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).

§ 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 paragraph (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 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) 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 this 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 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) 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.

(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) The procedures of paragraph (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