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).

$$(Fuel)_p = \frac{[H*S] - (HI)_{nb}}{2000 (HHV)_{bio} (Eff)_{bio}}$$
 (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).
- $(\mathrm{HI})_{\mathrm{nb}}$ = 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).

(5) For units subject to subpart D of this part and for units that use the methods in part 75 of this chapter to quantify CO₂ mass emissions in accordance with paragraph (a)(5) of this section, you may calculate biogenic CO₂ emissions from the combustion of biomass fuels listed in Table C-1 of this subpart using Equation C-15a. This equation may not be used to calculate biogenic CO₂ emissions from the combustion of tires or MSW; the methods described in paragraph (e)(3) of this section must be used for those fuels. Whenever $(HI)_A$, the annual heat input from combustion of biomass fuel in Equation C-15a, cannot be determined solely from the information in the electronic emissions reports under §75.64 of this chapter (e.g., in cases where a unit uses CEMS in combination with multiple F-factors, a worstcase F-factor, or a prorated F-factor to report heat input rather than reporting heat input based on fuel type), use the best available information (as described in \$\$98.33(c)(4)(ii)(C) and (c)(4)(ii)(D)) to determine $(HI)_A.$

 $CO_2 = 0.001 * (HI)_A * EF$ (Eq. C-15a)

Where:

- CO_2 = Annual CO_2 mass emissions from the combustion of a particular type of biomass fuel listed in Table C-1 (metric tons)
- $(HI)_A$ = Annual heat input from the biomass fuel, obtained, where feasible, from the electronic emissions reports required under §75.64 of this chapter. Where this is not feasible use best available information, as described in §§98.33(c)(4)(ii)(C) and (c)(4)(ii)(D) (mmBtu)
- $EF = CO_2$ emission factor for the biomass fuel, from Table C-1 (kg CO_2 /mmBtu)
- 0.001 = Conversion factor from kg to metric tons

 $[74\ {\rm FR}\ 56374,\ {\rm Oct.}\ 30,\ 2009,\ {\rm as}\ {\rm amended}\ {\rm at}\ 75\ {\rm FR}\ 79140,\ {\rm Dec.}\ 17,\ 2010]$

§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 or fuel mixture (blend) is specified in this paragraph. When the specified frequency for a particular fuel or blend is based on a specified time period (e.g., week, month, quarter, or half-year), fuel sampling and analysis is required only for those time periods in which the fuel or blend is combusted. The owner or operator may perform fuel sampling and analysis more often than the minimum required frequency, in order to obtain a more representative annual average HHV.

(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, and for any other solid or liquid fuel that is delivered in lots, analysis of at least one representative sample from each fuel lot is required. For fuel oil, as an alternative to sampling each fuel lot, a sample may be taken upon each addition of oil to the unit's storage tank. Flow proportional sampling, continuous drip sampling, or daily manual oil sampling may also be used, in lieu of sampling each fuel lot. If the daily manual oil sampling option is selected, sampling from a particular tank is required only on days when oil from the tank is combusted by the unit (or units) served by the tank. If you elect to sample from the storage tank upon each addition of oil to the tank, you must take at least one sample from each tank that is currently in service and whenever oil is added to the tank, for as long as the tank remains in service. You need not take any samples from a storage tank while it is out of service. Rather, take a sample when the tank is brought into service and whenever oil is added to the tank, for as long as the tank remains in service. If multiple additions of oil are made to a particular in-service tank on a given day (e.g., from multiple deliveries), one sample taken after the final addition of oil is sufficient. For the purposes of this section, a fuel lot is defined as a shipment or delivery of a single type of fuel (e.g., ship load, barge load, group of trucks, group of railroad cars, oil delivery via pipeline from a tank farm, etc.). However, if multiple deliveries of a particular type of fuel are received from the same supply source in a given calendar month, the deliveries for that month may be considered, collectively, to comprise a fuel lot, requiring only one representative sample, subject to the following conditions:

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(A) For coal, the "type" of fuel means the rank of the coal (*i.e.*, an-thracite, bituminous, sub-bituminous, or lignite). For fuel oil, the "type" of fuel means the grade number or classification of the oil (*e.g.*, No. 1 oil, No. 2 oil, kerosene, Jet A fuel, *etc.*).

(B) The owner or operator shall document in the monitoring plan under §98.3(g)(5) how the monthly sampling of each type of fuel is performed.

(iii) For liquid fuels other than fuel oil, and for gaseous fuels other than natural gas (including 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 other solid fuels (except MSW), weekly sampling is required to obtain composite samples, which are then analyzed monthly.

(v) For fuel blends that are received already mixed, or that are mixed onsite without measuring the exact amount of each component, as described in paragraph (a)(3)(ii) of this section, determine the HHV of the blend as follows. For blends of solid fuels (except MSW), weekly sampling is required to obtain composite samples, which are analyzed monthly. For blends of liquid or gaseous fuels, sampling and analysis is required at least once per calendar quarter. More frequent sampling is recommended if the composition of the blend varies significantly during the year.

(3) Special considerations for blending of fuels. In situations where different types of fuel listed in Table C-1 of this subpart (for example, different ranks of coal or different grades of fuel oil) are in the same state of matter (*i.e.*, solid, liquid, or gas), and are blended prior to combustion, use the following procedures to determine the appropriate CO_2 emission factor and HHV for the blend.

(i) If the fuels to be blended are received separately, and if the quantity (mass or volume) of each fuel is measured before the fuels are mixed and combusted, then, for each component of the blend, calculate the CO_2 mass emissions separately. Substitute into Equation C-2a of this subpart the total measured mass or volume of the component fuel (from company records),

together with the appropriate default CO_2 emission factor from Table C-1, and the annual average HHV, calculated according to §98.33(a)(2)(ii). In this case, the fact that the fuels are blended prior to combustion is of no consequence.

(ii) If the fuel is received as a blend (*i.e.*, already mixed) or if the components are mixed on site without precisely measuring the mass or volume of each one individually, a reasonable estimate of the relative proportions of the components of the blend must be made, using the best available information (*e.g.*, the approximate annual average mass or volume percentage of each fuel, based on the typical or expected range of values). Determine the appropriate CO_2 emission factor and HHV for use in Equation C-2a of this subpart, as follows: (A) Consider the blend to be the "fuel type," measure its HHV at the frequency prescribed in paragraph (a)(2)(v) of this section, and determine the annual average HHV value for the blend according to \$98.33(a)(2)(i).

(B) Calculate a heat-weighted CO_2 emission factor, $(EF)_B$, for the blend, using Equation C-16 of this section. The heat-weighting in Equation C-16 is provided by the default HHVs (from Table C-1) and the estimated mass or volume percentages of the components of the blend.

(C) Substitute into Equation C-2a of this subpart, the annual average HHV for the blend (from paragraph (a)(3)(ii)(A) of this section) and the calculated value of $(EF)_B$, along with the total mass or volume of the blend combusted during the reporting year, to determine the annual CO₂ mass emissions from combustion of the blend.

$$(EF)_{B} = \frac{\sum_{i=1}^{n} \left[(HHV)_{i} (\%Fuel)_{i} (EF)_{i} \right]}{(HHV)_{B}}$$

(Eq. C-16)

Where:

- $(EF)_B \mbox{ = Heat-weighted } CO_2 \mbox{ emission factor} \\ \mbox{ for the blend } (kg \mbox{ CO}_2/mmBtu) \mbox{ }$
- (HHV)_i = Default high heat value for fuel "i" in the blend, from Table C-1 (mmBtu per mass or volume)
- (%Fuel)_i = Estimated mass or volume percentage of fuel "i" (mass % or volume %, as applicable, expressed as a decimal fraction; *e.g.*, 25% = 0.25)
- (EF)_i = Default CO₂ emission factor for fuel "i" from Table C-1 (mmBtu per mass or volume)
- $(HHV)_B$ = Annual average high heat value for the blend, calculated according to §98.33(a)(2)(ii) (mmBtu per mass or volume)

(iii) Note that for the case described in paragraph (a)(3)(ii) of this section, if measured HHV values for the individual fuels in the blend or for the

blend itself are not routinely received at the minimum frequency prescribed in paragraph (a)(2) of this section (or at a greater frequency), and if the unit qualifies to use Tier 1, calculate (HHV)_B*, the heat-weighted default HHV for the blend, using Equation C-17 of this section. Then, use Equation C-16 of this section, replacing the term $(HHV)_B$ with $(HHV)_B{}^{\ast}$ in the denominator, to determine the heat-weighted CO₂ emission factor for the blend. Finally, substitute into Equation C-1 of this subpart, the calculated values of $(HHV)_{B}^{*}$ and $(EF)_{B}$, along with the total mass or volume of the blend combusted during the reporting year, to determine the annual CO₂ mass emissions from combustion of the blend.

$$HHV_{B}^{*} = \sum_{i=1}^{n} \left[(HHV)_{i} (\%Fuel)_{i} \right]$$

(Eq. C-17)

Where:

- $(\rm HHV)_{B}{}^{*}$ = Heat-weighted default high heat value for the blend (mmBtu per mass or Volume)
- $(\mathrm{HHV})_i$ = Default high heat value for fuel "i" in the blend, from Table C–1 (mmBtu per mass or volume)
- $(\%Fuel)_i$ = Estimated mass or volume percentage of fuel "i" in the blend (mass % or volume %, as applicable, expressed as a decimal fraction)

(iv) If the fuel blend described in paragraph (a)(3)(ii) of this section consists of a mixture of fuel(s) listed in Table C-1 of this subpart and one or more fuels not listed in Table C-1, calculate CO_2 and other GHG emissions only for the Table C-1 fuel(s), using the best available estimate of the mass or volume percentage(s) of the Table C-1 fuel(s) in the blend. In this case, Tier 1 shall be used, with the following modifications to Equations C-17 and C-1, to account for the fact that not all of the fuels in the blend are listed in Table C-1:

(A) In Equation C-17, apply the term (Fuel); only to the Table C-1 fuels. For each Table C-1 fuel, (Fuel)_i will be the estimated mass or volume percentage of the fuel in the blend, divided by the sum of the mass or volume percentages of the Table C-1 fuels. For example, suppose that a blend consists of two Table C-1 fuels ("A" and "B") and one fuel type ("C") not listed in the Table, and that the volume percentages of fuels A, B, and C in the blend, expressed as decimal fractions, are, respectively, 0.50, 0.30, and 0.20. The term $(Fuel)_i$ in Equation C-17 for fuel A will be 0.50/(0.50 + 0.30) = 0.625, and for fuel B, (Fuel); will be 0.30/(0.50 + 0.30) = 0.375.

(B) In Equation C-1, the term "Fuel" will be equal to the total mass or volume of the blended fuel combusted during the year multiplied by the sum of the mass or volume percentages of the Table C-1 fuels in the blend. For the example in paragraph (a)(3)(iv)(A) of this section, "Fuel" = (Annual volume of the blend combusted)(0.80).

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

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(5) If, for a particular type of fuel, valid HHV values are obtained at less than the minimum frequency specified in paragraph (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) You must use one of the following appropriate fuel sampling and analysis methods. 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. Alternatively, you may use a method published by a consensus-based standards organization if such a method exists, or you may use industry standard practice to determine the high heat values. Consensus-based standards organizations include, but are not limited to, the following: ASTM International (100 Barr Harbor Drive, P.O. Box CB700, West Conshohocken, Pennsylvania 262 - 1373, 19428-B2959, (800) http:// www.astm.org), the American National Standards Institute (ANSI, 1819 L Street, NW., 6th floor, Washington, DC $20036,\,(202)\,\,293\text{---}8020,\,\,http://www.ansi.org),$ the American Gas Association (AGA, 400 North Capitol Street, NW., 4th Floor, Washington, DC 20001, (202) 824-7000, http://www.aga.org), the American of Mechanical Engineers Society (ASME, Three Park Avenue, New York, NY 10016–5990, (800) 843–2763, http:// www.asme.org), the American Petroleum Institute (API, 1220 L Street, NW., Washington, DC 20005-4070, (202) 682-8000, http://www.api.org), and the North American Energy Standards Board (NAESB, 801 Travis Street, Suite 1675, Houston, TX 77002, (713) 356-0060, http://www.api.org). The method(s) used shall be documented in the Monitoring Plan required under §98.3(g)(5).

(b) For the Tier 3 Calculation Methodology:

(1) You must calibrate each oil and gas flow meter according to \$98.3(i) and the provisions of this paragraph (b)(1).

(i) Perform calibrations using any of the test methods and procedures in this paragraph (b)(1)(i). The method(s) used shall be documented in the Monitoring Plan required under §98.3(g)(5).

(A) You may use the calibration procedures specified by the flow meter manufacturer.

(B) You may use an appropriate flow meter calibration method published by a consensus-based standards organization, if such a method exists. Consensus-based standards organizations include, but are not limited to, the following: ASTM International (100 Barr Harbor Drive, P.O. Box CB700, West Conshohocken, Pennsylvania 19428-B2959. (800)262 - 1373.http:// www.astm.org), the American National Standards Institute (ANSI, 1819 L Street, NW., 6th floor, Washington, DC 20036, (202) 293-8020, http://www.ansi.org), the American Gas Association (AGA, 400 North Capitol Street, NW., 4th Floor, Washington, DC 20001, (202) 824-7000, http://www.aga.org), the American Society of Mechanical Engineers (ASME, Three Park Avenue, New York, NY 10016–5990, (800) 843–2763, http:// www.asme.org), the American Petroleum Institute (API, 1220 L Street, NW., Washington, DC 20005-4070, (202) 682-8000, http://www.api.org), and the North American Energy Standards Board (NAESB, 801 Travis Street, Suite 1675, Houston, TX 77002, (713) 356-0060, http://www.api.org).

(C) You may use an industry-accepted practice.

(ii) In addition to the initial calibration required by §98.3(i), recalibrate each fuel flow meter (except as otherwise provided in paragraph (b)(1)(iii) of this section) according to one of the following. You may recalibrate annually, at the minimum frequency specified by the manufacturer, or at the interval specified by industry standard practice.

(iii) Fuel billing meters are exempted from the initial and ongoing calibration requirements of this paragraph and from the Monitoring Plan and recrequirements of ordkeeping §§98.3(g)(5)(i)(C), (g)(6), and (g)(7), 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. Meters used exclusively to measure the flow rates of fuels that are only used for unit startup are also exempted from the initial and ongoing

calibration requirements of this para-graph.

(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 liquid or gaseous fuels is transported by a common pipe, you may either separately meter each of the fuels prior to mixing, using flow meters calibrated according to \$98.3(i), or consider the fuel mixture to be the "fuel type" and meter the mixed fuel, using a flow meter calibrated according to \$98.3(i).

(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 this 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) For each type of fuel, the minimum required frequency for collecting and analyzing samples for carbon content and (if applicable) molecular weight is specified in this paragraph. When the sampling frequency is based on a specified time period (*e.g.*, week, month, quarter, or half-year), fuel sampling and analysis is required for only those time periods in which the fuel is combusted.

(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 and for any other solid or liquid fuel that is delivered in lots, analysis of at least one representative sample from each fuel lot is required. For fuel oil, as an alternative to sampling each fuel lot, a sample may be taken upon each addition of oil to the storage tank. Flow proportional sampling, continuous drip sampling, or daily manual oil sampling may also be used, in lieu of sampling each fuel lot. If the daily manual oil sampling option is selected, sampling from a particular tank is required only on days when oil from the tank is combusted by the unit (or units) served by the tank. If you elect to sample from the storage tank upon each addition of oil to the tank. you must take at least one sample from each tank that is currently in service and whenever oil is added to the tank, for as long as the tank remains in service. You need not take any samples from a storage tank while it is out of service. Rather, take a sample when the tank is brought into service and whenever oil is added to the tank, for as long as the tank remains in service. If multiple additions of oil are made to a particular in service tank on a given day (e.g., from multiple deliveries), one sample taken after the final addition of oil is sufficient. For the purposes of this section, a fuel lot is defined as a shipment or delivery of a single type of fuel (e.g., ship load, barge load, group of trucks, group of railroad cars, oil delivery via pipeline from a tank farm, etc.). However, if multiple deliveries of a particular type of fuel are received from the same supply source in a given calendar month, the deliveries for that month may be considered, collectively, to comprise a fuel lot, requiring only one representative sample, subject to the following conditions:

(1) For coal, the "type" of fuel means the rank of the coal (*i.e.*, anthracite, bituminous, sub-bituminous, or lignite). For fuel oil, the "type" of fuel means the grade number or classification of the oil (*e.g.*, No. 1 oil, No. 2 oil, kerosene, Jet A fuel, *etc.*).

(2) The owner or operator shall document in the monitoring plan under §98.3(g)(5) how the monthly sampling of each type of fuel is performed.

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(C) For liquid fuels other than fuel oil 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 other solid fuels (except MSW), 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., process gas), daily sampling and analysis to determine the carbon content and molecular weight of the fuel is required if continuous, on-line equipment, such as a gas chromatograph, is in place to make these measurements. Otherwise, weekly sampling and analysis shall be performed.

(F) For mixtures (blends) of solid fuels, weekly sampling is required to obtain composite samples, which are analyzed monthly. For blends of liquid fuels, and for gas mixtures consisting only of natural gas and biogas, sampling and analysis is required at least once per calendar quarter. For gas mixtures that contain gases other than natural gas (including biogas), daily sampling and analysis to determine the carbon content and molecular weight of the fuel is required if continuous, on-line equipment is in place to make these measurements. Otherwise, weekly sampling and analysis shall be performed.

(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 specified 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) To calculate the CO_2 mass emissions from combustion of a blend of fuels in the same state of matter (solid, liquid, or gas), you may either:

(A) Apply Equation C-3, C-4 or C-5 of this subpart (as applicable) to each component of the blend, if the mass or volume, the carbon content, and (if applicable), the molecular weight of each component are accurately measured prior to blending; or

(B) Consider the blend to be the "fuel type." Then, at the frequency specified in paragraph (b)(3)(ii)(F) of this section, measure the carbon content and, if applicable, the molecular weight of the blend and calculate the annual average value of each parameter in the manner described in §98.33(a)(2)(ii). Also measure the mass or volume of the blended fuel combusted during the reporting year. Substitute these measured values into Equation C–3, C–4, or C–5 of this subpart (as applicable).

(4) You must use one of the following appropriate fuel sampling and analysis methods. 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. Alternatively, you may use a method published by a consensus-based standards organization if such a method exists, or you may use industry standard practice to determine the carbon content and molecular weight (for gaseous fuel) of the fuel. Consensus-based standards organizations include, but are not limited to, the following: ASTM International (100 Barr Harbor Drive, P.O. Box CB700, West Conshohocken, Pennsylvania 19428-B2959, (800) 262-1373, http://www.astm.org), the American National Standards Institute (ANSI, 1819 L Street, NW., 6th floor, Washington, 293-8020, DC 20036. (202) http:// www.ansi.org), the American Gas Association (AGA, 400 North Capitol Street, NW., 4th Floor, Washington, DC 20001, (202) 824-7000, http://www.aga.org), the American Society of Mechanical Engineers (ASME, Three Park Avenue, New York, NY 10016-5990, (800) 843-2763, http://www.asme.org), the American Petroleum Institute (API, 1220 L Street, NW., Washington, DC 20005-4070, (202) 682-8000, http://www.api.org), and the North American Energy Standards Board (NAESB, 801 Travis Street, Suite 1675, Houston, TX 77002, (713) 356-0060, http://www.api.org). The method(s) used

shall be documented in the Monitoring Plan required under §98.3(g)(5).

(c) For the Tier 4 Calculation Methodology, the CO_2 , flow rate, and (if applicable) moisture 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), (c)(4), and (c)(5) through (c)(7) of this chapter and appendix A to part 75 of this chapter.

(ii) The calibration drift test and relative accuracy test audit (RATA) procedures of Performance Specification 3 in appendix B to part 60 of this chapter (for the CO_2 concentration monitor) and Performance Specification 6 in appendix B to part 60 of this chapter (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 part 75 of this chapter, part 60 of this chapter, 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 part 75 of this chapter, appendix F to part 60 of this chapter, or an applicable State continuous monitoring program. If appendix F to part 60 of this chapter 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 CO₂ 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 part 75 of this chapter and the annual RATAs of the CERMS required by appendix F to part 60 of this chapter 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.

(6) For certain applications where combined process emissions and combustion emissions are measured, the CO_2 concentrations in the flue gas may be considerably higher than for combustion emissions alone. In such cases, the span of the CO_2 monitor may, if necessary, be set higher than the specified levels in the applicable regulations. If the CO_2 span value is set higher than 20 percent CO_2 , the cylinder gas audits of the CO₂ monitor under appendix F to part 60 of this chapter may be performed at 40 to 60 percent and 80 to 100 percent of span, in lieu of the prescribed calibration levels of 5 to 8 percent CO_2 and 10 to 14 percent CO_2 .

(7) Hourly average data from the CEMS shall be validated in a manner consistent with one of the following: \$ 60.13(h)(2)(i) through (h)(2)(vi) of this chapter; \$ 75.10(d)(1) of this chapter; or the hourly data validation requirements of an applicable State CEM regulation.

(d) Except as otherwise provided in §98.33 (b)(1)(vi) and (b)(1)(vii), when municipal solid waste (MSW) is either the primary fuel combusted in a unit or the only fuel with a biogenic component combusted in the unit, determine the biogenic portion of the CO₂ emissions 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 see §98.7). Perform the reference. 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

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each gas sample during normal unit operating conditions for at least 24 total (not necessarily consecutive) hours, or longer if the facility deems it necessary to obtain a representative sample. Notwithstanding this requirement, if the types of fuels combusted and their relative proportions are consistent throughout the year, the minimum required sampling time may be reduced to 8 hours if at least two 8hour samples and one 24-hour sample are collected under normal operating conditions, and arithmetic average of the biogenic fraction of the flue gas from the 8-hour samples (expressed as a decimal) is within ± 5 percent of the biogenic fraction from the 24-hour test. There must be no overlapping of the 8hour and 24-hour test periods. Document the results of the demonstration in the unit's monitoring plan. If the types of fuels and their relative proportions are not consistent throughout the year, an optional sampling approach that facilities may wish to consider to obtain a more representative sample is to collect an integrated sample by extracting a small amount of flue gas (e.g., 1 to 5 cc) in each unit operating hour during the quarter. Separate the total annual CO_2 emissions into the biogenic and non-biogenic fractions 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 is biogenic). When MSW is the primary fuel for multiple units at the facility, and the units are fed from a common fuel source, testing at only one of the units is sufficient.

(e) For other units that combust combinations of biomass fuel(s) (or heterogeneous fuels that have a biomass component, e.g., tires) and fossil (or other non-biogenic) fuel(s), in any proportions, ASTM D6866-08 (incorporated by reference, see §98.7) and ASTM D7459-08 (incorporated by reference, see §98.7) may be used to determine the biogenic portion of the CO₂ emissions in every calendar quarter in which biomass and non-biogenic fuels are co-fired in the unit. Follow the procedures in paragraph (d) of this section. If the primary fuel for multiple units at the facility consists of tires, and the

units are fed from a common fuel source, testing at only one of the units is sufficient.

(f) The records required under §98.3(g)(2)(i) shall include an explanation of how the following parameters are determined from company records (or, if applicable, from the best available information):

(1) Fuel consumption, when the Tier 1 and Tier 2 Calculation Methodologies are used, including cases where §98.36(c)(4) applies.

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

(3) Fossil fuel consumption when \$98.33(e)(2) 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)(iii) applies.

(6) Biogenic fuel consumption and high heating value, as applicable, under \S 98.33(e)(5) and (e)(6).

(7) Fuel usage for CH_4 and N_2O emissions calculations under 98.33(c)(4)(ii).

(8) Mass of biomass combusted, for premixed fuels that contain biomass and fossil fuels under 98.33(e)(1)(iii).

 $[74\ {\rm FR}\ 56374,\ {\rm Oct.}\ 30,\ 2009,\ {\rm as}\ {\rm amended}\ {\rm at}\ 75\ {\rm FR}\ 79146,\ {\rm Dec.}\ 17,\ 2010]$

§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 year-round in accordance with part 75 of this chapter, the missing data substitution procedures in part 75 of this chapter shall be followed for CO₂ 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 Meth-

odologies, 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 qualityassured 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 qualityassured 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.

 $[74\ {\rm FR}\ 56374,\ {\rm Oct.}\ 30,\ 2009,\ {\rm as}\ {\rm amended}\ {\rm at}\ 75\ {\rm FR}\ 79150,\ {\rm Dec.}\ 17,\ 2010]$

§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