

Stationary Fuel Combustion Sources

Final Rule: Mandatory Reporting of Greenhouse Gases

Under the Greenhouse Gas Reporting Program (GHGRP), owners or operators of facilities that emit 25,000 metric tons or more of GHGs per year (expressed as carbon dioxide equivalents) from stationary fuel combustion or that meet any other applicability requirements of the rule (see information sheet on General Provisions) are required to report emissions from stationary fuel combustion. Owners or operators must collect emission data; calculate GHG emissions; and follow the specified procedures for quality assurance, missing data, recordkeeping, and reporting.

How Is This Source Category Defined?

Stationary fuel combustion sources are devices that combust any solid, liquid, or gaseous fuel generally to:

- Produce electricity, steam, useful heat, or energy for industrial, commercial, or institutional use; or
- Reduce the volume of waste by removing combustible matter.

These devices include, but are not limited to, boilers, combustion turbines, engines, incinerators, and process heaters. The rule excludes flares (unless otherwise required by another subpart), portable equipment, emergency generators, emergency equipment, agricultural irrigation pumps, combustion of hazardous waste (except for co-fired fuels), and pilot lights.

Facilities that contain stationary fuel combustion units, but do not contain a source in any other source category covered by the rule, are not required to submit a report if their aggregate maximum rated heat input capacity from all stationary fuel combustion units is less than 30 million British thermal units per hour (mmBtu/hr).

Electricity generating units that are subject to EPA's Acid Rain Program (40 CFR part 75) or that report CO₂ mass emissions year-round through part 75 are covered under 40 CFR part 98, subpart D (Electricity Generation).

What GHGs Must Be Reported?

Facilities must report annual carbon dioxide (CO₂), methane (CH₄), and nitrous oxide (N₂O) emissions from each fuel combustion unit. For each unit, CO₂, CH₄, and N₂O emissions must be reported separately for each type of fuel combusted, including biomass fuels. In addition, facilities report any CO₂ emissions from sorbent use in air pollution control equipment if those emissions are not monitored by a continuous emissions monitoring system (CEMS).

How Should GHG Emissions Be Calculated?

The following methodologies can be used to calculate CO₂, CH₄, and N₂O emissions:

- Calculating CO₂ Emissions from Combustion
Facilities must calculate CO₂ emissions using one of four methodological tiers, subject to certain restrictions based on unit size and fuel combusted (see flow chart on page 3). As an alternative to any of the four tier calculation methodologies, units that report to EPA year-round heat input data under 40 CFR part 75 can calculate annual CO₂ emissions using part 75 methods.

- Tier 1 uses an emission factor that is multiplied by annual fuel use and a default heating value for that fuel.
- Tier 2 uses an emission factor that is multiplied by annual fuel use and a measured heating value of that fuel. Units that combust MSW or other solid fuels and generate steam must use steam production (in place of fuel use) and an emission factor.
- Tier 3 uses a calculation based on annual fuel use, measured carbon content, and, for gaseous fuels, molecular weight.
- Tier 4 requires a CEMS.

In general, reporters are required to calculate GHG emissions only for specific fuels that are listed in the rule (Table C-1), except that units larger than 250 mmBtu/hr also must additionally calculate GHG emissions for any non-listed fuel that provides 10 percent or more of the annual heat input to the unit.

- Calculating N₂O and CH₄ Emissions From Combustion

Most units can use an emission factor that is multiplied by annual fuel use and the high heat value of the fuel (a default high heat value prescribed in the rule can be used if a measured heat value is not available). Units that monitor and report annual heat input according to 40 CFR part 75 requirements will use an emission factor and the measured annual heat input.

- Calculating CO₂ Emissions From Sorbent Use

Fluidized bed boilers and units equipped with a wet flue gas desulfurization system or sorbent injection will use the calculation procedure provided in the rule to estimate CO₂ emissions from sorbent use if those emissions are not measured by a CEMS.

- Calculating Biogenic CO₂ Emissions From Biomass Fuel Combustion

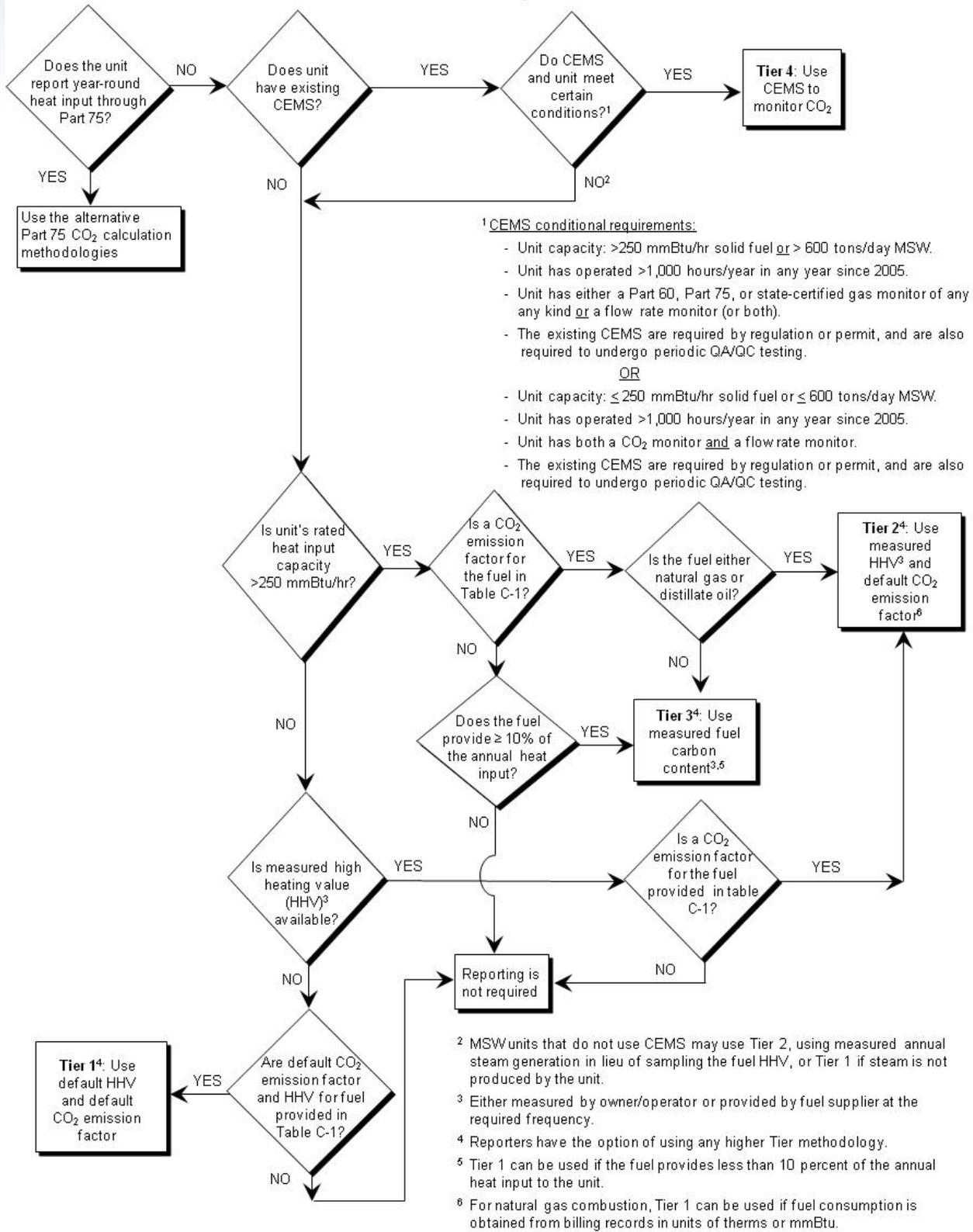
Facilities must estimate CO₂ emissions from the combustion of the biomass fuels listed in the rule. Emissions generally may be estimated using the Tier 1 Calculation Methodology described above. For units that combust municipal solid waste or pre-mixed biomass fuels, the rule provides methods for calculating the biogenic portion of CO₂ emissions.

What Measurements are Required?

Required measurements are determined as follows:

- Annual fuel use can be determined either by use of company records (e.g., billing data, steam generation, unit operating hours) or by direct measurement using flow meters, depending on the size of the unit and the type of fuel burned.
- Depending on the tier calculation method used and the fuel burned, reporters could be required to measure high heating value, molecular weight, or carbon content of fuel. The frequency of fuel sampling and analysis varies depending on the type of fuel combusted, and, may be daily, weekly, monthly, quarterly, semi-annually, or by lot.

General Stationary Fuel Combustion Requirements for CO₂ 40 CFR 98 Subpart C



What Information Must Be Reported?

In addition to the information required by the General Provisions at 40 CFR 98.3(c), the final rule requires facilities to report the following information:

- Annual mass emissions for each GHG for each combustion unit. Emissions can be reported as the aggregated emissions among multiple units under any of the three the following conditions:
 - Groups of units, if each unit has a maximum rated heat input capacity of 250 mmBtu/hr or less.
 - Units that share a common stack and use CEMS.
 - Oil-fired or gas-fired units that combust a common fuel, if the fuel is supplied through a metered common pipe.
- Other information used to verify reported emissions, including the type of combustion unit, the maximum rated heat input capacity (either for the individual unit, the total for all units measured by a CEMS on a common stack or duct, or the highest in a group of units), type of fuel combusted, the tier methodology used, and other information (as applicable for each calculation method used).

EPA temporarily deferred the requirement to report data elements that are used as inputs to emission equations (76 FR 53057, August 25, 2011). Some data elements were deferred until 2013 (Table A-6 of subpart A) and some until 2015 (Table A-7 of subpart A). Facilities, however, are required to retain records of these deferred data elements. The data elements that were deferred until 2013 were required to be reported to EPA by April 1, 2013, for reporting years 2010, 2011, and 2012 (as applicable) as part of the reporting year 2012 submissions. For the current status of reporting requirements for the 2015 inputs to emissions equations, consult the following link:

<http://www.epa.gov/climatechange/emissions/CBI.html>

For More Information

This document is provided solely for informational purposes. It does not provide legal advice, have legally binding effect, or expressly or implicitly create, expand, or limit any legal rights, obligations, responsibilities, expectations, or benefits in regard to any person. The series of information sheets is intended to assist reporting facilities/owners in understanding key provisions of the final rule.

Visit EPA's Web site (www.epa.gov/climatechange/emissions/ghgrulemaking.html) for more information, including the final preamble and rule, additional information sheets on specific industries, the schedule for training sessions, and other documents and tools. For questions that cannot be answered through the Web site, please contact us at: GHGreporting@epa.gov.