), you must report the information specified in paragraphs (e)(1)(i) through (xviii) of this section for the dehydrator.

(i) A unique name or ID number for the dehydrator. For the onshore petroleum and natural gas production industry segment, a different name or ID may be used for a single dehydrator for each location it operates at in a given year.

(ii) Dehydrator feed natural gas flow rate, in million standard cubic feet per day, determined by engineering estimate based on best available data.

(iii) Dehydrator feed natural gas water content, in pounds per million standard cubic feet.

(iv) Dehydrator outlet natural gas water content, in pounds per million standard cubic feet.

(v) Dehydrator absorbent circulation pump type (e.g., natural gas pneumatic, air pneumatic, or electric).

(vi) Dehydrator absorbent circulation rate, in gallons per minute.

(vii) Type of absorbent (e.g., triethylene glycol (TEG), diethylene glycol (DEG), or ethylene glycol (EG)).

(viii) Whether stripper gas is used in dehydrator.

(ix) Whether a flash tank separator is used in dehydrator.

(x) Total time the dehydrator is operating, in hours.

(xi) Temperature of the wet natural gas, in degrees Fahrenheit.

(xii) Pressure of the wet natural gas, in pounds per square inch gauge.

(xiii) Mole fraction of CH₄ in wet natural gas.

(xiv) Mole fraction of CO₂ in wet natural gas.

(xv) Whether any dehydrator emissions are vented to a vapor recovery device.

(xvi) Whether any dehydrator emissions are vented to a flare or regenerator firebox/fire tubes. If any emissions are vented to a flare or regenerator firebox/fire tubes, report the information specified in paragraphs (e)(1)(xvi)(A) through (C) of this section for these emissions from the dehydrator.

(A) Annual CO₂ emissions, in metric tons CO₂, for the dehydrator, calculated according to §98.233(e)(6).

(B) Annual CH₄ emissions, in metric tons CH₄, for the dehydrator, calculated

according to §98.233(e)(6).

(C) Annual N₂O emissions, in metric tons N₂O, for the dehydrator, calculated according to §98.233(e)(6).

(xvii) Whether any dehydrator emissions are vented to the atmosphere without being routed to a flare or regenerator firebox/fire tubes. If any emissions are not routed to a flare or regenerator firebox/fire tubes, then you must report the information specified in paragraphs (e)(1)(xvii)(A) and (B) of this section for those emissions from the dehydrator.

(A) Annual CO₂ emissions, in metric tons CO₂, for the dehydrator when not venting to a flare or regenerator firebox/fire tubes, calculated according to §98.233(e)(1), and, if applicable, (e)(5).

(B) Annual CH₄ emissions, in metric tons CH₄, for the dehydrator when not venting to a flare or regenerator firebox/fire tubes, calculated according to §98.233(e)(1) and, if applicable, (e)(5).

(xviii) Sub-basin ID that best represents the wells supplying gas to the dehydrator (for the onshore petroleum and natural gas production industry segment only).

(2) For glycol dehydrators with an annual average daily natural gas throughput less than 0.4 million standard cubic feet per day (as specified in §98.233(e)(2)), you must report the information specified in paragraphs (e)(2)(i) through (v) of this section for the entire facility.

(i) The total number of dehydrators at the facility.

(ii) Whether any dehydrator emissions were vented to a vapor recovery device. If any dehydrator emissions were vented to a vapor recovery device, then you must report the total number of dehydrators at the facility that vented to a vapor recovery device.

(iii) Whether any dehydrator emissions were vented to a control device other than a vapor recovery device or a flare or regenerator firebox/fire tubes. If any dehydrator emissions were vented to a control device(s) other than a vapor recovery device or a flare or regenerator firebox/fire tubes, then you must specify the type of control device(s) and the total number of dehydrators at the facility that were vented to each type of control device.

(iv) Whether any dehydrator emissions were vented to a flare or regenerator firebox/fire tubes. If any dehydrator emissions were vented to a flare or regenerator firebox/fire tubes, then you must report the information specified in paragraphs (e)(2)(iv)(A) through (D) of this section.

(A) The total number of dehydrators venting to a flare or regenerator firebox/fire tubes.

(B) Annual CO₂ emissions, in metric tons CO₂, for the dehydrators reported in paragraph (e)(2)(iv)(A) of this section, calculated according to §98.233(e)(6).

(C) Annual CH₄ emissions, in metric tons CH₄, for the dehydrators reported in paragraph (e)(2)(iv)(A) of this section, calculated according to §98.233(e)(6).

(D) Annual N₂O emissions, in metric tons N₂O, for the dehydrators reported in

paragraph (e)(2)(iv)(A) of this section, calculated according to §98.233(e)(6).

(v) For dehydrator emissions that were not vented to a flare or regenerator firebox/fire tubes, report the information specified in paragraphs (e)(2)(v)(A) and (B) of this section.

(A) Annual CO₂ emissions, in metric tons CO₂, for emissions from all dehydrators reported in paragraph (e)(2)(i) of this section that were not vented to a flare or regenerator firebox/fire tubes, calculated according to §98.233(e)(2), (e)(4), and, if applicable, (e)(5), where emissions are added together for all such dehydrators.

(B) Annual CH₄ emissions, in metric tons CH₄, for emissions from all dehydrators reported in paragraph (e)(2)(i) of this section that were not vented to a flare or regenerator firebox/fire tubes, calculated according to §98.233(e)(2), (e)(4), and, if applicable, (e)(5), where emissions are added together for all such dehydrators.

(3) For dehydrators that use desiccant (as specified in §98.233(e)(3)), you must report the information specified in paragraphs (e)(3)(i) through (iii) of this section for the entire facility.

(i) The same information specified in paragraphs (e)(2)(i) through (iv) of this section for glycol dehydrators, and report the information under this paragraph for dehydrators that use desiccant.

(ii) Annual CO₂ emissions, in metric tons CO₂, for emissions from all desiccant dehydrators reported under paragraph (e)(3)(i) of this section that are not venting to a flare or regenerator firebox/fire tubes, calculated according to §98.233(e)(3), (e)(4), and, if applicable, (e)(5), and summing for all such dehydrators.

(iii) Annual CH₄ emissions, in metric tons CH₄, for emissions from all desiccant dehydrators reported in paragraph (e)(3)(i) of this section that are not venting to a flare or regenerator firebox/fire tubes, calculated according to §98.233(e)(3), (e)(4), and, if applicable, (e)(5), and summing for all such dehydrators.

(f) *Liquids unloading*. You must indicate whether well venting for liquids unloading occurs at your facility, and if so, which methods (as specified in §98.233(f)) were used to calculate emissions. If your facility performs well venting for liquids unloading and uses Calculation Method 1, then you must report the information specified in paragraph (f)(1) of this section. If the facility performs liquids unloading and uses Calculation Method 2 or 3, then you must report the information specified in paragraph (f)(2) of this section.

(1) For each sub-basin and well tubing diameter and pressure group for which you used Calculation Method 1 to calculate natural gas emissions from well venting for liquids unloading, report the information specified in paragraphs (f)(1)(i) through (xii) of this section. Report information separately for wells with plunger lifts and wells without plunger lifts.

(i) Sub-basin ID.

(ii) Well tubing diameter and pressure group ID.

(iii) Plunger lift indicator.

(iv) Count of wells vented to the atmosphere for the sub-basin/well tubing diameter and pressure group.

(v) Percentage of wells for which the monitoring period used to determine the cumulative amount of time venting was not the full calendar year.

(vi) Cumulative amount of time wells were vented (sum of "T_p" from Equation W-7A or W-7B of this subpart), in hours.

(vii) Cumulative number of unloadings vented to the atmosphere for each well, aggregated across all wells in the sub-basin/well tubing diameter and pressure group.

(viii) Annual natural gas emissions, in standard cubic feet, from well venting for liquids unloading, calculated according to §98.233(f)(1).

(ix) Annual CO₂ emissions, in metric tons CO₂, from well venting for liquids unloading, calculated according to §98.233(f)(1) and (4).

(x) Annual CH₄ emissions, in metric tons CH₄, from well venting for liquids unloading, calculated according to §98.233(f)(1) and (4).

(xi) For each well tubing diameter group and pressure group combination, you must report the information specified in paragraphs (f)(1)(xi)(A) through (E) of this section for each individual well not using a plunger lift that was tested during the year.

(A) API Well Number of tested well.

(B) Casing pressure, in pounds per square inch absolute.

(C) Internal casing diameter, in inches.

(D) Measured depth of the well, in feet.

(E) Average flow rate of the well venting over the duration of the liquids unloading, in standard cubic feet per hour.

(xii) For each well tubing diameter group and pressure group combination, you must report the information specified in paragraphs (f)(1)(xii)(A) through (E) of this section for each individual well using a plunger lift that was tested during the year.

(A) API Well Number.

(B) The tubing pressure, in pounds per square inch absolute.

(C) The internal tubing diameter, in inches.

(D) Measured depth of the well, in feet.

(E) Average flow rate of the well venting over the duration of the liquids unloading, in standard cubic feet per hour.

(2) For each sub-basin for which you used Calculation Method 2 or 3 (as specified in §93.233(f)) to calculate natural gas emissions from well venting for liquids unloading, you must report the information in (f)(2)(i) through (x) of this section. Report information separately for each calculation method.

		<p>(i) Sub-basin ID.</p> <p>(ii) Calculation method.</p> <p>(iii) Plunger lift indicator.</p> <p>(iv) Number of wells vented to the atmosphere.</p> <p>(v) Cumulative number of unloadings vented to the atmosphere for each well, aggregated across all wells.</p> <p>(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.</p> <p>(vii) Annual CO₂ emissions, in metric tons CO₂, from well venting for liquids unloading, calculated according to §98.233(f)(2) or (3), as applicable, and §98.233(f)(4).</p> <p>(viii) Annual CH₄ emissions, in metric tons CH₄, from well venting for liquids unloading, calculated according to §98.233(f)(2) or (3), as applicable, and §98.233(f)(4).</p> <p>(ix) For wells without plunger lifts, the average internal casing diameter, in inches.</p> <p>(x) For wells with plunger lifts, the average internal tubing diameter, in inches.</p> <p>(g) <i>Completions and workovers with hydraulic fracturing.</i> You must indicate whether your facility had any gas well completions or workovers with hydraulic fracturing during the calendar year. If your facility had gas well completions or workovers with hydraulic fracturing during the calendar year, then you must report information specified in paragraphs (g)(1) through (10) of this section, for each sub-basin and well type combination. Report information separately for completions and workovers.</p> <p>(1) Sub-basin ID.</p> <p>(2) Well type combination.</p> <p>(3) Number of completions or workovers in the sub-basin and well type combination category.</p> <p>(4) Calculation method used.</p> <p>(5) If you used Equation W-10A to calculate annual volumetric total gas emissions, then you must report the information specified in paragraphs (g)(5)(i) and (ii) of this section.</p> <p>(i) Cumulative gas flowback time, in hours, from when gas is first detected until sufficient quantities are present to enable separation, and the cumulative flowback time, in hours, after sufficient quantities of gas are present to enable separation (sum of "T_{p,i}" and sum of "T_{p,s}" values used in Equation W-10A). You may delay the reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells included in this number. If you elect to delay reporting of this data element, you must report by the date specified in §98.236(cc) the total number of hours of flowback from all wells during completions or workovers and the API Well Number(s) for the well(s) included in the number.</p> <p>(ii) For the measured well(s), the flowback rate, in standard cubic feet per hour</p>
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(average of "FR_{s,p}" values used in Equation W-12A). You may delay the reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells that can be used for the measurement. If you elect to delay reporting of this data element, you must report by the date specified in §98.236(cc) the measured flowback rate during well completion or workover and the API Well Number(s) for the well(s) included in the measurement.

(6) If you used Equation W-10B to calculate annual volumetric total gas emissions, then you must report the information specified in paragraphs (g)(6)(i) and (ii) of this section.

(i) Vented natural gas volume, in standard cubic feet, for each well in the sub-basin ("FV_{s,p}" in Equation W-10B).

(ii) Flow rate at the beginning of the period of time when sufficient quantities of gas are present to enable separation, in standard cubic feet per hour, for each well in the sub-basin ("FR_{p,i}" in Equation W-10B).

(7) Annual gas emissions, in standard cubic feet ("E_{s,n}" in Equation W-10A or W-10B).

(8) Annual CO₂ emissions, in metric tons CO₂.

(9) Annual CH₄ emissions, in metric tons CH₄.

(10) If the well emissions were vented to a flare, then you must report the total N₂O emissions, in metric tons N₂O.

(h) *Completions and workovers without hydraulic fracturing.* You must indicate whether the facility had any gas well completions without hydraulic fracturing or any gas well workovers without hydraulic fracturing, and if the activities occurred with or without flaring. If the facility had gas well completions or workovers without hydraulic fracturing, then you must report the information specified in paragraphs (h)(1) through (4) of this section, as applicable.

(1) For each sub-basin with gas well completions without hydraulic fracturing and without flaring, report the information specified in paragraphs (h)(1)(i) through (vi) of this section.

(i) Sub-basin ID.

(ii) Number of well completions that vented gas directly to the atmosphere without flaring.

(iii) Total number of hours that gas vented directly to the atmosphere during venting for all completions in the sub-basin category (the sum of all "T_p" for completions that vented to the atmosphere as used in Equation W-13B).

(iv) Average daily gas production rate for all completions without hydraulic fracturing in the sub-basin without flaring, in standard cubic feet per hour (average of all "V_p" used in Equation W-13B). You may delay reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells that can be used for the measurement. If you elect to delay reporting of this data element, you must report by the date specified in §98.236(cc) the measured average daily gas production rate for all wells during completions and the API Well Number(s) for

the well(s) included in the measurement.

(v) Annual CO₂ emissions, in metric tons CO₂, that resulted from completions venting gas directly to the atmosphere (“E_{s,p}” from Equation W-13B for completions that vented directly to the atmosphere, converted to mass emissions according to §98.233(h)(1)).

(vi) Annual CH₄ emissions, in metric tons CH₄, that resulted from completions venting gas directly to the atmosphere (“E_{s,p}” from Equation W-13B for completions that vented directly to the atmosphere, converted to mass emissions according to §98.233(h)(1)).

(2) For each sub-basin with gas well completions without hydraulic fracturing and with flaring, report the information specified in paragraphs (h)(2)(i) through (vii) of this section.

(i) Sub-basin ID.

(ii) Number of well completions that flared gas.

(iii) Total number of hours that gas vented to a flare during venting for all completions in the sub-basin category (the sum of all “T_p” for completions that vented to a flare from Equation W-13B).

(iv) Average daily gas production rate for all completions without hydraulic fracturing in the sub-basin with flaring, in standard cubic feet per hour (the average of all “V_p” from Equation W-13B). You may delay reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells that can be used for the measurement. If you elect to delay reporting of this data element, you must report by the date specified in §98.236(cc) the measured average daily gas production rate for all wells during completions and the API Well Number(s) for the well(s) included in the measurement.

(v) Annual CO₂ emissions, in metric tons CO₂, that resulted from completions that flared gas calculated according to §98.233(h)(2).

(vi) Annual CH₄ emissions, in metric tons CH₄, that resulted from completions that flared gas calculated according to §98.233(h)(2).

(vii) Annual N₂O emissions, in metric tons N₂O, that resulted from completions that flared gas calculated according to §98.233(h)(2).

(3) For each sub-basin with gas well workovers without hydraulic fracturing and without flaring, report the information specified in paragraphs (h)(3)(i) through (iv) of this section.

(i) Sub-basin ID.

(ii) Number of workovers that vented gas to the atmosphere without flaring.

(iii) Annual CO₂ emissions, in metric tons CO₂ per year, that resulted from workovers venting gas directly to the atmosphere (“E_{s,wo}” in Equation W-13A for workovers that vented directly to the atmosphere, converted to mass emissions as specified in §98.233(h)(1)).

(iv) Annual CH₄ emissions, in metric tons CH₄ per year, that resulted from workovers venting gas directly to the atmosphere (“E_{s,wo}” in Equation W-13A for workovers that vented directly to the atmosphere, converted to mass emissions as specified in §98.233(h)(1)).

(4) For each sub-basin with gas well workovers without hydraulic fracturing and with flaring, report the information specified in paragraphs (h)(4)(i) through (v) of this section.

(i) Sub-basin ID.

(ii) Number of workovers that flared gas.

(iii) Annual CO₂ emissions, in metric tons CO₂ per year, that resulted from workovers that flared gas calculated as specified in §98.233(h)(2).

(iv) Annual CH₄ emissions, in metric tons CH₄ per year, that resulted from workovers that flared gas, calculated as specified in §98.233(h)(2).

(v) Annual N₂O emissions, in metric tons N₂O per year, that resulted from workovers that flared gas calculated as specified in §98.233(h)(2).

(i) *Blowdown vent stacks.* You must indicate whether your facility has blowdown vent stacks. If your facility has blowdown vent stacks, then you must report whether emissions were calculated by equipment or event type or by using flow meters or a combination of both. If you calculated emissions by equipment or event type for any blowdown vent stacks, then you must report the information specified in paragraph (i)(1) of this section considering, in aggregate, all blowdown vent stacks for which emissions were calculated by equipment or event type. If you calculated emissions using flow meters for any blowdown vent stacks, then you must report the information specified in paragraph (i)(2) of this section considering, in aggregate, all blowdown vent stacks for which emissions were calculated using flow meters.

(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), then you must report the equipment or event types and the information specified in paragraphs (i)(1)(i) through (iii) of this section for each equipment or event type. If a blowdown event resulted in emissions from multiple equipment types, and the emissions cannot be apportioned to the different equipment types, then you may report the information in paragraphs (i)(1)(i) through (iii) of this section for the equipment type that represented the largest portion of the emissions for the blowdown event.

(i) Total number of blowdowns in the calendar year for the equipment or event type (the sum of equation variable “N” from Equation W-14A or Equation W-14B of this subpart, for all unique physical volumes for the equipment or event type).

(ii) Annual CO₂ emissions for the equipment or event type, in metric tons CO₂, calculated according to §98.233(i)(2)(iii).

(iii) Annual CH₄ emissions for the equipment or event type, in metric tons CH₄, calculated according to §98.233(i)(2)(iii).

(2) *Report by flow meter.* If you elect to calculate emissions from blowdown vent stacks by using a flow meter according to §98.233(i)(3), then you must report the information specified in paragraphs (i)(2)(i) and (ii) of this section for the facility.

(i) Annual CO₂ emissions from all blowdown vent stacks at the facility for which emissions were calculated using flow meters, in metric tons CO₂ (the sum of all CO₂ mass emission values calculated according to §98.233(i)(3), for all flow meters).

(ii) Annual CH₄ emissions from all blowdown vent stacks at the facility for which emissions were calculated using flow meters, in metric tons CH₄, (the sum of all CH₄ mass emission values calculated according to §98.233(i)(3), for all flow meters).

(j) *Onshore production storage tanks.* You must indicate whether your facility sends produced oil to atmospheric tanks. If your facility sends produced oil to atmospheric tanks, then you must indicate which Calculation Method(s) you used to calculate GHG emissions, and you must report the information specified in paragraphs (j)(1) and (2) of this section as applicable. If you used Calculation Method 1 or Calculation Method 2, and any atmospheric tanks were observed to have malfunctioning dump valves during the calendar year, then you must indicate that dump valves were malfunctioning and you must report the information specified in paragraph (j)(3) of this section.

(1) If you used Calculation Method 1 or Calculation Method 2 to calculate GHG emissions, then you must report the information specified in paragraphs (j)(1)(i) through (xiv) of this section for each sub-basin and by calculation method.

(i) Sub-basin ID.

(ii) Calculation method used, and name of the software package used if using Calculation Method 1.

(iii) The total annual oil volume from gas-liquid separators and direct from wells that is sent to applicable onshore production storage tanks, in barrels. You may delay reporting of this data element if you indicate in the annual report that wildcat wells and delineation wells are the only wells in the sub-basin with oil production greater than or equal to 10 barrels per day and flowing to gas-liquid separators or direct to storage tanks. If you elect to delay reporting of this data element, you must report by the date specified in §98.236(cc) the total volume of oil from all wells and the API Well Number(s) for the well(s) included in this volume.

(iv) The average gas-liquid separator temperature, in degrees Fahrenheit.

(v) The average gas-liquid separator pressure, in pounds per square inch gauge.

(vi) The average sales oil or stabilized oil API gravity, in degrees.

(vii) The minimum and maximum concentration (mole fraction) of CO₂ in flash gas from onshore production storage tanks.

(viii) The minimum and maximum concentration (mole fraction) of CH₄ in flash gas from onshore production storage tanks.

(ix) The number of wells sending oil to gas-liquid separators or directly to atmospheric tanks.

(x) The number of atmospheric tanks.

(xi) An estimate of the number of atmospheric tanks, not on well-pads, receiving

your oil.

(xii) If any emissions from the atmospheric tanks at your facility were controlled with vapor recovery systems, then you must report the information specified in paragraphs (j)(1)(xii)(A) through (E) of this section.

(A) The number of atmospheric tanks that control emissions with vapor recovery systems.

(B) Total CO₂ mass, in metric tons CO₂, that was recovered during the calendar year using a vapor recovery system.

(C) Total CH₄ mass, in metric tons CH₄, that was recovered during the calendar year using a vapor recovery system.

(D) Annual CO₂ emissions, in metric tons CO₂, from atmospheric tanks equipped with vapor recovery systems.

(E) Annual CH₄ emissions, in metric tons CH₄, from atmospheric tanks equipped with vapor recovery systems.

(xiii) If any atmospheric tanks at your facility vented gas directly to the atmosphere without using a vapor recovery system or without flaring, then you must report the information specified in paragraphs (j)(1)(xiii)(A) through (C) of this section.

(A) The number of atmospheric tanks that vented gas directly to the atmosphere without using a vapor recovery system or without flaring.

(B) Annual CO₂ emissions, in metric tons CO₂, that resulted from venting gas directly to the atmosphere.

(C) Annual CH₄ emissions, in metric tons CH₄, that resulted from venting gas directly to the atmosphere.

(xiv) If you controlled emissions from any atmospheric tanks at your facility with one or more flares, then you must report the information specified in paragraphs (j)(1)(xiv)(A) through (D) of this section.

(A) The number of atmospheric tanks that controlled emissions with flares.

(B) Annual CO₂ emissions, in metric tons CO₂, from atmospheric tanks that controlled emissions with one or more flares.

(C) Annual CH₄ emissions, in metric tons CH₄, from atmospheric tanks that controlled emissions with one or more flares.

(D) Annual N₂O emissions, in metric tons N₂O, from atmospheric tanks that controlled emissions with one or more flares.

(2) If you used Calculation Method 3 to calculate GHG emissions, then you must report the information specified in paragraphs (j)(2)(i) through (iii) of this section.

(i) Report the information specified in paragraphs (j)(2)(i)(A) through (F) of this section, at the basin level, for atmospheric tanks where emissions were calculated using

Calculation Method 3.

(A) The total annual oil throughput that is sent to all atmospheric tanks in the basin, in barrels. You may delay reporting of this data element if you indicate in the annual report that wildcat wells and delineation wells are the only wells in the sub-basin with oil production less than 10 barrels per day and that send oil to atmospheric tanks. If you elect to delay reporting of this data element, you must report by the date specified in §98.236(cc) the total annual oil throughput from all wells and the API Well Number(s) for the well(s) included in this volume.

(B) An estimate of the fraction of oil throughput reported in paragraph (j)(2)(i)(A) of this section sent to atmospheric tanks in the basin that controlled emissions with flares.

(C) An estimate of the fraction of oil throughput reported in paragraph (j)(2)(i)(A) of this section sent to atmospheric tanks in the basin that controlled emissions with vapor recovery systems.

(D) The number of atmospheric tanks in the basin.

(E) The number of wells with gas-liquid separators ("Count" from Equation W-15 of this subpart) in the basin.

(F) The number of wells without gas-liquid separators ("Count" from Equation W-15 of this subpart) in the basin.

(ii) Report the information specified in paragraphs (j)(2)(ii)(A) through (D) of this section for each sub-basin with atmospheric tanks whose emissions were calculated using Calculation Method 3 and that did not control emissions with flares.

(A) Sub-basin ID.

(B) The number of atmospheric tanks in the sub-basin that did not control emissions with flares.

(C) Annual CO₂ emissions, in metric tons CO₂, from atmospheric tanks in the sub-basin that did not control emissions with flares, calculated using Equation W-15 of this subpart and adjusted for vapor recovery, if applicable.

(D) Annual CH₄ emissions, in metric tons CH₄, from atmospheric tanks in the sub-basin that did not control emissions with flares, calculated using Equation W-15 of this subpart and adjusted for vapor recovery, if applicable.

(iii) Report the information specified in paragraphs (j)(2)(iii)(A) through (E) of this section for each sub-basin with atmospheric tanks whose emissions were calculated using Calculation Method 3 and that controlled emissions with flares.

(A) Sub-basin ID.

(B) The number of atmospheric tanks in the sub-basin that controlled emissions with flares.

(C) Annual CO₂ emissions, in metric tons CO₂, from atmospheric tanks that controlled emissions with flares.

(D) Annual CH₄ emissions, in metric tons CH₄, from atmospheric tanks that

controlled emissions with flares.

(E) Annual N₂O emissions, in metric tons N₂O, from atmospheric tanks that controlled emissions with flares.

(3) If you used Calculation Method 1 or Calculation Method 2, and any gas-liquid separator liquid dump valves did not close properly during the calendar year, then you must report the information specified in paragraphs (j)(3)(i) through (iv) of this section for each sub-basin.

(i) The total number of gas-liquid separators whose liquid dump valves did not close properly during the calendar year.

(ii) The total time the dump valves on gas-liquid separators did not close properly in the calendar year, in hours (sum of the "T_n" values used in Equation W-16 of this subpart).

(iii) Annual CO₂ emissions, in metric tons CO₂, that resulted from dump valves on gas-liquid separators not closing properly during the calendar year, calculated using Equation W-16 of this subpart.

(iv) Annual CH₄ emissions, in metric tons CH₄, that resulted from the dump valves on gas-liquid separators not closing properly during the calendar year, calculated using Equation W-16 of this subpart.

(k) *Transmission storage tanks.* You must indicate whether your facility contains any transmission storage tanks. If your facility contains at least one transmission storage tank, then you must report the information specified in paragraphs (k)(1) through (3) of this section for each transmission storage tank vent stack.

(1) For each transmission storage tank vent stack, report the information specified in (k)(1)(i) through (iv) of this section.

(i) The unique name or ID number for the transmission storage tank vent stack.

(ii) Method used to determine if dump valve leakage occurred.

(iii) Indicate whether scrubber dump valve leakage occurred for the transmission storage tank vent according to §98.233(k)(2).

(iv) Indicate if there is a flare attached to the transmission storage tank vent stack.

(2) If scrubber dump valve leakage occurred for a transmission storage tank vent stack, as reported in paragraph (k)(1)(iii) of this section, and the vent stack vented directly to the atmosphere during the calendar year, then you must report the information specified in paragraphs (k)(2)(i) through (v) of this section for each transmission storage vent stack where scrubber dump valve leakage occurred.

(i) Method used to measure the leak rate.

(ii) Measured leak rate (average leak rate from a continuous flow measurement device), in standard cubic feet per hour.

(iii) Duration of time that the leak is counted as having occurred, in hours, as determined in §98.233(k)(3) (may use best available data if a continuous flow

measurement device was used).

(iv) Annual CO₂ emissions, in metric tons CO₂, that resulted from venting gas directly to the atmosphere, calculated according to §98.233(k)(1) through (4).

(v) Annual CH₄ emissions, in metric tons CH₄, that resulted from venting gas directly to the atmosphere, calculated according to §98.233(k)(1) through (4).

(3) If scrubber dump valve leakage occurred for a transmission storage tank vent stack, as reported in paragraph (k)(1)(iii), and the vent stack vented to a flare during the calendar year, then you must report the information specified in paragraphs (k)(3)(i) through (vi) of this section.

(i) Method used to measure the leak rate.

(ii) Measured leakage rate (average leak rate from a continuous flow measurement device) in standard cubic feet per hour.

(iii) Duration of time that flaring occurred in hours, as defined in §98.233(k)(3) (may use best available data if a continuous flow measurement device was used).

(iv) Annual CO₂ emissions, in metric tons CO₂, that resulted from flaring gas, calculated according to §98.233(k)(5).

(v) Annual CH₄ emissions, in metric tons CH₄, that resulted from flaring gas, calculated according to §98.233(k)(5).

(vi) Annual N₂O emissions, in metric tons N₂O, that resulted from flaring gas, calculated according to §98.233(k)(5).

(l) *Well testing.* You must indicate whether you performed gas well or oil well testing, and if the testing of gas wells or oil wells resulted in vented or flared emissions during the calendar year. If you performed well testing that resulted in vented or flared emissions during the calendar year, then you must report the information specified in paragraphs (l)(1) through (4) of this section, as applicable.

(1) If you used Equation W-17A to calculate annual volumetric natural gas emissions at actual conditions from oil wells and the emissions are not vented to a flare, then you must report the information specified in paragraphs (l)(1)(i) through (vi) of this section.

(i) Number of wells tested in the calendar year.

(ii) Average number of well testing days per well for well(s) tested in the calendar year.

(iii) Average gas to oil ratio for well(s) tested, in cubic feet of gas per barrel of oil.

(iv) Average flow rate for well(s) tested, in barrels of oil per day. You may delay reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells that are tested. If you elect to delay reporting of this data element, you must report by the date specified in §98.236(cc) the measured average flow rate for well(s) tested and the API Well Number(s) for the well(s) included in the measurement.

		<p>(v) Annual CO₂ emissions, in metric tons CO₂, calculated according to §98.233(l).</p> <p>(vi) Annual CH₄ emissions, in metric tons CH₄, calculated according to §98.233(l).</p> <p>(2) If you used Equation W-17A to calculate annual volumetric natural gas emissions at actual conditions from oil wells and the emissions are vented to a flare, then you must report the information specified in paragraphs (l)(2)(i) through (vii) of this section.</p> <p>(i) Number of wells tested in the calendar year.</p> <p>(ii) Average number of well testing days per well for well(s) tested in the calendar year.</p> <p>(iii) Average gas to oil ratio for well(s) tested, in cubic feet of gas per barrel of oil.</p> <p>(iv) Average flow rate for well(s) tested, in barrels of oil per day. You may delay reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells that are tested. If you elect to delay reporting of this data element, you must report by the date specified in §98.236(cc) the measured average flow rate for well(s) tested and the API Well Number(s) for the well(s) included in the measurement.</p> <p>(v) Annual CO₂ emissions, in metric tons CO₂, calculated according to §98.233(l).</p> <p>(vi) Annual CH₄ emissions, in metric tons CH₄, calculated according to §98.233(l).</p> <p>(vii) Annual N₂O emissions, in metric tons N₂O, calculated according to §98.233(l).</p> <p>(3) If you used Equation W-17B to calculate annual volumetric natural gas emissions at actual conditions from gas wells and the emissions were not vented to a flare, then you must report the information specified in paragraphs (l)(3)(i) through (v) of this section.</p> <p>(i) Number of wells tested in the calendar year.</p> <p>(ii) Average number of well testing days per well for well(s) tested in the calendar year.</p> <p>(iii) Average annual production rate for well(s) tested, in actual cubic feet per day. You may delay reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells that are tested. If you elect to delay reporting of this data element, you must report by the date specified in §98.236(cc) the measured average annual production rate for well(s) tested and the API Well Number(s) for the well(s) included in the measurement.</p> <p>(iv) Annual CO₂ emissions, in metric tons CO₂, calculated according to §98.233(l).</p> <p>(v) Annual CH₄ emissions, in metric tons CH₄, calculated according to §98.233(l).</p> <p>(4) If you used Equation W-17B to calculate annual volumetric natural gas emissions at actual conditions from gas wells and the emissions were vented to a flare, then you must report the information specified in paragraphs (l)(4)(i) through (vi) of this section.</p>
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		<p>(i) Number of wells tested in calendar year.</p> <p>(ii) Average number of well testing days per well for well(s) tested in the calendar year.</p> <p>(iii) Average annual production rate for well(s) tested, in actual cubic feet per day. You may delay reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells that are tested. If you elect to delay reporting of this data element, you must report by the date specified in §98.236(cc) the measured average annual production rate for well(s) tested and the API Well Number(s) for the well(s) included in the measurement.</p> <p>(iv) Annual CO₂ emissions, in metric tons CO₂, calculated according to §98.233(l).</p> <p>(v) Annual CH₄ emissions, in metric tons CH₄, calculated according to §98.233(l).</p> <p>(vi) Annual N₂O emissions, in metric tons N₂O, calculated according to §98.233(l).</p> <p>(m) <i>Associated natural gas</i>. You must indicate whether any associated gas was vented or flared during the calendar year. If associated gas was vented or flared during the calendar year, then you must report the information specified in paragraphs (m)(1) through (8) of this section for each sub-basin.</p> <p>(1) Sub-basin ID.</p> <p>(2) Indicate whether any associated gas was vented directly to the atmosphere without flaring.</p> <p>(3) Indicate whether any associated gas was flared.</p> <p>(4) Average gas to oil ratio, in standard cubic feet of gas per barrel of oil (average of the "GOR" values used in Equation W-18 of this subpart).</p> <p>(5) Volume of oil produced, in barrels, in the calendar year during the time periods in which associated gas was vented or flared (the sum of "V_{p,q}" used in Equation W-18 of this subpart). You may delay reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells from which associated gas was vented or flared. If you elect to delay reporting of this data element, you must report by the date specified in §98.236(cc) the volume of oil produced for well(s) with associated gas venting and flaring and the API Well Number(s) for the well(s) included in the measurement.</p> <p>(6) Total volume of associated gas sent to sales, in standard cubic feet, in the calendar year during time periods in which associated gas was vented or flared (the sum of "SG" values used in Equation W-18 of §98.233(m)). You may delay reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells from which associated gas was vented or flared. If you elect to delay reporting of this data element, you must report by the date specified in §98.236(cc) the measured total volume of associated gas sent to sales for well(s) with associated gas venting and flaring and the API Well Number(s) for the well(s) included in the measurement.</p> <p>(7) If you had associated gas emissions vented directly to the atmosphere without flaring, then you must report the information specified in paragraphs (m)(7)(i) through (iii) of this section for each sub-basin.</p> <p>(i) Total number of wells for which associated gas was vented directly to the</p>
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atmosphere without flaring.

(ii) Annual CO₂ emissions, in metric tons CO₂, calculated according to §98.233(m) (3) and (4).

(iii) Annual CH₄ emissions, in metric tons CH₄, calculated according to §98.233(m) (3) and (4).

(8) If you had associated gas emissions that were flared, then you must report the information specified in paragraphs (m)(8)(i) through (iv) of this section for each sub-basin.

(i) Total number of wells for which associated gas was flared.

(ii) Annual CO₂ emissions, in metric tons CO₂, calculated according to §98.233(m) (5).

(iii) Annual CH₄ emissions, in metric tons CH₄, calculated according to §98.233(m) (5).

(iv) Annual N₂O emissions, in metric tons N₂O, calculated according to §98.233(m) (5).

(n) *Flare stacks.* You must indicate if your facility contains any flare stacks. You must report the information specified in paragraphs (n)(1) through (12) of this section for each flare stack at your facility, and for each industry segment applicable to your facility.

(1) Unique name or ID for the flare stack. For the onshore petroleum and natural gas production industry segment, a different name or ID may be used for a single flare stack for each location where it operates at in a given calendar year.

(2) Indicate whether the flare stack has a continuous flow measurement device.

(3) Indicate whether the flare stack has a continuous gas composition analyzer on feed gas to the flare.

(4) Volume of gas sent to the flare, in standard cubic feet ("V_s" in Equations W-19 and W-20 of this subpart).

(5) Fraction of the feed gas sent to an un-lit flare ("Z_u" in Equation W-19 of this subpart).

(6) Flare combustion efficiency, expressed as the fraction of gas combusted by a burning flare.

(7) Mole fraction of CH₄ in the feed gas to the flare ("X_{CH₄}" in Equation W-19 of this subpart).

(8) Mole fraction of CO₂ in the feed gas to the flare ("X_{CO₂}" in Equation W-20 of this subpart).

(9) Annual CO₂ emissions, in metric tons CO₂ (refer to Equation W-20 of this subpart).

(10) Annual CH₄ emissions, in metric tons CH₄ (refer to Equation W-19 of this subpart).

(11) Annual N₂O emissions, in metric tons N₂O (refer to Equation W-40 of this subpart).

(12) Indicate whether a CEMS was used to measure emissions from the flare. If a CEMS was used to measure emissions from the flare, then you are not required to report N₂O and CH₄ emissions for the flare stack.

(o) *Centrifugal compressors.* You must indicate whether your facility has centrifugal compressors. You must report the information specified in paragraphs (o)(1) and (2) of this section for all centrifugal compressors at your facility. For each compressor source or manifolded group of compressor sources that you conduct as found leak measurements as specified in §98.233(o)(2) or (4), you must report the information specified in paragraph (o)(3) of this section. For each compressor source or manifolded group of compressor sources that you conduct continuous monitoring as specified in §98.233(o)(3) or (5), you must report the information specified in paragraph (o)(4) of this section. Centrifugal compressors in onshore petroleum and natural gas production are not required to report information in paragraphs (o)(1) through (4) of this section and instead must report the information specified in paragraph (o)(5) of this section.

(1) *Compressor activity data.* Report the information specified in paragraphs (o)(1) (i) through (xiv) of this section for each centrifugal compressor located at your facility.

(i) Unique name or ID for the centrifugal compressor.

(ii) Hours in operating-mode.

(iii) Hours in not-operating-depressurized-mode.

(iv) Indicate whether the compressor was measured in operating-mode.

(v) Indicate whether the compressor was measured in not-operating-depressurized-mode.

(vi) Indicate which, if any, compressor sources are part of a manifolded group of compressor sources.

(vii) Indicate which, if any, compressor sources are routed to a flare.

(viii) Indicate which, if any, compressor sources have vapor recovery.

(ix) Indicate which, if any, compressor source emissions are captured for fuel use or are routed to a thermal oxidizer.

(x) Indicate whether the compressor has blind flanges installed and associated dates.

(xi) Indicate whether the compressor has wet or dry seals.

(xii) If the compressor has wet seals, the number of wet seals.

		<p>(xiii) Power output of the compressor driver (hp).</p> <p>(xiv) Indicate whether the compressor had a scheduled depressurized shutdown during the reporting year.</p> <p>(2) <i>Compressor source.</i> (i) For each compressor source at each compressor, report the information specified in paragraphs (o)(2)(i)(A) through (C) of this section.</p> <p>(A) Centrifugal compressor name or ID. Use the same ID as in paragraph (o)(1)(i) of this section.</p> <p>(B) Centrifugal compressor source (wet seal, isolation valve, or blowdown valve).</p> <p>(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.</p> <p>(ii) For each leak or vent, report the information specified in paragraphs (o)(2)(ii)(A) through (E) of this section.</p> <p>(A) Indicate whether the leak or vent is for a single compressor source or manifolded group of compressor sources and whether the emissions from the leak or vent are released to the atmosphere, routed to a flare, combustion (fuel or thermal oxidizer), or vapor recovery.</p> <p>(B) Indicate whether an as found measurement(s) as identified in §98.233(o)(2) or (4) was conducted on the leak or vent.</p> <p>(C) Indicate whether continuous measurements as identified in §98.233(o)(3) or (5) were conducted on the leak or vent.</p> <p>(D) Report emissions as specified in paragraphs (o)(2)(ii)(D)(1) and (2) of this section for the leak or vent. If the leak or vent is routed to a flare, combustion, or vapor recovery, you are not required to report emissions under this paragraph.</p> <p>(1) Annual CO₂ emissions, in metric tons CO₂.</p> <p>(2) Annual CH₄ emissions, in metric tons CH₄.</p> <p>(E) If the leak or vent is routed to flare, combustion, or vapor recovery, report the percentage of time that the respective device was operational when the compressor source emissions were routed to the device.</p> <p>(3) <i>As found measurement sample data.</i> 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.</p> <p>(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.</p>
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(A) Name or ID of leak or vent. Use same leak or vent ID as in paragraph (o)(2)(i)(C) of this section.

(B) Measurement date.

(C) Measurement method. If emissions were not detected when using a screening method, report the screening method. If emissions were detected using a screening method, report only the method subsequently used to measure the volumetric emissions.

(D) Measured flow rate, in standard cubic feet per hour.

(E) For each compressor attached to the leak or vent, report the compressor mode during which the measurement was taken.

(F) If the measurement is for a manifolded group of compressor sources, indicate whether the measurement location is prior to or after comingling with non-compressor emission sources.

(ii) For each compressor mode-source combination where a reporter emission factor as calculated in Equation W-23 was used to calculate emissions in Equation W-22, report the information specified in paragraphs (o)(3)(ii)(A) through (D) of this section.

(A) The compressor mode-source combination.

(B) The compressor mode-source combination reporter emission factor, in standard cubic feet per hour ($EF_{s,m}$ in Equation W-23).

(C) The total number of compressors measured in the compressor mode-source combination in the current reporting year and the preceding two reporting years ($Count_m$ in Equation W-23).

(D) Indicate whether the compressor mode-source combination reporter emission factor is facility-specific or based on all of the reporter's applicable facilities.

(4) *Continuous measurement data.* If the measurement methods specified in §98.233(o)(3) or (5) are conducted, report the information specified in paragraphs (o)(4)(i) through (iv) of this section for each continuous measurement conducted on each leak or vent associated with each compressor source or manifolded group of compressor sources.

(i) Name or ID of leak or vent. Use same leak or vent ID as in paragraph (o)(2)(i)(C) of this section.

(ii) Measured volume of flow during the reporting year, in million standard cubic feet.

(iii) Indicate whether the measured volume of flow during the reporting year includes compressor blowdown emissions as allowed for in §98.233(o)(3)(ii) and (o)(5)(iii).

(iv) If the measurement is for a manifolded group of compressor sources, indicate whether the measurement location is prior to or after comingling with non-compressor emission sources.

(5) *Onshore petroleum and natural gas production.* Centrifugal compressors with

wet seal degassing vents in onshore petroleum and natural gas production must report the information specified in paragraphs (o)(5)(i) through (iii) of this section.

(i) Number of centrifugal compressors that have wet seal oil degassing vents.

(ii) Annual CO₂ emissions, in metric tons CO₂, from centrifugal compressors with wet seal oil degassing vents.

(iii) Annual CH₄ emissions, in metric tons CH₄, from centrifugal compressors with wet seal oil degassing vents.

(p) *Reciprocating compressors.* You must indicate whether your facility has reciprocating compressors. You must report the information specified in paragraphs (p) (1) and (2) of this section for all reciprocating compressors at your facility. For each compressor source or manifolded group of compressor sources that you conduct as found leak measurements as specified in §98.233(p)(2) or (4), you must report the information specified in paragraph (p)(3) of this section. For each compressor source or manifolded group of compressor sources that you conduct continuous monitoring as specified in §98.233(p)(3) or (5), you must report the information specified in paragraph (p)(4) of this section. Reciprocating compressors in onshore petroleum and natural gas production are not required to report information in paragraphs (p)(1) through (4) of this section and instead must report the information specified in paragraph (p)(5) of this section.

(1) *Compressor activity data.* Report the information specified in paragraphs (p)(1) (i) through (xiv) of this section for each reciprocating compressor located at your facility.

(i) Unique name or ID for the reciprocating compressor.

(ii) Hours in operating-mode.

(iii) Hours in standby-pressurized-mode.

(iv) Hours in not-operating-depressurized-mode.

(v) Indicate whether the compressor was measured in operating-mode.

(vi) Indicate whether the compressor was measured in standby-pressurized-mode.

(vii) Indicate whether the compressor was measured in not-operating-depressurized-mode.

(viii) Indicate which, if any, compressor sources are part of a manifolded group of compressor sources.

(ix) Indicate which, if any, compressor sources are routed to a flare.

(x) Indicate which, if any, compressor sources have vapor recovery.

(xi) Indicate which, if any, compressor source emissions are captured for fuel use or are routed to a thermal oxidizer.

(xii) Indicate whether the compressor has blind flanges installed and associated

dates.

(xiii) Power output of the compressor driver (hp).

(xiv) Indicate whether the compressor had a scheduled depressurized shutdown during the reporting year.

(2) *Compressor source.* (i) For each compressor source at each compressor, report the information specified in paragraphs (p)(2)(i)(A) through (C) of this section.

(A) Reciprocating compressor name or ID. Use the same ID as in paragraph (p)(1)(i) of this section.

(B) Reciprocating compressor source (isolation valve, blowdown valve, or rod packing).

(C) Unique name or ID for the leak or vent. If the leak or vent is connected to a manifolded group of compressor sources, use the same leak or vent ID for each compressor source in the manifolded group. If multiple compressor sources are released through a single vent for which continuous measurements are used, use the same leak or vent ID for each compressor source released via the measured vent. For a single compressor using as found measurements, you must provide a different leak or vent ID for each compressor source.

(ii) For each leak or vent, report the information specified in paragraphs (p)(2)(ii)(A) through (E) of this section.

(A) Indicate whether the leak or vent is for a single compressor source or manifolded group of compressor sources and whether the emissions from the leak or vent are released to the atmosphere, routed to a flare, combustion (fuel or thermal oxidizer), or vapor recovery.

(B) Indicate whether an as found measurement(s) as identified in §98.233(p)(2) or (4) was conducted on the leak or vent.

(C) Indicate whether continuous measurements as identified in §98.233(p)(3) or (5) were conducted on the leak or vent.

(D) Report emissions as specified in paragraphs (p)(2)(ii)(D)(1) and (2) of this section for the leak or vent. If the leak or vent is routed to flare, combustion, or vapor recovery, you are not required to report emissions under this paragraph.

(1) Annual CO₂ emissions, in metric tons CO₂.

(2) Annual CH₄ emissions, in metric tons CH₄.

(E) If the leak or vent is routed to flare, combustion, or vapor recovery, report the percentage of time that the respective device was operational when the compressor source emissions were routed to the device.

(3) *As found measurement sample data.* If the measurement methods specified in §98.233(p)(2) or (4) are conducted, report the information specified in paragraph (p)(3)(i) of this section. If the calculation specified in §98.233(p)(6)(ii) is performed, report the information specified in paragraph (p)(3)(ii) of this section.

(i) For each as found measurement performed on a leak or vent, report the information specified in paragraphs (p)(3)(i)(A) through (F) of this section.

(A) Name or ID of leak or vent. Use same leak or vent ID as in paragraph (p)(2)(i)(C) of this section.

(B) Measurement date.

(C) Measurement method. If emissions were not detected when using a screening method, report the screening method. If emissions were detected using a screening method, report only the method subsequently used to measure the volumetric emissions.

(D) Measured flow rate, in standard cubic feet per hour.

(E) For each compressor attached to the leak or vent, report the compressor mode during which the measurement was taken.

(F) If the measurement is for a manifolded group of compressor sources, indicate whether the measurement location is prior to or after comingling with non-compressor emission sources.

(ii) For each compressor mode-source combination where a reporter emission factor as calculated in Equation W-28 was used to calculate emissions in Equation W-27, report the information specified in paragraphs (p)(3)(ii)(A) through (D) of this section

(A) The compressor mode-source combination.

(B) The compressor mode-source combination reporter emission factor, in standard cubic feet per hour ($EF_{s,m}$ in Equation W-28).

(C) The total number of compressors measured in the compressor mode-source combination in the current reporting year and the preceding two reporting years ($Count_m$ in Equation W-28).

(D) Indicate whether the compressor mode-source combination reporter emission factor is facility-specific or based on all of the reporter's applicable facilities.

(4) *Continuous measurement data.* If the measurement methods specified in §98.233(p)(3) or (5) are conducted, report the information specified in paragraphs (p)(4)(i) through (iv) of this section for each continuous measurement conducted on each leak or vent associated with each compressor source or manifolded group of compressor sources.

(i) Name or ID of leak or vent. Use same leak or vent ID as in paragraph (p)(2)(i)(C) of this section.

(ii) Measured volume of flow during the reporting year, in million standard cubic feet.

(iii) Indicate whether the measured volume of flow during the reporting year includes compressor blowdown emissions as allowed for in §98.233(p)(3)(ii) and (p)(5)(iii).

(iv) If the measurement is for a manifolded group of compressor sources, indicate whether the measurement location is prior to or after comingling with non-compressor

emission sources.

(5) *Onshore petroleum and natural gas production.* Reciprocating compressors in onshore petroleum and natural gas production must report the information specified in paragraphs (p)(5)(i) through (iii) of this section.

(i) Number of reciprocating compressors.

(ii) Annual CO₂ emissions, in metric tons CO₂, from reciprocating compressors.

(iii) Annual CH₄ emissions, in metric tons CH₄, from reciprocating compressors.

(q) *Equipment leak surveys.* If your facility is subject to the requirements of §98.233(q), then you must report the information specified in paragraphs (q)(1) and (2) of this section. Natural gas distribution facilities with emission sources listed in §98.232(i)(1) must also report the information specified in paragraph (q)(3) of this section.

(1) You must report the information specified in paragraphs (q)(1)(i) and (ii) of this section.

(i) Except as specified in paragraph (q)(1)(ii) of this section, the number of complete equipment leak surveys performed during the calendar year.

(ii) Natural gas distribution facilities performing equipment leak surveys across a multiple year leak survey cycle must report the number of years in the leak survey cycle.

(2) You must indicate whether your facility contains any of the component types listed in §98.232(d)(7), (e)(7), (f)(5), (g)(3), (h)(4), or (i)(1), for your facility's industry segment. For each component type that is located at your facility, you must report the information specified in paragraphs (q)(2)(i) through (v) of this section. If a component type is located at your facility and no leaks were identified from that component, then you must report the information in paragraphs (q)(2)(i) through (v) of this section but report a zero ("0") for the information required according to paragraphs (q)(2)(iii), (iv), and (v) of this section.

(i) Component type.

(ii) Total number of the surveyed component type that were identified as leaking in the calendar year ("x_p" in Equation W-30 of this subpart for the component type).

(iii) Average time the surveyed components are assumed to be leaking and operational, in hours (average of "T_{p,z}" from Equation W-30 of this subpart for the component type).

(iv) Annual CO₂ emissions, in metric tons CO₂, for the component type as calculated using Equation W-30 (for surveyed components only).

(v) Annual CH₄ emissions, in metric tons CH₄, for the component type as calculated using Equation W-30 (for surveyed components only).

(3) Natural gas distribution facilities with emission sources listed in §98.232(i)(1) must also report the information specified in paragraphs (q)(3)(i) through (viii) and, if applicable, (q)(3)(ix) of this section.

(i) Number of above grade transmission-distribution transfer stations surveyed in

the calendar year.

(ii) Number of meter/regulator runs at above grade transmission-distribution transfer stations surveyed in the calendar year ("Count_{MR,y}" from Equation W-31 of this subpart, for the current calendar year).

(iii) Average time that meter/regulator runs surveyed in the calendar year were operational, in hours (average of "T_{w,y}" from Equation W-31 of this subpart, for the current calendar year).

(iv) Number of above grade transmission-distribution transfer stations surveyed in the current leak survey cycle.

(v) Number of meter/regulator runs at above grade transmission-distribution transfer stations surveyed in current leak survey cycle (sum of "Count_{MR,y}" from Equation W-31 of this subpart, for all calendar years in the current leak survey cycle).

(vi) Average time that meter/regulator runs surveyed in the current leak survey cycle were operational, in hours (average of "T_{w,y}" from Equation W-31 of this subpart, for all years included in the leak survey cycle).

(vii) Meter/regulator run CO₂ emission factor based on all surveyed transmission-distribution transfer stations in the current leak survey cycle, in standard cubic feet of CO₂ per operational hour of all meter/regulator runs ("EF_{s,MR,i}" for CO₂ calculated using Equation W-31 of this subpart).

(viii) Meter/regulator run CH₄ emission factor based on all surveyed transmission-distribution transfer stations in the current leak survey cycle, in standard cubic feet of CH₄ per operational hour of all meter/regulator runs ("EF_{s,MR,i}" for CH₄ calculated using Equation W-31 of this subpart).

(ix) If your natural gas distribution facility performs equipment leak surveys across a multiple year leak survey cycle, you must also report:

(A) The total number of meter/regulator runs at above grade transmission-distribution transfer stations at your facility ("Count_{MR}" in Equation W-32B of this subpart).

(B) Average estimated time that each meter/regulator run at above grade transmission-distribution transfer stations was operational in the calendar year, in hours per meter/regulator run ("T_{w,avg}" in Equation W-32B of this subpart).

(C) Annual CO₂ emissions, in metric tons CO₂, for all above grade transmission-distribution transfer stations at your facility.

(D) Annual CH₄ emissions, in metric tons CH₄, for all above grade transmission-distribution transfer stations at your facility.

(r) *Equipment leaks by population count.* If your facility is subject to the requirements of §98.233(r), then you must report the information specified in paragraphs (r)(1) through (3) of this section, as applicable.

(1) You must indicate whether your facility contains any of the emission source types required to use Equation W-32A of this subpart. You must report the information specified in paragraphs (r)(1)(i) through (v) of this section separately for each emission source type required to use Equation W-32A of this subpart that is located at your facility. Onshore petroleum and natural gas production facilities must report the

information specified in paragraphs (r)(1)(i) through (v) of this section separately by component type, service type, and geographic location (*i.e.*, Eastern U.S. or Western U.S.).

(i) Emission source type. Onshore petroleum and natural gas production facilities must report the component type, service type and geographic location.

(ii) Total number of the emission source type at the facility (“Count_e” in Equation W-32A of this subpart).

(iii) Average estimated time that the emission source type was operational in the calendar year, in hours (“T_e” in Equation W-32A of this subpart).

(iv) Annual CO₂ emissions, in metric tons CO₂, for the emission source type.

(v) Annual CH₄ emissions, in metric tons CH₄, for the emission source type.

(2) Natural gas distribution facilities must also report the information specified in paragraphs (r)(2)(i) through (v) of this section.

(i) Number of above grade transmission-distribution transfer stations at the facility.

(ii) Number of above grade metering-regulating stations that are not transmission-distribution transfer stations at the facility.

(iii) Total number of meter/regulator runs at above grade metering-regulating stations that are not above grade transmission-distribution transfer stations (“Count_{MR}” in Equation W-32B of this subpart).

(iv) Average estimated time that each meter/regulator run at above grade metering-regulating stations that are not above grade transmission-distribution transfer stations was operational in the calendar year, in hours per meter/regulator run (“T_{w,avg}” in Equation W-32B of this subpart).

(v) If your facility has above grade metering-regulating stations that are not above grade transmission-distribution transfer stations and your facility also has above grade transmission-distribution transfer stations, you must also report:

(A) Annual CO₂ emissions, in metric tons CO₂, from above grade metering-regulating stations that are not above grade transmission-distribution transfer stations.

(B) Annual CH₄ emissions, in metric tons CH₄, from above grade metering-regulating stations that are not above grade transmission-distribution transfer stations.

(3) Onshore petroleum and natural gas production facilities must also report the information specified in paragraphs (r)(3)(i) and (ii) of this section.

(i) Calculation method used.

(ii) Onshore petroleum and natural gas production facilities must report the information specified in paragraphs (r)(3)(ii)(A) and (B) of this section, for each major equipment type, production type (*i.e.*, natural gas or crude oil), and geographic location combination in Tables W-1B and W-1C of this subpart.

(A) An indication of whether the facility contains the major equipment type.

(B) If the facility does contain the equipment type, the count of the major equipment type.

(s) *Offshore petroleum and natural gas production.* You must report the information specified in paragraphs (s)(1) through (3) of this section for each emission source type listed in the most recent BOEMRE study.

(1) Annual CO₂ emissions, in metric tons CO₂.

(2) Annual CH₄ emissions, in metric tons CH₄.

(3) Annual N₂O emissions, in metric tons N₂O.

(t) [Reserved]

(u) [Reserved]

(v) [Reserved]

(w) *EOR injection pumps.* You must indicate whether CO₂ EOR injection was used at your facility during the calendar year and if any EOR injection pump blowdowns occurred during the year. If any EOR injection pump blowdowns occurred during the calendar year, then you must report the information specified in paragraphs (w)(1) through (8) of this section for each EOR injection pump system.

(1) Sub-basin ID.

(2) EOR injection pump system identifier.

(3) Pump capacity, in barrels per day.

(4) Total volume of EOR injection pump system equipment chambers, in cubic feet (“V_v” in Equation W-37 of this subpart).

(5) Number of blowdowns for the EOR injection pump system in the calendar year.

(6) Density of critical phase EOR injection gas, in kilograms per cubic foot (“R_c” in Equation W-37 of this subpart).

(7) Mass fraction of CO₂ in critical phase EOR injection gas (“GHG_{CO2}” in Equation W-37 of this subpart).

(8) Annual CO₂ emissions, in metric tons CO₂, 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_{nl}” in Equation W-38 of this subpart).

(3) Average CO₂ retained in hydrocarbon liquids downstream of the storage tank, in metric tons per barrel under standard conditions (“S_{nl}” in Equation W-38 of this subpart).

(4) Annual CO₂ emissions, in metric tons CO₂, from CO₂ retained in hydrocarbon liquids produced through EOR operations downstream of the storage tank (“Mass_{CO2}” in Equation W-38 of this subpart).

(y) [Reserved]

(z) *Combustion equipment at onshore petroleum and natural gas production facilities and natural gas distribution facilities.* If your facility is required by §98.232(c)(22) or (i)(7) to report emissions from combustion equipment, then you must indicate whether your facility has any combustion units subject to reporting according to paragraphs (a)(1)(xvii) or (a)(8)(i) of this section. If your facility contains any combustion units subject to reporting according to paragraphs (a)(1)(xvii) or (a)(8)(i) of this section, then you must report the information specified in paragraphs (z)(1) and (2) of this section, as applicable.

(1) Indicate whether the combustion units include: External fuel combustion units with a rated heat capacity less than or equal to 5 million Btu per hour; or, internal fuel combustion units that are not compressor-drivers, with a rated heat capacity less than or equal to 1 mmBtu/hr (or the equivalent of 130 horsepower). If the facility contains external fuel combustion units with a rated heat capacity less than or equal to 5 million Btu per hour or internal fuel combustion units that are not compressor-drivers, with a rated heat capacity less than or equal to 1 million Btu per hour (or the equivalent of 130 horsepower), then you must report the information specified in paragraphs (z)(1)(i) and (ii) of this section for each unit type.

(i) The type of combustion unit.

(ii) The total number of combustion units.

(2) Indicate whether the combustion units include: External fuel combustion units with a rated heat capacity greater than 5 million Btu per hour; internal fuel combustion units that are not compressor-drivers, with a rated heat capacity greater than 1 million Btu per hour (or the equivalent of 130 horsepower); or, internal fuel combustion units of any heat capacity that are compressor-drivers. If your facility contains: External fuel combustion units with a rated heat capacity greater than 5 mmBtu/hr; internal fuel combustion units that are not compressor-drivers, with a rated heat capacity greater than 1 million Btu per hour (or the equivalent of 130 horsepower); or internal fuel combustion units of any heat capacity that are compressor-drivers, then you must report the information specified in paragraphs (z)(2)(i) through (vi) of this section for each combustion unit type and fuel type combination.

(i) The type of combustion unit.

(ii) The type of fuel combusted.

(iii) The quantity of fuel combusted in the calendar year, in thousand standard cubic feet, gallons, or tons.

(iv) Annual CO₂ emissions, in metric tons CO₂, calculated according to §98.233(z)

(1) and (2).

(v) Annual CH₄ emissions, in metric tons CH₄, calculated according to §98.233(z) (1) and (2).

(vi) Annual N₂O emissions, in metric tons N₂O, calculated according to §98.233(z) (1) and (2).

(aa) Each facility must report the information specified in paragraphs (aa)(1) through (9) of this section, for each applicable industry segment, by using best available data. If a quantity required to be reported is zero, you must report zero as the value.

(1) For onshore petroleum and natural gas production, report the data specified in paragraphs (aa)(1)(i) and (ii) of this section.

(i) Report the information specified in paragraphs (aa)(1)(i)(A) through (C) of this section for the basin as a whole.

(A) The quantity of gas produced in the calendar year from wells, in thousand standard cubic feet. This includes gas that is routed to a pipeline, vented or flared, or used in field operations. This does not include gas injected back into reservoirs or shrinkage resulting from lease condensate production.

(B) The quantity of gas produced in the calendar year for sales, in thousand standard cubic feet.

(C) The quantity of crude oil and condensate produced in the calendar year for sales, in barrels.

(ii) Report the information specified in paragraphs (aa)(1)(ii)(A) through (M) of this section for each unique sub-basin category.

(A) State.

(B) County.

(C) Formation type.

(D) The number of producing wells at the end of the calendar year (exclude only those wells permanently taken out of production, *i.e.*, plugged and abandoned) .

(E) The number of producing wells acquired during the calendar year.

(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 taken out of production (*i.e.*, plugged and abandoned) during the calendar year.

(I) Average mole fraction of CH₄ in produced gas.

(J) Average mole fraction of CO₂ in produced gas.

(K) If an oil sub-basin, report the average GOR of all wells, in thousand standard cubic feet per barrel.

(L) If an oil sub-basin, report the average API gravity of all wells.

(M) If an oil sub-basin, report average low pressure separator pressure, in pounds per square inch gauge.

(2) For offshore production, report the quantities specified in paragraphs (aa)(2)(i) and (ii) of this section.

(i) The total quantity of gas handled at the offshore platform in the calendar year, in thousand standard cubic feet, including production volumes and volumes transferred via pipeline from another location.

(ii) The total quantity of oil and condensate handled at the offshore platform in the calendar year, in barrels, including production volumes and volumes transferred via pipeline from another location.

(3) For natural gas processing, report the information specified in paragraphs (aa)(3)(i) through (vii) of this section.

(i) The quantity of natural gas received at the gas processing plant in the calendar year, in thousand standard cubic feet.

(ii) The quantity of processed (residue) gas leaving the gas processing plant in the calendar year, in thousand standard cubic feet.

(iii) The cumulative quantity of all NGLs (bulk and fractionated) received at the gas processing plant in the calendar year, in barrels.

(iv) The cumulative quantity of all NGLs (bulk and fractionated) leaving the gas processing plant in the calendar year, in barrels.

(v) Average mole fraction of CH₄ in natural gas received.

(vi) Average mole fraction of CO₂ in natural gas received.

(vii) Indicate whether the facility fractionates NGLs.

(4) For natural gas transmission compression, report the quantity specified in paragraphs (aa)(4)(i) through (v) of this section.

(i) The quantity of gas transported through the compressor station in the calendar year, in thousand standard cubic feet.

(ii) Number of compressors.

(iii) Total compressor power rating of all compressors combined, in horsepower.

(iv) Average upstream pipeline pressure, in pounds per square inch gauge.

(v) Average downstream pipeline pressure, in pounds per square inch gauge.

(5) For underground natural gas storage, report the quantities specified in paragraphs (aa)(5)(i) through (iii) of this section.

(i) The quantity of gas injected into storage in the calendar year, in thousand standard cubic feet.

(ii) The quantity of gas withdrawn from storage in the calendar year, in thousand standard cubic feet.

(iii) Total storage capacity, in thousand standard cubic feet.

(6) For LNG import equipment, report the quantity of LNG imported in the calendar year, in thousand standard cubic feet.

(7) For LNG export equipment, report the quantity of LNG exported in the calendar year, in thousand standard cubic feet.

(8) For LNG storage, report the quantities specified in paragraphs (aa)(8)(i) through (iii) of this section.

(i) The quantity of LNG added into storage in the calendar year, in thousand standard cubic feet.

(ii) The quantity of LNG withdrawn from storage in the calendar year, in thousand standard cubic feet.

(iii) Total storage capacity, in thousand standard cubic feet.

(9) For natural gas distribution, report the quantities specified in paragraphs (aa)(9)(i) through (vii) of this section.

(i) The quantity of natural gas received at all custody transfer stations in the calendar year, in thousand standard cubic feet. This value may include meter corrections, but only for the calendar year covered by the annual report.

(ii) The quantity of natural gas withdrawn from in-system storage in the calendar year, in thousand standard cubic feet.

(iii) The quantity of natural gas added to in-system storage in the calendar year, in thousand standard cubic feet.

(iv) The quantity of natural gas delivered to end users, in thousand standard cubic feet. This value does not include stolen gas, or gas that is otherwise unaccounted for.

(v) The quantity of natural gas transferred to third parties such as other LDCs or pipelines, in thousand standard cubic feet. This value does not include stolen gas, or gas that is otherwise unaccounted for.

(vi) The quantity of natural gas consumed by the LDC for operational purposes, in thousand standard cubic feet.

(vii) The estimated quantity of gas stolen in the calendar year, in thousand standard cubic feet.

		<p>(bb) For any missing data procedures used, report the information in §98.3(c)(8) except as provided in paragraphs (bb)(1) and (2) of this section.</p> <p>(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.</p> <p>(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.</p> <p>(cc) If you elect to delay reporting the information in paragraph (g)(5)(i), (g)(5)(ii), (h)(1)(iv), (h)(2)(iv), (j)(1)(iii), (j)(2)(i)(A), (l)(1)(iv), (l)(2)(iv), (l)(3)(iii), (l)(4)(iii), (m)(5), or (m)(6) of this section, you must report the information required in that paragraph no later than the date 2 years following the date specified in §98.3(b) introductory text.</p>
<p>Subpart X – Petrochemical Production (§98.246)</p>	<p>All In</p>	<p>In addition to the information required by §98.3(c), each annual report must contain the information specified in paragraphs (a), (b), or (c) of this section, as appropriate for each process unit.</p> <p>(a) If you use the mass balance methodology in §98.243(c), you must report the information specified in paragraphs (a)(1) through (13) of this section for each type of petrochemical produced, reported by process unit.</p> <p>(1) The petrochemical process unit ID number or other appropriate descriptor.</p> <p>(2) The type of petrochemical produced, names of products, and names of carbon-containing feedstocks.</p> <p>(3) Annual CO₂ emissions calculated using Equation X-4 of this subpart.</p> <p>(4) The temperature (in °F) at which the gaseous feedstock and product volumes used in Equation X-1 of §98.243 were determined.</p> <p>(5) Annual quantity of each type of petrochemical produced from each process unit (metric tons).</p> <p>(6) For each feedstock and product, provide the information specified in paragraphs (a)(6)(i) through (a)(6)(iii) of this section.</p> <p>(i) Name of each method used to determine carbon content or molecular weight in accordance with §98.244(b)(4);</p> <p>(ii) Description of each type of device (e.g., flow meter, weighing device) used to determine flow or mass in accordance with §98.244(b)(1) through (3).</p> <p>(iii) Identification of each method (i.e., method number, title, or other description) used to determine flow or mass in accordance with §98.244(b)(1) through (3).</p> <p>(7) [Reserved]</p> <p>(8) Identification of each combustion unit that burned both process off-gas and supplemental fuel, including combustion units that are not part of the petrochemical process unit.</p> <p>(9) The number of days during which off-specification product was produced if the alternative to sampling and analysis specified in §98.243(c)(4) is used for a product, and,</p>

if applicable, the date of any process change that reduced the monthly average composition to less than 99.5 percent for each product or feedstock for which you comply with the alternative to sampling and analysis specified in §98.243(c)(4).

(10) You may elect to report the flow and carbon content of wastewater, and you may elect to report the annual mass of carbon released in fugitive emissions and in process vents that are not controlled with a combustion device. These values may be estimated based on engineering analyses. These values are not to be used in the mass balance calculation.

(11) If you determine carbon content or composition of a feedstock or product using a method under §98.244(b)(4)(xv)(B), report the information listed in paragraphs (a)(11)(i) through (a)(11)(iii) of this section. Include the information in paragraph (a)(11)(i) of this section in each annual report. Include the information in paragraphs (a)(11)(ii) and (a)(11)(iii) of this section only in the first applicable annual report, and provide any changes to this information in subsequent annual reports.

(i) Name or title of the analytical method.

(ii) A copy of the method. If the method is a modification of a method listed in §§98.244(b)(4)(i) through (xiv), you may provide a copy of only the sections that differ from the listed method.

(iii) An explanation of why an alternative to the methods listed in §§98.244(b)(4)(i) through (xiv) is needed.

(12) Name and annual quantity (in metric tons) of each carbon-containing feedstock included in Equations X-1, X-2, and X-3 of §98.243.

(13) Name and annual quantity (in metric tons) of each product included in Equations X-1, X-2, and X-3.

(b) If you measure emissions in accordance with §98.243(b), then you must report the information listed in paragraphs (b)(1) through (10) of this section.

(1) The petrochemical process unit ID or other appropriate descriptor, and the type of petrochemical produced.

(2) For CEMS used on stacks that include emissions from stationary combustion units that burn any amount of off-gas from the petrochemical process, report the relevant information required under §98.36(c)(2) and (e)(2)(vi) for the Tier 4 calculation methodology. Sections 98.36(c)(2)(ii) and (c)(2)(ix) do not apply for the purposes of this subpart.

(3) For CEMS used on stacks that do not include emissions from stationary combustion units, report the information required under §98.36(b)(6), (b)(7), and (e)(2)(vi).

(4) For each CEMS monitoring location that meets the conditions in paragraph (b) (2) or (3) of this section, provide an estimate based on engineering judgment of the fraction of the total CO₂ emissions that results from CO₂ directly emitted by the petrochemical process unit plus CO₂ generated by the combustion of off-gas from the petrochemical process unit.

(5) For each CEMS monitoring location that meets the conditions in paragraph (b) (2) of this section, report the CH₄ and N₂O emissions expressed in metric tons of each

		<p>gas. For each CEMS monitoring location, provide an estimate based on engineering judgment of the fraction of the total CH₄ and N₂O emissions that is attributable to combustion of off-gas from the petrochemical process unit.</p> <p>(6) [Reserved]</p> <p>(7) Information listed in §98.256(e) of subpart Y of this part for each flare that burns process off-gas.</p> <p>(8) Annual quantity of each type of petrochemical produced from each process unit (metric tons).</p> <p>(9) Name and annual quantity (in metric tons) of each carbon-containing feedstock.</p> <p>(10) Name and annual quantity (in metric tons) of each product.</p> <p>(c) If you comply with the combustion methodology specified in §98.243(d), you must report under this subpart the information listed in paragraphs (c)(1) through (c)(5) of this section.</p> <p>(1) The ethylene process unit ID or other appropriate descriptor.</p> <p>(2) For each stationary combustion unit that burns ethylene process off-gas (or group of stationary sources with a common pipe), except flares, the relevant information listed in §98.36 for the applicable Tier methodology. For each stationary combustion unit or group of units (as applicable) that burns ethylene process off-gas, provide an estimate based on engineering judgment of the fraction of the total emissions that is attributable to combustion of off-gas from the ethylene process unit.</p> <p>(3) Information listed in §98.256(e) of subpart Y of this part for each flare that burns ethylene process off-gas.</p> <p>(4) Name and annual quantity of each feedstock (metric tons).</p> <p>(5) Annual quantity of ethylene produced from each process unit (metric tons).</p>
Subpart Y – Petroleum Refineries (§98.256)	All In	<p>In addition to the reporting requirements of §98.3(c), you must report the information specified in paragraphs (a) through (q) of this section.</p> <p>(a) For combustion sources, follow the data reporting requirements under subpart C of this part (General Stationary Fuel Combustion Sources).</p> <p>(b) For hydrogen plants, follow the data reporting requirements under subpart P of this part (Hydrogen Production).</p> <p>(c)-(d) [Reserved]</p> <p>(e) For flares, owners and operators shall report:</p> <p>(1) The flare ID number (if applicable).</p> <p>(2) A description of the type of flare (steam assisted, air-assisted).</p> <p>(3) A description of the flare service (general facility flare, unit flare, emergency</p>

only or back-up flare).

(4) The calculated CO₂, CH₄, and N₂O annual emissions for each flare, expressed in metric tons of each pollutant emitted.

(5) A description of the method used to calculate the CO₂ emissions for each flare (e.g., reference section and equation number).

(6) If you use Equation Y-1a of §98.253, an indication of whether daily or weekly measurement periods are used, the annual volume of flare gas combusted (in scf/year) and the annual average molecular weight (in kg/kg-mole), and annual average carbon content of the flare gas (in kg carbon per kg flare gas).

(7) If you use Equation Y-1b of §98.253, an indication of whether daily or weekly measurement periods are used, the annual volume of flare gas combusted (in scf/year), the annual average CO₂ concentration (volume or mole percent), the number of carbon containing compounds other than CO₂ in the flare gas stream, and for each of the carbon containing compounds other than CO₂ in the flare gas stream:

(i) The annual average concentration of the compound (volume or mole percent).

(ii) [Reserved]

(8) If you use Equation Y-2 of this subpart, an indication of whether daily or weekly measurement periods are used, the annual volume of flare gas combusted (in million (MM) scf/year), the annual average higher heating value of the flare gas (in mmBtu/mm scf), and an indication of whether the annual volume of flare gas combusted and the annual average higher heating value of the flare gas were determined using standard conditions of 68 °F and 14.7 psia or 60 °F and 14.7 psia.

(9) If you use Equation Y-3 of §98.253, the number of SSM events exceeding 500,000 scf/day.

(10) The basis for the value of the fraction of carbon in the flare gas contributed by methane used in Equation Y-4 of §98.253.

(f) For catalytic cracking units, traditional fluid coking units, and catalytic reforming units, owners and operators shall report:

(1) The unit ID number (if applicable).

(2) A description of the type of unit (fluid catalytic cracking unit, thermal catalytic cracking unit, traditional fluid coking unit, or catalytic reforming unit).

(3) Maximum rated throughput of the unit, in bbl/stream day.

(4) The calculated CO₂, CH₄, and N₂O annual emissions for each unit, expressed in metric tons of each pollutant emitted.

(5) A description of the method used to calculate the CO₂ emissions for each unit (e.g., reference section and equation number).

(6) If you use a CEMS, the relevant information required under §98.36 for the Tier 4 Calculation Methodology, the CO₂ annual emissions as measured by the CEMS (unadjusted to remove CO₂ combustion emissions associated with additional units, if

present) and the process CO₂ emissions as calculated according to §98.253(c)(1)(ii). Report the CO₂ annual emissions associated with sources other than those from the coke burn-off in accordance with the applicable subpart (e.g., subpart C of this part in the case of a CO boiler).

(7) If you use Equation Y-6 of §98.253, the annual average exhaust gas flow rate, %CO₂, and %CO.

(8) If you use Equation Y-7a of this subpart, the annual average flow rate of inlet air and oxygen-enriched air, %O₂, %O_{oxy}, %CO₂, and %CO.

(9) If you use Equation Y-7b of this subpart, the annual average flow rate of inlet air and oxygen-enriched air, %N_{2,oxy}, and %N_{2,exhaust}.

(10) If you use Equation Y-8 of §98.253, the basis for the value of the average carbon content of coke.

(11) Indicate whether you use a measured value, a unit-specific emission factor, or a default for CH₄ emissions. If you use a unit-specific emission factor for CH₄, report the basis for the factor.

(12) Indicate whether you use a measured value, a unit-specific emission factor, or a default emission factor for N₂O emissions. If you use a unit-specific emission factor for N₂O, report the basis for the factor.

(13) If you use Equation Y-11 of §98.253, the number of regeneration cycles or measurement periods during the reporting year and the average coke burn-off quantity per cycle or measurement period.

(g) For fluid coking unit of the flexicoking type, the owner or operator shall report:

(1) The unit ID number (if applicable).

(2) A description of the type of unit.

(3) Maximum rated throughput of the unit, in bbl/stream day.

(4) Indicate whether the GHG emissions from the low heat value gas are accounted for in subpart C of this part or §98.253(c).

(5) If the GHG emissions for the low heat value gas are calculated at the flexicoking unit, also report the calculated annual CO₂, CH₄, and N₂O emissions for each unit, expressed in metric tons of each pollutant emitted, and the applicable equation input parameters specified in paragraphs (f)(7) through (f)(13) of this section.

(h) For on-site sulfur recovery plants and for emissions from sour gas sent off-site for sulfur recovery, the owner and operator shall report:

(1) The plant ID number (if applicable).

(2) For each on-site sulfur recovery plant, the maximum rated throughput (metric tons sulfur produced/stream day), a description of the type of sulfur recovery plant, and an indication of the method used to calculate CO₂ annual emissions for the sulfur recovery plant (e.g., CO₂ CEMS, Equation Y-12, or process vent method in §98.253(j)).

(3) The calculated CO₂ annual emissions for each on-site sulfur recovery plant, expressed in metric tons. The calculated annual CO₂ emissions from sour gas sent off-site for sulfur recovery, expressed in metric tons.

(4) [Reserved]

(5) If you recycle tail gas to the front of the sulfur recovery plant, indicate whether the recycled flow rate and carbon content are included in the measured data under §98.253(f)(2) and (3). Indicate whether a correction for CO₂ emissions in the tail gas was used in Equation Y-12 of §98.253. If so, then report:

(i) Indicate whether you used the default (95 percent) or a unit specific correction, and if a unit-specific correction was used, report the value of the correction and the approach used.

(ii) If the following data are not used to calculate the recycling correction factor, report the information specified in paragraphs (h)(5)(ii)(A) through (B) of this section.

(A) The annual volume of recycled tail gas (in scf/year) only.

(B) The annual average mole fraction of carbon in the tail gas (in kg-mole C/kg-mole gas).

(6) If you use a CEMS, the relevant information required under §98.36 for the Tier 4 Calculation Methodology, the CO₂ annual emissions as measured by the CEMS and the annual process CO₂ emissions calculated according to §98.253(f)(1). Report the CO₂ annual emissions associated with fuel combustion in accordance with subpart C of this part (General Stationary Fuel Combustion Sources).

(7) If you use the process vent method in §98.253(j) for a non-Claus sulfur recovery plant, the relevant information required under paragraph (l)(5) of this section.

(i) For coke calcining units, the owner and operator shall report:

(1) The unit ID number (if applicable).

(2) Maximum rated throughput of the unit, in metric tons coke calcined/stream day.

(3) The calculated CO₂, CH₄, and N₂O annual emissions for each unit, expressed in metric tons of each pollutant emitted.

(4) A description of the method used to calculate the CO₂ emissions for each unit (e.g., reference section and equation number).

(5) If you use Equation Y-13 of §98.253, an indication of whether coke dust is recycled to the unit (e.g., all dust is recycled, a portion of the dust is recycled, or none of the dust is recycled).

(6) If you use a CEMS, the relevant information required under §98.36 for the Tier 4 Calculation Methodology, the CO₂ annual emissions as measured by the CEMS and the annual process CO₂ emissions calculated according to §98.253(g)(1).

(7) Indicate whether you use a measured value, a unit-specific emission factor or a default emission factor for CH₄ emissions. If you use a unit-specific emission factor for

CH₄, report the basis for the factor.

(8) Indicate whether you use a measured value, a unit-specific emission factor, or a default emission factor for N₂O emissions. If you use a unit-specific emission factor for N₂O, report the basis for the factor.

(j) For asphalt blowing operations, the owner or operator shall report:

(1) The unit ID number (if applicable).

(2) [Reserved]

(3) The type of control device used to reduce methane (and other organic) emissions from the unit.

(4) The calculated annual CO₂ and CH₄ emissions for each unit, expressed in metric tons of each pollutant emitted.

(5) If you use Equation Y-14 of §98.253, the basis for the CO₂ emission factor used.

(6) If you use Equation Y-15 of §98.253, the basis for the CH₄ emission factor used.

(7) If you use Equation Y-16a of §98.253, the basis for the carbon emission factor used.

(8) If you use Equation Y-16b of §98.253, the basis for the CO₂ emission factor used and the basis for the carbon emission factor used.

(9) If you use Equation Y-17 of §98.253, the basis for the CH₄ emission factor used.

(10) If you use Equation Y-19 of this subpart, the relevant information required under paragraph (l)(5) of this section.

(k) For delayed coking units, the owner or operator shall report:

(1) The cumulative annual CH₄ emissions (in metric tons of CH₄) for all delayed coking units at the facility.

(2) A description of the method used to calculate the CH₄ emissions for each unit (e.g., reference section and equation number).

(3) The total number of delayed coking units at the facility; the total number of delayed coking drums at the facility; and, for each coke drum or vessel, the typical drum outage (*i.e.* the unfilled distance from the top of the drum, in feet).

(4) For each set of coking drums that are the same dimensions, the number of coking drums in the set, and the mole fraction of methane in coking gas (in kg-mole CH₄/kg-mole gas, wet basis).

(5) The basis for the volumetric void fraction of the coke vessel prior to steaming

and the basis for the mole fraction of methane in the coking gas.

(6) If you use Equation Y-19 of this subpart, the relevant information required under paragraph (l)(5) of this section for each set of coke drums or vessels of the same size.

(l) For each process vent subject to §98.253(j), the owner or operator shall report:

(1) The vent ID number (if applicable).

(2) The unit or operation associated with the emissions.

(3) The type of control device used to reduce methane (and other organic) emissions from the unit, if applicable.

(4) The calculated annual CO₂, CH₄, and N₂O emissions for each vent, expressed in metric tons of each pollutant emitted.

(5) The annual volumetric flow discharged to the atmosphere (in scf), and an indication of the measurement or estimation method, annual average mole fraction of each GHG above the concentration threshold or otherwise required to be reported and an indication of the measurement or estimation method, and for intermittent vents, the number of venting events and the cumulative venting time.

(m) For uncontrolled blowdown systems, the owner or operator shall report:

(1) An indication of whether the uncontrolled blowdown emissions are reported under §98.253(k) or §98.253(j) or a statement that the facility does not have any uncontrolled blowdown systems.

(2) The cumulative annual CH₄ emissions (in metric tons of CH₄) for uncontrolled blowdown systems.

(3) For uncontrolled blowdown systems reporting under §98.253(k), the basis for the value of the methane emission factor used for uncontrolled blowdown systems.

(4) For uncontrolled blowdown systems reporting under §98.253(j), the relevant information required under paragraph (l)(5) of this section.

(n) For equipment leaks, the owner or operator shall report:

(1) The cumulative CH₄ emissions (in metric tons of each pollutant emitted) for all equipment leak sources.

(2) The method used to calculate the reported equipment leak emissions.

(3) The number of each type of emission source listed in Equation Y-21 of this subpart at the facility.

(o) For storage tanks, the owner or operator shall report:

(1) The cumulative annual CH₄ emissions (in metric tons of CH₄) for all storage tanks, except for those used to process unstabilized crude oil.

		<p>(2) For storage tanks other than those processing unstabilized crude oil:</p> <p>(i) The method used to calculate the reported storage tank emissions for storage tanks other than those processing unstabilized crude (<i>i.e.</i>, either AP 42, Section 7.1 (incorporated by reference, see §98.7), or Equation Y-22 of this section).</p> <p>(ii) [Reserved]</p> <p>(3) The cumulative CH₄ emissions (in metric tons of CH₄) for storage tanks used to process unstabilized crude oil or a statement that the facility did not receive any unstabilized crude oil during the reporting year.</p> <p>(4) For storage tanks that process unstabilized crude oil:</p> <p>(i) The method used to calculate the reported unstabilized crude oil storage tank emissions.</p> <p>(ii)-(iv) [Reserved]</p> <p>(v) The basis for the mole fraction of CH₄ in vent gas from unstabilized crude oil storage tanks.</p> <p>(vi) If you did not use Equation Y-23, the tank-specific methane composition data and the annual gas generation volume (scf/yr) used to estimate the cumulative CH₄ emissions for storage tanks used to process unstabilized crude oil.</p> <p>(5)-(7) [Reserved]</p> <p>(p) For loading operations, the owner or operator shall report:</p> <p>(1) The cumulative annual CH₄ emissions (in metric tons of each pollutant emitted) for loading operations.</p> <p>(2) The types of materials loaded that have an equilibrium vapor-phase concentration of methane of 0.5 volume percent or greater, and the type of vessel (barge, tanker, marine vessel, etc.) in which each type of material is loaded.</p> <p>(3) The type of control system used to reduce emissions from the loading of material with an equilibrium vapor-phase concentration of methane of 0.5 volume percent or greater, if any (submerged loading, vapor balancing, etc.).</p> <p>(q) Name of each method listed in §98.254 or a description of manufacturer's recommended method used to determine a measured parameter.</p>
Subpart Z – Phosphoric Acid Production (§98.266)	All In	<p>In addition to the information required by §98.3(c), each annual report must contain the information specified in paragraphs (a) through (f) of this section.</p> <p>(a) Annual phosphoric acid production, by origin of the phosphate rock (tons).</p> <p>(b) Annual phosphoric acid production capacity (tons).</p> <p>(c) Annual arithmetic average percent inorganic carbon or carbon dioxide in phosphate rock from monthly records (percent by weight, expressed as a decimal fraction).</p>

		<p>(d) Annual phosphate rock consumption from monthly measurement records by origin (tons).</p> <p>(e) If you use a CEMS to measure CO₂ emissions, then you must report the information in paragraphs (e)(1) and (e)(2) of this section.</p> <p>(1) The identification number of each wet-process phosphoric acid process line.</p> <p>(2) The annual CO₂ emissions from each wet-process phosphoric acid process line (metric tons) and the relevant information required under 40 CFR 98.36 (e)(2)(vi) for the Tier 4 Calculation Methodology.</p> <p>(f) If you do not use a CEMS to measure emissions, then you must report the information in paragraphs (f)(1) through (9) of this section.</p> <p>(1) Identification number of each wet-process phosphoric acid process line.</p> <p>(2) Annual CO₂ emissions from each wet-process phosphoric acid process line (metric tons) as calculated by either Equation Z-1a or Equation Z-1b of this subpart.</p> <p>(3) Annual phosphoric acid permitted production capacity (tons) for each wet-process phosphoric acid process line (metric tons).</p> <p>(4) Method used to estimate any missing values of inorganic carbon content or carbon dioxide content of phosphate rock for each wet-process phosphoric acid process line.</p> <p>(5) [Reserved]</p> <p>(6) [Reserved]</p> <p>(7) Number of wet-process phosphoric acid process lines.</p> <p>(8) Number of times missing data procedures were used to estimate phosphate rock consumption (months), inorganic carbon contents of the phosphate rock (months), and CO₂ contents of the phosphate rock (months).</p> <p>(9) Annual process CO₂ emissions from phosphoric acid production facility (metric tons).</p>
Subpart AA – Pulp and Paper Manufacturing (§98.276)	25,000 metric tons CO ₂ e/year	<p>In addition to the information required by §98.3(c) and the applicable information required by §98.36, each annual report must contain the information in paragraphs (a) through (l) of this section as applicable:</p> <p>(a) Annual emissions of CO₂, biogenic CO₂, CH₄, biogenic CH₄ N₂O, and biogenic N₂O (metric tons per year).</p> <p>(b) [Reserved]</p> <p>(c) Basis for determining the annual mass of the spent liquor solids combusted (whether based on T650 om-05 Solids Content of Black Liquor, TAPPI (incorporated by reference, see §98.7) or an online measurement system).</p> <p>(d) [Reserved]</p>

		<p>(e) The default emission factor for CO₂, CH₄, or N₂O, used in Equation AA-1 of this subpart (kg CO₂, CH₄, or N₂O per mmBtu).</p> <p>(f)-(i) [Reserved]</p> <p>(j) Annual steam purchases (pounds of steam per year).</p> <p>(k) Total annual production of unbleached virgin chemical pulp produced onsite during the reporting year in air-dried metric tons per year. This total annual production value is the sum of all kraft, semichemical, soda, and sulfite pulp produced onsite, prior to bleaching, through all virgin pulping lines. Do not include mechanical pulp or secondary fiber repulped for paper production in the virgin pulp production total.</p> <p>(l) For each pulp mill lime kiln, report the information specified in paragraphs (l)(1) and (2) of this section.</p> <p>(1) The quantity of calcium oxide (CaO) produced (metric tons).</p> <p>(2) The percent of annual heat input, individually for each fossil fuel type.</p>
<p>Subpart BB – Silicon Carbide Production (§98.286)</p>	<p>All In</p>	<p>In addition to the information required by §98.3(c), each annual report must contain the information specified in paragraphs (a) or (b) of this section, as applicable for each silicon carbide production facility.</p> <p>(a) If a CEMS is used to measure process CO₂ emissions, you must report under this subpart the relevant information required for the Tier 4 Calculation Methodology in §98.36 and the information listed in this paragraph (a):</p> <p>(1) Annual consumption of petroleum coke (tons).</p> <p>(2) Annual production of silicon carbide (tons).</p> <p>(3) Annual production capacity of silicon carbide (tons).</p> <p>(b) If a CEMS is not used to measure process CO₂ emissions, you must report the information in paragraph (b)(1) through (8) of this section for all silicon carbide process units or production furnaces combined:</p> <p>(1) [Reserved]</p> <p>(2) <i>Annual production of silicon carbide (tons).</i></p> <p>(3) Annual production capacity of silicon carbide (tons).</p> <p>(4) [Reserved]</p> <p>(5) Whether carbon content of the petroleum coke is based on reports from the supplier or through self measurement using applicable ASTM standard method.</p> <p>(6) [Reserved]</p> <p>(7) Sampling analysis results for carbon content of consumed petroleum coke as determined for QA/QC of supplier data under §98.284(d) (percent by weight expressed</p>

		<p>as a decimal fraction).</p> <p>(8) Number of times in the reporting year that missing data procedures were followed to measure the carbon contents of petroleum coke (number of months) and petroleum coke consumption (number of months).</p>
<p>Subpart CC – Soda Ash Manufacturing (§98.296)</p>	<p>All In</p>	<p>In addition to the information required by §98.3(c), each annual report must contain the information specified in paragraphs (a) or (b) of this section, as appropriate for each soda ash manufacturing facility.</p> <p>(a) If a CEMS is used to measure CO₂ emissions, then you must report under this subpart the relevant information required under §98.36 and the following information in this paragraph (a):</p> <p>(1) Annual consumption of trona or liquid alkaline feedstock for each manufacturing line (tons).</p> <p>(2) Annual production of soda ash for each manufacturing line (tons).</p> <p>(3) Annual production capacity of soda ash for each manufacturing line (tons).</p> <p>(4) Identification number of each manufacturing line.</p> <p>(b) If a CEMS is not used to measure CO₂ emissions, then you must report the information listed in this paragraph (b):</p> <p>(1) Identification number of each manufacturing line.</p> <p>(2) Annual process CO₂ emissions from each soda ash manufacturing line (metric tons).</p> <p>(3) Annual production of soda ash for each manufacturing line (tons).</p> <p>(4) Annual production capacity of soda ash for each manufacturing line (tons).</p> <p>(5)-(7) [Reserved]</p> <p>(8) Whether CO₂ emissions for each manufacturing line were calculated using a trona input method as described in Equation CC-1 of this subpart, a soda ash output method as described in Equation CC-2 of this subpart, or a site-specific emission factor method as described in Equations CC-3 through CC-5 of this subpart.</p> <p>(9) Number of manufacturing lines located used to produce soda ash.</p> <p>(10) If you produce soda ash using the liquid alkaline feedstock process and use the site-specific emission factor method (§98.293(b)(3)) to estimate emissions then you must report the following relevant information for each manufacturing line or stack:</p> <p>(i) Stack gas volumetric flow rate during performance test (dscfm).</p> <p>(ii) Hourly CO₂ concentration during performance test (percent CO₂).</p> <p>(iii) CO₂ emission factor (metric tons CO₂/metric tons of process vent flow from</p>

		<p>mine water stripper/evaporator).</p> <p>(iv) CO₂ mass emission rate during performance test (metric tons/hour).</p> <p>(v) Average process vent flow from mine water stripper/evaporator during performance test (pounds/hour).</p> <p>(vi) Annual process vent flow rate from mine water stripper/evaporator (thousand pounds/hour).</p> <p>(11) Number of times missing data procedures were used and for which parameter as specified in this paragraph (b)(11):</p> <p>(i) Trona or soda ash (number of months).</p> <p>(ii) Inorganic carbon contents of trona or soda ash (weeks).</p> <p>(iii) Process vent flow rate from mine water stripper/evaporator (number of months).</p>
<p>Subpart DD- Electrical Transmission and Distribution Equipment Use (\$98.306)</p>	<p>Electrical transmission and distribution equipment use at facilities where the total nameplate capacity of SF₆ and PFC containing equipment exceeds 17,820 pounds</p>	<p>In addition to the information required by §98.3(c), each annual report must contain the following information for each electric power system, by chemical:</p> <p>(a) Nameplate capacity of equipment (pounds) containing SF₆ and nameplate capacity of equipment (pounds) containing each PFC:</p> <p>(1) Existing at the beginning of the year (excluding hermetically sealed-pressure switchgear).</p> <p>(2) New during the year (all SF₆-insulated equipment, including hermetically sealed-pressure switchgear).</p> <p>(3) Retired during the year (all SF₆-insulated equipment, including hermetically sealed-pressure switchgear).</p> <p>(b) Transmission miles (length of lines carrying voltages above 35 kilovolt).</p> <p>(c) Distribution miles (length of lines carrying voltages at or below 35 kilovolt).</p> <p>(d) Pounds of SF₆ and PFC stored in containers, but not in energized equipment, at the beginning of the year.</p> <p>(e) Pounds of SF₆ and PFC stored in containers, but not in energized equipment, at the end of the year.</p> <p>(f) Pounds of SF₆ and PFC purchased in bulk from chemical producers or distributors.</p> <p>(g) Pounds of SF₆ and PFC purchased from equipment manufacturers or distributors with or inside equipment, including hermetically sealed-pressure switchgear.</p> <p>(h) Pounds of SF₆ and PFC returned to facility after off-site recycling.</p>

		<p>(i) Pounds of SF₆ and PFC in bulk and contained in equipment sold to other entities.</p> <p>(j) Pounds of SF₆ and PFC returned to suppliers.</p> <p>(k) Pounds of SF₆ and PFC sent off-site for recycling.</p> <p>(l) Pounds of SF₆ and PFC sent off-site for destruction.</p>
<p>Subpart EE – Titanium Dioxide Production (§98.316)</p>	<p>All In</p>	<p>In addition to the information required by §98.3(c), each annual report must contain the information specified in paragraphs (a) or (b) of this section, as applicable for each titanium dioxide production line.</p> <p>(a) If a CEMS is used to measure CO₂ emissions, then you must report the relevant information required under §98.36(e)(2)(vi) for the Tier 4 Calculation Methodology and the following information in this paragraph (a).</p> <ol style="list-style-type: none"> (1) Identification number of each process line. (2) Annual consumption of calcined petroleum coke (tons). (3) Annual production of titanium dioxide (tons). (4) Annual production capacity of titanium dioxide (tons). (5) Annual production of carbon-containing waste (tons), if applicable. <p>(b) If a CEMS is not used to measure CO₂ emissions, then you must report the information listed in this paragraph (b):</p> <ol style="list-style-type: none"> (1) Identification number of each process line. (2) Annual CO₂ emissions from each chloride process line (metric tons/year). (3) Annual consumption of calcined petroleum coke for each process line (tons). (4) Annual production of titanium dioxide for each process line (tons). (5) Annual production capacity of titanium dioxide for each process line (tons). (6) [Reserved] (7) Annual production of carbon-containing waste for each process line (tons), if applicable. (8) Monthly production of titanium dioxide for each process line (tons). (9) [Reserved] (10) Whether monthly carbon content of the petroleum coke is based on reports from the supplier or through self measurement using applicable ASTM standard

		<p>methods.</p> <p>(11) Carbon content for carbon-containing waste for each process line (percent by weight expressed as a decimal fraction).</p> <p>(12) If carbon content of petroleum coke is based on self measurement, the ASTM standard methods used.</p> <p>(13) Sampling analysis results of carbon content of petroleum coke as determined for QA/QC of supplier data under §98.314(d) (percent by weight expressed as a decimal fraction).</p> <p>(14) Number of separate chloride process lines located at the facility.</p> <p>(15) The number of times in the reporting year that missing data procedures were followed to measure the carbon contents of petroleum coke (number of months); petroleum coke consumption (number of months); carbon-containing waste generated (number of months); and carbon contents of the carbon-containing waste (number of times during year).</p>
<p>Subpart FF – Underground Coal Mines (§98.326)</p>	<p>Underground coal mines liberating 36,500,000 actual cubic feet of CH₄ or more per year</p>	<p>In addition to the information required by §98.3(c), each annual report must contain the following information for each mine:</p> <p>(a) Quarterly CH₄ liberated from each ventilation monitoring point, (metric tons CH₄).</p> <p>(b) Weekly CH₄ liberated from each degasification system monitoring point (metric tons CH₄).</p> <p>(c) Quarterly CH₄ destruction at each ventilation and degasification system destruction device or point of offsite transport (metric tons CH₄).</p> <p>(d) Quarterly CH₄ emissions (net) from all ventilation and degasification systems (metric tons CH₄).</p> <p>(e) Quarterly CO₂ emissions from on-site destruction of coal mine gas CH₄, where the gas is not a fuel input for energy generation or use (e.g., flaring) (metric tons CO₂).</p> <p>(f) Quarterly volumetric flow rate for each ventilation monitoring point and units of measure (scfm or acfm), date and location of each measurement, and method of measurement (quarterly sampling or continuous monitoring), used in Equation FF-1 of this subpart.</p> <p>(g) Quarterly CH₄ concentration for each ventilation monitoring point, dates and locations of each measurement and method of measurement (sampling or continuous monitoring).</p> <p>(h) Weekly volumetric flow rate used to calculate CH₄ liberated from degasification systems and units of measure (acfm or scfm), and method of measurement (sampling or continuous monitoring), used in Equation FF-3 of this subpart.</p> <p>(i) Quarterly CH₄ concentration (%) used to calculate CH₄ liberated from degasification systems and if the data is based on CEMS or weekly sampling.</p> <p>(j) Weekly volumetric flow rate used to calculate CH₄ destruction for each destruction device and each point of offsite transport, and units of measure (acfm or</p>

		<p>scfm).</p> <p>(k) Weekly CH₄ concentration (%) used to calculate CH₄ flow to each destruction device and each point of offsite transport (C).</p> <p>(l) Dates in quarterly reporting period where active ventilation of mining operations is taking place.</p> <p>(m) Dates in quarterly reporting period where degasification of mining operations is taking place.</p> <p>(n) Dates in quarterly reporting period when continuous monitoring equipment is not properly functioning, if applicable.</p> <p>(o) Temperatures (°R), pressure (atm), moisture content, and the moisture correction factor (if applicable) used in Equation FF-1 and FF-3 of this subpart; and the gaseous organic concentration correction factor, if Equation FF-9 was required.</p> <p>(p) For each destruction device, a description of the device, including an indication of whether destruction occurs at the coal mine or off-site. If destruction occurs at the mine, also report an indication of whether a back-up destruction device is present at the mine, the annual operating hours for the primary destruction device, the annual operating hours for the back-up destruction device (if present), and the destruction efficiencies assumed (percent).</p> <p>(q) A description of the gas collection system (manufacturer, capacity, and number of wells) the surface area of the gas collection system (square meters), and the annual operating hours of the gas collection system.</p> <p>(r) Identification information and description for each well, shaft, and vent hole, including paragraphs (r)(1) through (r)(3) of this section:</p> <p>(1) Indication of whether the well, shaft, or vent hole is monitored individually, or as part of a centralized monitoring point. Note which method (sampling or continuous monitoring) was used.</p> <p>(2) Start date and close date of each well, shaft, and vent hole.</p> <p>(3) Number of days the well, shaft, or vent hole was in operation during the reporting year.</p> <p>(s) For each centralized monitoring point, identification of the wells and shafts included in the point. Note which method (sampling or continuous monitoring) was used.</p> <p>(t) Mine Safety and Health Administration (MSHA) identification for this coal mine.</p>
<p>Subpart GG – Zinc Production (§98.336)</p>	<p>25,000 metric tons CO₂e/year</p>	<p>In addition to the information required by §98.3(c), each annual report must contain the information specified in paragraphs (a) or (b) of this section, as applicable, for each Waelz kiln or electrothermic furnace.</p> <p>(a) If a CEMS is used to measure CO₂ emissions, then you must report under this subpart the relevant information required for the Tier 4 Calculation Methodology in §98.36 and the information listed in this paragraph (a):</p> <p>(1) Annual zinc product production capacity (tons).</p>

		<p>(2) Annual production quantity for each zinc product (tons).</p> <p>(3) Annual facility production quantity for each zinc product (tons).</p> <p>(4) Number of Waelz kilns at each facility used for zinc production.</p> <p>(5) Number of electrothermic furnaces at each facility used for zinc production.</p> <p>(b) If a CEMS is not used to measure CO₂ emissions, then you must report the information listed in this paragraph (b):</p> <p>(1) Identification number and annual process CO₂ emissions from each individual Waelz kiln or electrothermic furnace (metric tons).</p> <p>(2) Annual zinc product production capacity (tons).</p> <p>(3) Annual production quantity for each zinc product (tons).</p> <p>(4) Number of Waelz kilns at each facility used for zinc production.</p> <p>(5) Number of electrothermic furnaces at each facility used for zinc production.</p> <p>(6) [Reserved]</p> <p>(7) [Reserved]</p> <p>(8) Whether carbon content of each carbon-containing input material charged to each kiln or furnace is based on reports from the supplier or through self measurement using applicable ASTM standard method.</p> <p>(9) If carbon content of each carbon-containing input material charged to each kiln or furnace is based on self measurement, the ASTM Standard Test Method used.</p> <p>(10) [Reserved]</p> <p>(11) Whether carbon content of the carbon electrode used in each furnace is based on reports from the supplier or through self measurement using applicable ASTM standard method.</p> <p>(12) If carbon content of carbon electrode used in each furnace is based on self measurement, the ASTM standard method used.</p> <p>(13) If you use the missing data procedures in §98.335(b), you must report how the monthly mass of carbon-containing materials with missing data was determined and the number of months the missing data procedures were used.</p>
<p>Subpart HH – Municipal Solid Waste Landfills (§98.346)</p>	<p>Municipal solid waste landfills that generate CH₄ in amounts equivalent to 25,000 metric tons CO₂e or</p>	<p>In addition to the information required by §98.3(c), each annual report must contain the following information for each landfill.</p> <p>(a) A classification of the landfill as “open” (actively received waste in the reporting year) or “closed” (no longer receiving waste), the year in which the landfill first started accepting waste for disposal, the last year the landfill accepted waste (for open landfills, enter the estimated year of landfill closure), the capacity (in metric tons) of the landfill, an indication of whether leachate recirculation is used during the reporting year and its typical frequency of use over the past 10 years (e.g., used several times a year for the</p>

	<p>more per year</p>	<p>past 10 years, used at least once a year for the past 10 years, used occasionally but not every year over the past 10 years, not used), an indication as to whether scales are present at the landfill, and the waste disposal quantity for each year of landfilling required to be included when using Equation HH-1 of this subpart (in metric tons, wet weight).</p> <p>(b) Method for estimating reporting year and historical waste disposal quantities, reason for its selection, and the range of years it is applied. For years when waste quantity data are determined using the methods in §98.343(a)(3), report separately the quantity of waste determined using the methods in §98.343(a)(3)(i) and the quantity of waste determined using the methods in §98.343(a)(3)(ii). For historical waste disposal quantities that were not determined using the methods in §98.343(a)(3), provide the population served by the landfill for each year the Equation HH-2 of this subpart is applied, if applicable, or, for open landfills using Equation HH-3 of this subpart, provide the value of landfill capacity (LFC) used in the calculation.</p> <p>(c) Waste composition for each year required for Equation HH-1 of this subpart, in percentage by weight, for each waste category listed in Table HH-1 to this subpart that is used in Equation HH-1 of this subpart to calculate the annual modeled CH₄ generation.</p> <p>(d) For each waste type used to calculate CH₄ generation using Equation HH-1 of this subpart, you must report:</p> <p>(1) Degradable organic carbon (DOC) and fraction of DOC dissimilated (DOC_F) values used in the calculations.</p> <p>(2) Decay rate (k) value used in the calculations.</p> <p>(e) Fraction of CH₄ in landfill gas (F), an indication of whether the fraction of CH₄ was determined based on measured values or the default value, and the methane correction factor (MCF) used in the calculations. If an MCF other than the default of 1 is used, provide an indication of whether active aeration of the waste in the landfill was conducted during the reporting year, a description of the aeration system, including aeration blower capacity, the fraction of the landfill containing waste affected by aeration, the total number of hours during the year the aeration blower was operated, and other factors used as a basis for the selected MCF value.</p> <p>(f) The surface area of the landfill containing waste (in square meters), identification of the type of cover material used (as either organic cover, clay cover, sand cover, or other soil mixtures). If multiple cover types are used, the surface area associated with each cover type.</p> <p>(g) The modeled annual methane generation rate for the reporting year (metric tons CH₄) calculated using Equation HH-1 of this subpart.</p> <p>(h) For landfills without gas collection systems, the annual methane emissions (i.e., the methane generation, adjusted for oxidation, calculated using Equation HH-5 of this subpart), reported in metric tons CH₄, the oxidation fraction used in the calculation, and an indication of whether passive vents and/or passive flares (vents or flares that are not considered part of the gas collection system as defined in §98.6) are present at this landfill.</p> <p>(i) For landfills with gas collection systems, you must report:</p> <p>(1) Total volumetric flow of landfill gas collected for destruction for the reporting</p>
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		<p>year (cubic feet at 520 °R or 60 degrees Fahrenheit and 1 atm).</p> <p>(2) Annual average CH₄ concentration of landfill gas collected for destruction (percent by volume).</p> <p>(3) Monthly average temperature and pressure for each month at which flow is measured for landfill gas collected for destruction, or statement that temperature and/or pressure is incorporated into internal calculations run by the monitoring equipment.</p> <p>(4) An indication as to whether flow was measured on a wet or dry basis, an indication as to whether CH₄ concentration was measured on a wet or dry basis, and if required for Equation HH-4 of this subpart, monthly average moisture content for each month at which flow is measured for landfill gas collected for destruction.</p> <p>(5) An indication of whether destruction occurs at the landfill facility, off-site, or both. If destruction occurs at the landfill facility, also report for each measurement location the number of destruction devices associated with that measurement location and the annual operating hours and the destruction efficiency (percent) for each destruction device associated with that measurement location.</p> <p>(6) Annual quantity of recovered CH₄ (metric tons CH₄) calculated using Equation HH-4 of this subpart for each measurement location.</p> <p>(7) A description of the gas collection system (manufacturer, capacity, and number of wells), the surface area (square meters) and estimated waste depth (meters) for each area specified in Table HH-3 to this subpart, the estimated gas collection system efficiency for landfills with this gas collection system, the annual operating hours of the gas collection system for each measurement location, and an indication of whether passive vents and/or passive flares (vents or flares that are not considered part of the gas collection system as defined in §98.6) are present at the landfill.</p> <p>(8) Methane generation corrected for oxidation calculated using Equation HH-5 of this subpart, reported in metric tons CH₄, and the oxidation fraction used in the calculation.</p> <p>(9) Methane generation (G_{CH₄}) value used as an input to Equation HH-6 of this subpart. Specify whether the value is modeled (G_{CH₄} from HH-1 of this subpart) or measured (R from Equation HH-4 of this subpart).</p> <p>(10) Methane generation corrected for oxidation calculated using Equation HH-7 of this subpart, reported in metric tons CH₄, and the oxidation fraction used in the calculation.</p> <p>(11) Methane emissions calculated using Equation HH-6 of this subpart, reported in metric tons CH₄, and the oxidation fraction used in the calculation.</p> <p>(12) Methane emissions calculated using Equation HH-8 of this subpart, reported in metric tons CH₄, and the oxidation fraction used in the calculation.</p>
Subpart II – Industrial Wastewater Management (§98.356)	25,000 metric tons CO ₂ e/year	<p>In addition to the information required by §98.3(c), each annual report must contain the following information for each wastewater treatment system.</p> <p>(a) A description or diagram of the industrial wastewater treatment system, identifying the processes used to treat industrial wastewater and industrial wastewater treatment sludge. Indicate how the processes are related to each other and identify the anaerobic processes. Provide a unique identifier for each anaerobic process, indicate the average depth in meters of each anaerobic lagoon, and indicate whether biogas</p>

generated by each anaerobic process is recovered. The anaerobic processes must be identified as:

- (1) Anaerobic reactor.
- (2) Anaerobic deep lagoon (depth more than 2 meters).
- (3) Anaerobic shallow lagoon (depth less than 2 meters).
- (4) Anaerobic sludge digester.

(b) For each anaerobic wastewater treatment process (reactor, deep lagoon, or shallow lagoon) you must report:

- (1) Weekly average COD or BOD₅ concentration of wastewater entering each anaerobic wastewater treatment process, for each week the anaerobic process was operated.
- (2) Volume of wastewater entering each anaerobic wastewater treatment process for each week the anaerobic process was operated.
- (3) Maximum CH₄ production potential (B₀) used as an input to Equation II-1 or II-2 of this subpart, from Table II-1 to this subpart.
- (4) Methane conversion factor (MCF) used as an input to Equation II-1 or II-2 of this subpart, from Table II-1 to this subpart.
- (5) Annual mass of CH₄ generated by each anaerobic wastewater treatment process, calculated using Equation II-1 or II-2 of this subpart.

(c) For each anaerobic wastewater treatment process from which biogas is not recovered, you must report the annual CH₄ emissions, calculated using Equation II-3 of this subpart.

(d) For each anaerobic wastewater treatment process and anaerobic sludge digester from which some biogas is recovered, you must report:

- (1) Annual quantity of CH₄ recovered from the anaerobic process calculated using Equation II-4 of this subpart.
- (2) Total weekly volumetric biogas flow for each week (up to 52 weeks/year) that biogas is collected for destruction.
- (3) Weekly average CH₄ concentration for each week that biogas is collected for destruction.
- (4) Weekly average biogas temperature for each week at which flow is measured for biogas collected for destruction, or statement that temperature is incorporated into monitoring equipment internal calculations.
- (5) Whether flow was measured on a wet or dry basis, whether CH₄ concentration was measured on a wet or dry basis, and if required for Equation II-4 of this subpart, weekly average moisture content for each week at which flow is measured for biogas collected for destruction, or statement that moisture content is incorporated into

		<p>monitoring equipment internal calculations.</p> <p>(6) Weekly average biogas pressure for each week at which flow is measured for biogas collected for destruction, or statement that pressure is incorporated into monitoring equipment internal calculations.</p> <p>(7) CH₄ collection efficiency (CE) used in Equation II-5 of this subpart.</p> <p>(8) Whether destruction occurs at the facility or off-site. If destruction occurs at the facility, also report whether a back-up destruction device is present at the facility, the annual operating hours for the primary destruction device, the annual operating hours for the back-up destruction device (if present), the destruction efficiency for the primary destruction device, and the destruction efficiency for the back-up destruction device (if present).</p> <p>(9) For each anaerobic process from which some biogas is recovered, you must report the annual CH₄ emissions, as calculated by Equation II-6 of this subpart.</p> <p>(e) The total mass of CH₄ emitted from all anaerobic processes from which biogas is not recovered (calculated in Equation II-3 of this subpart) and from all anaerobic processes from which some biogas is recovered (calculated in Equation II-6 of this subpart) using Equation II-7 of this subpart.</p>
<p>Subpart JJ – Manure Management (§98.366)</p>	<p>Manure management systems with combined CH₄ and N₂O emissions in amounts equivalent to 25,000 metric tons CO₂e or more per year</p>	<p>(a) In addition to the information required by §98.3(c), each annual report must contain the following information:</p> <p>(1) List of manure management system components at the facility.</p> <p>(2) Fraction of manure from each animal type that is handled in each manure management system component.</p> <p>(3) Average annual animal population (for each animal type) for static populations or the results of Equation JJ-4 for growing populations.</p> <p>(4) Average number of days that growing animals are kept at the facility (for each animal type).</p> <p>(5) The number of animals produced annually for growing populations (for each animal type).</p> <p>(6) Typical animal mass (for each animal type).</p> <p>(7) Total facility emissions (results of Equation JJ-15).</p> <p>(8) CH₄ emissions from manure management system components listed in §98.360(b), except digesters (results of Equation JJ-2).</p> <p>(9) VS value used (for each animal type).</p> <p>(10) B₀ value used (for each animal type).</p> <p>(11) Methane conversion factor used for each MMS component.</p>

		<p>(12) Average ambient temperature used to select each methane conversion factor.</p> <p>(13) N₂O emissions (results of Equation JJ-13).</p> <p>(14) N value used for each animal type.</p> <p>(15) N₂O emission factor selected for each MMS component.</p> <p>(b) Facilities with anaerobic digesters must also report:</p> <p>(1) CH₄ emissions from anaerobic digesters (results of Equation JJ-5).</p> <p>(2) CH₄ flow to the digester combustion device for each digester (results of Equation JJ-6, or value from fully integrated monitoring system as described in 98.363(b)).</p> <p>(3) CH₄ destruction for each digester (results of Equation JJ-11).</p> <p>(4) CH₄ leakage for each digester (results of Equation JJ-12).</p> <p>(5) Total annual volumetric biogas flow for each digester (results of Equation JJ-7).</p> <p>(6) Average annual CH₄ concentration for each digester (results of Equation JJ-8).</p> <p>(7) Average annual temperature at which gas flow is measured for each digester (results of Equation JJ-9).</p> <p>(8) Average annual gas flow pressure at which gas flow is measured for each digester (results of Equation JJ-10).</p> <p>(9) Destruction efficiency used for each digester.</p> <p>(10) Number of days per year that each digester was operating.</p> <p>(11) Collection efficiency used for each digester.</p>
<p>Subpart LL – Suppliers of Coal-Based Liquid Fuels (§98.386)</p>	<p>Producers of coal-to-liquid products: All in</p> <p>Importers & Exporters: 25,000 metric tons CO₂e/year</p>	<p>In addition to the information required by §98.3(c), the following requirements apply:</p> <p>(a) Producers shall report the following information for each coal-to-liquid facility:</p> <p>(1) [Reserved]</p> <p>(2) For each product listed in Table MM-1 of subpart MM of this part that enters the coal-to-liquid facility to be further processed or otherwise used on site, report the total annual quantity in metric tons or barrels. For natural gas liquids, quantity shall reflect the individual components of the product.</p> <p>(3) For each feedstock reported in paragraph (a)(2) of this section that was produced by blending a fossil fuel-based product with a biomass-based product, report the percent of the volume reported in paragraph (a)(2) of this section that is fossil fuel-</p>

based (excluding any denaturant that may be present in any ethanol product).

(4) Each standard method or other industry standard practice used to measure each quantity reported in paragraph (a)(2) of this section.

(5) [Reserved]

(6) For each product (leaving the coal-to-liquid facility) listed in Table MM-1 of subpart MM of this part, report the total annual quantity in metric tons or barrels. For natural gas liquids, quantity shall reflect the individual components of the product. Those products that enter the facility, but are not reported in (a)(2), shall not be reported under this paragraph.

(7) For each product reported in paragraph (a)(6) of this section that was produced by blending a fossil fuel-based product with a biomass-based product, report the percent of the volume reported in paragraph (a)(6) of this section that is fossil fuel-based (excluding any denaturant that may be present in any ethanol product).

(8) Each standard method or other industry standard practice used to measure each quantity reported in paragraph (a)(6) of this section.

(9) For every feedstock reported in paragraph (a)(2) of this section for which Calculation Methodology 2 of subpart MM of this part was used to determine an emissions factor, report:

(i) The number of samples collected according to §98.394(c).

(ii) The sampling standard method used.

(iii) The carbon share test results in percent mass.

(iv) The standard method used to test carbon share.

(v) The calculated CO₂ emissions factor in metric tons CO₂ per barrel or per metric ton of product.

(10) For every non-solid feedstock reported in paragraph (a)(2) of this section for which Calculation Methodology 2 of subpart MM of this part was used to determine an emissions factor, report:

(i) The density test results in metric tons per barrel.

(ii) The standard method used to test density.

(11) For every product reported in paragraph (a)(6) of this section for which Calculation Methodology 2 of this subpart was used to determine an emissions factor, report:

(i) The number of samples collected according to §98.394(c).

(ii) The sampling standard method used.

(iii) The carbon share test results in percent mass.

		<p>(iv) The standard method used to test carbon share.</p> <p>(v) The calculated CO₂ emissions factor in metric tons CO₂ per barrel or metric ton of product.</p> <p>(12) For every non-solid product reported in paragraph (a)(6) of this section for which Calculation Method 2 of subpart MM of this part was used to determine an emissions factor, report:</p> <p>(i) The density test results in metric tons per barrel.</p> <p>(ii) The standard method used to test density.</p> <p>(13) [Reserved]</p> <p>(14) For each specific type of biomass that enters the coal-to-liquid facility to be co-processed with fossil fuel-based feedstock to produce a product reported in paragraph (a)(6) of this section, report the annual quantity in metric tons or barrels.</p> <p>(15) Each standard method or other industry standard practice used to measure each quantity reported in paragraph (a)(14) of this section.</p> <p>(16) The CO₂ emissions in metric tons that would result from the complete combustion or oxidation of each feedstock reported in paragraph (a)(2) of this section that were calculated according to §98.393(b) or (h).</p> <p>(17) The CO₂ emissions in metric tons that would result from the complete combustion or oxidation of each product (leaving the coal-to-liquid facility) reported in paragraph (a)(6) of this section that were calculated according to §98.393(a) or (h).</p> <p>(18) Annual CO₂ emissions in metric tons that would result from the complete combustion or oxidation of each type of biomass feedstock co-processed with fossil fuel-based feedstocks reported in paragraph (a)(14) of this section, calculated according to §98.393(c).</p> <p>(19) Annual CO₂ emissions that would result from the complete combustion or oxidation of all products, calculated according to §98.393(d).</p> <p>(20) Annual quantity of bulk NGLs in metric tons or barrels received for processing during the reporting year.</p> <p>(b) In addition to the information required by §98.3(c), each importer shall report all of the following information at the corporate level:</p> <p>(1) [Reserved]</p> <p>(2) For each product listed in Table MM-1 of subpart MM of this part, report the total annual quantity in metric tons or barrels. For natural gas liquids, quantity shall reflect the individual components of the product as listed in Table MM-1 of subpart MM of this part.</p> <p>(3) For each product reported in paragraph (b)(2) of this section that was produced by blending a fossil fuel-based product with a biomass-based product, report the percent of the volume reported in paragraph (b)(2) of this section that is fossil fuel-based</p>
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(excluding any denaturant that may be present in any ethanol product).

(4) Each standard method or other industry standard practice used to measure each quantity reported in paragraph (b)(2) of this section.

(5) For each product reported in paragraph (b)(2) of this section for which Calculation Methodology 2 of this subpart used was used to determine an emissions factor, report:

(i) The number of samples collected according to §98.394(c)

(ii) The sampling standard method used.

(iii) The carbon share test results in percent mass.

(iv) The standard method used to test carbon share.

(v) The calculated CO₂ emissions factor in metric tons per barrel or per metric ton of product.

(6) For each non-solid product reported in paragraph (b)(2) of this section for which Calculation Methodology 2 of this subpart was used to determine an emissions factor, report:

(i) The density test results in metric tons per barrel.

(ii) The standard method used to test density.

(7) The CO₂ emissions in metric tons that would result from the complete combustion or oxidation of each imported product reported in paragraph (b)(2) of this section, calculated according to §98.393(a).

(8) The total sum of CO₂ emissions that would result from the complete combustion or oxidation of all imported products, calculated according to §98.393(e).

(c) In addition to the information required by §98.3(c), each exporter shall report all of the following information at the corporate level:

(1) [Reserved]

(2) For each product listed in table MM-1 of subpart MM of this part, report the total annual quantity in metric tons or barrels. For natural gas liquids, quantity shall reflect the individual components of the product.

(3) For each product reported in paragraph (c)(2) of this section that was produced by blending a fossil fuel-based product with a biomass-based product, report the percent of the volume reported in paragraph (c)(2) of this section that is fossil fuel-based (excluding any denaturant that may be present in any ethanol product).

(4) Each standard method or other industry standard practice used to measure each quantity reported in paragraph (c)(2) of this section.

(5) For each product reported in paragraph (c)(2) of this section for which Calculation Methodology 2 of this subpart was used to determine an emissions factor,

		<p>report:</p> <ul style="list-style-type: none"> (i) The number of samples collected according to §98.394(c). (ii) The sampling standard method used. (iii) The carbon share test results in percent mass. (iv) The standard method used to test carbon share. (v) The calculated CO₂ emissions factor in metric tons CO₂ per barrel or per metric ton of product. <p>(6) For each non-solid product reported in paragraph (c)(2) of this section for which Calculation Methodology 2 of this subpart used was used to determine an emissions factor, report:</p> <ul style="list-style-type: none"> (i) The density test results in metric tons per barrel. (ii) The standard method used to test density. <p>(7) The CO₂ emissions in metric tons that would result from the complete combustion or oxidation of each exported product reported in paragraph (c)(2) of this section, calculated according to §98.393(a).</p> <p>(8) Total sum of CO₂ emissions that would result from the complete combustion or oxidation of all exported products, calculated according to §98.393(e).</p> <p>(d) <i>Blended feedstock and products.</i> (1) Producers, exporters, and importers must report the following information for each blended product and feedstock where emissions were calculated according to §98.393(i):</p> <ul style="list-style-type: none"> (i) Volume or mass of each blending component. (ii) The CO₂ emissions in metric tons that would result from the complete combustion or oxidation of each blended feedstock or product, using Equation MM-12 or Equation MM-13 of §98.393. (iii) Whether it is a blended feedstock or a blended product. <p>(2) For a product that enters the facility to be further refined or otherwise used on site that is a blended feedstock, producers must meet the reporting requirements of paragraph (a)(2) of this section by reflecting the individual components of the blended feedstock.</p> <p>(3) For a product that is produced, imported, or exported that is a blended product, producers, importers, and exporters must meet the reporting requirements of paragraphs (a)(6), (b)(2), and (c)(2) of this section, as applicable, by reflecting the individual components of the blended product.</p>
Subpart MM – Suppliers of Petroleum Products	(A) All petroleum refineries	In addition to the information required by §98.3(c), the following requirements apply:

<p>(§98.396)</p>	<p>that distill crude oil.</p> <p>(B) Importers of an annual quantity of petroleum products and natural gas liquids that is equivalent to 25,000 metric tons CO₂e or more.</p> <p>(C) Exporters of an annual quantity of petroleum products and natural gas liquids that is equivalent to 25,000 metric tons CO₂e or more.</p>	<p>(a) Refiners shall report the following information for each facility:</p> <p>(1) [Reserved]</p> <p>(2) For each petroleum product or natural gas liquid listed in Table MM-1 of this subpart that enters the refinery to be further refined or otherwise used on site, report the annual quantity in metric tons or barrels. For natural gas liquids, quantity shall reflect the individual components of the product.</p> <p>(3) For each feedstock reported in paragraph (a)(2) of this section that was produced by blending a petroleum-based product with a biomass-based product, report the percent of the volume reported in paragraph (a)(2) of this section that is petroleum-based (excluding any denaturant that may be present in any ethanol product).</p> <p>(4)-(5) [Reserved]</p> <p>(6) For each petroleum product and natural gas liquid (ex refinery gate) listed in Table MM-1 of this subpart, report the annual quantity in metric tons or barrels. For natural gas liquids, quantity shall reflect the individual components of the product. Petroleum products and natural gas liquids that enter the refinery, but are not reported in (a)(2), shall not be reported under this paragraph.</p> <p>(7) For each product reported in paragraph (a)(6) of this section that was produced by blending a petroleum-based product with a biomass-based product, report the percent of the volume reported in paragraph (a)(6) of this section that is petroleum-based (excluding any denaturant that may be present in any ethanol product).</p> <p>(8) [Reserved]</p> <p>(9) For every feedstock reported in paragraph (a)(2) of this section for which Calculation Method 2 of this subpart was used to determine an emissions factor, report:</p> <p>(i) The number of samples collected according to §98.394(c)</p> <p>(ii) The sampling standard method used.</p> <p>(iii) The carbon share test results in percent mass.</p> <p>(iv) The standard method used to test carbon share.</p> <p>(v) The calculated CO₂ emissions factor in metric tons CO₂ per barrel or per metric ton of product.</p> <p>(10) For every non-solid feedstock reported in paragraph (a)(2) of this section for which Calculation Method 2 of this subpart was used to determine an emissions factor, report:</p> <p>(i) The density test results in metric tons per barrel.</p> <p>(ii) The standard method used to test density.</p> <p>(11) For every petroleum product and natural gas liquid reported in paragraph (a)(6) of this section for which Calculation Method 2 of this subpart was used to determine</p>
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an emissions factor, report:

(i) The number of samples collected according to §98.394(c).

(ii) The sampling standard method used.

(iii) The carbon share test results in percent mass.

(iv) The standard method used to test carbon share.

(v) The calculated CO₂ emissions factor in metric tons CO₂ per barrel or per metric ton of product.

(12) For every non-solid petroleum product and natural gas liquid reported in paragraph (a)(6) for which Calculation Method 2 was used to determine an emissions factor, report:

(i) The density test results in metric tons per barrel.

(ii) The standard method used to test density.

(13) [Reserved]

(14) For each specific type of biomass that enters the refinery to be co-processed with petroleum feedstocks to produce a petroleum product reported in paragraph (a)(6) of this section, report the annual quantity in metric tons or barrels.

(15) [Reserved]

(16) The CO₂ emissions in metric tons that would result from the complete combustion or oxidation of each petroleum product and natural gas liquid (ex refinery gate) reported in paragraph (a)(6) of this section that were calculated according to §98.393(a) or (h).

(17) The CO₂ emissions in metric tons that would result from the complete combustion or oxidation of each feedstock reported in paragraph (a)(2) of this section that were calculated according to §98.393(b) or (h).

(18) The CO₂ emissions in metric tons that would result from the complete combustion or oxidation of each type of biomass feedstock co-processed with petroleum feedstocks reported in paragraph (a)(14) of this section, calculated according to §98.393(c).

(19) The sum of CO₂ emissions that would result from the complete combustion or oxidation of all products, calculated according to §98.393(d).

(20) For all crude oil that enters the refinery, report the annual quantity in barrels.

(21) The quantity of bulk NGLs in metric tons or barrels received for processing during the reporting year. Report only quantities of bulk NGLs not reported in (a)(2) of this section.

(22) Volume of crude oil in barrels that you injected into a crude oil supply or

reservoir.

(b) In addition to the information required by §98.3(c), each importer shall report all of the following information at the corporate level:

(1) [Reserved]

(2) For each petroleum product and natural gas liquid listed in Table MM-1 of this subpart, report the annual quantity in metric tons or barrels. For natural gas liquids, quantity shall reflect the individual components of the product.

(3) For each product reported in paragraph (b)(2) of this section that was produced by blending a petroleum-based product with a biomass-based product, report the percent of the volume reported in paragraph (b)(2) of this section that is petroleum-based (excluding any denaturant that may be present in any ethanol product).

(4) [Reserved]

(5) For each product reported in paragraph (b)(2) of this section for which Calculation Method 2 of this subpart was used to determine an emissions factor, report:

(i) The number of samples collected according to §98.394(c).

(ii) The sampling standard method used.

(iii) The carbon share test results in percent mass.

(iv) The standard method used to test carbon share.

(v) The calculated CO₂ emissions factor in metric tons CO₂ per barrel or per metric ton of product.

(6) For each non-solid product reported in paragraph (b)(2) of this section for which Calculation Method 2 of this subpart was used to determine an emissions factor, report:

(i) The density test results in metric tons per barrel.

(ii) The standard method used to test density.

(7) The CO₂ emissions in metric tons that would result from the complete combustion or oxidation of each imported petroleum product and natural gas liquid reported in paragraph (b)(2) of this section, calculated according to §98.393(a).

(8) The sum of CO₂ emissions that would result from the complete combustion oxidation of all imported products, calculated according to §98.393(e).

(c) In addition to the information required by §98.3(c), each exporter shall report all of the following information at the corporate level:

(1) [Reserved]

(2) For each petroleum product and natural gas liquid listed in Table MM-1 of this

subpart, report the annual quantity in metric tons or barrels. For natural gas liquids, quantity shall reflect the individual components of the product.

(3) For each product reported in paragraph (c)(2) of this section that was produced by blending a petroleum-based product with a biomass-based product, report the percent of the volume reported in paragraph (c)(2) of this section that is petroleum based (excluding any denaturant that may be present in any ethanol product).

(4) [Reserved]

(5) For each product reported in paragraph (c)(2) of this section for which Calculation Method 2 of this subpart was used to determine an emissions factor, report:

(i) The number of samples collected according to §98.394(c).

(ii) The sampling standard method used.

(iii) The carbon share test results in percentmass.

(iv) The standard method used to test carbon share.

(v) The calculated CO₂ emissions factor in metric tons CO₂ per barrel or per metric ton of product.

(6) For each non-solid product reported in paragraph (c)(2) of this section for which Calculation Method 2 of this subpart used was used to determine an emissions factor, report:

(i) The density test results in metric tons per barrel.

(ii) The standard method used to test density.

(7) The CO₂ emissions in metric tons that would result from the complete combustion or oxidation of for each exported petroleum product and natural gas liquid reported in paragraph (c)(2) of this section, calculated according to §98.393(a).

(8) The sum of CO₂ emissions that would result from the complete combustion or oxidation of all exported products, calculated according to §98.393(e).

(d) *Blended non-crude feedstock and products.* (1) Refineries, exporters, and importers must report the following information for each blended product and non-crude feedstock where emissions were calculated according to §98.393(i):

(i) Volume or mass of each blending component.

(ii) The CO₂ emissions in metric tons that would result from the complete combustion or oxidation of each blended non-crude feedstock or product, using Equation MM-12 or Equation MM-13 of this section.

(iii) Whether it is a blended non-crude feedstock or a blended product.

(2) For a product that enters the refinery to be further refined or otherwise used on site that is a blended non-crude feedstock, refiners must meet the reporting requirements of paragraph (a)(2) of this section by reflecting the individual components

		<p>of the blended non-crude feedstock.</p> <p>(3) For a product that is produced, imported, or exported that is a blended product, refiners, importers, and exporters must meet the reporting requirements of paragraphs (a)(6), (b)(2), and (c)(2) of this section, as applicable, by reflecting the individual components of the blended product.</p>
<p>Subpart NN – Suppliers of Natural Gas and Natural Gas Liquids (§98.406)</p>	<p>(A) All fractionators. (B) Local natural gas distribution companies that deliver 460,000 thousand standard cubic feet or more of natural gas per year.</p>	<p>(a) In addition to the information required by §98.3(c), the annual report for each NGL fractionator covered by this rule shall contain the following information.</p> <p>(1) Annual quantity (in barrels) of each NGL product supplied to downstream facilities in the following product categories: ethane, propane, normal butane, isobutane, and pentanes plus.</p> <p>(2) Annual quantity (in barrels) of each NGL product received from other NGL fractionators in the following product categories: ethane, propane, normal butane, isobutane, and pentanes plus.</p> <p>(3) Annual volumes in Mscf of natural gas received for processing.</p> <p>(4) Annual quantities (in barrels) of y-grade, o-grade, and other bulk NGLs:</p> <p>(i) Received.</p> <p>(ii) Supplied to downstream users that are not fractionated by the reporter.</p> <p>(5) Annual quantity (in barrels) of propane that the NGL fractionator odorizes at the facility and delivers to others.</p> <p>(6) Annual CO₂ emissions (metric tons) that would result from the complete combustion or oxidation of the quantities in paragraphs (a)(1) and (a)(2) of this section, calculated in accordance with §98.403(a) and (c)(1).</p> <p>(7) Annual CO₂ mass emissions (metric tons) that would result from the combustion or oxidation of fractionated NGLs supplied less the quantity received from other fractionators, calculated in accordance with §98.403(c)(2). If the calculated value is negative, the reporter shall report the value as zero.</p> <p>(8) The specific industry standard used to measure each quantity reported in paragraph (a)(1) of this section.</p> <p>(9) If the NGL fractionator developed reporter-specific EFs or HHVs, report the following for each product type:</p> <p>(i) The specific industry standard(s) used to develop reporter-specific higher heating value(s) and/or emission factor(s), pursuant to §98.404(b)(2) and (c)(3).</p> <p>(ii) The developed HHV(s).</p> <p>(iii) The developed EF(s).</p> <p>(b) In addition to the information required by §98.3(c), the annual report for each</p>

LDC shall contain the following information.

(1) Annual volume in Mscf of natural gas received by the LDC at its city gate stations for redelivery on the LDC's distribution system, including for use by the LDC.

(2) Annual volume in Mscf of natural gas placed into storage or liquefied and stored (Fuel₁ in Equation NN-5a).

(3) Annual volume in Mscf of natural gas withdrawn from on-system storage and annual volume in Mscf of vaporized liquefied natural gas (LNG) withdrawn from storage for delivery on the distribution system (Fuel₂ in Equation NN-5a).

(4) [Reserved]

(5) Annual volume in Mscf of natural gas that bypassed the city gate(s) and was supplied through the LDC distribution system. This includes natural gas from producers and natural gas processing plants from local production, or natural gas that was vaporized upon receipt and delivered, and any other source that bypassed the city gate (Fuel₂ in Equation NN-5b).

(6) Annual volume in Mscf of natural gas delivered to downstream gas transmission pipelines and other local distribution companies.

(7) Annual volume in Mscf of natural gas delivered by the LDC to each large end-user as defined in §98.403(b)(2)(i) of this section.

(8) The total annual CO₂ mass emissions (metric tons) associated with the volumes in paragraphs (b)(1) through (b)(7) of this section, calculated in accordance with §98.403(a) and (b)(1) through (b)(3).

(9) Annual CO₂ emissions (metric tons) that would result from the complete combustion or oxidation of the annual supply of natural gas to end-users registering less than 460,000 Mscf, calculated in accordance with §98.403(b)(4). If the calculated value is negative, the reporter shall report the value as zero.

(10) The specific industry standard used to develop the volume reported in paragraph (b)(1) of this section.

(11) If the LDC developed reporter-specific EFs or HHVs, report the following:

(i) The specific industry standard(s) used to develop reporter-specific higher heating value(s) and/or emission factor(s), pursuant to §98.404 (b)(2) and (c)(3).

(ii) The developed HHV(s).

(iii) The developed EF(s).

(12) The customer name, address, and meter number of each large end-user reported in paragraph (b)(7) of this section. Additionally, report whether the quantity of natural gas reported in paragraph (b)(7) of this section is the total quantity delivered to a large end-user's facility, or the quantity delivered to a specific meter located at the facility.

(i) If known, report the EIA identification number of each LDC customer.

		<p>(ii) [Reserved]</p> <p>(13) The annual volume in Mscf of natural gas delivered by the local distribution company to each of the following end-use categories. For definitions of these categories, refer to EIA Form 176 (Annual Report of Natural Gas and Supplemental Gas Supply & Disposition) and Instructions.</p> <p>(i) Residential consumers.</p> <p>(ii) Commercial consumers.</p> <p>(iii) Industrial consumers.</p> <p>(iv) Electricity generating facilities.</p> <p>(c) Each reporter shall report the number of days in the reporting year for which substitute data procedures were used for the following purpose:</p> <p>(1) To measure quantity.</p> <p>(2) To develop HHV(s).</p> <p>(3) To develop EF(s).</p>
<p>Subpart OO – Suppliers of Industrial Greenhouse Gases (§98.416)</p>	<p>Producers: All in</p> <p>Importers & Exporters with annual bulk imports or exports of N₂O, fluorinated GHG, and CO₂ that in combination are equivalent to 25,000 metric tons CO₂e or more.</p>	<p>In addition to the information required by §98.3(c), each annual report must contain the following information:</p> <p>(a) Each fluorinated GHG or nitrous oxide production facility shall report the following information:</p> <p>(1) Mass in metric tons of each fluorinated GHG or nitrous oxide produced at that facility by process, except for amounts that are captured solely to be shipped off site for destruction.</p> <p>(2) Mass in metric tons of each fluorinated GHG or nitrous oxide transformed at that facility, by process.</p> <p>(3) Mass in metric tons of each fluorinated GHG that is destroyed at that facility and that was previously produced as defined at §98.410(b). Quantities to be reported under this paragraph (a)(3) of this section include but are not limited to quantities that are shipped to the facility by another facility for destruction and quantities that are returned to the facility for reclamation but are found to be irretrievably contaminated and are therefore destroyed.</p> <p>(4) [Reserved]</p> <p>(5) Total mass in metric tons of each fluorinated GHG or nitrous oxide sent to another facility for transformation.</p> <p>(6) Total mass in metric tons of each fluorinated GHG sent to another facility for destruction, except fluorinated GHGs that are not included in the mass produced in §98.413(a) because they are removed from the production process as by-products or other wastes. Quantities to be reported under this paragraph (a)(6) could include, for example, fluorinated GHGs that are returned to the facility for reclamation but are found to be irretrievably contaminated and are therefore sent to another facility for destruction.</p>

(7) Total mass in metric tons of each fluorinated GHG that is sent to another facility for destruction and that is not included in the mass produced in §98.413(a) because it is removed from the production process as a byproduct or other waste.

(8)-(9) [Reserved]

(10) Mass in metric tons of any fluorinated GHG or nitrous oxide fed into the transformation process, by process.

(11) Mass in metric tons of each fluorinated GHG that is fed into the destruction device and that was previously produced as defined at §98.410(b). Quantities to be reported under this paragraph (a)(11) of this section include but are not limited to quantities that are shipped to the facility by another facility for destruction and quantities that are returned to the facility for reclamation but are found to be irretrievably contaminated and are therefore destroyed.

(12) Mass in metric tons of each fluorinated GHG or nitrous oxide that is measured coming out of the production process, by process.

(13) Mass in metric tons of each used fluorinated GHGs or nitrous oxide added back into the production process (e.g., for reclamation), including returned heels in containers that are weighed to measure the mass in §98.414(a), by process.

(14) Names and addresses of facilities to which any nitrous oxide or fluorinated GHGs were sent for transformation, and the quantities (metric tons) of nitrous oxide and of each fluorinated GHG that were sent to each for transformation.

(15) Names and addresses of facilities to which any fluorinated GHGs were sent for destruction, and the quantities (metric tons) of each fluorinated GHG that were sent to each for destruction.

(16) Where missing data have been estimated pursuant to §98.415, the reason the data were missing, the length of time the data were missing, the method used to estimate the missing data, and the estimates of those data.

(b) By March 31, 2011 or within 60 days of commencing fluorinated GHG destruction, whichever is later, a fluorinated GHG production facility or importer that destroys fluorinated GHGs shall submit a one-time report containing the following information for each destruction process:

(1) Destruction efficiency (DE).

(2) Methods used to determine the destruction efficiency.

(3) Methods used to record the mass of fluorinated GHG destroyed.

(4) Chemical identity of the fluorinated GHG(s) used in the performance test conducted to determine DE.

(5) Name of all applicable federal or state regulations that may apply to the destruction process.

(6) If any process changes affect unit destruction efficiency or the methods used to record mass of fluorinated GHG destroyed, then a revised report must be submitted to reflect the changes. The revised report must be submitted to EPA within 60 days of the

change.

(c) Each bulk importer of fluorinated GHGs or nitrous oxide shall submit an annual report that summarizes its imports at the corporate level, except for shipments including less than twenty-five kilograms of fluorinated GHGs or nitrous oxide, transshipments, and heels that meet the conditions set forth at §98.417(e). The report shall contain the following information for each import:

(1) Total mass in metric tons of nitrous oxide and each fluorinated GHG imported in bulk, including each fluorinated GHG constituent of the fluorinated GHG product that makes up between 0.5 percent and 100 percent of the product by mass.

(2) Total mass in metric tons of nitrous oxide and each fluorinated GHG imported in bulk and sold or transferred to persons other than the importer for use in processes resulting in the transformation or destruction of the chemical.

(3) Date on which the fluorinated GHGs or nitrous oxide were imported.

(4) Port of entry through which the fluorinated GHGs or nitrous oxide passed.

(5) Country from which the imported fluorinated GHGs or nitrous oxide were imported.

(6) Commodity code of the fluorinated GHGs or nitrous oxide shipped.

(7) Importer number for the shipment.

(8) Total mass in metric tons of each fluorinated GHG destroyed by the importer.

(9) If applicable, the names and addresses of the persons and facilities to which the nitrous oxide or fluorinated GHGs were sold or transferred for transformation, and the quantities (metric tons) of nitrous oxide and of each fluorinated GHG that were sold or transferred to each facility for transformation.

(10) If applicable, the names and addresses of the persons and facilities to which the fluorinated GHGs were sold or transferred for destruction, and the quantities (metric tons) of each fluorinated GHG that were sold or transferred to each facility for destruction.

(d) Each bulk exporter of fluorinated GHGs or nitrous oxide shall submit an annual report that summarizes its exports at the corporate level, except for shipments including less than twenty-five kilograms of fluorinated GHGs or nitrous oxide, transshipments, and heels. The report shall contain the following information for each export:

(1) Total mass in metric tons of nitrous oxide and each fluorinated GHG exported in bulk.

(2) Names and addresses of the exporter and the recipient of the exports.

(3) Exporter's Employee Identification Number.

(4) Commodity code of the fluorinated GHGs and nitrous oxide shipped.

(5) Date on which, and the port from which, fluorinated GHGs and nitrous oxide

		<p>were exported from the United States or its territories.</p> <p>(6) Country to which the fluorinated GHGs or nitrous oxide were exported.</p> <p>(e) By March 31, 2011, or within 60 days of commencing fluorinated GHG production, whichever is later, a fluorinated GHG production facility shall submit a one-time report describing the following information:</p> <p>(1) The method(s) by which the producer in practice measures the mass of fluorinated GHGs produced, including the instrumentation used (Coriolis flowmeter, other flowmeter, weigh scale, etc.) and its accuracy and precision.</p> <p>(2) The method(s) by which the producer in practice estimates the mass of fluorinated GHGs fed into the transformation process, including the instrumentation used (Coriolis flowmeter, other flowmeter, weigh scale, etc.) and its accuracy and precision.</p> <p>(3) The method(s) by which the producer in practice estimates the fraction of fluorinated GHGs fed into the transformation process that is actually transformed, and the estimated precision and accuracy of this estimate.</p> <p>(4) The method(s) by which the producer in practice estimates the masses of fluorinated GHGs fed into the destruction device, including the method(s) used to estimate the concentration of the fluorinated GHGs in the destroyed material, and the estimated precision and accuracy of this estimate.</p> <p>(5) The estimated percent efficiency of each production process for the fluorinated GHG produced.</p> <p>(f) By March 31, 2011, all fluorinated GHG production facilities shall submit a one-time report that includes the concentration of each fluorinated GHG constituent in each fluorinated GHG product as measured under §98.414(n). If the facility commences production of a fluorinated GHG product that was not included in the initial report or performs a repeat measurement under §98.414(n) that shows that the identities or concentrations of the fluorinated GHG constituents of a fluorinated GHG product have changed, then the new or changed concentrations, as well as the date of the change, must be reflected in a revision to the report. The revised report must be submitted to EPA by the March 31st that immediately follows the measurement under §98.414(n).</p> <p>(g) Isolated intermediates that are produced and transformed at the same facility are exempt from the reporting requirements of this section.</p> <p>(h) Low-concentration constituents are exempt from the reporting requirements of this section.</p>
<p>Subpart PP – Suppliers of Carbon Dioxide (§98.426)</p>	<p>Producers: All in</p> <p>Bulk importers & exporters with annual bulk imports or exports of N₂O, fluorinated</p>	<p>In addition to the information required by §98.3(c) of subpart A of this part, the annual report shall contain the following information, as applicable:</p> <p>(a) If you use Equation PP-1 of this subpart, report the following information for each mass flow meter or CO₂ stream that delivers CO₂ to containers:</p> <p>(1) Annual mass in metric tons of CO₂.</p> <p>(2) Quarterly mass in metric tons of CO₂.</p>

	<p>GHG, and CO₂ that in combination are equivalent to 25,000 metric tons CO₂e or more</p>	<p>(3) Quarterly concentration of the CO₂ stream.</p> <p>(4) The standard used to measure CO₂ concentration.</p> <p>(5) The location of the flow meter in your process chain in relation to the points of CO₂ stream capture, dehydration, compression, and other processing.</p> <p>(b) If you use Equation PP-2 of this subpart, report the following information for each volumetric flow meter or CO₂ stream that delivers CO₂ to containers:</p> <p>(1) Annual mass in metric tons of CO₂.</p> <p>(2) Quarterly volume in standard cubic meters of CO₂.</p> <p>(3) Quarterly concentration of the CO₂ stream in volume or weight percent.</p> <p>(4) Report density as follows:</p> <p>(i) Quarterly density of the CO₂ stream in metric tons per standard cubic meter if you report the concentration of the CO₂ stream in paragraph (b)(3) of this section in weight percent.</p> <p>(ii) Quarterly density of CO₂ in metric tons per standard cubic meter if you report the concentration of the CO₂ stream in paragraph (b)(3) of this section in volume percent.</p> <p>(5) The method used to measure density.</p> <p>(6) The standard used to measure CO₂ concentration.</p> <p>(7) The location of the flow meter in your process chain in relation to the points of CO₂ stream capture, dehydration, compression, and other processing.</p> <p>(c) For the aggregated annual mass of CO₂ emissions calculated using Equation PP-3a or PP-3b, report the following:</p> <p>(1) If you use Equation PP-3a of this subpart, report the annual CO₂ mass in metric tons from all flow meters and CO₂ streams that deliver CO₂ to containers.</p> <p>(2) If you use Equation PP-3b of this subpart, report:</p> <p>(i) The total annual CO₂ mass through main flow meter(s) in metric tons.</p> <p>(ii) The total annual CO₂ mass through subsequent flow meter(s) in metric tons.</p> <p>(iii) The total annual CO₂ mass supplied in metric tons.</p> <p>(iv) The location of each flow meter in relation to the point of segregation.</p> <p>(d) If you use Equation PP-4 of this subpart, report at the corporate level the annual mass of CO₂ in metric tons in all CO₂ containers that are imported or exported.</p>
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		<p>(e) Each reporter shall report the following information:</p> <p>(1) The type of equipment used to measure the total flow of the CO₂ stream or the total mass or volume in CO₂ containers.</p> <p>(2) The standard used to operate and calibrate the equipment reported in (e)(1) of this section.</p> <p>(3) The number of days in the reporting year for which substitute data procedures were used for the following purpose:</p> <p>(i) To measure quantity.</p> <p>(ii) To measure concentration.</p> <p>(iii) To measure density.</p> <p>(f) Report the aggregated annual quantity of CO₂ in metric tons that is transferred to each of the following end use applications, if known:</p> <p>(1) Food and beverage.</p> <p>(2) Industrial and municipal water/wastewater treatment.</p> <p>(3) Metal fabrication, including welding and cutting.</p> <p>(4) Greenhouse uses for plant growth.</p> <p>(5) Fumigants (e.g., grain storage) and herbicides.</p> <p>(6) Pulp and paper.</p> <p>(7) Cleaning and solvent use.</p> <p>(8) Fire fighting.</p> <p>(9) Transportation and storage of explosives.</p> <p>(10) Injection of carbon dioxide for enhanced oil and natural gas recovery that is covered by subpart UU of this part.</p> <p>(11) Geologic sequestration of carbon dioxide that is covered by subpart RR of this part.</p> <p>(12) Research and development.</p> <p>(13) Other.</p> <p>(g) Each production process unit that captures a CO₂ stream for purposes of supplying CO₂ for commercial applications or in order to sequester or otherwise inject it underground when custody of the CO₂ is maintained shall report the percentage of that stream, if any, that is biomass-based during the reporting year.</p>
Subpart QQ –	Importers	(a) Each importer of fluorinated GHGs contained in pre-charged equipment or

<p>Importers and Exporters of Fluorinated Greenhouse Gases Contained in Pre-Charged Equipment or Closed-Cell Foams (§98.436)</p>	<p>and exporters of an annual quantity of fluorinated greenhouse gases contained in pre-charged equipment or closed-cell foams that is equivalent to 25,000 metric tons CO₂e or more.</p>	<p>closed-cell foams must submit an annual report that summarizes its imports at the corporate level, except for transshipments, as specified:</p> <p>(1) Total mass in metric tons of each fluorinated GHG imported in pre-charged equipment or closed-cell foams.</p> <p>(2) For each type of pre-charged equipment with a unique combination of charge size and charge type, the identity of the fluorinated GHG used as a refrigerant or electrical insulator, charge size (holding charge, if applicable), and number imported.</p> <p>(3) For closed-cell foams that are imported inside of equipment, the identity of the fluorinated GHG contained in the foam, the mass of the fluorinated GHG contained in the foam in each piece of equipment, and the number of pieces of equipment imported with each unique combination of mass and identity of fluorinated GHG within the closed-cell foams.</p> <p>(4) For closed cell-foams that are not imported inside of equipment, the identity of the fluorinated GHG in the foam, the density of the fluorinated GHG in the foam (kg fluorinated GHG/cubic foot), and the volume of foam imported (cubic feet) for each type of closed-cell foam with a unique combination of fluorinated GHG density and identity.</p> <p>(5) Dates on which the pre-charged equipment or closed-cell foams were imported.</p> <p>(6) If the importer does not know the identity and mass of the fluorinated GHGs within the closed-cell foam, the importer must report the following:</p> <p>(i) Total mass in metric tons of CO₂e of the fluorinated GHGs imported in closed-cell foams.</p> <p>(ii) For closed-cell foams that are imported inside of equipment, the mass of the fluorinated GHGs in CO₂e contained in the foam in each piece of equipment and the number of pieces of equipment imported for each equipment type.</p> <p>(iii) For closed-cell foams that are not imported inside of equipment, the density in CO₂e of the fluorinated GHGs in the foam (kg CO₂e/cubic foot) and the volume of foam imported (cubic feet) for each type of closed-cell foam.</p> <p>(iv) Dates on which the closed-cell foams were imported.</p> <p>(v) Name of the foam manufacturer for each type of closed-cell foam where the identity and mass of the fluorinated GHGs is unknown.</p> <p>(vi) Certification that the importer was unable to obtain information on the identity and mass of the fluorinated GHGs within the closed-cell foam from the closed-cell foam manufacturer or manufacturers.</p> <p>(b) Each exporter of fluorinated GHGs contained in pre-charged equipment or closed-cell foams must submit an annual report that summarizes its exports at the corporate level, except for transshipments, as specified:</p> <p>(1) Total mass in metric tons of each fluorinated GHG exported in pre-charged equipment or closed-cell foams.</p> <p>(2) For each type of pre-charged equipment with a unique combination of charge size and charge type, the identity of the fluorinated GHG used as a refrigerant or electrical insulator, charge size (including holding charge, if applicable), and number</p>
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		<p>exported.</p> <p>(3) For closed-cell foams that are exported inside of equipment, the identity of the fluorinated GHG contained in the foam in each piece of equipment, the mass of the fluorinated GHG contained in the foam in each piece of equipment, and the number of pieces of equipment exported with each unique combination of mass and identity of fluorinated GHG within the closed-cell foams.</p> <p>(4) For closed-cell foams that are not exported inside of equipment, the identity of the fluorinated GHG in the foam, the density of the fluorinated GHG in the foam (kg fluorinated GHG/cubic foot), and the volume of foam exported (cubic feet) for each type of closed-cell foam with a unique combination of fluorinated GHG density and identity.</p> <p>(5) Dates on which the pre-charged equipment or closed-cell foams were exported.</p> <p>(6) If the exporter does not know the identity and mass of the fluorinated GHG within the closed-cell foam, the exporter must report the following:</p> <p>(i) Total mass in metric tons of CO₂e of the fluorinated GHGs exported in closed-cell foams.</p> <p>(ii) For closed-cell foams that are exported inside of equipment, the mass of the fluorinated GHGs in CO₂e contained in the foam in each piece of equipment and the number of pieces of equipment imported for each equipment type.</p> <p>(iii) For closed-cell foams that are not exported inside of equipment, the density in CO₂e of the fluorinated GHGs in the foam (kg CO₂ e/cubic foot) and the volume of foam imported (cubic feet) for each type of closed-cell foam.</p> <p>(iv) Dates on which the closed-cell foams were exported.</p> <p>(v) Name of the foam manufacturer for each type of closed-cell foam where the identity and mass of the fluorinated GHGg is unknown.</p> <p>(vi) Certification that the exporter was unable to obtain information on the identity and mass of the fluorinated GHGs within the closed-cell foam from the closed-cell foam manufacturer or manufacturers.</p>
<p>Subpart RR – Geologic Sequestration of Carbon Dioxide (§98.446)</p>	<p>All in</p>	<p>In addition to the information required by §98.3(c), report the information listed in this section.</p> <p>(a) If you receive CO₂ by pipeline, report the following for each receiving flow meter:</p> <p>(1) The total net mass of CO₂ received (metric tons) annually.</p> <p>(2) If a volumetric flow meter is used to receive CO₂ report the following unless you reported yes to paragraph (a)(4) of this section:</p> <p>(i) The volumetric flow through a receiving flow meter at standard conditions (in standard cubic meters) in each quarter.</p> <p>(ii) The volumetric flow through a receiving flow meter that is redelivered to another facility without being injected into your well (in standard cubic meters) in each quarter.</p>

(iii) The CO₂ concentration in the flow (volume percent CO₂ expressed as a decimal fraction) in each quarter.

(3) If a mass flow meter is used to receive CO₂ report the following unless you reported yes to paragraph (a)(4) of this section:

(i) The mass flow through a receiving flow meter (in metric tons) in each quarter.

(ii) The mass flow through a receiving flow meter that is redelivered to another facility without being injected into your well (in metric tons) in each quarter.

(iii) The CO₂ concentration in the flow (weight percent CO₂ expressed as a decimal fraction) in each quarter.

(4) If the CO₂ received is wholly injected and not mixed with any other supply of CO₂, report whether you followed the procedures in §98.444(a)(4).

(5) The standard or method used to calculate each value in paragraphs (a)(2) through (a)(3) of this section.

(6) The number of times in the reporting year for which substitute data procedures were used to calculate values reported in paragraphs (a)(2) through (a)(3) of this section.

(7) Whether the flow meter is mass or volumetric.

(8) A numerical identifier for the flow meter.

(b) If you receive CO₂ in containers, report:

(1) The mass (in metric tons) or volume at standard conditions (in standard cubic meters) of contents in containers received in each quarter.

(2) The concentration of CO₂ of contents in containers (volume or wt. percent CO₂ expressed as a decimal fraction) in each quarter.

(3) The mass (in metric tons) or volume (in standard cubic meters) of contents in containers that is redelivered to another facility without being injected into your well in each quarter.

(4) The net mass of CO₂ received (in metric tons) annually.

(5) The standard or method used to calculate each value in paragraphs (b)(1), (b)(2), and (b)(3) of this section.

(6) The number of times in the reporting year for which substitute data procedures were used to calculate values reported in paragraphs (b)(1) and (b)(2) of this section.

(c) If you use more than one receiving flow meter, report the total net mass of CO₂ received (metric tons) through all flow meters annually.

(d) The source of the CO₂ received according to the following categories:

(1) CO₂ production wells.

(2) Electric generating unit.

(3) Ethanol plant.

(4) Pulp and paper mill.

(5) Natural gas processing.

(6) Gasification operations.

(7) Other anthropogenic source.

(8) Discontinued enhanced oil and gas recovery project.

(9) Unknown.

(e) Report the date that you began collecting data for calculating total amount sequestered according to §98.448(a)(7) of this subpart.

(f) Report the following. If the date specified in paragraph (e) of this section is during the reporting year for this annual report, report the following starting on the date specified in paragraph (e) of this section.

(1) For each injection flow meter (mass or volumetric), report:

(i) The mass of CO₂ injected (metric tons) annually.

(ii) The CO₂ concentration in flow (volume or weight percent CO₂ expressed as a decimal fraction) in each quarter.

(iii) If a volumetric flow meter is used, the volumetric flow rate at standard conditions (in standard cubic meters) in each quarter.

(iv) If a mass flow meter is used, the mass flow rate (in metric tons) in each quarter.

(v) A numerical identifier for the flow meter.

(vi) Whether the flow meter is mass or volumetric.

(vii) The standard used to calculate each value in paragraphs (f)(1)(ii) through (f)(1)(iv) of this section.

(viii) The number of times in the reporting year for which substitute data procedures were used to calculate values reported in paragraphs (f)(1)(ii) through (f)(1)(iv) of this section.

(ix) The location of the flow meter.

(2) The total CO₂ injected (metric tons) in the reporting year as calculated in Equation RR-6 of this subpart.

(3) For CO₂ emissions from equipment leaks and vented emissions of CO₂, report

the following:

(i) The mass of CO₂ emitted (in metric tons) annually from equipment leaks and vented emissions of CO₂ from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

(ii) The mass of CO₂ emitted (in metric tons) annually from equipment leaks and vented emissions of CO₂ from equipment located on the surface between the production wellhead and the flow meter used to measure production quantity.

(4) For each separator flow meter (mass or volumetric), report:

(i) CO₂ mass produced (metric tons) annually.

(ii) CO₂ concentration in flow (volume or weight percent CO₂ expressed as a decimal fraction) in each quarter.

(iii) If a volumetric flow meter is used, volumetric flow rate at standard conditions (standard cubic meters) in each quarter.

(iv) If a mass flow meter, mass flow rate (metric tons) in each quarter.

(v) A numerical identifier for the flow meter.

(vi) Whether the flow meter is mass or volumetric.

(vii) The standard used to calculate each value in paragraphs (f)(4)(ii) through (f)(4)(iv) of this section.

(viii) The number of times in the reporting year for which substitute data procedures were used to calculate values reported in paragraphs (f)(4)(ii) through (f)(4)(iv) of this section.

(5) The entrained CO₂ in produced oil or other fluid divided by the CO₂ separated through all separators in the reporting year (weight percent CO₂ expressed as a decimal fraction) used as the value for X in Equation RR-9 of this subpart and as determined according to your EPA-approved MRV plan.

(6) Annual CO₂ produced in the reporting year as calculated in Equation RR-9 of this subpart.

(7) For each leakage pathway through which CO₂ emissions occurred, report:

(i) A numerical identifier for the leakage pathway.

(ii) The CO₂ (metric tons) emitted through that pathway in the reporting year.

(8) Annual CO₂ mass emitted (metric tons) by surface leakage in the reporting year as calculated by Equation RR-10 of this subpart.

(9) Annual CO₂ (metric tons) sequestered in subsurface geologic formations in the reporting year as calculated by Equation RR-11 or RR-12 of this subpart.

(10) Cumulative mass of CO₂ (metric tons) reported as sequestered in subsurface

		<p>geologic formations in all years since the well or group of wells became subject to reporting requirements under this subpart.</p> <p>(11) Date that the most recent MRV plan was approved by EPA and the MRV plan approval number that was issued by EPA.</p> <p>(12) An annual monitoring report that contains the following components:</p> <p>(i) A narrative history of the monitoring efforts conducted over the previous calendar year, including a listing of all monitoring equipment that was operated, its period of operation, and any relevant tests or surveys that were conducted.</p> <p>(ii) A description of any changes to the monitoring program that you concluded were not material changes warranting submission of a revised MRV plan under §98.448(d).</p> <p>(iii) A narrative history of any monitoring anomalies that were detected in the previous calendar year and how they were investigated and resolved.</p> <p>(iv) A description of any surface leakages of CO₂, including a discussion of all methodologies and technologies involved in detecting and quantifying the surface leakages and any assumptions and uncertainties involved in calculating the amount of CO₂ emitted.</p> <p>(13) If a well is permitted under the Underground Injection Control program, for each injection well, report:</p> <p>(i) The well identification number used for the Underground Injection Control permit.</p> <p>(ii) The Underground Injection Control permit class.</p> <p>(14) If an offshore well is not subject to the Safe Drinking Water Act, for each injection well, report any well identification number and any identification number used for the legal instrument authorizing geologic sequestration.</p>
<p>Subpart SS – Electrical Equipment Manufacture or Refurbishment (§98.456)</p>	<p>Total annual purchases of SF₆ and PFCs that exceed 23,000 pounds</p>	<p>In addition to the information required by §98.3(c), each annual report must contain the following information for each chemical at the facility level:</p> <p>(a) Pounds of SF₆ and PFCs stored in containers at the beginning of the year.</p> <p>(b) Pounds of SF₆ and PFCs stored in containers at the end of the year.</p> <p>(c) Pounds of SF₆ and PFCs purchased in bulk.</p> <p>(d) Pounds of SF₆ and PFCs returned by equipment users with or inside equipment.</p> <p>(e) Pounds of SF₆ and PFCs returned to site from off site after recycling.</p> <p>(f) Pounds of SF₆ and PFCs inside new equipment delivered to customers.</p>

		<p>(g) Pounds of SF₆ and PFCs delivered to equipment users in containers.</p> <p>(h) Pounds of SF₆ and PFCs returned to suppliers.</p> <p>(i) Pounds of SF₆ and PFCs sent off site for destruction.</p> <p>(j) Pounds of SF₆ and PFCs sent off site to be recycled.</p> <p>(k) The nameplate capacity of the equipment, in pounds, delivered to customers with SF₆ or PFCs inside, if different from the quantity in paragraph (f) of this section.</p> <p>(l) A description of the engineering methods and calculations used to determine emissions from hoses or other flow lines that connect the container to the equipment that is being filled.</p> <p>(m) The values for EF_{ci} of Equation SS-5 of this subpart for each hose and valve combination and the associated valve fitting sizes and hose diameters.</p> <p>(n) The total number of fill operations for each hose and valve combination, or, F_{ci} of Equation SS-5 of this subpart.</p> <p>(o) If the mass of SF₆ or the PFC disbursed to customers in new equipment over the period p is determined according to the methods required in §98.453(h), report the mean value of nameplate capacity in pounds for each make, model, and group of conditions.</p> <p>(p) If the mass of SF₆ or the PFC disbursed to customers in new equipment over the period p is determined according to the methods required in §98.453(h), report the number of samples and the upper and lower bounds on the 95 percent confidence interval for each make, model, and group of conditions.</p> <p>(q) Pounds of SF₆ and PFCs used to fill equipment at off-site electric power transmission or distribution locations, or M_F, of Equation SS-6 of this subpart.</p> <p>(r) Pounds of SF₆ and PFCs used to charge the equipment prior to leaving the electrical equipment manufacturer or refurbishment facility, or M_C, of Equation SS-6 of this subpart.</p> <p>(s) The nameplate capacity of the equipment, in pounds, installed at off-site electric power transmission or distribution locations used to determine emissions from installation, or N_i, of Equation SS-6 of this subpart.</p> <p>(t) For any missing data, you must report the reason the data were missing, the parameters for which the data were missing, the substitute parameters used to estimate emissions in their absence, and the quantity of emissions thereby estimated.</p>
<p>Subpart TT— Industrial Waste Landfills (§98.466)</p>	<p>25,000 metric tons CO₂e/year</p>	<p>In addition to the information required by §98.3(c), each annual report must contain the following information for each landfill.</p> <p>(a) Report the following general landfill information:</p> <p>(1) A classification of the landfill as “open” (actively received waste in the reporting year) or “closed” (no longer receiving waste).</p>

		<p>(2) The year in which the landfill first started accepting waste for disposal.</p> <p>(3) The last year the landfill accepted waste (for open landfills, enter the estimated year of landfill closure).</p> <p>(4) The capacity (in metric tons) of the landfill.</p> <p>(5) An indication of whether leachate recirculation is used during the reporting year and its typical frequency of use over the past 10 years (<i>e.g.</i>, used several times a year for the past 10 years, used at least once a year for the past 10 years, used occasionally but not every year over the past 10 years, not used).</p> <p>(b) Report the following waste characterization and modeling information:</p> <p>(1) The number of waste streams (including "Other Industrial Solid Waste (not otherwise listed)" and "Inerts") for which Equation TT-1 of this subpart is used to calculate modeled CH₄ generation.</p> <p>(2) A description of each waste stream (including the types of materials in each waste stream) for which Equation TT-1 of this subpart is used to calculate modeled CH₄ generation.</p> <p>(3) The fraction of CH₄ in the landfill gas, F, (volume fraction, dry basis, corrected to 0% oxygen) for the reporting year and an indication as to whether this was the default value or a value determined through measurement data.</p> <p>(4) The methane correction factor (MCF) value used in the calculations. If an MCF value other than the default of 1 is used, provide a description of the aeration system, including aeration blower capacity, the fraction of the landfill containing waste affected by the aeration, the total number of hours during the year the aeration blower was operated, and other factors used as a basis for the selected MCF value.</p> <p>(5) For each waste stream, the decay rate (k) value used in the calculations.</p> <p>(c) Report the following historical waste information:</p> <p>(1) [Reserved]</p> <p>(2) For each waste stream identified in paragraph (b) of this section, the method(s) for estimating historical waste disposal quantities and the range of years for which each method applies.</p> <p>(3) For each waste stream identified in paragraph (b) of this section for which Equation TT-2 of this subpart is used, provide:</p> <p>(i) [Reserved]</p> <p>(ii) The year of the data used in Equation TT-2 of §98.463 for the waste disposal quantity and production quantity, for each year used in Equation TT-2 to calculate the average waste disposal factor (WDF).</p> <p>(iii) [Reserved]</p>
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		<p>CH₄.</p> <p>(2) An indication of whether passive vents and/or passive flares (vents or flares that are not considered part of the gas collection system as defined in §98.6) are present at this landfill.</p> <p>(h) For landfills with gas collection systems, in addition to the reporting requirements in paragraphs (a) through (f) of this section, provide:</p> <p>(1) The annual methane generation, adjusted for oxidation, calculated using Equation TT-6 of this subpart, reported in metric tons CH₄.</p> <p>(2) The oxidation factor used in Equation TT-6 of this subpart.</p> <p>(3) All information required under 40 CFR 98.346(i)(1) through (7) and 40 CFR 98.346(i)(9) through (12).</p>
<p>Subpart UU – Injection of Carbon Dioxide (§98.476)</p>	<p>All In</p>	<p>If you are subject to this part and report under this subpart, you are not required to report the information in §98.3(c)(4) for this subpart. In addition to the information required by §98.3(c)(1) through §98.3(c)(3) and by §98.3(c)(5) through §98.3(c)(9), you must report the information listed in this section.</p> <p>(a) If you receive CO₂ by pipeline, report the following for each receiving flow meter:</p> <p>(1) The total net mass of CO₂ received (metric tons) annually.</p> <p>(2) If a volumetric flow meter is used to receive CO₂:</p> <p>(i) The volumetric flow through a receiving flow meter at standard conditions (in standard cubic meters) in each quarter.</p> <p>(ii) The volumetric flow through a receiving flow meter that is redelivered to another facility without being injected into your well (in standard cubic meters) in each quarter.</p> <p>(iii) The CO₂ concentration in the flow (volume percent CO₂ expressed as a decimal fraction) in each quarter.</p> <p>(3) If a mass flow meter is used to receive CO₂:</p> <p>(i) The mass flow through a receiving flow meter (in metric tons) in each quarter.</p> <p>(ii) The mass flow through a receiving flow meter that is redelivered to another facility without being injected into your well (in metric tons) in each quarter.</p> <p>(iii) The CO₂ concentration in the flow (weight percent CO₂ expressed as a decimal fraction) in each quarter.</p> <p>(4) The standard or method used to calculate each value in paragraphs (a)(2) through (a)(3) of this section.</p> <p>(5) The number of times in the reporting year for which substitute data procedures were used to calculate values reported in paragraphs (a)(2) through (a)(3) of this section.</p>

		<p>(6) Whether the flow meter is mass or volumetric.</p> <p>(b) If you receive CO₂ in containers, report:</p> <p>(1) The mass (in metric tons) or volume at standard conditions (in standard cubic meters) of contents in containers in each quarter.</p> <p>(2) The concentration of CO₂ of contents in containers (volume or weight percent CO₂ expressed as a decimal fraction) in each quarter.</p> <p>(3) The mass (in metric tons) or volume (in standard cubic meters) of contents in containers that is redelivered to another facility without being injected into your well in each quarter.</p> <p>(4) The net total mass of CO₂ received (in metric tons) annually.</p> <p>(5) The standard or method used to calculate each value in paragraphs (b)(1), (b)(2), and (b)(3) of this section.</p> <p>(6) The number of times in the reporting year for which substitute data procedures were used to calculate values reported in paragraphs (b)(1) and (b)(2) of this section.</p> <p>(c) If you use more than one receiving flow meter, report the net total mass of CO₂ received (metric tons) through all flow meters annually.</p> <p>(d) The source of the CO₂ received according to the following categories:</p> <p>(1) CO₂ production wells.</p> <p>(2) Electric generating unit.</p> <p>(3) Ethanol plant.</p> <p>(4) Pulp and paper mill.</p> <p>(5) Natural gas processing.</p> <p>(6) Gasification operations.</p> <p>(7) Other anthropogenic source.</p> <p>(8) Discontinued enhanced oil and gas recovery project.</p> <p>(9) Unknown.</p> <p>(e) Report the following:</p> <p>(1) Whether the facility received a Research and Development project exemption from reporting under 40 CFR part 98, subpart RR, for this reporting year. If you received an exemption, report the start and end dates of the exemption approved by EPA.</p> <p>(2) Whether the facility includes a well or group of wells where a CO₂ stream was injected into subsurface geologic formations to enhance the recovery of oil during this</p>
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		<p>reporting year.</p> <p>(3) Whether the facility includes a well or group of wells where a CO₂ stream was injected into subsurface geologic formations to enhance the recovery of natural gas during this reporting year.</p> <p>(4) Whether the facility includes a well or group of wells where a CO₂ stream was injected into subsurface geologic formations for acid gas disposal during this reporting year.</p> <p>(5) Whether the facility includes a well or group of wells where a CO₂ stream was injected for a purpose other than those listed in paragraphs (e)(1) through (4) of this section. If you injected CO₂ for another purpose, report the purpose of the injection.</p>
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