Subpart C of 40 CFR 98, As Modified by Proposed 20.2.300 NMAC – Reporting of Greenhouse Gas Emissions

plain text = unchanged EPA rule language

underline = added by 20.2.300 NMAC (NMED-Musick Rebuttal Exhibit 1)

~~strikeout~~ = deleted by 20.2.300 NMAC (NMED-Musick Rebuttal Exhibit 1)

Note: This version of 40 CFR 98 Subpart C includes amendments published on July 12, 2010 (75 FR 39736) and September 22, 2010 (75 FR 57669), and Technical Corrections as signed by the EPA Administrator on October 7, 2010. These EPA amendments are incorporated as plain text, not underline/strikeout.

Subpart C – General Stationary Fuel Combustion

§98.30 Definition of the source category.

(a) Stationary fuel combustion sources are devices that combust solid, liquid, or gaseous fuel, generally for the purposes of producing electricity, generating steam, or providing useful heat or energy for industrial, commercial, or institutional use, or reducing the volume of waste by removing combustible matter. Stationary fuel combustion sources include, but are not limited to, boilers, simple and combined-cycle combustion turbines, engines, incinerators, and process heaters.

(b) This source category does not include:

(1) Portable equipment, as defined in §98.6.

(2) Emergency generators and emergency equipment, as defined in §98.6.

(3) Irrigation pumps at agricultural operations.

(4) Flares, unless otherwise required by provisions of another subpart of 40 CFR part 98 to use methodologies in this subpart.

(5) Electricity generating units that are subject to subpart D of this part.

(c) For a unit that combusts hazardous waste (as defined in 40 CFR 261.3), reporting of GHG emissions is not required unless either of the following conditions apply:

(1) Continuous emission monitors (CEMS) are used to quantify CO_2 mass emissions.

(2) Any fuel listed in Table C-1 of this subpart is also combusted in the unit. In this case, report GHG emissions from combustion of all fuels listed in Table C-1 of this subpart.

§98.31 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains one or more stationary fuel combustion sources and the facility meets the applicability requirements of either §§98.2(a)(1), 98.2(a)(2), or 98.2(a)(3).

§98.32 GHGs to report.

(a) You must report CO_2, CH_4, and N_2O mass emissions from each stationary fuel combustion unit.

(b) [Reporting only] Facilities that generate electricity either for sale or for use onsite must also report fugitive HFC emissions from cooling units by following the requirements of §98.33(f).

§98.33 Calculating GHG emissions.

You must calculate CO_2 emissions according to paragraph (a) of this section, and calculate CH_4 and N_2O emissions according to paragraph (c) of this section.

(a) *CO_2 emissions from fuel combustion.* Calculate CO_2 emissions by using one of the four calculation methodologies in this paragraph (a) subject to the conditions, requirements, and restrictions set forth in paragraph (b) of this section. If you co-fire biomass fuels with fossil fuels, report CO_2 emissions from the combustion of biomass separately using the methods in paragraph (e) of this section.

(1) *Tier 1 Calculation Methodology.* Calculate the annual CO_2 mass emissions for each type of fuel by using Equation C-1 of this section.

$$CO_2 = 1x10^{-3} * Fuel * HHV * EF \qquad \text{(Eq. C-1)}$$

Where:

CO_2 = Annual CO_2 mass emissions for the specific fuel type (metric tons).

Fuel = Mass or volume of fuel combusted per year, from company records as defined in §98.6 (express mass in short tons for solid fuel, volume in standard cubic feet for gaseous fuel, and volume in gallons for liquid fuel).

HHV = Default high heat value of the fuel, from Table C-1 of this subpart (mmBtu per mass or mmBtu per volume, as applicable).

EF = Fuel-specific default CO_2 emission factor, from Table C-1 of this subpart (kg CO_2/mmBtu).

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

(2) *Tier 2 Calculation Methodology*. Calculate the annual CO_2 mass emissions for each type of fuel by using either Equation C2a or C2c of this section, as appropriate.

(i) Equation C-2a of this section applies to any type of fuel listed in Table C-1 of the subpart, except for municipal solid waste (MSW). For MSW combustion, use Equation C-2c of this section.

$$CO_2 = 1x10^{-3} * Fuel * HHV * EF \qquad \text{(Eq. C-2a)}$$

Where:

CO2 = Annual CO2 mass emissions for a specific fuel type (metric tons).

Fuel = Mass or volume of the fuel combusted during the year, from company records as defined in §98.6 (express mass in short tons for solid fuel, volume in standard cubic feet for gaseous fuel, and volume in gallons for liquid fuel).

HHV = Annual average high heat value of the fuel from all valid samples for the year (mmBtu per mass or volume). The average HHV shall be calculated according to the requirements of paragraph (a)(2)(ii) of this section.

EF = Fuel-specific default CO2 emission factor, from Table C-1 of this subpart (kg CO2/mmBtu).

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

(ii) The minimum number of HHV samples for determining annual average HHV is specified (e.g., monthly, quarterly, semi-annually, or by lot) in §98.34. The method for computing the annual average HHV is a function of how frequently you perform or receive from the fuel supplier the results of fuel sampling for HHV. The method is specified in paragraph (a)(2)(ii)(A) or (a)(2)(ii)(B) of this section, as applicable.

(A) If the results of fuel sampling are received monthly or more frequently, then the annual average HHV shall be calculated using Equation C-2b of this section. If multiple HHV determinations are made in any month, average the values for the month arithmetically.

$$(HHV)_{annual} = \frac{\sum_{i=1}^{n}(HHV)_i * (Fuel)_i}{\sum_{i=1}^{n}(Fuel)_i} \qquad \text{(Eq. C-2b)}$$

Where:

$(HHV)_{annual}$ = Weighted annual average high heat value of the fuel (mmBtu per mass or volume).

$(HHV)_i$ = High heat value of the fuel, for month "i" (mmBtu per mass or volume).

$(Fuel)_i$ = Mass or volume of the fuel combusted during month "i" (express mass in short tons for solid fuel, volume in standard cubic feet for gaseous fuel, and volume in gallons for liquid fuel).

n = Number of months in the year that fuel is burned in the unit.

(B) If the results of fuel sampling are received less frequently than monthly, then the annual average HHV shall be computed as the arithmetic average HHV for all values for the year (including valid samples and substitute data values under 98.35).

(iii) For units that combust municipal solid waste (MSW) and that produce steam, use Equation C-2c of this section. Equation C-2c of this section may also be used for any ~~other~~ solid biomass fuel listed in Table C-1 of this subpart provided that steam is generated by the unit.

$$CO_2 = 1 \times 10^{-3} \text{ Steam} * B * EF \qquad \text{(Eq. C-2c)}$$

Where:

CO2 = Annual CO2 mass emissions from MSW or solid fuel combustion (metric tons).

Steam = Total mass of steam generated by MSW or solid fuel combustion during the reporting year (lb steam).

B = Ratio of the boiler's maximum rated heat input capacity to its design rated steam output capacity (mmBtu/lb steam).

EF = Fuel-specific default CO2 emission factor, from Table C-1 of this subpart (kg CO2/mmBtu).

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

(3) *Tier 3 Calculation Methodology*. Calculate the annual CO_2 mass emissions for each fuel by using either Equation C3, C4, or C5 of this section, as appropriate.

(i) For a solid fuel, use Equation C-3 of this section.

$$CO_2 = \frac{44}{12} * \text{Fuel} * \text{CC} * 0.91 \qquad \text{(Eq. C-3)}$$

Where:

CO2	=	Annual CO2 mass emissions from the combustion of the specific solid fuel (metric tons).
Fuel	=	Annual mass of the solid fuel combusted, from company records as defined in §98.6 (short tons).
CC	=	Annual average carbon content of the solid fuel (percent by weight, expressed as a decimal fraction, e.g., 95% = 0.95). The annual average carbon content shall be determined using the same procedures as specified for HHV in paragraph (a)(2)(ii) of this section.
44/12	=	Ratio of molecular weights, CO2 to carbon.
0.91	=	Conversion factor from short tons to metric tons.

(ii) For a liquid fuel, use Equation C-4 of this section.

$$CO_2 = \frac{44}{12} * \text{Fuel} * \text{CC} * 0.001 \qquad \text{(Eq. C-4)}$$

Where:

CO2	=	Annual CO2 mass emissions from the combustion of the specific liquid fuel (metric tons).
Fuel	=	Annual volume of the liquid fuel combusted (gallons). The volume of fuel combusted must be measured directly, using fuel flow meters calibrated according to §98.3(i). Fuel billing meters may be used for this purpose. Tank drop measurements may also be used.
CC	=	Annual average carbon content of the liquid fuel (kg C per gallon of fuel). The annual average carbon content shall be determined using the same procedures as specified for HHV in paragraph (a)(2)(ii) of this section.
44/12	=	Ratio of molecular weights, CO2 to carbon.
0.001	=	Conversion factor from kg to metric tons.

(iii) For a gaseous fuel, use Equation C-5 of this section.

$$CO_2 = \frac{44}{12} * Fuel * CC * \frac{MW}{MVC} * 0.001 \qquad \text{(Eq. C-5)}$$

Where:

CO2	=	Annual CO2 mass emissions from combustion of the specific gaseous fuel (metric tons).
Fuel	=	Annual volume of the gaseous fuel combusted (scf). The volume of fuel combusted must be measured directly, using fuel flow meters calibrated according to §98.3(i). Fuel billing meters may be used for this purpose.
CC	=	Annual average carbon content of the liquid fuel (kg C per gallon of fuel). The annual average carbon content shall be determined using the same procedures as specified for HHV in paragraph (a)(2)(ii) of this section.
MW	=	Annual average molecular weight of the gaseous fuel (kg/kg-mole). The annual average carbon content shall be determined using the same procedures as specified for HHV in paragraph (a)(2)(ii) of this section.
MVC	=	Molar volume conversion factor (849.5 scf per kg-mole at standard conditions, as defined in §98.6).
44/12	=	Ratio of molecular weights, CO2 to carbon.
0.001	=	Conversion factor from kg to metric tons.

(iv) Fuel flow meters that measure mass flow rates may be used for liquid fuels, provided that the fuel density is used to convert the readings to volumetric flow rates. The density shall be measured at the same frequency as the carbon content, using ASTM D1298-99 (Reapproved 2005) "Standard Test Method for Density, Relative Density (Specific Gravity), or API Gravity of Crude Petroleum and Liquid Petroleum Products by Hydrometer Method" (incorporated by reference, see §98.7).

(v) The following default density values may be used for fuel oil, in lieu of using the ASTM method in paragraph (a)(3)(iv) of this section: 6.8 lb/gal for No. 1 oil; 7.2 lb/gal for No. 2 oil; 8.1 lb/gal for No. 6 oil.

(4) *Tier 4 Calculation Methodology*. Calculate the annual CO_2 mass emissions from all fuels combusted in a unit, by using quality-assured data from continuous emission monitoring systems (CEMS).

(i) This methodology requires a CO_2 concentration monitor and a stack gas volumetric flow rate monitor, except as otherwise provided in paragraph (a)(4)(iv) of this section. Hourly measurements of CO_2 concentration and stack gas flow rate are converted to CO_2 mass emission rates in metric tons per hour.

(ii) When the CO_2 concentration is measured on a wet basis, Equation C-6 of this section is used to calculate the hourly CO_2 emission rates:

$$CO_2 = 5.18x10^{-7} * C_{CO2} * Q \qquad \text{(Eq. C-6)}$$

Where:

CO_2	=	CO2 mass emission rate (metric tons/hr).
C_{CO2}	=	Hourly average CO2 concentration (% CO2).
Q	=	Hourly average stack gas volumetric flow rate (scfh).
5.18×10^{-7}	=	Conversion factor (metric tons/scf/% CO2).

(iii) If the CO_2 concentration is measured on a dry basis, a correction for the stack gas moisture content is required. You shall either continuously monitor the stack gas moisture content as described in §75.11(b)(2) of this chapter or, for certain types of fuel, use a default moisture percentage from §75.11(b)(1) of this chapter. For each unit operating hour, a moisture correction must be applied to Equation C-6 of this section as follows:

$$CO_2^* = CO_2\left(\frac{100 - \%H_2O}{100}\right) \qquad \text{(Eq. C-7)}$$

Where:

CO_2*	=	Hourly CO2 mass emission rate, corrected for moisture (metric tons/hr).
CO_2	=	Hourly CO2 mass emission rate from Equation C-6 of this section, uncorrected (metric tons/hr).
%H2O	=	Hourly moisture percentage in the stack gas (measured or default value, as appropriate).

(iv) An oxygen (O_2) concentration monitor may be used in lieu of a CO_2 concentration monitor in a CEMS installed before January 1, 2011, to determine the hourly CO_2 concentrations, in accordance with Equation F-14a or F-14b (as applicable) in appendix F to 40 CFR part 75, if the effluent gas stream monitored by the CEMS consists solely of combustion products (i.e., no process CO_2 emissions are mixed with the combustion products) and if only fuels that are listed in Table 1 in section 3.3.5 of appendix F to 40 CFR part 75 are combusted in the unit. If the O_2 monitoring option is selected, the F-factors used in Equations F-14a and F-14b shall be determined according to section 3.3.5 or section 3.3.6 of appendix F to 40 CFR part 75, as applicable. If Equation F-14b is used, the hourly moisture percentage in the stack gas shall be either a measured value in accordance with §75.11(b)(2) of this chapter, or, for certain types of fuel, a default moisture value from §75.11(b)(1) of this chapter. An operator without a CO_2 monitor who uses a CEMS and O_2 concentrations to calculate and report a unit's CO_2 emissions, and who regularly conducts a Relative Accuracy Test Audit (RATA) for the unit, must include in the RATA at least annually the monitoring of CO_2 concentration and flow, and the calculation of CO_2 mass. The operator must retain these results and make them available to the department upon request

(v) Each hourly CO_2 mass emission rate from Equation C-6 or C-7 of this section is multiplied by the operating time to convert it from metric tons per hour to metric tons. The operating time is the fraction of the hour during which fuel is combusted (e.g., the unit operating time is 1.0 if the unit operates for the whole hour and is 0.5 if the unit operates for 30 minutes in the hour). For common stack configurations, the operating time is the fraction of the hour during which effluent gases flow through the common stack.

(vi) The hourly CO_2 mass emissions are then summed over each calendar quarter and the quarterly totals are summed to determine the annual CO_2 mass emissions.

(vii) If both biomass and fossil fuel are combusted during the year, determine and report the biogenic CO_2 mass emissions separately, as described in paragraph (e) of this section.

(5) *Alternative methods for units with continuous monitoring systems.* Units not subject to the Acid Rain Program that report data to EPA according to 40 CFR part 75

may use the alternative methods in this paragraph in lieu of using any of the four calculation methodology tiers.

(i) For a unit that combusts only natural gas and/or fuel oil, is not subject to the Acid Rain Program, monitors and reports heat input data year-round according to appendix D to 40 CFR part 75, but is not required by the applicable 40 CFR part 75 program to report CO_2 mass emissions data, calculate the annual CO_2 mass emissions for the purposes of this part as follows:

(A) Use the hourly heat input data from appendix D to 40 CFR part 75, together with Equation G-4 in appendix G to 40 CFR part 75 to determine the hourly CO_2 mass emission rates, in units of tons/hr;

(B) Use Equations F-12 and F-13 in appendix F to 40 CFR part 75 to calculate the quarterly and cumulative annual CO_2 mass emissions, respectively, in units of short tons; and

(C) Divide the cumulative annual CO_2 mass emissions value by 1.1 to convert it to metric tons.

(ii) For a unit that combusts only natural gas and/or fuel oil, is not subject to the Acid Rain Program, monitors and reports heat input data year-round according to 40 CFR 75.19 of this chapter but is not required by the applicable 40 CFR part 75 program to report CO_2 mass emissions data, calculate the annual CO_2 mass emissions for the purposes of this part as follows:

(A) Calculate the hourly CO_2 mass emissions, in units of short tons, using Equation LM-11 in 40 CFR 75.19(c)(4)(iii).

(B) Sum the hourly CO_2 mass emissions values over the entire reporting year to obtain the cumulative annual CO_2 mass emissions, in units of short tons.

(C) Divide the cumulative annual CO_2 mass emissions value by 1.1 to convert it to metric tons.

(iii) For a unit that is not subject to the Acid Rain Program, uses flow rate and CO_2 (or O_2) CEMS to report heat input data year-round according to 40 CFR part 75, but is not required by the applicable 40 CFR part 75 program to report CO_2 mass emissions data, calculate the annual CO_2 mass emissions as follows:

(A) Use Equation F-11 or F-2 (as applicable) in appendix F to 40 CFR part 75 to calculate the hourly CO_2 mass emission rates from the CEMS data. If an O_2 monitor is used, convert the hourly average O_2 readings to CO_2 using Equation F-14a or F-14b in appendix F to 40 CFR part 75 (as applicable), before applying Equation F-11 or F-2.

(B) Use Equations F-12 and F-13 in appendix F to 40 CFR part 75 to calculate the quarterly and cumulative annual CO_2 mass emissions, respectively, in units of short tons.

(C) Divide the cumulative annual CO_2 mass emissions value by 1.1 to convert it to metric tons.

(D) If both biomass and fossil fuel are combusted during the year, determine and report the biogenic CO_2 mass emissions separately, as described in paragraph (e) of this section.

(b) *Use of the four tiers.* Use of the four tiers of CO_2 emissions calculation methodologies described in paragraph (a) of this section is subject to the following conditions, requirements, and restrictions:

(1) The Tier 1 Calculation Methodology:

(i) May be used for any fuel listed in Table C-1 of this subpart that is combusted in a unit with a maximum rated heat input capacity of 250 mmBtu/hr or less at a facility that is not subject to verification under 20.2.301 NMAC, and may be used for any fuel listed in Table C-1a of this subpart that is combusted in a unit with a maximum rated heat input capacity of 250 mmBtu/hr or less at any facility..

(ii) May be used for MSW in a unit of any size that does not produce steam, if the use of Tier 4 is not required.

(iii) May be used for solid, gaseous, or liquid biomass fuels in a unit of any size provided that the fuel is listed in Table C-1 of this subpart and that the emissions are not cap emissions.

(iv) May not be used if you routinely perform fuel sampling and analysis for the fuel high heat value (HHV) or routinely receive the results of HHV sampling and analysis from the fuel supplier at the minimum frequency specified in §98.34(a), or at a greater frequency. In such cases, Tier 2 or a higher tier method shall be used.

(2) The Tier 2 Calculation Methodology:

(i) May be used for the combustion of ~~any type of fuel~~ pipeline quality natural gas, or any fuel listed in Table C-1a of this subpart, in a unit with a maximum rated heat input capacity of 250 mmBtu/hr or less ~~provided that the fuel is listed in Table C-1 of this subpart~~.

(ii) May be used in a unit with a maximum rated heat input capacity greater than 250 mmBtu/hr for the combustion of pipeline quality natural gas and distillate fuel oil.

(iii) May be used for MSW or solid biomass fuel in a unit of any size that produces steam, if Equation C-2c is employed and if the use of Tier 4 is not required.

(iv) May be used for the combustion of any fuel listed in Table C-1 at any facility that is not subject to 20.2.301 NMAC or to 40 CFR 98.

(3) The Tier 3 Calculation Methodology:

(i) May be used for a unit of any size at any facility that combusts any type of fuel listed in Table C-1 of this subpart (except for MSW), unless the use of Tier 4 is required.

(ii) Shall be used for a unit with a maximum rated heat input capacity greater than 250 mmBtu/hr ~~that combusts any type of fuel listed in Table C-1 of this subpart (except MSW)~~,or that is located at a facility that is subject to verification under 20.2.301 NMAC, unless either of the following conditions apply:

(A) The use of Tier 1 or 2 is permitted, as described in paragraphs (b)(1)~~(iii)~~ and (b)(2)~~(ii)~~ of this section.

(B) The use of Tier 4 is required.

(iii) Shall be used for a fuel not listed in Table C-1 of this subpart ~~if the fuel is combusted in a unit with a maximum rated heat input capacity greater than 250 mmBtu/hr~~ provided that ~~both of the following conditions apply:~~

~~(A) The~~ the use of Tier 4 is not required.

~~(B) The fuel provides 10% or more of the annual heat input to the unit or, if §98.36(c)(3)applies, to a group of units served by common supply pipe.~~

(4) The Tier 4 Calculation Methodology:

(i) May be used for a unit of any size, combusting any type of fuel.

(ii) Shall be used if the unit meets all six of the conditions specified in paragraphs (b)(4)(ii)(A) through (b)(4)(ii)(F) of this section:

(A) The unit has a maximum rated heat input capacity greater than 250 mmBtu/hr, or if the unit combusts municipal solid waste and has a maximum rated input capacity greater than 250 tons per day of MSW.

(B) The unit combusts solid fossil fuel or MSW, either as a primary or secondary fuel.

(C) The unit has operated for more than 1,000 hours in any calendar year since 2005.

(D) The unit has installed CEMS that are required either by an applicable Federal or State regulation or the unit's operating permit.

(E) The installed CEMS include a gas monitor of any kind or a stack gas volumetric flow rate monitor, or both and the monitors have been certified, either in accordance with the requirements of 40 CFR part 75, part 60 of this chapter, or an applicable State continuous monitoring program.

(F) The installed gas or stack gas volumetric flow rate monitors are required, either by an applicable Federal or State regulation or by the unit's operating permit, to undergo periodic quality assurance testing in accordance with either appendix B to 40 CFR part 75, appendix F to 40 CFR part 60, or an applicable State continuous monitoring program.

(iii) Shall be used for a unit with a maximum rated heat input capacity of 250 mmBtu/hr or less and for a unit that combusts municipal solid waste with a maximum rated input capacity of 250 tons of MSW per day or less, if the unit meets all of the following three conditions:

(A) The unit has both a stack gas volumetric flow rate monitor and a CO_2 concentration monitor.

(B) The unit meets the conditions specified in paragraphs (b)(4)(ii)(B) through (b)(4)(ii)(D) of this section.

(C) The CO_2 and stack gas volumetric flow rate monitors meet the conditions specified in paragraphs (b)(4)(ii)(E) and (b)(4)(ii)(F) of this section.

(5) The Tier 4 Calculation Methodology shall be used beginning on:

(i) January 1, 2010, for a unit that is required to report CO_2 mass emissions beginning on that date, if all of the monitors needed to measure CO_2 mass emissions have been installed and certified by that date.

(ii) January 1, 2011, for a unit that is required to report CO_2 mass emissions beginning on January 1, 2010, if all of the monitors needed to measure CO_2 mass emissions have not been installed and certified by January 1, 2010. In this case, you may use Tier 2 or Tier 3 to report GHG emissions for 2010.

(6) You may elect to use any applicable higher tier for one or more of the fuels combusted in a unit. For example, if a 100 mmBtu/hr unit combusts natural gas and distillate fuel oil, you may elect to use Tier 1 for natural gas and Tier 3 for the fuel oil, even though Tier 1 could have been used for both fuels. However, for units that use either the Tier 4 or the alternative calculation methodology specified in paragraph (a)(5) of this section, CO_2 emissions from the combustion of all fuels shall be based solely on CEMS measurements.

(c) *Calculation of CH_4 and N_2O emissions from stationary combustion sources.* You must calculate annual CH_4 and N_2O mass emissions only for units that are required to report CO_2 emissions using the calculation methodologies of this subpart and for only those fuels that are listed in Table C-2 of this subpart.

(1) Use Equation C-8 of this section to estimate CH_4 and N_2O emissions for any fuels for which you use the Tier 1 or Tier 3 calculation methodologies for CO_2. Use the same values for fuel combustion that you use for the Tier 1 or Tier 3 calculation.

$$CH_4 \text{ or } N_2O = 1 \times 10^{-3} * Fuel * HHV * EF \qquad \text{(Eq. C-8)}$$

Where:

CH_4 or N_2O = Annual CH4 or N2O emissions from the combustion of a particular type of fuel (metric tons).

Fuel = Mass or volume of the fuel combusted, either from company records or directly measured by a fuel flow meter, as applicable (mass or volume per year).

HHV = Default high heat value of the fuel from Table C-1 of this subpart (mmBtu per mass or volume).

EF = Fuel-specific default emission factor for CH4 or N2O, from Table C-2 of this subpart (kg CH4 or N2O per mmBtu).

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

(2) Use Equation C-9a of this section to estimate CH_4 and N_2O emissions for any fuels for which you use the Tier 2 Equation C-2a of this section to estimate CO_2 emissions. Use the same values for fuel combustion and HHV that you use for the Tier 1 or Tier 3 calculation.

$$CH_4 \text{ or } N_2O = 1 \times 10^{-3} * HHV * EF * Fuel \qquad \text{(Eq. C-9a)}$$

Where:

CH_4 or N_2O = Annual CH4 or N2O emissions from the combustion of a particular type of fuel (metric tons).

Fuel = Mass or volume of the fuel combusted during the reporting year.

HHV = High heat value of the fuel, averaged for all valid measurements for the reporting year (mmBtu per mass or volume).

EF = Fuel-specific default emission factor for CH4 or N2O, from Table C-2 of this subpart (kg CH4 or N2O per mmBtu).

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

(3) Use Equation C-9b of this section to estimate CH_4 and N_2O emissions for any fuels for which you use Equation C-2c of this section to calculate the CO_2 emissions. Use the same values for steam generation and the ratio "B" that you use for Equation C-2c.

$$CH_4 \text{ or } N_2O = 1 \times 10^{-3} \text{ Steam} * B * EF \qquad \text{(Eq. C-9b)}$$

Where:

CH_4 or N_2O = Annual CH4 or N2O emissions from the combustion of a solid fuel (metric tons).

Steam = Total mass of steam generated by solid fuel combustion during the reporting year (lb steam).

B = Ratio of the boiler's maximum rated heat input capacity to its design rated steam output (mmBtu/lb steam).

EF = Fuel-specific emission factor for CH4 or N2O, from Table C-2 of this subpart (kg CH4 or N2O per mmBtu).

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

(4) Use Equation C-10 of this section for units in the Acid Rain Program, units that monitor and report heat input on a year-round basis according to 40 CFR part 75, and units that use the Tier 4 Calculation Methodology.

$$CH_4 \text{ or } N_2O = 0.001 * (HI)_A * EF \qquad \text{(Eq. C-10)}$$

Where:

CH_4 or N_2O = Annual CH4 or N2O emissions from the combustion of a particular type of fuel (metric tons).

$(HI)_A$ = Cumulative annual heat input from the fuel, derived from the electronic data reports required under §75.64 of this chapter or, for Tier 4 units, from the best available information as described in paragraph (c)(4)(ii) of this section(mmBtu).

EF = Fuel-specific emission factor for CH4 or N2O, from Table C-2 of this section (kg CH4 or N2O per mmBtu).

0.001 = Conversion factor from kg to metric tons.

(i) If only one type of fuel listed in Table C-2 of this subpart is combusted during normal operation, substitute the cumulative annual heat input from combustion of the fuel into Equation C-10 of this section to calculate the annual CH_4 or N_2O emissions.

(ii) If more than one type of fuel listed in Table C-2 of this subpart is combusted during normal operation, use Equation C-10 of this section separately for each type of fuel. If flow rate and diluent gas monitors are used to measure the unit heat input, use the best available information (e.g., fuel feed rate measurements, fuel heating values, engineering analysis) to estimate the annual heat input from each type of fuel.

(5) When multiple fuels are combusted during the reporting year, sum the fuel-specific results from Equations C-8, C-9a, C-9b, or C-10 of this section (as applicable) to obtain the total annual CH_4 and N_2O emissions, in metric tons.

(d) *Calculation of CO_2 from sorbent.*

(1) When a unit is a fluidized bed boiler, is equipped with a wet flue gas desulfurization system, or uses other acid gas emission controls with sorbent injection, use Equation C-11 of this section to calculate the CO_2 emissions from the sorbent, if those CO_2 emissions are not monitored by CEMS:

$$CO_2 = 0.91 * S * R * \left(\frac{MW_{CO2}}{MW_S} \right) \quad \text{(Eq. C-11)}$$

Where:

CO_2 = CO2 emitted from sorbent for the reporting year (metric tons).

S = Limestone or other sorbent used in the reporting year, from company records (short tons).

R = 1.00, the calcium-to-sulfur stoichiometric ratio.

MW_{CO2} = Molecular weight of carbon dioxide (44).

MW_S = Molecular weight of sorbent (100 if calcium carbonate).

0.91 = Conversion factor from short tons to metric tons

(2) The annual CO_2 mass emissions for the unit shall be the sum of the CO_2 emissions from the combustion process and the CO_2 emissions from the sorbent.

(e) *CO_2 emissions from combustion of biomass.* Use the procedures of this paragraph (e) to estimate biogenic CO_2 emissions from units that combust a combination of biomass and fossil fuels. Reporting of CO_2 emissions from combustion of biomass is required only for those biomass fuels listed in Table C-1 of this section, unless emissions are measured using CEMS.

(1) If CEMS are not used to measure CO_2, use Equation C-1 or C-2c of this subpart to calculate the annual CO_2 mass emissions from the combustion of biomass (except MSW) for a unit of any size. Determine the mass of biomass combusted using one of the following procedures in this paragraph (e)(1), as appropriate.

(i) Use company records.

(ii) Follow the procedures in paragraph (e)(5) of this section.

(iii) For premixed fuels that contain biomass and fossil fuels (e.g., mixtures containing biodiesel), use best available information to determine the mass of biomass fuels and document the procedure used in the GHG Monitoring Plan required by §98.3(g)(5).

(2) If a CO_2 CEMS (or a surrogate O_2 monitor) and a stack gas flow rate monitor are used to determine the annual CO_2 mass emissions either according to 40 CFR part 75, the Tier 4 Calculation Methodology, or the alternative calculation methodology specified in paragraph (a)(5)(iii); and if both fossil fuel and biomass (except for MSW) are combusted

in the unit during the reporting year, you may use the following procedure to determine the annual biogenic CO_2 mass emissions. If MSW or a fossil fuel/biomass mixture containing an undeterminable quantity of fossil fuels is combusted in the unit, follow the procedures in paragraph (e)(3) of this section.

(i) For each operating hour, use Equation C-12 of this section to determine the volume of CO_2 emitted.

$$V_{CO2h} = \frac{(\%CO_2)_h}{100} * Q_h * t_h \qquad \text{(Eq. C-12)}$$

Where:

V_{CO2h} = Hourly volume of CO2 emitted (scf).

$(\%CO2)_h$ = Hourly average CO2 concentration, measured by the CO2 concentration monitor, or, if applicable, calculated from the hourly average O2 concentration (%CO2).

Q_h = Hourly average stack gas volumetric flow rate, measured by the stack gas volumetric flow rate monitor (scfh).

t_h = Source operating time (decimal fraction of the hour during which the source combusts fuel, i.e., 1.0 for a full operating hour, 0.5 for 30 minutes of operation, etc.).

100 = Conversion factor from percent to a decimal fraction.

(ii) Sum all of the hourly V_{CO2h} values for the reporting year, to obtain V_{total}, the total annual volume of CO_2 emitted.

(iii) Calculate the annual volume of CO_2 emitted from fossil fuel combustion using Equation C-13 of this section. If two or more types of fossil fuel are combusted during the year, perform a separate calculation with Equation C-13 of this section for each fuel and sum the results.

$$V_{ff} = \frac{\text{Fuel} * F_c * \text{HHV}}{10^6} \qquad \text{(Eq. C-13)}$$

Where:

V_{ff} = Annual volume of CO2 emitted from combustion of a particular fossil fuel (scf).

Fuel = Total quantity of the fossil fuel combusted in the reporting year, from company records, as defined in §98.6 (lb for solid fuel, gallons for liquid fuel, and scf for gaseous fuel).

F_c = Fuel-specific carbon based F-factor, either a default value from Table 1 in section 3.3.5 of appendix F to 40 CFR part 75 or a site-specific value determined under section 3.3.6 of appendix F to 40 CFR part 75 (scf CO2/mmBtu).

HHV = High heat value of the fossil fuel, from fuel sampling and analysis (annual average value in Btu/lb for solid fuel, Btu/gal for liquid fuel and Btu/scf for gaseous fuel, sampled as specified (e.g., monthly, quarterly, semi-annually, or by lot) in §98.34(a)(2)). The average HHV shall be calculated according to the requirements of paragraph (a)(2)(ii) of this section.

10^6 = Conversion factor, Btu per mmBtu.

(iv) Subtract V_{ff} from V_{total} to obtain V_{bio}, the annual volume of CO_2 from the combustion of biomass. If a CEMS is being used to measure the combined combustion and process emissions from a unit that is subject to another subpart of part 98, then also subtract CO_2 process emissions from V_{total} to determine V_{bio}. The CO_2 process emissions must be calculated according to the requirements of the applicable subpart.

(v) Calculate the biogenic percentage of the annual CO_2 emissions,expressed as a decimal fraction, using Equation C-14 of this section:

$$\% \, Biogenic = \frac{V_{bio}}{V_{total}} \qquad \text{(Eq. C-14)}$$

(vi) Calculate the annual biogenic CO_2 mass emissions, in metric tons, by multiplying the results obtained from Equation C-14 of this section by the annual CO_2 mass emissions in metric tons, as determined:

(A) Under paragraph (a)(4)(vi) of this section, for units using the Tier 4 Calculation Methodology.

(B) Under paragraph (a)(5)(iii)(B) of this section, for units using the alternative calculation methodology specified in paragraph (a)(5)(iii).

(C) From the electronic data report required under §75.64 of this chapter, for units in the Acid Rain Program and other units using CEMS to monitor and report CO_2 mass emissions according to 40 CFR part 75. However, before calculating the annual biogenic CO_2 mass emissions, multiply the cumulative annual CO_2 mass emissions by 0.91 to convert from short tons to metric tons.

(3) For a unit that combusts MSW, the annual biogenic CO_2 emissions shall be calculated using the procedures in this paragraph (3).

(i) If the Tier 1 or Tier 2 Calculation Methodology is used to quantify CO_2 mass emissions:

(A) Use Equation C-1 or C-2c of this subpart, as appropriate, to calculate the annual CO_2 mass emissions from MSW combustion.

(B) Determine the relative proportions of biogenic and non-biogenic CO_2 emissions on a quarterly basis using the method specified in §98.34(d).

(C) Determine the annual biogenic CO_2 mass emissions from MSW combustion by multiplying the annual CO_2 mass emissions by the annual average biogenic decimal fraction obtained from §98.34(d).

(ii) If the unit uses Tier 4 to quantify CO_2 emissions:

(A) Follow the procedures in paragraphs (e)(2)(i) and (ii) of this section, to determine V_{total}.

(B) If any fossil fuel was combusted during the year, follow the procedures in paragraph (e)(2)(iii) of this section, to determine V_{ff}.

(C) Subtract V_{ff} from V_{total}, to obtain V_{MSW}, the annual volume of CO_2 emissions from MSW combustion.

(D) Determine the annual volume of biogenic CO_2 emissions (V_{bio}) from MSW combustion as follows. Multiply the annual volume of CO_2 emissions from MSW combustion (V_{MSW}) by the annual average biogenic decimal fraction obtained from ASTM D6866-08 and ASTM D7459-08.

(E) Calculate the biogenic percentage of the annual CO_2 emissions from the unit, using Equation C-14 of this section. For the purposes of this calculation, the term "V_{bio}" in the numerator of Equation C-14 of this section shall be the results of the calculation performed under paragraph (e)(3)(ii)(D) of this section.

(F) Calculate the annual biogenic CO_2 mass emissions according to paragraph (e)(2)(vi)(A) of this section.

(4) As an alternative to the procedures in paragraph (e)(2) of this section, use ASTM Methods D7459-08 and D6866-08 to determine the biogenic portion of the annual CO_2 emissions, as described in §98.34(e). If this option is selected, the results of each determination shall be expressed as a decimal fraction (e.g., 0.30, if 30 percent of the CO_2 is biogenic), and the values shall be averaged over the reporting year. The annual biogenic

CO_2 mass emissions shall be calculated by multiplying the the total annual CO_2 mass emissions by the annual average biogenic fraction obtained from ASTM D6866-08 and ASTM D7459-08.

(5) If Equation C-1 of this section is selected to calculate the annual biogenic mass emissions for wood, wood waste, or other solid biomass-derived fuel, Equation C-15 of this section may be used to quantify biogenic fuel consumption, provided that all of the required input parameters are accurately quantified. Similar equations and calculation methodologies based on steam generation and boiler efficiency may be used, provided that they are documented in the GHG Monitoring Plan required by §98.3(g)(5).

$$(Fuel)_p = \frac{[H * S] - (HI)_{nb}}{2000\,(HHV)_{bio}\,(Eff)_{bio}} \qquad \text{(Eq. C-15)}$$

Where:

$(Fuel)_p$ = Quantity of biomass consumed during the measurement period "p" (tons/year or tons/month, as applicable).

H = Average enthalpy of the boiler steam for the measurement period (Btu/lb).

S = Total boiler steam production for the measurement period (lb/month or lb/year, as applicable).

$(HI)_{nb}$ = Heat input from co-fired fossil fuels and non-biomass-derived fuels for the measurement period, based on company records of fuel usage and default or measured HHV values (Btu/month or Btu/year, as applicable).

$(HHV)_{bio}$ = Default or measured high heat value of the biomass fuel (Btu/lb).

$(Eff)_{bio}$ = Percent efficiency of biomass-to-energy conversion, expressed as a decimal fraction.

2000 = Conversion factor (lb/ton).

(f) [Reporting only] Calculating fugitive HFC emissions from cooling units. Owners or operators of electricity generating facilities shall calculate fugitive HFC emissions for each HFC compound used in cooling units that support power generation or are used in heat transfers to cool stack gases using either the methodology in paragraph (f)(1) or (f)(2). The owner or

operator is not required to report GHG emissions from air or water cooling systems or condensers that do not contain HFCs.

(1) Use Equation C-16 [Eq. 103-1 in 20.2.300 NMAC] to calculate annual HFC emissions:

$$HFC = HFC_I + HFC_{P/A} - HFC_{S/D} + HFC_{CC} \qquad \text{Eq. C-16}$$

Where:

HFC = Annual fugitive HFC emission, metric tons;

HFC_I = The difference between the quantity of HFC in storage at the beginning of the year and the quantity in storage at the end of the year. Stored HFC includes HFC contained in cylinders (such as 115-pound storage cylinders), gas carts, and other storage containers. It does not include HFC gas held in operating equipment. The change in inventory will be negative if the quantity of HFC in storage increases over the course of the year.

$HFC_{P/A}$ = The sum of all HFC acquired from other entities during the year either in storage containers or in equipment.

$HFC_{S/D}$ = The sum of all the HFC sold or otherwise transferred offsite to other entities during the year either in storage containers or in equipment.

HFC_{CC} = The net change in the total nameplate capacity (i.e. the full and proper charge) of the cooling equipment). The net change in capacity will be negative if the total nameplate capacity at the end of the year is less than the total nameplate capacity at the beginning of the year.

(2) Use service logs to document HFC usage and emissions from each cooling unit. Service logs should document all maintenance and service performed on the unit during the report year, including the quantity of HFCs added to or removed

from the unit, and include a record at the beginning and end of each report year. The operator may use service log information along with the following simplified material balance equations to quantify fugitive HFCs from unit installation, servicing, and retirement, as applicable. The operator shall include the sum of HFC emissions from the applicable equations in the greenhouse gas emissions data report.

$$HFC_{Install} = R_{new} - C_{new}$$

$$HFC_{Service} = R_{recharge} - R_{Recover}$$

$$HFC_{Retire} = C_{retire} - R_{retire}$$

Where:

$HFC_{Install}$ = HFC emitted during initial charging/installation of the unit, kilograms;

$HFC_{Service}$ = HFC emitted during use and servicing of the unit for the report year, kilograms;

HFC_{Retire} = HFC emitted during the removal from service/retirement of the unit, kilograms;

R_{new} = HFC used to fill new unit (omit if unit was pre-charged by the manufacturer), kilograms;

C_{new} = Nameplate capacity of new unit (omit if unit was pre-charged by the manufacturer), kilograms;

$R_{recharge}$ = HFC used to recharge the unit during maintenance and service, kilograms;

$R_{recover}$ = HFC recovered from the unit during maintenance and service, kilograms;

C_{retire} = Nameplate capacity of the retired unit, kilograms; and

R_{retire} = HFC recovered from the retired unit, kilograms.

§98.34 Monitoring and QA/QC requirements.

The CO_2 mass emissions data for stationary fuel combustion sources shall be monitored as follows:

(a) For the Tier 2 Calculation Methodology:

(1) All fuel samples shall be taken at a location in the fuel handling system that provides a sample representative of the fuel combusted. The fuel sampling and analysis may be performed by either the owner or operator or the supplier of the fuel.

(2) The minimum required frequency of the HHV sampling and analysis for each type of fuel is specified in this paragraph. When the specified frequency is based on a specified time period (i.e., weekly, monthly, quarterly, or semiannually), fuel sampling and analysis is required only for those periods in which the unit operates.

(i) For natural gas, semiannual sampling and analysis is required (i.e., twice in a calendar year, with consecutive samples taken at least four months apart).

(ii) For coal and fuel oil, analysis of at least one representative sample from each fuel lot is required. For the purposes of this section, a fuel lot is defined as a shipment or delivery of a single fuel (e.g., ship load, barge load, group of trucks, group of railroad cars, etc.).

(iii) For liquid fuels other than fuel oil, for fossil fuel-derived gaseous fuels, and for biogas; sampling and analysis is required at least once per calendar quarter. To the extent practicable, consecutive quarterly samples shall be taken at least 30 days apart.

(iv) For solid fuels other than coal and MSW, weekly sampling is required to obtain composite samples, which are then analyzed monthly.

(3) If different types of fuel (e.g., different ranks of coal or different grades of fuel oil) are blended prior to combustion, use one of the following procedures in this paragraph.

(i) Use a weighted HHV value in the emission calculations, based on the relative proportions of each fuel in the blend.

(ii) Take a representative sample of the blend and analyze it for HHV.

(4) If, for a particular type of fuel, HHV sampling and analysis is performed more often than the minimum frequency specified in paragraphs (a)(2)of this section, the results of all valid fuel analyses shall be used in the GHG emission calculations.

(5) If, for a particular type of fuel, valid HHV values are obtained at less than the minimum frequency specifed in paragraphs (a)(2) of this section, appropriate substitute data values shall be used in the emissions calculations, in accordance with missing data procedures of §98.35.

(6) Use any applicable fuel sampling and analysis methods in this paragraph (a)(6) to determine the high heat values. Alternatively, for gaseous fuels, the HHV may be calculated using chromatographic analysis together with standard heating values of the fuel constituents, provided that the gas chromatograph is operated, maintained, and calibrated according to the manufacturer's instructions.

(i) ASTM D4809-06 Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method) (incorporated by reference, see §98.7).

(ii) ASTM D240-02 (Reapproved 2007) Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (incorporated by reference, see §98.7).

(iii) ASTM D1826-94 (Reapproved 2003) Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter (incorporated by reference, see §98.7).

(iv) ASTM D3588-98 (Reapproved 2003) Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels (incorporated by reference, see §98.7).

(v) ASTM D4891-89 (Reapproved 2006) Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion (incorporated by reference, see §98.7).

(vi) GPA Standard 2172–09 Calculation of Gross Heating Value, Relative Density, Compressibility and Theoretical Hydrocarbon Liquid Content for Natural Gas Mixtures for Custody Transfer (incorporated by reference, see §98.7).

(vii) GPA Standard 2261–00, Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography (incorporated by reference, see §98.7).

(viii) ASTM D5865-07a, Standard Test Method for Gross Calorific Value of Coal and Coke (incorporated by reference, see §98.7).

(b) For the Tier 3 Calculation Methodology:

(1) Calibrate each oil and gas flow meter according to §98.3(i) and the provisions of paragraph (b).

(i) Perform calibrations using any of the test methods and procedures in this paragraph (b)(1)(i):

(A) An applicable flow meter test method listed in paragraphs (b)(4)(i) through (b)(4)(viii) of this section.

(B) The calibration procedures specified by the flow meter manufacturer.

(C) An industry-accepted or industry standard calibration practice.

(ii) In addition to the initial calibration required by §98.3(i), recalibrate each fuel flow meter (except for qualifying billing meters under paragraph (b)(1)(iii) of this section) either annually, at the minimum frequency specified by the manufacturer, or at the interval specified by the industry consensus standard practice used.

(iii) Fuel billing meters are exempted from the initial and ongoing calibration requirements of this paragraph, provided that the fuel supplier and the unit combusting the fuel do not have any common owners and are not owned by subsidiaries or affiliates of the same company.

(iv) For the initial calibration of an orifice, nozzle, or venturi meter; in-situ calibration of the transmitters is sufficient. A primary element inspection (PEI) shall be performed at least once every three years.

(v) For the continuously-operating units and processes described in §98.3(i)(6), the required flow meter recalibrations and, if necessary, the PEIs may be postponed until the next scheduled maintenance outage.

(vi) If a mixture of fuels is transported by a common pipe (e.g., still gas and supplementary natural gas), you must either separately meter each of the fuels prior to mixing using flow meters calibrated according to §98.3(i), or use flow meters calibrated according to §98.3(i) to measure the mixed fuel at the common pipe and to separately meter an appropriate subset of the fuels prior to mixing. If the latter option is chosen, quantify the fuels that are not measured prior to mixing by subtracting out the fuels measured prior to mixing from the fuel measured at the common pipe.

(2) Oil tank drop measurements (if used to determine liquid fuel use volume) shall be performed according to any an appropriate method published by a consensus-based standards organization (e.g., the American Petroleum Institute).

(3) The carbon content and, if applicable, molecular weight of the fuels shall be determined according to the procedures in paragraph (b)(3).

(i) All fuel samples shall be taken at a location in the fuel handling system that provides a sample representative of the fuel combusted. The fuel sampling and analysis may be performed by either the owner or operator or by the supplier of the fuel.

(ii) At a minimum, fuel samples shall be collected at the frequency specified in this paragraph. When sampling is required at a specified time interval (e.g., weekly, monthly, quarterly, or semiannually), fuel sampling and analysis is required for only those specified periods in which the unit operates.

(A) For natural gas, semiannual sampling and analysis is required (i.e., twice in a calendar year, with consecutive samples taken at least four months apart).

(B) For coal and fuel oil, analysis of at least one representative sample from each fuel lot is required. For the purposes of this section, a fuel lot is defined as a shipment or delivery of a single fuel (e.g., ship load, barge load, group of trucks, group of railroad cars, etc.).

(C) For other liquid fuels other than fuel oil, for fossil fuel-derived gaseous fuels, and for biogas; sampling and analysis is required at least once per calendar quarter. To the extent practicable, consecutive quarterly samples shall be taken at least 30 days apart.

(D) For solid fuels other than coal, weekly sampling is required to obtain composite samples, which are then analyzed monthly.

(E) For gaseous fuels other than natural gas and biogas (e.g., refinery gas), daily sampling and analysis to determine the carbon content and molecular weight of the fuel is required if the necessary equipment is in place to make these measurements. Otherwise, weekly sampling and analysis shall be performed. <u>The equipment necessary to perform daily sampling and analysis of carbon content and molecular weight for refinery fuel gas shall be installed no later than January 1, 2012.</u>

(iii) If, for a particular type of fuel, sampling and analysis for carbon content and molecular weight is performed more often than the minimum frequency specified in paragraph (b)(3) of this section, the results of all valid fuel analyses shall be used in the GHG emission calculations.

(iv) If, for a particular type of fuel, sampling and analysis for carbon content and molecular weight is performed at less than the minimum frequency specifed in paragraph (b)(3) of this section, appropriate substitute data values shall be used in the emissions calculations, in accordance with the missing data procedures of §98.35.

(v) The procedures of paragraphs (a)(3) of this section apply to carbon content and molecular weight determinations.

(4) Use any applicable standard method from the following list to quality assure the data from each fuel flow meter.

(i) AGA Report No. 3, Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids, Part 1: General Equations and Uncertainty Guidelines (1990) and Part 2: Specification and Installation Requirements (2000)(incorporated by reference, see §98.7).

(ii) AGA Transmission Measurement Committee Report No. 7, Measurement of Gas by Turbine Meters (2006) (incorporated by reference, see §98.7).

(iii) ASME MFC–3M–2004 Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi (incorporated by reference, see §98.7).

(iv) ASME MFC–4M–1986 (Reaffirmed 1997), Measurement of Gas Flow by Turbine Meters (incorporated by reference, see §98.7).

(v) ASME MFC–5M–1985 (Reaffirmed 1994), Measurement of Liquid Flow in Closed Conduits Using Transit-Time Ultrasonic Flowmeters (incorporated by reference, see §98.7).

(vi) ASME MFC–6M–1998 Measurement of Fluid Flow in Pipes Using Vortex Flowmeters (incorporated by reference, see §98.7).

(vii) ASME MFC–7M–1987 (Reaffirmed 1992), Measurement of Gas Flow by Means of Critical Flow Venturi Nozzles (incorporated by reference, see §98.7).

(viii) ASME MFC–9M–1988 (Reaffirmed 2001), Measurement of Liquid Flow in Closed Conduits by Weighing Method (incorporated by reference, see §98.7).

(5) Use any applicable methods from the following list to determine the carbon content and molecular weight (for gaseous fuel) of the fuel. Alternatively, the results of chromatographic analysis of the fuel may be used, provided that the gas chromatograph is operated, maintained, and calibrated according to the manufacturer's instructions.

(i) ASTM D1945-03 Standard Test Method for Analysis of Natural Gas by Gas Chromatography (incorporated by reference, see §98.7).

(ii) ASTM D1946-90 (Reapproved 2006) Standard Practice for Analysis of Reformed Gas by Gas Chromatography (incorporated by reference, see §98.7).

(iii) ASTM D2502-04 (Reapproved 2002) Standard Test Method for Estimation of Molecular Weight (Relative Molecular Mass) of Petroleum Oils from Viscosity Measurements (incorporated by reference, see §98.7).

(iv) ASTM D2503-92 (Reapproved 2007) Standard Test Method for Relative Molecular Mass (Relative Molecular Weight) of Hydrocarbons by Thermoelectric Measurement of Vapor Pressure (incorporated by reference, see §98.7).

(v) ASTM D3238-95 (Reapproved 2005) Standard Test Method for Calculation of Carbon Distribution and Structural Group Analysis of Petroleum Oils by the n-d-M Method (incorporated by reference, see §98.7).

(vi) ASTM D5291-02 (Reapproved 2007) Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants (incorporated by reference, see §98.7).

(vii) ASTM D5373-08 Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal (incorporated by reference, see §98.7).

(c) For the Tier 4 Calculation Methodology, the CO_2 and flow rate monitors must be certified prior to the applicable deadline specified in §98.33(b)(5).

(1) For initial certification, you may use any one of the following three procedures in this paragraph.

(i) §75.20(c)(2) and (4) and appendix A to 40 CFR part 75.

(ii) The calibration drift test and relative accuracy test audit (RATA) procedures of Performance Specification 3 in appendix B to part 60 (for the CO_2 concentration monitor) and Performance Specification 6 in appendix B to part 60 (for the continuous emission rate monitoring system (CERMS)).

(iii) The provisions of an applicable State continuous monitoring program.

(2) If an O_2 concentration monitor is used to determine CO_2 concentrations, the applicable provisions of 40 CFR part 75, 40 CFR part 60, or an applicable State continuous

monitoring program shall be followed for initial certification and on-going quality assurance, and all required RATAs of the monitor shall be done on a percent CO_2 basis.

(3) For ongoing quality assurance, follow the applicable procedures in either appendix B to 40 CFR part 75, appendix F to 40 CFR part 60, or an applicable State continuous monitoring program. If appendix F to 40 CFR part 60 is selected for on-going quality assurance, perform daily calibration drift assessments for both the CO_2 monitor (or surrogate O_2 monitor) and the flow rate monitor, conduct cylinder gas audits of the CO_2 concentration monitor in three of the four quarters of each year (except for non-operating quarters), and perform annual RATAs of the CO_2 concentration monitor and the CERMS.

(4) For the purposes of this part, the stack gas volumetric flow rate monitor RATAs required by appendix B to 40 CFR part 75 and the annual RATAs of the CERMS required by appendix F to 40 CFR part 60 need only be done at one operating level, representing normal load or normal process operating conditions, both for initial certification and for ongoing quality assurance.

(5) If, for any source operating hour, quality assured data are not obtained with a CO_2 monitor (or surrogate O_2 monitor), flow rate monitor, or (if applicable) moisture monitor, use appropriate substitute data values in accordance with the missing data provisions of §98.35.

(d) When municipal solid waste (MSW) is combusted in a unit, determine the biogenic portion of the CO_2 emissions from MSW combustion using ASTM D6866-08 Standard Test Methods for Determining the Biobased Content of Solid, Liquid, and Gaseous Samples Using Radiocarbon Analysis (incorporated by reference, see §98.7) and ASTM D7459-08 Standard Practice for Collection of Integrated Samples for the Speciation of Biomass (Biogenic) and Fossil-Derived Carbon Dioxide Emitted from Stationary Emissions Sources (incorporated by reference, see §98.7). Perform the ASTM D7459-08 sampling and the ASTM D6866-08 analysis at least once in every calendar quarter in which MSW is combusted in the unit. Collect each gas sample during normal unit operating conditions while MSW is the only fuel being combusted for at least 24 consecutive hours or for as long as is necessary to obtain a sample large enough to meet the specifications of ASTM D6866-08. Separate CO_2 emissions into the biogenic and non-biogenic fraction using the average proportion of biogenic emissions of all samples analyzed during the reporting year. Express the results as a decimal fraction (e.g., 0.30,

if 30 percent of the CO_2 from MSW combustion is biogenic). If there is a common fuel source of MSW that feeds multiple units at the facility, performing the testing at only one of the units is sufficient.

(e) For units that use CEMS to measure the total CO_2 mass emissions and combust a combination of biogenic fuels (other than MSW) with a fossil fuel, ASTM D6866-08 and ASTM D7459-08 may be used to determine the biogenic portion of the CO_2 emissions. Perform the ASTM D7459-08 sampling and the ASTM D6866-08 analysis at least once in every calendar quarter in which biogenic and non-biogenic fuels are co-fired in the unit. The relative proportions of the biogenic and non-biogenic fuels during the sampling shall be representative of the average fuel blend for a typical operating year. Collect each gas sample using ASTM D7459-08 during normal unit operation for at least 24 consecutive hours or for as long as is necessary to obtain a sample large enough to meet the specifications of ASTM D6866-08.

(f) Whenever company records are used in the calculation of CO_2 emissions, the records required under §98.3(g) shall include both the company records and an explanation of how those records are used to estimate the following parameters:

(1) Fuel consumption, when the Tier 1 and Tier 2 Calculation Methodologies are used.

(2) Fuel consumption, when solid fuel is combusted and the Tier 3 Calculation Methodology is used.

(3) Fossil fuel consumption when §98.33(e) applies to a unit that uses CEMS to quantify CO_2 emissions and that combusts both fossil and biomass fuels.

(4) Sorbent usage, when §98.33(d) applies.

(5) Quantity of steam generated by a unit when §98.33(a)(2) applies.

(6) Biogenic fuel consumption under §98.33(e)(5).

(g) As part of the GHG Monitoring Plan required under §98.3(g)(5), you must document the procedures used to ensure the accuracy of the estimates of fuel usage, sorbent usage, steam production, and boiler efficiency (as applicable) in paragraph (f) of this section, including but not limited to calibration of weighing equipment, fuel flow meters, steam flow meters, and other measurement devices. The estimated accuracy of measurements made with these devices shall also be recorded, and the technical basis for these estimates shall be provided.

§98.35 Procedures for estimating missing data.

Whenever a quality-assured value of a required parameter is unavailable (e.g., if a CEMS malfunctions during unit operation or if a required fuel sample is not taken), a substitute data value for the missing parameter shall be used in the calculations.

(a) For all units subject to the requirements of the Acid Rain Program, and all other stationary combustion units subject to the requirements of this part that monitor and report emissions and heat input data in accordance with 40 CFR part 75, the missing data substitution procedures in 40 CFR part 75 shall be followed for CO_2 concentration, stack gas flow rate, fuel flow rate, high heating value, and fuel carbon content.

(b) For units that use the Tier 1, Tier 2, Tier 3, and Tier 4 Calculation Methodologies, perform missing data substitution as follows for each parameter:

(1) For each missing value of the high heating value, carbon content, or molecular weight of the fuel, substitute the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident. If the "after" value has not been obtained by the time that the GHG emissions report is due, you may use the "before" value for missing data substitution or the best available estimate of the parameter, based on all available process data (e.g., electrical load, steam production, operating hours). If, for a particular parameter, no quality-assured data are available prior to the missing data incident, the substitute data value shall be the first quality-assured value obtained after the missing data period.

(2) For missing records of CO_2 concentration, stack gas flow rate, percent moisture, fuel usage, and sorbent usage, the substitute data value shall be the best available estimate of the parameter, based on all available process data (e.g., electrical load, steam production, operating hours, etc.). You must document and retain records of the procedures used for all such estimates.

§98.36 Data reporting requirements.

(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 emissions data in paragraphs (b) through (d) of this section (as applicable) and the emissions verification data in paragraph (e) of this section.

(b) *Units that use the four tiers.* 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 CO_2 emissions, except as otherwise provided in paragraphs (c) and (d) of this section:

(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 for boilers and process heaters only and relevant units of measure for other combustion sources.

(4) Each type of fuel combusted in the unit during the report year.

(5) The tier used to calculate the CO_2 emissions for each type of fuel combusted (i.e., Tier 1, 2, 3, or 4).

(6) For a unit that uses Tiers 1, 2, and 3; the CO_2, CH_4, and N_2O emissions for each type of fuel combusted, expressed in metric tons of each gas and in metric tons of CO_2e.

(7) For a unit that uses Tier 4:

(i) For units that burn fossil fuels only, the annual CO_2 emissions for all fuels combined. Reporting CO_2 emissions by type of fuel is not required.

(ii) For units that burn both fossil fuels and biomass, the annual CO_2 emissions from combustion of all fossil fuels combined and the annual CO_2 emissions from combustion of all biomass fuels combined. Reporting CO_2 emissions by type of fuel is not required.

(iii) Annual CH_4 and N_2O emissions for each type of fuel combusted expressed in metric tons of each gas and in metric tons of CO_2e.

(8) Annual CO_2 emissions from sorbent (if calculated using Equation C-11 of this subpart), expressed in metric tons.

(9) Annual GHG emissions from all fossil fuels burned in the unit (i.e., the sum of the CO_2 , CH_4, and N_2O emissions), expressed in metric tons of CO_2e.

(10) Customer meter number for units that combust natural gas.

(11) For units that generate electricity, nameplate generating capacity (MW) and net power generated (MWh) during the reporting year.

(12) For each cogeneration unit, indicate whether topping or bottoming cycle and provide useful thermal output as applicable, in mmBtu. Where steam or heat is acquired from another facility for the generation of electricity, report the provider and amount of acquired steam or heat in mmBtu. Where supplemental firing has been applied to support

electricity generation or industrial output, report this purpose and fuel consumption by fuel type using the following units:

(i) For gases, report in units of million standard cubic feet.

(ii) For liquids, report in units of gallons.

(iii) For non-biomass solids, report in units of short tons.

(iv) For biomass-derived solid fuels, report in units of bone dry short tons.

(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) An identification number for each unit in the group.

(iii) Cumulative maximum rated heat input capacity of the group (mmBtu/hr).

(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 CO_2, CH_4, and N_2O mass emissions aggregated for each type of fuel combusted in the group of units during the year, expressed in metric tons of each gas and in metric tons of CO_2e. If any of the units burn both fossil fuels and biomass, report also the annual CO_2 emissions from combustion of all fossil fuels combined and annual CO_2 emissions from combustion of all biomass fuels combined, expressed in metric tons.

(vii) The tier used to calculate the CO_2 mass emissions for each type of fuel combusted in the units (i.e., Tier 1, Tier 2, or Tier 3).

(viii) The calculated CO_2 mass emissions (if any) from sorbent.

(ix) Annual GHG emissions from all fossil fuels burned in the group (i.e., the sum of the CO_2 , CH_4, and N_2O emissions), expressed in metric tons of CO2e.

(2) *Monitored common stack or duct configurations.* When the flue gases from two or more stationary combustion units at a facility are discharged through a common stack or duct before exiting to the atmosphere and if CEMS are used to continuously monitor CO_2 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. 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) Identification numbers of the units sharing the common stack or duct.

(iii) Maximum rated heat input capacity of each unit sharing the common stack or duct (mmBtu/hr).

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

(v) The methodology used to calculate the CO_2 mass emissions, i.e., Tier 4.

(vi) If the any of the units burn both fossil fuels and biomass, annual CO_2 mass emissions, annual CO_2 emissions from combustion of fossil fuels, and annual CO_2 emissions from combustion of biomass measured at the common stack or duct, expressed in metric tons.

(vii) The annual CH_4 and N_2O emissions from the units sharing the common stack or duct, expressed in metric tons of each gas and in metric tons of CO_2e.

(viii) Annual GHG emissions from all fossil fuels burned in the group (i.e., the sum of the CO_2 , CH_4, and N_2O emissions), expressed in metric tons of CO2e.

(3) *Common pipe configurations.* When two or more liquid-fired or gaseous-fired stationary combustion units at a facility combust the same type of 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 that is calibrated in accordance with §98.34(a). If a portion of the fuel

measured at the common pipe is diverted to a chemical or industrial process where it is used but not combusted, you may subtract the diverted fuel from the fuel measured at the common pipe prior to performing the GHG emissions calculations, provided that the amount of fuel diverted is also measured with a calibrated flow meter per §98.3(i). If 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. 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) The identification numbers of the units served by the common pipe.

(iii) Maximum rated heat input capacity of each 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 CO_2 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 CO_2 mass emissions from combustion of all fossil fuels and annual CO_2 emissions from combustion of all biomass fuels from the units served by the common pipe, expressed in metric tons.

(vii) Annual CH_4 and N_2O emissions from the units served by the common pipe, expressed in metric tons of each gas and in metric tons of CO_2e.

(viii) Annual GHG emissions from all fossil fuels burned in units served by the common pipe (i.e., the sum of the CO_2, CH_4, and N_2O emissions), expressed in metric tons of CO_2e.

(d) Units subject to 40 CFR part 75.

(1) For stationary combustion units that are either subject to the Acid Rain Program or not in the Acid Rain Program but monitor and report CO_2 mass emissions year-round according to 40 CFR part 75, you shall report the following unit-level information:

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

(ii) Annual CO_2, CH_4, and N_2O emissions at each monitored location, expressed in metric tons of CO_2e.

(iii) Identification of the Part 75 methodology used to determine the CO_2 mass emissions.

(iv) Annual fuel consumption, if not reported under 40 CFR part 75.

(A) For gases, report in units of thousands of standard cubic feet.

(B) For liquids, report in units of gallons.

(C) For non-biomass solids, report in units of short tons.

(D) For biomass solid fuels, report in units of bone dry short tons or bone dry metric tons.

(v) Average carbon content of each fuel, if used to compute CO_2 emissions but not reported under 40 CFR part 75.

(vi) Average high heating value of each fuel, if used to compute CO_2 emissions but not reported under 40 CFR part 75.

(vii) For units that burn both fossil fuels and biomass, the annual CO2 emissions from combustion of all fossil fuels combined and the annual CO2 emissions from combustion of all biomass fuels combined. Reporting CO2 emissions by type of fuel is not required.

(viii) For units that generate electricity, nameplate generating capacity (MW) and net power generated (MWh) during the reporting year.

(ix) For each cogeneration unit, indicate whether topping or bottoming cycle and provide useful thermal output as applicable, in mmBtu. Where steam or heat is acquired from another facility for the generation of electricity, report the provider and amount of acquired steam or heat in mmBtu. Where supplemental firing has been applied to support electricity generation or industrial output, report this purpose and fuel consumption by fuel type using the units in §98.36(b)(12).

(2) For units that use the alternative CO_2 mass emissions calculation methods for units with continuous monitoring systems 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, or multiple stack identification numbers that represent the monitored locations (e.g., 1, 2, CS001, MS1A, 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 40 CFR part 75 or 40 CFR 75.19:

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

(B) The methodology used to calculate the CO_2 mass emissions for each fuel type.

(C) A code or flag to indicate whether heat input is calculated according to appendix D to 40 CFR part 75 or 40 CFR 75.19.

(D) Annual CO_2, CH_4, and N_2O emissions at each monitored location, across all fuel types, expressed in metric tons of CO_2e.

(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 40 CFR part 75:

(A) Fuel combusted during the reporting year.

(B) Methodology used to calculate the CO_2 mass emissions.

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

(D) The total annual CO_2, CH_4, and N_2O emissions at each monitored location, expressed in metric tons of CO_2e.

<u>(iv) The information required in paragraphs (d)(1)(iv) through (d)(1)(ix) of §98.36(d), as applicable.</u>

(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 monitor and report CO_2 mass emissions and heat input data year-round, in accordance with 40 CFR part 75.

(2) For stationary combustion sources using the Tier 1, Tier 2, Tier 3, and Tier 4 Calculation Methodologies in §98.33(a) to quantify CO_2 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.

(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 CO_2 emissions calculations for each type of fuel combusted, in mmBtu per short ton for solid fuels, mmBtu per gallon for liquid fuels, and mmBtu per scf for gaseous fuels. Specify the date on which each fuel sample was taken. Indicate whether each HHV is a measured value of a substitute data value.

(D) If Equation C-2c of this subpart is used to calculate CO_2 mass emissions, report the total quantity (i.e., pounds) of steam produced from MSW or solid fuel combustion during the 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.

(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.

(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 the 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). Report all measured values if the fuel is sampled monthly or less frequently. Otherwise, for daily and weekly sampling, report monthly average values determined using the calculation procedures in Equation C-2b for each variable. 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.

(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 for each type of fuel combusted.

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

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

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

(B) The cumulative CO_2 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 CO_2 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 40 CFR part 75, 40 CFR part 60, 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 CO_2 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 CEMS are used to quantify the annual CO_2 emissions and biogenic CO_2 is determined according to §98.33(e)(2), you shall report the following additional information, as applicable:

(A) The annual volume of CO_2 emitted from the combustion of all fuels, i.e., V_{total}, in scf.

(B) The annual volume of CO_2 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 CO_2 for each fuel separately as well as the total.

(C) The annual volume of CO_2 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 CO_2 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 CO_2 mass emissions, in metric tons.

(x) When ASTM methods D7459-08 and D6866-08 are used to determine the biogenic portion of the annual CO_2 emissions from MSW combustion, report:

(A) The results of each quarterly sample analysis, expressed as a decimal fraction (e.g., if the biogenic fraction of the CO_2 emissions from MSW combustion is 30 percent, report 0.30).

(B) Annual combined biomass and fossil fuel CO_2 emissions from MSW combustion, in metric tons of CO_2e.

(C) The quantities V_{ff}, V_{total}, and V_{MSW} from §98.33(e)(4)(ii), if CEMS are used to measure CO_2 emissions.

(D) The annual volume of biogenic CO_2 emissions from MSW combustion, in metric tons.

(xi) When ASTM methods D7459-08 and D6866-08 are used to determine the biogenic portion of the annual CO_2 emissions from a unit that co-fires biogenic (other than MSW) 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 CO_2 emissions is 30 percent, report 0.30).

(3) Within ~~30~~20 days of receipt of a written request from the ~~Administrator~~ secretary, 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 CO_2 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 CO_2 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 CO_2 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 CO_2 mass emissions under §98.33(a)(2)(iii) or to quantify solid fuel usage under §98.33(c)(3).

(4) Within ~~30~~20 days of receipt of a written request from the ~~Administrator~~ secretary, you shall submit the verification data and information described in paragraphs (e)(2)(iii), (e)(2)(v), and (e)(2)(vii) of this section.

§98.37 Records That Must be Retained.

In addition to the requirements of §98.3(g), you must retain the applicable records specified in §§98.34(f) and (g), 98.35(b), and 98.36(e).

§98.38 Definitions.

Except as specified in this section, all~~All~~ terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

"Bottoming cycle plant" means a cogeneration plant in which the energy input to the system is first applied to a useful thermal energy application or process, and at least some of the reject heat emerging from the application or process is then used for electricity production.

"Cogeneration unit" means a stationary fuel combustion device which simultaneously generates electrical and thermal energy that is (i) used by the operator of the facility where the cogeneration unit is located; or (ii) transferred to another facility for use by that facility.

"Cogeneration system" means individual cogeneration components including the prime mover (heat engine), generator, heat recovery, and electrical interconnection, configured into an integrated system that provides sequential generation of multiple forms of useful energy (usually electrical and thermal), at least one form of which the facility consumes on-site or makes available to other users for an end-use other than electricity generation.

"Liquified petroleum gases (LPG)" means the mixture of hydrocarbon gases containing predominantly propane and smaller amounts of butane, propylene or other hydrocarbons, including standard grades such as HD-5, and sold commercially under the name "propane".

"Pipeline quality natural gas" means natural gas having a high heat value greater than 970 Btu/scf and equal to or less than 1,100 Btu/scf, and which is at least ninety percent methane by volume and less than five percent carbon dioxide by volume.

"Topping cycle plant" means a cogeneration plant in which the energy input to the plant is first used to produce electricity, and at least some of the reject heat from the electricity production process is then used to provide useful thermal output.

Table C-1 of Subpart C—Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel

Fuel Type	Default High Heat Value	Default CO_2 Emission Factor
Coal and Coke	**mmBtu/short ton**	**kg CO_2 /mmBtu**
Anthracite	25.09	103.54
Bituminous	24.93	93.40
Subbituminous	17.25	97.02
Lignite	14.21	96.36
Coke	24.80	102.04
Mixed (Commercial sector)	21.39	95.26
Mixed (Industrial coking)	26.28	93.65
Mixed (Industrial sector)	22.35	93.91
Mixed (Electric Power sector)	19.73	94.38
Natural Gas	**mmBtu/scf**	**kg CO_2 /mmBtu**
Pipeline (Weighted U.S. Average)	1.028×10^{-3}	53.02
Petroleum Products	**mmBtu/gallon**	**kg CO_2 /mmBtu**
Distillate Fuel Oil No. 1	0.139	73.25
Distillate Fuel Oil No. 2	0.138	73.96
Distillate Fuel Oil No. 4	0.146	75.04
Residual Fuel Oil No. 5	0.140	72.93
Residual Fuel Oil No. 6	0.150	75.10
Still Gas	0.143	66.72
Kerosene	0.135	75.20
Liquefied petroleum gases (LPG)	0.092	62.98
Propane	0.091	61.46
Propylene	0.091	65.95
Ethane	0.096	62.64

Table C-1 of Subpart C—Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel

Fuel Type	Default High Heat Value	Default CO_2 Emission Factor
Ethylene	0.100	67.43
Isobutane	0.097	64.91
Isobutylene	0.103	67.74
Butane	0.101	65.15
Butylene	0.103	67.73
Naphtha (<401 deg F)	0.125	68.02
Natural Gasoline	0.110	66.83
Other Oil (>401 deg F)	0.139	76.22
Pentanes Plus	0.110	70.02
Petrochemical Feedstocks	0.129	70.97
Petroleum Coke	0.143	102.41
Special Naphtha	0.125	72.34
Unfinished Oils	0.139	74.49
Heavy Gas Oils	0.148	74.92
Lubricants	0.144	74.27
Motor Gasoline	0.125	70.22
Aviation Gasoline	0.120	69.25
Kerosene-Type Jet Fuel	0.135	72.22
Asphalt and Road Oil	0.158	75.36
Crude Oil	0.138	74.49
Fossil Fuel-derived Fuels (Solid)	**mmBtu/short ton**	**kg CO_2 /mmBtu**
Municipal Solid Waste[1]	9.95	90.7
Tires	26.87	85.97
Fossil Fuel-derived Fuels (Gaseous)	**mmBtu/scf**	**kg CO_2 /mmBtu**
Blast Furnace Gas	0.092×10^{-3}	274.32
Coke Oven Gas	0.599×10^{-3}	46.85
Biomass Fuels – Solid	**mmBtu/short Ton**	**kg CO_2 /mmBtu**
Wood and Wood Residuals	15.38	93.80
Agricultural Byproducts	8.25	118.17
Peat	8.00	111.84
Solid Byproducts	25.83	105.51
Biomass Fuels – Gaseous	**mmBtu/scf**	**kg CO_2 /mmBtu**

Table C-1 of Subpart C—Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel

Fuel Type	Default High Heat Value	Default CO_2 Emission Factor
Biogas (Captured methane)	0.841×10^{-3}	52.07
Biomass Fuels – Liquid	**mmBtu/gallon**	**kg CO_2 /mmBtu**
Ethanol (100%)	0.084	68.44
Biodiesel (100%)	0.128	73.84
Rendered Animal Fat	0.125	71.06
Vegetable Oil	0.120	81.55

[1]Allowed only for units that do not generate steam and use Tier 1.

Table C-1a of Subpart C—Fuels for which Tier 1 or Tier 2 Calculation Methodologies May Be Used

Fuel Type	Default High Heat Value	Default CO_2 Emission Factor
Petroleum Products	**mmBtu/gallon**	**kg CO_2 /mmBtu**
Distillate Fuel Oil No. 1	0.139	73.25
Distillate Fuel Oil No. 2	0.138	73.96
Distillate Fuel Oil No. 4	0.146	75.04
Kerosene	0.135	75.20
Liquefied petroleum gases (LPG)	0.092	62.98
Propane	0.091	61.46
Propylene	0.091	65.95
Ethane	0.096	62.64
Ethylene	0.100	67.43
Isobutane	0.097	64.91
Isobutylene	0.103	67.74
Butane	0.101	65.15
Butylene	0.103	67.73
Natural Gasoline	0.110	66.83
Motor Gasoline	0.125	70.22
Aviation Gasoline	0.120	69.25

Table C-1a of Subpart C—Fuels for which Tier 1 or Tier 2 Calculation Methodologies May Be Used

Fuel Type	Default High Heat Value	Default CO_2 Emission Factor
Kerosene-Type Jet Fuel	0.135	72.22

Table C-2 of Subpart C—Default CH_4 and N_2O Emission Factors for Various Types of Fuel.

Fuel Type	Default CH_4 Emission Factor (kg CH_4 /mmBtu)	Default N_2O Emission Factor (kg N_2O/mmBtu)
Coal and Coke (All fuel types in Table C-1)	1.1×10^{-2}	1.6×10^{-03}
Natural Gas	1.0×10^{-03}	1.0×10^{-04}
Petroleum (All fuel types in Table C-1)	3.0×10^{-03}	6.0×10^{-04}
Municipal Solid Waste	3.2×10^{-02}	4.2×10^{-03}
Tires	3.2×10^{-02}	4.2×10^{-03}
Blast Furnace Gas	2.2×10^{-05}	1.0×10^{-04}
Coke Oven Gas	4.8×10^{-04}	1.0×10^{-04}
Biomass Fuels - Solid (All fuel types in Table C-1)	3.2×10^{-02}	4.2×10^{-03}
Biogas	3.2×10^{-03}	6.3×10^{-04}
Biomass Fuels – Liquid (All fuel types in Table C-1)	1.1×10^{-03}	1.1×10^{-04}

Note: Those employing this table are assumed to fall under the IPCC definitions of the "Energy Industry" or "Manufacturing Industries and Construction". In all fuels except for coal the values for these two categories are identical. For coal combustion, those who fall within the IPCC "Energy Industry" category may employ a value of 1 g of CH_4/MMBtu.

[1]Allowed only for units that do not generate steam and use Tier 1.

Table C-2 of Subpart C—Default CH_4 and N_2O Emission Factors for Various Types of Fuel.

Fuel Type	Default CH_4 Emission Factor (kg CH_4 /mmBtu)	Default N_2O Emission Factor (kg N_2O/mmBtu)
Coal and Coke (All fuel types in Table C-1)	1.1×10^{-2}	1.6×10^{-03}
Natural Gas	1.0×10^{-03}	1.0×10^{-04}

Fuel Type	Default CH_4 Emission Factor (kg CH_4 /mmBtu)	Default N_2O Emission Factor (kg N_2O/mmBtu)
Petroleum (All fuel types in Table C-1)	3.0×10^{-03}	6.0×10^{-04}
Municipal Solid Waste	3.2×10^{-02}	4.2×10^{-03}
Tires	3.2×10^{-02}	4.2×10^{-03}
Blast Furnace Gas	2.2×10^{-05}	1.0×10^{-04}
Coke Oven Gas	4.8×10^{-04}	1.0×10^{-04}
Biomass Fuels - Solid (All fuel types in Table C-1)	3.2×10^{-02}	4.2×10^{-03}
Biogas	3.2×10^{-03}	6.3×10^{-04}
Biomass Fuels – Liquid (All fuel types in Table C-1)	1.1×10^{-03}	1.1×10^{-04}

Note: Those employing this table are assumed to fall under the IPCC definitions of the "Energy Industry" or "Manufacturing Industries and Construction". In all fuels except for coal the values for these two categories are identical. For coal combustion, those who fall within the IPCC "Energy Industry" category may employ a value of 1 g of CH_4/MMBtu.