



Greenhouse Gas Inventory Guidance

Direct Emissions from Stationary Combustion Sources



December 2023

The U.S. EPA Center for Corporate Climate Leadership’s (The Center) Greenhouse Gas guidance is based on The Greenhouse Gas Protocol: A Corporate Accounting and Reporting Standard (GHG Protocol) developed by the World Resources Institute (WRI) and the World Business Council for Sustainable Development (WBCSD). The Center’s GHG guidance is meant to extend upon the GHG Protocol to align more closely with EPA-specific GHG calculation methodologies and emission factors, and to support the Center’s GHG management tools.

For more information regarding the Center for Corporate Climate Leadership, visit www.epa.gov/climateleadership.

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Section 1: Introduction

Combustion of fuels in stationary combustion sources result in the following greenhouse gas (GHG) emissions: carbon dioxide (CO₂), methane (CH₄), and nitrous oxide (N₂O). Sources of emissions from stationary combustion include boilers, heaters, furnaces, kilns, ovens, flares, thermal oxidizers, dryers, and any other equipment or machinery that combusts carbon bearing fuels or waste stream materials.

This document presents guidance for calculating scope 1 direct GHG emissions resulting from stationary combustion of fuels at owned or leased sources that are within an organization's inventory boundary. This guidance applies to all organizations whose operations involve stationary combustion of fuel.

This document covers the direct emissions from combustion of fuels and does not address the upstream emissions associated with the extraction, production, and transportation of these fuels, which are included in Scope 3, Category 3, fuel- and energy-related activities. For more information on the upstream emissions of purchased fuels, see the EPA's [Scope 3 Inventory Guidance page](#).

1.1 Greenhouse Gases Included

The greenhouse gases CO₂, CH₄, and N₂O are emitted during the combustion of fuels. CO₂ accounts for the majority of the GHG emissions from stationary combustion sources. In the U.S., CO₂ emissions represent more than 99 percent of the total CO₂ equivalent GHG emissions from all commercial, industrial, and electricity generation combustion sources. Emissions from CH₄ and N₂O together represent less than one percent of the total CO₂ equivalent emissions from the same sources.¹

Organizations should account for all CO₂, CH₄, and N₂O emissions associated with stationary combustion. Given the relative emissions contributions of each gas, CH₄ and N₂O emissions are sometimes excluded because organizations may assume these to be not material. However, as outlined in Chapter 1 of the GHG Protocol, the materiality of a source can only be established after it has been assessed. This does not necessarily require a rigorous quantification of all sources, but at a minimum, an estimate based on available data should be developed for all sources and categories of GHGs and included in an organization's GHG inventory.

Emissions of CH₄ and N₂O depend not only upon fuel characteristics, but also on technology type and combustion characteristics, application of pollution control equipment, and ambient environmental conditions. Emissions of these gases also vary with the size, efficiency, and vintage of the combustion technology, as well as maintenance and operational practices. However, the methods used to calculate CO₂ emissions can also be used to calculate emissions of CH₄ and N₂O with reasonable accuracy when applying appropriate CH₄ and N₂O emission factors.

Organizations that wish to examine CH₄ and N₂O emissions from stationary combustion sources in more detail can consult the Intergovernmental Panel on Climate Change (IPCC) Guidelines for National Greenhouse Gas Inventories or [EPA's Compilation of Air Pollutant Emission Factors](#).

¹ See Table 3-7 of U.S. EPA Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2021, EPA 430-R-23-002, April 2023 <https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks-1990-2021>.

1.2 Biomass Fuels

Not all stationary combustion sources burn fossil fuels. Biomass (non-fossil) fuels (e.g., agricultural waste or biomass-derived gases) may be combusted in stationary sources independently or co-fired with fossil fuels. The emission calculation methods discussed in this document can be used to calculate CO₂, CH₄, and N₂O emissions from combustion of these fuels. The GHG Protocol requires that CO₂ emissions from biomass combustion at stationary sources be reported as biomass CO₂ emissions (in terms of total amount of biogenic CO₂ emitted) and be tracked separately from fossil CO₂ emissions. Biomass CO₂ emissions are not included in the overall CO₂ equivalent emissions inventory for organizations following this guidance. CH₄ and N₂O emissions from biomass are included in the overall CO₂ equivalent emissions inventory. There has been increased scientific inquiry into GHG accounting for biomass in energy production. The EPA's Science Advisory Board found that "there are circumstances in which biomass is grown, harvested and combusted in a carbon neutral fashion but carbon neutrality may not an appropriate assumption; it is a conclusion that should be reached only after considering a particular feedstock's production and consumption cycle. There is considerable heterogeneity in feedstock types, sources and production methods and thus net biogenic carbon emissions will vary considerably."² According to the GHG Protocol, "consensus methods have yet to be developed under the GHG Protocol Corporate Standard for accounting of sequestered atmospheric carbon as it moves through the value chain of biomass-based industries," though some general considerations for accounting for sequestered atmospheric carbon are discussed in Chapter 9 and Appendix B of the GHG Protocol.

1.3 Waste-Derived Fuels

Waste-derived fuels in solid, liquid, and gaseous form may be combusted in stationary sources as well. Typical waste-derived fuels include, but are not limited to, used tires, used motor oils, municipal solid waste (MSW), hazardous waste, landfill gas, and byproduct gases. These waste-derived fuels are treated like any other fuels in an organization's inventory. Therefore, any GHG produced from combustion of a fossil-based waste product is reported in an organization's inventory. Any CO₂ emissions from combustion of a biomass waste are treated as biomass CO₂ as described in Section 1.2. This applies to entire waste streams or portions of the waste stream. For example, the CO₂ produced from combusting the biomass portion of MSW (e.g., yard waste, paper products) is reported as biomass CO₂. The CO₂ produced from combusting the fossil portion of the MSW (e.g., plastics) is reported as CO₂ and is included in an organization's inventory.

Emissions from waste-derived fuels only include the actual emissions from the combustion process and do not include any "offsets" from use of the waste-derived fuel.

1.4 Non-Combustion Emission Sources

The combustion of fuel does not account for all GHG emissions related to stationary combustion sources. For example, use of natural gas may result in fugitive methane emissions from leaks in gas transportation lines owned by the organization. Storage of fuels may also result in fugitive emissions. For example, methane is emitted from fuel storage tanks or from coal piles. Typically, these sources are minor compared to combustion emissions; however, organizations should account for these non-combustion sources using guidance specific to the fugitive emissions for their sector.

² EPA Science Advisory Board Review of the 2011 Draft Accounting Framework for CO₂ Emissions for Biogenic Sources Study. 2012. <https://yosemite.epa.gov/sab/sabproduct.nsf/0/2F9B572C712AC52E8525783100704886?OpenDocument>.

Section 2: Calculating Emissions

There are two main methods for estimating GHG emissions from stationary combustion sources:

- Direct measurement
- Analysis of fuel input

Direct measurement of CO₂ emissions is performed using a Continuous Emissions Monitoring System (CEMS). Fuel analysis is essentially a mass balance approach in which carbon content factors are applied to fuel input to determine emissions. Both methods are described in more detail in the following sections.³

For both the CEMS and fuel analysis approaches, it is recommended that organizations calculate emissions by facility as opposed to aggregated entity-wide emissions only. This method increases the accuracy and credibility of the inventory.

2.1 Continuous Emissions Monitoring System (CEMS) Method

Continuous emissions monitoring is the continuous measurement of pollutants emitted into the atmosphere in exhaust gases from combustion or industrial processes. Several U.S. EPA regulatory programs (e.g., Acid Rain Program, New Source Performance Standards, Greenhouse Gas Reporting Program [GHGRP], and Maximum Available Control Technology Standards) have provisions regarding CEMS.

CEMS can be used to measure CO₂ emissions during the reporting year. Title IV of the U.S. Clean Air Act requires owners or operators of electricity generating units to report CO₂ emissions from affected units under the Acid Rain Program. 40 CFR Part 75, which establishes requirements for the monitoring, recordkeeping, and reporting from affected units under the Acid Rain Program, outlines two approaches for determining CO₂ emissions using CEMS:

- A monitor measuring hourly average CO₂ (or O₂) concentration percent by volume of flue gas and a flow monitoring system measuring the volumetric flow rate of flue gas can be used to determine CO₂ mass emissions. Annual CO₂ emissions are determined by aggregating the hourly CO₂ mass emissions.
- A monitor measuring O₂ concentration percent by volume of flue gas combined with theoretical CO₂ and flue gas production based on fuel characteristics can be used to determine CO₂ flue gas emissions and CO₂ mass emissions. Annual CO₂ emissions are determined based on the operating time of the unit.

40 CFR Part 98 also includes these same two approaches for organizations that use a CEMS to report to the GHGRP. If an organization has reported quality assured CO₂ emissions data from one of the above CEMS approaches to satisfy their Title IV or GHGRP requirements, it is recommended that they report these same CO₂ emissions in their GHG inventory. Organizations that collect CO₂ emissions data from a CEMS that does not conform to the specific requirements prescribed under 40 CFR Part 75 or 40 CFR Part 98, and organizations with no CEMS installed, should use the fuel analysis methods outlined in Section 2.2 below. Because a CEMS cannot be used to calculate CH₄ and N₂O emissions, organizations should use the fuel analysis method for those emissions. A CEMS may not measure all stationary combustion emissions from an

³ Units reporting CO₂ emissions under the Acid Rain Program or GHGRP, through either the CEMS or fuel analysis approach, are required to include CO₂ emissions from sorbent use (e.g., limestone used in flue gas desulfurization equipment). Organizations not required to report under these programs should be sure to include any CO₂ emissions from sorbent use in their GHG inventory. Procedures to calculate these emissions are outlined in 40 CFR Part 75 Appendix G, Section 3 and 40 CFR Part 98, Subpart C.

emissions source, for example, if the facility has a heat recovery system generator, a duct burner, or other combustion equipment. In this case, organizations should use the fuel analysis method to estimate emissions not measured by the CEMS.

2.2 Fuel Analysis Method

The fuel analysis method to calculate CO₂ emissions involves determining the carbon content of fuel combusted using either fuel-specific information or default emission factors and applying that carbon content to the amount of fuel burned during the reporting year.

For affected units under the Acid Rain Program, Appendix G of 40 CFR Part 75 describes fuel analysis methods for calculating CO₂ emissions based on the measured carbon content of the fuel, adjusted for any unburned carbon, and the amount of fuel combusted. For organizations that report under the GHGRP, Subpart C of 40 CFR Part 98 describes fuel analysis methods applicable to that program.

If an organization is measuring and reporting GHG emissions under their Title IV or GHGRP requirements using the fuel analysis methods outlined in 40 CFR Part 75 or 40 CFR Part 98, it is recommended that they report these same emissions in their organizational GHG inventory.

For organizations not reporting GHG emissions under the Acid Rain Program or GHGRP, this guidance provides a fuel analysis method to calculate their GHG emissions. One of three equations below can be used in the fuel analysis method to calculate CO₂ emissions for each type of fuel combusted. Two of these equations can also be used to calculate CH₄ and N₂O emissions using appropriate emission factors. The appropriate equation to use depends on what is known about the characteristics of the fuel being consumed.

Equation 1 is recommended when fuel consumption is known only in mass or volume units, and no information is available about the fuel heat content or carbon content. This equation is the least preferred. It has the most uncertainty because its emission factors are based on default fuel heat content, rather than actual heat content.

Equation 1:

$$\text{Emissions} = \text{Fuel} \times \text{EF}_1$$

Where:

Emissions = Mass of CO₂, CH₄, or N₂O emitted

Fuel = Mass or volume of fuel combusted

EF₁ = CO₂, CH₄, or N₂O emission factor per mass or volume unit

Equation 2 is recommended when the actual fuel heat content is provided by the fuel supplier or is otherwise known. It is also recommended when the fuel use is provided in energy units (e.g., therms of natural gas). In such cases, the fuel use in energy units can be multiplied directly by the emission factor (EF₂). Equation 2 is a preferable approach over Equation 1

Equation 2:

$$\text{Emissions} = \text{Fuel} \times \text{HHV} \times \text{EF}_2$$

Where:

$$\text{Emissions} = \text{Mass of CO}_2, \text{CH}_4, \text{ or N}_2\text{O emitted}$$

$$\text{Fuel} = \text{Mass or volume of fuel combusted}$$

HHV = Fuel heat content (higher heating value), in units of energy per mass or volume of fuel

EF₂ = CO₂, CH₄, or N₂O emission factor per energy unit

because it uses emission factors that are based on energy units as opposed to mass or volume units. Emission factors based on energy units are less variable than factors per mass or volume units because the carbon content of a fuel is more closely related to the heat content of the fuel than to the physical quantity of fuel.

Equation 3 is recommended to calculate CO₂ emissions when the actual carbon content of the fuel is known. Carbon content is typically expressed as a percentage by mass, which requires fuel use data in mass units. This equation is most preferred for CO₂ calculations because CO₂ emissions are directly related to the fuel's carbon content. Because Equation 3 is only applicable to CO₂ emissions, Equation 1 or 2 should be used in conjunction to calculate CH₄ and N₂O emissions.

Equation 3:

$$\text{Emissions} = \text{Fuel} \times \text{CC} \times 44/12$$

Where:

$$\text{Emissions} = \text{Mass of CO}_2 \text{ emitted}$$

$$\text{Fuel} = \text{Mass or volume of fuel combusted}$$

CC = Fuel carbon content, in units of mass of carbon per mass or volume of fuel

44/12 = ratio of molecular weights of CO₂ and carbon

Follow the steps below to calculate emissions.

Step 1: Select the appropriate equation.

Based on the information available on the characteristics of the fuel being consumed, select the appropriate equation to use in calculating emissions. See the discussion above on the three possible equations.

Step 2: Determine the amount of fuel combusted.

Each fuel type should be quantified separately. This can be based on fuel receipts, purchase records, or through direct measurement at the combustion device. If purchase records are used, care should be taken to subtract out any fuel used to

produce feedstocks or materials such as plastics where the carbon is ultimately stored. Section 3 describes in more detail the different sources that can be used to determine the amount of fuel combusted and the possible units in which fuel combustion may be measured.

Step 3: Determine equation inputs.

The selected equation specifies which inputs are needed to calculate emissions. As appropriate, determine the quantity of fuel combusted, fuel carbon content, fuel heat content, and emission factors associated with each fuel consumed. Further guidance is given in Section 3.

Step 4: Calculate emissions.

Use the appropriate equation with the fuel consumption and other equation inputs to calculate the emissions of CO₂, CH₄, and N₂O. Multiply the emissions of CH₄ and N₂O by the respective global warming potential (GWP) to calculate CO₂ equivalent emissions. For GWP values, see the latest release of the EPA's [GHG Emission Factors Hub](#). Sum the CO₂ equivalent emissions from CH₄ and N₂O with the emissions of CO₂ to calculate the total CO₂ equivalent (CO₂e) emissions.

Example Emissions Calculation

An organization has an on-site natural gas boiler. The organization does not meter the gas that enters the boiler directly. However, the organization does have a record of the natural gas utility bills for the reporting year in question. The bills list the amount of fuel purchased in terms of energy (e.g., therms) as well as the cubic feet of gas purchased and the heating value of the gas. It is assumed that there are no fugitive releases of gas, there is no inventory of natural gas stored on-site, and that all the natural gas purchased is combusted (i.e., no feedstock use of gas). The following information is available from the fuel supplier:

Table 1: Example Emissions Calculation

Month	Amount of Gas Purchased (scf)	Heat Content (Btu/scf)	Amount of Gas Purchased (therms)
January	550,000	1,025	5,637.5
February	580,000	1,025	5,945
March	530,000	1,025	5,432.5
April	480,000	1,025	4,920
May	500,000	1,025	5,125
June	490,000	1,025	5,022.5
July	510,000	1,025	5,227.5
August	390,000	1,025	3,997.5
September	480,000	1,025	4,920
October	540,000	1,025	5,535
November	490,000	1,025	5,022.5
December	460,000	1,025	4,715
Total	6,000,000		61,500

Note: scf = standard cubic feet, 1 therm = 100,000 Btu

Step 1: The amount of fuel combusted has been determined based on purchase data on utility bills from the supplier.

Step 2: Carbon content is not known, so Equation 3 cannot be used. Sufficient information is available to use either Equation 1 or 2, because fuel consumption and actual fuel heat content are available. Equation 2 is selected because this is the preferred approach if the actual fuel heat content is known.

Step 3: Fuel heat content has been provided by the supplier. EPA's [GHG Emission Factors Hub](#) is used to determine the emission factors per energy unit for natural gas: 53.06 kg CO₂/mmBtu, 1.0 g CH₄/mmBtu, 0.10 g N₂O/mmBtu.

Step 4: The emissions are calculated as follows:

Natural use is converted to mmBtu: 61,500 therms × 0.1 mmBtu/therm = 6,150 mmBtu

Because fuel use is known in energy units, it can be multiplied directly by emission factors:

6,150 mmBtu × 53.06 kg CO₂/mmBtu × 10⁻³ metric tons/kg = 326.3 metric tons CO₂

$$6,150 \text{ mmBtu} \times 1.0 \text{ g CH}_4/\text{mmBtu} \times 10^{-3} \text{ kg/g} = 6.15 \text{ kg CH}_4$$

$$6,150 \text{ mmBtu} \times 0.10 \text{ g N}_2\text{O}/\text{mmBtu} \times 10^{-3} \text{ kg/g} = 0.615 \text{ kg N}_2\text{O}$$

CH₄ and N₂O emissions are converted to CO₂ equivalent emissions⁴:

$$6.15 \text{ kg CH}_4 \times 28 \text{ GWP} \times 10^{-3} \text{ metric tons/kg} = 0.2 \text{ metric tons CO}_2\text{e}$$

$$0.615 \text{ kg N}_2\text{O} \times 265 \text{ GWP} \times 10^{-3} \text{ metric tons/kg} = 0.2 \text{ metric tons CO}_2\text{e}$$

The CO₂e emissions from CH₄ and N₂O are summed with the emissions of CO₂ to calculate total CO₂e emissions:

$$326.3 \text{ metric tons CO}_2 + 0.2 \text{ metric tons CO}_2\text{e} + 0.2 \text{ metric tons CO}_2\text{e} = 326.7 \text{ metric tons CO}_2\text{e}$$

⁴ This calculation uses GWP values from the IPCC's Fifth Assessment Report (AR5). These will be incorporated into the GHG Emission Factors Hub in the 2024 release.

Section 3: Choice of Activity Data and Emission Factors

This section discusses choices of activity data and factors used for calculating emissions with the default fuel analysis method provided in Section 2.2. This guidance has been structured to accommodate a wide range of organizations with varying levels of information and measurements in various units. If the organization has a CEMS installed or has carbon content data based on fuel sampling information, it should refer to guidance in 40 CFR Part 75 or 40 CFR Part 98 to calculate CO₂ emissions.

3.1 Activity Data Sources

When calculating GHG emissions with the fuel analysis method, the first piece of information that needs to be determined is the quantity of fuel combusted for each fuel type during the reporting year. One method of determining the amount of fuel combusted at a facility is to measure the fuel input into each combustion device and to sum the measured data of each combustion device in the facility. Typical fuel measurement systems measure the volume of fuel combusted, such as fuel flow meters for natural gas and fuel oil, or the weight of fuel combusted, such as coal feed belt scales.

If fuel use data are not directly measured, then fuel purchase records can be used to determine the amount of fuel combusted. Records could include monthly utility bills for natural gas or periodic invoices for deliveries of fuel oil. If a particular fuel type is used for both stationary and mobile sources, care should be taken to avoid double counting the fuel use.

Commodity natural gas may be purchased from a provider other than the local distribution utility. In this situation, the reporting organization may receive natural gas invoices from both the commodity supplier as well as from the local distribution utility, who charges a fee for gas deliveries. It is recommended that the consumption from the local utility be used as the activity data, because this is based on fuel meters located at the organization's facility. To avoid counting the same consumption twice, ensure that consumption from the commodity supplier is not also included in the activity data.

There are several factors that could lead to differences between the amount of fuel purchased and the amount of fuel combusted during a reporting period, for example:

- Changes in fuel storage inventory
- Fuel used as feedstock
- Fugitive releases or fuel spills

For changes in fuel storage inventory, Equation 4 can be used to calculate actual fuel use. Fuel purchase data are usually reported as the amount of fuel provided by a supplier as it crosses the gate of the facility. However, once fuel enters the facility there could be some losses before it reaches the combustion device. Before calculating emissions, organizations should subtract the amount of fuel lost in fugitive releases or spills from the amount of fuel purchased. These losses are particularly important for natural gas, which could be lost due to fugitive releases from facility valves and piping, as these

Equation 4: Accounting for Changes in Fuel Inventory

$$\text{Fuel B} = \text{Fuel P} + (\text{Fuel S}_T - \text{Fuel S}_E)$$

where:

Fuel B = Fuel burned in reporting period

Fuel P = Fuel purchased in reporting period

Fuel S_T = Fuel stock at start of reporting period

Fuel S_E = Fuel stock at end of reporting period

fugitive emissions could be significant. These fugitive natural gas releases represent fugitive methane emissions that should be accounted for separately from combustion emissions.

Purchased fuels could also be used as feedstock for products produced by the reporting organization. In this case the carbon in the fuel would be stored in the product as opposed to being released through combustion. In their scope 1 emissions, organizations only include direct emissions from their facilities. If carbon leaves the facility stored in a product, even if the product is subsequently burned or otherwise releases the stored carbon, this would be included in an organization's scope 3 emissions, not their scope 1 emissions. Therefore, organizations should subtract any amount of fuel that is used as feedstock from the amount of fuel purchased before calculating scope 1 emissions.

For certain equipment, such as emergency generators, gathering fuel consumption data through direct measurement or based on fuel purchases may not be practical. If such equipment generally represents an insignificant source of GHG emissions, an acceptable method to estimate fuel consumption is to multiply measured or estimated operating hours by the hourly fuel consumption rate.

If fuel consumption data are not available for certain facilities or operations, an estimate should be made for completeness. The fraction of total GHG emissions that is estimated should be limited so as not to have a significant impact on accuracy. If the organization is one of many tenants in a facility and does not have the actual amount of fuel used in its space, the organization may estimate its fuel consumption by multiplying the fuel use of the entire facility by the percentage of the floor area that the organization occupies. Organizations may also estimate fuel consumption using published values for average energy consumption per square foot of floor area. For example, such values are provided by the U.S. Energy Information Administration's Commercial Building Energy Consumption Survey.

3.2 Activity Data Units

Fuel is measured in terms of physical units (i.e., mass or volume). For organizations that directly measure their own fuel consumption, it is recommended that they track fuel use in terms of these physical units as they represent the primary measurement data. Organizations that do not directly measure how much fuel they use need to rely on data from fuel suppliers. Suppliers may provide data in physical units or in energy units (e.g., therms of natural gas). Suppliers may also be able to provide data on carbon content or heat content of the fuel, which is discussed further in Section 3.3.

It is possible that organizations may only know the cost of fuels purchased. This is the least accurate method of determining fuel use and is not recommended for GHG reporting. If the amount spent on fuel is the only information initially available, it is recommended that organizations contact their fuel supplier to request data in physical or energy units. If no other information is available, organizations should use fuel prices to convert the amount spent to physical or energy units and should document the prices used. Price varies widely for specific fuels, especially over the geographic area and timeframe typically established for reporting GHG emissions.

The approaches for measuring or recording the amount of fuel used are listed in order of preference below.

1. An organization has fuel consumption data by fuel type in terms of physical units either measured on site or provided by a supplier with accurate data on carbon content of the specific fuel as determined by the fuel supplier or by fuel sampling and analysis (see Section 3.3).
2. An organization has fuel consumption data by fuel type in terms of physical units with accurate data on heat content of the specific fuel as determined by the fuel supplier or by fuel sampling and analysis (see Section 3.3). Alternatively, organization has fuel consumption data from the supplier in energy units.

3. An organization has data on the physical quantity of fuel purchased but not the carbon or heat content.
4. An organization only has data on cost of fuels purchased and must convert to physical quantity based on dividing total expenditures by average prices.

3.3 Fuel Carbon Content and Heat Content

Emissions of CO₂ from fuel combustion are dependent on the amount of carbon in the fuel, which is specific to the fuel type and grade of the fuel. It is recommended that organizations determine the actual carbon content of the fuels consumed, if possible. The most accurate method to determine a fuel's carbon content data is through chemical analysis of the fuel. This data may be obtained directly from the fuel supplier.

Carbon content can also be determined by fuel sampling and analysis. Fuel sampling and analysis should be performed periodically with the frequency dependent on the type of fuel. The sampling frequency should be greater for more variable fuels (e.g., coal, wood, MSW) than for more homogenous fuels (e.g., natural gas, fuel oil). The sampling and analysis methodologies used should be detailed in the organization's Inventory Management Plan (IMP). Refer to 40 CFR Part 75, Appendix G or 40 CFR Part 98, Subpart C for recommended sampling rates and methods.

If actual fuel carbon content is available, either from the supplier or from sampling and analysis, Equation 3 in Section 2.2 may be used to calculate CO₂ emissions. Because Equation 3 is only applicable to CO₂ emissions, Equation 1 or 2 should be used in conjunction to calculate CH₄ and N₂O emissions. It is also good practice to track the carbon content values used and to indicate if they vary over time.

If carbon content is not available, it is recommended that organizations determine the actual heat content of the fuel, if possible. The heat content of purchased fuel is often known and provided by the fuel supplier because it is directly related to the useful output or value of the fuel. Heat content can also be determined by fuel sampling and analysis, using methods discussed above. It is recommended that organizations use heat contents determined by one of these methods rather than default heat content, as these should better represent the characteristics of the specific fuel consumed. If actual fuel heat content is available, either from the supplier or from sampling and analysis, then Equation 2 in Section 2.2 may be used to calculate CO₂, CH₄, and N₂O emissions. It is also good practice to track the heat content values used and to indicate if they vary over time.

When determining fuel heat content or tracking fuel use data in energy units, it is important to distinguish between lower heating values (LHV) and higher heating values (HHV), also called net calorific value and gross calorific value, respectively. Heating values describe the amount of energy released when a fuel is burned completely, and LHV and HHV are different methods to measure the amount of energy released. A given fuel, therefore, always has both a LHV and a HHV. The LHV assumes that the steam released during combustion remains as a gas. The HHV assumes that the steam is condensed to a liquid, thus releasing more energy. HHV is typically used in the U.S. and in Canada, while other countries typically use LHV.

All emission factors and default heat content values in the EPA [GHG Emission Factors Hub](#) are based on HHV. Therefore, if fuel consumption is measured in LHV units, this must be converted to HHV before calculating emissions. To convert from LHV to HHV, a simplified convention used by the International Energy Agency can be used. For coal and petroleum⁵, divide energy in LHV by 0.95. For natural gas⁶, divide by 0.90.

⁵ Oil Information, [Database documentation](#), page 103. 2023 Edition. International Energy Administration (IEA).

⁶ Natural Gas Information, [Database documentation](#), page 63. 2023 Edition. International Energy Administration (IEA).

3.4 Emission Factors

If actual fuel carbon content is not available, the fuel analysis method for calculating emissions relies on default emission factors. These factors approximate the carbon content of fuel to quantify the amount of CO₂ that will be released when the fuel is combusted. Emission factors also assume typical combustion technology to quantify the amount of CH₄ and N₂O that will be released.

Stationary combustion emission factors are available in Table 1 of EPA's [GHG Emission Factors Hub](#). This includes factors defined per unit of fuel mass or volume and factors defined by per unit of fuel energy content. As discussed in Section 2.2, using the emission factors per energy unit, along with Equation 2, is preferable to using emission factors per mass or volume.

It is recommended that organizations use the newest emission factors available at the time they calculate emissions for a reporting year.⁷ Emission factors are based on fuel characteristics. At times, there may be changes in the methodology used to develop emission factors. These methodology changes are noted in the GHG Emission Factors Hub and should be applied like other methodology changes in the organization's GHG inventory. In such cases, prior years' emissions should be adjusted in a manner consistent with the organization's base year adjustment policy.

Not all stationary combustion devices burn standard fuels. Combustion devices could also burn waste fuels, such as MSW, with mixed biomass and fossil carbon content. Flares and thermal oxidizers could burn waste gas streams. These combustion sources and waste fuels are treated like other combustion sources and fuel types. If the carbon content of the waste fuel is known, Equation 3 can be used to quantify emissions. If the carbon content is not known, determining the appropriate emission factors can be challenging due to the variability and non-standardized nature of waste fuels. Emission factors are provided in the [GHG Emission Factors Hub](#) for waste fuels such as MSW, tires, and used oil. For more complex waste gas streams, an example calculation is provided below. If none of these options are possible, an organization can use the emission factor for a fuel that most closely represents the waste fuel.

Example: Determining an Emission Factor for a Gas Waste Stream

An organization has a thermal oxidizer destroying a waste gas stream of different components. The organization has data on volume of gas combusted and on the mole fraction of the different components of the waste gas stream.

The first step is to determine the total number of moles in the waste stream per a specific volume. This step is based on the assumed temperature and pressure of the gas. Assuming conditions of 1 atm and 25° C, there are 2.55 x 10⁻³ lb-mole of gas per cubic foot of gas. This factor could be adjusted to meet the specific temperature and pressure conditions of the organization's waste gas stream. An emission factor is then determined per cubic feet of gas based on the following Equation 5.

Table 2 shows an example gas waste stream with the mole fractions of different components.

Equation 5: Determining Emission Factor for Gas Waste Stream

$$\text{Emission Factor} \left(\frac{\text{lb C}}{\text{ft}^3 \text{ gas}} \right) = \sum_{i=1}^n \text{MF}_i \times \text{MC}_{\text{gas}} \times \text{m.w.}_i \times \text{CF}_i$$

Where:

$$\text{MF}_i = \text{Molar fraction of gas component } i \left(\frac{\text{lb-mole } i}{\text{lb-mole gas}} \right)$$

$$\text{MC}_{\text{gas}} = \text{Molar concentration of gas} \left(\frac{\text{lb-mole gas}}{\text{ft}^3 \text{ gas}} \right)$$

$$\text{m.w.}_i = \text{Molecular weight of gas component } i \left(\frac{\text{lb } i}{\text{lb-mole } i} \right)$$

$$\text{CF}_i = \text{Carbon fraction of gas component } i \left(\frac{\text{lb C}}{\text{lb } i} \right)$$

⁷ This applies whether an organization uses a calendar year period or other period for their GHG Inventory. For example, if an organization is calculating a GHG Inventory in August for a July through June reporting year, the inventory should use the newest factors available in August.

Gas Component	MF	MC	m.w.	CF	Lb C / ft ³ gas
CO ₂	5%	2.55×10^{-3}	44	27%	0.0015
CH ₄	30%	2.55×10^{-3}	16	75%	0.0092
C ₃ H ₈	20%	2.55×10^{-3}	44	82%	0.018
C ₆ H ₆	35%	2.55×10^{-3}	78	92%	0.064
Other non-C	10%	2.55×10^{-3}	-	0%	0.0
Total	100%	-	-	-	0.093

As calculated in Table 2 the emission factor for this example gas waste stream is 0.093 lb C per ft³ of waste gas. To obtain total CO₂ emissions from this waste gas combustion, the emission factor can be multiplied by the total amount of gas combusted and by 44/12, the ratio of the molecular weights of CO₂ and carbon.

Section 4: Completeness

For an organization's GHG inventory to be complete, it must include all emission sources within the organization's chosen inventory boundaries. See Chapter 3 of the GHG Protocol for detailed guidance on setting organizational boundaries and Chapter 4 of the GHG Protocol for detailed guidance on setting operational boundaries of the inventory.

On an organizational level, the inventory should include emissions from all applicable facilities or fleets of vehicles. Completeness of organization-wide emissions can be checked by comparing the list of sources included in the GHG emissions inventory with those included in other emissions inventories, environmental reporting, financial reporting, etc.

At the operational level, an organization should include all GHG emissions from the sources included in their inventory. Possible GHG emission sources are stationary fuel combustion, combustion of fuels in mobile sources, purchases of electricity, emissions from air conditioning equipment, and process or fugitive emissions. Organizations may refer to this guidance document for calculating emissions from stationary combustion sources and to the Center's GHG Guidance documents for calculating emissions from other sources. Operational completeness of stationary combustion sources can be checked by comparing the sources included in the GHG inventory with those reported under regulatory programs (e.g., Title V air permit), or in annual fuel use surveys. Examples of types of fuel combustion sources that should be included are as follows:

- Boilers/furnaces
- Internal combustion engines
- Turbines
- Flares
- Process heaters/ovens
- Incinerators
- Cooling systems (e.g., natural gas chillers)

As described in Chapter 1 of the GHG Protocol, there is no materiality threshold set for reporting emissions. The materiality of a source can only be established after it has been assessed. This does not necessarily require a rigorous quantification of all sources, but at a minimum, an estimate based on available data should be developed for all sources.

Section 5: Uncertainty Assessment

There is some level of uncertainty associated with all methods of calculating GHG emissions. It is recommended that organizations attempt to identify the areas of highest uncertainty in their emissions calculations and consider options for improving the quality of this data in the future.

If the CEMS approach is used to calculate emissions, it is recommended that the organization follow the QA/QC recommendations and requirements outlined in 40 CFR Part 98. Entities utilizing CEMS to comply with Clean Air Act regulations are required to develop a quality assurance plan. This plan should address CO₂ emissions measurement.

The accuracy of calculating emissions from fuel combustion in stationary sources from the fuel analysis method is partially determined by the availability of data on the amount of fuel consumed or purchased. If the amount of fuel combusted is directly measured or metered before entering the combustion device, then the resulting uncertainty should be low. Data on the quantity of fuel purchased should also be a fairly accurate representation of fuel combusted, provided that any necessary adjustments are made for changes in fuel inventory, fuel used as feedstock, fugitive releases, or spills. Uncertainty will be higher if only prices of fuels purchased are used to estimate fuel consumption, or if an estimation approach is used.

The accuracy of calculating emissions from stationary combustion sources with the fuel analysis method is also determined by the factors used to convert fuel use into emissions. Uncertainty in the factors arises primarily because they are national averages and do not reflect the variability in fuel sources. For example, carbon content factors for coal vary greatly, depending on its characteristics, chemical properties, and annual fluctuations in the fuel quality. Therefore, using the U.S. default emission factors for coal may result in greater uncertainty than for other fuels if the local fuel supplies do not match the default fuel characteristics.

Section 6: Documentation

To ensure that emissions calculations are transparent and verifiable, the documentation sources listed in Table 3 should be maintained. These documentation sources should be collected to ensure accuracy and transparency, and should also be included in the organization's Inventory Management Plan (IMP).

Table 3: Documentation Sources for Stationary Combustion

Data	Documentation Source
Fuel consumption data	Purchase receipts or utility bills; delivery receipts; contract purchase or firm purchase records; stock inventory documentation; metered fuel documentation
Heat contents and carbon contents used other than defaults provided	Purchase receipts or utility bills; delivery receipts; contract purchase or firm purchase records; other documentation from suppliers; EIA, EPA, or industry reports
Prices used to convert cost of fuels purchased to amount or energy content of fuel consumed	Purchase receipts; delivery receipts; contract purchase or firm purchase records; EIA, EPA, or industry reports
All assumptions made in calculating fuel consumption, heat contents, and emission factors	All applicable sources

Section 7: Inventory Quality Assurance and Quality Control (QA/QC)

Chapter 7 of the GHG Protocol provides general guidelines for implementing a QA/QC process for all emissions calculations. For stationary combustion sources, activity data and emission factors can be verified using a variety of approaches:

- Fuel consumption data by source or facility can be compared with fuel purchasing data, accounting for any changes in inventory.
- Fuel energy use data can be compared with data provided to the U.S. Department of Energy or other U.S. Environmental Protection Agency reports or surveys.
- CEMS emissions data can be compared to emissions calculated using the fuel analysis method.
- If any emission factors were calculated or obtained from the fuel supplier, these factors can be compared to U.S. average emission factors.
- The rate at which suppliers change/update heating values can be examined to approximate accuracy.
- Depending on the end-use, some non-energy uses of fossil fuels, such as for manufacturing plant feedstocks, can result in long term storage of some or all of the carbon contained in the fuel. This guidance addresses fuel use for combustion purposes only. Therefore, all fuel consumption for other purposes should be excluded from this analysis.
- Examining the quality control associated with equipment used for facility level fuel measurements and equipment used to calculate site-specific emission factors, or emissions.