Technical Support Document for Stationary Fuel Combustion Emissions: Proposed Rule for Mandatory Reporting of Greenhouse Gases

Office of Air and Radiation
U.S. Environmental Protection Agency

January 30, 2009

Table of Contents

Page

List of Tables and Figures

Page

[This page intentionally left blank.]

1.0 Source Category Description

The stationary fuel combustion source category consists of equipment that converts the chemical energy in solid, liquid, or gaseous fuels to high temperature heat energy by oxidation. During stationary combustion, fossil fuels, or waste fuels such as coal, oil, natural gas, refinery gas, municipal waste, and biomass are burned to produce high temperature heat which produces useful heat and work for use in electricity generation and industrial sources, and space heating. Combustion can also be used to incinerate waste in order to reduce the volume of waste or destroy chemical compounds. Stationary fuel combustion sources are located in all sectors of the economy and include boilers, heaters, engines, furnaces, kilns, ovens, flares, incinerators, dryers, and any other equipment or machinery that burns fuel.

1.1 GHG Emissions

The stationary combustion of carbon-based fuels produces three significant greenhouse gases: carbon dioxide (CO_2), methane (CH_4) and nitrous oxide (N_2O). The amount of CO_2 emitted is directly related to the carbon content of the fuel. Typically, nearly 100 percent of the fuel carbon is oxidized to CO_2. The CH_4 and N_2O emissions from stationary combustion are much smaller and are indirectly related to the carbon and nitrogen contents of the fuel. In the U.S., CO_2 emissions represent over 99 percent of the total CO_2-equivalent[1] (CO_2e) GHG emissions from all commercial, industrial, and electricity generation stationary combustion sources. CH_4 and N_2O emissions together represent less than one percent of the total CO_2e emissions from the same sources (U.S. EPA, 2008 - Inventory of U.S. Greenhouse Gases and Sinks).

1.2 GHG Emissions Sources

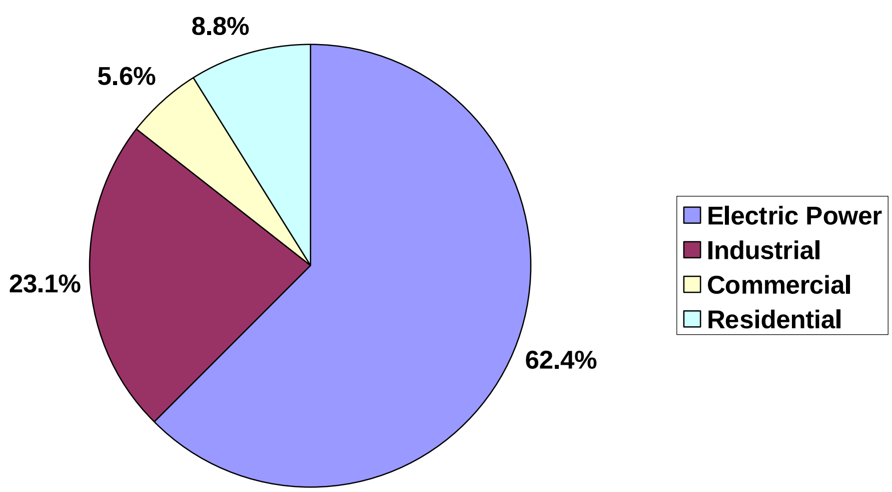
The largest stationary combustion category from a fuel usage and GHG emissions standpoint is electricity generation (See Table 1). The electric power industry, as illustrated here, includes all power producers, consisting of both regulated utilities and non-utilities (e.g., independent power producers, qualifying cogenerators, and other small power producers) and contributed just over 62 percent of stationary combustion GHG emissions in 2006. Stationary combustion by industrial sources also contributes a significant portion of total GHG emissions. CO_2 emissions from industrial sources such as steel production, chemical manufacture, petroleum refining, and pulp and paper production comprised roughly 23 percent of total GHG emissions in 2006.

[1] CO_2-equivalent is the equivalent global warming potential of an amount of a greenhouse gas other than CO_2 in terms of CO_2 emissions. CH_4 and N_2O both have higher global warming potentials than CO_2. The CO_2e of one ton of CH_4 is 21 tons, and one ton of N_2O is equivalent to 310 tons of CO_2.

Table 1
Stationary Combustion Source Sector GHG Emissions

Stationary Combustion Source Sector	2006 CO_2e Emissions (million metric tons)	Percent of Category CO_2e Emissions
Electric Power	2,338.9	62.4
Industrial	866.8	23.1
Commercial	211.3	5.6
Residential	330.4	8.8
Total	3747.4	--
Source: U.S. EPA Inventory of U.S. Greenhouse Gas Emissions and Sinks, April 2008		

Figure 1
2006 Stationary Combustion Emissions (Percent of Total)



The commercial and residential sectors emitted about 14 percent of GHG emissions from stationary fuel combustion. The commercial sector includes emissions from fuel combustion in commercial and institutional buildings (space heating and cooling, water heating, cooking and baking, and dryers). The residential sector includes emissions from household fuel combustion (space heating, water heating, and cooking).

1.3 Stationary Fuel Combustion Categories Covered by this Document

This document addresses monitoring and reporting methods for stationary fuel combustion sources at electric generating facilities, and stationary combustion sources.

Electric Generating Facilities are facilities which include equipment on a contiguous property that are constructed for the purpose of supplying electrical output to any utility power distribution system. Stationary fuel combustion equipment at the facilities includes, but is not limited to, conventional boilers, combustion turbines, or engines that provide energy to one or more electric generation turbines.

Stationary Fuel Combustion Facilities are combustion sources that occur at facilities other than electric generating facilities.

1.4 Costs Associated with GHG Reporting Rule and Emission Thresholds

Cost information and discussion associated with facilities' compliance with the GHG Reporting Rule are presented in the Regulatory Impact Analysis (RIA) associated with this rule. All of the emission thresholds discussion is contained in the Thresholds Technical Support Document (Docket # EPA-HQ-OAR-2008-0508-046).

2.0 Review of Existing GHG Reporting Programs

EPA reviewed a variety of existing mandatory and voluntary stationary source GHG reporting programs to obtain information on appropriate quantification and reporting methodologies, and to incorporate existing requirements where possible. Table 2 lists the GHG reporting programs that were reviewed by EPA in developing the stationary combustion requirements. Program quantification method comparison tables are provided in Appendix A.

Table 2
Mandatory and Voluntary GHG Reporting Programs

GHG Reporting Program	Reported GHGs from Stationary Combustion	Mandatory or Voluntary Program Participation
U.S. EPA Acid Rain Program, 40 CFR Part 75	CO_2	Mandatory
California ARB Mandatory GHG Reporting Rule – Proposed	CO_2, CH_4, N_2O	Mandatory
Regional Greenhouse Gas Initiative (RGGI)	CO_2	Mandatory
European Union Emissions Trading Scheme (EU ETS)	CO_2	Mandatory
Australian National GHG Reporting System – Proposed	CO_2, CH_4, N_2O	Mandatory
Canadian GHG National Reporting Program	CO_2, CH_4, N_2O	Mandatory
California Climate Action Registry (CCAR)	CO_2, CH_4, N_2O	Voluntary

The Climate Registry (TCR)	CO_2, CH_4, N_2O	Voluntary
U.S. EPA Climate Leaders	CO_2, CH_4, N_2O	Voluntary
U.S. DOE 1605(b) Voluntary Reporting of GHGs Program, 10 CFR 300	CO_2, CH_4, N_2O	Voluntary

In addition, EPA reviewed inventory-related guidance and protocols used for national inventories including the U.S. EPA's "Inventory of U.S. Greenhouse Gas Emissions and Sinks," and the 2006 Guidelines for National Greenhouse Gas Inventories from the Intergovernmental Panel on Climate Change (IPCC). Also, many of the programs reviewed relied on the World Resources Institute (WRI)/World Business Council for Sustainable Development (WBCSD) GHG Protocol. The WRI/WBCSD GHG Protocol consists of corporate accounting and reporting standards and separate calculation tools.

The existing programs, including the mandatory federal CO_2 emission reporting under the Acid Rain Program, all share the same quantification methodologies for the determination of combustion GHG emissions - either direct stack emission measurements using a continuous emissions monitoring system (CEMS), or a calculation approach based on fuel measurements. Specifically, the program methodologies include:

- A direct measurement approach for CO_2 using a CEMS to measure stack CO_2 or O_2 concentration and a stack flow rate monitor;

- A calculation approach for CO_2 derived from mass balance principles and fuel measurements; and

- A calculation approach for CH_4 and N_2O based on fuel usage and generic or source specific emission factors derived from source tests.

A number of programs, both voluntary and mandatory, tier the methodologies to assign or recommend a particular quantification method. The IPCC Guidelines and Good Practice Guidance for the development of national inventories have developed the tier concept for GHG monitoring methodologies. Tiers represent levels of methodological complexity: Tier 1 is the basic method; Tier 2 is the intermediate; and Tier 3 the most demanding in terms of complexity and data requirements. Tiers 2 and 3 are sometimes referred to as higher tier methods and are generally considered to be more accurate (IPCC, 2006). The IPCC recommends the use of higher tier methods for sources that are determined to be significant within the context of overall emissions from an inventory.

3.0 Measurement and Quantification Methods

EPA examined a combination of direct measurement and fuel-based approaches to quantify stationary combustion GHG emissions. The following section describes the CO_2 quantification methods used in the electric power sector by Acid Rain Program electric generating units (EGUs), and a tier-based approach for CO_2 that assigns monitoring methods based on source size and uncertainty in the emission estimate. EPA considered only a fuel-based quantification approach for CH_4 and N_2O consistent with existing GHG programs.

3.1 CO_2 Emission Methodologies for Electric Generating Sources

A significant portion of stationary combustion sources in the electric power sector are subject to CO_2 monitoring, recordkeeping, and reporting requirements under the Title IV Acid Rain Program in 40 CFR Part 75. Congress required that EPA include CO_2 monitoring under the Acid Rain Program, and these systems generally rely on monitor components that are also used for SO_2 and NO_X data reporting. The Acid Rain Program includes EGUs that burn fossil fuels, and that serve a generator with a nameplate capacity greater than 25 megawatts. There are approximately 1,200 facilities with a total of over 3,400 units subject to the CO_2 emission monitoring and reporting requirements of Part 75 under Title IV.

The mandatory and voluntary GHG reporting programs in the U.S. reviewed by EPA all require or recommend that Acid Rain Program EGUs report the annual CO_2 emissions measured and reported to EPA under the Acid Rain Program. The California Mandatory GHG Reporting Program and the RGGI Program also reference compliance with Part 75 certification and QA/QC requirements for EGUs subject to Part 75. RGGI, which is limited to EGUs, also requires the use of Part 75 electronic data recordkeeping and reporting.

3.1.1 Part 75 CO_2 Monitoring and Reporting Overview

The Part 75 methods for CO_2 include both direct measurement approaches using CEMS, and mass balance-based calculation approaches. Part 75 also includes certification and QA/QC requirements to ensure that data validity is confirmed at the beginning of a monitoring program and then maintained over time. Missing data requirements encourage monitoring availability. There are also electronic data reporting and recordkeeping requirements. The Part 75 monitoring methods for CO_2 are summarized in Table 3, and the usage of those methods by Acid Rain Program sources is shown in Table 4. Each of the methods is briefly described in the following section.

Table 3
CO_2 Measurement Methodologies in 40 CFR Part 75

Rule Citation	Eligible Units	Methodology
§ 75.13(a)	All units	Measurement method - CO_2 CEMS and flow monitor.
§ 75.13(b) and App. G § 2.1	All units	Calculation method based on fuel sampling and analysis for fuel carbon content, and fuel consumption measurements. Sampling frequency varies by fuel type.
§ 75.13(b) and App. G § 2.2	Coal units	Calculation method based on weekly fuel sampling and analysis for fuel and fly ash carbon content, fuel consumption measurements, and the collected amount of fly ash.

§ 75.13(b) and App. G § 2.3	Gas and oil units	Calculation method based on measured heat content, hourly fuel consumption, and carbon based F-factors.*
§ 75.13(b) and App. G § 3.1	Fluidized bed boilers or units with sorbent injection	Calculation method based on measured daily sorbent usage and either stoichiometric ratios or CEMS measured SO_2 removal rates. Absorbent CO_2 emissions are added to fuel based emissions estimated per App. G §§ 2.1 and 2.2.
§ 75.13(c)	All units	Measurement Method - O_2 CEMS and flow monitor.
§ 75.13(d) and § 75.19(c)	Low mass emission gas and oil units	Calculation method based on default emission factors and maximum rated heat input and operating time, or quarterly fuel consumption records.
*F-factors are ratios of the gas volume of the products of combustion to the heat content of the fuel.		

Table 4
2006 Mass Emissions by CO_2 Measurement Methodology

Mass Emission Calculation Methodology	Reported 2006 CO_2 Mass Emissions (million metric tons)	Percent of Total CO_2 Mass Emissions	Percent of Total Number of Units Reporting
CEMS (§ 75.13)	1,925	85%	33%
Fuel sampling and analysis for carbon and daily fuel use measurements (App. G)	27	1%	5%
Heat content, F-factor, and daily Appendix D fuel use(App. G)	309	14%	59%
Low Mass Emission Units - default emission factors and quarterly fuel use or maximum rated fuel use (§ 75.19)	0.7	0%	3%
All Methods	2,263	100%	100%

3.1.2 Part 75 CEMS

About 85 percent of CO_2 mass emissions reported under the Acid Rain Program are based on CEMS measurements, and all coal fired Acid Rain Program units use CEMS for CO_2 measurement. Part 75 CEMS for CO_2 mass emission measurements consist of either a CO_2 or O_2 CEMS combined with a flow monitoring system. Part 75 systems consist of a sampling interface between the stack gas and analyzer or sensor, the analyzer or sensor, and data acquisition and handling system (DAHS).

These systems continuously measure the gas concentration and volumetric stack flow to calculate emissions in pounds per hour and tons per year. Most Part 75 CO_2 CEMS measure on a wet basis, without removing the stack moisture prior to the analyzer. This matches the flow monitors which also measure the stack flow without removing the stack gas water vapor. If CO_2

is measured on a dry basis (stack moisture removed prior to the analyzer), the calculation must include a correction for stack gas moisture content to so that the volumetric concentration matches the volumetric flow basis. This may be done either using a measured moisture percentage with a continuous moisture monitor or a default moisture percentage. If an O_2 CEMS is used, the CO_2 concentration is back calculated from the O_2 concentration based on fuel based F-factors (F-factors are provided in Appendix B of this document). Simplified data calculations are shown below. Emission calculation equations are in Appendix F of Part 75.

A. Wet CO_2 CEMS Mass Rate Calculation

$$CO_2 = KC_{CO2w}Q_s$$

Where:
CO_2 = CO_2 mass emission rate (tons per hour);
C_{CO2w} = Hourly average CO_2 concentration (percent by volume, wet basis);
Q_s = Hourly average stack gas volumetric flow rate (scfh); and
K = Conversion factor (converts CO_2 volume to CO_2 mass based on CO_2 molecular weight), 5.7 H 10^{-7} CO_2/scf CO_2/%CO_2.

B. Dry CO_2 CEMS Mass Rate Calculation

$$CO_2 = KC_{CO2d}\,Q_s\,\frac{(100 - \%H_2O)}{100}$$

Where:
C_{CO2d} = Hourly average CO_2 concentration (percent by volume, dry basis); and
$\%H_2O$ = Stack moisture concentration (percent by volume).

C. O_2 CEMS - CO_2 Concentration Calculation

Wet basis O_2 CEMS: $$C_{CO2w} = \frac{100}{20.9}\frac{F_c}{F}\left[20.9\left(\frac{100-\%H_2O}{100}\right) - C_{O2w}\right]$$

Dry basis O_2 CEMS: $$C_{CO2d} = 100\frac{F_c}{F}\frac{20.9 - C_{O2d}}{20.9}$$

Where
C_{O2w} = Hourly average O_2 concentration (percent by volume, wet basis);
C_{O2d} = Hourly average O_2 concentration (percent by volume, dry basis);
F = Oxygen-based F-factor;
Fc = Carbon-based F-factor; and
20.9 = concentration of O_2 in ambient air (percent by volume).

3.1.3 Part 75, Appendix G Mass Balance Based Calculation Methods

Part 75, Appendix G outlines alternative calculation methods for estimating CO_2 emissions based on mass balance principles and fuel measurements. In summary, the methods require sampling of the fuel, analyses for the carbon or heat content of the fuel, and measuring the quantity of fuel consumed. Daily emissions are calculated based on the quantity of fuel burned and carbon fraction (assumes 100 percent oxidation of fuel carbon to CO_2), or the quantity of fuel burned and heat content of the fuel, and a heat content based emission factor (F-factor). The rule specifies fuel-specific sampling and analysis methods (industry consensus standards are incorporated by reference) for determining carbon or heat content (gross calorific value or high heating value). The sampling frequencies depend on the fuel type, and are shown in Table 5.

Table 5
Required Sampling and Analysis Frequency by Fuel in 40 CFR Part 75, Appendix G

Fuel Combusted	Sampling and Analysis Frequency
Coal	One sample per week representative of the fuel bunkered or burned.
Oil fuel in lots	One sample per delivery.
Gaseous fuel in lots	One sample per delivery.
Gaseous fuel that is not pipeline natural gas or natural gas and is not delivered in shipments or lots	One sample per day or hour based on the variability in the fuel heat content.
Pipeline natural gas or natural gas	One sample per month.

Acid Rain Program units that use the calculation methods in Appendix G of Part 75 compile daily fuel feed rates from company records for all fuels. Gas and oil units measure fuel use on an hourly basis using volumetric or mass fuel flow meters that are also used to calculate SO_2 or NO_X emissions under the non-CEMS alternatives in Appendices D and E of Part 75.

A. Calculating CO_2 Emissions Using Carbon Content (Appendix G, Section 2.1)

The carbon analysis approach is only used by about five percent of Acid Rain units, and no coal fired units are using this method. One reason is that Part 75 requires Acid Rain units to use diluent monitors (CO_2 or O_2) as part of the NO_X rate CEMS. These same monitors are then used for CO_2 emissions. Another reason is that sources do not typically measure the fuel carbon content but do measure heat content as part of fuel purchasing, and gas or oil fired units measure heat content under the alternative non-CEMS methods for SO_2 and NO_X in Appendices D and E of Part 75.

The basic equation for the carbon-based calculation is shown below:

$$W_{CO_2} = \frac{(MW_C + MW_{O_2})\, x\, W_C}{2{,}000\ MW_C}$$

Where:
W_{CO2} = CO_2 emitted from combustion, tons/day;
MW_C = Molecular weight of carbon (12.0);
MW_{O2} = Molecular weight of oxygen (32.0); and
Wc = Carbon burned, lbs/day, based on fuel carbon concentration and fuel feed rates.

B. Calculating CO_2 Emissions Using Heat Content (Appendix G, Section 2.3)

Almost 60 percent of Acid Rain units calculate CO_2 emissions based on the measured heat content and emission factor approach in Section 2.3 of Appendix G. This approach is limited to gas-fired and oil-fired units and uses fuel-specific F factors for the emission factors. An F-factor is a fuel specific ratio that numerically defines the relationship between the volume of CO_2 produced by combustion and the caloric heat content of the fuel combusted. Appendix G specifies the F-factors for a number of fuels, but also allows the source to calculate an F-factor specific to its fuel (Part 75 F-factors are listed in Appendix B). The basic heat-content based calculation is shown below:

$$W_{CO_2} = \frac{F_c \; x \; H \; x \; U_f \; x \; MW_{CO_2}}{2000}$$

Where:
W_{CO2} = CO_2 emitted from combustion, tons/hour;
MW_{CO2} = Molecular weight of CO_2 (44);
F_c = Carbon based F-factor, 1040 scf/mmBtu for natural gas; 1,420 scf/mmBtu for crude, residual, or distillate oil; and calculated according to the procedures in section 3.3.5 of appendix F of Part 75 for other gaseous fuels;
H = Hourly heat input in mmBtu (heat content x hourly fuel use - weight basis); and
U_f = 1/385 scf CO_2/lb-mole at 14.7 psia and 68^oF.

C. Additional Appendix G Methods

There are also two Appendix G methods that are not currently used by any Acid Rain Program source. One method in Section 2.2 of Appendix G supplements the fuel carbon based approach for coal fired units with sampling and analysis of the collected fly ash for unburned carbon. The carbon captured in the fly ash is deducted from the fuel carbon in the CO_2 emission calculation. The other method in Section 3 of Appendix G accounts for the carbon in carbonate absorbents used in fluidized bed combustors or injected downstream of the boiler for acid gas control. The method relies on the measured daily sorbent usage and the stoichiometric ratios for the sorbent - acid gas reaction.

3.1.4 Low Mass Emitters

Under the Acid Rain Program gas-fired or oil-fired units that emit no more than 25 tons per year of SO_2 and less than 100 tons per year of NO_X are defined as low mass emission units (LME) in Part 75. The units may use a simpler calculation and reporting approach with default or unit specific emission factor, measured or default heat content, and quarterly fuel measurements or maximum rated fuel use (§75.19(c)). The basic calculation is similar to the heat content based calculation in Appendix G:

$$W_{CO2} = EF_{CO2} \times HI_{hr}$$

Where:
W_{CO2} = CO_2 emitted from fuel combustion, tons/hour;
HI_{hr} = Hourly heat input in mmBtu (heat content x hourly fuel use - weight basis); and
EF_{CO2} = CO_2 emission factor (ton CO_2 /mmBtu).

The main difference in this method from the Appendix G heat content method is in the heat input determination. LME sources have the option of either using the equipment's maximum rated heat input capacity (no fuel measurement required), or to measure fuel use on a long term basis (quarterly) instead of the hourly fuel metering required for the Appendix G heat content based calculation. The quarterly fuel measurement is apportioned to each hour based on load. The heat content can be based on default values (specified in Part 75) or measured heat content (similar to Appendix G).

Natural gas and oil fired units are required to use default emission factors specified in Part 75. Units burning a gaseous fuel other than natural gas are required to develop an emission factor from unit specific fuel sampling and analysis.

Table 6
Default Factors for Part 75 Low Mass Emitters (From Part 75, Tables LM-3 and LM-5)

Fuel Combusted	Default High Heating Value (HHV)	Default CO_2 Emission Factor
Pipeline Natural Gas	1,050 Btu/scf	0.059 short ton CO_2/mmBtu
Other Natural Gas	1,100 Btu/scf	
Diesel Fuel	20,050 Btu/lb or 167,500 Btu/gallon	0.081 short ton CO_2/mmBtu
Residual Oil	19,700 Btu/lb or 151,700 Btu/gallon	

There are only about 100 Acid Rain units that use the LME methodology for CO_2. These are mainly peaking units that operate during high electricity demand periods, usually during the summer air conditioning season.

3.2 CO_2 Emission Methodologies for Stationary Combustion

There are many stationary fuel combustion sources that could be covered under a mandatory GHG reporting program that are not regulated under 40 CFR Part 75, or do not have process-specific monitoring methods specified for other source categories. For these sources, four methods described below could be considered for calculating CO_2 emissions. These methodologies are similar to those in Part 75, and include a CEMS measurement-based methodology and calculation methodologies.

The methodologies are classified according to methodological complexity using a four tier system. As discussed in the beginning of this section, the IPCC Guidelines and Good Practice Guidance for the development of national inventories developed the tier concept for GHG monitoring methodologies. Under the IPCC system Tier 1 is the basic method; Tier 2 is the intermediate; and Tier 3 the most demanding in terms of complexity and data requirements. Higher tier methods are generally considered to be more accurate, and IPCC recommends the use of higher tier methods for significant sources

Given the general hierarchy of methods described in the review, a direct measurement (CEMS) approach would be a Tier 4 method and require the most rigorous monitoring. Tiers 3 and 2 could be defined by measurement strategies using a combination of direct fuel measurement and the application of a combination of fuel-specific factors. The least rigorous tier, Tier 1, could be met by using quarterly fuel consumption records combined with default factors. Each of the tiers is discussed below.

3.2.1 Tier 4 Methodology - CEMS

The Tier 4 methodology is a continuous monitoring approach similar to Part 75, that includes CEMS for each affected unit at a facility and the recording of emissions and fuel data. The CEMS include a CO_2 or O_2 concentration monitor and a flow monitor. Emissions are calculated in the same manner as described for a Part 75 CEMS.

One option might be to make Tier 4 the minimum requirement for large solid fuel-fired units that already have an existing certified diluent CEMS or stack flow rate monitor, as well as smaller solid fuel fired units that have both a certified diluent CEMS and a flow monitor. This would not result in significant burden on reporters, as the monitoring equipment is already installed, while leading to the highest confidence in the emissions data reported.

A diluent CEMS is included under many existing air pollution requirements so that sources can convert concentrations measured by a pollutant CEMS into the terms of the pollutant limitation (pounds of pollutant per million Btu or concentration of the pollutant corrected to percent CO_2 or O_2). Table 7 identifies emission standards, under the New Source Performance Standards (NSPS) in 40 CFR Part 60 that include a diluent CEMS requirement.

A large unit could be a solid fossil fuel fired unit with a maximum rated heat input capacity greater than 250 mmBtu/hr or a municipal waste combustor with a capacity greater than 250 tons/day of municipal solid waste (MSW). These large unit cutoffs are the same as in the NSPS for EGUs in 40 CFR Part 60, Subparts D and Da, and for municipal waste combustors in Subparts Ea and Eb.

Sources with Part 60 CEMS could be required to continue to operate the diluent CO_2 or O_2 monitor per Part 60 performance specifications and quality assurance requirements, and, if necessary, install a stack flow monitor.

Municipal solid waste combustion sources with an O_2 diluent CEMS could be required to install a CO_2 diluent CEMS instead of back calculating CO_2 based on O_2 concentrations. F-factors for different fuels have been found to be consistent within the fossil fuel categories (e.g., bituminous coal, subbituminous coal, natural gas). MSW and other alternative waste fuels, however, are more variable, and therefore will have more variation in the F-factor, increasing the emission uncertainty.

Exemptions could be included for units that operate not more than 1,000 hours in any one year since 2005. This would reduce the burden on sources with much lower emissions than reflected by the unit capacity.

Table 7
Large Unit NSPS Diluent CEMS - 40 CFR Part 60

Part 60 Subpart	Title	Stationary Combustion Source Type*
D	Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction Is Commenced After August 17, 1971.	Fossil-fuel and wood-residue-fired steam generating unit of more than 73 MW heat input rate (250 mmBtu/hr). Gas fired units are exempt from the CEMS requirement.
Da	Standards of Performance for Electric Utility Steam Generating Units for Which Construction Is Commenced After September 18, 1978.	Electric utility steam generating unit capable of combusting more than 73 MW (250 mmBtu/hr) heat input of fossil fuel (either alone or in combination with any other fuel). Similar sized combined cycle gas turbines burning 50 percent or more solid derived fuel for which construction commenced after February 28, 2005.
Db	Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units.	Coal or oil fired steam generating unit that has a heat input capacity from fuels combusted of greater than 29 MW (100 mmBtu/hr).
Ea	Standards of Performance for Municipal Waste Combustors for Which Construction is Commenced After December 20, 1989 and on or Before September 20, 1994.	Municipal waste combustor unit with a capacity greater than 225 megagrams per day (250 tons per day) of municipal solid waste.
Eb	Standards of Performance for Municipal Waste Combustors for Which Construction is Commenced After September 20, 1994.	Municipal waste combustor unit with a combustion capacity greater than 250 tons per day of municipal solid waste.
AAAA	Standards of Performance for Small Municipal Waste Combustion Units for Which Commenced After August 30, 1999 or for Which Modifications or Reconstruction is Commenced After June 6, 2001.	Municipal waste combustion unit with the capacity to combust at least 35 tons per day but no more than 250 tons per day of municipal solid waste or refuse-derived fuel.
*Describes general type of unit subject to diluent CEMS requirements. There may be fuel, size, and other specific exemptions to the CEMS requirement.		

3.2.2 Tier 3 Methodology - Fuel Carbon Content

A Tier 3 methodology would use the carbon content and the amount of fuel burned to determine the CO_2 mass emissions. This could be a minimum requirement for any unit with a heat input capacity greater than 250 mmBtu/hr. Fuel combusted could be obtained from company records for solid fuels, and is measured directly for liquid and gaseous fuels, usually using either fuel flow meters or tank drop measurements. CO_2 mass emissions are estimated by multiplying the carbon content of the fuel by the fuel consumption for each fuel combusted. This methodology assumes all carbon is converted to CO_2.

The minimum frequencies of the fuel sampling for fuel carbon content deemed necessary are specified in Table 8. To ensure the greatest certainty in the data, the sampling and analysis could be required to be done according to voluntary consensus standards.

Table 8
Sampling and Analysis Frequency

Fuel Combusted	Sampling Frequency	Analysis Frequency
Coal	Weekly	Monthly*
Other Solid Fuel	Weekly	Monthly*
Natural Gas	Monthly	Monthly
Fuel Oil	Monthly	Monthly
Other Liquid Fuels	Monthly	Monthly
Other Gaseous Fuels (e.g., refinery gas, process gas)	Daily	Daily

*Composite of weekly samples.

The sampling and analysis frequency in Table 8 is comparable to the frequency required by Part 75, Appendix G (see Table 5), and the California reporting rule with minimum sampling baselines of monthly for natural gas and fuel oil, weekly for solid fuels, and daily sampling for more variable process gas (e.g., refinery fuel gas, coke oven gas, blast furnace gas). The minimum daily sampling and analysis requirement for process gas is also consistent with EU ETS requirements.

For solid or liquid fuels, the formula to calculate CO_2 annual mass emissions using the Tier 3 methodology is:

$$CO_2 = \sum_{p=1}^{n} \frac{44}{12} * (Fuel)_n * (CC)_n$$

Where:
CO_2 = Annual CO_2 combustion emissions, tons;
$(Fuel)_n$ = Mass of the fuel combusted in the month, week, or day "n";
$(CC)_n$ = Carbon content of the fuel for the time period "n" expressed as a decimal fraction; and
44/12 = Ratio of the molecular weights of CO_2 to carbon.

In the case of gaseous fuel consumption, the formula will be adjusted to include the ratio of the molecular weight of the gaseous fuel to the molar volume conversion factor (***MW/MVC***):

$$CO_2 = \sum_{p=1}^{n} \frac{44}{12} * (Fuel)_n * (CC)_n * \frac{MW}{MVC}$$

Facilities which use the same liquid or gaseous fuel source for all units at a facility or a group of units could calculate facility-wide CO_2 emissions or group CO_2 emissions based on measurements of the common fuel source (e.g., a natural gas meter at the facility gate).

3.2.3 Tier 2 Methodology - Fuel Heat Content

Tier 2 would be most appropriate for small units with capacity equal or less than 250 mmBtu/hr or 250 tons of MSW/hr. Tier 2 data collection is similar to Tier 3 except annual CO_2 mass emissions are estimated using measured fuel heat content (HHV) or fuel heat content provided by the fuel suppliers. Emissions are estimated by multiplying the fuel heat content by the amount of fuel burned and a default fuel specific emission factor (emission factor is in terms of CO_2 mass emissions for a given fuel heat input). The minimum sampling and analysis frequency would be monthly for all fuels. Sampling and analysis could be required to be performed using voluntary consensus standards. The basic equation is shown below:

$$CO_2 = \sum_{p=1}^{n} 1\,x\,10^{-3}\ (Fuel)_n * (HHV)_n * EF$$

Default emission factors are shown in Appendix C.

The Tier 2 approach would be modified for municipal solid waste combustion because of the variable heat content of solid waste, and greater difficulty in collecting a representative solid waste sample for the heat content analysis. The source measures the steam output, and uses the ratio of the maximum rated heat input to design steam output (mmBtu/lb steam) to estimate heat input. A similar approach is used by California in their rule. The calculation is shown below:

$$CO_2 = (Steam)(B)(EF)$$

Where:
Steam = Total mass of steam generated by MSW combustion during the year;
B = Ratio of boiler's maximum rated heat input capacity to its design rated steam output capacity (mmBtu/lb); and
EF = Fuel-specific default CO_2 emission factor (kg CO_2/mmBtu).

3.2.4 Tier 1 Methodology - Default Heat Content

Tier 1 methodology is the simplest and least rigorous methodology and its use could be limited to small units that combust homogenous fuels. For each type of fuel combusted, the source could be required to estimate the annual CO_2 mass emissions based on a fuel specific default CO_2 emission factor, a default heat content, and the annual fuel consumption from company records, using the following formula:

$$CO_2 = Fuel * HHV_d * EF$$

Default fuel-specific high heat values and CO_2 emission factors are compiled in Appendix D.

3.2.5 CO_2 Emissions from Carbonate Sorbents

In addition to the four method tiers, facilities could also be required to report emissions resulting from the use of a carbonate sorbent. Absorbent use will occur when a source has a wet flue gas desulfurization system, has a fluidized bed boiler, or uses sorbent injection for acid gas emissions control in another manner. In most cases, these emissions will be measured by a CEMS, as has been the experience for Acid Rain Program sources.

If emissions from sorbent usage are not otherwise quantified, a methodology similar to the sorbent calculation methodology in Appendix G of Part 75 could be used to quantify absorbent CO_2 emissions. This method requires measurement and recording of absorbent use, and the calculation is shown below:

$$CO_2 = S * R * \left(\frac{MW_{CO2}}{MW_S} \right)$$

Where:
CO_2 = CO_2 emitted from sorbent for the report year (metric tons);
S = Limestone or other sorbent used in the report year (metric tons);
R = Stoichiometric ratio of moles of CO_2 released upon capture of one mole of acid gas;
MW_{CO2} = Molecular weight of carbon dioxide; and
MW_S = Molecular weight of sorbent (100 if calcium carbonate).

The CO_2 emitted from the sorbent is added to the CO_2 emitted from fuel combustion to determine the total CO_2 mass emissions for the unit.

3.3 CO_2 Emissions Methodologies for Units that Burn Biomass

The existing CO_2 reporting programs reviewed by EPA, except for the Acid Rain Program, allow the segregation and separate reporting of CO_2 emissions from the combustion of biomass derived non-fossil fuels. CO_2 emissions from biomass combustion are segregated because it is assumed that the carbon released during stationary source combustion of biomass is recycled as U.S. forests and crops regenerate. Emissions of CH_4 and N_2O from the combustion of biomass and biomass-based fuels are not segregated, since these emissions are not based on the natural carbon cycle.

Biomass is defined as non-fossilized and biodegradable organic material originating from plants, animals and micro-organisms, including products, byproducts, residues and waste from agriculture, forestry and related industries as well as the non-fossilized and biodegradable organic fractions of industrial and municipal wastes, including gases and liquids recovered from the decomposition of non-fossilized and biodegradable organic material. This is the same definition as used by the EU Emissions Trading Scheme and California's mandatory GHG reporting rule. In addition, biomass-derived fuels or biomass fuels could also mean fuels derived from biomass.

This treatment of biomass fuels is consistent with the IPCC Guidelines and annual Inventory of Greenhouse Gas Emissions and Sinks, which accounts for the release of these CO_2 emissions in accounting for carbon stock changes from agriculture, forestry, and other land use. In this case, the carbon flux that occurs in land-use is estimated on a national basis in national inventories.

Other programs use a more restrictive definition of biomass. For example, RGGI adds additional sustainable harvest criteria to define fuels that are eligible for biomass treatment and exclusion from fossil-fuel CO_2 reporting: "Eligible biomass includes sustainably harvested woody and herbaceous fuel sources that are available on a renewable or recurring basis (excluding old growth timber), including dedicated energy crops and trees, agricultural food and feed crop residues, aquatic plants, unadulterated wood and wood residues, animal wastes, other clean organic wastes not mixed with other solid wastes, biogas, and other neat liquid biofuels derived from such fuel sources." (RGGI Model Rule - final with corrections, 2007).

Biomass fuels are combusted alone (100 percent biomass) or in combination with fossil fuel. There are also waste fuels that are a mix of materials derived from biomass and fossil fuels; for example, municipal solid waste (MSW) may include materials derived from both biomass (paper waste) and fossil fuels (plastic waste).

3.3.1 Biomass Fuels except for Municipal Solid Waste

For sources that burn a combination of pure biomass and fossil fuel, and measure total CO_2 emissions with a CEMS, sources could be required to estimate the percent CO_2 from biomass fuels by estimating the volume of fossil CO_2 emissions based on a calculation approach. The calculation approach uses the total amount of fossil fuel burned, the fuel heat content, and carbon based F-factor; the biomass CO_2 mass emissions is the difference between the CEMS measured CO_2 volume and calculated fossil fuel CO_2 volume. This approach is similar to the approaches in both the California reporting rule and EU Emissions Trading Scheme.

If the source uses a calculation methodology, CO_2 emissions from pure biomass fuels or a mixture of pure biomass and fossil fuels are calculated and reported in the same manner as CO_2 emissions for fossil fuels or emissions from carbonates. The annual CO_2 emissions from each fuel are summed, and the biomass percentage is determined by dividing the sum of biomass fuel CO_2 emissions by the total annual CO_2 emissions.

3.3.2 Municipal Solid Waste

Several different approaches were considered for a source that elects to report the biomass portion of CO_2 emissions, when a mixed fuel (MSW) is combusted in an affected unit. The California rule requires sources that combust MSW to determine the biomass-derived portion of CO_2 emissions using ASTM D6866-06a every three months. The ASTM D6866-06 method is a carbon dating approach that measures the radiocarbon (^{14}C) composition of a gas sample, and compares it with the ^{14}C content of a modern reference sample. The ^{14}C isotope is present in all plant material, while absent in all fossil fuels. Each sample is taken during normal operating conditions over at least 24 consecutive hours. The average proportionalities between plant material carbon and fossil carbon determined by the analyses are used to apportion CO_2 emissions between fossil and biomass fuels.

The EU ETS program allows a variety of methods to apportion the biomass and non-fossil portions of a mixed fuel. Approaches include a manual sorting approach to determine component fractions, differential methods determining heating values of a binary mixture and its two pure components, and a similar isotopic analysis as the ASTM D6866-06a analysis approach. For fuels or materials originating from a production process with defined and traceable input streams, the operator may alternatively base the determination of the biomass fraction on a mass-balance of fossil and biomass carbon entering and leaving the process. In any case, the methodology must be approved by the regulatory agency.

EPA determined that the California approach of quarterly source testing that collects an integrated gas sample per ASTM D7459-08, and an analysis of the sample per ASTM D6866-06a provides a standardized, consistent, and low cost approach for the determination of the biogenic CO_2 fraction for mixed fuels like MSW. The integrated gas sample can be easily taken from stacks which already have CEMS, which is the case with the source population affected by this requirement

ASTM D6866-06a was originally developed to support the U.S. Department of Agriculture's Biobased Products Preferred Procurement Program, and is the required method for the determination of biobased content under 7 CFR Part 2902. EPA is also currently reviewing the method for the Renewable Fuel Standard Requirements in 40 CFR Part 80.

To ensure confidence in the emissions data reported, sources could be required to perform the ASTM D6866-06a analysis at least once in every calendar quarter in which MSW, or other mixed fuel, is combusted in the unit. Each gas sample could be taken using ASTM D7459-08, 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 D6866-06a). The owner or operator would divide total CO_2 emissions between biogenic emissions and non-biogenic emissions, using the average proportionalities of all samples analyzed during the report year. 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.

3.4 Calculating CH_4 and N_2O Emissions from Stationary Fuel Combustion Sources

To estimate CH_4 and N_2O emissions, the methodology is based on fuel consumption and default CH_4 and N_2O emission factors. Part 75 units measuring and reporting heat input on a year round basis according to §§75.10(c) and 75.64 could calculate the annual CH_4 and N_2O emissions in metric tons using the cumulative annual heat input from the electronic data report required under §75.64, multiplied by a the corresponding fuel specific emission factor.

For all other units, the annual CH_4 and N_2O emissions in metric tons could be based on the mass or volume of fuel combusted multiplied by the fuel heat content and the corresponding fuel specific emission factor. Default heat contents may be used by sources using a Tier 1 methodology for CO_2.

The annual CH_4 and N_2O emissions are converted to metric tons CO_2 equivalent by the global warming potential (GWP) factors in Table 9.

Table 9
GWP Factors - CH_4 and N_2O

Greenhouse Gas	Global Warming Potential (GWP)
CO_2	1
CH_4*	21
N_2O	310

*The CH_4 GWP includes the direct effects and those indirect effects due to the production of tropospheric ozone and stratospheric water vapor. The indirect effect due to the production of CO_2 is not included.

Source: IPCC Climate Change 1995: The Science of Climate Change. (1996) Intergovernmental Panel on Climate Change, J.T. Houghton, L.G. Meira Filho, B.A. Callander, N. Harris, A. Kattenberg, and K. Maskell, eds. Cambridge University Press, Cambridge U.K.

3.5 Other Quantification Options Considered

3.5.1 Require Part 75 CO_2 Emissions Quantification and Monitoring Requirements for All Stationary Combustion Sources

Another approach to quantify CO_2 emissions would be to extend the Acid Rain Program CO_2 monitoring requirements in 40 CFR Part 75 to all affected facilities, instead of the separate four tier approach for non-Acid Rain combustion sources. This approach would add extensive electronic data capture and reporting. This approach has the advantage of ensuring a high level of transparency, accuracy, and consistency among reporters. The disadvantage of this approach is that it would be more costly than the option described above, and may not be deemed necessary for a GHG reporting program designed to collect data to support a range of future policies. The Part 75 program was designed to support a cap and trade emission control program, and the requirements for that program are necessary to assure that allowances are consistently valued, and that emission reductions are in fact achieved.

3.5.2 Require a Tier 4 CEMS Methodology for all Non-Part 75 Solid Fuel-Burning Sources that Have a Rated Heat Capacity Greater Than 250 Million Btus per Hour

Another option would be to require the use of CEMS for all solid fuel burning sources that have a rated heat input capacity of greater than 250 million Btus per hour. CEMS can have a higher degree of measurement accuracy than sampling and calculation methodologies for solid fuels due to the increased sampling required to achieve representative sampling of a heterogeneous solid fuel. The cost of installing and maintaining a CEMS, however, is significantly higher than the cost of calculating emissions using a carbon content or heat input based methodology. In addition, the variability of carbon content across samples of the same coal rank is significantly less than the variability of sulfur and other elements. Therefore representative sampling is not as difficult for carbon as it would be for sulfur, and can be achieved if the overall sampling strategy meets ASTM standards.

When considering the cost associated with the addition of CEMS as compared to the added benefit for the CO_2 measurement and reporting process, it could be argued that requiring sources to purchase and install a complete system with a CO_2 CEMS and flow monitor would place an unnecessary burden for emissions reporting program. However, if the measurement and reporting provisions under this program are used in the future as part of specific compliance program, EPA would need to reexamine this decision to ensure a consistent and effective compliance oversight process.

3.5.3 Allow Tier 2 Methodology Calculation for All Gas and Oil Fired Sources

Another option would be to allow oil-fired and gas-fired units of all sizes (other than units burning facility-produced process gas) to use the Tier 2 methodology. Unlike Tier 3, which requires sampling for fuel carbon content, Tier 2 uses measured fuel heat content and a fuel-specific default CO_2 emission factor.

An approach similar to the Tier 2 approach without any size limit is allowed under Appendix G of Part 75 for all gas- or oil-fired Acid Rain Program units firing fuels with low heat content variability. The Appendix G approach requires compilation of daily fuel consumption based on hourly records, while Tier 2 and Tier 3 would require less frequent fuel consumption compilation (the frequency varies dependent on fuel type).

3.5.4 Provide Methodology Flexibility through Guidelines and Minimum Standards

In lieu of required monitoring methods, EPA considered a method guideline approach similar to the approach taken by the voluntary DOE 1605(b) GHG reporting program, which sets minimum standards for methodologies and data. The 1605(b) program requires reporters who wish to register their reductions to "rate" their data and emission estimation methods. The program also establishes minimum standards for the methods and data used to calculate overall emissions. This approach was adopted by DOE to resolve a number of difficulties associated with adapting emissions inventory methods to the problem of calculating "entity" emissions and using such entity estimates to register reductions.

The emission rating system is similar to the tier approach described above. It is an ordinal rating of emission estimation methods by sector and emission source. The best available method, based on the four evaluation criteria of accuracy, reliability, verifiability and practical application, is usually rated "A," and given a value of four points. An A rating is restricted to methodologies where computations are based on a preponderance of values indicative of on-site conditions over multiple periods. The next best method, or best method in those cases where no methodology qualifies for an A rating , will be rated "B" and given a value of three points; the next best rated "C" and given a value of two points; and the least accurate method rated "D" and given a value of one point.

Reporters assign the rating provided in the program's Technical Guidelines to each source for each year in which emissions are reported. The average rating (weighted by emissions) of all of the entity's reported emissions (and sequestration in this program's case) must be 3.0 or higher in the base period and any year in which reductions are reported in order for the reductions or sequestration to qualify as "registered reductions."

Table 10 is taken from the Technical Guidelines and broadly describes the method rating system. The Technical Guidelines also provide fuel specific monitoring methodology ratings for the stationary combustion sector, and default factors for heat content and emissions.

Table 10
DOE 1605(b) Measurement and Estimation Method Ratings

Rating	Points	Typical Description
A	4	Continuous direct measurement (CEMS) of actual emission source; or emission factor based upon multiple recent, regularly repeated, on-site direct measurements of sources, multiplied by measured activity data. Activity data measure actual use rather than purchases (if applicable).
B	3	Emission factor based on limited direct measurements of source or representative sample

		multiplied by measured activity data. Activity data measure actual use, rather than purchases (if applicable).
C	2	Default emission factor multiplied by measured activity data; or emission factor based on single measurement multiplied by estimated activity data.
D	1	Default emission factor multiplied by estimated activity data or static one-time monitoring.

From Table 1.A.1., DOE Technical Guidelines, Voluntary Reporting of GHGs 1605(b) Program, January, 2007.

3.5.5 *De minimis* Source Exemptions

The California mandatory reporting rule allows alternative monitoring methods of the operator's choosing for *de minimis* sources. The *de minimis* category under the CARB rule can include one or more units that collectively produce no more than three percent of the facility's total CO_2e emissions, but in no case exceeding 20,000 metric tons CO_2e. The EU ETS has a *de minimis* category that can cover minor sources selected by an operator that emit 1,000 tons or less per year, or that contribute less than two percent of total annual CO_2 emissions (up to no more than 20,000 tons). Monitoring and emission quantification may be performed for these units using non-tier methods. One way to alleviate burden to smaller sources would be to provide the simple Tier 1 methodology for smaller sources.

4.0 Substitute Data Procedures

The existing federal CO_2 emissions reporting under the Acid Rain Program and California's GHG reporting rule both provide for the use of substitute data during periods when quality assured monitoring data are not available to quantify emissions. EPA also proposes to include missing data requirements in the federal GHG reporting rule to help ensure data quality. Acid Rain Program EGUs could be required to continue to use the missing data procedures in Part 75, Subpart D and Appendix G. Stationary fuel combustion sources could estimate missing data using a simple averaging approach of the most recent quality assured data.

4.1 Part 75 Missing Data

Part 75 requires affected Acid Rain Program units to record CO_2 emissions data for every hour that they operate, including periods of start-up, shutdown, and malfunction. If one of the required monitoring systems is not working or is out-of-control (e.g., if it fails one of its required quality assurance tests), data from an approved backup monitor or from an EPA reference method may be reported, or missing data substitution procedures must be used to estimate emissions.

The missing data routines for CEMS in Subpart D of Part 75, consists of mathematical algorithms that are used to determine an appropriate substitute value for any unit operating hour in which quality-assured data are not obtained for a monitored parameter. The routines generally use historic quality-assured monitoring data to determine the substitute data values. The Part 75 missing data procedures for CEMS (gas and stack flow) are designed to provide conservatively high substitute data values, to ensure that emissions are not underestimated during monitor outages. The missing data algorithms also become increasingly conservative (biased towards higher emissions) as monitor downtime increases so that sources have an incentive to maintain high data availability.

The standard Part 75 missing data algorithms for fuel flow rate metering are fuel-specific and load-based. The substitute data value for each hour is simply an arithmetic average of the data in the corresponding load bin, based on a look back through 720 hours of quality-assured data. If data are missing for that load bin, the next higher load bin is used. Missing data substitution for fuel heat content data is designed to provide conservatively high substitute values, but missing substitute data for fuel carbon content can be either the last quality assured value or a default value.

4.2 Other Stationary Combustion Units

Table 11 summarizes potential missing data methodologies for units using GHG emission calculation methodologies in Tiers 2, 3, and 4. For each missing value of the heat content, carbon content, or molecular weight of the fuel, and any CEMS measured CO_2 concentration or stack gas moisture, the substitute data value could be the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident. If, for a particular parameter, no quality-assured data are available prior to the missing data incident, the substitute data value could be the first quality-assured value obtained after the missing data period.

For missing fuel flow rates and stack flow rates under Tiers 3 and 4, the substitute data values would be the best available estimates of these parameters, based on process and operating data (e.g., production rate, load, unit operating time, etc.) This same substitute data approach would be used when fuel usage data and sorbent usage data are missing.

Table 11
Overview of General Stationary Combustion Missing Data Values

Parameter	Missing Data Value
Fuel heat content, carbon content, and molecular weight.	Arithmetic average of quality-assured values immediately preceding and immediately following missing data period. The first quality-assured value after the missing data is used, if no value is available preceding the missing data period.
CO_2 concentration and stack gas moisture content (CEMS).	
Fuel flow and fuel use rates.	Best available estimates of these parameters, based on process and operating data (e.g., production rate, load, unit operating time, etc.)
Stack gas flow rate (CEMS).	
Carbonate absorbent usage.	

4.3 Other Missing Data Options

None of the routines for general stationary combustion units are biased high to ensure against under reporting or to encourage high monitor availability. Sources under a GHG emission inventory reporting program do not have the same incentives as Part 75 sources to report lower emissions, and compliance with an emission cap is not an issue. Therefore the Part 75 approach, based on data availability might not be appropriate for stationary combustion since those routines have a bias for higher emissions.

Alternatively for Part 75 sources, the potential bias in existing methods based on data availability is acceptable versus the complexity of having Acid Rain Program EGUs calculate two different sets of CO_2 emissions data based on different missing data routines. Also, because data availability in the Acid Rain Program is very high, over reporting due to data substitution will be minimal, and not at a level that would warrant requiring all Acid Rain Program sources to prepare, record, and report two sets of missing data calculations.

5.0 Quality Assurance/Quality Control

5.1 Quality Assurance for CEMS

Sources using CEMS to quantify CO_2 emissions could be required to meet existing quality assurance requirements that apply to the CEMS under 40 CFR Parts 60 or 75, or a State's program.

5.2 Quality Assurance for Calculation Approaches

Acid Rain Program EGUs using the non-CEMS calculation methods in Appendix G could be required to meet the current applicable Part 75 quality assurance requirements for the fuel data used in mass balance and emission factor calculations. These include fuel flow meter calibration and accuracy test procedures in Appendix D of Part 75.

For stationary combustion sources using the Tiers 1 through 3, specific consensus standards similar to those in Part 75 for fuel sampling and analysis for carbon, heat content, and density could be required.

Oil and gas fuel flow meter calibrations could also be required following consensus standards or procedures recommended by the instrument manufacturer. Sources could also use the procedures in Appendix D to Part 75. An initial calibration could be required, as well as on-going calibrations. The on-going tests could be required once per year, or less frequently based on manufacturer's recommendations. The annual schedule is similar to Part 75, which requires fuel flow meter accuracy testing every four fuel flowmeter QA operating quarters, with conditions to extend the period between tests.

5.3 Monitoring Plan and QA/QC Plan

Some version of a monitoring plan and QA/QC plan that outlines the standard operating procedures for emission quantification and quality assurance are required by many of the existing or proposed GHG reporting programs.

Acid Rain Program sources currently submit detailed monitoring plans that include collection of CO_2 related data. Except for certain diagrams and blueprints, the monitoring plan data are submitted electronically. Table 12 summarizes Part 75 monitoring plan contents.

Table 12
Part 75 Monitoring Plan Contents

Format	Monitoring Plan Elements
Electronic	Unit information, such as the unit type, the maximum heat input capacity, the operating range of the unit (in terms of MWs or steam load), the type(s) of fuel combusted, the type(s) of emission controls, etc.
	Unit-stack configuration information, indicating how the effluent gases from the unit discharge to the atmosphere (i.e., through a single stack or multiple stacks, or through a common stack shared with other units.)
	A description of the methodology used to monitor each pollutant or parameter (e.g., CEMS, Appendix D, Appendix E, etc.)
	Monitoring system information (e.g., the pollutant or parameter monitored by the system, the make, model and serial number of each analyzer, span and range information, etc.)
	Mathematical formulas used to calculate emissions and heat input.
Hard Copy	Schematic diagrams and blueprints.
	Data flow diagrams.

A separate QA/QC plan detailing those activities is also required by Part 75, QA/QC plants are retained on-site and are not submitted to EPA. Part 75 QA/QC plan elements include:

- QA test procedures, and monitor adjustment procedures;
- Emissions and QA test recordkeeping and reporting procedures;
- Missing data procedures related to add-on control equipment; and
- Preventive maintenance procedures.

Required monitoring or QA/QC plan requirements in other GHG reporting programs, except for the EU ETS are not as extensive as those in the Acid Rain Program. California's GHG rule requires facilities to document the data acquisition and handling activities for the calculation and reporting of emissions. The activities include parameter measurements, monitoring, fuel analysis, recordkeeping, and the emission calculations. The documentation is not submitted to the State, but is used in the third party verification process. The EU ETS, which is an emission trading program, has specific monitoring plan requirements similar to the Acid Rain Program, and requires submittal and approval prior to data collection.

Minimal requirements for a GHG reporting program could be to document the process used to collect the necessary data for the GHG emission calculations, identify key facility personnel involved in calculating and reporting the GHG emissions, and log any changes to the GHG emission accounting methods.

Facilities could also be required to prepare and maintain a Quality Assurance Project Plan that documents the procedures used to ensure the accuracy of the estimates of fuel usage and/or sorbent usage (as applicable), including calibration of weighing equipment, fuel flow meters, and other measurement devices. The estimated accuracy of measurements made with these devices shall also be recorded, as well as the technical basis for these estimates.

Submittal of the plans prior to monitoring, although necessary in a trading or compliance based program, might not be required for an emissions reporting program.

6.0 Types of Emissions Information to be Reported

In order to support data collection for a range of future climate policies, additional data beyond actual GHG emissions data could be required to be reported. For example, additional information on the number, types, and size of combustion sources could be required to be reported. Sufficient fuel and quantification methodology information could be required to support the reported emissions, and to allow a level of EPA verification of emissions. EPA's intention is to develop a reporting scheme that where practicable, integrates the new reporting requirements with existing data collection and data management systems.

6.1 Data Elements Reported Under Existing Programs

Many of the stationary fuel combustion sources that would be affected by the proposed GHG Reporting Rule currently report criteria and hazardous pollutant emissions or other emissions related data to EPA or to the States under the Clean Air Act. Section 821 of the Clean Air Act required reporting of CO_2 emissions from Acid Rain Program EGUs. Under section 110 of Title I of the Clean Air Act, EPA has long required State Implementation Plans (SIPs) to provide for the submission by States to EPA of emission inventories containing information regarding the emissions of criteria pollutants and their precursor compounds. In addition a number of States have developed their own GHG reporting programs. Data elements reported under the Acid Rain Program, National Emissions Inventory (NEI), and other GHG reporting programs are briefly outlined below.

6.1.1 Acid Rain Program EGUs

Acid Rain Program EGUs currently report extensive CO_2 emissions data and monitoring information directly to EPA through quarterly electronic reports. Part 75 requires affected units to record CO_2 emissions data for every hour that they operate, including periods of start-up, shutdown, and malfunction.

Most of the detailed records are kept electronically, for a minimum of three years, using a DAHS, although some monitoring plan information and QA test support data is kept in hard copy. The DAHS records all data from the monitoring systems, translates it into the required units of measure, and stores the data. When emissions data are missing, the DAHS automatically performs missing data substitution. The DAHS also electronically records and stores operating data for the combustion unit, monitoring plan data, and the results of QA checks and tests.

Facilities submit electronic data on a unit basis in Part 75 quarterly reports. Quarterly reports include:

- Facility information;
- The hourly CO_2 emissions data, operating data, results of the required QA tests, and other information specified in the monitoring plan and recordkeeping sections of Part 75;
- For Appendix D units, the type of gas or oil fuel burned in the hour, amounts, and fuel heat input;
- Unit operating hours for the quarter and cumulative operating hours for the calendar year;
- Short tons of CO_2 emitted during the quarter and cumulative CO_2 mass emissions for the calendar year; and
- Total heat input (mmBtu) for quarter and cumulative heat input for calendar year.

6.1.2 NEI Report Formats

States report their criteria and hazardous pollutant inventories to the NEI. The facility based reports for point sources include data elements down to the unit and process (fuel) level. Reported data elements required by the Consolidated Emissions Reporting Rule (CERR) that are relevant to GHG reporting include:

- Facility information;
- Point and process identification and a process-level code that describes the equipment and/or operation which is emitting pollutants;
- Fuel ash, sulfur, and heat content on an annual average basis;
- Activity or throughput on a daily average and annual basis; and
- Emission factors and annual emissions.

6.1.3 Other GHG Reporting Programs

There are a number of other GHG reporting programs (See Table 2, above) including mandatory programs (such as the California reporting rule and EU ETS) and voluntary programs (EPA's Climate Leaders and The Climate Registry). California, EU ETS, and The Climate Registry have third party verification, while Climate Leaders relies on EPA's own verification.

Under California's GHG rule, electric generating facilities are required to report unit level combustion GHG emissions, nameplate generating capacity, fuel consumption, heat content by fuel type, and carbon content if measured. Operators are permitted to aggregate information for multiple generating units that combust the same fuel type if the facility lacks the necessary equipment to report by generating unit. For general stationary fuel combustion sources, California requires facility reporting of total annual GHG emissions, annual GHG emissions by fuel type, the amount of each fuel burned, fuel heat content, carbon content if measured, and GHG emission factors.

The EU ETS program also requires reporting at the facility level. For all emission sources and/or source streams, facilities report annual total CO_2 emissions, the quantification approach (measurement or calculation), chosen tiers and method (if applicable), activity data (fuel use), heat content, and emission factors. If a mass balance approach is used, the carbon content is also reported.

EPA's voluntary Climate Leaders program requires only limited reporting of the annual total GHG emissions. Another voluntary GHG reporting program, The Climate Registry, requires reporting of total stationary combustion GHG emissions and identification of the associated quantification methodology tier.

6.2 Proposed Reporting Elements

Table 13 includes the type of information that could be required to be reported in a mandatory GHG reporting rule.

Table 13
Emission Reporting Elements for all Stationary Combustion Units

Data Element	Description
Unit identifier	Assigned by facility.
Unit type	Boiler, combustion turbine, engine, process heater, etc.
Unit capacity	Maximum rated heat input of the unit in mmBtu/hr (boilers, combustion turbines, engines, and process heaters only).
Fuel Type and Amount	Each type of fuel combusted in the unit during the report year, and the amount consumed in the year.
Fuel Characteristics	Heat content and carbon content (carbon content if measured).
Emission Methodology	The method used to calculate CO_2 emissions for each type of fuel (e.g., Part 75, Tier 1, Tier 2, etc.)
Part 75 Methodology	If applicable, which one of the monitoring and reporting methodologies in Part 75 was used to quantify the CO_2 emissions.
GHG emissions for each fuel	Annual CO_2, CH_4, and N_2O emissions for each fuel in metric tons.
CO_2 emissions from sorbent use (if applicable)	Annual CO_2 emissions in metric tons per year.
The total GHG emissions	Annual CO_2e emissions from the unit in metric tons.

6.2.1 Consolidated Reporting of Unit Data

The direct dependence of CO_2 emissions on the fuel carbon content and amount of fuel burned, rather than type of combustion equipment, allows for aggregation of reported data above the unit level. Also the default CH_4 and N_2O emission factors are based strictly on the type of fuel burned, and not the type of combustor. Therefore, a facility could be allowed to report the combined GHG emissions from the facility, instead of unit information, if it combusts the same type of homogeneous oil or gaseous fuel through a common supply line.

To further reduce burden, aggregation of small units at a facility could be allowed as long as the total rated heat input of the group does not exceed 250 mmBtu/hr. Unit specific fuel usage still would be quantified. In this case the data elements in Table 13 could be reported as a group. The 250 mmBtu/hr level corresponds to the large combustion source cutoff for the monitoring tiers.

For units using CEMS to monitor CO_2 emissions and stack gas flow at a common stack, or measuring fuel flow and characteristics at a common pipe for multiple units, the source could group units that are ducted to that stack and similarly report the data elements in Table 13 as a group as described for small units.

6.2.2 Verification Data

If the mandatory GHG reporting rule relies on EPA verification, additional data would have to be provided on the quantification methods to allow for EPA to perform its own offsite verification review. No additional data would be needed for Acid Rain Program units since that data is already provided to EPA. The Part 75 electronic reports provide hourly measurements as well as quality assurance test results. For the tiered methods, the basic unit level reporting requirement assists in emission verification. A potential verification is outlined below:

- Tier 1 would require a check of the total quantity of each type of fuel combusted during the report year.

- For Tier 2, EPA could check emissions if the quantity of each type of fuel combusted during each measurement period (day or month) is reported, along with all high heat values used in the emission calculations, the methods used to determine the HHVs, and flags indicating which HHVs (if any) are substitute data values.

- Tier 3 data verification requirements are similar to Tier 2 with the addition of carbon content values for each measurement period, and if required, fuel molecular weight. Fuel flow meter calibrations could be reported to verify the data quality of the fuel measurements.

- For the CEMS based Tier 4 method, the number of unit operating days and hours could be reported, along with daily CO_2 mass emission totals, and substitute data hours. This is similar to data reported in NSPS summary reports. The results of the initial CEMS certification tests and the major on-going QA tests would be reported to verify data quality. Units burning MSW could also be required to report the results of the quarterly sample analyses used to determine the biogenic percentage of CO_2 emissions, the annual volumes of biogenic and fossil CO_2, and the F-factors and fuel heat content values used in the calculations.

- Finally, units with acid gas scrubbing that do not use a CEMS could report the type and amount of sorbent used.

7.0 References

Australian Department of Climate Change, Regulation Policy Paper, National Greenhouse and Energy Reporting System, February 2008.
http://www.climatechange.gov.au/inventory/methodology/index.html

Australian Department of Climate Change, Overview Paper - Technical Guidelines for the Estimation of Greenhouse Emissions and Energy at Facility-Level (Energy, Industrial Process, and Waste Sectors in Australia), December 2007.
http://www.climatechange.gov.au/inventory/methodology/index.html

California Air Resources Board (CARB), Attachment A: Modified Regulatory Language, including Appendix A, Proposed Regulation for the Mandatory Reporting of Greenhouse Gas Emissions as modified in May 2008. http://www.arb.ca.gov/regact/2007/ghg2007/ghg2007.htm

California Climate Action Registry (CCAR) http://www.climateregistry.org/tools/protocols/general-reporting-protocol.html

Canada Gazette, Vol. 142, No. 7, February 16, 2008, Notice with respect to reporting of greenhouse gases (GHGs) for 2008. http://canadagazette.gc.ca/partI/2008/20080216/html/notice-e.html#d108

European Union, Emission Trading Scheme (ETS) - Guidelines for Monitoring and Reporting Greenhouse Gas Emissions (Pursuant to Directive 2003/87/EC of the European Parliament and of the Council), July 18, 2007. http://ec.europa.eu/environment/climat/emission/mrg_en.htm

International Panel on Climate Change (IPCC), 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Vol. 3 (Provides methodologies for estimating national inventories of anthropogenic emissions by sources and removals by sinks of greenhouse gases). http://www.ipcc-nggip.iges.or.jp/public/2006gl/index.htm

Regional Greenhouse Gas Initiative (RGGI), Regional Greenhouse Gas Initiative Model Rule, (Final with corrections), January 5, 2007. http://www.rggi.org/modelrule.htm

Shigehara, R. T., EMI, Inc., Memorandum to John Schakenbach, U.S. EPA Clean Air Markets Division, January 8, 2008.

The Climate Registry (TCR), General Reporting Protocol of the Voluntary Reporting Program, May 2008. http://www.theclimateregistry.org/reference.html

U.S. Department of Energy (DOE), Technical Guidelines for the Voluntary Reporting of Greenhouse Gases (1605(b)) Program, January 2007. http://www.pi.energy.gov/enhancingGHGregistry/technicalguidelines.html

U.S. Environmental Protection Agency, Greenhouse Gas Inventory Core Module Guidance, Direct Emissions from Stationary Combustion Sources, May 2008, EPA430-K-08-003. http://www.epa.gov/stateply/resources/cross-sector.html

U.S. Environmental Protection Agency, Inventory of U.S. Greenhouse Gas Emissions and Sinks*: 1990 - 2006*, April 2008, US EPA 430-R-08-005. http://www.epa.gov/climatechange/emissions/usinventoryreport.html

U.S., Federal Register, Vol. 67, No. 111, June 10, 2002, page 39602 - Consolidated Emissions Reporting, Final Rule. http://www.epa.gov/ttn/chief/cerr/cerr.pdf

U.S., Title 10, Code of Federal Regulations, Part 300 - Guidelines for Voluntary Greenhouse Gas Reporting (Guidelines for the voluntary greenhouse gas reporting program under Section 1605b of the Energy Policy Act of 1992).
http://www.pi.energy.gov/enhancingGHGregistry/generalguidelines.html

U.S., Title 40, Code of Federal Regulations, Part 75 - Continuous Emission Monitoring (Requirements for the monitoring, recordkeeping, and reporting of SO_2, NO_X, CO_2, and Hg emissions, volumetric flow, and opacity data from affected units under the Acid Rain Program, NO_X, mass and Hg emission reduction programs).
http://www.epa.gov/airmarkets/emissions/consolidated.html

U.S., Title 40, Code of Federal Regulations, Part 60 - Standards of Performance for New Stationary Sources. http://www.epa.gov/lawsregs/search/40cfr.htm

[This page intentionally left blank.]

Appendix A

GHG Methods and Reporting

Reporting Program/ Guidance	Fuel	Monitoring Methods and/or GHG Calculation Methods	Input Data used to calculate emissions (Source of Data)	Mandatory or Voluntary Program/ Reporting Requirement	Quality Assurance/ Quality Control Procedures	IPCC or WRI/WBCSD Elements
California ARB Mandatory Reporting Rule (Proposed)	Biomass fuel, municipal waste	Use CEMS data if CEMS used is in compliance with 40 CFR Parts 60 or 75; otherwise, calculate emissions by measuring steam output and combining with default emission factors. If a mix of fossil and non-fossil fuels are burned, CO_2 emissions are generally apportioned by determining the fossil fuel CO_2 emissions using a calculation method and subtracting from CEMS total mass emissions; however, sources that combust fuels or fuel mixtures that are at least five percent biomass by weight and not pure biomass, except waste-derived fuels that are less than 30 percent biomass by weight of total fuels combusted for the report year, shall determine the biomass-derived portion of CO_2 emissions using ASTM D6866-06a. If using CEMS, source must also monitor net energy output. Use fuel consumption and default emission factor based on measured or default heat content to calculate CH_4 and N_2O.	Stack gas concentration and flow (CEMS only), fuel burned and net energy output.	Mandatory/Annual reporting.	Third party verification.	Uses some IPCC emission factors, requires third party verification.

(cont.)

GHG Methods and Reporting (cont.)

Reporting Program/ Guidance	Fuel	Monitoring Methods and/or GHG Calculation Methods	Input Data used to calculate emissions (Source of Data)	Mandatory or Voluntary Program/ Reporting Requirement	Quality Assurance/ Quality Control Procedures	IPCC or WRI/WBCSD Elements
California ARB Mandatory Reporting Rule (Proposed)	Refinery fuel gas, other low Btu gases	Use CEMS data if CEMS used is in compliance with 40 CFR Parts 60 or 75; otherwise calculate emissions using daily gas consumption, and carbon content or heat content for each fuel gas that is measured daily or weekly based on refinery size. Refinery gas carbon content is calculated three times per day (every eight hours) and flexi-coker gas, once per day. May use in-line continuous monitor for carbon content. For CH_4 and N_2O, use fuel consumption and a default emission factor based on measured heat content if available, or default heat content. If using CEMS, must also monitor net energy output. Use fuel consumption and default emission factor based on measured or default heat content to calculate CH_4 and N_2O.	Stack gas concentration and flow (CEMS only), fuel burned and net energy output.	Mandatory/Annual reporting	Third party verification.	Uses some IPCC emission factors, requires third party verification.

(cont.)

GHG Methods and Reporting (cont.)

Reporting Program/ Guidance	Fuel	Monitoring Methods and/or GHG Calculation Methods	Input Data used to calculate emissions (Source of Data)	Mandatory or Voluntary Program/ Reporting Requirement	Quality Assurance/ Quality Control Procedures	IPCC or WRI/WBCSD Elements
California ARB Mandatory Reporting Rule (Proposed)	Fuel Oil	Use CEMS data if CEMS used is in compliance with 40 CFR Parts 60 or 75; otherwise calculate emissions based on fuel consumption and carbon or heat content. Measure and record fuel consumption at the receipt of each new fuel shipment or delivery, or monthly; and measure carbon content monthly, or heat content monthly or by shipment. Emissions calculations are based on either carbon content and fuel consumption, or heat content, fuel consumption, and an ARB default emission factor. May also calculate emissions based on annual fuel combustion and default heat content and emission factors. If using CEMS, must also monitor net energy output. Use fuel consumption and default emission factor based on measured or default heat content to calculate CH_4 and N_2O.	Stack gas concentration and flow (CEMS only), fuel burned and net energy output.	Mandatory/Annual reporting.	Third party verification.	Uses some IPCC emission factors, requires third party verification.
California ARB Mandatory Reporting Rule (Proposed)	Solid fuels	Use CEMS data if CEMS used is in compliance with 40 CFR Parts 60 or 75; otherwise, calculate emissions using monthly measured fuel as fired, and carbon or heat content based on a composite of four weekly samples (per specified ASTM methods). Apply an emission factor based on the measured carbon content, or a default factor if only measuring heat content. Use fuel consumption and default emission factor based on measured or default heat content to calculate CH_4 and N_2O.	Stack gas concentration and flow (CEMS only), fuel burned and net energy output.	Mandatory/Annual reporting.	Third party verification.	Uses some IPCC emission factors, requires third party verification.

(cont.)

GHG Methods and Reporting (cont.)

Reporting Program/ Guidance	Fuel	Monitoring Methods and/or GHG Calculation Methods	Input Data used to calculate emissions (Source of Data)	Mandatory or Voluntary Program/ Reporting Requirement	Quality Assurance/ Quality Control Procedures	IPCC or WRI/WBCSD Elements
California ARB Mandatory Reporting Rule (Proposed)	Natural gas	Use CEMS data if CEMS used is in compliance with 40 CFR Parts 60 or 75; otherwise, calculate emissions using natural gas consumption and heat content measured monthly. May use supplier's heat content if within GCV range of 975 to 1100 Btu/scf; if GCV outside of range, use carbon content method and measure monthly. Use default emission factor or measured monthly carbon content (carbon content not relevant to CH_4 and N_2O). Use fuel consumption and default emission factor based on measured or default heat content to calculate CH_4 and N_2O.	Stack gas concentration and flow (CEMS only), fuel burned and net energy output.	Mandatory/Annual reporting.	Third party verification.	Uses some IPCC emission factors, requires third party verification.
California Climate Action Registry (CCAR)	All fuels	Use CEMS emissions data as used in 40 CFR Part 75 or calculate using fuel measurements made directly according to industry approved methods (recorded fuel purchases or sales invoices measuring any stock change) and specified or source-derived emission factors. CHP facilities may calculate emissions associated with each energy product stream using three methods: efficiency method; energy content method; and work potential method. If a mix of fossil and non-fossil fuels are burned, CO_2 emissions are separately apportioned using a fuel calculation approach for the biomass fuel. The Registry also requires sources to calculate efficiency metrics (i.e., CO_2 mass emissions per unit of energy output and fossil fuel input), and CHP energy output allocations.	Fuel burned and EIA default emissions factors; can use alternative factor if a more accurate and accepted by certifier.	Voluntary/Annual reporting.	Third party verification.	May use IPCC emission factors; requires third party verification. Accounting and reporting principles are consistent with the WRI/WBCSD GHG Protocol Initiative.

(cont.)

GHG Methods and Reporting (cont.)

Reporting Program/ Guidance	Fuel	Monitoring Methods and/or GHG Calculation Methods	Input Data used to calculate emissions (Source of Data)	Mandatory or Voluntary Program/ Reporting Requirement	Quality Assurance/ Quality Control Procedures	IPCC or WRI/WBCSD Elements
The Climate Registry (TCR)	All fuels	Use CEMS data if measured in accordance with 40 CFR Part 75; otherwise calculate emissions. Preferably measure each unit's fuel use, but may use purchase records. Measure fuel heat and carbon content on a frequency determined by fuel variability to develop emission factors. May also use default fuel-based emission factors. Optional method for CHP facilities to apportion emissions to electric and heat output. To calculate CH_4 and N_20 emissions, multiply fuel burned by a default emission factor.	CEMS data or fuel burned.	Voluntary/Annual reporting.	Third party verification.	Uses IPCC tier approach for measurement methods, and requires third party verification. Accounting and reporting principles are consistent with the WRI/WBCSD Protocol Initiative; the inventory quality guidance is from the WRI/WBCSD GHG Protocol Corporate Standard (Revised Edition), Chapter 7.
Chicago Climate Exchange (CCX)	All fuels	Use CEMS data, or calculate emissions using CCX and WRI/WBCSD protocols.	CEMS data or fuel burned.	Voluntary/Annual reporting.	Third party verification.	Uses WRI/WBCSD measurement protocols and emission factors.

(cont.)

GHG Methods and Reporting (cont.)

Reporting Program/ Guidance	Fuel	Monitoring Methods and/or GHG Calculation Methods	Input Data used to calculate emissions (Source of Data)	Mandatory or Voluntary Program/ Reporting Requirement	Quality Assurance/ Quality Control Procedures	IPCC or WRI/WBCSD Elements
Regional Greenhouse Gas Initiative (RGGI)	Biomass (does not include biomass mixed with other waste)	Use 40 CFR Part 75, and include additional biomass fuel and net energy output monitoring measurements. Biofuel measurements include: 1) sampling and analysis of each shipment received for carbon content, heating value, and moisture content; 2) mass or volumetric measurement of fuel burned; and 3) operating hours. Sampling and analysis should be done per methods in the New York State Renewable Energy Portfolio Standard Biomass Guidebook, May 2006. As-fired biomass CO_2 emissions shall be the lower of the CEMS when biomass fired alone, or calculation method when combined with other fuels.	Same as 40 CFR Part 75 plus net energy output.	Mandatory/Quarterly reporting.	As required by 40 CFR Part 75.	No.
Regional Greenhouse Gas Initiative (RGGI)	Fossil fuels	Use 40 CFR Part 75, plus net energy output monitoring.	Same as 40 CFR Part 75 plus net energy output.	Mandatory/Quarterly reporting.	As required by 40 CFR Part 75.	No.
Regional Greenhouse Gas Initiative (RGGI)	Natural gas, fuel oil, refinery fuel gas, blast furnace gas, other fossil fuel derived gases	Use 40 CFR Part 75, plus net energy output monitoring.	Same as 40 CFR Part 75 plus net energy output.	Mandatory/Quarterly reporting.	As required by 40 CFR Part 75.	No.

(cont.)

GHG Methods and Reporting (cont.)

Reporting Program/ Guidance	Fuel	Monitoring Methods and/or GHG Calculation Methods	Input Data used to calculate emissions (Source of Data)	Mandatory or Voluntary Program/ Reporting Requirement	Quality Assurance/ Quality Control Procedures	IPCC or WRI/WBCSD Elements
U.S. DOE 1605(b)	Biomass fuel, municipal waste, other waste	Use CEMS emissions data or calculate emissions using fuel burned based on measured purchases or consumption. May use measured, contractual, or default calorific values (GCV). Default emission factors may be used from AP42 or IPCC Revised Guidelines. Do not calculate CO_2 emissions for biomass fuels; estimate biomass fraction of municipal solid waste or landfill gas by sampling and analysis or using EIA default factors.	Fuel burned.	Voluntary/Annual reporting. Do not report biomass CO_2 emissions.	No requirement.	Uses IPCC Revised Guidelines as a source of emission factors.
U.S. DOE 1605(b)	Refinery fuel gas	Calculate mass emissions using fuel burned based on measured purchases or consumption. Use EIA default emission factors for refinery gas or develop CO_2 emission factor based on gas analysis.	Fuel burned.	Voluntary/Annual reporting.	No requirement.	Uses IPCC Ordinal rating system for emissions calculations.
U.S. DOE 1605(b)	Fuel Oil	Use CEMS emissions data or calculate emissions using fuel burned based on measured purchases or consumption. May use measured, contractual, or default calorific values (GCV) provided in the guidelines by oil type.	Fuel burned.	Voluntary/Annual reporting.	No requirement.	Uses IPCC Ordinal rating system for emissions calculations.

(cont.)

GHG Methods and Reporting (cont.)

Reporting Program/ Guidance	Fuel	Monitoring Methods and/or GHG Calculation Methods	Input Data used to calculate emissions (Source of Data)	Mandatory or Voluntary Program/ Reporting Requirement	Quality Assurance/ Quality Control Procedures	IPCC or WRI/WBCSD Elements
U.S. DOE 1605(b)	Coal, petroleum coke	Use CEMS data if CEMS used is in compliance with 40 CFR Part 75; otherwise, do a mass balance calculation. For the coal mass balance calculation, use fuel burned, carbon content, and fraction combusted to calculate emissions. For the petroleum coke mass balance equation, use measured consumption and actual carbon content based on periodic samples if available; otherwise, use consumption estimates and/or default emissions factors. To calculate CH_4 and N_20 emissions, multiply fuel burned by a default emission factor (factors prepared by EPA and IPCC).	Fuel burned, carbon content, and fraction combusted and/or default emissions factors.	Voluntary/Annual reporting.	No requirement.	Uses IPCC Ordinal rating system for emissions calculations.
U.S. DOE 1605(b)	Natural gas	Calculate mass emissions using fuel burned based on measured purchases or consumption, measured, contractual, or default calorific values (GCV), and default emission factors. Reporters burning natural gas with a Btu content < 975 Btu/scf or >1,100 Btu/scf should develop an emission factor based on gas analysis.	Fuel burned.	Voluntary/Annual reporting.	No requirement.	Uses IPCC Ordinal rating system for emissions calculations.

(cont.)

GHG Methods and Reporting (cont.)

Reporting Program/ Guidance	Fuel	Monitoring Methods and/or GHG Calculation Methods	Input Data used to calculate emissions (Source of Data)	Mandatory or Voluntary Program/ Reporting Requirement	Quality Assurance/ Quality Control Procedures	IPCC or WRI/WBCSD Elements
U.S. EPA 40 CFR Part 75	Refinery fuel gas, blast furnace gas, other fossil fuel derived gases	Use a CO_2 or O_2 diluent CEMS and a stack flow monitor, or calculate mass emissions using daily or hourly fuel sampling for GCV and carbon content (monthly if fuel demonstrates low GCV variability), and fuel flow monitoring. May use an on-line GCV calorimeter or gas chromatograph. Use carbon content (or GCV and F-factor) combined with daily mass fuel flow to calculate daily emissions.	Stack gas concentration and flow (CEMS only) or fuel burned and carbon content or hourly heat input or defaults.	Mandatory/Quarterly reporting.	Monitoring plan, performance specifications, certification and on-going quality assurance test requirements.	No.
U.S. EPA 40 CFR Part 75	Fuel Oil	Use a CO_2 or O_2 diluent CEMS and a stack flow monitor, or calculate mass emissions using one of three methods: 1) sample each fuel oil shipment or delivery, and measure fuel flow; 2) use the percent carbon content (or fuel GCV and F-factor) and mass fuel flow; or 3) use an F-factor and hourly heat input.	Stack gas concentration and flow (CEMS only) or fuel burned and carbon content or hourly heat input or defaults.	Mandatory/Quarterly reporting.	Monitoring plan, performance specifications, certification, and on-going quality assurance test requirements.	No.

(cont.)

GHG Methods and Reporting (cont.)

Reporting Program/ Guidance	Fuel	Monitoring Methods and/or GHG Calculation Methods	Input Data used to calculate emissions (Source of Data)	Mandatory or Voluntary Program/ Reporting Requirement	Quality Assurance/ Quality Control Procedures	IPCC or WRI/WBCSD Elements
U.S. EPA 40 CFR Part 75	Coal, petroleum coke	Use a CO_2 or O_2 diluent CEMS and a stack flow monitor, or calculate mass emissions using fuel sampling for percent carbon content (or fuel GCV and F-factor) and fuel flow monitoring for mass fuel flow.	Stack gas concentration and flow (CEMS only) or fuel burned and carbon content or hourly heat input or defaults.	Mandatory/Quarterly reporting.	Monitoring plan, performance specifications, certification and on-going quality assurance test requirements.	No.
U.S. EPA 40 CFR Part 75	Natural gas	Use a CO_2 or O_2 diluent CEMS and a stack flow monitor, or calculate mass emissions using fuel sampling for percent carbon content (or fuel GCV and F-factor) and fuel flow monitoring for mass fuel flow.	Stack gas concentration and flow (CEMS only) or fuel burned and carbon content or hourly heat input or defaults.	Mandatory/Quarterly reporting.	Monitoring plan, performance specifications, certification and on-going quality assurance test requirements.	No.

(cont.)

GHG Methods and Reporting (cont.)

Reporting Program/ Guidance	Fuel	Monitoring Methods and/or GHG Calculation Methods	Input Data used to calculate emissions (Source of Data)	Mandatory or Voluntary Program/ Reporting Requirement	Quality Assurance/ Quality Control Procedures	IPCC or WRI/WBCSD Elements
U.S. EPA Climate Leaders	Biomass fuel, municipal waste, other waste	Use CEMS data if measured in accordance with 40 CFR Part 75; otherwise, use calculation method based on fuel use and emission factors. Sample and analyze waste fuels to determine waste fuel emission factors instead of provided default factors when possible. Part 75 units should use Part 75 non-CEMS methods (found in Appendix G). Other units should collect the amount of fuel burned, and use supplier or sampled energy content data.	CEMS data or fuel burned.	Voluntary/Annual reporting.	EPA review or third party verification. CEMS should be quality assured per 40 CFR Part 75.	Uses IPCC third party verification concept. Uses WRI/WBCSD measurement protocols and emission factors.
U.S. EPA Climate Leaders	All commercial fossil fuels	Use CEMS or non-CEMS (Appendix G) data if measured/calculated in accordance with 40 CFR Part 75; otherwise, use a calculation method based on fuel burned, the heating value of fuel (energy content), and emission factors. To calculate CH_4 and N_2O emissions, multiply fuel burned by U.S. EPA fuel-type and sector-specific default factors.	CEMS data or fuel burned with heating value of fuel.	Voluntary/Annual reporting.	EPA review or third party verification. CEMS should be quality assured as required by 40 CFR Part 75.	Uses IPCC third party verification concept. Uses WRI/WBCSD measurement protocols and emission factors.

(cont.)

GHG Methods and Reporting (cont.)

Reporting Program/ Guidance	Fuel	Monitoring Methods and/or GHG Calculation Methods	Input Data used to calculate emissions (Source of Data)	Mandatory or Voluntary Program/ Reporting Requirement	Quality Assurance/ Quality Control Procedures	IPCC or WRI/WBCSD Elements
Australian National GHG and Energy Reporting System (Proposed)	Fossil and non-fossil fuels	Use CEMS data or a calculation method according to following tier protocol: the highest quality, Tier 1, uses CEMS; Tier 2 calculates emissions using an emission factor based on direct sampling and analysis conforming to Australian standards or equivalent; Tier 3 calculates emissions using an emission factor based on a representative bias free method but not conforming to a standard; and the least stringent, Tier 4, uses default emission factors.	Fuel burned.	Mandatory/Annual reporting.	Estimation of facility-specific emission factors should be conducted in accordance with existing recognized standards (Australian, ISO, ASTM).	Measurement approaches are rated in a manner similar to IPCC tiers, and third party audits are required. Emission categories based on WRI/WBCSD (Scope 1 direct, Scope 2 indirect, Scope 3 indirect).
Canadian GHG National Reporting Program	Fossil fuels, Biomass fuels	CEMS may be used for CO_2 when a CO_2 diluent monitor is installed for measurements of other pollutants. Calculation methods: 1) reference Annex FCCC/CP/2002/8, IPCC Inventory Guidelines and Good Practices; 2) measure facility or unit fuel consumed; and 3) use an emission factor (default or source derived). These are Tier 3 (IPCC) approaches. Biomass CO_2 emissions must be separated if blended fuels are burned.	Fuel burned, or stack gas.	Mandatory/Annual reporting.	Use standard measurement methods (e.g., ISO methods), calibrate and maintain measurement equipment, and have a QA/QC process that enables verification.	Requires methodologies in UNFCCC Decision 18/CP.8 and Annex FCCC/CP/2002/8, which reference Inventory Guidelines and Good Practices.

(cont.)

GHG Methods and Reporting (cont.)

Reporting Program/ Guidance	Fuel	Monitoring Methods and/or GHG Calculation Methods	Input Data used to calculate emissions (Source of Data)	Mandatory or Voluntary Program/ Reporting Requirement	Quality Assurance/ Quality Control Procedures	IPCC or WRI/WBCSD Elements
EU Emissions Trading Scheme	Biomass fuel (non-fossilized and biodegradable organic material originating from plants, animals, and micro-organisms: specifically identifies fuels in guidelines)	Emissions are determined using a mass balance approach. Fuel consumption for blended fuels is determined with a maximum uncertainty of 5 - 1.5%, based on facility size, which is similar to fossil fuels. Activity or fuel content measurements must be done using a standardized method that limits sampling and measurement bias and has a known level of uncertainty. Pure biomass source streams (≤3% non-biomass) may use non-tier methods, and have an emission factor of zero. Mixed fuel streams (biomass and fossil) shall identify the biomass portion through approved sampling methods using CEN, ISO, or national standards. A biomass portion uses a zero emission factor. If determination of the biomass portion is not feasible, assume 100% fossil. Sources may use CO_2 CEMS combined with a stack flow monitor or a mass balance flow determination if they can demonstrate that CEMS achieves greater accuracy than the highest tier calculation approach; the methodology must apportion the biomass fraction of CEMS emissions. The CEMS methodology also requires verification against a mass-balance estimate.	Fuel burned and heat content from fuel supplier or derived from operator measurement.	Mandatory/Annual reporting.	Accreditation according to EN ISO 17025; third party verification.	Applies monitoring method uncertainty tiers similar to IPCC based on facility size (emissions), uses IPCC emission factors, and requires third party verification.

(cont.)

GHG Methods and Reporting (cont.)

Reporting Program/ Guidance	Fuel	Monitoring Methods and/or GHG Calculation Methods	Input Data used to calculate emissions (Source of Data)	Mandatory or Voluntary Program/ Reporting Requirement	Quality Assurance/ Quality Control Procedures	IPCC or WRI/WBCSD Elements
EU Emissions Trading Scheme	Solid fuel and non-commercial gaseous or liquid fuels	Emissions are determined using a mass balance calculation approach. Fuel consumption is determined with a maximum uncertainty of 5 - 1.5%, based on facility size. Heat content is measured by the operator or contracted laboratory, and the sampling procedure and frequency are designed to ensure that the annual average has a maximum uncertainty of less than 1/3 of the maximum uncertainty required by the approved activity data tier level. Country specific emission factors may be used for sources with $CO_2 \leq 500{,}000$ tonnes/year. Sources may use CO_2 CEMS combined with a stack flow monitor or a mass balance flow determination to calculate mass emissions if they can demonstrate that CEMS achieves greater accuracy than the highest tier calculation approach. The CEMS methodology also requires performing supplementary calculations or a mass balance-based emissions estimate to compare with CEMS results.	Fuel burned and heat content derived from operator measurement or default factors.	Mandatory/Annual reporting.	Accreditation according to EN ISO 17025; third party verification.	Applies monitoring method uncertainty tiers similar to IPCC based on facility size (emissions), uses IPCC emission factors, and requires third party verification.

(cont.)

GHG Methods and Reporting (cont.)

Reporting Program/ Guidance	Fuel	Monitoring Methods and/or GHG Calculation Methods	Input Data used to calculate emissions (Source of Data)	Mandatory or Voluntary Program/ Reporting Requirement	Quality Assurance/ Quality Control Procedures	IPCC or WRI/WBCSD Elements
EU Emissions Trading Scheme	Commercial gaseous and liquid fuels	Emissions are determined using a mass balance calculation approach. Fuel consumption is determined with a maximum uncertainty of 5 - 1.5%, based on facility size. NCV is provided by the fuel supplier, provided it is based on accepted standards, or determined using country specific factors as reported in latest UNFCCC inventory. Emission factors are country specific or derived based on measurements using a standardized method that limits sampling and measurement bias and has a known level of uncertainty. Sources may use CO_2 CEMS combined with a stack flow monitor or a mass balance flow determination to calculate mass emissions if they can demonstrate that CEMS achieves greater accuracy than the highest tier calculation approach. The CEMS methodology also requires performing supplementary calculations or a mass balance-based emissions estimate to compare with CEMS results.	Fuel burned and heat content from fuel supplier or derived from operator measurement.	Mandatory/Annual reporting.	Accreditation according to EN ISO 17025; third party verification.	Applies monitoring method uncertainty tiers similar to IPCC based on facility size (emissions), uses IPCC emission factors, and requires third party verification.

[This page intentionally left blank.]

Appendix B

Part 75 F- and F_C- Factors[1]
(from Appendix F, Table 1)

Fuel	F-factor (dscf/mmBtu)	F_C-factor (scf CO_2/mmBtu)
Coal (as defined by ASTM D388-99[2]):		
Anthracite	10,100	1,970
Bituminous	9,780	1,800
Subbituminous	9,820	1,840
Lignite	9,860	1,910
Petroleum Coke	9,830	1,850
Tire Derived Fuel	10,260	1,800
Oil	9,190	1,420
Gas:		
Natural gas	8,710	1,040
Propane	8,710	1,190
Butane	8,710	1,250
Wood:		
Bark	9,600	1,920
Wood residue	9,240	1,830

[1] Determined at standard conditions: 20 EC (68 EF) and 29.92 inches of mercury.
[2] Incorporated by reference under 40 CFR 75.6.

Municipal Solid Waste F- and F_C- Factors[1]
(from Part 60, Appendix B, Method 19, Table 19-2)

Fuel	F-factor (dscf/mmBtu)	F_C-factor (scf CO_2/mmBtu)
Municipal Solid Waste	9,570	1,820

[1] Determined at standard conditions: 20 EC (68 EF) and 29.92 inches of mercury.

[This page intentionally left blank.]

Appendix 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
Sub-bituminous	17.25	97.02
Lignite	14.21	96.36
Unspecified (Residential/Commercial)	22.24	95.26
Unspecified (Industrial Coking)	26.28	93.65
Unspecified (Other Industrial)	22.18	93.91
Unspecified (Electric Power)	19.97	94.38
Coke	24.80	102.04
Natural Gas	**mmBtu/scf**	**kg CO_2/mmBtu**
Unspecified (Weighted U.S. Average)	1.027×10^{-3}	53.02
Petroleum Products	**mmBtu/gallon**	**kg CO_2/mmBtu**
Asphalt & Road Oil	0.158	75.55
Aviation gasoline	0.120	69.14
Distillate Fuel Oil (# 1, 2, & 4)	0.139	73.10
Jet Fuel	0.135	70.83
Kerosene	0.135	72.25
LPG (energy use)	0.092	62.98
Propane	0.091	63.02
Ethane	0.069	59.54
Isobutane	0.099	65.04

(cont.)

Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel (cont.)

Fuel Type	Default High Heat Value	Default CO_2 Emission Factor
Petroleum Products (cont.)	**mmBtu/gallon**	**kg CO_2/mmBtu**
n-Butane	0.103	64.93
Lubricants	0.144	74.16
Motor Gasoline	0.124	70.83
Residual Fuel Oil (# 5 & 6)	0.150	78.74
Crude Oil	0.138	74.49
Naphtha (< 401 deg. F)	0.125	66.46
Natural Gasoline	0.110	66.83
Other Oil (> 401 def. F)	0.139	73.10
Pentanes Plus	0.110	66.83
Petrochemical Feedstocks	0.129	70.97
Petroleum Coke	0.143	102.04
Special Naphtha	0.125	72.77
Unfinished Oils	0.139	74.49
Waxes	0.132	72.58
Biomass-derived Fuels (solid)	**mmBtu/short Ton**	**kg CO_2/mmBtu**
Wood and Wood waste (12% moisture content) or other solid biomass-derived fuels	15.38	93.80
Biomass-derived Fuels (Gas)	**mmBtu/scf**	**kg CO_2/mmBtu**
Biogas	Varies	52.07

Note: Heat content factors are based on higher heating values (HHV). Also, for petroleum products, the default heat content values have been converted from units of mmBtu per barrel to mmBtu per gallon.

Sources: U.S. EPA, *Inventory of Greenhouse Gas Emissions and Sinks: 1990-2005* (2007), Annex 2.1,Tables A-28, A-31, A-32, A-35, and A-36, except: Heat Content factors for Unspecified Coal (by sector),Coke, Naphtha (<401 deg. F), and Other Oil (>401 deg. F) (from U.S. Energy Information Administration, *Annual Energy Review 2005* (2006), Tables A-1, A-4, and A-5); Heat Content factors for Coal (by type) and LPG and all factors for Wood and Wood Waste, Landfill Gas, and Wastewater Treatment Biogas (from EPA Climate Leaders, Stationary Combustion Guidance (2004), Tables B-1 and B-2).