

CHAPTER 13: COMMON CALCULATION METHODS

(Guidance for Regulation Section 95125)

The sector-specific reporting requirements described in chapters 7-12 require application of specific calculation methods that often apply to multiple types of facilities. In the regulation these methods are contained in section 95125. This chapter provides explanation and examples of the requirements of section 95125.

13.1 Method for Calculating CO₂ Emissions from Fuel Combustion Using Default Emission Factors and Default Heat Content, Section 95125(a)

Section 95125(a) of the GHG reporting regulation provides the methods and requirements for calculating CO₂ emissions from combustion sources using default emission factors. These factors are provided in Appendix A of the regulation. If using emission factors for calculating CO₂ emissions, only these factors may be used.

The use of default emission factors is limited to certain facility types, as specified within the regulation and summarized in Table 13.1. When using section 95125(a), the heat content values and emission factors provided in Tables 4 and 5 in Appendix A of the regulation must be used. If you choose to use measured fuel heat content values specific to your facility, rather than the regulation Appendix A defaults, then refer to section 95125(c), which includes methodologies and frequencies for fuel high heat sampling.

Table 13.1 Applicability of Section 95125(a) Default Emission Factors

Source Category	When Default Emission Factors Can Be Used
General Stationary Combustion (§95115)	CO ₂ emissions from any fuel combustion for facilities not identified as crude oil or natural gas production facilities
Cement Plants (§95110)	CO ₂ emissions from biomass solids combustion, including the biomass component of mixtures
Electrical Generating Facilities & Retail Providers (§95111) and Cogeneration Facilities (§95112)	CO ₂ emissions from start-up fuels used at biomass fueled facilities
Cogeneration Facilities (§95112)	CO ₂ emissions when completing an abbreviated GHG emissions data report for cogeneration.

The purpose of this chapter is to provide guidance on the requirements of section 95125 of the mandatory GHG reporting regulation. As described more specifically in Chapter 1 of this document, this guidance does not add to, substitute for, or amend the regulatory requirements as written in these or other sections of the regulation [Subchapter 10, Article 2, sections 95100 to 95133, title 17, California Code of Regulations].

Source Category	When Default Emission Factors Can Be Used
Refineries (\$95113)	CO ₂ from combustion of distillate oil, diesel fuel, gasoline, kerosene (middle distillate), liquefied petroleum gas (LPG), No. 1, No. 2, No. 4, No. 5, No. 6 fuels, and residual fuel oils
Hydrogen Plants (\$95114)	Same as Refineries

13.1.1 Inputs for Estimating Emissions

To estimate emissions using the emission factors in the regulation, the key data needed is the amount of fuel consumed, by fuel type, for the facility over the course of the year being reported. This includes any reportable fuel consumed during the inventory year. For many facilities this information can be easily compiled from invoices provided by fuel suppliers. Or, facility fuel measurement devices can be used to quantify fuel use, as long as the equipment meets the fuel measurement accuracy requirements in section 95103(a)(9) of the regulation. When the fuel is manufactured on-site, as with refineries, then this fuel use must also be quantified and reported.

Once the annual fuel use data has been collected for each fuel combusted, the next step is to use the information in Appendix A of the regulation to compute the fuel combustion CO₂ emissions. The specific equation within section 95125(a) of the regulation is below:

Equation 1

$$CO_2 = \text{Fuel Combusted} * HHV_D * EF_{CO_2} * 0.001$$

Where:

CO_2 = CO₂ emissions from a specific fuel type, metric tonnes CO₂ per year

$Fuel$ = Mass or volume of fuel combusted specified by fuel type, units of mass or volume per year

HHV_D = Default high heat value specified by fuel type supplied by ARB, MMBtu per unit of mass or volume

EF_{CO_2} = Default carbon dioxide emission factor provided in Appendix A, kg CO₂ per MMBtu

0.001 = Factor to convert kg to metric tonnes

The quantity of fuel burned is the first input to the equation. The default high heat values and emission factors are obtained from Appendix A, Tables 4 and 5. It is important that the amount of fuel consumed for each specific fuel used in stationary combustion operations be reported, along with the associated emissions for the fuel combusted. The emissions of CO₂ from fuel consumption by mobile sources (cars, trucks, tractors, etc.) and portable equipment are not required to be reported, but they may be included at the option of the operator in the emissions data report. (See the guidance for section 95125(i) in this chapter for reporting mobile sources.)

13.1.2 Steps for Computing GHG Emissions

Below are the steps for computing CO₂ emissions from stationary combustion activities at a general stationary combustion (GSC) facility or another facility eligible to use this method. Examples of computing emissions for various fuel types follow.

Step 1 - Collect Facility Fuel Use Data.

Based on a combination of fuel invoices and on-site measurements, the facility has the following annual fuel usage:

Natural Gas (pipeline, 1050 Btu/scf)	2,500,000 therms/year for 2008
Coal (bituminous)	4,050 short tons/year for 2008
Diesel (distillate fuel oil)	10,000 gallons/year for 2008
Municipal Solid Waste (MSW)	1,800 short tons/year for 2008
Tires	300 short tons/year for 2008 (burned with MSW)

Because emissions reporting is on a calendar year basis, it may be necessary to subdivide fuel use between months if invoices do not exactly end and begin on December 31st and January 1st, respectively. Refer to the guidance for section 95125(k) in this chapter for an example of dividing fuel use between December and January.

For simplicity, in this example we consolidated the fuel use for each fuel type into a single value. During actual reporting, the fuel use would be subdivided and reported at the individual meter level, if available (section 95103(a)(2)). For example, if the natural gas combustion was from two separately metered boilers, the fuel use would be separately reported. The respective boiler emissions data do not need to be reported at the meter level, but can be consolidated up to the fuel-type level, which is the example shown here.

Step 2 - Identify Emission Factors and High Heat Values.

With the types and quantity of fuel compiled in step 1, the next step is to refer to regulation Appendix A, Tables 4 and 5, to identify the appropriate fuel-specific emission factors and heat values. These values are shown below in Table 13.1.2. Note that for natural gas a series of emission factors is provided in the appendix. If the average annual high heat value (HHV) for the natural gas used is available from the fuel supplier or other source, select the most appropriate emission factor. If the HHV is not available, then use the “Unspecified” natural gas emission factor.

Table 13.1.2 Summary of Fuel Used and Emission Factors

<i>Fuel</i>	<i>Quantity Consumed</i>	<i>High Heat Value (MMBtu/Unit)</i>	<i>EF (heat units)</i>
Natural Gas	2,500,000 therms	1050 Btu/scf (from supplier)	53.42 kg CO ₂ /MMBtu
Coal (bituminous)	4,050 short tons	24.93 MMBtu/short ton	93.40 kg CO ₂ /MMBtu

Diesel (distillate)	10,000 gallons	5.825 MMBtu/barrel	73.1 kg CO ₂ /MMBtu
MSW	1,800 short tons	8.7 MMBtu/short ton	90.65 kg CO ₂ /MMBtu
Tires	300 short tons	Not Provided	90 kg CO ₂ /MMBtu

Step 3 - Calculate Emissions.

The next step is to calculate CO₂ emissions using the compiled fuel use and emission factor data. This is best performed in a spreadsheet. To reduce potential unit conversion errors, the equation provided in section 95125(a) (Equation 1, above) includes the fuel's high heat value (HHV) as an input. This approach converts all fuel use to Btu per mass or volume, which is then multiplied by an appropriate emission factor provided in kilograms of CO₂ per MMBtu (million British Thermal Units). This approach is also comparable with the approach in section 95125(c), in which HHV is directly measured for input into the emissions evaluation calculations.

There is an alternative computation approach available if care is taken to ensure that the final emission units are correct. With this approach the HHV is not required because in most cases the emission factors in Appendix A are provided in the appropriate fuel use units (emissions/ton, emissions/gallon, etc.). Therefore, it is not always necessary to use the HHV input, and instead the emissions can be directly computed. If using this approach, the emissions estimation equation can be simplified to the following:

Equation 2

$$CO_2 = \text{Fuel Combusted (fuel units)} * EF_{CO_2} \text{ (kg CO}_2\text{/fuel units)}$$

When using this approach, it is especially important that appropriate and correct unit conversions are applied so that the final CO₂ combustion emissions are reported as metric tonnes of CO₂ per year. This conversion issue is somewhat reduced if Equation 1 and HHV are used.

13.1.3 Examples for Computing GHG Emissions for Various Fuel Types

Example 1a - Estimating Natural Gas Combustion Emissions

To compute emissions for natural gas combustion, Equation 1 is used with the HHV_D value obtained from the fuel provider. This should be an annual average HHV_D. Refer to Table 4 in Appendix A for the appropriate emission factor for the provided HHV. In this case it is 53.42 kg CO₂/MMBtu for natural gas with a heat content range of 1050 to 1075 Btu/scf. If the heat content for the natural gas is unknown, then use the “Unspecified” natural gas emission factor of 53.02.

Optionally, if the fuel is variable or a more refined approach is desired, the combustion CO₂ emissions may be computed monthly, based on the fuel use and HHV_D for each month, applying the appropriate Table 4 emission factor for each HHV value. Using this approach, the monthly emissions values are summed to obtain an annual value. (See the guidance for section 95125(k) for an example of estimating emissions when billing cycles split the December and January months.)

The example below uses annual fuel use and HHV values in Equation 1.

$$\begin{aligned} \text{CO}_2 \text{ emissions} &= \text{Fuel Combusted} * \text{HHV}_D * \text{EF}_{\text{CO}_2} * 0.001 \\ &= 2,500,000 \text{ therms/year} * 1050 \text{ Btu/scf} * 53.42 \text{ kg} \\ &\quad \text{CO}_2/\text{MMBtu} * 0.001 \text{ tonnes/kg} \end{aligned}$$

Based on the values in the equation above, clearly there is an inconsistency because the units are not consistent. Note that heat is provided in units of therms, Btu, and MMBtu. In addition, fuel use is provided as therms, but the heat content value is in units of Btu/scf. The heat units are simple to standardize because 1 therm = 100,000 Btu and 1,000,000 Btu = 1 MMBtu.

To convert the therms combusted to scf, use the supplied heat content value of 1050 Btu/scf, which creates consistency in the units. This is illustrated below.

$$\begin{aligned} \text{Convert } 2,500,000 \text{ therms to scf:} \\ &= 2,500,000 \text{ therms/year} * (1 \text{ scf}/1050 \text{ Btu}) * (100,000 \text{ Btu/therm}) \end{aligned}$$

$$\begin{aligned} \text{The heat units cancel, leaving:} \\ &= 238,095,238 \text{ scf of fuel combusted/year} \end{aligned}$$

Returning to the emissions equation:

$$\begin{aligned} \text{CO}_2 \text{ emissions} &= 238,095,238 \text{ scf/year} * 1050 \text{ Btu/scf} * 53.42 \text{ kg CO}_2/\text{MMBtu} \\ &\quad * 0.001 \text{ kg/metric tonne} \\ &= 13,355,000,000 \text{ Btu/MMBtu} * \text{tonne CO}_2/\text{year} * (\text{MMBtu}/1,000,000 \\ &\quad \text{Btu}) \\ &= 13,355 \text{ metric tonnes CO}_2 \end{aligned}$$

For a simpler computation, note that the natural gas use is provided in therms and the natural gas emission factor is provided as kg CO₂/MMBtu. Because of this, the Appendix A emission factors can be used directly, with only a conversion of therms to MMBtu for the fuel consumption. The heat content of the fuel is not needed, except to determine which natural gas emission factor to use. The emissions calculation using Equation 2 is shown below.

$$\begin{aligned} \text{CO}_2 \text{ emissions} &= \text{Fuel Combusted} * \text{EF}_{\text{CO}_2} \\ &= 2,500,000 \text{ therms/year} * 53.42 \text{ kg CO}_2/\text{MMBtu} \\ &= 25,000 \text{ therms/year} * (0.1 \text{ MMBtu/therm}) * 53.42 \text{ kg} \\ &\quad \text{CO}_2/\text{MMBtu} \\ &= 13,355,000 \text{ kg CO}_2 * (\text{metric tonne}/1000 \text{ kg}) \\ &= 13,355 \text{ metric tonne CO}_2/\text{year} \end{aligned}$$

Example 1b - Estimating Coal Burning Combustion Emissions

For computing the coal emissions, the coal fuel use, default heat value, and emission factor are input into equation 1.

$$\begin{aligned}
 \text{CO}_2 \text{ emissions} &= \text{Fuel Combusted} * \text{HHV}_D * \text{EF}_{\text{CO}_2} * 0.001 \\
 &= 4,200 \text{ short tons/year} * 24.93 \text{ MMBtu/short ton} * 93.4 \text{ kg} \\
 &\quad \text{CO}_2/\text{MMBtu} * 0.001 \text{ metric tonnes/kg} \\
 &= 9,779 \text{ metric tonnes CO}_2/\text{year}
 \end{aligned}$$

An alternative to this approach is to multiply the fuel used by the emission factor provided in terms of kg CO₂/short ton. This is 4,200 short tons/year * 2,328.35 kg CO₂/short ton * 0.001 metric tonnes/kg. The short ton units cancel out leaving 4,200 * 2,328.35 kg CO₂/year * 0.001 = 9,779 tonnes CO₂/year.

Example 1c - Estimating Diesel (Distillate) Combustion Emissions

To compute the diesel emissions, the fuel use, default heat value, and emission factor are input into Equation 1.

$$\begin{aligned}
 \text{CO}_2 \text{ emissions} &= \text{Fuel Combusted} * \text{HHV}_D * \text{EF}_{\text{CO}_2} * 0.001 \\
 &= 10,000 \text{ gallons/year} * 5.825 \text{ MMBtu/barrel} * 10.14 \text{ kg CO}_2/\text{gallon} * \\
 &\quad 0.001 \text{ metric tonnes/kg.}
 \end{aligned}$$

As shown in the equation, the HHV is in units of MMBtu/barrel, and the emission factor and fuel use are provided as gallons. Therefore it is necessary to convert barrels to gallons. For the U.S. petroleum industry, one barrel is equal to 42 gallons (see unit conversions in Table 1, Appendix A).

$$\begin{aligned}
 \text{CO}_2 \text{ emissions} &= 10,000 \text{ gallons/year} * 5.825 \text{ MMBtu/barrel} * (1 \text{ barrel}/42 \text{ gallons}) * \\
 &\quad 10.14 \text{ kg CO}_2/\text{gallon} * \\
 &\quad 0.001 \text{ metric tonnes/kg.} \\
 &= 101 \text{ metric tonnes CO}_2/\text{year}
 \end{aligned}$$

As with the coal example, the provided emission factor of 10.14 kg CO₂/gallon could be directly multiplied by the 10,000 gallons of fuel used and then converted to metric tonnes to once again compute 101 metric tonnes CO₂/year.

Example 1d - Estimating MSW Combustion Emissions

To calculate the emissions from municipal solid waste (MSW) the same approach is used, applying Equation 1, with inputs of fuel use, default heat value, and emission factor.

$$\begin{aligned}
 \text{CO}_2 \text{ emissions} &= \text{Fuel Combusted} * \text{HHV}_D * \text{EF}_{\text{CO}_2} * 0.001 \\
 &= 1,800 \text{ short tons/year} * 8.7 \text{ MMBtu/short ton} * 90.65 \text{ kg CO}_2/\text{MMBtu} * \\
 &\quad 0.001 \text{ metric tonnes/kg} \\
 &= 1420 \text{ metric tonnes CO}_2/\text{year}
 \end{aligned}$$

Burning of solid waste presents a special case. The regulation requires that the CO₂ emissions for the biomass and fossil fuel fractions of combusted fuels be separately identified and reported (except in the case of waste-derived fuels that are less than 30 percent by weight of total fuels combusted). Although this method can be used to determine the overall gross MSW emissions, it does not provide an indication of the biomass portion of the fuel. The methods provided in section 95125(h) of the regulation must be used for determining the biomass component in of the MSW burned (except for GSC facilities, which may use other methods to calculate the fossil fuel/biomass split).

13.1.3.5 Example 1e - Estimating Tire Burning Emissions

Calculating emissions from burning tires presents a different challenge. An emission factor is not provided in Table 4. In addition, the tire emission factor in Table 5 is provided in units of kg CO₂/MMBtu. Because of this, the high heat content or heat value must be determined for the tires in order to compute the emissions. In this situation, because the regulation does not provide a default HHV, section 95125(a) is not applicable and cannot be used for computing tire burning CO₂ emissions. The default emission factor method provided in section 95125(a) is not applicable for tires and other fuels that require a HHV not provided in the regulation. Instead, the methods provided in sections 95125(c), 95125(d), or 95125(g) must be used to estimate the CO₂ emissions from tire burning.

Further, when the tire (or other) emissions are computed using the appropriate methods it is important to remember that when fuels are co-fired, the quantity of each fuel and its associated emissions must be reported. An exception is when CEMS are used, in which case the emissions may be combined, but the fuel use must still be separately reported. For natural gas, coal, and diesel in this example, both the quantity of each fuel and the associated emissions can easily be identified and quantified. However, because both tires and MSW are considered waste derived fuels and they contain a non-fossil fuel component, the biomass portion of the fuel must be separately quantified and reported. The methods for quantifying the biomass portion of combustion emissions are provided in section 95125(h) of the regulation and the associated guidance.

13.1.4. Tabulate Computed GHG Emissions for Reporting

Table 13.1.4 summarizes the calculated emissions to prepare for reporting. The regulation specifies the units in which fuel use must be reported - gases must be reported in units of standard cubic feet, liquids as gallons, non-biomass solids as short tons, and biomass-derived solid fuels as bone dry short tons. Table 13.1.4 below summarizes the emissions and fuel use in the appropriate regulation reporting units.

Table 13.1.4 Summary of Emissions

<i>Fuel</i>	<i>Quantity Consumed (measured units)</i>	<i>Quantity Consumed (regulation units)</i>	<i>Emissions (metric tonnes CO₂/year)</i>
Natural Gas (HHV = 1050 Btu/scf)	2,500,000 therms	238 MMScf †	13,355
Coal (bituminous)	4,200 short tons	4,200 short tons	9,780
Diesel (distillate)	10,000 gallons	10,000 gallons	101
MSW - Total*	1,800 short tons	1,620 bone dry short tons ††	1,420*
Tires	400 short tons	400 short tons	To be determined
		TOTAL	24,656

† 2,500,000 therms * (scf/1050 Btu) * 100,000 Btu/therm * (MMScf/1,000,000 scf); HHV from fuel supplier and based on average of monthly values obtained.

†† Calculated based on 10% moisture content in raw fuel, based on periodic testing

* Prior to reporting, the biomass portion of the MSW must be determined. The biomass and fossil-based portions of the fuel combusted and associated emissions must be reported separately.

13.1.5 Check and Document Emissions Results

Finally, ARB staff recommends double checking all fuel use, emission factor, and heat value inputs. Also, please confirm that all unit conversions have been performed correctly. After double checking the calculations, document all results and assumptions as completely as possible. Computations such as these are easily maintained in spreadsheets with annotations and notes to describe the estimates, data sources, person performing the estimates, the dates the estimates were performed and similar information. For additional assistance please refer to the ARB GHG emissions reporting webpage: <http://www.arb.ca.gov/cc/reporting/ghg-rep/ghg-rep.htm>, or see the “Contacts” section within the GHG reporting guidance document.

Note that for this facility, the facility emissions computed using the default emission factors totals to 24,654 tonnes. This is less than the 25,000 metric tonne combustion CO₂ threshold that triggers the general stationary combustion (GSC) facility reporting requirements. When tire emissions are also estimated and included in the total, it is likely the facility total will be over the 25,000 tonne threshold. And, even though the MSW emissions will be subdivided into biomass and fossil fuel components, the total CO₂ combustion emissions are used in evaluating facility applicability for the 25,000 tonne threshold¹. Because errors and incomplete data can make the difference between reporting and not reporting, or between receiving a positive verification opinion or an adverse opinion, it is important to strive for completeness and accuracy.

¹ There is one exception to this. Pass-through CO₂ from combustion of landfill gas or biogas, assumed to be 50% of the gas, is not included in the 25,000 tonne emissions evaluation for applicability, because those emissions are not a product of combustion. The pass-through CO₂ must be included in the emissions report, however.

13.2 Method for Calculating CH₄ and N₂O Emissions from Fuel Combustion Using Default Emission Factors, Section 95125(b)

CH₄ and N₂O emissions represent a small fraction of GHG emissions from fuel combustion. While CH₄ and N₂O emissions are strongly dependent on the combustion technology, GHG calculation methods are fuel-specific.

Section 95125(b) of the GHG reporting regulation provides the methods and requirements for calculating CH₄ and N₂O emissions from stationary combustion sources using fuel-based:

- facility-specific emission factors, or
- default emission factors and
 - default higher heating values or
 - measured higher heating values.

The less rigorous method requiring use of default emission factors and default higher heating values for calculating CH₄ and N₂O emissions is available to all facility types that combust common fuels, as specified within the regulation. Alternatively, more rigorous methods are specified for facility operators who combust uncommon or highly variable fuel types or decide the default values are not representative of their operations.

A generic procedure is described below, followed by an example based on default emission factors.

Step 1. Decide which method(s) you will use to determine CH₄ and N₂O emission factors for each fuel combusted at your facility.

If you combust fuels listed in Table 6 of Appendix A, you must either apply the ARB-approved default emission factors provided for each fuel type (g CH₄ or N₂O per MMBtu) or choose to conduct ARB-approved source tests (g CH₄ or N₂O per unit of mass or volume of fuel, as specified in section 95104(a)(9)).

The default methane and nitrous oxide emission factors for stationary combustion in Table 6 of Appendix A are provided for use with section 95125(b) of the regulation. For readability, these emission factors are provided in units of grams/MMBtu, but *should be converted* when using them in the equations in section 95125(b), to ensure emissions are reported in metric tonnes.

If one or more of the fuels you combust are not listed in Table 6 of Appendix A of the regulation, then you must conduct ARB-approved source tests on each unlisted fuel to determine CH₄ and N₂O emission factors. Since the source test results are expressed in kg CH₄ or N₂O per unit of mass or volume of fuel, you will not need to determine heat content to calculate emissions. See the equation below.

Equation using Source-Test Emission Factors, section 95125(b)(4)

$$\text{CH}_4 \text{ or N}_2\text{O} = \text{Fuel} * \text{EF}_s * 0.001$$

Where:

CH ₄ or N ₂ O	=	CH ₄ or N ₂ O emissions from a specific fuel type, metric tonnes CH ₄ or N ₂ O per year
Fuel	=	Mass or volume of fuel combusted specified by fuel type, unit of mass or volume per year
EF _s	=	Source-test emission factor, kg CH ₄ or N ₂ O per unit of mass or volume
0.001	=	Factor to convert kg to metric tonnes

Guidance on conducting ARB-approved source tests is provided in Appendix B. Emission factors derived from source testing are specific to each combination of fuel-type and combustion technology. For example, if you conduct source testing on a steam boiler combusting refinery fuel gas, the derived CH₄ and N₂O emission factors are used only when calculating CH₄ and N₂O emissions from similar boilers combusting refinery fuel gas.

Step 2. If not conducting source testing, decide which method(s) you will use to determine heat content for each fuel combusted at your facility.

Determine whether you need to implement fuel sampling and testing methods to measure higher heating values. If you or your fuel supplier already measure heat content, as specified in section 95125(c), the measured heat content must be used to calculate emissions.

If you combust fuels listed in Table 4 of regulation Appendix A, you must either apply the ARB-approved default heat content values provided for each fuel type (MMBtu per unit of mass or volume) or choose to measure higher heating values according the sampling and test methods specified in section 95125(c).

If one or more of the fuels you combust are not listed, then you must measure higher heating value for each unlisted fuel using the sampling and test methods specified in section 95125(c).

Section 95125(c) provides the required methods available to all facility types for measuring heat content used in CH₄ and N₂O emissions calculations.

The same method for measuring heat content is also applicable for calculating CO₂ emissions for specified industrial sectors and fuels.

Equation using measured heat content, section 95125(b)(2)

$$\text{CH}_4 \text{ or N}_2\text{O} = \sum_{1}^n \text{Fuel}_p * \text{HHV}_p * \text{EF} * 0.001$$

Where:

- CH₄ or N₂O = Combustion emissions from specific fuel type, metric tonnes CH₄ or N₂O per year
- n = Period/frequency of heat content measurements over the year (e.g. monthly n = 12)
- Fuel_p = Mass or volume of fuel combusted for the measurement period specified by fuel type, units of mass or volume per unit time
- HHV_p = High heat value measured for the measurement period specified by fuel type, MMBtu per unit mass or volume
- EF = Default CH₄ or N₂O emission factor provided in Appendix A, kg CH₄ or N₂O per MMBtu
- 0.001 = Factor to convert kg to metric tonnes

Equation using default heat content, section 95125(b)(3)

$$\text{CH}_4 \text{ or N}_2\text{O} = \text{Fuel} * \text{HHV}_D * \text{EF} * 0.001$$

Where:

- CH₄ or N₂O = CH₄ or N₂O emissions from a specific fuel type, metric tonnes CH₄ or N₂O per year
- Fuel = Mass or volume of fuel combusted specified by fuel type, unit of mass or volume per year
- HHV_D = Default high heat value specified by fuel type provided in Appendix A, MMBtu per unit of mass or volume
- EF = Default emission factor provided in Appendix A, kg CH₄ or N₂O per MMBtu
- 0.001 = Factor to convert kg to metric tonnes

13.2.1 Example for Computing CH₄ and N₂O Emissions

An example is provided for computing CH₄ and N₂O emissions for a facility that combusts five different fuel types. For this example, emissions are calculated based on fuel consumption aggregated at the facility level. The same procedure is used to calculate emissions at the combustion device or generating unit level, if required for a particular industrial sector in sections 95110-95115 of the regulation. In this example, the facility operator has chosen to use ARB-approved default emission factors and high heat values, if available.

Note that in cases where billing invoices do not end on December 31st and begin on January 1st, it may be necessary to prorate fuel use. Refer to the guidance for section 95125(k) for an example.

Step 1. Collect Facility Fuel Use Data

Based on a combination of fuel invoices and on-site measurements, the facility has determined the following fuel usage for calendar year 2008:

Fuel type	Quantity for Calendar Year 2008
Natural Gas	400 million scf
Coal (bituminous)	4,050 short tons
Diesel (distillate fuel oil)	10,000 gallons
Municipal Solid Waste (MSW)	1,800 short tons
Tires	300 short tons (burned with MSW)

Step 2. Identify Emission Factors and High Heat Values

With the types and quantities of fuel compiled in step 1, the next step is to refer to Appendix A, Tables 6 and 4, to identify the appropriate fuel-specific default emission factors and heat values. These values are shown below in Table 13.1.2.

Table 13.1.2 Summary of Fuel Used and Emission Factors

Fuel	Quantity Consumed	High Heat Value (MMBtu/Unit)	EF CH ₄ (g/MMBtu)	EF N ₂ O (g/MMBtu)
Natural Gas	400 million scf	1,027 Btu/scf =1,027 MMBtu/million scf	0.9 g CH ₄ /MMBtu	0.1 g N ₂ O/MMBtu
Coal (bituminous)	4,050 short tons	24.93 MMBtu/short ton	10.0 g CH ₄ /MMBtu	1.5 g N ₂ O/MMBtu
Diesel (distillate)	10,000 gallons	5.825 MMBtu/barrel = 0.1387 MMBtu/gallon	3.0 g CH ₄ /MMBtu	0.6 g N ₂ O/MMBtu
MSW	1,800 short tons	8.7 MMBtu/short ton	30.0 g CH ₄ /MMBtu	4.0 g N ₂ O/MMBtu
Tires	300 short tons	Not Provided	3.0 g CH ₄ /MMBtu	0.6 g N ₂ O/MMBtu

Step 3. Calculate Emissions

The next step is to calculate CH₄ and N₂O emissions using the compiled fuel use and emission factor data in Table 13.1.2. These calculations are best performed in a spreadsheet. The unit conversions from grams to metric tonnes and from barrels to gallons are provided in Table 1 in Appendix A.

Example 1a - Natural Gas Emissions

CH ₄ emissions	=	Fuel Combusted * HHV _D * EF _{CH₄}
	=	400 million scf * 1027 MMBtu/million scf * 0.9 g CH ₄ /MMBtu * metric tonnes/10 ⁶ g
	=	0.3697 metric tonnes
 N ₂ O emissions	=	 Fuel Combusted * HHV _D * EF _{N₂O}
	=	400 million scf * 1027 MMBtu/million scf * 0.1 g N ₂ O/MMBtu * metric tonnes/10 ⁶ g
	=	0.04108 metric tonnes

Example 1b - Coal

CH ₄ emissions	=	Fuel Combusted * HHV _D * EF _{CH₄}
	=	4050 short tons * 24.93 MMBtu/short ton * 10.0 g CH ₄ /MMBtu metric tonnes/10 ⁶ g
	=	1.010 metric tonnes
 N ₂ O emissions	=	 Fuel Combusted * HHV _D * EF _{N₂O}
	=	4050 short tons * 24.93 MMBtu/short ton * 1.5 g N ₂ O/MMBtu metric tonnes/10 ⁶ g
	=	0.1514 metric tonnes

Example 1c - Diesel

$$\begin{aligned}
 \text{CH}_4 \text{ emissions} &= \text{Fuel Combusted} * \text{HHV}_D * \text{EF}_{\text{CH}_4} \\
 &= 10,000 \text{ gallons} * 5.825 \text{ MMBtu/barrel} * 1 \text{ barrel}/42 \text{ gallons} * 3.0 \text{ g} \\
 &\quad \text{CH}_4/\text{MMBtu} * \text{metric tonnes}/10^6 \text{ g} \\
 &= 0.004161 \text{ metric tonnes} \\
 \\
 \text{N}_2\text{O emissions} &= \text{Fuel Combusted} * \text{HHV}_D * \text{EF}_{\text{N}_2\text{O}} \\
 &= 10,000 \text{ gallons} * 5.825 \text{ MMBtu/barrel} * 1 \text{ barrel}/42 \text{ gallons} * 0.6 \text{ g} \\
 &\quad \text{N}_2\text{O}/\text{MMBtu} * \text{metric tonnes}/10^6 \text{ g} \\
 &= 0.0008321 \text{ metric tonnes}
 \end{aligned}$$

Example 1d - MSW

$$\begin{aligned}
 \text{CH}_4 \text{ emissions} &= \text{Fuel Combusted} * \text{HHV}_D * \text{EF}_{\text{CH}_4} \\
 &= 1800 \text{ short tons} * 8.7 \text{ MMBtu/short ton} * 30.0 \text{ g CH}_4/\text{MMBtu} * \text{metric} \\
 &\quad \text{tonnes}/10^6 \text{ g} \\
 &= 0.4698 \text{ metric tonnes} \\
 \\
 \text{N}_2\text{O emissions} &= \text{Fuel Combusted} * \text{HHV}_D * \text{EF}_{\text{N}_2\text{O}} \\
 &= 1800 \text{ short tons} * 8.7 \text{ MMBtu/short ton} * 4.0 \text{ g N}_2\text{O}/\text{MMBtu} * \text{metric} \\
 &\quad \text{tonnes}/10^6 \text{ g} \\
 &= 0.06264 \text{ metric tonnes}
 \end{aligned}$$

Example 1e - Tires

Tires do have default emission factors listed for CH₄ and N₂O (Table 6, Appendix A), but do not have an ARB-approved default higher heating value based on units of mass or volume (Table 4, Appendix A). Therefore, the operator has two options:

- (1) Conduct ARB-approved source tests to determine CH₄ and N₂O emission factors based on short tons (g CH₄/short ton and g N₂O /short ton). Guidance on conducting ARB-approved source tests is provided in Appendix A.
- (2) Measure higher heating value as specified in 95125(c) for waste-derived fuels (MMBtu/short ton), and use the default emission factors expressed as a function of heat content, provided in Table 6.

Step 4. Tabulate Emissions for Reporting

Table 131.3 summarizes the calculated emissions to prepare for reporting. The regulation specifies the units in which fuel use must be reported - gases must be reported in units of standard cubic feet, liquids as gallons, non-biomass solids as short

tons, and biomass-derived solid fuels as bone dry short tons. Table 3 below summarizes the emissions and fuel use in the appropriate regulation reporting units.

Table 13.1.3 Summary of Emissions

<i>Fuel</i>	<i>Quantity Consumed</i>	<i>High Heat Value (MMBtu/Unit)</i>	<i>EF CH₄ (g/MMBtu)</i>	<i>EF N₂O (g/MMBtu)</i>	<i>Emissions (metric tonnes CH₄/year)</i>	<i>Emissions (metric tonnes N₂O/year)</i>
Natural Gas	400 million scf	1,027 Btu/scf = 1,027 MMBtu/million scf	0.9	0.1	0.3697	0.04108
Coal (bituminous)	4,050 short tons	24.93 MMBtu/short ton	10.0 g CH ₄ /MMBtu	1.5	1.010	0.1514
Diesel (distillate)	10,000 gallons	5.825 MMBtu/barrel = 0.1387 MMBtu/gallon	3.0	0.6	0.004161	0.0008321
MSW	1,800 short tons	8.7 MMBtu/short ton	30.0	4.0	0.4698	0.6264
Tires	300 short tons	16 MMBtu/short ton (measured, for purposes of example)	3.0	0.6	0.01440	0.002880

Step 5. Check Results

Finally, ARB staff recommends double-checking all fuel use, emission factors, and heat value inputs. Also, confirm that all unit conversions have been performed correctly. After double checking the calculations, document all results and assumptions as completely as possible. Computations such as these are easily maintained in spreadsheets with annotations and notes to describe the estimates, data sources, job function and employee performing the estimates, the dates the estimates were performed and similar information.

Because errors and incomplete data can make the difference between reporting and not reporting, or between receiving a positive verification opinion or an adverse opinion, it is important to strive for completeness and accuracy.

13.3 Method for Calculating CO₂ emissions from Fuel Combustion Using Measured Heat Content, Section 95125(c)

The calculation method found in section 95125(c) requires the operator or fuel supplier to measure fuel flow rate and fuel high heat content. These variables are then multiplied by a supplied CO₂ emissions factor and appropriate conversion factor to calculate stationary combustion CO₂ emissions.

Step 1. Determine the amount of each fuel combusted on a monthly basis.

For solid, liquid or gaseous fuel, first determine the mass or volume of fuel combusted daily at a representative location. The frequency with which you determine the mass or volume of fuel combusted is determined by the type of fuel. See Table 13.3.1 for specifics.

The operator must use procedures to quantify fuel use with an accuracy of at least ±5 percent. The regulation requires that devices used to measure fuel flow for GHG calculations be maintained and calibrated to meet this level of accuracy. Staff recommends such devices be operated and maintained according to OEM instructions so that they retain this level of accuracy, and that new equipment be installed and calibrated according to OEM specifications. See Appendix A of this document for additional discussion of fuel use measurement accuracy.

Solid fuel samples are collected on a weekly basis. The weekly samples are combined into a composite monthly sample for the determination of HHV, as required by and described in section 95125(c)(1)(A)4. An equal mass of each weekly sample should be included in the monthly composite sample, and the operator should ensure that the monthly composite is homogenous.

Step 1a. If necessary, convert instrument derived LHV to HHV

If you presently have installed instrumentation that determines fuel Low Heating Value (LHV), convert to HHV. (If this is not the case move on to Step 2.) If you install a heat content monitor to measure your fuel HHV, staff recommends you install a HHV monitor as this will provide more accurate heat content data (rather than converting LHV to HHV).

Converting LHV to HHV. If you currently have installed an on-line analyzer that measures only LHV, you will need to convert LHV to HHV using the approach shown in section 95125(c)(1)(C) where $HHV = LHV \times CF$. If the fuel in question is natural gas you should use a conversion factor (CF) of 1.11.

Step 2. Determine the fuel High Heating Value (HHV)

Refer to Table 13.3.1 to determine fuel consumption measurement frequency for your particular fuel.

Table 13.3.1 HHV Measurement Frequency - 95125(c)

<i>Fuel</i>	<i>HHV measurement frequency</i>	<i>Comments</i>
Middle distillates (diesel, gasoline, fuel oil, kerosene) Residual oil Liquid-waster derived LPG (ethane, propane, isobutene, n-butane, unspecified LPG)	at receipt of each new fuel shipment or monthly	
Natural gas, associated gas, mixtures of low Btu gas excluding refinery fuel gas	monthly for gas or mixtures with HHV in range 975- 1100 Btu/scf	Use 95125(d) for natural gas, associated gas and mixtures of low Btu gas outside this range
Solid fuels	monthly - with weekly sub-sampling	Determine solid fuel HHV by analysis of monthly composite sample
Biomass gases - including landfill gas and biogas from wastewater treatment or agricultural processes	monthly	
Waste-derived fuels that are partly but not pure biomass		Use 95125(h)(2) if applicable

As stated in section 95125(c) and shown in Table 13.3.1, operators who combust natural gas, associated gas, or a mixture of natural gas and associated gas or low Btu gases may use this method only if the HHV of the fuel or fuel mixture falls within the range of 975 - 1100 Btu/scf. If the fuel HHV is above or below this range, the operator must use the method found in section 95125(d) for measuring carbon content on a monthly basis.

Step 3. Calculate CO₂ stationary combustion emissions.

Table 13.3.2 summarizes the data required to calculate fuel stationary combustion CO₂ emissions.

Table 13.3.2 Data Requirements - CO₂ Stationary Combustion Emissions - 95125(c)

<i>Required Data</i>	<i>Units/Value</i>	<i>Data Source</i>
<i>Mass or volume of fuel combusted during measurement period</i>	<i>mass or volume/unit time</i> <i>Fuel_p</i>	<i>operator determined</i>
<i>Fuel high heating value (HHV)</i>	<i>MMBtu/unit mass or volume</i> <i>HHV_p</i>	<i>operator determined</i>
<i>CO₂ emission factor</i>	<i>kg CO₂/MMBtu</i> <i>EF</i>	<i>supplied see Appendix A. Table 4</i>
<i>Conversion factor - kg to metric tonnes</i>	<i>kg/metric tonnes</i> <i>0.001</i>	<i>supplied</i>

Use the equation below to calculate CO₂ stationary combustion emissions for each applicable fuel.

$$CO_2 = \sum_1^n Fuel_p * HHV_p * EF * 0.001$$

The superscript n designates the frequency with which the fuel HHV is determined. See Table 13.3.1 to determine this value. For instance if you combust natural gas which has an HHV within the 975 - 1100 Btu/scf range, you are required to determine the natural gas HHV on a monthly basis. In this case n = 12 and you would repeat this calculation 12 times, once for each month of the annual reporting cycle.

The subscript p (Fuel_p and HHV_p) refers to the individual fuels for which you use this method to calculate CO₂ emissions.

The fuel specific CO₂ emission factors are found in the rightmost two columns of Table 4 in Appendix A. Check your fuel units to ensure they are appropriate. If you need to convert units (e.g. liters to gallons) check the conversion factor which you use.

If you do not find EF values for your fuel in Table 4, this method (95125(c)) is probably not appropriate. The alternative is to consult the guidance for method 95125(d), measured carbon content, in the next section.

13.4 Method for Calculating CO₂ emissions from Fuel Combustion Using Measured Carbon Content, Section 95125(d)

The calculation method found in section 95125(d) requires the operator or fuel supplier to measure fuel use and fuel carbon content. These variables are then multiplied by appropriate conversion factors to calculate stationary combustion CO₂ emissions.

The operator must use procedures to quantify fuel use with an accuracy of at least ±5 percent. The regulation requires that devices used to measure fuel flow for GHG

calculations be maintained and calibrated to meet this level of accuracy. Staff recommends such devices be operated and maintained according to OEM instructions so that they retain this level of accuracy, and that new equipment be installed and calibrated according to OEM specifications. See Appendix A of this document for additional discussion of fuel use measurement accuracy.

13.4.1 Stationary combustion CO₂ emissions for solid fuels

There are two variables required to calculate CO₂ stationary combustion emissions resulting from the combustion of a solid fuel - the amount of fuel burned and the carbon content of that fuel.

Operators measuring solid fuels must validate fuel use consumption estimates with belt or conveyor scale calibrations at least quarterly. Solid fuel samples are collected on a weekly basis, for each fuel burned that week. The weekly samples are combined into a composite monthly sample for the determination of HHV, as required by section 95125(d)(1)(B) and discussed below. In addition, the regulation requires the operator to randomly monitor the homogeneity of the composite once per year by submitting the weekly samples for comparative analysis.

Step 1. Determine the amount of each fuel combusted on a monthly basis.

First, determine the mass of fuel combusted each month at a representative location. If the fuel is pre-treated in any way (e.g., pulverized, dried, treated with additives), sample after these points to ensure that the mass measurement is representative of the fuel that is combusted. Sample at a time and in a manner that is representative of normal operating conditions. An equivalent mass of each weekly sample should be included in the monthly composite sample, and the operator should ensure that the monthly composite is homogenous.

If your scale or measurement device provides mass in units other than kilograms, convert fuel mass to kilograms and express the mass of fuel combusted monthly in metric tonnes for use in the formula below. See Table 2 of regulation Appendix A for conversion factors.

A reminder: the operator is also required to report *annual* fuel consumption for each fuel combusted (in short tons for fossil fuels, and in bone dry short tons for biomass solids). A database containing monthly fuel consumption data is recommended to enable easy calculation, conversion, and reporting of the annual consumption for each fuel.

Step 2. Determine the carbon content of each solid fuel that you combust.

As discussed in step 1, sample collection must be representative and unbiased. Rather than sampling the coal pile, for example, collect samples from a location as close to the combustion equipment as is safely possible, beyond all pretreatment processes that may alter the chemical composition or physical nature of the fuel. You should also collect a large enough sample each week to ensure that the sample is representative of the fuel. Also, before withdrawing a sub-sample for analysis from the monthly composite sample, please ensure that the composite sample is well mixed and homogeneous.

Supplier-provided carbon content. If your fuel supplier provides you with a monthly analysis of a solid fuel you purchase, it may be acceptable to use this data. However, you should examine the representativeness of this data before using it to calculate your monthly emissions. Is the carbon content data you receive from your fuel supplier representative of the fuel you actually burn? Do you pre-treat the fuel once you receive it from your supplier? Does that pretreatment change the carbon content of the fuel? Does the fuel sit outside for extended periods of time and dry or absorb moisture? These are questions that may be raised during the verification process. If you have concerns about the representativeness of the data you receive from your fuel supplier, the best way to ensure that this carbon content value is representative is to collect a sample just prior to combustion, analyze the sample and compare this data with that you receive from your fuel supplier.

For each representative monthly sample, determine what mass percentage of the fuel is carbon. The regulation specifies use of ASTM Method 5373-02 for the determination of fuel carbon content of coal, coke, solid biomass derived fuels and waste derived fuels. (An exception is made for waste-derived fuels composed partly of biomass. When the biomass content exceeds 30 percent, the operator is referred to section 95125(h)(2) of the regulation, for which guidance is provided later in this chapter.) The carbon content used to calculate emissions is expressed as a decimal number. That is, if carbon constitutes 80% of the mass of your fuel, you would enter 0.80 in the equation to calculate monthly emissions.

Step 3. Calculate solid fuel stationary combustion CO₂ emissions.

The required data are listed in the table below.

Table 13.4.1 Stationary Combustion CO₂ emissions - Solid Fuels

<i>Required Data</i>	<i>Data Frequency</i>	<i>Units/Value</i>	<i>Data Source</i>
mass of solid fuel combusted	monthly	metric tonnes/month Fuel _n	operator determined
carbon content of solid fuel	monthly -- value derived from composite of weekly samples	percent carbon (expressed as decimal fraction of 100) CC _n	operator determined
conversion factor - carbon to CO ₂	NA	kg CO ₂ /kg C 3.664	supplied

Use the formula below to calculate your stationary combustion CO₂ emissions.

$$\text{CO}_2 = \sum_1^{12} \text{Fuel}_n * \text{CC}_n * 3.664$$

The subscript n refers to the individual months of the year - months 1 to 12 or January to December. Thus for each solid fuel you will repeat this calculation twelve times and sum the results. For each month multiply your fuel consumption by the carbon

content of the fuel for that month. Make sure the units are correct - metric tonnes of fuel combusted and percent carbon in the fuel. Then multiply this value by the conversion factor 3.664 to calculate your CO₂ emissions in metric tonnes per month. Sum all your monthly emissions to arrive at your annual emissions in metric tonnes of CO₂/year.

13.4.2 Stationary combustion CO₂ emissions for liquid fuels

There are two variables required to calculate CO₂ stationary combustion emissions resulting from the combustion of a liquid fuel - the amount of fuel burned and the carbon content of that fuel.

Step 1. Determine the amount of each fuel combusted on a monthly basis.

First, determine the volume of each liquid fuel combusted during the month at a representative location. Fuel volume combusted must be determined with an accuracy of at least ±5%. If your fuel flow meter provides data in units other than gallons, convert the reading to gallons using the correct conversion factor.

Step 2. Determine the carbon content of each liquid fuel that you combust.

Choose a sampling location that will provide an accurate representation of the composition of the liquid fuel that is combusted. Approved analytical methods are listed in section 95125(d)(2)(B)2. If you contract your fuel analysis to an outside laboratory, please ensure that the contractor is using one of these methods. For the purpose of emission calculations, fuel carbon content should be expressed as kilograms of carbon per gallon of fuel. Caution: two different unit systems are used in this expression of carbon content - Imperial (gallons) and SI (kilograms). A conversion may be necessary to ensure the carbon content is expressed correctly.

Step 3. Calculate liquid fuel stationary combustion CO₂ emissions.

The required data are listed in the table below.

Table 13.4.2 Stationary Combustion CO₂ emissions - Liquid Fuels

<i>Required Data</i>	<i>Data Frequency</i>	<i>Units/Value</i>	<i>Data Source</i>
volume of liquid fuel combusted	monthly	gallons/month Fuel _n	operator determined
carbon content of liquid fuel	monthly	kg C/gallon of fuel CC _n	operator determined

² The following ASTM methods are cited in the regulation for petroleum-based liquid fuels and liquid waste-derived fuels: ASTM D5291-02 (Reapproved 2007) "Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants," ultimate analysis of oil or computations based on ASTM D3238-95 (Reapproved 2005) and either ASTM D2502-04 or ASTM D2503-92 (Reapproved 2002).

conversion factor - carbon to CO ₂	NA	kg CO ₂ /kg C 3.664	supplied
conversion factor - kg to metric tonnes	NA	metric tonnes/kg 0.001	supplied

Use the formula below to calculate your stationary combustion CO₂ emissions.

$$\text{CO}_2 = \sum_1^{12} \text{Fuel}_n * \text{CC}_n * 3.664 * 0.001$$

The subscript n refers to the individual fuels, and the range of the summation (1 through 12) refers to months January (1) to December (12). Thus for each liquid fuel you will repeat this calculation twelve times and sum the results. For each month multiply your fuel consumption by the carbon content of the fuel for that month. Make sure the units are correct - gallons of fuel combusted and kilograms carbon per gallon of fuel. Then multiply this value by the conversion factors 3.664 and 0.001 to calculate your CO₂ emissions in metric tonnes per month. Sum all your monthly emissions to arrive at your annual emissions in metric tonnes of CO₂/year.

A reminder: you are also required to report *annual* fuel consumption for each fuel combusted. Thus it would be advisable to maintain a data base containing monthly fuel consumption data so that you may easily calculate and report your annual consumption for each fuel.

13.4.3 Stationary combustion CO₂ emissions for gaseous fuels

There are several scenarios under which you may either be required or choose to use the following methodology to measure carbon content of a gaseous fuel you combust in order to determine CO₂ stationary combustion emissions.

- You combust natural gas or associated gas which has a high heating value (HHV) outside the 975 - 1100 Btu/scf range. Inside this range you may use a measured HHV value and emission factor to calculate CO₂ emissions.
- You are an operator of a crude oil or natural gas production facility that combusts natural gas (outside the 975 - 1100 Btu/scf range), associated gas, low Btu gas, or mixtures of these gases.
- You are a petroleum refiner who combusts refinery fuel gas or a mixture of gaseous fuels containing refinery fuel gas or flexigas.

In each of these cases the calculation methodology is similar, the major difference being the frequency with which you must determine your fuel or fuel mixture carbon content.

Step 1. Determine the amount of each gaseous fuel combusted each month.

You should measure the total volume (in standard cubic feet - scf) of each gaseous fuel you combust each month. Determine the volume of each gaseous fuel combusted during the month at a representative location, with an accuracy of at least ±5%. If

your fuel flow meter provides data in units other than standard cubic feet, convert the reading to standard cubic feet using the correct conversion factor. Your gas flow meter should be temperature compensated, i.e., it should provide gas flow volume corrected to a specific temperature (20°C or 60°F). If you are unsure as to which of these temperatures for which your gas meter expresses volume, check the meter or consult the meter manufacturer. This information is required when you calculate CO₂ combustion emissions.

Step 2. Determine the carbon content of each gaseous fuel that you combust.

The frequency with which you must determine fuel carbon content is dictated by the type of gaseous fuel you combust. Refer to the table below for specifics.

Table 13.4.3 Gaseous Fuels - Required Carbon Content Determination Frequency

<i>Gaseous Fuel</i>	<i>Carbon Analysis Frequency</i>
Natural gas	monthly
Associated Gas	
Natural gas/Associate gas/low Btu gas mixtures	
Flexigas	daily
Refinery fuel gas	measure 3X/day (every 8 hours) - use average
Refinery Fuel gas mixtures	

Carbon content may be determined by either discrete sampling followed by lab analysis, or by on-line instrumentation (e.g. gas chromatograph). Lab analysis should be conducted using one of the approved ASTM methods.³ On-line instrumentation should be installed, maintained and calibrated according to OEM instructions. On-line instrumentation must be installed at a location that ensures representative sampling of the gaseous fuel combusted.

If you combust refinery fuel gas or a refinery fuel gas mixture you must determine carbon content 3 times per day - every eight hours. This doesn't mean that you must sample at exactly eight hour intervals. Sample at a time when operational conditions are representative of normal conditions. Average the 8 hour determinations to calculate the daily average carbon content.

Note: You must also determine the fuel or fuel mixture molecular weight for all refinery fuel gas, refinery fuel gas mixtures, and flexigas.

Step 3. Calculate gaseous fuel stationary combustion CO₂ emissions.

For Natural Gas, Associated Gas and Natural Gas/Associated Gas/Low Btu gas Mixtures: If you combust natural gas, associated gas or mixtures of natural gas and associated gas, the required data are shown in the following table. You should use the formula immediately below the table to calculate your stationary combustion CO₂ emissions.

³ ASTM D1945-03 or ASTM D1946-90 (Reapproved 2006).

Table 13.4.4 Stationary Combustion CO₂ emissions - Natural Gas, Associated Gas and Natural Gas/Associated Gas/Low Btu Gas Mixtures

<i>Required Data</i>	<i>Data Frequency</i>	<i>Units/Value</i>	<i>Data Source</i>
volume of gaseous fuel combusted	monthly total	scf/month Fuel _n	operator determined
carbon content of gaseous fuel	monthly	kg C/kg-mole fuel CC _n	operator determined
1/molar volume conversion factor	NA	1/MVC scf/kg-mole MVC = 849.5 scf/kg-mole @ 20°C or 836 scf/kg-mole @ 60°F	supplied
conversion factor - carbon to CO ₂	NA	kg CO ₂ /kg C 3.664	supplied
conversion factor - kg to metric tonnes	NA	metric tonnes/kg 0.001	supplied

NA: not applicable

$$\text{CO}_2 = \sum_1^{12} \text{Fuel}_n * \text{CC}_n * 1/\text{MVC} * 3.664 * 0.001$$

The subscript n refers to the individual fuels, and the range of the summation (1 to 12) refers to months January (1) to December (12). Thus, for each gaseous fuel the operator repeats this calculation twelve times and sums the results. For each month, multiply fuel consumption by the carbon content of the fuel for that month. You will want to make sure the units are correct: scf of fuel combusted and kilograms carbon per kg-mole of fuel. Next, choose the correct molar volume conversion (MVC) factor based on the temperature at which you measured gas volume (20°C or 60°F) and multiply by the inverse of the MVC. Finally, multiply by the conversion factors 3.664 and 0.001 to calculate your CO₂ emissions in metric tonnes per month. Sum all your monthly emissions to arrive at your annual emissions in metric tonnes of CO₂/year.

For Refinery Fuel Gas and Flexigas: If you combust flexigas, refinery fuel gas, or mixtures using refinery fuel gas, the required data are shown in the following table. You will use the formula immediately below the table to calculate your stationary combustion CO₂ emissions.

Table 13.4.5 Stationary Combustion CO₂ emissions - Flexigas, Refinery Fuel Gas, and Refinery Fuel Gas Mixtures

<i>Required Data</i>	<i>Data Frequency</i>	<i>Units/Value</i>	<i>Data Source</i>
volume of gaseous fuel combusted	daily total	scf/daily Fuel _n	operator determined
carbon content of gaseous fuel	flexigas - daily Refinery fuel gas - daily average of 3 measurements	kg C/kg-mole fuel CC _n	operator determined
fuel molecular weight	flexigas - daily refinery fuel gas - daily average of 3 measurements	MW _{RFG-A} kg/kg-mole	operator determined
1/molar volume conversion factor	NA	1/MVC scf/kg-mole MVC = 849.5 scf/kg-mole @ 20°C or 836 scf/kg-mole @ 60°F	supplied
conversion factor - carbon to CO ₂	NA	kg CO ₂ /kg C 3.664	supplied
conversion factor - kg to metric tonnes	NA	metric tonnes/kg 0.001	supplied

NA = not applicable

$$CO_2 = \sum_1^{365} Fuel_n * CC_n * MW_{RFG-A} / MVC * 3.664 * 0.001$$

The subscript n refers to the individual fuels, and the range of the summation (1 to 365) refers to days of the year. Thus, for each gaseous fuel, the operator repeats this calculation 365 times and sums the results. For each day, fuel consumption is multiplied by the carbon content of the fuel for that day. You will want to make sure the units are correct - scf of fuel combusted and kilograms carbon per kg-mole of fuel. Next, choose the correct molar volume conversion factor based on the temperature at which you measured gas volume (20°C or 60°F) and multiply by the inverse of the MVC. Finally, multiply by the conversion factors 3.664 and 0.001 to calculate your CO₂ emissions in metric tonnes per day. Sum all your daily emissions to arrive at your annual emissions in metric tonnes of CO₂/year. Repeat the calculation for each refinery fuel gas system under consideration.

13.5 Method for Calculating CO₂ Emissions from Fuel Combustion Using Measured Heat and Measured Carbon Content (Refinery Fuel Gas), Section 95125(e)

The method presented below is one of three procedural approaches for calculating CO₂ emissions from the combustion of refinery fuel gas. Additional methods are discussed in Chapter 10 of this document.

This method involves the measurement of both heat content and carbon content for a refinery fuel gas (RFG) system. The method requires use of an on-line high heating value (HHV) analyzer. HHV data and a daily carbon content determination are used to derive a daily refinery fuel system specific CO₂ emission factor (EF). This emission factor is then used with a daily average RFG system HHV value (from the on-line analyzer) to calculate CO₂ emissions.

Step 1. Calculate a RFG system specific daily emissions factor.

The operator must determine the carbon content and HHV for the RFG system in order to calculate a CO₂ emission factor. To do this, once per day, determine the carbon content (kg C/kg fuel), molecular weight (kg fuel/kg-mole) and the HHV (Btu/scf) of the RFG system under consideration. Carbon content and fuel molecular weight are measured by drawing a representative RFG sample and performing a carbon analysis. Alternatively, carbon content and molecular weight may be determined using on-line instrumentation (e.g., a gas chromatograph).

High heating value is determined either using data from the carbon analysis or from an on-line HHV analyzer. When using data from an on-line HHV analyzer, the operator uses either the hourly average HHV value coinciding with the hour in which the carbon content determination is made, or the hour in which the sample was collected for analysis. A daily emission factor (metric tonnes CO₂/MMBtu) is then calculated using the equation found in section 95125(e)(3), shown below. The operators should ensure that a representative sample is drawn for carbon analysis, the HHV analyzer is properly installed in an appropriate location, the carbon content analysis accurately characterizes the fuel, and sampling is performed under conditions representative of prevailing operational parameters.

The data required to calculate a RFG system specific CO₂ emission factor are listed in the table below. Use the formula found below the table to calculate the emission factor.

Table 13.5.1 CO₂ Emission Factor - Refinery Fuel Gas System

<i>Required Data</i>	<i>Data Frequency</i>	<i>Units/Value</i>	<i>Data Source</i>
RFG carbon content	daily*	kg C/kg RFG CC _A	operator determined
High Heating Value of RFG	daily* - derived from hourly average on-line analyzer or fuel analysis	Btu/scf HHV _A	operator determined
RFG molecular weight	daily* - derived from on-line analyzer or fuel analysis	kg /kg-mole fuel MW _A	operator determined
molar volume conversion	NA	scf/kg-mole MVC = 849.5 scf/kg-mole @ 20°C or 836 scf/kg-mole @ 60°F	supplied - choose appropriate value
conversion factor - kg C to kg CO ₂	NA	3.664	supplied
conversion factor - kg/Btu to metric tonnes/Btu	NA	1000	supplied

* measurement frequency for “small refiners” is weekly

$$EF_{CO_2-A} = CC_A / HHV_A * MW_A / MVC * 3.664 * 1.000$$

The A subscripts in the formula refer to the specific refinery fuel gas system for which the operator calculates an emission factor. Choose the correct molar volume conversion factor based on the temperature at which you measured gas volume (20°C or 60°F). For example, dry gas meters are temperature compensated to provide volume at a specified temperature. Check the meter or the OEM manual to determine the temperature at which your gas meter provides gas volume.

Also please make sure your units are correct. The emission factor is expressed in units of metric tonnes of CO₂/MMBtu.

Step 2. Determine the amount of each fuel combusted on a daily basis.

For each refinery fuel gas system determine the volume of fuel combusted daily at a representative location. If you mix refinery fuel gas with another fuel prior to combustion you may choose to calculate emissions for the mixture rather than calculate emissions from each fuel separately. You must still determine and report the volume of refinery fuel gas combusted.

Remember the amount of fuel combusted must be determined with an accuracy of at least ±5%. This requirement means that flow measurement devices must be capable of this level of accuracy, and operated, maintained and calibrated according to OEM instructions so that they retain this level of accuracy.

Step 3. Calculate Refinery Fuel Gas System Specific Stationary Combustion CO₂ emissions.

Once you have determined a daily CO₂ emission factor for your RFG system and daily fuel consumption, daily CO₂ emissions are calculated using the daily average RFG HHV derived from the on-line continuous HHV analyzer. Use of a daily average HHV is designed to integrate daily variations in RFG heating value (and indirectly, carbon content). Data requirements are shown in the table below. This calculation is accomplished using the formula found in section 95125(e)(4) and shown below the table.

Table 13.5.2 Stationary Combustion CO₂ Emissions - Refinery Fuel Gas

<i>Required Data</i>	<i>Data Frequency</i>	<i>Units/Value</i>	<i>Data Source</i>
RFG HHV	daily average derived from on-line analyzer	Btu/scf HHV _{DA}	operator determined
volume of RFG combusted daily	daily*	scf FR _A	operator determined
RFG system specific CO ₂ emission factor	daily*	metric tonnes CO ₂ /MMBtu MW _A	operator determined
conversion factor - Btu to MMBtu	NA	0.000001	supplied

* measurement frequency for “small refiners” is weekly

$$CO_{2-A} = \sum_1^{365} HHV_{DA} * FR_A * EF_{CO2-A} * 0.000001$$

The subscript A refers to the specific refinery fuel gas system for which you are calculating emissions. RFG CO₂ emissions for all RFG systems are then summed to calculate facility RFG CO₂ emissions.

Small refineries. Refiners that qualify as “small” refiners under California statutes may calculate CO₂ emissions on a weekly (rather than daily) basis. See Title 13, California Code of Regulations, Section 22609(a)(32) to determine whether your facility is “small”.

13.6 Method for Calculating CO₂ emissions from Fuel Combustion for Fuel Mixtures (Petroleum Refineries and Crude Oil and Natural Gas Processing), Section 95125(f)

Regulation section 95125(f) does not contain new methods for the calculation of stationary combustion CO₂ emissions. Rather, the section specifies methods for calculating CO₂ combustion emissions for fuel mixtures, as applicable to operators of

petroleum refineries, oil and gas production facilities, and natural gas processing facilities.

There are several basic approaches available to these facilities when fuel mixtures are combusted. These can be summarized as follows:

- a) The operator may determine emissions from each fuel separately. That is, the amount of each fuel combusted is measured along with the appropriate fuel data (HHV and/or carbon content) for each fuel, and fuel specific calculations are performed to yield emissions for each fuel. Results are then summed to provide total combustion emissions from the mixture.
- b) The operator may calculate CO₂ emissions of the fuel mixture by measuring flow rates separately for each fuel in mixture or of the fuel mixture, determining the appropriate fuel data (HHV and/or carbon content) for the mixture, and then calculating CO₂ emissions for the mixture.
- c) Or, the operator may choose to use a continuous emissions monitoring system (CEMS) to determine CO₂ stationary combustion emissions, as addressed in the next section of this document.

13.6.1 Specified Alternatives

The following table shows the more specific requirements applicable to the facilities and fuel mixtures specified at section 95125(f)(1)(C)-(D).

Table 13.6.1 Choice of Methods for Fuel Mixtures

<i>Fuel</i>	<i>Mixed With</i>	<i>Applicable Calculation Methods</i>
Refinery Fuel Gas	Natural Gas Flexigas Low Btu Gases	95125(g), 95125(d)(3)(A), or 95125(e)
Natural Gas Associated Gas	Low Btu Gases	95125(g), or If mixture HHV 975-1100 Btu/scf → 95125(c) If mixture HHV <975 or >1100 Btu/scf → 95125(d)

Petroleum Refineries. If the operator mixes refinery fuel gas with any other fuel, the more stringent requirements and calculation methods apply. In other words, emissions from the mixture must be quantified using the same methods applicable for the combustion of refinery fuel gas as a single fuel. The operator may alternatively use a CEMS to determine stationary combustion CO₂ emissions.

Oil and Gas Production Facilities; Natural Gas Production and Processing Facilities. If the operator mixes associated gas or natural gas with a low Btu gas prior to combustion, the mixture is treated in the same manner as natural gas. If the HHV of the mixture falls within “pipeline” grade limits (975-1100 Btu/scf), the operator may determine HHV of the mixture monthly and calculate CO₂ emissions using the methods in section 95125(c). If the HHV of the mixture is outside these limits (<975 or >1100 Btu/scf) the operator determines the carbon content of the mixture monthly and uses the method found in section 95125(d) to calculate emissions. Again, the operator may

also use a CEMS to determine stationary combustion CO₂ emissions consistent with section 95125(g), as described below.

13.7 Method for Calculating CO₂ Emissions Using Continuous Emissions Monitoring Systems (CEMS), Section 95125(g)

Continuous emissions monitoring systems (CEMS) are employed at many stationary sources, including power plants, to monitor emissions of air pollutants in response to local, state and federal regulations. Many CEMS continuously monitor and record O₂ or CO₂ concentrations from an exhaust stack at a facility. These existing CEMS may be used by most operators to determine CO₂ emissions from units subject to reporting in section 95101. Most CEMS are regulated in accordance with 40 CFR Part 60 and/or Part 75, federal regulations that address their installation, certification, operation, and maintenance. CO₂ emissions are reported using the methodologies provided in 40 CFR Part 75, Appendix F. This section provides guidance for requirements beyond 40 CFR Part 60 and Part 75, as specified in section 95125(g) of the mandatory reporting regulation.

13.7.1 CEMS Installation and Operation

Where a choice is provided in the ARB mandatory reporting regulation between using a fuel-based calculation or using a CEMS to calculate CO₂ emissions, the operator makes a choice of reporting method and continues to use that method for all future emissions data reports.

Operators who elect to install a new CEMS system or CO₂ CEMS components, however, may report combustion emissions on the basis of the fuel-based calculations for the 2008, 2009, and 2010 report years. The new CO₂ CEMS must be operational for purposes of emissions reporting by January 1, 2011.

The new CEMS must measure CO₂ concentrations and flue gas flow and be installed and operated according to the requirements of 40 CFR Part 75, not Part 60. This requirement does not mean that the emissions must be reported to the U.S. EPA, however.

Electricity generating facilities that combust biomass solid fuels or municipal solid waste must use CO₂ CEMS data to determine CO₂ emissions if the facility already measures CO₂ concentrations and flue gas flow. If not, the operator is provided alternative methodologies to calculate CO₂ emissions.

You may elect to add to an existing CEMS device for the purposes of measuring CO₂ concentrations or flue gas flow. If you are adding a new device to an existing CEMS you must meet the installation and operational requirements of either 40 CFR Part 60 or Part 75 depending on which regulation applies to your facility. If your facility is subject to both 40 CFR Part 60 and Part 75, you must comply with 40 CFR Part 75.

Installation timelines and reporting requirements for new devices are under the same requirements as a new CEMS installation, as described above.

13.7.2 Reporting CO₂ Emissions

CO₂ emissions are required to be reported in metric tonnes/year. You are required to use the methodologies in 40 CFR Part 75, Appendix F which allow you to calculate annual CO₂ emissions in short tons based on the sum of hourly CO₂ mass emissions. These emissions will need to be converted to metric tonnes.

Example 1: Conversion of Short Tons to Metric Tonnes

Situation: An operator using methodologies provided in 40 CFR Part 75, Appendix F has calculated the CO₂ emissions for the year to be 27,000 (short) tons CO₂.

Question: What are the CO₂ emissions in metric tonnes CO₂?

Answer: Use the following conversion; 1 (short) ton = 0.9072 metric tonnes.

27,000 (short) tons CO₂ * 0.9072 metric tonnes = 24,494 metric tonnes CO₂

If CO₂ emissions are reported using a CEMS, you are not required to separately report process and combustion emissions. Also, if only fossil fuels are co-fired then it is not necessary to report emissions separately for each type of fossil fuel. However, biomass-derived CO₂ emissions must be reported separately. See the biomass guidance below.

Annual fuel consumption data are still required for each fuel type.

13.7.3 Measurement Methods by Fuel Type

CEMS are used in facilities that combust of a wide variety of fuels. To reflect the variability of these fuels section 95125(g) establishes fuel specific requirements. The following sections outline fuel specific requirements, as summarized in Table 13.7.1.

13.7.3.1 *Single Fossil Fuel*

If your facility combusts a fossil fuel you may use CO₂ or O₂ concentrations and flue gas flow measurements to determine hourly CO₂ mass emissions using methodologies provided in 40 CFR Part 75, Appendix F.

If O₂ concentrations are used, an optional Relative Accuracy Test Audit (RATA) could be performed to compare the calculated CO₂ concentrations to the measured CO₂ concentrations. The methodology to perform this RATA is outlined in 40 CFR Part 60, Appendix B, Performance Specification 3. This optional comparison RATA would help to determine if measuring CO₂ concentrations rather than O₂ concentrations would be a more accurate method for your facility. On the whole, the preferred method is to measure CO₂ concentrations.

13.7.3.2 *Mixture of Fossil Fuels*

Similar to combustion of a single fossil fuel type, if you are combusting a mixture of fossil fuels you may use CO₂ or O₂ concentrations and flue gas flow measurements to

determine hourly CO₂ mass emissions. Especially with fuel mixtures, however, the preferred method is CO₂ concentration measurement.

If O₂ concentrations are used for fuel mixtures, careful scrutiny of the calculated CO₂ emissions from O₂ concentration measurements should be done to ensure that the reported CO₂ emissions are accurate for the fuel mixtures your facility is combusting. An optional RATA to compare the calculated CO₂ concentrations to the measured CO₂ concentrations to confirm the accuracy of the calculated CO₂ concentrations is recommended.

When only fossil fuels are combusted, it is not necessary to separately report CO₂ emissions by each fossil fuel type. You may, however, elect to report CO₂ emissions by fossil fuel type using the methodologies provided in the regulation that pertain to your type of facility. Annual fuel consumption data are still required for each fuel type.

13.7.3.3 Pure Biomass Fuel

If you are combusting a pure biomass fuel, then CO₂ emissions can be determined either by directly measuring CO₂ concentration or measuring O₂ concentrations and calculating the CO₂ emissions.

If O₂ concentrations are used, then an annual Relative Accuracy Test Audit (RATA) must be performed to compare the calculated CO₂ concentrations to the measured CO₂ concentrations. This RATA must meet requirements in 40 CFR Part 60, Appendix B, Performance Specification 3.

13.7.3.4 Pure Biomass Co-Fired with Fossil Fuels

If you are co-firing pure biomass with fossil fuels you cannot use O₂ concentration to calculate CO₂ emissions.

Biomass-derived CO₂ emissions need to be separately reported from fossil fuel-derived CO₂ emissions. The operator may choose from two methods. First, the operator may use the methods designated in section 95111(c) to calculate the fossil fuel emissions by fuel type, and then subtract the fossil fuel-related emissions from the total CEMS CO₂ emissions. Example 2 provides an example of this calculation.

Example 2: Fuel Usage Calculation Method to Determine Biomass-derived CO₂ Emissions

Situation: A facility uses CEMS to report CO₂ emissions. The CEMS measured a total of 34,000 metric tonnes CO₂/year. The facility co-fires pure biomass and natural gas. 42 MMscf of natural gas are burned per month at the facility. What are the biomass-derived CO₂ emissions?

Answer: The operator has the option to calculate the biomass-derived CO₂ emissions using the following equation.

Annual Pure Biomass CO₂ Emissions = Total Annual CEMS CO₂ Emissions - Annual Fossil Fuel CO₂ Emissions (using method §95125(c) or (d))

Step 1: Calculate annual fossil fuel (natural gas) CO₂ emissions using methodologies provided in sections §95125(c) or (d); see applicable section guidance for details.

For this example the annual CO₂ emissions from natural gas are 27,444 metric tonnes CO₂/year

Step 2: Apply the equation:

Biomass Fuel CO₂ Emissions = 34,000 metric tonnes CO₂/year (from CEMS) - 27,444 metric tonnes CO₂/year (calculated from fossil fuel)

Biomass Fuel CO₂ Emissions = 6,556 metric tonnes CO₂/year

Second, the operator may use the method provided in regulation section 95125(h)(2). This method is discussed in detail in Chapter 13.8.2 of this document. The methodology in section 95125(h)(2) is only feasible on fuels with a biomass content greater than 5 percent by weight, however.

13.7.3.5 Waste Derived Fuels, Including Municipal Solid Waste

You cannot use O₂ concentration to calculate CO₂ emissions if you combust waste derived fuels. The highly variable nature of waste derived fuels require that you directly measure CO₂ concentrations and flue gas flow.

If you combust waste-derived fuels that contain biomass you must measure and report biomass-derived CO₂ emissions separately from the other fuel's emissions. For a detailed discussion of how to calculate biomass-derived CO₂ emissions from waste derived fuels, see the guidance for section 95125(h)(2). Reporting biomass-derived CO₂ emissions separately is optional if your facility combusts waste-derived fuels that are less than 30 percent by weight of total fuels combusted for the report year. If biomass-derived CO₂ emissions are not measured, then the total CEMS CO₂ emissions are to be reported as fossil fuel-derived CO₂ emissions.

Table 13.7.1 Measurement Method By Fuel Type

Fuel Type		Measure O ₂	Measure CO ₂	RATA Comparing Measured CO ₂ Emissions to Calculated CO ₂ Emissions from O ₂ Concentrations	Biomass-Derived Emissions Analysis §95125(h)(2)	Fuel Based Calculations to Report Fossil Fuel Emissions
Fossil Fuels	Single fuel types	Yes	Yes	Optional	N/A	N/A
	Multiple fossil fuels co-fired	Yes	Yes	Optional	N/A	Optional
Biomass Fuels	Pure biomass	Yes	Yes	Yes	No	N/A
	Biomass co-fired with fossil fuels	No	Yes	No	Yes - if fuel mixture is > 5% biomass by weight	Yes
Waste Derived Fuels including Municipal Solid Waste	<30% by Weight of the total fuel combusted /year	No	Yes	N/A	Optional*	No
	≥30% by Weight of the total fuel combusted /year	No	Yes	N/A	Yes	No
All Fuels New CEMS Installation		No	Yes	N/A	See fuel type above	See fuel type above

*If biomass-derived CO₂ emissions are not measured, the total CEMS CO₂ emissions are to be reported as fossil fuel CO₂ emissions.

N/A: not applicable

13.8 Method for Calculating CO₂ Emissions from Combustion of Biomass, Municipal Solid Waste (MSW), or Waste Derived Fuels with Biomass, Section 95125(h)

Section 95125(h) contains methodologies that certain facilities may use to quantify CO₂ emissions when they combust pure biomass solid fuels, waste fuels, or fuel mixtures. The three distinct methodologies provided in sections 95125(h)(1), (h)(2), and (h)(3) are reviewed respectively below.

13.8.1 Method to Calculate CO₂ Emissions from Facilities with Boilers that Combust Biomass Solid Fuels or Municipal Solid Waste, Section 95125(h)(1)

The CO₂ method provided in section 95125(h)(1)(A) is used to calculate CO₂ emissions from facilities that combust biomass solid fuels or municipal solid waste to produce steam and do not measure the high heat content of their fuels. The following is the equation from this section:

$$\text{CO}_2 = \text{Heat} * \text{CCEF} * 3.664 * 0.001$$

Where:

CO₂ = CO₂ emissions from fuel combustion, metric tonnes per year

Heat = Heat calculated in section 95125(h)(1)(B), MMBtu per year

CCEF = Default carbon content emission factor provided in Table 4 of Appendix A, kg carbon per MMBtu

3.664 = CO₂ to carbon molar ratio

0.001 = Conversion factor to convert kilograms to metric tonnes

The method utilizes default factors for carbon content by fuel type provided in Table 4 of Appendix A of the regulation and the heat content of the steam generated for the report year from the facility's boiler.

A second equation is provided in section 95125(h)(1)(B) that shows how to calculate the heat content from the steam. The heat content is calculated by multiplying the design heat input rate of the boiler by the pounds of steam produced during the report year.

$$\text{Heat} = \text{Steam} * B$$

Where:

Heat = Heat, MMBtu per year

Steam = Actual Steam generated, pounds per year

B = Boiler Design Heat Input/Boiler Design Steam Output, as Design MMBtu per pound Steam

Example 1 shows how the two formulas are used together to determine CO₂ emissions from a facility that combusts MSW.

Example 1: CO₂ Emissions from a Facility that Combusts Municipal Solid Waste

An operator needs to calculate CO₂ emissions from a facility that burns municipal solid waste to produce steam. The boiler design heat input rate at the facility is 173.3 MMBtu/ lb Steam and the total steam generated in the report year was 30,000 lbs.

Using 95125(h)(1)(B):

$$\text{Heat} = (173.3 \text{ MMBtu} / \text{lb Steam}) (30,000 \text{ lbs Steam} / \text{year}) = 5,199,000 \text{ MMBtu/year}$$

Using 95125(h)(1)(A) and carbon content for municipal solid waste from Appendix A (24.74 kg C / MMBtu), total CO₂ emissions may be calculated as follows:

$$\text{CO}_2 = (5,199,000 \text{ MMBtu/year})(24.74 \text{ kg C} / \text{MMBtu}) (3.664 \text{ CO}_2 / \text{C}) (0.001 \text{ tonne} / \text{kg}) = 471,276 \text{ tonnes CO}_2 / \text{year}$$

13.8.2 Method to Determine the Biomass Portion of Fuels and Fuel Mixtures, section 95125(h)(2)

The regulation requires that CO₂ emissions associated with biomass-derived fuels be calculated and reported separately from CO₂ emissions from fossil fuels. For certain fuels and fuel mixtures, this calculation can be problematic. The methodology provided in section 95125(h)(2) can be used to determine the biomass portion of a fuel or fuel mixture when fuel-based methodologies don't work. Section 95125(h)(2) does not provide a method for computing the overall CO₂ combustion emissions for the fuels burned. The methodologies for this purpose are identified for each sector by fuel type in sections 95110 through 95115 of the regulation.

The methodology in section 95125(h)(2) utilizes the analysis prescribed in the ASTM Method D6866-06a. The analysis is based on the fact that Carbon-14, a naturally occurring element in all living tissues, is present in a defined level of 100 percent in contemporary biomass and is absent (0 percent) in fossil fuels. The carbon analysis of the CO₂ gas taken from the facility stack determines the amount of biomass CO₂ vs. fossil CO₂ present in the CO₂ emissions produced by fuel combustion. For example, an analysis of the CO₂ emissions from a facility that co-fires 40 percent straw by weight and 60 percent coal would be 40 percent biomass carbon.

It is not feasible to use the ASTM Method D6866-06a to determine the biomass-derived portion of fuels or fuel mixtures when the total fuels being analyzed are less than 5 percent biomass. Thus, unless the operator co-fires pure biomass with fossil fuels, CO₂ emissions from combusting fuels or fuel mixtures believed to have less than 5 percent biomass-derived substances must be reported as if all the CO₂ is from fossil-fuels.

An operator using ASTM Method D6866-06a is required to collect gas samples every three months during normal operating conditions over at least 24 consecutive hours. The samples are analyzed and the percent biomass-derived carbon emissions determined once per quarter. The quarterly percentage of biomass-derived carbon emissions are summed and divided by four to yield an annual average percentage. This average annual percentage is applied to the total CO₂ emissions from all fuels

combusted for the report year to determine the amount of total CO₂ emissions that are from biomass-derived fuels. Example 2 illustrates these calculations.

If there is a common fuel source for multiple units at the facility the operator may elect to conduct ASTM D6866-06a testing for just one of the units. A recently released ASTM Method D7459-08 addresses sampling procedures for ASTM Method D6866-06a. ARB recommends that operators consult ASTM Method D7459-08 for additional guidance on how to collect samples.

Example 2: Determining the Percent of Fuel that is Biomass-Derived

An operator of a facility that combusts municipal solid waste needs to determine what portion of the CO₂ emissions are from biomass-derived fuel and what emissions are from fossil fuels. He has already calculated CO₂ emissions for the report year using the method in section 95125(h)(1) and conducted four D6866-06a analyses of CO₂ taken from his facility. The operator knows that:

400,000 metric tonnes = total CO₂ emissions from the facility for the report year

61% = biomass portion of CO₂ emissions taken in January

75% = biomass portion of CO₂ emissions taken in April

70% = biomass portion of CO₂ emissions taken in July

80% = biomass portion of CO₂ emissions taken in October

71.5% = biomass portion averaged over all samples $((61+75+70+80)/4)$

Thus,

CO₂ emissions from biomass = $0.715 * 400,000$ metric tonnes = 286,000 metric tonnes

CO₂ emissions from fossil fuels = $400,000 - 286,000 = 114,000$ metric tonnes

Certain operators may choose to conduct the ASTM Method D6866-06a analysis though not required to do so. This option is available to operators who combust fossil fuels with waste-derived fuels that include biomass, when the waste-derived portion of the total fuel mixture is less than 30 percent by weight. For example, if the operator combusts 20 percent tires by weight and 80 percent coal, the operator is not required to conduct the D6866-06a analysis. However, in the absence of the ASTM Method D6866-06a analysis, all CO₂ emissions reported from fuel combustion must be categorized as from fossil fuels. The operator will lose the option to report any portion of CO₂ emissions as biomass-derived. In this example, if the tires themselves are estimated to contain 15 percent biomass, then the overall total fuel mixture would have an estimated biomass content of 3 percent. This amount of biomass is too small to feasibly conduct the D6866-06a analysis. Thus, all CO₂ emissions from fuel combustion must be reported as from fossil fuels.

13.8.3 Method to Calculate CO₂ Emissions Using a Site-Specific Emission Factor, section 95125(h)(3)

In lieu of using the methodology provided in section 95125(h)(1) to calculate CO₂ emissions, section 95125(h)(3) provides an alternative methodology for operators who combust biomass solid fuels or waste-derived fuels including MSW. The method allows

the operator to develop their own source specific emission factors derived from source tests conducted at least annually. To use this method, operators must have ARB approved source test plans and emission factors. If the operator combusts fuels that are at least 5 percent biomass but not pure biomass, the operator must also meet the requirements in section 95125(h)(2) to determine the amount of CO₂ emissions associated with biomass-derived fuels versus fossil fuels.

Operators who choose to use site-specific emission factors to calculate CO₂ emissions are requested to review Appendix B of this document. Appendix B provides detailed information on getting ARB approval for plans and emission factors and on methodologies for conducting sources tests.

13.9 Method for Calculating Mobile Combustion Emissions, Section 95125(i)

[[Section to be completed later - voluntary reporting category]]

The California GHG reporting regulation allows for the voluntary reporting of your mobile source emissions. If you choose to report these emissions you must follow the methods provided within the regulation when applicable. This is to ensure consistency between reporting facilities. We also recommend being as complete as possible if you choose to report mobile sources.

13.10 Method for Calculating Fugitive CH₄ Emissions from Coal Storage, Section 95125(j)

Certain types of facilities are required to report fugitive methane (CH₄) emissions from coal stored on site. Facilities required to report these emissions when present include cement plants, electric generating facilities, and most cogeneration facilities.

The approach for calculating fugitive coal methane emissions is relatively simple. The key information needed is the total annual coal purchases (in short tons) for the report year and the source of those purchases. Annual purchases of coal should be compiled from purchasing records or other reliable information. GHG emissions reporting is based on calendar year emissions. Therefore, for any purchases that span the December-January time period, it may be necessary to pro-rate these emissions to reflect only the January 1 to December 31 reporting period. See the guidance for Section 95125(k), for indirect electricity usage, for additional information on subdividing the fuel use across years.

The equation below is used to calculate fugitive methane emissions from coal storage:

$$CH_4 \text{ (metric tonnes)} = PC \text{ (tons)} * EF \text{ (scf CH}_4\text{/ton)} * CF_1 / CF_2$$

Where

CH_4 = CH₄ emissions in the report year, metric tonnes per year

PC = Purchased coal in the report year, tons per year

EF = Default emission factor for CH₄ based on coal origin and mine type provided in Appendix A Table 10, scf CH₄/ton

CF₁ = Units conversion factor equals 0.04228, lbs CH₄/scf

CF₂ = Units conversion factor equals 2,204.6, lbs/metric ton

Table 10 in Appendix A of the regulation provides the emission factors for calculating the fugitive methane emissions (the EF value in the equation above). Multiple coal-supplying regions are provided in the table. If coal is provided from various sources, then the equation above should be applied separately for each coal source based on its origin, and the results summed.

Example. Table 13.10.1 below illustrates the calculations. The first column shows the source of the coal purchased, the second column shows the amount purchased, the third shows the emission factor in the regulation, and the fourth column is the conversion factor to convert from standard cubic foot (scf) per year to metric tonnes of CH₄ per year. The final column was computed by multiplying columns two, three, and four together. In this scenario, the reported methane emissions would be 5.16 metric tonnes of methane per year coal storage.

Table 13.10.1 Estimating Facility Fugitive Methane Emissions from Coal Storage

<i>Coal Source</i>	<i>Amount Purchased Jan 1 to Dec 31, 2008 (tons coal/year)</i>	<i>Emission Factor (scf CH₄ /ton coal)</i>	<i>Conversion Factor (scf/year to tonnes/year)</i>	<i>Emissions (tonnes CH₄/year)</i>
Rockies (Piceance Basin, underground)	3,137	63.8	1.92 x 10 ⁻⁵	3.84
Rockies (Raton Basin, surface)	6,358	10.8	1.92 x 10 ⁻⁵	1.32
Total	9,495			5.16

Note that the emission factors for coal mined from underground sources are significantly higher than surface mined coal. This is because the surface mined coal has already lost a significant amount of the entrained methane due to its ongoing exposure to the atmosphere. For underground deposits, a fair amount of the methane remains trapped within the coal until it is released during the mining, shipping, and storage activities.

This simplified method does not take into account how long the coal has been stored on site, or the storage time and the decay rate of the methane emissions, which will reduce over time. This avoids unnecessarily complex computations given the small contribution of this source to the facility's inventory.

In many cases these emissions will be able to be claimed as *de minimis*, though still reported. For additional information about *de minimis*, refer to the guidance for section 95103 of the regulation. Also, for a *de minimis* example specific to fugitive methane coal emissions, refer to the Power/Utility reporting protocol developed by the California Climate Action Registry (<http://www.climateregistry.org/tools/protocols/industry-specific-protocols.html>, see Chapter 10).

13.11 Method for Calculating Indirect Electricity Usage, Section 95125(k)

All reporting sectors are required to report their indirect electricity usage. Indirect electricity is any electricity provided by an electricity retail provider or other facility that is not owned or operated by the user of the energy. Most typically, indirect electricity is purchased electricity, obtained from a power company such as Southern California Edison or Pacific Gas and Electric.

The GHG reporting regulation requires you to report the amount of electrical energy purchased in kilowatt-hours (kWh), by energy provider. The GHG emissions associated with these energy purchases are not reported.

Only the amount of electricity purchased (in kWh) and the supplier(s) of the electricity are reported. The indirect emissions from electricity purchased are not reported.

To determine the annual indirect electricity usage for your facility, the recommended method is to use the energy bills provided by your electricity provider. Your monthly bills will include the number of kilowatt-hours consumed. A kilowatt-hour (kWh) is a measure of the energy used by electric loads, such as lights, office equipment, air conditioning, or machinery.

Depending on how your facility is structured, you may need to combine multiple bills to capture the full facility electricity usage. Once you have your bills for the entire year, you have all of the information needed to complete this portion of the GHG emissions report.

The GHG reporting period spans a full calendar year (January 1st to December 31st), so if your bills begin and end at the start and end of each month, then simply add them up for each provider. Report the total kilowatt-hour consumed from each energy provider and the name of the provider.

In most cases it will also be necessary to subdivide the January and December bills to provide electricity use for the appropriate January to December date splits. This pro-rating is easily done by calculating the amount of electricity used per day during the billing period, and then multiplying the number of days in the partial month by the energy use per day.

The equation below shows this calculation.

Calculating electricity use for partial months:

Step 1.

Average kWh use per day = Electricity use (kWh) in Month / Total number days month

Step 2.

*kWh used in reporting period = Average kWh per day * Number of days in the reporting period*

This calculation for pro-rating the electricity use needs to be performed for the December and January electricity purchases unless the December billing date ends exactly on December 31.

Example. As an example, assume a facility has the following electricity bills from December 16, 2007, to January 15, 2009, and subsequent months, all from ACME Power Providers. Each billing period is shown with the amount of energy provided, the number of days in the billing period, the kWh per day (= kWh billed for period / # days in period), the number of days in the 2008 reporting year, and the amount of electricity billed in the reporting year (= kWh per day * # of days in Reporting year). The kWh for each month or partial month are summed to get the total of 13,505 kWh per year. This is the value to be reported in the GHG emissions report, along with the name of the energy provider, ACME Power.

Table 13.11.1 Example Billing and Computing Annual Usage

<i>Billing Period</i>	<i>kWh Billed for Period</i>	<i># of Days in Period</i>	<i>kWh per day</i>	<i># of Days in Reporting Year</i>	<i>kWh for Reporting Year</i>
Dec 16, 2007 - Jan 15, 2008	1,087	31	35	15	526
Jan 16 - Feb 15	1,007	31	32	31	1,007
Feb 16 - Mar 15	1,104	28	39	28	1,104
Mar 16 - Apr 15	1,242	31	40	31	1,242
Apr 16 - May 15	1,097	30	37	30	1,097
May 16 - Jun 15	1,174	31	38	31	1,174
Jun 16 - Jul 15	1,302	30	43	30	1,302
Jul 16 - Aug 15	1,187	31	38	31	1,187
Aug 16 - Sep 15	1,194	31	39	31	1,194
Sept 16 - Oct 15	1,027	30	34	30	1,027
Oct 16 - Nov 15	1,318	31	43	31	1,318
Nov 16 - Dec 15	1,275	30	43	30	1,275
Dec 16, 2008 - Jan 15, 2009	1,117	31	36	16	577
				Total Reported kWh for 2008	13,505

13.12 Method for Calculating Thermal Energy Usage, Section 95125(I)

Under the California GHG reporting regulation, all reporting sectors are required to report their indirect thermal energy usage. Indirect thermal energy is any thermal energy provided by a facility that is not owned or operated by the user of the energy. This could include purchased steam, district heat, or cooling. The thermal energy generated from cogeneration activities under operational control of your reporting facility is reported as direct energy, rather than indirect energy. Thermal energy purchased or acquired from a cogeneration facility that is separately operated and maintained, even if on the same facility site, is reportable as indirect thermal energy.

The GHG reporting regulation requires reporting of the amount of thermal energy purchased in British Thermal Units (Btu), by energy provider. The GHG emissions associated with these energy purchases are not reported.

Only the amount of thermal energy purchased (in Btu) and the supplier(s) of the energy are reported. The indirect emissions from purchased thermal energy are not reported.

To determine the annual indirect thermal energy usage for your facility, the recommended method is to use your facility thermal energy purchase records. These records should include the information necessary to estimate annual thermal energy purchases in Btu. If the heating or cooling information is not provided in Btu units on the purchase records, The Climate Registry General Reporting Protocol⁴ provides additional methods available for computing energy consumption based on the enthalpy of the steam delivered, boiler efficiencies, cooling demand, or other inputs.

Depending on how your facility is structured, you may need to combine multiple bills to capture the full facility thermal usage. Once you have your records for the entire year, you have all of the information needed to complete this portion of the GHG emissions report.

The GHG reporting period spans a full calendar year (January 1st to December 31st), so if your bills begin and end at the start and end of each month, then simply add them up for each provider. Report the total kilowatt-hour consumed from each energy provider and the name of the provider. However, in most cases it will be necessary to subdivide the January and December bills to provide electricity use for the appropriate January to December date splits.

See the guidance for section 95125(k) for an example of splitting billing cycles across months. For reporting, also ensure that the units reported are Btu, and not therms or another unit of measure (1 therm = 100,000 Btu). Table 1 in Appendix A of the regulation provides common conversion factors.

As with indirect electricity reporting, we are not asking for the calculation and reporting of the GHG emissions associated with indirect thermal energy purchases. Only the steam, heat or cooling obtained from another operator needs to be reported. Facility operators with their own cogeneration activities that meet the reporting threshold will report these emissions as specified in section 95112 of the regulation.

⁴ The Climate Registry, General Reporting Protocol, Version 3.1, May 2008. Section 15.
<http://www.theclimateregistry.org/reference.html>