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# Calculating Greenhouse Gas Emissions from Iron and Steel Production

**A component tool of the Greenhouse Gas Protocol Initiative**

January 2008.

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## **1.0 Overview**

### ***1.1 Purpose of tool***

This document provides guidance on the estimation of greenhouse gas (GHG) emissions from sources associated with Iron and Steel production. A companion spreadsheet, available at [www.ghgprotocol.com](http://www.ghgprotocol.com), implements the methods described in this document. Together these documents comprise the ‘Iron and Steel Tool’, one of many calculation tools available under the Greenhouse Gas Protocol Initiative, a joint program of the World Resources Institute and the World Business Council for Sustainable Development. The Iron and Steel Tool may be used by companies for internal or public reporting needs, or to participate in a GHG program. Likewise GHG programs, including voluntary or mandatory programs and emission trading schemes, may also customize this tool for their program’s needs.

This guidance explains best practices for the selection and implementation of emission calculation methods, as well as for the collection, documentation, and quality control of data. It often presents different methods for calculating emissions from single sources so that different users of the Iron and Steel tool may match the rigor and detail of their emission inventory to their needs or goals. The guidance has been structured so that any company, regardless of its experience or resources, should be able to produce reliable estimates of its emissions. In particular, default values for virtually all of the parameters in the methods are supplied so that, at the very least, a company needs only to supply data on production volumes or the amount of fuel consumed, for example.

This tool updates the Corporate Standard’s previous guidance for the Iron and Steel sector that was issued in 2002. Major revisions in this update include the provision of methods for specific industrial activities within the overall iron and steel manufacturing process. For example, facilities may now account for the emissions from Direct Reduced Iron and sinter production, as well as coke manufacture. Furthermore, this update includes expanded coverage of stationary combustion sources, such as reheating furnaces, which may contribute significantly to an Iron and Steel facility’s overall emissions.

Users of the Iron and Steel Tool and of other tools available under the GHG Protocol Initiative should consult the Corporate Standard (available at [www.ghgprotocol.org](http://www.ghgprotocol.org)), which outlines best practices for general GHG accounting issues. In particular, the Corporate Standard explains why Iron and Steel companies need to have clearly set their

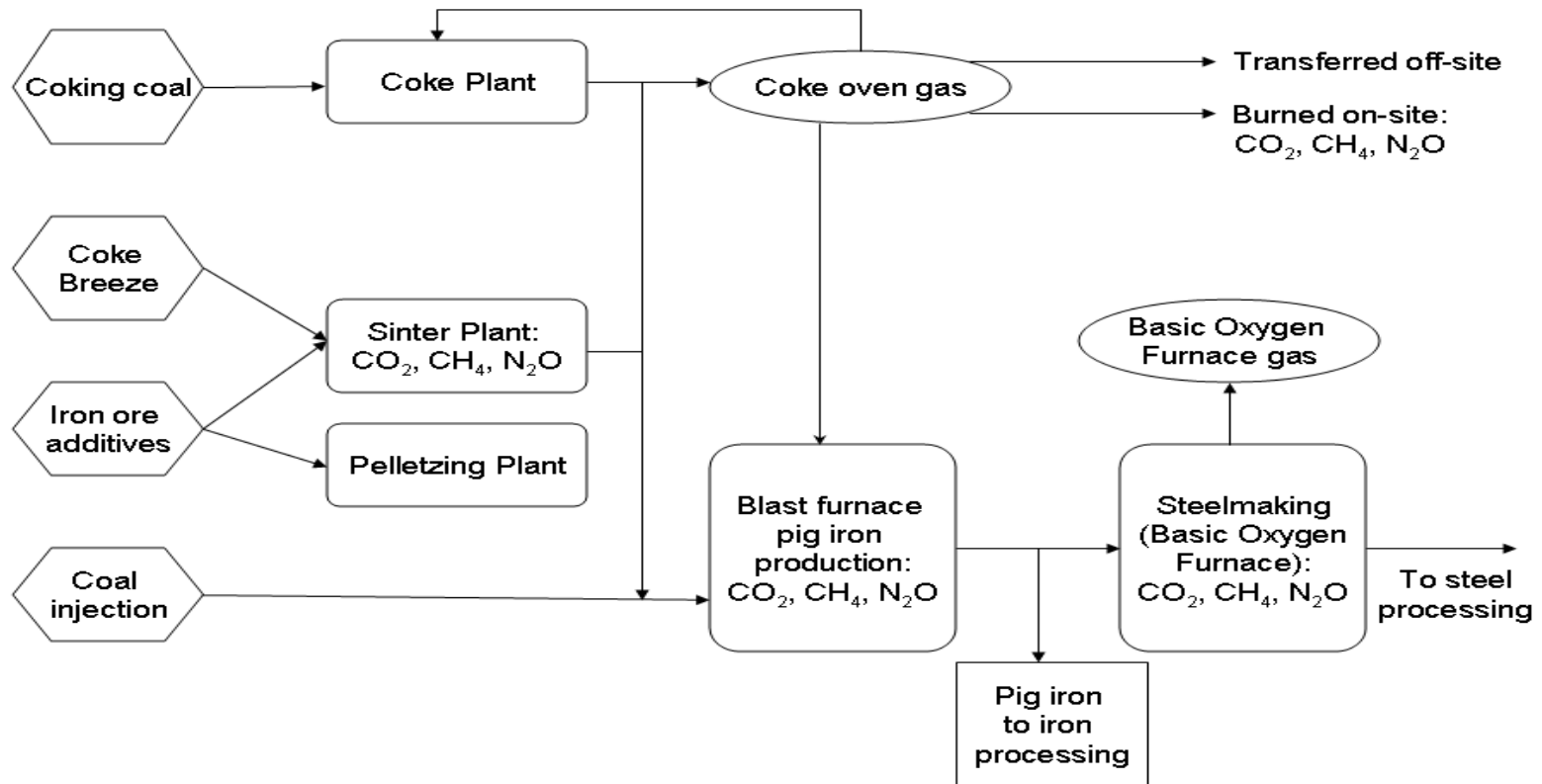
organizational and operational boundaries prior to developing an inventory. Because boundaries constitute a critical issue in GHG accounting that has to be considered prior to the use of this tool, Section 2.0 of this guidance summarizes some basic concepts related to the drawing of boundaries (see Section 2.0). Users should consult the Corporate Standard for further guidance and information.

## ***1.2 Domain of application***

The manufacture of iron and steel is an energy intensive activity that generates carbon dioxide (CO<sub>2</sub>), methane (CH<sub>4</sub>), and nitrous oxide (N<sub>2</sub>O) emissions at various stages during the production process (Figure 1). Although CO<sub>2</sub> is easily the main GHG emitted, N<sub>2</sub>O and CH<sub>4</sub> emissions are not necessarily trivial. Hence, the Iron and Steel tool has incorporated methods for each of these three GHGs whenever possible. Figure 1 summarizes the industrial activities and associated GHG emissions that are considered in this tool.

Please note that this tool does not provide guidance on calculating emissions from transport vehicles ('mobile combustion') or the consumption of purchased electricity, heat and steam. Instead, users interesting in calculating emissions from these sources should consult the relevant tools from the Protocol Initiative's website ([www.ghgprotocol.org](http://www.ghgprotocol.org)).

**Figure 1.** The main GHG emission sources associated with iron and steel production that are considered in this tool. Other sources that are not represented here and that may contribute significantly to a facility's overall emissions include the on-site transportation of materials and the consumption of purchased electricity, heat and steam. Figure modified from the 2006 IPCC Guidelines for National Greenhouse Gas Inventories.



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## **2.0 Organizational and Operational Boundaries**

The manner in which organizational and operational boundaries are drawn determines both the sources that are included within an inventory and the emissions from those sources that are reported by a company. Because it is critical that boundaries are consistently and reliably drawn across a company's constituent facilities and units, organizational and operational boundaries are briefly discussed here. Users are strongly encouraged to consult the Corporate Standard for further guidance.

### **2.1 Organizational boundaries**

For corporate inventories, the exact accounting of the emissions from a source depends on whether that source is wholly owned, a joint venture, subsidiary, or other legal entity. The Corporate Standard provides two approaches for determining how such accounting should be undertaken.

#### I. Equity share approach

A company reports the percentage GHG emissions from a source that mirrors the percentage financial ownership that company has in the source. One exception relates to fixed asset investments: whenever a company owns only a small part of the shares of a source and does not exert significant financial control, the company does not account for that source's emissions.

#### II. Control Approach

A company reports 100% of the emissions from sources over which it has control. Two alternative criteria can be used to define control:

(a) Financial control. A company exerts financial control over the source if it has the ability to direct both the financial and operating policies of the source with a view to gaining economic benefits from such activities.

(b) Operational control. A company has operational control over a source if it has the full authority to introduce and implement its operating policies and practices at the source.

The Corporate Standard encourages companies to use both the equity share approach and a control approach when reporting under voluntary schemes. However, contractual arrangements might determine the ownership of and reporting requirements for GHG

emissions, and various other factors might influence the choice of an approach, including:

- Liability and risk management. In assessing risk the equity share and financial control approaches might be most appropriate choices.
- Management information and performance tracking. The control approaches would allow managers to be held accountable for activities under their control.
- Completeness of reporting. Companies may find it difficult to provide matching records or lists of financial assets as proof that sources are correctly accounted for under the operational control approach.

Once an appropriate approach has been determined it should be consistently applied across all of the facilities and units under the control of the reporting company.

## **2.2 Operational boundaries**

Having established its organizational boundaries, a company is then able to establish the scope (or ‘operational boundaries’) of an emissions source. Robustly defined operational boundaries will help a company better manage the full spectrum of GHG risks and opportunities that exist along its value chain. In particular, the use of scopes helps companies meet the reporting requirements of corporate reporting programs, voluntary GHG registries, and other GHG programs.

Emissions fall under one of three scopes. Scope 1 emissions are ‘direct’; that is, they stem from sources that are owned or controlled by the reporting company. Scopes 2 and 3 refer to ‘indirect’ emissions that originate from sources that are controlled by third parties, but that are nonetheless related to the activities of the reporting company. Scope 2 emissions stem from the consumption of purchased electricity, and Scope 3 emissions from all other indirect sources, notably the third party transport of raw materials.

Scope 2 emissions are not considered in this document, although Scope 3 emissions from the production of coke and of limestone and dolomite are. Otherwise, the methods in this tool pertain to Scope 1 emissions.

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## 3.0 Methodologies

### 3.1 Introduction

#### Tiers

Many of the methods described in this document are categorized as belonging to one of three tiers. Typically the equations underlying a method do not change amongst tiers. Instead, the values of the parameters forming those equations do, and tiers differ in how much those values are representative of the activities of the reporting company. As the tier level increases from Tier 1 to Tier 3 the values become more specific to the reporting company, leading to greater accuracy in the emissions calculations. A tier system is used here to emphasize the advantages of collecting and using facility-specific information, and to distinguish between the different sets of default factors that are available for some methods (e.g., both Tier 1 and Tier 3 default emission factors are offered for reheating furnaces).

- Tier 1: Tier 1 methods estimate emissions by multiplying production data, such as the volume of fuel used or steel produced, by an industry-specific default emission factor. Tier 1 defaults are supplied for all of the methods in the Iron and Steel Tool, where appropriate.
- Tier 2: Tier 2 methods require data that are less general. For instance, a Tier 2 emission factor might reflect the typical industrial practices within a specific country, whereas a Tier 1 factor constitutes a global default value. Facility-specific data are not considered Tier 2. Tier 2 data might be available from national statistical agencies or industry associations.
- Tier 3: Tier 3 methods require facility-specific data, such as the composition of the fuel combusted at a facility, or the specific types of technologies employed at a facility.

Facilities should ensure that only a single method is used to calculate the emissions from a single source so as to help avoid the double counting of emissions. Particular care should be exercised when fuels have dual energy and process uses, as might happen with blast furnace gases, sinter off gases and coke oven gasses, which, although the product of industrial processes, can also be used to supply energy to industrial processes. Companies are recommended to use the most accurate method possible given the data they have at hand.



### Differences between CO<sub>2</sub> and CH<sub>4</sub>/N<sub>2</sub>O

The recommended methods for calculating CO<sub>2</sub> emissions often differ from those for N<sub>2</sub>O and CH<sub>4</sub> emissions. This is because CO<sub>2</sub> emissions are largely determined by the carbon contents of the consumed materials, whereas N<sub>2</sub>O and CH<sub>4</sub> emissions are much more influenced by the combustion or emission control technologies employed by the industrial apparatus. Consequently, CO<sub>2</sub> emissions are best determined using a material balance approach that tracks the flow of carbon through the industrial process, whereas N<sub>2</sub>O and CH<sub>4</sub> emissions are best determined using equipment or process-specific emission factors. The methods in this guidance will treat CO<sub>2</sub> separately from N<sub>2</sub>O and CH<sub>4</sub>.

N<sub>2</sub>O is only considered by this tool in relation to stationary combustion sources. This is because the N<sub>2</sub>O emissions from the industrial processes specific to the Iron and Steel sector are assumed to be negligible.

### Global Warming Potentials

The Global Warming Potential (GWP) of a greenhouse gas is a measure of how much a given mass of that gas contributes to global warming. GWPs are given on a relative scale that compares the gas in question to carbon dioxide, whose GWP is therefore 1.0. Over a 100 year time horizon the GWP of CH<sub>4</sub> is 21, whereas that of N<sub>2</sub>O is 310 (IPPC Second Assessment Report).

In this tool the emissions of each greenhouse gas are multiplied by a relevant GWP to determine the potential impacts on global warming of these emissions. The product of this multiplication is given in units of CO<sub>2</sub>-equivalents (metric tones CO<sub>2</sub>-e.). The spreadsheet program that accompanies this guidance allows facilities to calculate both the absolute emissions of individual GHGs and their CO<sub>2</sub>-equivalency.

## **3.2 Stationary Combustion**

Stationary combustion emissions account for roughly half of the overall emissions from an Iron and Steel company and include CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O emissions. Stationary combustion sources belong to four main types:

1. Electricity generation; e.g., captive power plant boilers
2. Re-heating furnaces (other coal and oil use); e.g., mill sections

3. Coke production
4. Flaring

### 3.2.1 Emissions from Electricity Generation and Reheating Furnaces

#### **CO<sub>2</sub>**

The calculation of CO<sub>2</sub> emissions from Electricity Generation and Reheating Furnaces requires data on the carbon content, heating value and oxidation fraction of the consumed fuel(s). Default, Tier 1 values for each of these factors are supplied.

The following sections provide information on these factors and on how the fuel consumption data should be gathered.

#### Fuel Consumption Data

Facilities need to collate data on the amount of fuel consumed over the reporting year and disaggregate these data by fuel type. These data can come directly from on-site metering of the fuel inputs into the combustion units or from the output of these units. Alternatively, the data may be calculated from purchase or delivery records, in which case companies should be careful to account for inventory stock changes following Equation 1:

<b>Equation 1</b>	<b>Accounting for Changes in Fuel Stocks</b>
$\text{Total Annual Fuel Consumption} = \text{Annual Fuel Purchases} - \text{Annual Fuel Sales} + \text{Fuel Stock at Beginning of Year} - \text{Fuel Stock at End of Year}$	

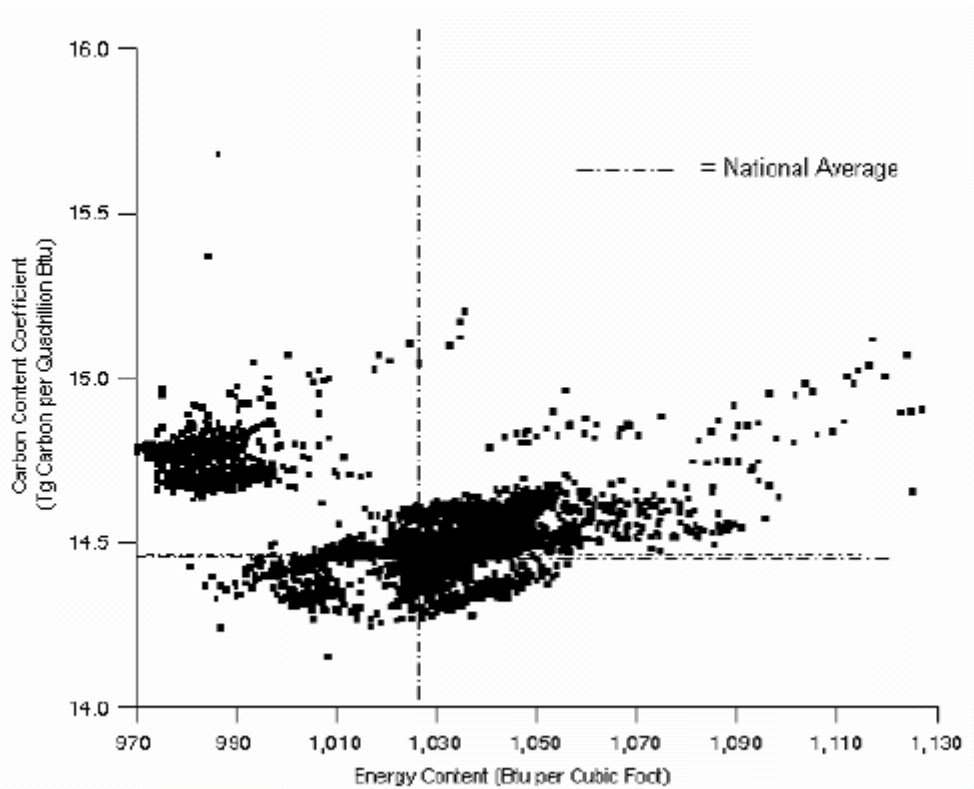
#### Fuel Carbon Content and Heating Values

The *carbon content* of a fuel is the fraction or mass of carbon atoms relative to the total mass or number of atoms in the fuel; it is thus a measure of the potential CO<sub>2</sub> emissions from that fuel's combustion.

The carbon content of a given fuel can show variation over space and time (see Figure 2 for an example). The extent of variation can depend on the units chosen to express the carbon content data - less variability is often seen when the data are expressed on an

energy basis (e.g., Kg carbon/MJ or tonnes carbon/ million Btu) compared to a mass or volume basis (e., kg C/ Kg fuel). Carbon content values can be converted to energy units using heating or calorific values.

**Figure 2.** Spatial variation in the carbon content of pipeline-quality natural gas in the U.S.



Source: Energy Information Administration (1994), Emissions of Greenhouse Gases in the United States 1987-1992.

A fuel's *heating value* is the amount of heat released during the combustion of a specified amount of that fuel (example units are MJ/Kg, thousand Btu/lb, and MMBtu/bbl). Two alternative metrics of heating value may be used to adjust carbon content data: lower heating value (LHV; also known as Net Calorific Value (NGV)) and higher heating value (HHV; also known as Gross Calorific Value (GCV)). These metrics differ in how they consider the different physical states (liquid or gaseous) that water exists in following combustion. The HHV includes the latent energy of condensation of water following combustion, whereas the LHV is obtained by subtracting the heat of vaporization of the water produced by combustion from the higher heating value. More specifically:

**Equation 2****Inter-converting HHV and LHV data**

$$LHV = HHV - 0.212H - 0.0245M - 0.008Y$$

Where:

$M$  = % moisture

$H$  = % hydrogen

$Y$  = percent oxygen

A commonly accepted approximation for inter-converting LHV and HHV data is to assume that the LHV is 95% of the HHV for solid fuels, such as coal and oil, but 90% of the HHV for gaseous fuels, such as natural gas.

One benefit of the HHV over the LHV is that the relationship between carbon content and heating values is more direct using the former. This is because the LHV is partly a function of the fuel's moisture content, which can vary significantly. In North America the convention is to use HHV, whereas LHV is used outside North America.

Carbon content factors can be converted to an energy scale using heating values with Equation 3:

**Equation 3****Converting carbon content factors from a mass or volume basis to an energy basis**

$$F_{c,h} = \frac{F_c}{HVf}$$

Where:

$F_{c,h}$  = Carbon content of fuel on a heating value basis (e.g., short tons carbon / million Btu or metric tons carbon / GJ)

$F_c$  = Carbon content of fuel on a mass or volume basis (e.g., short ton carbon / short ton)

$HVf$  = Heating value of fuel (e.g., MJ/Kg, thousand Btu/lb or MMBtu/bbl, etc.)

To summarize, given the variability that can exist in fuel composition, companies are encouraged to use Tier 3, facility-specific values for carbon content and heating values whenever possible. Ideally, the carbon content factors should be expressed on an energy scale using higher heating values. Tier 3 information may be available from suppliers or from the Material Safety Data Sheets for purchased fuels. In case facility-specific values can not be derived, plants may use the Tier 1 default values in Appendix I. Companies may use a mix of plant-specific and default values in a single calculation (e.g., custom carbon content factor, but default HHV data). Tier 2 values may be available from national statistical agencies and other national-level organizations.

## Fuel Fraction Carbon Oxidation Factor

A small fraction of a fuel's carbon content can escape oxidation and remain as a solid after combustion in the form of ash or soot (for solid fuels) or particulate emissions (for natural gas and other gaseous fuels). This unoxidized fraction is a function of several factors, including fuel type, combustion technology, equipment age, and operating practices. This fraction can be assumed to contribute no further to CO<sub>2</sub> emissions, so it is easily corrected for in estimating CO<sub>2</sub> emissions. The stationary combustion CO<sub>2</sub> methods in this tool use an 'oxidation factor' to account for the unoxidised fraction (where 1.00 = complete oxidation). In general, variability in the oxidation factor is low for gaseous and liquid fuels, but can be much larger for solid fuels. For example, an Australian study of coal-fired boilers found that the oxidation factor ranged from 0.99 – 0.88 (IPCC, 2006).

The preferred approach for developing a Tier 3 facility-specific oxidation factor is to measure the quantity of residual solid left over from the combustion process and then analyze that residue's carbon content. However, if this is not possible a Tier 1 default value of 1.00 can be assumed.

## Calculating CO<sub>2</sub> Emissions

Facilities should first ensure that all units are consistent with each other (Appendix III provides unit conversion ratios). Facilities are encouraged to express any Tier 2/3 carbon content data on an energy basis using HHV values, before using Equation 4 to calculate the emissions. Otherwise, when these data are expressed on a mass or volume basis, Equation 5 should be used. Default, Tier 1 values for use with Equations 4 and 5 are given in Appendix I.

### Equation 4

Calculating CO<sub>2</sub> emissions using carbon content data that are expressed on a mass or volume basis

Mass basis: 
$$E = A_{f,v} \cdot F_{c,v} \cdot F_{ox} \cdot \frac{44}{12}$$

Volume basis: 
$$E = A_{f,m} \cdot F_{c,m} \cdot F_{ox} \cdot \frac{44}{12}$$

Where:

E = Amount of CO<sub>2</sub> emitted (metric tons)

$A_{f,v}$  = Volume of fuel consumed (e.g., liters, gallons, m<sup>3</sup>, etc.)

$A_{f,m}$  = Mass of fuel consumed (e.g., kg, short ton, etc.)

$F_{c,v}$  = Carbon content of fuel on a volume basis (e.g., short tons carbon / gallon)

$F_{c,m}$  = Carbon content of fuel on a mass basis (e.g., short tons carbon / short ton)

$F_{OX}$  = Fraction oxidation factor

44/12 = The ratio of the molecular weight of carbon to that of CO<sub>2</sub>

**Equation 5** Calculating CO<sub>2</sub> emissions from stationary combustion sources using carbon content data expressed on an energy basis:

$$E = A \cdot HV_f \cdot F_{c,h} \cdot F_{ox} \cdot \frac{44}{12}$$

Where:

$E$  = Amount of CO<sub>2</sub> emitted (metric tonnes)

$A$  = Mass of fuel consumed (e.g., metric tonnes)

$HV_f$  = Heating value of fuel (e.g., MJ/Kg or thousand Btu/lb)

$F_{c,h}$  = Carbon content of fuel on a heating value basis (e.g., short tons C/million Btu or metric tonnes C/GJ)

$F_{OX}$  = Fraction oxidation factor

44/12 = The ratio of the molecular weight of carbon to that of CO<sub>2</sub>

### CH<sub>4</sub> and N<sub>2</sub>O emissions

The N<sub>2</sub>O and CH<sub>4</sub> emissions from Electricity Generation and Reheating Furnaces can be calculated using Equation 6. This tool provides two sets of default emission factors that can be used with Equation 6. Appendix II lists fuel-specific default factors that are Tier 1. Table 1 lists equipment-specific factors that are Tier 3. Facilities are encouraged to use the Tier 3 factors whenever possible, although they may instead use the Tier 1 factors if they do not have reliable data on the equipment in use at their combustion units. Tier 2 factors that are fuel- and country-specific, but not equipment-specific, may also be used and may be obtainable from national statistical agencies and other national-level organizations. Note that the default N<sub>2</sub>O factors are generally based on limited measurements and have a high degree of uncertainty.

**Equation 6** Calculating N<sub>2</sub>O and CH<sub>4</sub> emissions from stationary combustion sources

*Tier 1:*  $E = A_f \cdot HHV_f \cdot EF * GWP$

*Tier 3:*  $E = A_f \cdot HHV_f \cdot ESEF * GWP$

Where:

$E$  = Amount of either N<sub>2</sub>O or CH<sub>4</sub> emitted (metric tonnes CO<sub>2</sub>-equivalent)

$A_f$  = Amount of fuel combusted on a mass or volume basis (e.g., lb, bbl, etc.)

$EF$  = Tier 1 fuel-specific emission factor (see Appendix II for default values)

$ESEF$  = Tier 3 Equipment-specific emission factor (see Table 1 for default values)

$GWP$  = 21 for CH<sub>4</sub> or 310 for N<sub>2</sub>O

**Table 1:** Tier 3 equipment-specific CH<sub>4</sub> and N<sub>2</sub>O default emission factors for stationary combustion sources

Technology		LHV/NCV basis: kg/TJ fuel		HHV/GCV basis: kg/TJ fuel				
		CH <sub>4</sub>	N <sub>2</sub> O	CH <sub>4</sub>	N <sub>2</sub> O			
Basic Technology		Configuration		CH <sub>4</sub>	N <sub>2</sub> O			
<b>Liquid fuels</b>	Residual fuel oil/ Shale oil boilers			3.000	0.300	3.158	0.316	
	Gas/Diesel oil boilers			0.200	0.400	0.211	0.421	
	Large stationary diesel oil engines >600hp (447kW)			4.000	N/A	4.211	N/A	
	Liquified Petroleum Gases (LPG) boilers			0.900	4.000	0.947	4.211	
<b>Solid fuels</b>	Other bituminous /Sub-bituminous overfeed stoker boilers			1.000	0.700	1.053	0.737	
	Other bituminous /Sub-bituminous underfeed stoker boilers			14.000	0.700	14.737	0.737	
	Other bituminous/sub-bituminous pulverised	Dry bottom, wall fired			0.700	0.500	0.737	0.526
		Dry bottom, tangentially fired			0.700	1.400	0.737	1.474
		Wet bottom			0.900	1.400	0.947	1.474
	Other bituminous spreader stokers			1.000	0.700	1.053	0.737	
	Other bituminous/sub-bituminous fluidised bed combustor	Circulating bed			1.000	61.000	1.053	64.211
		Bubbling bed			1.000	61.000	1.053	64.211
<b>Natural Gas</b>	Boilers			1.000	1.000	1.111	1.111	
	Gas-fired gas turbines >3MW			4.000	1.000	4.444	1.111	
	Natural gas-fired reciprocating engines	2-Stroke lean burn			693.000	N/A	770.000	N/A
		4-Stroke lean burn			597.000	N/A	663.333	N/A
		4-Stroke rich burn			110.000	N/A	122.222	N/A
<b>Biomass</b>	Wood/wood waste boilers			11.000	7.000	11.579	7.368	

Source: IPCC 2006, Volume 2, Chapter 2.

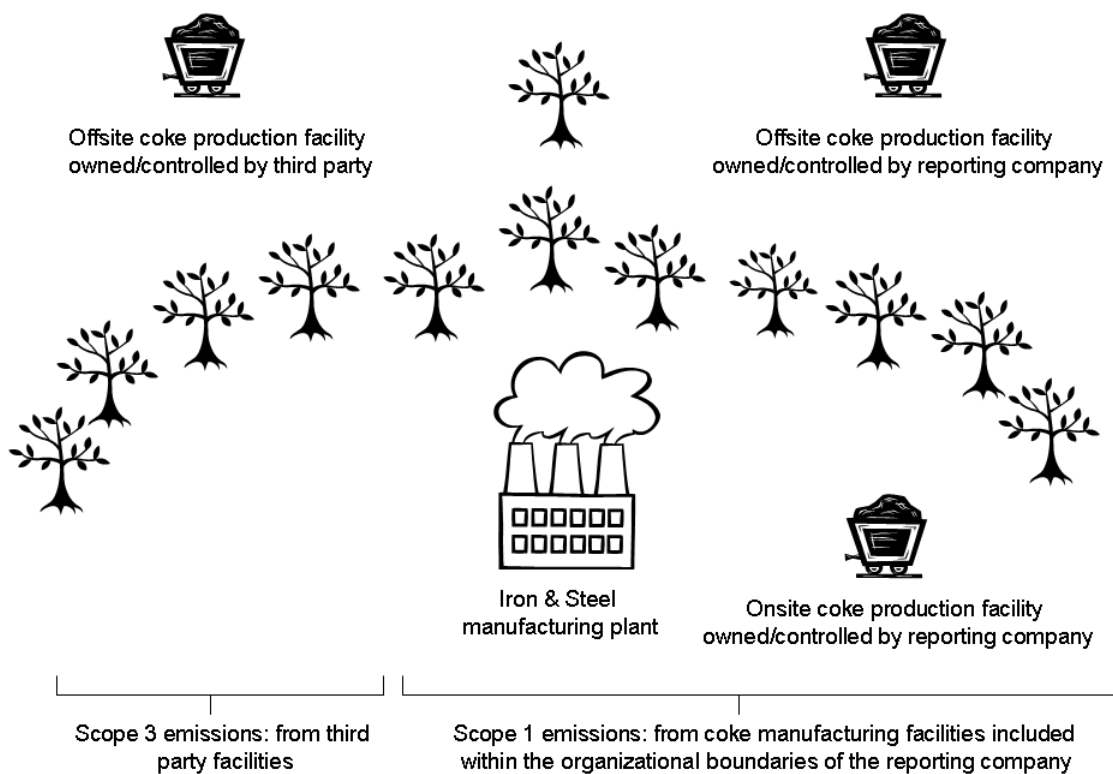
### 3.2.2 Emissions from Coke Making

#### CO<sub>2</sub>

This guidance provides two methods for calculating the CO<sub>2</sub> emissions from coke manufacture. Facilities should choose between the two based on whether or not the coke they consumed was produced onsite. This is because coke manufacture may entail the use of by-products from industrial activities that took place within the site of coke production. Facilities that consume coke produced off-site should not account for the emissions from these by-products; otherwise, emissions from these by-products might be double-counted.

The separate consideration of emissions from onsite and offsite coke manufacture also allows the separation of emissions based on ownership. In other words, if coke is purchased from an entity outside the organizational boundaries of the reporting company, the associated emissions are Scope 3, not Scope 1. Likewise, if the coke production facility is offsite, but located within the corporate boundaries of the reporting company, the facility's emissions fall under Scope 1. Figure 3 demonstrates this principle.

**Figure 3.** Diagram illustrating how the accounting of emissions from coke manufacturing facilities depends on whether those facilities exist within the organizational boundaries of the reporting company.



Emissions from onsite and offsite coke production should be estimated using Equations 7 and 8, respectively. Both equations require carbon content data for each material input into the coke plant. Companies are encouraged to use facility-specific (Tier 3) values whenever possible. However, if companies do not have the requisite information they may then use the default, Tier 1 values (see Table 2).

Equation 7	Calculating CO <sub>2</sub> emissions from onsite coke production
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$$E_{CO_2,energy} = \left[ \begin{array}{l} CC \cdot C_{CC} + \sum_a (PM_a \cdot C_a) + BG \cdot C_{BG} \\ -CO \cdot C_{CO} - COG \cdot C_{COG} - \sum_b (COB_b \cdot C_b) \end{array} \right] \cdot \frac{44}{12}$$

Where:

$E_{CO_2,energy}$  = emissions of CO<sub>2</sub> from onsite coke production, tonnes

$CC$  = quantity of coking coal consumed for coke production in onsite integrated iron and steel production facilities, tonnes

$PM_a$  = quantity of other process material a, other than those listed as separate terms, such as natural gas and fuel oil, consumed for coke and sinter production in onsite coke production and iron and steel production facilities, tonnes

$BG$  = quantity of blast furnace gas consumed in coke ovens, m<sup>3</sup> (or other unit such as tonnes or GJ).

$CO$  = quantity of coke produced onsite at iron and steel production facilities, tonnes

$COG$  = quantity of coke oven gas transferred offsite, m<sup>3</sup> (or other unit such as tonnes or GJ).

$COB_b$  = quantity of coke oven by-product b, transferred offsite to other facilities, tonnes

$C_x$  = carbon content of material input or output x, tonnes C/(unit for material x) [e.g., tonnes C/tonne]

#### Equation 8 Calculating CO<sub>2</sub> emissions from offsite coke production

$$E_{CO_2,energy} = \left[ \begin{array}{l} CC \cdot C_{CC} + \sum_a (PM_a \cdot C_a) - NIC \cdot C_{NIC} \\ -COG \cdot C_{COG} - \sum_b (COB_b \cdot C_b) \end{array} \right] \cdot \frac{44}{12}$$

Where:

$E_{CO_2,energy}$  = emissions of CO<sub>2</sub> from offsite coke production (tonnes)

$CC$  = quantity of coking coal used in non-integrated coke production facilities (tonnes)

$PM_a$  = quantity of other process material a, other than coking coal, such as natural gas and fuel oil consumed nationally in non-integrated coke production (tonnes)

$NIC$  = quantity of coke produced offsite in non-integrated coke production facilities nationally (tonnes)

$COG$  = quantity of coke oven gas produced in offsite non-integrated coke production facility (tonnes)

$COB_b$  = quantity of coke oven by-product b, produced nationally in offsite non-integrated facilities and transferred offsite to other facilities (tonnes)

$C_x$  = carbon content of material input or output x, tonnes C/(unit for material x) [e.g., tonnes C/tonne]

**Table 2.** Carbon contents for materials consumed in process sources

<b>Process Materials</b>	<b>Carbon Content*</b> (kg C/kg)
Blast Furnace Gas	0.17
Charcoal <sup>a</sup>	0.91
Coal	0.67 <sup>1</sup>
Coal tar	0.62
Coke	0.83
Coke Oven gas	0.47
Coking Coal	0.73
Direct reduced Iron (DRI)	0.02
Dolomite	0.13
EAF Carbon Electrodes	0.82 <sup>2</sup>
EAF Charge Carbon	0.83 <sup>3</sup>
Fuel Oil	0.86 <sup>4</sup>
Gas Coke	0.83
Hot Briquetted iron	0.02
Limestone	0.12
Natural Gas	0.73
Oxygen Steel Furnace Gas	0.35
Petroleum Coke	0.87
Purchased pig Iron	0.04
Scrap Iron	0.04
Steel	0.01

Sources and Notes:

\* Default values are consistent with those provided in the IPCC 2006 Guidelines (Volume 2) and have been calculated with the following assumptions:

<sup>1</sup> Assumed other bituminous coal

<sup>2</sup> Assumed 80% petroleum coke and 20% coal tar

<sup>3</sup> Assumed coke oven gas

<sup>4</sup> Assumed gas/diesel fuel

<sup>a</sup> The CO<sub>2</sub> emissions from charcoal can be calculated using this carbon content value, but are reported as zero for the purposes of corporate inventories.

## CH<sub>4</sub>

The CH<sub>4</sub> emissions from coke manufacture can be calculated using Equation 9, regardless of whether the coke was produced onsite or offsite.

Equation 9     Calculating CH<sub>4</sub> emissions from coke production

$$E_{CH_4} = EF_{CH_4} \cdot Coke$$

Where:

$E_{CH_4}$  = The amount of  $CH_4$  emitted from coke manufacture.

$EF_{CH_4}$  = The  $CH_4$  emission factor (g  $CH_4$  / tonne coke)

Coke = The amount of coke produced (metric tonnes coke)

The default value for the  $CH_4$  emission factor is: 0.1 g/metric tonne coke.

### 3.2.3 Emissions from Flaring

Flares are a special category of stationary combustion sources because they are not typically operated for the purpose of producing useful energy and because they tend to function at relatively low combustion efficiencies (i.e., they allow a larger percentage of the fuel to pass unburnt). Flaring is generally uncommon in Iron and Steel operations as most integrated plants recycle the coke-oven and blast furnace gases they produce. Exceptions arise when industrial operations are interrupted and systems must be taken offline.

The  $CO_2$  and  $CH_4$  emissions from flares should be estimated following Equations 10 and 11, respectively. There is no method to calculate flare  $N_2O$  emissions.

#### **$CO_2$**

##### Equation 10 Calculating $CO_2$ emissions from flares

$$CO_2 \text{ Emissions} = Q \times 5.16^{-5} \times C_{\text{mole ratio}}$$

Where:

$CO_2$  Emissions = annual emissions from flaring (tonne/yr)

Q = Volume Gas Flared (scf/yr)

$C_{\text{mole ratio}} = \sum(\text{lbmole } HC_i / \text{lbmole gas} * \text{lbmoles C} / \text{lbmole } HC_i)$ , where  $HC_i$  = Hydrocarbon molecule i

$5.16 * 10^{-5} = 1/\text{Molar Volume (lbmole 379.3scf)} * \text{Combustion Efficiency (.98)} * 1 \text{ lbmoles } CO_2 / \text{lbmole C} * MW_{CO_2} (44 \text{ lb/lbmole}) * \text{tonne}/2204.6 \text{ lb}$

#### **$CH_4$**

##### Equation 11 Calculating $CH_4$ emissions from flares

$$CH_4 \text{ Emissions} = Q_{fg} \cdot 3.83^{-7} \cdot CH_4 \text{ mole ratio} \cdot GWP$$

Where:

CH<sub>4</sub> Emissions = annual emissions from flaring (tonne/yr)

Q<sub>fg</sub> = Volume Gas Flared (scf/yr)

CH<sub>4</sub> mole ratio = lbmole CH<sub>4</sub>/ lbmoles gas

$3.83 \times 10^{-7} = 1/\text{Molar Volume (lbmole 379.3scf)} \times .02 (\% \text{ Uncombusted CH}_4/100) *$

MW<sub>CH<sub>4</sub></sub> (16 lb/lbmole) \* tonne/2204.6 lb)

GWP = 21

### 3.3 Industrial Process Emissions

The four main sources that contribute to process GHG emissions are:

1. Sinter making
2. Pelletizing
3. Iron and steel making
4. Direct Reduced Iron (DRI) production

CO<sub>2</sub> and CH<sub>4</sub> are the main GHGs emitted by process sources. N<sub>2</sub>O emissions may also occur, but these are considered very small and are not considered further by the Iron and Steel Tool.

#### 3.3.1 CO<sub>2</sub> methods for process sources

These methods require data on the carbon content of the materials consumed during the industrial processes. Companies are encouraged to use Tier 3, facility-specific values whenever possible. However, the default, Tier 1 values in Table 2 may be used in the absence of other, more detailed information.

#### Sinter production

The CO<sub>2</sub> emissions should be calculated following Equation 12.

<b>Equation 12</b>	<b>Calculating CO<sub>2</sub> emissions from sinter production</b>
$E_{CO_2} = \left[ \begin{array}{l} CBR \cdot C_{CBR} + COG \cdot C_{COG} + BG \cdot C_{BG} \\ + \sum_A (PM_a \cdot C_a) - SOG \cdot C_{SOG} \end{array} \right] \cdot \frac{44}{12}$	

Where:

E<sub>CO<sub>2</sub></sub> = emissions of CO<sub>2</sub> from sinter production (tonnes)

*CBR* = quantity of purchased and onsite produced coke breeze used for sinter production (tonnes)

*COG* = quantity of coke oven gas consumed in blast furnace in sinter production (m<sup>3</sup>)

*BG* = quantity of blast furnace gas consumed in sinter production (m<sup>3</sup>)

*PM<sub>a</sub>* = quantity of other process material *a*, other than those listed as separate terms, such as natural gas and fuel oil, consumed during sinter production (tonnes)

*SOG* = quantity of sinter off gas transferred offsite either to iron and steel production facilities or other facilities (m<sup>3</sup>)

*C<sub>x</sub>* = carbon content of material input or output *x*, tonnes *C*/(unit for material *x*) [e.g., tonnes *C*/tonne]. See the default values in Table 2.

## Iron and Steel Production

The CO<sub>2</sub> emissions from iron and steel making can be calculated following Equation 13.

Equation 13 Calculating CO<sub>2</sub> emissions from iron and steel production

$$E_{CO_2} = \left[ \begin{array}{l} PC \cdot C_{PC} + \sum_a (COB_a \cdot C_a) + CI \cdot C_{CI} + L \cdot C_L + D \cdot C_D + CE \cdot C_{CE} \\ + \sum_b (O_b \cdot C_b) + COG \cdot C_{COG} - S \cdot C_S - IP \cdot C_{IP} - BG \cdot C_{BG} \end{array} \right] \cdot \frac{44}{12}$$

Where:

*E<sub>CO2</sub>* = emissions of CO<sub>2</sub> from iron and steel production (tonnes)

*PC* = quantity of coke consumed in iron and steel production (not including sinter production) (tonnes)

*COB<sub>a</sub>* = quantity of onsite coke oven by-product *a*, consumed in blast furnace (tonnes)

*CI* = quantity of coal directly injected into blast furnace (tonnes)

*L* = quantity of limestone consumed in iron and steel production (tonnes)

*D* = quantity of dolomite consumed in iron and steel production (tonnes)

*CE* = quantity of carbon electrodes consumed in EAFs (tonnes)

*O<sub>b</sub>* = quantity of other carbonaceous and process material *b*, consumed in iron and steel production, such as sinter or waste plastic (tonnes)

*COG* = quantity of coke oven gas consumed in blast furnace in iron and steel production (m<sup>3</sup>)

*S* = quantity of steel produced (tonnes)

*IP* = quantity of iron production not converted to steel (tonnes)

*BG* = quantity of blast furnace gas transferred offsite (m<sup>3</sup>)

*C<sub>x</sub>* = carbon content of material input or output *X*, tonnes *C*/(unit for material *X*) [e.g., tonnes *C*/tonne]. See the default values in Table 2.

## Direct Reduced Iron (DRI) Production

The CO<sub>2</sub> emissions from DRI production stem from the combustion of fuel, coke breeze, metallurgical coke or other carbonaceous materials. The emissions can be calculated following Equation 14.

Equation 14 Calculating CO<sub>2</sub> emissions from DRI production

$$E_{CO_2} = (DRI_{NG} \cdot C_{NG} + DRI_{BZ} \cdot C_{BZ} + DRI_{CK} \cdot C_{CK}) \cdot \frac{44}{12}$$

Where:

$E_{CO_2}$  = emissions of CO<sub>2</sub> (tonnes)

$DRI_{NG}$  = amount of natural gas used in direct reduced iron production (GJ)

$DRI_{BZ}$  = amount of coke breeze used in direct reduced iron production (GJ)

$DRI_{CK}$  = amount of metallurgical coke used in direct reduced iron production (GJ)

$C_{NG}$  = carbon content of natural gas (tonne C/GJ) (see Table 2)

$C_{BZ}$  = carbon content of coke breeze (tonne C/GJ) (see Table 2)

$C_{CK}$  = carbon content of metallurgical coke (tonne C/GJ) (see Table 2)

### 3.3.2 CH<sub>4</sub> methods for process sources

The CH<sub>4</sub> emissions from steel-making are assumed to be negligible and are therefore not discussed here. Instead this toll provides methods for estimating the CH<sub>4</sub> emissions from sinter, pig iron and DRI production using Equations 15, 16 and 17, respectively.

Tier 1 default values for the emission factors used in Equations 15 and 17 are given in Table 3. These values should only be used in the absence of facility-specific data that would allow the derivation of Tier 3 values. Please note that no default is available for pig iron production (Equation 16).

#### Equation 15 Calculating CH<sub>4</sub> emissions from sinter production

$$E_{CH_4} = SI \cdot EF_{SI} \cdot GWP$$

#### Equation 16 Calculating CH<sub>4</sub> emissions from pig iron production

$$E_{CH_4} = PI \cdot EF_{PI} \cdot GWP$$

#### Equation 17 Calculating CH<sub>4</sub> emissions from DRI production

$$E_{CH_4} = DRI \cdot EF_{DRI} \cdot GWP$$

Where:

$E_{CH_4}$  = emissions of CH<sub>4</sub> (kg)

$SI$  = quantity of sinter produced (tonnes)

$PI$  = quantity of iron produced, including iron converted to steel and not converted to steel (tonnes)  
 $DRI$  = quantity of direct reduced iron produced (tonnes)  
 $EF_X$  = emission factor, kg CH<sub>4</sub>/tonne  $X$  produced  
 $GWP = 21$

**Table 3.** Tier 1 CH<sub>4</sub> Emission Factors for process emission sources

Process	Emission Factor
Sinter production	0.07 kg per tonne of sinter produced
DRI Production	1 kg/TJ (on a net calorific basis)

Source: IPCC 2006 (Volume 3, Chapter 4)

### 3.4 Limestone and Dolomite Production

Two different methods are presented here to allow facilities to calculate the CO<sub>2</sub> emissions from limestone and dolomite production. The choice between them is determined by the available data and by whether or not production occurs within the organizational boundaries of the reporting company. If the associated emissions are direct (Scope 1) then the Scope 1 method should be used. If the associated emissions are indirect (Scope 3) and the reporting company does not have access to the data required by the Scope 1 method, it should use the Scope 3 method instead.

#### 3.4.1 Scope 1 emissions

The Scope 1 method requires data on the type(s) and quantity(ies) of the carbonate(s) consumed to produce lime, as well as the respective emission factor(s) for these carbonate(s). Emissions should be calculated following Equation 18. Note that this method assumes that no lime kiln dust (LKD) is recycled to the kiln, because such recycling is rarely carried out.

**Equation 18** Calculating Scope 1 CO<sub>2</sub> emissions from lime production

$$E_{CO_2} = \sum_i (EF_i \cdot M_i \cdot F_i) - M_d \cdot C_d \cdot (1 - F_d) \cdot EF_d$$

Where:

$E_{CO_2}$  = emissions of CO<sub>2</sub> from lime production (tonnes)

$EF_i$  = emission factor for carbonate  $I$  (tonnes CO<sub>2</sub>/tonne carbonate). See defaults in Table 4.

$M_i$  = weight or mass of carbonate  $i$  consumed (tonnes)

$F_i$  = fraction calcination achieved for carbonate  $I$  (fraction). See below

$M_d$  = weight or mass of LKD (tonnes)

$C_d$  = weight fraction of original carbonate in the LKD (fraction). See below

$F_d$  = fraction calcination achieved for the LKD (fraction). See below

$EF_d$  = emission factor for the uncalcined carbonate in the LKD (tonnes CO<sub>2</sub>/tonne carbonate). See below

Companies are encouraged to use facility-specific values for the parameters in Equation 18 whenever possible. However, default Tier 1 values may be used in the absence of other, more detailed data. Specifically:

- Carbonate emission factor ( $EF_i$ ). Refer to the values in Table 4.
- Carbonate calcination fraction ( $F_i$ ). A value of 1.0 (ie. 100 % calcination) may be assumed.
- LKD calcination fraction ( $F_d$ ). A value of 1.0 (ie. 100 % calcination) may be assumed.
- Weight fraction of original carbonate in the LKD ( $C_d$ ). Because calcium carbonate is overwhelmingly the dominant carbonate present in the raw materials used in limestone and dolomite production, facilities may assume that it makes up 100 percent of the carbonate remaining in the LKD. Hence, the Tier 1 default for  $C_d$  is equal to the calcium carbonate ratio in the raw material feed to the kiln.

**Table 4.** Tier 1 emission factors for common carbonate species

Carbonate	Mineral name(s)	Emission factor (tonnes CO <sub>2</sub> /tonne carbonate)
CaCO <sub>3</sub>	Calcite or aragonite	0.44
MgCO <sub>3</sub>	Magnesite	0.52
CaMg(CO <sub>3</sub> ) <sub>2</sub>	Dolomite	0.48
FeCO <sub>3</sub>	Siderite	0.38
Ca(Fe,Mg,Mn)(CO <sub>3</sub> ) <sub>2</sub>	Ankerite	0.41-0.48
MnCO <sub>3</sub>	Rhodochrosite	0.38
Na <sub>2</sub> CO <sub>3</sub>	Sodium carbonate or soda ash	0.41

Source: IPCC 2006 Guidelines, Volume 2, Table 2.1.

### 3.4.2 Scope 3 emissions



The reporting company should calculate the Scope 3 (i.e. indirect) CO<sub>2</sub> emissions from lime production using Equation 19. This is an output-based method that requires data only on the amount of lime that facilities import. These data are then multiplied by an emission factor that is based on the stoichiometric ratios and CaO / CaO·MgO contents of a combination of lime types that is assumed to typify the output of the lime production industry. The resulting estimate of CO<sub>2</sub> emissions is then corrected for the production of hydrated lime and of any Lime Kiln Dust (LKD) that is not returned to the kiln.

**Equation 19**    **Calculating Scope 3 CO<sub>2</sub> emissions from lime production**

$$E_{CO_2} = \sum (M_L \cdot EF_{lime}) * (1 - (H_{fraction} \cdot H_{water})) \cdot LKD_{CF}$$

Where:

$E_{CO_2}$  = emissions of CO<sub>2</sub> from lime production (tonnes)

$EF_{lime}$  = emission factor for the specific type of lime that is imported. The default value is: 0.75 tonnes CO<sub>2</sub>/ tonne lime produced. See below

$M_L$  = weight or mass of lime produced (tonnes)

$H_{fraction}$  = Fraction of imported lime that is hydrated. Default value: 0.1

$H_{water}$  = Water content of hydrated lime (fraction). Default value: 0.1

$LKD_{CF}$  = Correction factor for the production of lime kiln dust (LKD) that is not returned to the lime kiln. Default value: 1.02

The default emission factor assumes that the produced lime is 85% high calcium lime and 15% dolomitic lime (see Equation 20). Should the reporting company have access to more accurate information, it should adjust the default emission factor based on Equation 20 and Table 5 to reflect the actual combination of lime types present in the imported lime and on the CaO / CaO·MgO contents of these types.

**Equation 20**    **Deriving a custom CO<sub>2</sub> emission factor for Scope 3 emissions**

$$EF_{lime} = (Proportion_i \cdot EF_i) + (Proportion_j \cdot EF_j) + \dots$$

Where:

$EF_{lime}$  = aggregated emission factor for lime produced

$Proportion_i$  = Fraction of lime type  $i$  in the lime imported by the reporting company

$EF_i$  = Emission factor for lime type  $i$  (tonnes CO<sub>2</sub>/ tonne lime produced) (see Table 5)

**Table 5:** Properties of various lime types

Lime Type	<b>Stoichiometric Ratio</b> (tonnes CO <sub>2</sub> per tonne CaO or CaO·MgO) (1)	<b>Range of CaO Content</b> (%)	<b>Range of MgO content</b> (%)	<b>Default value for CaO or CaO·MgO content</b> (fraction) (2)	<b>Default emission factor</b> (tonnes CO <sub>2</sub> per tonne lime) (1)•(2)
High-calcium lime	0.785	93-98	0.3-2.5	0.95	0.75
Dolomitic lime	0.913	55-57	38-41	0.95 or 0.85	0.86 or 0.77
Hydraulic lime	0.785	65-92	NA	0.75	0.59

Source: IPCC 2006 Guidelines, Volume 2, Table 2.1.

**Appendix I: Defaults for estimating the CO<sub>2</sub> emissions from the stationary combustion of fuels**

Both Tables I-1 and I-2 below contain Tier 1 defaults for various fuel properties (fuel heating value, carbon content and carbon oxidation fraction) that should enable companies to calculate the CO<sub>2</sub> emissions from fuel combustion.

**Table I-1.** Tier 1 defaults for carbon content values

Fuel		Carbon content		
		% basis (% w/w)	Energy basis (=carbon content / heating value)	
			Lower Heating Value (LHV) / Net Calorific Value (NCV) basis (kg/GJ)	Higher Heating Value (HHV) / Gross Calorific Value (GCV) basis (kg/GJ)
<b>Crude oil and derived substances</b>	Crude oil	0.85	20	19.00
	Orimulsion	0.58	21	19.95
	Natural Gas Liquids	0.77	17.5	16.63
	Motor Gasoline	0.84	18.9	17.96
	Aviation Gasoline	0.85	19.1	18.15
	Jet Gasoline	0.85	19.1	18.15
	Jet Kerosene	0.86	19.5	18.53
	Other Kerosene	0.86	19.6	18.62
	Shale oil	0.76	20	19.00
	Gas/.Diesel oil	0.87	20.2	19.19
	Residual Fuel oil	0.85	21.1	20.05
	Liquified Petroleum Gases	0.81	17.2	15.48
	Ethane	0.78	16.8	15.12
	Naphtha	0.89	20	19.00
	Bitumen	0.88	22	20.90
Lubricants	0.80	20	19.00	

Fuel	Carbon content		
	% basis (% w/w)	Energy basis (=carbon content / heating value)	
		Lower Heating Value (LHV) / Net Calorific Value (NCV) basis (kg/GJ)	Higher Heating Value (HHV) / Gross Calorific Value (GCV) basis (kg/GJ)
Petroleum coke	0.86	26.6	25.27
Refinery feedstocks	0.86	20	19.00
Refinery Gas	0.78	15.7	14.13
Paraffin waxes	0.80	20	19.00
White Spirit & SBP	0.80	20	19.00
Other petroleum products	0.80	20	19.00
<b>Coal and derived products</b>			
Anthracite	0.72	26.8	25.46
Coking coal	0.73	25.8	24.51
Other bituminous coal	0.67	25.8	24.51
Sub-bituminous coal	0.50	26.2	24.89
Lignite	0.33	27.6	26.22
Oil shale and tar sands	0.26	29.1	27.65
Brown coal briquettes	0.55	26.6	25.27
Patent fuel	0.55	26.6	25.27
Coke oven coke / lignite coke / coke breeze	0.82	29.2	27.74
Gas coke	0.82	29.2	27.74
Coal tar	0.62	22	20.90
Gas works gas	0.47	12.1	10.89
Coke oven gas	0.47	12.1	10.89
Blast furnace gas	0.17	70.8	63.72
Oxygen steel furnace gas	0.35	49.6	44.64
<b>Natural Gas</b>			
Natural Gas	0.73	15.3	13.77
<b>Non-biomass waste</b>			
Municipal wastes (non-biomass fraction)	0.25	25	23.75
Industrial wastes	NA	39	NA

Fuel		Carbon content		
		% basis (% w/w)	Energy basis (=carbon content / heating value)	
			Lower Heating Value (LHV) / Net Calorific Value (NCV) basis (kg/GJ)	Higher Heating Value (HHV) / Gross Calorific Value (GCV) basis (kg/GJ)
	Waste oils	0.80	20	19.00
<b>Peat</b>	Peat	0.28	28.9	27.46
<b>Biomass waste</b>	Wood/Wood waste	0.48	30.5	28.98
	Sulphite lyes (Black liquor)	0.31	26	24.70
	Other primary solid biomass fuels	0.32	27.3	25.94
	Charcoal	0.90	30.5	28.98
	Biogasoline	0.52	19.3	18.34
	Biodiesels	0.52	19.3	18.34
	Other liquid biofuels	0.59	21.7	20.62
	Landfill gas	0.75	14.9	13.41
	Sludge gas	0.75	14.9	13.41
	Other biogas	0.75	14.9	13.41
	Municipal wastes (biomass fraction)	0.32	27.3	25.94

**Table I-2.** Tier 1 defaults for fuel heating values and carbon oxidation factors.

Fuel		Heating values		Carbon oxidation factor (%)
		Higher Heating Values (HHV) / Gross Calorific Values (GCV) units (thousand Btu / lb)	Lower Heating Values (LHV) / Net Calorific Values (NCV) units MJ/kg / TJ/Gg	
<b>Crude oil and derived substances</b>	Crude oil	21.31	42.3	100
	Orimulsion	13.85	27.5	100
	Natural Gas Liquids	22.26	44.2	100
	Motor Gasoline	22.31	44.3	100
	Aviation Gasoline	22.31	44.3	100
	Jet Gasoline	22.31	44.3	100
	Jet Kerosene	22.21	44.1	100
	Other Kerosene	22.06	43.8	100
	Shale oil	19.19	38.1	100
	Gas/.Diesel oil	21.66	43	100
	Residual Fuel oil	20.35	40.4	100
	Liquified Petroleum Gases	25.15	47.3	100
	Ethane	24.67	46.4	100
	Naphtha	22.41	44.5	100
	Bitumen	20.25	40.2	100
	Lubricants	20.25	40.2	100
	Petroleum coke	16.37	32.5	100
	Refinery feedstocks	21.66	43	100
	Refinery Gas	24.93	49.5	100
	Paraffin waxes	20.25	40.2	100
White Spirit & SBP	20.25	40.2	100	
Other petroleum products	20.25	40.2	100	
<b>Coal and</b>	Anthracite	13.45	26.7	100

<b>derived products</b>	Coking coal		14.20	28.2	100
	Other bituminous coal		12.99	25.8	100
	Sub-bituminous coal		9.52	18.9	100
	Lignite		5.99	11.9	100
	Oil shale and tar sands		4.48	8.9	100
	Brown coal briquettes		10.43	20.7	100
	Patent fuel		10.43	20.7	100
	Coke oven coke / lignite coke / coke breeze		14.20	28.2	100
	Gas coke		14.20	28.2	100
	Coal tar		14.10	28	100
	Gas works gas		20.58	38.7	100
	Coke oven gas		20.58	38.7	100
	Blast furnace gas		1.31	2.47	100
	Oxygen steel furnace gas		3.75	7.06	100
<b>Natural Gas</b>	Natural Gas		25.52	48	100
<b>Non-biomass waste</b>	Municipal wastes (non-biomass fraction)		5.04	10	100
	Industrial wastes	NA		NA	100
	Waste oils		20.25	40.2	100
<b>Peat</b>	Peat		4.92	9.76	100
<b>Biomass waste</b>	Wood/Wood waste		7.86	15.6	100
	Sulphite lyes (Black liquor)		5.94	11.8	100
	Other primary solid biomass fuels		5.84	11.6	100
	Charcoal		14.86	29.5	100
	Biogasoline		13.60	27	100
	Biodiesels		13.60	27	100
	Other liquid biofuels		13.80	27.4	100
	Landfill gas		26.80	50.4	100
	Sludge gas		26.80	50.4	100
	Other biogas		26.80	50.4	100
	Municipal wastes (biomass fraction)		5.84	11.6	100

**Appendix II: Tier 1 Defaults for estimating the CH<sub>4</sub> and N<sub>2</sub>O emissions from the stationary combustion of fuels**

		Lower Heating Value(LHV)/Net Calorific Value (NCV) Basis				Higher Heating Value(HHV)/Gross Calorific Value (GCV) Basis			
		kg GHG / TJ fuel		kg GHG / ton fuel		kg GHG / TJ fuel		kg GHG / ton fuel	
		CH <sub>4</sub>	N <sub>2</sub> O	CH <sub>4</sub>	N <sub>2</sub> O	CH <sub>4</sub>	N <sub>2</sub> O	CH <sub>4</sub>	N <sub>2</sub> O
<b>Crude oil and derived substances</b>	<b>Fuel</b>								
	Crude oil	3.000	0.600	0.134	0.027	2.850	0.570	0.127	0.025
	Orimulsion	3.000	0.600	0.087	0.017	2.850	0.570	0.083	0.017
	Natural Gas Liquids	3.000	0.600	0.140	0.028	2.850	0.570	0.133	0.027
	Motor Gasoline	3.000	0.600	0.140	0.028	2.850	0.570	0.133	0.027
	Aviation Gasoline	3.000	0.600	0.140	0.028	2.850	0.570	0.133	0.027
	Jet Gasoline	3.000	0.600	0.140	0.028	2.850	0.570	0.133	0.027
	Jet Kerosene	3.000	0.600	0.139	0.028	2.850	0.570	0.132	0.026
	Other Kerosene	3.000	0.600	0.138	0.028	2.850	0.570	0.131	0.026
	Shale oil	3.000	0.600	0.120	0.024	2.850	0.570	0.114	0.023
	Gas/.Diesel oil	3.000	0.600	0.136	0.027	2.850	0.570	0.129	0.026
	Residual Fuel oil	3.000	0.600	0.128	0.026	2.850	0.570	0.121	0.024
	Liquified Petroleum Gases	1.000	0.100	0.053	0.005	0.900	0.090	0.047	0.005
	Ethane	1.000	0.100	0.052	0.005	0.900	0.090	0.046	0.005
	Naphtha	3.000	0.600	0.141	0.028	2.850	0.570	0.134	0.027
	Bitumen	3.000	0.600	0.127	0.025	2.850	0.570	0.121	0.024
	Lubricants	3.000	0.600	0.127	0.025	2.850	0.570	0.121	0.024
	Petroleum coke	3.000	0.600	0.103	0.021	2.850	0.570	0.098	0.020
	Refinery feedstocks	3.000	0.600	0.136	0.027	2.850	0.570	0.129	0.026
	Refinery Gas	1.000	0.100	0.055	0.006	0.900	0.090	0.050	0.005
Paraffin waxes	3.000	0.600	0.127	0.025	2.850	0.570	0.121	0.024	
White Spirit & SBP	3.000	0.600	0.127	0.025	2.850	0.570	0.121	0.024	
Other petroleum products	3.000	0.600	0.127	0.025	2.850	0.570	0.121	0.024	
<b>Coal and derived products</b>	Anthracite	1.000	1.500	0.028	0.042	0.950	1.425	0.027	0.040
	Coking coal	10.000	1.500	0.297	0.045	9.500	1.425	0.282	0.042



		Lower Heating Value(LHV)/Net Calorific Value (NCV) Basis				Higher Heating Value(HHV)/Gross Calorific Value (GCV) Basis			
		kg GHG / TJ fuel		kg GHG / ton fuel		kg GHG / TJ fuel		kg GHG / ton fuel	
		CH <sub>4</sub>	N <sub>2</sub> O	CH <sub>4</sub>	N <sub>2</sub> O	CH <sub>4</sub>	N <sub>2</sub> O	CH <sub>4</sub>	N <sub>2</sub> O
<b>Fuel</b>	Other bituminous coal	10.000	1.500	0.272	0.041	9.500	1.425	0.258	0.039
	Sub-bituminous coal	10.000	1.500	0.199	0.030	9.500	1.425	0.189	0.028
	Lignite	10.000	1.500	0.125	0.019	9.500	1.425	0.119	0.018
	Oil shale and tar sands	10.000	1.500	0.094	0.014	9.500	1.425	0.089	0.013
	Brown coal briquettes	10.000	1.500	0.218	0.033	9.500	1.425	0.207	0.031
	Patent fuel	10.000	1.500	0.218	0.033	9.500	1.425	0.207	0.031
	Coke oven coke & lignite coke	10.000	1.500	0.297	0.045	9.500	1.425	0.282	0.042
	Gas coke	1.000	0.100	0.030	0.003	0.950	0.095	0.028	0.003
	Coal tar	10.000	1.500	0.295	0.044	9.500	1.425	0.280	0.042
	Gas works gas	1.000	0.100	0.043	0.004	0.900	0.090	0.039	0.004
	Coke oven gas	1.000	0.100	0.043	0.004	0.900	0.090	0.039	0.004
	Blast furnace gas	1.000	0.100	0.003	0.000	0.900	0.090	0.002	0.000
	Oxygen steel furnace gas	1.000	0.100	0.008	0.001	0.900	0.090	0.007	0.001
	<b>Natural Gas</b>	Natural Gas	1.000	0.100	0.053	0.005	0.900	0.090	0.051
<b>Non-biomass waste</b>	Municipal wastes (non-biomass fraction)	30.000	4.000	0.316	0.042	28.500	3.800	0.300	0.040
	Industrial wastes	30.000	4.000	N/A	N/A	28.500	3.800	N/A	N/A
	Waste oils	30.000	4.000	1.269	0.169	28.500	3.800	1.206	0.161
<b>Peat</b>	Peat	2.000	1.500	0.021	0.015	1.900	1.425	0.020	0.015
<b>Biomass waste</b>	Wood/Wood waste	30.000	4.000	0.493	0.066	28.500	3.800	0.468	0.062
	Sulphite lyes (Black liquor)	3.000	2.000	0.037	0.025	2.850	1.900	0.035	0.024
	Other primary solid biomass fuels	30.000	4.000	0.366	0.049	28.500	3.800	0.348	0.046
	Charcoal	200.000	4.000	6.211	0.124	190.000	3.800	5.900	0.118
	Biogasoline	3.000	0.600	0.085	0.017	2.850	0.570	0.081	0.016
	Biodiesels	3.000	0.600	0.085	0.017	2.850	0.570	0.081	0.016
	Other liquid biofuels	3.000	0.600	0.087	0.017	2.850	0.570	0.082	0.016
	Landfill gas	1.000	0.100	0.056	0.006	0.900	0.090	0.050	0.005

Fuel		Lower Heating Value(LHV)/Net Calorific Value (NCV) Basis				Higher Heating Value(HHV)/Gross Calorific Value (GCV) Basis			
		kg GHG / TJ fuel		kg GHG / ton fuel		kg GHG / TJ fuel		kg GHG / ton fuel	
		CH <sub>4</sub>	N <sub>2</sub> O	CH <sub>4</sub>	N <sub>2</sub> O	CH <sub>4</sub>	N <sub>2</sub> O	CH <sub>4</sub>	N <sub>2</sub> O
	Sludge gas	1.000	0.100	0.056	0.006	0.900	0.090	0.050	0.005
	Other biogas	1.000	0.100	0.056	0.006	0.900	0.090	0.050	0.005
	Municipal wastes (biomass fraction)	30.000	4.000	0.366	0.049	28.500	3.800	0.348	0.046

### Appendix III. Unit Conversion Ratios

<b>Mass</b>			
1 pound (lb)	453.6 grams (g)	0.4536 kilograms (kg)	0.0004536 metric tons (tonne)
1 kilogram (kg)	2.205 pounds (lb)		
1 short ton (ton)	2'000 pounds (lb)	907.2 kilograms (kg)	
1 metric ton	2'205 pounds (lb)	1'000 kilograms (kg)	1.1023 short tons (tons)
<b>Volume</b>			
1 cubic foot (ft <sup>3</sup> )	7.4805 gallons (gal)	0.1781 barrel (bbl)	
1 cubic foot (ft <sup>3</sup> )	28.32 liters (L)	0.02832 cubic meters (m <sup>3</sup> )	
1 gallon (gal)	0.0238 barrel (bbl)	3.785 liters (L)	0.003785 cubic meters (m <sup>3</sup> )
1 barrel (bbl)	42 gallons (gal)	158.99 liters (L)	0.1589 cubic meters (m <sup>3</sup> )
1 litre (L)	0.001 cubic meters (m <sup>3</sup> )	0.2642 gallons (gal)	
1 cubic meter (m <sup>3</sup> )	6.2897 barrels (bbl)	264.2 gallons (gal)	1'000 liters (L)
<b>Energy</b>			
1 kilowatt hour (kWh)	3412 Btu (btu)	3'600 kilojoules (KJ)	
1 megajoule (MJ)	0.001 gigajoules (GJ)		
1 gigajoule (GJ)	0.9478 million Btu (million btu)	277.8 kilowatt hours (kWh)	
1 Btu (btu)	1'055 joules (J)		
1 million Btu (million btu)	1.055 gigajoules (GJ)	293 kilowatt hours (kWh)	
1 therm (therm)	100'000 btu	0.1055 gigajoules (GJ)	29.3 kilowatt hours (kWh)
<b>Other</b>			
kilo	1'000		
mega	1'000'000		
giga	1'000'000'000		
tera	1'000'000'000'000		
1 psi	0.06895 bar		
1 kgf / cm <sup>3</sup> (tech atm)	0.9807 bar		
1 atmosphere (atm)	1.01325 bar	101.325 kilo pascals	14.696 pounds per square inch (psia)
1 mile (statue)	1.609 kilometers		
1 metric ton	21 metric tons CO <sub>2</sub>		

CH <sub>4</sub>	equivalent*	
1 metric ton N <sub>2</sub> O	310 metric tons CO <sub>2</sub> equivalent*	
1 metric ton carbon	3.664 metric tons CO <sub>2</sub>	