Iron and Steel Production

Guidance Manual for Estimating Greenhouse Gas Emissions

Greenhouse Gas Division
Environment Canada

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Purpose of the Guidance Manual

This technical guidance manual represents one of a series of manuals developed under a voluntary initiative supported by the Minerals and Metals component of the Government of Canada Action Plan 2000 on Climate Change. The purpose of these manuals is to help facilities in the identified minerals and metals sectors to estimate and compile inventories of their GHG emissions. Contributions to the development of these manuals were provided by the Minerals and Metals Branch at Environment Canada, the Mining and Mineral Sciences Laboratories at Natural Resources Canada, various industry stakeholders, provincial representatives and other key stakeholders where possible. The guidance in this manual is consistent with Canada’s national GHG accounting methodologies and the IPCC Good Practice Guidance (IPCC, 2000). It is also compatible with other internationally accepted standards (e.g. WRI/WBCSD).

The guidance manuals developed under this voluntary initiative will be used as an input in the definition of “nationally consistent quantification protocols,” which will be defined by the Government of Canada in collaboration with the provinces and territories as part of the development of a one-window harmonized GHG reporting system. Such a system is intended to serve federal reporting needs (to enhance the detail and precision of the National GHG Inventory and to support the Large Final Emitters legislative framework), as well as provincial and territorial reporting needs. Additional consultation and analysis on the definition of the nationally consistent quantification protocols are expected, in line with recommendations made at the Fall 2003 stakeholder workshops on GHG reporting. These workshops were hosted jointly by Natural Resources Canada, Environment Canada, Alberta Environment and the Ontario Ministry of the Environment and discussions were focused on approaches to a domestic system for mandatory reporting of GHG emissions in Canada.

Primary Iron and Steel Production

A Guidance Manual for Estimating Greenhouse Gas Emissions From Fuel Combustion and Process-Related Sources

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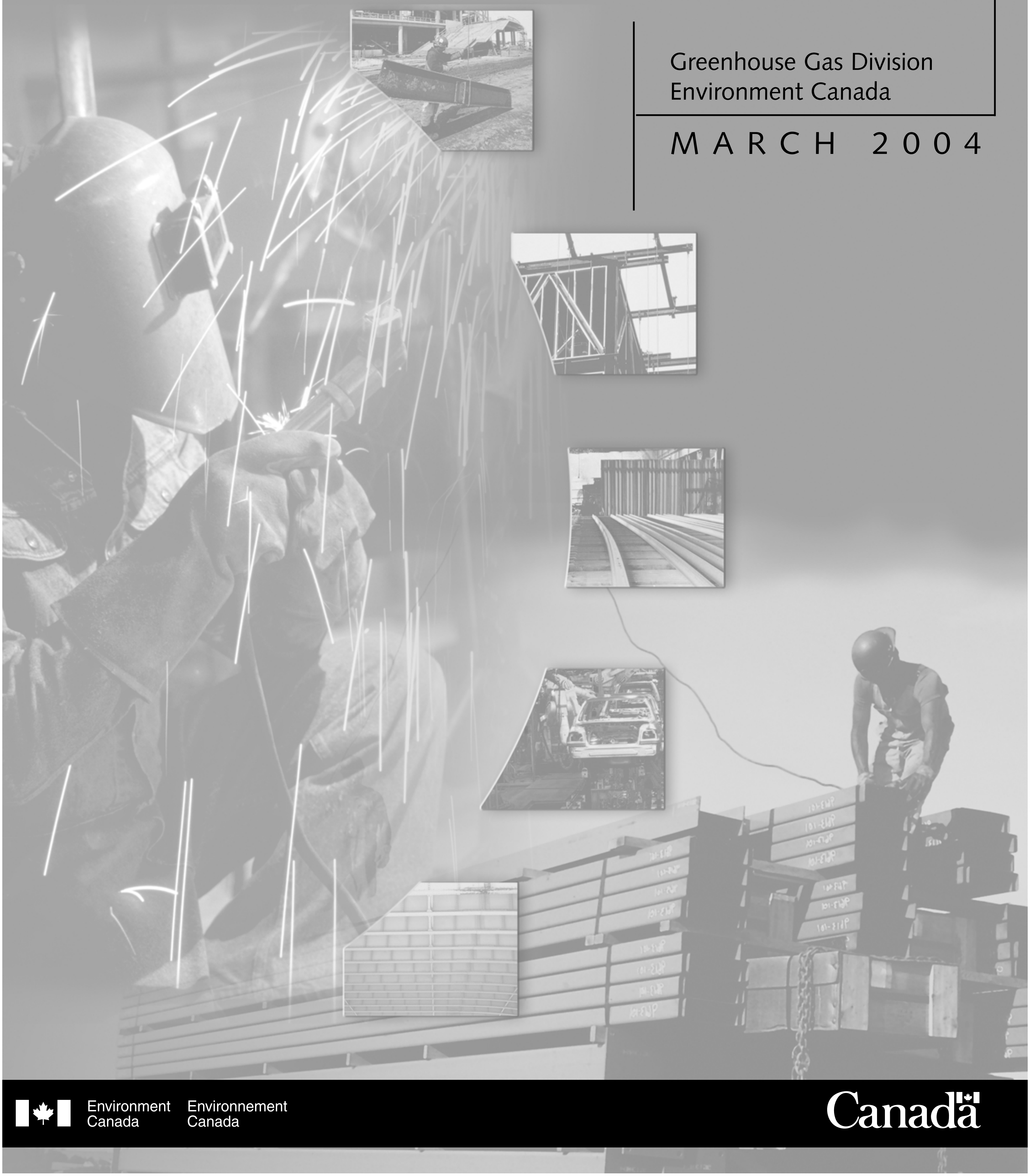

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Section 1: Introduction

1.1 Purpose and Scope

This manual provides guidance on how facilities in the iron and steel sector that are involved in the primary production of iron and steel (e.g. integrated, non-integrated operations) should estimate their greenhouse gas (GHG) emissions from fuel combustion and specific process-related activities. To the extent possible, the manual addresses all GHG emissions accounting for a facility or portions of a facility. This document does not provide guidance on how a corporate entity might aggregate emissions from individual facilities or other activities to produce a corporate-wide inventory. Guidance on how this can be achieved has been addressed by other efforts.[1]

This manual has been developed under a voluntary setting and is intended to serve as a useful resource to help facilities in the identified sector to estimate their GHG emissions. The decision to make use of this resource, either fully or in part, resides with the facility.

Fuel combustion under this guidance manual includes all stationary combustion activities for the purpose of generating heat or work (e.g. on-site generation of electricity, heat or steam production). This includes waste incineration if the waste is combusted for energy (waste incineration used as a disposal method is not included here). Also included are mobile fuel combustion activities that occur on-site at the facility and that are integral to the production process[2] (e.g. on-site transportation of raw materials or intermediate products from one process to another). For all combustion sources, carbon dioxide (CO_2), methane (CH_4) and nitrous oxide (N_2O) are the only GHGs for which guidance is provided.

Process-related activities include the specific industrial processes that directly result in GHG emissions and where the main purpose of the process is not the supply of energy — for example, the emissions are generated as a result of the chemical reactions involved in a particular process (e.g. CO_2 from calcination of limestone). The use of fossil fuels as feedstock or chemical reagents (e.g. metallurgical coke as a reducing agent) and the direct use of specific GHGs (e.g. sulfur hexafluoride [SF_6]) in particular production processes or facility systems (e.g. hydrofluorocarbons [HFCs] in industrial refrigeration units) are also covered here. The GHGs emitted from process-related sources at a primary iron and steel production facility and for which guidance is provided include CO_2 and HFCs.

Fugitive emissions,[3] which are intentional or unintentional releases of GHGs (e.g. CH_4 releases from coal mining, venting or flaring of natural gases), and indirect emissions from the consumption of electricity are not covered here. GHG emissions generated by mobile combustion source activities that occur off-site (e.g. transportation of materials or supplies to the facility or products to customers) or that occur on-site at the facility but are not integral to the production process are also not addressed. Separate guidance would need to be developed to address these emissions.

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[1] Framework documents, such as the World Resources Institute/World Business Council for Sustainable Development report The Greenhouse Gas Protocol: A Corporate Accounting and Reporting Standard (WRI/WBCSD, 2001), exist and can be referenced for these purposes.

[2] Integral to the production process means that if a particular mobile combustion activity did not occur, the product would not be produced.

[3] As per the Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC, 1997), fugitive emissions are intentional or unintentional releases of gases to the atmosphere that may arise from the production, processing, transmission, storage and use of fuels. These include emissions from combustion only where it does not support a productive activity (e.g. flaring of natural gases at oil and gas production facilities).

The intended users of this guidance manual are facility operations staff who have solid technical knowledge of the day-to-day process operations at the facility. This type of knowledge is essential in understanding and assessing the facility's operations in terms of the GHG emission sources occurring at the facility and the various operational parameters that may affect such emissions.

1.2 Guiding Principles

Facilities emitting GHGs may eventually need to report these emissions in order to respond to or participate in future government or industry initiatives related to the management of GHG emissions. Guidance manuals such as this one are being developed to serve as a useful resource and to guide industrial facilities on how to estimate their emissions. The ultimate goal in developing estimation guidance manuals for facilities is to promote the incorporation of the following principles[4] into the development of their GHG emissions inventories:

- **Completeness** — The estimation and reporting of emissions should include all sources and sinks, as well as all GHGs mentioned in the *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories* (IPCC, 1997). Emissions are accounted for where and when they occur. Double-counting is to be avoided.
- **Consistency** — Emission estimates should be internally consistent in all of their elements over a period of years. Emission estimates are consistent if the same methodologies are used for the base and subsequent years and if consistent data sets are used to estimate emissions or removals from sources or sinks.
- **Transparency** — The assumptions and methodologies used for calculating emission estimates should be clearly explained to facilitate replication and assessment of the calculation by users of the reported information. The transparency of emission calculations is fundamental to the success of the process for the communication and consideration of this information.
- **Comparability** — Estimates of emissions and removals reported by facilities should be comparable among all facilities.
- **Accuracy** — Emission or removal estimates should be accurate in the sense that they are systematically neither over nor under true emissions or removals, as far as can be judged, and that uncertainties are quantified and reduced as far as practicable.

The importance of adopting these principles when estimating GHG emissions relates directly to the quality and credibility that is ultimately associated with the emission estimates that are developed. In addition, the guidance manual is expected to promote a common understanding of the purpose and nature of a GHG inventory — namely, that this is a complete accounting of these emissions within a given boundary over a given period of time.

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[4] These principles are drawn from the IPCC Guidelines (IPCC, 1997).

1.3 Guidance Document Framework

This guidance document consists of individual sections that provide details on:

- the identification of GHG emission sources from stationary and mobile fuel combustion and process-related activities at your facility;
- various estimation approaches that could be used to estimate your GHG emissions and tools to help select the appropriate method for your facility;
- aspects of uncertainty assessment;
- quality assurance / quality control (QA/QC);
- verification; and
- reporting of emissions information.

The sections identify the steps that should be completed to obtain the necessary information or perform the identified activities. To assist you in using this guidance manual, various templates have been developed and are available in the appendices of this document.

Section 2: Identification of Greenhouse Gas Emissions

2.1 Emission Sources

In order to proceed with the estimation of GHG emissions from the stationary and mobile fuel combustion and process-related activities of your facility, a necessary first step is to identify the potential sources of GHG emissions that are occurring at the facility in question. A facility involved in the primary production of iron and steel may have various stationary and mobile fuel combustion processes occurring on-site that lead to GHG emissions. Several primary process sources directly linked with iron- and steel-making or with other facility systems may also result in GHG emissions, depending on the configuration of the specific facility. The following subsections provide further details on these possible sources.

2.1.1 Stationary Fuel Combustion Sources

The process of fuel combustion generates a variety of emissions, of which CO_2 makes up the largest component. Emissions of CH_4 and N_2O are produced in small quantities and are due to the incomplete combustion of hydrocarbons in fuel.

Various types of fuels may be combusted at the facility for the purpose of producing energy in the form of electricity, heat and/or steam. It is important to identify all fuels that are used at the facility, the specific processes that consume these fuels and the quantities used in each process. General examples of combustion processes that may exist at a facility include:

- fossil fuel combustion in an on-site central electric power plant;
- natural gas combustion in a gas turbine generator in a co-generation unit;
- fossil fuels used to fire boilers for steam generation to operate process equipment;
- fossil fuel combustion to provide heat in process furnaces; and
- fossil fuel combustion to provide heat for space heating/cooling.

Examples of specific stationary combustion processes or units that may exist at iron and steel production facilities include heat generation for coke ovens, coke by-products recovery plants (combustion associated with sulphur recovery operation), sintering and pelletization, blast furnace stoves or shaft furnaces, natural gas reformer units, electric arc or basic oxygen furnaces, steel re-heat furnaces, ladle furnaces, cutting torches, pre-heaters for various furnace types, etc.

Note on the Use of Coke:
In iron and steel production, coke is consumed for the primary purpose of the reduction of iron ore (the coke serving as a reducing agent). Carbon in the coke may also serve as a fuel in this process to provide the heat of reaction. Because reduction is the primary purpose for the coke use in this process, the emissions from this coke use should be reported as process-related emissions (not as stationary combustion emissions). It is important to ensure that these emissions are not double-counted under the stationary combustion section (where coke may be included as a fuel type used in various processes other than blast furnaces). This is also applicable to other quantities of fuels that may be used primarily as reducing agents such as coal, charcoal, natural gas, oil, tar and pulverized plastics.

Note on Coke Oven Gas:

Coke oven gas (COG) is generated during the coke oven operations where coal is baked to produce metallurgical coke. The COG is generally collected, cleaned and recycled as a combustion fuel in the coke oven operations or in other on-site processes. As described in the above note, the coke that is generated is used as a reducing agent in subsequent iron-making processes and associated emissions are accounted for under process-related emissions. However, emissions from the combustion of COG can be directly estimated at the point where combustion occurs and included under stationary combustion sources. If some of the COG is exported off-site (e.g. not combusted or otherwise handled in on-site processes), it may be necessary to adjust the stationary combustion emissions to avoid overestimation.

Note on Blast Furnace Gas:
Blast furnace gas (BFG) is a by-product gas stream produced during blast furnace operations, and it may too be collected, cleaned and combusted as a fuel on-site. Special consideration is necessary when accounting for the use of BFG, and this is detailed separately under the process-related emissions section (see Section 3.4.3.1).

Biomass Combustion:
Combustion sources at the facility may involve combustion of biomass fuels (e.g. wood fuel / wood waste, spent pulping liquor, etc.) where there are CO_2 and non-CO_2 (i.e. CH_4, N_2O) emissions occurring. When estimating CO_2 emissions from biomass fuel combustion, it is important to note that these emissions are to be estimated and documented for information purposes only. They should not be included in the overall total for CO_2 emissions from stationary combustion for your facility (these emissions would be taken into account as a loss of biomass [forest] stocks under a separate guidance manual for Land Use Change and Forestry). CH_4 and N_2O emissions from biomass fuel combustion are to be estimated and reported in the overall total facility emissions for these GHGs.

2.1.2 Mobile Fuel Combustion Sources

There may be mobile fuel combustion sources that occur on-site through various transportation-related activities that are integral to the production process. This may include the on-site transport of raw material or intermediate products from one process to another at the facility, using different modes of transport (e.g. heavy equipment, heavy duty truck, train, quarry vehicle, pipeline[5], etc). It is important to identify the fuel types used in such mobile combustion source activities (e.g. diesel, gasoline) and the mode(s) of transport or vehicle type(s) used on-site. As described under stationary fuel combustion, the GHG emissions that result from fuel combustion sources are CO_2, CH_4 and N_2O

2.1.3 Process-related Sources

GHG emissions from process-related sources at iron and steel facilities will vary, depending on the type of facility and the different production processes used at the facility (e.g. integrated iron and steel facilities, electric arc furnace steel mills, direct reduction facilities).

For typical integrated facilities, the reduction of iron ore with metallurgical coke (and other reductants and additives such as injected pulverized coal, oil, natural gas and/or pulverized plastics) to form raw (or pig) iron in the blast furnace results in emissions of CO_2. Coke and other reductants are used primarily in this process as both reducing agents and sources of fuel for the heat of reaction in the process. The emissions from this use of coke (or other reductants) should be calculated as process-related emissions rather than stationary combustion emissions. Limestone ($CaCO_3$) used as a flux in the blast furnace is calcined and results in additional CO_2 emissions.

Alternately, iron ore may also be processed through direct reduction,using hydrogen (H_2) and carbon monoxide (CO) as reducing agents in a shaft furnace, at temperatures below the melting point of iron ore. CO_2 is produced as the reducing gases react with the iron ore feed and reduce the iron oxide to metallic iron (called direct reduced iron [DRI]). The H_2 and CO are obtained from the reforming of natural gas.

Ore based processes, such as the blast furnace, smelting reduction and direct reduction processes, necessitate the use of carbon and hydrogen based reducing agents, including the energy resources of coal, oil, natural gas and derivatives such as coke, to bring about the reduction of iron oxide to iron at high temperature (IISI Committee on Technology, 1998).[6]

Further refining of pig iron to steel, either in basic oxygen furnaces (BOFs) or combined with recycled steel scrap in electric arc furnaces (EAFs), results in additional CO_2 emissions from oxidation of the carbon in the melt and, in EAFs, consumption of graphite (carbon) electrodes. Limestone, lime and blown carbon (for foamy slag) used in these refining processes are additional sources of CO_2 emissions.

Coke production and sintering may also occur at integrated facilities. When limestone is used in the sintering process, emissions of CO_2 occur and should be calculated as process emissions.

Non-integrated facilities typically produce steel in EAFs from scrap stock (sometimes with additional pig iron and/or direct reduced iron). In this case, the production process and emission sources are as described above. Other sources of GHG emissions from iron and steel production facilities may include the use of HFCs in stationary refrigeration applications or other cooling systems.

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[5] Pipeline transport is included in national inventories as Other Transport under the Transportation Combustion category. Facilities may use this mode of non-vehicular transport on-site to transport feed materials or intermediate products from one process to another. Emissions result from the combustion of the fuel used to propel products in the pipeline. (Olsen, K. et. al., 2003)

[6] For a conventional blast furnace route, these reducing agents may account for more than 60% of the total energy demand of an integrated steel plant, but only about 35% of this value will be consumed for energetic purposes (ie. melting of iron, slag etc.) as the remainder is involved directly in the reduction process and, therefore is present as a raw material. There is a theoretical limit to the energy consumption in the reduction process below which reduction could not take place (IISI, 1998). The situation is similar in the case of the DRI process except that solid iron is produced.

To summarize, the process-related emission sources for the primary production of iron and steel and other facility systems, depending on the type of facility may include:

- CO_2 from use of reducing agents (e.g. coke and other additives in blast furnace, CO in DRI process);
- CO_2 from use of limestone carbonates (e.g. in sintering, blast furnace or BOF);
- CO_2 from oxidation of carbon in process melts (e.g. BOF, EAF)
- CO_2 from consumption of carbon electrodes in EAF
- CO_2 from carbon blown into EAF to make foamy slag
- CO_2 from on-site lime production (lime used as a flux agent)
- CO_2 from soda ash use
- HFCs used in refrigeration / cooling systems.

Emissions due to the carbon content of the various impurities in scrap steel have not been explicitly accounted for in this guidance, although it may be accounted for in Sections 3.4.3.4 and 3.4.3.5 when calculating the difference in carbon content between the input materials (e.g. pig iron, scrap steel) and the output materials (e.g. crude steel).

2.2 Process Overview

To assist in the understanding and identification of sources of GHG emissions from stationary and mobile fuel combustion and specific process activities in your facility's operations, it is necessary to generate a process flow diagram(s) that identifies the unit operations, on-site transport-related activities and production processes at the facility. The flow diagram should identify:

- the input/output flows for the combustion processes or activities that generate GHG emissions;
- the input/output flows for the specific production processes that generate GHG emissions and other operating systems where GHGs are used; and
- any process emission recycling that may occur or other GHG emission abatement process or technology used.

Another important set of information when identifying sources of GHG emissions is the stoichiometry[7] of the chemical processes that result in the generation of GHG emissions. In general, the combustion of any hydrocarbon fuel (with the composition C_nH_m) occurs through the following basic chemical reaction:

$$C_nH_m + (n + \frac{m}{4})\,O_2 \rightarrow n\,CO_2 + (\frac{m}{2})\,H_2O$$

For the majority of combustion processes, air is used as the source of oxygen, and the above reaction is rewritten to show:

$$C_nH_m + (n + \frac{m}{4})\,(O_2 + 3.785\,N_2)^* \rightarrow n\,CO_2 + (\frac{m}{2})\,H_2O + 3.785\,(n + \frac{m}{4})\,N_2$$

* The composition of air is approximated as 79.1% nitrogen and 20.9% oxygen.

For several process-related sources, the chemical reaction(s) involved that results in GHG emissions will vary according to the specific production process(es) and operating conditions at the facility. As

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[7] The term stoichiometry refers to the physical ratios (molar ratios) of each element that must mix to bring the process to completion.

an example, the calcination process of dolomitic limestone ($CaCO_3$-$MgCO_3$) which may be used as a flux in the blast furnace involves heating the limestone at high temperatures. The reaction, which results in CO_2 emissions, is as follows:

$$CaCO_3 \cdot MgCO_3 + heat \rightarrow CaO \cdot MgO + 2\ CO_2$$

It is useful to document the chemical reactions involved in order to understand how the GHG emissions are generated and the basis for the estimation methods used to quantify these emissions.

2.3 Source Categorization

When identifying the sources of GHG emissions at the facility in question, it is useful to categorize the emission sources to assist in tracking and reporting of the emissions. Categorizing sources may also help clarify the estimation process and ensure that no GHG emission-generating activities are omitted. For stationary combustion sources, general categories that are based on the primary end purpose of the combustion process (e.g. electricity, steam or heat production) could be used. Other methods of categorization may be based on fuel type or combustion technology type. Mobile combustion sources are typically categorized by the fuel type combusted and the mode of transport or vehicle type. Process-related emissions are largely associated with specific processes (e.g. emissions from the electrolytic process) or particular applications, which essentially define the categories. Whatever categories are selected, it is important, when necessary, to document appropriate explanations to describe what the categories include to ensure clarity.

Step 1: Identification of Emission Sources

a) Determine the potential sources of GHG emissions from stationary and mobile fuel combustion and specific production processes or facility systems by analyzing your facility's operations in detail, and identify the specific area(s), process(es) and/or equipment used where GHG emissions are occurring.

b) Construct an engineering flow diagram(s) for your facility, which details the various processes of interest that are occurring within the facility. Limit the diagram(s) to those processes involving fuel combustion and specific production processes or systems that result in GHG emissions covered here.

c) Document typical engineering specifications for the identified process(es), such as reaction temperatures, flow rates, etc. Include these in the flow diagram.

d) Identify the fuel and combustion technology types used in each stationary and mobile combustion source.

e) Identify the relevant stoichiometric chemical reactions related to the sources of GHG emissions at the facility.

f) List any side reactions that may decrease or reduce emissions and catalytic processes or other methods (e.g. recycling of by-product CO_2, pollution control devices) that may be used to control emissions generated by the fuel combustion or process activities.

g) Document each emission source under the chosen categories.

Section 3: Estimation of Greenhouse Gas Emissions

3.1 Emission Estimation Methods

There are several methods that may be employed to calculate or estimate GHG emissions from the sources that have been identified for your facility. Direct measurement is typically the most accurate method that can be used. Normally, however, these data are not readily available, and the majority of GHG emissions from fuel combustion and process-related activities have historically been estimated. Estimation is the method used by many countries when preparing their national GHG inventories. The subsections that follow provide details on selected estimation approaches that are considered under this guidance manual.

The appropriate method to choose will depend on various factors, such as available activity data, emission factors (EFs), assumptions made, combustion or process technologies used, etc. These methodologies are selected to be consistent with accounting methodologies used by national governments to report GHG emissions to the United Nations Framework Convention on Climate Change and the methodologies that would be used under the Kyoto Protocol to this Convention.

3.2 Data Sources

When choosing an estimation method for calculating GHG emissions, it is necessary to assess what data sources are available for the facility in question. For fuel combustion emissions, the types of data that are required as a minimum for any estimation approach are the amount and type of fuel combusted. The extent to which this information is available in disaggregated form is a key factor in deciding which estimation method is appropriate (e.g. by combustion technology unit, combustion process, mode of transport/vehicle type or facility level). The more disaggregated this information is, the more accurate the emission estimates will be. This is particularly true for CH_4 and N_2O emissions due to the technology-dependent nature of such emission processes. Also, the disaggregation of fuel consumption between stationary combustion and mobile combustion sources will be necessary to ensure appropriate accounting of emissions.

For process-related emissions, the types of data sources required include, but are not limited to, raw material consumption data (e.g. iron ore, scrap steel), input/output production data for iron-making and steel-making processes (e.g. quantities of pig iron, crude steel), consumption data for various feed materials or components that are processed or consumed (e.g. coke used as a reducing agent, limestone used as flux material, carbon electrodes in EAFs), data on specific material properties from composition analysis (e.g. carbon content, quantity of impurities) or direct plant material stocks (e.g. HFCs).

Possible sources of the data described above include:

- process or plant operators, equipment maintenance personnel (fuel consumption, feed material input rates, production output rates — may be metered or tracked by log books per process or equipment unit to monitor operational performance; periodic measured weight differences in material stocks or plant records of material used);
- financial accounting department (data available on fuel usage, reagent use, raw process feed materials by facility through monthly invoices, shipment receipts, etc.);

- fuel or raw material suppliers, equipment suppliers (quantity of fuels delivered for billing purposes, fuel or raw material composition data, EF data, process equipment operating data); and
- on- or off-site laboratory facilities (composition data for fuels, product quality data, gas analyses of specific process streams, etc.).

Step 2: Identification of Data Sources

a) Conduct a survey of the various facility data systems to identify the available data sources by relevant emission source category (e.g. stationary combustion, mobile combustion, process-related).

b) Document appropriate details on these data sources (e.g. party responsible for data collection, frequency of collection, etc.).

c) It is important to select data sources that are authoritative and can be counted on to be consistent and readily available for the foreseeable future.

3.3 Selection of Estimation Methodology

To help inventory practitioners decide which estimation method to use, a number of decision trees have been developed for the emission sources covered here. The following subsections present such decision tools, where it was deemed appropriate, for the fuel combustion and specific process-related sources that may be occurring at your facility.

Important Note:
It may be possible for you to use more than one estimation approach to determine the emissions of a specific GHG from your facility. In this instance, it is essential to recognize that double-counting of emissions may occur when combining emission estimates that were developed using different estimation methods. Activity data would need to be adjusted to ensure that double-counting is avoided. For example, you may know the quantity of fuel combusted by one particular boiler (say, Boiler A) at your facility. This would allow you to use the Detailed Source-based Approach for estimating CO_2 emissions from this combustion unit. For other combustion units at the facility that use the same fuel type, you may not know the individual quantity of fuel combusted by each of these units. In this case, you may need to use the total quantity of that fuel supplied to the facility to estimate CO_2 emissions from these combustion units. To avoid double-counting, the quantity of fuel combusted by Boiler A should be subtracted from the total quantity of the fuel supplied to the facility prior to estimating the emissions for the other combustion units.

Step 3: Selection of Estimation Methodology

a) Proceed through the decision trees that are available in the following subsections for the relevant GHG emission source applicable to your facility to determine the estimation method that is appropriate for your facility.

b) Document specific details, if necessary, at each decision point to explain what factors led you to follow one path over another through the decision tree.

3.3.1 Stationary Combustion Emissions

Figure 1 is to be used to choose a method for estimating CO_2 emissions from the stationary fuel combustion sources identified. Similarly, Figure 2 is to be used to select a method for CH_4 and N_2O (non-CO_2) emissions from combustion sources.

3.3.2 Mobile Combustion Emissions

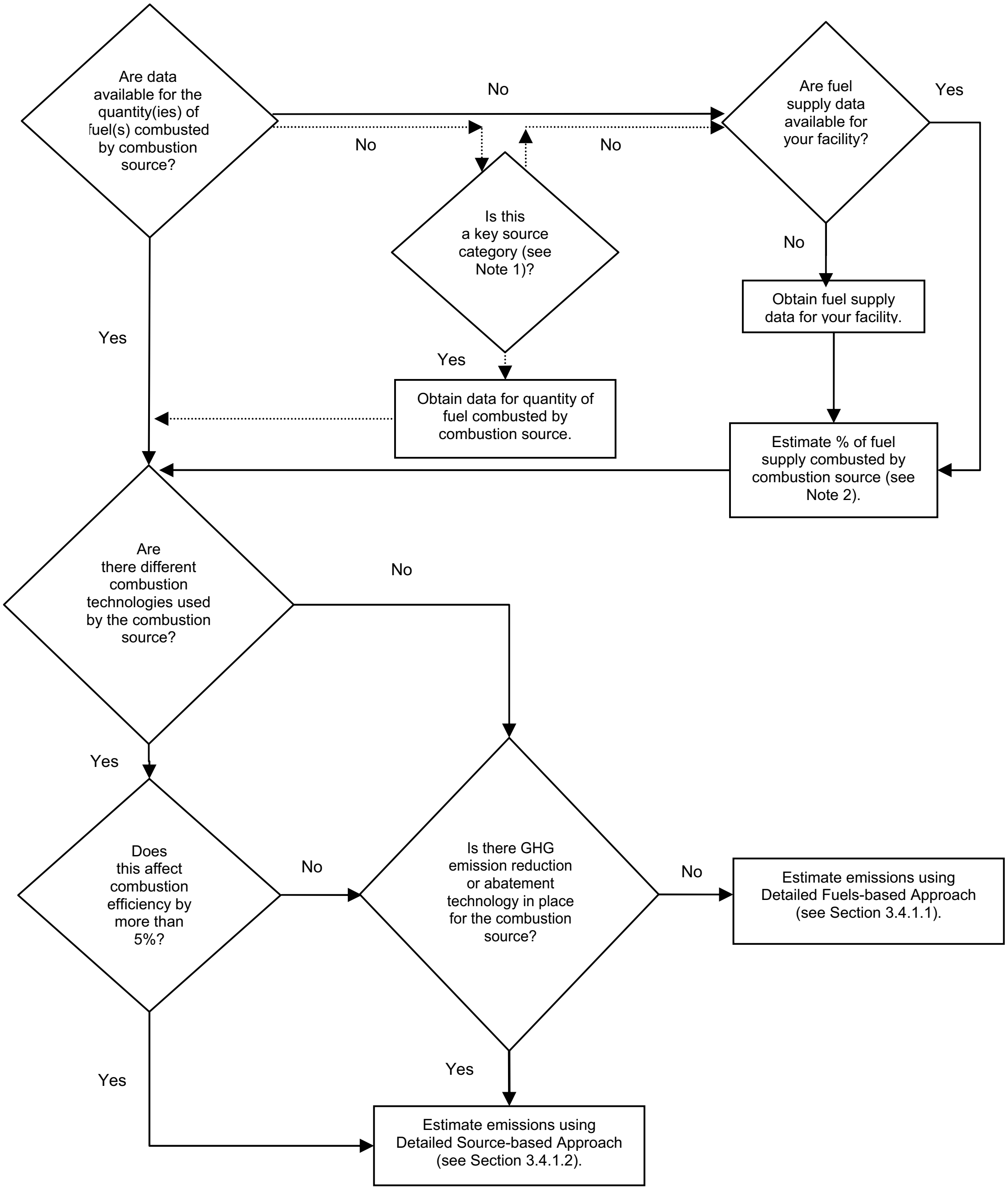
A decision tree has not been provided for estimating mobile combustion emissions as it was not deemed appropriate or necessary. The inventory practitioner is simply to proceed to Section 3.4 for the methodology included in this guidance manual for such emission sources.

3.3.3 Process-related Emissions

A decision tree is presented in Figure 3 to assist in the selection of the estimation method to use for specific emission sources in the iron-making process. Figure 4 is to be used to choose a method for specific emission sources in the steel-making process.

Decision trees have not been provided for other potential process-related emissions as it was not deemed appropriate or necessary. The inventory practitioner is simply to proceed to Section 3.4 for the methodology included in this guidance manual for such emission sources.

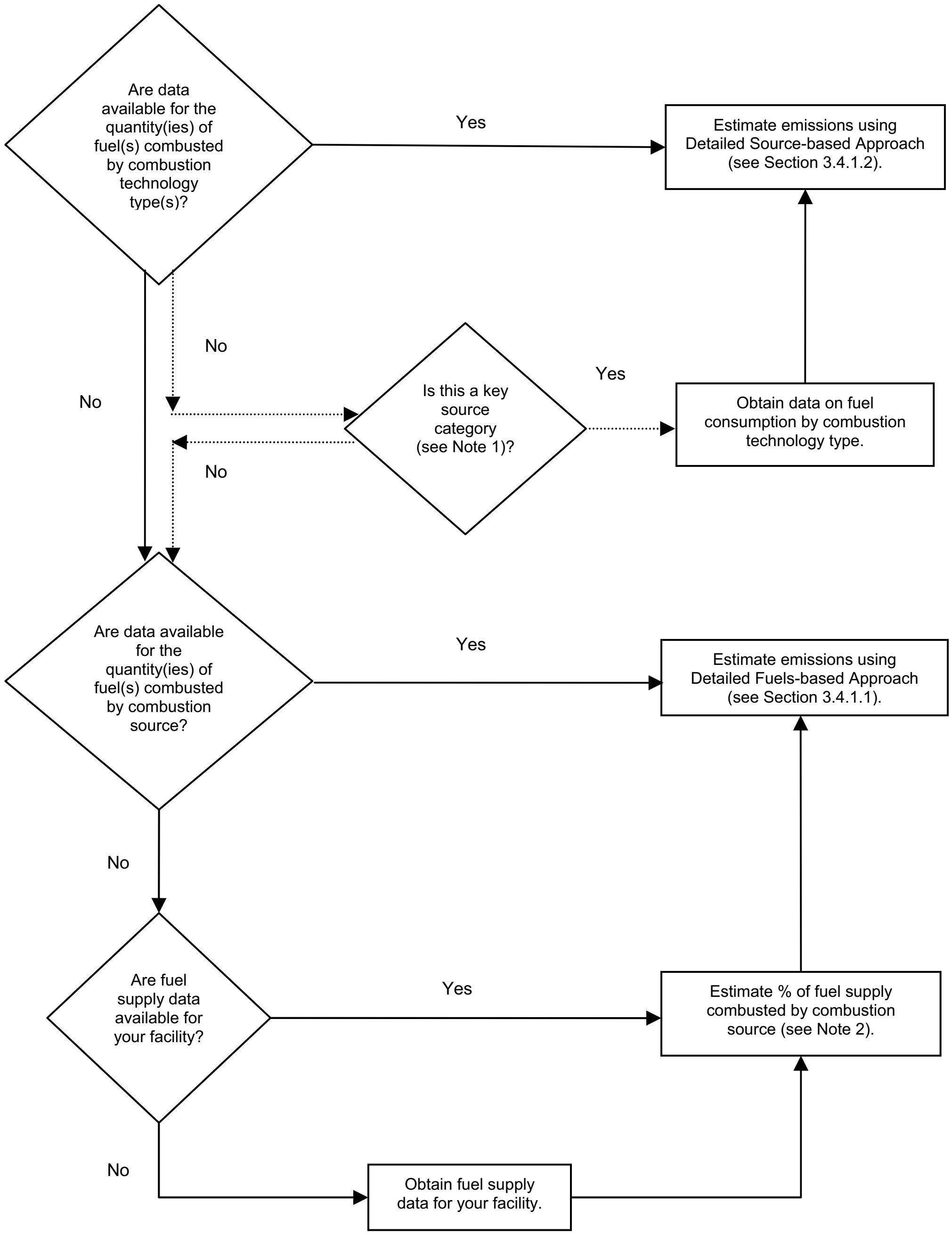
Figure 1: Decision Tree for Selecting the Method for Estimating CO_2 Emissions from Stationary Fuel Combustion



Note 1: From the IPCC Guidelines (IPCC, 1997), a *key source category* is one that is prioritized within the national GHG inventory system because its estimate has a significant influence on a country's total inventory of direct GHG emissions in terms of the absolute level of emissions, the trend in emissions or both. For a facility, a similar definition can be used, where a key source category is one that is prioritized within the facility's GHG inventory system. For further details on this aspect, see Section 3.5. This step in the decision tree can be ignored until your facility has a GHG inventory for several (at least three to five) inventory years.

Note 2: Total fuel supply data may include quantities of fuel that are used for non-energy purposes (e.g. feedstock material). It is necessary to subtract such quantities of fuel from total fuel supplies in order to determine quantities of fuel combusted for the purpose of generating energy.

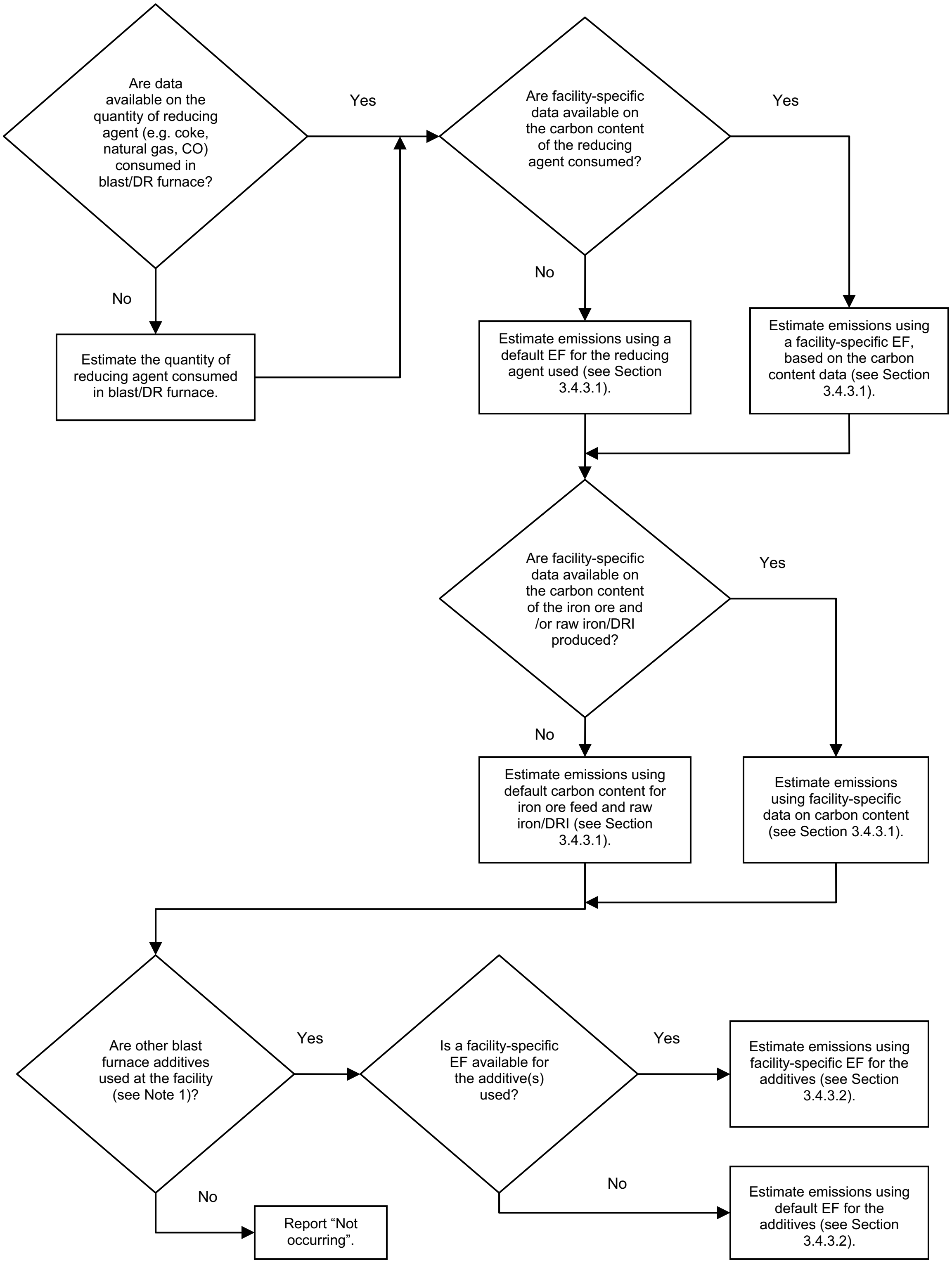
Figure 2: Decision Tree for Selecting the Method for Estimating CH_4 and N_2O Emissions from Stationary Fuel Combustion



Note 1: From the IPCC Guidelines (IPCC, 1997), a key source category is one that is prioritized within the national GHG inventory system because its estimate has a significant influence on a country's total inventory of direct GHG emissions in terms of the absolute level of emissions, the trend in emissions or both. For a facility, a similar definition can be used, where a key source category is one that is prioritized within the facility's GHG inventory system. For further details on this aspect, see Section 3.5. This step in the decision tree can be ignored until your facility has a GHG inventory for several (at least three to five) inventory years.

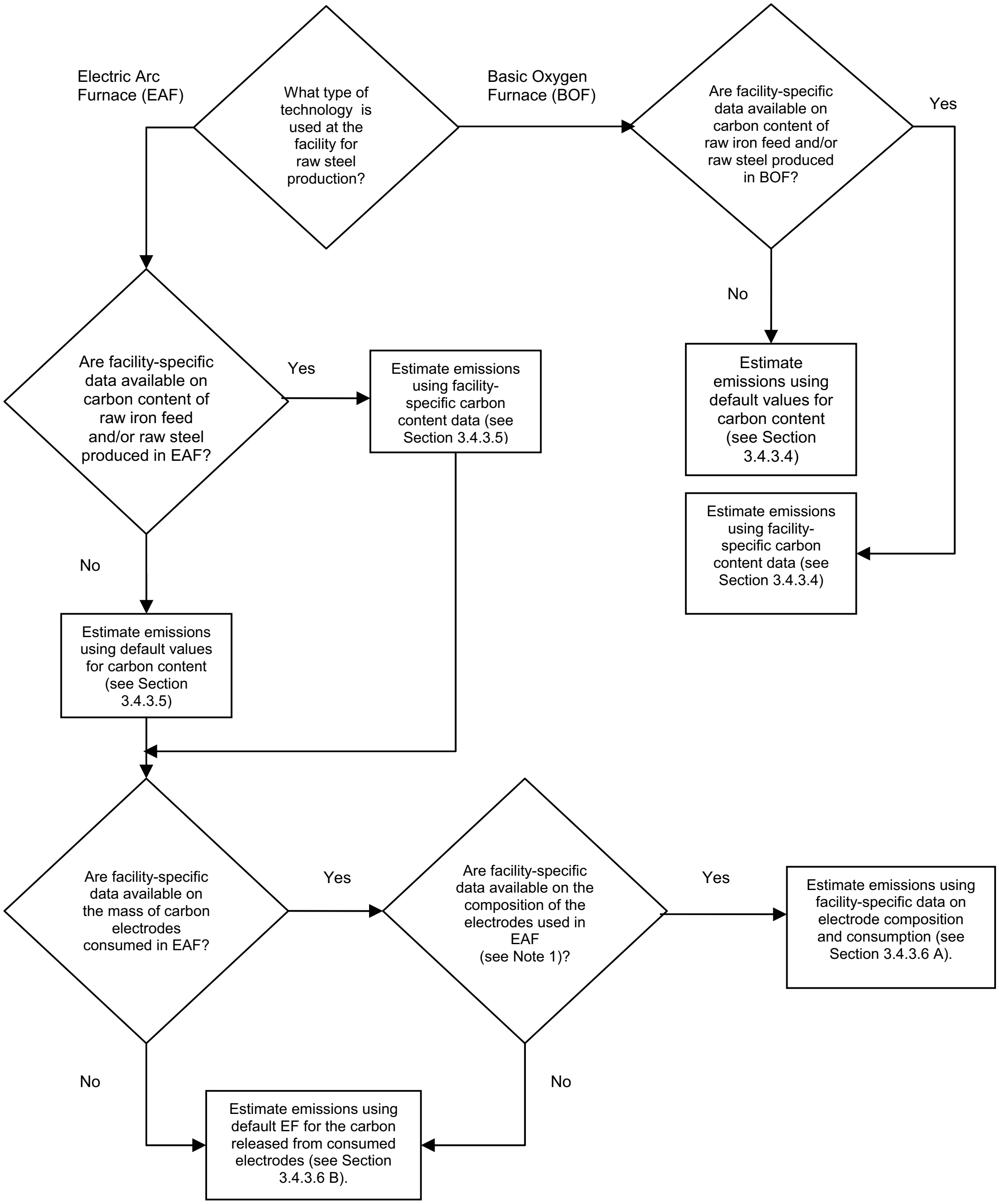
Note 2: Total fuel supply data may include quantities of fuel that are used for non-energy purposes (e.g. feedstock material). It is necessary to subtract such quantities of fuel from total fuel supplies in order to determine quantities of fuel combusted for the purpose of generating energy.

Figure 3: Decision Tree for Selecting the Method(s) for Estimating GHG Emissions from Specific Sources in Iron Production (Blast furnace or direct reduction (DR) process)



Note 1: Other carbon-bearing agents such as charcoal, waste materials, tar, plastics (e.g. PVC, PET, PE) , etc. may be added to the blast furnace for reductant / fuel purposes.

Figure 4: Decision Tree for Selecting the Method(s) for Estimating GHG Emissions from Specific Sources in Steel Production



Note 1: Material composition data includes data on percent carbon content in the graphite (carbon) electrodes.

3.4 Emissions Calculation

When estimating your GHG emissions, the estimates should be calculated based on a one-year inventory period. The calendar year is the common (and preferred) time period used. Also, separate values are to be estimated and documented for emissions of the individual GHGs applicable to your facility (e.g. CO_2, CH_4, N_2O, perfluorocarbons [PFCs], SF_6, etc.). Metric units should be used in measurements and calculations to be consistent with international conventions.

As mentioned previously, estimates of GHG emissions are normally obtained using a calculation methodology. However, if there are direct measurements available for a specific GHG from a particular process or equipment unit in your facility (e.g. through a continuous monitoring program), please include all details on these data and make use of these data to determine the total emissions.

For the estimation methodologies that make use of EFs, it is important for inventory practitioners to use the following basic guidelines to increase consistency and transparency:

- If it is possible to use local or facility-specific EFs that are available, it is important to provide all details on the source of the EF and other relevant information, such as assumptions, conventions, conversions, etc., associated with the EF. For newly developed facility-specific EFs, details on the methodology used to develop the EF should be documented, including data sources, scientific or technical literature used,[8] etc.
- Fuel-specific EFs that may be used should be based on the physical quantity of the fuel used, since fuels are typically measured or reported in physical units; hence, the number of conversions required to derive the estimates is reduced. To convert an EF that is in energy units (e.g. grams per terajoule) to physical units of the fuel, use the appropriate calorific value conversion factor for the particular fuel type. Appropriate gross calorific values may be available from the fuel supplier, or default values are provided in Appendix A.[9] It is important to document what conversion factors are used.

It is possible that the inventory practitioner has a good reason to change or refine the methodology used to estimate emissions from specific source categories. This may occur, for example, as a result of a change in available data, an increase in capacity for inventory preparation or an improvement in the estimation of key source categories. Such changes in methodology are desirable when they result in more accurate and complete estimates. When a change in methodology occurs, it is necessary that the user recalculate the base year emissions, using the changed method. To be consistent with international requirements (IPCC, 2000), it is good practice to recalculate previously prepared emission estimates for all inventory years, as far as possible, using the changed method. This is important to ensure that emission trends can be assessed consistently and are reliable. The user should document what recalculations it has chosen to perform.

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[8] Complete references for these sources of information should be provided in the GHG inventory and made available for consultation if necessary. This reflects the basic principle of transparency.

[9] The gross calorific values presented in Table A.9 in Appendix A are taken from the Statistics Canada publication *Quarterly Report on Energy Supply-Demand in Canada* (Statistics Canada, 2001).

Step 4: Estimation of Emissions

a) Estimate the emissions from the stationary fuel combustion sources identified at your facility using the selected methodology from Step 3.

b) Estimate the emissions from the mobile fuel combustion sources identified at your facility, using the methodology provided in Section 3.4.2.

c) Estimate the emissions from the process-related sources identified at your facility using the selected methodology from Step 3, where applicable.

d) Document all details of the estimation process, including all assumptions made, data used, conversion factors, calculations, worksheets, etc.

3.4.1 Stationary Combustion Emissions

This section describes the estimation methods considered appropriate for use in estimating emissions from stationary fuel combustion sources. There are two methods described: the Detailed Fuels-based Approach (Section 3.4.1.1) and the Detailed Source-based Approach (Section 3.4.1.2).

3.4.1.1 Detailed Fuels-based Approach

The Detailed Fuels-based Approach estimates the quantity of GHG emissions (i.e. CO_2, CH_4 or N_2O) using the general equation:

$$\boxed{\text{Emissions} = \text{Quantity of Fuel Combusted}_{ab} \times \text{Emission Factor}_{ab}}$$

where: a = fuel type;
b = sector or source activity.

This approach requires a good knowledge of the quantity and quality of fuel types consumed in the source combustion processes identified and the use of CO_2 EFs that are fuel-specific. For CH_4 and N_2O emissions, the EFs that are used are fuel-specific and do not differentiate between different combustion technologies. EFs may be available that incorporate assumptions regarding a typical or common combustion technology type(s) used. This approach does not account for emission reduction or abatement technologies that may be in use at the facility.

To calculate CO_2, CH_4 and N_2O emissions under this approach, first determine the quantity of fuel combusted for each fuel type used in the stationary combustion process(es) identified at the facility.

Next, it is necessary to choose an appropriate EF for each fuel type consumed. It is good practice to use a facility-specific or locally available EF, as this should be more representative of local or facility conditions with regards to fuel types and/or operating conditions. General guidance on developing a facility-specific EF is provided below. If appropriate data cannot be obtained, a default EF from Appendix A for the fuel type(s) should be used.[10]

For each fuel type used for combustion, calculate the estimated emissions, according to the general equation above, using the selected EF and the quantity of fuel combusted. Templates are available in

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[10] The EFs listed in Appendix A are the EFs used by Environment Canada when generating the national GHG inventory. You will note that the CO2 EFs are sector-specific or province-specific. The CH4 and N2O EFs are sector-specific and may be linked to the use of a common combustion technology type(s).

Appendix A (Tables A.1–A.3) to record the fuel input data, the selected EF and the calculated CO_2, CH_4 and N_2O emissions.

Finally, sum the results across all fuels (except for biomass fuels for CO_2) to give the total emissions released (by GHG type) from stationary fuel combustion at the facility. CO_2 emissions from the combustion of biomass fuels are estimated but are listed separately as information items.

General Guidance to Develop a Facility-specific EF:

a) CO_2 Emission Factor

CO_2 EFs for fuel combustion are primarily dependent on the properties of the fuel and, to a lesser extent, the combustion technology. The following general equation (adapted from Joint EMEP/CORINAIR, 2001) can be used to determine a CO_2 EF, by fuel type, for the Detailed Fuels-based Approach:

$$\boxed{EF_{CO_2} = \left(\frac{44}{12}\right) \cdot C_{C\ fuel} \cdot \infty}$$

where:
EF_{CO_2} = facility EF, by fuel type (in mass of CO_2 / mass of fuel [e.g. g/kg (grams/kilogram)]);
$C_{C\ fuel}$ = carbon content of fuel (in mass of C / mass of fuel [e.g. g/kg]);
∞ = fraction of carbon oxidized.

The fuel composition data for the fuel combusted at the facility can be used to determine the carbon content of the fuel. It is necessary to convert from carbon (C) to CO_2 by multiplying by the molecular weight ratio of CO_2 to C (44/12). Also, it is necessary to take into account the fraction of carbon that is oxidized to CO_2. Small amounts of carbon may remain unoxidized (in the form of soot or ash). An appropriate assumption regarding the efficiency of the combustion process(es) used may be needed here.

Also, it is assumed that the only product of oxidation is CO_2. Products of incomplete oxidation, such as carbon monoxide (CO), are assumed to undergo complete oxidation to CO_2 in the atmosphere after being emitted (IPCC, 1997). Thus, all carbon from these emissions is accounted for in the total for CO_2 emissions.

For fuels where the carbon content varies significantly from year to year (such as coal), a new EF should be developed for each inventory period.

b) CH_4 or N_2O Emission Factor

Emissions of CH_4 or N_2O from fuel combustion are technology-dependent. Because of this dependence, the development of a facility-specific EF for use in the Detailed Fuels-based Approach is not as straightforward as for CO_2. It may be necessary to make assumptions regarding a "typical" combustion technology type used at the facility that is considered representative of the combustion process(es) at the facility.

The EF that is developed for the fuel type is to be based on CH_4 or N_2O emissions data measured in situ for the combustion technology type(s) used. In the case where one fuel type (i.e. natural gas) is combusted by only one type of combustion technology at the facility, the EF developed would be specific to that fuel type and combustion unit (similar to EFs developed under the Detailed Source-based Approach in the following subsection). Refer to Section 3.4.1.2 for further guidance and suggested calculations to obtain the EF.

If one specific fuel type is combusted by more than one type of combustion technology at the facility, a weighted EF could be developed based on the technology split (i.e. using rated capacity or other comparable parameter) for the facility and EFs that are available for each technology type. This is a similar approach to that used to develop the national EFs for CH_4 and N_2O (adapted from SGA Energy Limited, 2000).

3.4.1.2 Detailed Source-based Approach

This approach is similar to the approach discussed in the previous section, in that it uses the same general equation for estimating the GHG emissions:

$$\boxed{\text{Emissions} = \text{Quantity of Fuel Combusted}_{abc} \times \text{Emission Factor}_{abc}}$$

where:
a = fuel type;
b = sector or source activity;
c = technology type.

This approach requires additional knowledge of source emissions variability and efficiency of the combustion processes. The EFs used are specific to the combustion technology used in the combustion sources identified. Also, the use of any emission reduction or abatement technology is taken into consideration under this approach.

To calculate CO_2, CH_4 and N_2O emissions under this approach, first determine the quantity of fuel combusted for each fuel type used in the combustion technology unit(s) used at the facility.

Next, it is necessary to choose an appropriate EF that is specific to the fuel type consumed and the combustion technology type used. For facility-specific EFs, general guidance on how to develop these EFs is provided below. If data cannot be obtained to develop a facility-specific EF, a default EF value from Appendix B for the fuel type(s) and combustion technology type(s) should be used.[11] If there is no CO_2 EF listed in Appendix B for a technology type used at the facility, it is sufficient to use a facility-specific or default CO_2 EF by fuel type that would be used under the Detailed Fuels-based Approach (see previous section and default EFs listed in Appendix A).

For each fuel type and combustion technology used for combustion, calculate the estimated emissions using the selected EF and the quantity of fuel combusted. Templates are available in Appendix B (Tables B.1–B.3) to record the fuel input data, the selected EF and the calculated CO_2, CH_4 and N_2O emissions.

An additional important factor to consider is accounting for the presence of a GHG emission control technology, if any:

- It will be necessary to make adjustments to the appropriate emission estimates to account for the GHG emission reduction or abatement technologies in place. You should identify the emission control technology(ies) used at your facility and the associated percent reduction in the specific GHG(s). To avoid double-counting of reductions achieved due to the emission control technology(ies), it is important to verify whether the EF used in Step 2 is based on uncontrolled or controlled emissions.

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[11] The EFs listed in Appendix B have been compiled from the U.S. EPA's *Compilation of Air Pollutant Emission Factors* (U.S. EPA, 1995).

- It is important to detail the performance, operational parameters and any key assumptions for the emission abatement technology within the GHG inventory, since little information exists on these technologies in the public domain. This follows the basic principle of transparency.
- Calculate the net emission estimate for the applicable GHG using the percent reduction for the control technology unit at your facility.

Finally, sum the results across all fuels (except for biomass fuels for CO_2) to give the total emissions released (by GHG type) from stationary fuel combustion at the facility. CO_2 emissions from the combustion of biomass fuels are estimated but are listed separately as information items.

General Guidance to Develop a Facility-specific EF:

For a CO_2, CH_4 or N_2O EF that is to be used in the Detailed Source-based Approach, the EF that is developed is specific to the fuel type combusted and the combustion technology type used (e.g. industrial boiler, cyclone furnace, travelling grate stoker, etc.). The EF is to be based on emissions data obtained for the GHG in question from the combustion technology unit. The method used to obtain the emissions data (e.g. continuous emissions monitoring system [CEMS], stack sampling, engineering calculation) for the particular combustion unit should be fully documented.

The emissions data obtained may be in concentration measurements (e.g. parts per million by volume dry air [ppmvd]). To convert emissions measured in concentration units to mass units, the following equation can be used (adapted from U.S. EPA, 2001):

$$\boxed{E_x = \frac{(C \cdot MW \cdot Q \cdot 60)}{(V \cdot 10^6)}}$$

where: E_x = hourly emissions of GHG x in g/h (grams/hour);
C = GHG concentration in ppmvd (parts per million by volume dry air);
MW = molecular weight of the GHG in g/mol (grams/mole);
Q = stack gas volumetric flow rate in dscmm (dry standard cubic metres/minute);
60 = 60 min/h (minutes/hour);
V = volume occupied by 1 mole of ideal gas at standard temperature and pressure (0.022414 m^3/g-mol at 0°C and 101.325 kPa).

The pitot tube measurement technique can be used to determine the stack gas volumetric flow rate.

To calculate the EF per physical unit of fuel combusted, the fuel flow rate into the combustion unit is required:

$$\boxed{EF_x = \frac{E_x}{Q_f}}$$

where: EF_x = emission factor for GHG x in g/physical unit of fuel combusted (e.g. kg, m^3, L);
E_x = emissions of GHG x in g/h;
Q_f = fuel flow rate in, in physical unit/h (e.g. kg/h, m^3/h, L/h).

Units and conversions other than those listed in the above equations may be used, depending on the measurement technique(s) applied and/or measurement equipment used to obtain the emissions data. Ultimately, quantities should be converted to metric units.

There may be GHG emissions control technology or equipment associated with the specific combustion unit for which an EF is being developed. The EF that is developed may account for the

GHG emission reductions achieved due to the use of the control technology if, for example, the emissions data used to develop the EF are measured at a point after the control equipment. It is necessary to identify whether the EF is based on controlled or uncontrolled emissions to ensure that double-counting of any GHG reductions achieved is avoided. Also, relevant design criteria of the emissions control technology should be documented in order to understand how varying process parameters can affect emissions.

If it is felt that the EF from a particular unit may vary over time (e.g. due to varying fuel characteristics or combustion conditions), measurements may be required over a longer period, and a statistical approach (probability distribution, linear regression, etc.) may be required to develop a mean for the EF. In addition, measurement programs may need to be initiated at regular intervals (e.g. every two years) to ensure that the EF being used is still representative. In each of these cases, it is best to document the measurement program undertaken, any assumptions or statistical approaches used and any periodic sampling program that may be undertaken.

Emission Factor Development

An EF is a representative value that attempts to relate the quantity of a pollutant released to the atmosphere with an activity associated with the release of that pollutant (U.S. EPA, 1995). In this instance, the activity is fuel combustion. EFs can be developed at the facility level based on data from the facility over a defined time period. The facility-specific EF can then be used to estimate emissions from the facility. Such EFs are preferred over general or industry-averaged EFs, since they would provide the best representation of emissions from a facility's specific operations. It may be necessary to update facility-specific EFs on a periodic basis to account for changes in facility conditions.

The types of data that are available or that can be obtained for the facility will define the type of EF that can be developed. Your facility may already have the data required to develop a facility-specific EF. Sources to check are your plant operator(s) or laboratory facilities used. Also, your local fuel suppliers should have information on fuel composition and quality. Suppliers of the combustion units used at your facility may be able to provide information on expected or actual test data on combustion performance or technology specifications.[1] The facility may have existing emissions monitoring systems in place or regular emissions testing programs for measuring emissions of pollutants other than the GHGs being considered (CO_2, CH_4, N_2O). Possible modifications to these systems or programs could allow additional monitoring for these GHGs.

If the facility data are not already available, there are several methods that can be used to obtain the data. These include (adapted from U.S. EPA, 2001):

(i) Fuel sampling and analysis
This method can be used to determine the composition of the fuel type and hence the percent carbon of the fuel. Samples of the fuel are taken from specific sample points and then sent for laboratory analysis, where gas chromatographic techniques are typically applied. Details on the sampling method and lab techniques used should be provided if you choose to collect facility data through this method. Standardized sampling and lab analysis protocols should be used when available.

(ii) Continuous emissions monitoring system (CEMS)
This method can be used to obtain direct data on emissions of CO_2, CH_4 and/or N_2O from separate combustion processes on a continuous basis. This is the preferred method when data on emissions are needed over an extended period. There are various types of monitoring systems available for installation, which use different instrumentation equipment. It is necessary for your facility to ensure the proper operation and calibration of the monitoring equipment used.

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[1] It should be recognized, however that the manufacturer's test data may not be representative of in-the-field performance, and on-site emission measurements may still be required to improve the accuracy of the estimates.

(iii) Predictive emissions monitoring

It may be possible to use this method to obtain data on emissions of CO_2, CH_4 and/or N_2O, using process parameters to predict emissions over an extended period. A correlation between emissions and specific process parameters is developed initially, where emissions testing is conducted and varying process parameters are monitored. These data can then be used to develop emission curves. The accuracy of the curves should be checked through periodic stack sampling.

(iv) Stack sampling and analysis

This method can be used to obtain direct data on emissions of CO_2, CH_4 and/or N_2O over a short period (during the period of the test). Stack samples are collected and sent for laboratory analysis. Details on the sampling method and lab techniques used should be provided if you choose to collect facility data through this method. Standardized sampling and lab analysis protocols should be used when available.

Important Factors to Consider When Collecting Data to Develop a Facility-specific EF: (adapted from U.S. EPA, 1995, except where noted)

- Fuel composition or emissions data that are already available or that are collected will be applicable only to the conditions existing at the time of sampling, testing or monitoring. To provide the best estimate of longer-term (i.e. yearly or a typical day) emissions, these conditions should be representative of the facility's routine operations. Testing should be conducted at normal operating conditions.
- To account for variability in fuel composition or emissions over time, it is preferable to obtain facility data over an extended period (i.e. through a number of tests performed over an extended timeframe or through CEMS). An EF that is developed based on fuel composition or emissions data over a short period could result in less accurate emission estimates.
- The quality of an EF is dependent on the estimated reliability of the tests used to develop the factor and on both the amount and the representative characteristics of those data. It is preferable that an EF be based on many observations or on more widely accepted test procedures. Such an EF is considered to be of higher quality (more accurate), whereas a factor based on a single observation of questionable quality or one extrapolated from another factor for a similar process would be of lower quality.
- It is necessary to ensure that sampling and testing techniques that are used to obtain facility data are consistent to avoid uncertainty due to changes in these areas. Relevant QA/QC procedures for sampling and lab analysis should be documented and followed.
- The activity data that will be used with the developed facility-specific EF to estimate emissions are the quantity of fuel supplied or combusted. Since this parameter is measured in physical units of the fuel, the EF should also be in physical units of the fuel type (Olsen et al., 2002).

3.4.2 Mobile Combustion Emissions

Emissions from on-site mobile combustion activities that are integral to the production process are estimated using the general equation described under stationary fuel combustion, adapted to mobile sources:

$$\text{Emissions} = \text{Quantity of Fuel Combusted}_{ab} \times \text{Emission Factor}_{ab}$$

where a = fuel type;
b = mode of transport or vehicle type.

To calculate CO_2, CH_4 and N_2O emissions, first determine the quantity of each fuel type combusted in the on-site mobile combustion activities identified. If the same fuel type is combusted by more than one mode of transport and/or vehicle type, it will be necessary to determine the individual quantities combusted by each mode or type of vehicle. It is also necessary to disaggregate fuel quantities used in stationary and mobile combustion applications if the same fuel types are used. The inventory practitioner should document how the appropriate fuel quantities have been determined and if necessary, provide clarification on how fuel combustion sources have been classified.

Next, it is necessary to choose an appropriate EF for each fuel type consumed. It is good practice to use a facility-specific or locally available EF as this should be more representative of local or facility conditions with regards to fuel types and/or operating conditions of the modes of transport used. The general guidance provided under the stationary combustion section on EF development is also applicable here. As described previously, CO_2 EFs are fuel-specific while CH_4 and N_2O EFs are fuel-specific and technology-dependent (e.g. affected by the type of pollution control devices that may be employed)[12.] If facility-specific data is not available, a default EF from Appendix C for the fuel type(s) and mode of transport/vehicle type should be used.

For each fuel type used for mobile combustion, calculate the estimated emissions, according to the general equation above, using the selected EF and the quantity of fuel combusted. Templates are available in Appendix C (Tables C.1 - C.3) to record the fuel input data, the selected EF and the calculated CO_2, CH_4 and N_2O emissions. The results are then summed across all fuels to give the total emissions released from mobile fuel combustion sources at the facility.

3.4.3 Process-related Emissions

This section describes the estimation methods considered as appropriate for estimating emissions from various process-related emission sources that may exist at the facility. A general template is available in Appendix D (Table D.1) to record the specific process-related sources that exist at the facility in question and the corresponding GHG emissions that are estimated for the identified sources.

3.4.3.1 CO_2 Emissions from Use of Reducing Agents

In the blast furnace, raw iron (also termed pig iron) is produced through the reduction of iron ore and this process requires the use of carbon as a reducing agent and results in CO_2 being released (as the carbon is oxidized). Metallurgical coke is the primary reducing agent used (other sources such as coal or petroleum coke may also be used). In this process, carbon may also be emitted as CO_2 due to the presence of carbonates in the iron ore material and carbon may be sequestered in the raw iron produced. Similarly, in the direct reduction process, direct reduced iron (DRI) is produced in the solid state through the reduction of the iron ore feed where H_2 and CO are used as the reducing agents.

As previously discussed, carbon is performing a dual role in the above processes, serving as a reductant and a fuel. The primary purpose for the oxidation of the carbon is to reduce the iron ore to raw iron or direct reduced iron. Hence, the emissions should be reported as process-related emissions. It is important to ensure that these emissions are not double-counted under the stationary combustion section.

To calculate CO_2 emissions from oxidation of the reducing agent used in blast furnace or direct reduction operations and to account for carbon in the iron ore and the raw iron/direct reduced iron produced, use the following equation:

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[12] If it is not known whether the mode of transport employed has pollution control devices in place or how this impacts GHG emissions, it is good practice to use fuel EFs for uncontrolled conditions to be conservative when estimating emissions until such information is available.

$$\text{Emissions}_{CO_2} = EF_{RA} \times Q_{RA} + (M_{\text{C in Iron Ore}} - M_{\text{C in Raw Iron/DRI}}) \times \frac{44}{12}$$

where:
EF_{RA} = emission factor for the reducing agent (tonnes CO_2/tonne reducing agent);
Q_{RA} = quantity of reducing agent consumed in the blast/direct reduction furnace (tonnes);
$M_{\text{C in Iron Ore}}$ = mass of carbon in the iron ore feed (tonnes C);
$M_{\text{C in Raw Iron/DRI}}$ = mass of carbon in the raw iron/DRI produced (tonnes C);
44/12 = stoichiometric ratio of CO_2/C;

A facility-specific EF for the reducing agent should be used in the above equation to ensure accuracy of the estimates. This EF may be developed using the following equation where the necessary data should be obtained from on-site material analysis or from suppliers.

$$EF_{RA} = C_{RA} \times \frac{44}{12}$$

where:
C_{RA} = carbon content of the reducing agent (mass C/mass of reducing agent);
44/12 = stoichiometric ratio of CO_2/C;

Facility-specific data should also be obtained for the carbon content of the raw iron ore used and the raw iron/DRI produced in these processes. These values would be multiplied by the quantity of iron ore fed into the furnace and the quantity of raw iron/DRI produced, respectively. It is important to note that most of the carbon stored in the raw iron/DRI at this stage is subsequently released when the raw iron/DRI undergoes further processing to produce steel (this is accounted for in a later section).

If facility-specific data are not available, default values for the EF for various reducing agents and for the carbon content of iron ore and raw iron/DRI are provided in Appendix D (see Tables D.2 & D.3).

Note on the Use of Blast Furnace Gas:
Blast furnace gas (BFG) is produced during the blast furnace operations and this gas may be collected, cleaned and combusted as a fuel in the blast furnace operations or in other on-site processes. CO_2 emissions that would result from the combustion of BFG are already accounted for in the calculations above for the use of a reducing agent. This is worth noting in order to avoid double-counting emissions as BFG may be listed under the stationary combustion section as a fuel that is burned on-site.

If some of the BFG generated is exported off-site (i.e. not burned or otherwise handled in on-site processes), it may be necessary to adjust the process emissions to account for this. The CO_2 emissions linked to the quantity of BFG exported off-site should be calculated and then subtracted from the process emissions. It is important to document this to ensure clarity if such an adjustment is conducted.

3.4.3.2 *CO_2 Emissions from Use of Other Blast Furnace Additives*

There may be other carbon-bearing agents added to the blast furnace (e.g. charcoal, waste materials, tar, plastic compounds such as PVC, PET, PE, etc.) for reductant/fuel purposes (WRI/WBCSD, 2002). CO_2 emissions from these other blast furnace additives are to be calculated using the equation below:

$$\boxed{\text{Emissions}_{CO_2} = EF_{BF\,Add} \times Q_{BF\,Add}}$$

where:
$EF_{BF\,Add}$ = EF for the blast furnace additive (tonnes CO_2 / tonne of additive);
$Q_{BF\,Add}$ = quantity of additive consumed in blast furnace (tonnes).

EFs are specific to each additive that may be employed and facility-specific EFs should be obtained for the particular materials used at the facility in question (the EF equation listed in the previous section can be applied here). If there is no data available to develop facility-specific EFs, there are default values provided in Table D.4 for various blast furnace additives that may be used.

For any biomass materials (e.g. charcoal, wood chips) that may be added to this process, the estimated CO_2 emissions associated with the use of these materials are to be calculated and recorded but are not to be included in the overall CO_2 emission totals for the facility. As previously discussed in Section 2.1.1, CO_2 emissions associated with the use of biomass materials would be taken into account as a loss of biomass [forest] stocks under a separate guidance manual for Land Use Change and Forestry (IPCC, 1997).

3.4.3.3 *CO_2 Emissions from Use of Limestone*

Limestone ($CaCO_3$) or dolomite ($CaCO_3$-$MgCO_3$) may be used in the sintering process or added directly to the blast furnace as a flux where these carbonate compounds are heated at high temperatures, resulting in CO_2 emissions. Limestone may also be added to steelmaking furnaces to remove impurities in the melt. Emissions of CO_2 from the use of limestone or dolomite fluxes are estimated based on the mass of carbonate used, the purity of the reagent and the stoichiometry of the calcination reaction. To calculate emissions from the use of these carbonates, use the following equation:

$$\boxed{\text{Emissions}_{CO_2} = \left[\left(\frac{44}{100}\right) \times f_{ls} \times Q_{ls} \right] + \left[\left(\frac{2 \times 44}{184}\right) \times f_d \times Q_d \right]}$$

where:
f_{ls} = fractional purity of limestone (tonnes $CaCO_3$/tonne of total raw material);
Q_{ls} = quantity of limestone consumed (tonnes);
f_d = fractional purity of dolomite (tonnes $CaCO_3$-$MgCO_3$/tonne of total raw material);
Q_d = quantity of dolomite consumed (tonnes);
44/100 = stoichiometric ratio of $CO_2/CaCO_3$ (limestone);
(2 x 44)/184 = stoichiometric ratio of $CO_2/CaCO_3$-$MgCO_3$ (dolomite).

If the fractional purity of the limestone and/or dolomite used is unknown, a default value of 1 can be used (IPCC, 1997)

3.4.3.4 *CO_2 Emissions from Steel Production (Basic Oxygen Furnace)*

The production of raw steel in a basic oxygen furnace (BOF) results in CO_2 emissions due to the oxidation of carbon in the raw (or pig) iron that is fed into the furnace. Scrap steel may also be used as feed material in this process and the carbon in this material also needs to be taken into consideration. Emissions are based on the difference between the carbon contents of the raw iron (and scrap steel, if applicable) and the raw steel. To calculate emissions from BOF steelmaking, use the following equation:

$$\text{Emissions}_{CO_2} = (\,M_{\text{C in Raw Iron}} + M_{\text{C in Scrap Steel}} - M_{\text{C in Raw Steel}}\,) \times \frac{44}{12}$$

where:
$M_{\text{C in Raw Iron}}$ = mass of carbon in the raw iron used for steel production (tonnes);
$M_{\text{C in Scrap Steel}}$ = mass of carbon in scrap steel used for steel production (tonnes);
$M_{\text{C in Raw Steel}}$ = mass of carbon in raw steel produced from BOF (tonnes);
44/12 = stoichiometric ratio of CO_2/C.

The mass of carbon in the input and output flows identified in the above equation would be based on the carbon content of the input or output flow(s) multiplied by the quantity of the material used (e.g. raw iron, scrap steel) or produced (e.g. raw steel) in the BOF process. Facility-specific data should be obtained for the carbon content parameter (from material analysis). If not available, appropriate default values from Table D.3 in Appendix D may be used. There is no default carbon content value provided for scrap steel in this guidance and appropriate assumptions may be necessary until facility-specific data on its carbon content are available.

3.4.3.5 *CO_2 Emissions from Steel Production (Electric Arc Furnace)*

The production of steel in an electric arc furnace results in CO_2 emissions due to several sources, including the oxidation of carbon in the feed materials (e.g. scrap steel primarily but may also include raw iron and/or DRI pellets) charged to the furnace. Carbon may also be found in the impurities in the scrap steel used. Another source of CO_2 emissions occurring in EAFs is the consumption of carbon electrodes used in the process (covered in the next section).

The calculation of the emissions due to oxidation of carbon contained in the input materials that are fed into the EAF is the same as that presented in the previous section for similar emissions in the BOF where the following equation is used:

$$\text{Emissions}_{CO_2} = (\,M_{\text{C in Scrap Steel}} + M_{\text{C in Raw Iron/DRI}} - M_{\text{C in Raw Steel}}\,) \times \frac{44}{12}$$

where:
$M_{\text{C in Scrap Steel}}$ = mass of carbon in scrap steel used for steel production (tonnes);
$M_{\text{C in Raw Iron/DRI}}$ = mass of carbon in the raw iron/DRI used for steel production (tonnes);
$M_{\text{C in Raw Steel}}$ = mass of carbon in raw steel produced from EAF (tonnes);
44/12 = stoichiometric ratio of CO_2/C.

As discussed in Section 3.4.3.4, it is recommended to use facility-specific data for the carbon contents of the input and output feeds of the EAF process. If not available, there are default values available in Table D.3 in Appendix D. There is no default carbon content value provided for scrap steel in this guidance and appropriate assumptions may be necessary until facility-specific data on its carbon content are available.

3.4.3.6 *CO_2 Emissions from Electrode Consumption (Electric Arc Furnace)*

As mentioned previously, another source of CO_2 emissions that occurs in EAFs is the consumption of the carbon (graphite) electrodes during the steel-making process. Calculating emissions from electrode consumption requires data for the net carbon consumption per tonne of raw steel produced. In addition, material composition information for the electrodes is required to determine the percent carbon content. Whenever possible, facility-specific data for electrode composition should be obtained to ensure accuracy in the estimates for the facility (from on-site material analysis or electrode suppliers).

A. ⇒ If information on the material composition of the electrodes is available or analysis has been carried out, use the following equation (adapted from IAI, 2003):

$$\boxed{\text{Emissions}_{CO_s} = NCC \times MP \times \frac{\%C_e}{100} \times \frac{44}{12}}$$

where: NCC = net carbon consumption per tonne of raw steel (tonnes C/tonne raw steel);
MP = mass of raw steel produced in EAF (tonnes);
$\%C_e$ = carbon content in carbon electrodes (%);
44/12 = stoichiometric ratio of CO_2/C..

Facilities using carbon electrodes will have to determine the net carbon consumption value by monitoring the use of electrodes (if not already done). A mass-balance approach involving measurement of the mass of electrodes before and after use in the EAF process is recommended in order to determine the net rate of carbon consumption as a function of steel production. Any weight measurements should be made in accordance with national or international standards.

B. ⇒ If facility-specific data is not available for electrode composition and consumption, the following equation may be used (IPCC, 2000):

$$\boxed{\text{Emissions}_{CO_2} = \frac{44}{12} \times EF_{EAF} \times MP}$$

where: EF_{EAF} = EF for carbon released from electrode consumption in EAF (kg carbon/tonne steel);
MP = mass of raw steel produced in EAF (tonnes);
44/12 = stoichiometric ratio of CO_2/C.

A default value of 1.25 kg carbon per tonne of raw steel produced may be used for the EF_{EAF}.[13]

3.4.3.7 *CO_2 Emissions from Carbon Use in Foamy Slag (EAF)*

To remove impurities from the steel in the EAF, a slag is formed (through the addition of limestone and/or lime) as the temperature of the molten steel rises. As the EAF capacity is reached with a full charge of molten steel and slag formation has occurred, carbon and oxygen are injected into the slag in order to make the slag foam (Davis, 2000).[14] Carbonaceous materials that may serve as the carbon source here include coke, charcoal or anthracite coal.

To calculate emissions from carbon blown into the EAF to produce a foamy slag, use the following equation:

$$\boxed{\text{Emissions}_{CO_2} = \frac{44}{12} \times \frac{\%C_{BC}}{100} \times Q_{BC}}$$

where: 44/12 = stoichiometric ratio of CO_2/C;
$\%C_{BC}$ = carbon content of the carbon-bearing material blown in (%);
Q_{BC} = quantity of carbon-bearing material blown into the process (tonnes).

If facility-specific data for the percent carbon content of the carbon-bearing material are unknown, a default value of 100 could be used until such data becomes available.

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[13] The default value for the amount of carbon released from consumed electrodes was taken from (IPCC, 2000). A range of 1 – 1.5 kg was listed in this resource and the midpoint of this range was selected in order to provide a default value here.

[14] Foamy slag improves the furnace power input, lowers hearth refractory wear by shielding arc radiation, and improves heat transfer to the cooler scrap zones near the furnace walls." (Davis, 2000, pg. 580).

3.4.3.8 CO_2 Emissions from Lime Production

Lime is used as a flux reagent in the steel-making process to capture impurities and this lime may be produced on-site. The lime production process involves the calcination of calcium carbonate ($CaCO_3$) in limestone to produce calcium oxide, CaO (or quick lime) and this reaction results in emissions of CO_2. Emission calculations are based on the tonnage of quicklime and lime kiln dust (LKD) (if this quantity is known) produced at the kiln and on the type of limestone used as the feed material (e.g. high calcium or dolomitic). If lime is produced on site, the inventory practitioner should refer to the methodological guidance contained in *A Guidance Manual for Estimating Greenhouse Gas Emissions from Fuel Combustion and Process-Related Sources For Lime Production* (Environment Canada, 2004) to estimate CO_2 emissions from this process-related source.

3.4.3.9 CO_2 Emissions from Use of Soda Ash

Soda ash (or sodium carbonate, Na_2CO_3) may be used on site at the facility as part of desulphurization processes used for hot metal pretreatment and/or treatment of flue gases. CO_2 emissions result from the use of soda ash where a similar calcination reaction occurs as with the use of limestone. Emissions can be estimated using the following equation, which is based on soda ash consumption, the stoichiometry of the chemical reaction and the purity of the soda ash:

$$\boxed{\text{Emissions}_{CO_2} = \frac{44}{106} \times P_{\text{Soda Ash}} \times M_{\text{Soda Ash}}}$$

where: (44/106) = stoichiometric ratio of CO_2/Na_2CO_3;
$P_{\text{soda ash}}$ = fractional purity of soda ash used (tonnes $CaCO_3$/tonne of total raw material);
$M_{\text{soda ash}}$ = quantity of soda ash (Na_2CO_3) used (tonnes).

The purity of the soda ash used at the facility should be obtained to ensure accuracy of the estimates. If not available, a default value of 1 can be used.

3.4.3.10 HFC Emissions from Use in Refrigeration/Cooling Systems

HFCs are typically used in refrigeration equipment and air conditioning units. Emissions of HFCs at a facility may occur through unintentional leaks or operating losses from the system(s). To calculate such emissions, the following basic equation can be used:

$$\boxed{Q_{\text{operation, t}} = Q_{\text{consumption, t}}}$$

where: $Q_{\text{operation, t}}$ = quantity of HFC emitted during system operations in year t;
$Q_{\text{consumption, t}}$ = quantity of HFC consumed during system operations in year t.

The quantity of HFCs consumed in a given year can be determined directly by compiling facility data on the quantity of HFCs that are recharged to each system during annual servicing (to account for system leakages). The type of HFC used by each equipment unit should be documented separately in addition to the individual quantity consumed for each HFC type.

If facility data are not available on the actual quantity of HFCs recharged, such quantities may be estimated using the following equation based on default annual leakage rates:

$$\boxed{Q_{\text{operation, t}} = Q_{\text{stock, t}} \times LR}$$

where: $Q_{\text{stock, t}}$ = quantity of HFC stocked in existing system in year t;
LR = annual leakage rate in percentage of total HFC charge in the stock.

Equipment suppliers should be able to provide information on the quantity of HFCs originally charged to the system(s). Default leakage rates for generic categories of equipment that use HFCs are provided in Table D.5 in Appendix D.

3.5 Inventory Quality and Methodological Improvement

When compiling the annual emission estimates for your facility, key aspects to consider are the management of inventory quality and improvement in the overall estimates. With regard to managing the inventory quality, it is helpful to prioritize your efforts when preparing estimates and conducting QA/QC activities. Improvements can be made to those estimates, with the greatest contribution to improving the accuracy of the estimates and reducing overall uncertainty. This prioritization should be done through a key source assessment.

Conducting a key source assessment will identify key source categories. From the IPCC Guidelines (IPCC, 1997), a *key source category* is "one that is prioritized within the national inventory system because its estimate has a significant influence on a country's total inventory of direct greenhouse gases in terms of the absolute level of emissions, the trend in emissions, or both." A similar definition can be applied to your facility, where a key source category is one that is prioritized within your facility's inventory system. Key source categories for your facility should receive additional attention with respect to the methods used to estimate emissions and the QA/QC procedures that are applied.

The aspect of key sources was incorporated into the decision trees that were provided for the inventory practitioner's use in previous sections (see Figures 1–4). It is important for the inventory practitioner to note that a facility is not expected to be able to perform a key source assessment until the facility has compiled an annual inventory of its GHG emissions for a period of at least three to five years. At that point, it would be useful for a facility to perform a key source assessment if the facility's inventory emission estimates or data need to be improved.

The approaches considered here for the performance of a key source assessment are in accordance with the Tier 1 approach described in the IPCC's Good Practice Guidance (IPCC, 2000). To determine key source categories at your facility, a quantitative and qualitative approach should be used. Key considerations in this analysis include the following:

- The source categories identified previously for your facility should be disaggregated to the level where EFs are distinguished. For combustion, this will likely be to the level of the main fuel types, but it could even be to the level of individual boilers or mode of transport, for example. For process emissions, the specific process activity involved could be used.
- The analysis should be performed with emissions specified in CO_2-equivalent units according to standard GWPs.[15]
- The analysis should be performed for each GHG that is emitted by the source category (the methods, EFs and related uncertainties are different for each gas).
- Source categories that use the same EFs based on common assumptions should be aggregated before analysis.

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[15] The recommended GWPs are those from the IPCC's Second Assessment Report (IPCC, 1995), since these are currently used for reporting national GHG inventories and are also those recommended for use during the first commitment period of the Kyoto Protocol. These GWPs are provided in Appendix H.

3.5.1 Quantitative Approach

The quantitative approach uses two perspectives to identify key source categories: a Level Assessment and a Trend Assessment. A Level Assessment analyzes the emission contribution that each source makes to the facility total. A Trend Assessment analyzes the trend of emission contributions from each source to identify where the greatest absolute changes (either increases or reductions) have taken place over a given period. A cumulative emissions threshold is used to identify the source categories that are key source categories. The Good Practice Guidance (IPCC, 2000) suggests a threshold of 95%, which has been determined to be the level at which 90% of the uncertainty in an inventory is covered by key source categories. The 95% cumulative emissions threshold is to be used in both the Level Assessment and the Trend Assessment approaches. The inventory practitioner is referred to Annex 1 in the report *Canada's Greenhouse Gas Inventory: 1990–2001* (Olsen et al., 2003) to observe how the key source assessment is done nationally.

3.5.1.1 Level Assessment

To calculate the level contribution of each source category to the total inventory level, the following equation is used:

$$\boxed{L_{x,t} = \frac{E_{x,t}}{E_t}}$$

where: $L_{x,t}$ = Level Assessment for source x in year t;
$E_{x,t}$ = the emission estimate (in CO_2 equivalents) of source category x in year t;
E_t = the total inventory estimate (in CO_2 equivalents) in year t.

The percent contribution of each source category to the level of emissions is determined and then sorted from greatest to least. A cumulative total is then calculated. Key source categories are those that, when summed together in descending order of magnitude, add up to over 95% of the total emissions estimate.

A spreadsheet analysis is recommended for this evaluation. Table E.1 in Appendix E presents a template spreadsheet that can be used for the Level Assessment.

3.5.1.2 Trend Assessment

To calculate the trend contribution of each source category to the trend in the total inventory, the following equation is used:

$$\boxed{T_{x,t} = L_{x,t} \times [\,\{\frac{E_{x,t} - E_{x,0}}{E_{x,t}}\} - \{\frac{E_t - E_0}{E_t}\}\,]}$$

where: $T_{x,t}$ = the contribution of the source category trend to the overall inventory trend, called the Trend Assessment. The Trend Assessment is always recorded as an absolute value, i.e. a negative value is always recorded as the equivalent positive value;
$L_{x,t}$ = the Level Assessment for source x in year t (derived in the previous equation);
$E_{x,t}$ and $E_{x,0}$ = the emission estimates of source category x in years t and 0, respectively;
E_t and E_0 = the total inventory estimates in years t and 0, respectively.

The source category trend is the change in the source category emissions over time, calculated by subtracting the base year (year 0) estimate for source category x from the current year (year t) estimate and dividing by the current year estimate. The total trend is the change in the total inventory emissions over time and is calculated in a similar manner. The Trend Assessment will identify source categories that have a trend that is different from the trend of the overall inventory.

Similar calculations are completed here as for the Level Assessment. The source categories' percent contributions to the total trend are calculated and sorted in descending order, and then a cumulative total is determined. When source category contributions provide at least 95% of the cumulative total of contributions, the sources are considered to be key source categories. Table E.2 in Appendix E presents a template spreadsheet that can be used for the Trend Assessment.

3.5.2 Qualitative Approach

A qualitative approach uses subjective criteria to determine key source categories that may not be prioritized by the quantitative approach. The Good Practice Guidance (IPCC, 2000) uses the following criteria:

- *Mitigation techniques and technologies* — You should identify those source categories where the emissions are being reduced significantly through the use of mitigation techniques or technologies.
- *High expected emissions growth* — You should identify those source categories where the emissions are expected to grow significantly in the future.
- *High uncertainty* — You should identify those source categories where the emissions are the most uncertain.
- *Unexpectedly low or high emissions* — You should conduct order-of-magnitude checks to identify calculation errors and discrepancies.

These criteria should be applied to the source categories for your facility, and the key source categories identified through this qualitative analysis should be documented. You should report all sources of information that were considered and specify those that led to your final observations with respect to key source categories.

As part of managing the quality of the emissions inventory, the key source analysis should be used to prioritize emission sources that should undergo methodological improvement. For the stationary fuel combustion emission estimation methodologies presented in this guidance, it is expected that the accuracy of emission estimates improves in an ordinal fashion as indicated below:

Detailed Fuels-based < Detailed Source-based

For mobile combustion and process-related emission estimation methodologies, the following general relationship is expected in terms of level of accuracy:

Methodology using default or generic data < Methodology using facility-specific data

This means that if a key source is identified for an estimate produced using the Detailed Fuels-based Approach, inventory practitioners should establish a plan for methodological improvement by revising such estimates by using the Detailed Source-based Approach. Similarly, if an emission estimate for a mobile combustion or process-related source that was derived using default data is identified as a key source, this emission estimate should be revised using facility-specific data or perhaps direct emissions monitoring for some emission sources and GHG types.

Section 4: Uncertainty Assessment

An uncertainty assessment is an essential part of an emissions inventory, since it identifies the level of uncertainty that is deemed to be associated with GHG emission estimates, and this can be another important tool in managing the quality of the emissions inventory. This assessment can help to prioritize efforts to improve the emissions inventory accuracy in the future and guide decisions on methodological choice.

There are different categories of uncertainty[16] associated with GHG emissions, and the level of complexity can vary greatly in terms of how to assess these uncertainties. The focus here will be on estimation uncertainty, which exists when GHG emissions are quantified, and, more specifically, on parameter uncertainty.[17] Parameter uncertainty refers to the uncertainty associated with quantifying the parameters (e.g. activity data, EFs, other parameters) used as inputs to estimation models or methodologies (WRI/WBCSD, 2003).

For the estimation methodologies considered under this guidance manual, potential sources of parameter uncertainties may include, but are not limited to:

- activity data — uncertainty in the basic activity data related to data adequacy, correctness or completeness;
- EFs — use of simplified representations with averaged values or inappropriate application of EFs that are not representative of the facility's process or operating conditions;
- sampling equipment used to obtain measured emissions is not properly calibrated; and
- use of data sets that are not fully representative of facility operations.

An uncertainty assessment should be performed on the emission estimates developed for your facility.

It is necessary to first quantify the uncertainty range associated with each source of uncertainty (e.g. activity data, EFs, other parameters). These uncertainties may be evaluated through statistical analysis (if appropriate sets of sample data are available), measurement equipment precision determinations and/or consulting with experts to give an estimation of the uncertainty range of the data used (WRI/WBCSD, 2003).

If using conventional statistical analysis, the IPCC Guidelines (IPCC, 1997) recommend calculating a 95% confidence interval to define the range of uncertainty.

Uncertainty ranges are often assessed using expert judgement. When soliciting expert judgement, it is important to recognize that:

- the expert judgement(s) is to take into account all the available data;
- the expert(s) should be someone with special knowledge or experience with the particular quantity being assessed;

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[16] Two broad categories of uncertainty include scientific uncertainty and estimation uncertainty; the former arises when the science of the actual emission and/or removal process is not sufficiently understood, and the latter arises whenever GHG emissions are quantified (WRI/WBCSD, 2003).

[17] A second type of estimation uncertainty is model uncertainty, which refers to the uncertainty associated with mathematical models that may be used to characterize the relationships between various parameters and emission processes (WRI/WBCSD, 2003). If such models are used to estimate certain facility emissions, it may be necessary to assess the uncertainty associated with the model(s) using available sources of scientific or engineering expertise familiar with the specific model(s).

- the expert judgement needs to be documented and explained with sufficient clarity; and
- the expert judgement should be corroborated with other sources (either other experts or independent sources) to avoid or minimize potential biases in the expert judgement.

If national EFs were used to estimate the emissions, the uncertainties listed in Table F.2 in Appendix F can be used.[18] These are considered to represent the maximum uncertainty associated with the national EFs. For AP-42 EFs that may have been used to estimate emissions, a quantitative uncertainty assessment cannot be performed for these estimates, since only qualitative ratings are available for the AP-42 EFs (U.S. EPA, 1995).[19] In this instance, a qualitative assessment of the uncertainty should be completed for the emission estimate. For other default parameters made available in the appendices, uncertainty ranges were not available in the literature sources consulted.

To calculate an overall uncertainty for the emission estimate for each source category, the parameter uncertainties determined above for each source of uncertainty associated with the emission estimate can be combined using a sum of squares approach.[20] This approach is valid as long as the uncertainties follow a normal distribution, they have no significant covariance and the individual uncertainties are less than 60%.[21] The following equation is used to calculate an overall percent uncertainty for the emission estimate:

$$\boxed{c = \pm \sqrt{a^2 + b^2}}$$

where: c = overall percent uncertainty;
a = percent uncertainty associated with parameter A (e.g. EF);
b = percent uncertainty associated with parameter B (e.g. activity data).

It is important to understand that uncertainty is compounded by multiplication, meaning that the resulting emission estimate will be less certain than its least certain component (e.g. EF, activity data). This is also applicable when combining qualitative uncertainty estimates.[22]

Once the uncertainties in the emission source categories have been determined, they may be combined to provide an uncertainty estimate for the entire set of emission estimates compiled for the facility. This overall uncertainty for the total emissions estimated from all source categories would be calculated by GHG type (CO_2, CH_4, N_2O, PFCs, HFCs or SF_6).

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[18] These uncertainties are in fact the overall uncertainties that were derived for the national GHG emission estimates prepared for the 1990 inventory. These uncertainties are being applied to the EF component, as it can be expected that the EF is the greatest contributor to the overall uncertainty of the fuel combustion emission estimates. The level of uncertainty associated with the national energy activity data used is considered to be relatively low in comparison. Future efforts need to be conducted to obtain revised up-to-date uncertainties for the national inventory.

[19] The AP-42 EFs are given a rating from A through E, with A being the best. This rating is only a general indication of the accuracy of the EF. When moving from fuel average EFs to technology average EFs, it is more difficult to establish quantitative uncertainties for a wide range of technologies based on a small number of measurements. For this reason, qualitative uncertainties are deemed more appropriate.

[20] When the estimation of certain emissions involves more than two parameters or there is covariance (parameters are interdependent), the use of the Monte Carlo approach is preferable where resources are available.

[21] If the 60% condition is not met, the limiting values would be combined to give an overall range, which leads to upper and lower limiting values that are asymmetrical about the central estimate.

[22] The overall uncertainty must be equivalent to or greater (i.e. more uncertain) than the most uncertain element in the calculation (e.g. if the most uncertain element is the EF, which is an AP-42 EF and has a ranking of E, then the overall uncertainty must be ranked E or higher).

This can be calculated using the following equation, which represents a weighted average approach:

$$\boxed{e = \pm \frac{\sqrt{\sum C_i^2 \cdot c_i^2}}{E}}$$

where:
e = overall percent uncertainty for the estimate E;
E = total GHG estimate from all source categories ($E = \sum [C_i]$);
C_i = GHG estimate from source category i;
c_i = overall percent uncertainty for GHG estimate from source category i.

Table F.1 in Appendix F provides a spreadsheet template that can be used to report results from the uncertainty assessment.

Section 5: Quality Assurance / Quality Control

5.1 Quality Assurance / Quality Control Procedures

When preparing emission estimates for your facility, it is important to consider elements of QA/QC[23] during this process. You should identify basic QA/QC procedures that you consider appropriate for your facility emission estimates to ensure that data are complete and of sufficient quality, the documentation is transparent and the estimation methodologies have been applied in the correct way. Consistent application of these QA/QC procedures will add confidence that all emission measurements and calculations have been made correctly.

The following table presents a list of suggested elements that you may consider using as part of the QA/QC procedures for your emissions inventory. These are general elements that may or may not be applicable. You should document the specific QA/QC procedures that you have performed during or after the preparation of the emission estimates for the facility in question.

Table 1: General-level QA/QC Procedures[1]

QC Activity	Procedures
Check that assumptions and criteria for the selection of activity data and EFs are documented.	• Cross-check descriptions of activity data and EFs with information on source categories and ensure that these are properly recorded and archived. • Check to make sure that emissions from use of coke (or other reducing agents) have not been counted as both a combustion and process emission source (no double-counting). • Check that double-counting of emissions has not occurred in the consideration of BFG as a fuel.
Check for transcription errors in data input and references.	• Confirm that bibliographical data references are properly cited in the internal documentation. • Cross-check a sample of input data from each source category (either measurements or parameters used in calculations) for transcription errors.
Check that emissions are calculated correctly.	• Reproduce a representative sample of emission calculations. • Check that manufacturer's specifications for instrument operation, calibration and maintenance are followed for direct emission measurements. • Check that available national or international measurement standards are used for measured consumption or production data at the plant level.
Check the activity data, EFs and other parameters used to calculate emissions.	• Compare fuel consumption data by source with fuel purchasing data. • Compare EFs that are developed or obtained from fuel suppliers with national or other default factors. • Evaluate QC associated with fuel, emission or other parameter measurements and analyses completed that were used to develop EFs or emission estimates.
Check that parameter and emission units are correctly recorded and that appropriate conversion factors are used.	• Check that units are properly labelled in calculation sheets. • Check that units are correctly carried through from beginning to end of calculations. • Check that conversion factors are correct. • Check that temporal and spatial adjustment factors are used correctly.

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[23] Quality control can be defined as a system of routine technical activities to measure and control the quality of the emission estimates as they are being developed. A QC system is designed to: (i) provide routine and consistent checks to ensure data integrity, correctness and completeness; (ii) identify and address errors and omissions; and (iii) document and archive relevant material and record all QC activities. Quality assurance can be defined as a set of activities that include a planned system of review procedures conducted by personnel not directly involved in the emission estimate compilation/development process (adapted from IPCC, 2000, Chapter 8).

Check the integrity of database files.	• Confirm that the appropriate data processing steps are correctly represented in the database. • Confirm that data relationships are correctly represented in the database. • Ensure that data fields are properly labelled and have the correct design specifications. • Ensure that adequate documentation of database and model structure and operation are archived.
Check for consistency in data between source categories.	• Identify parameters (e.g. activity data, constants) that are common to multiple source categories and confirm that there is consistency in the values used for these parameters in the emission calculations.
Check that the movement of inventory data among processing steps is correct.	• Check that emissions data are correctly aggregated from lower reporting levels to higher reporting levels when preparing summaries. • Check that emissions data are correctly transcribed between different intermediate products.
Check that uncertainties in emissions and removals are estimated or calculated correctly.	• Check that qualifications of individuals providing expert judgement for uncertainty estimates are appropriate. • Check that qualifications, assumptions and expert judgements are recorded. • Check that calculated uncertainties are complete and calculated correctly. • If necessary, duplicate error calculations or a small sample of the probability distributions used by Monte Carlo analyses.
Undertake review of internal documentation.	• Check that there is detailed internal documentation to support the estimates and enable duplication of the emission and uncertainty estimates. • Check that inventory data, supporting data and inventory records are archived and stored to facilitate detailed review. • Check integrity of any data archiving arrangements of outside organizations involved in inventory preparation.
Check methodological and data changes resulting in recalculations.	• Check for temporal consistency in time series input data for each source category. • Check for consistency in the algorithm/method used for calculations throughout the time series.
Undertake completeness checks.	• Confirm that estimates are reported for all source categories and for all years from the appropriate base year to the period of the current inventory. • Check that known data gaps that result in incomplete source category emission estimates are documented.
Compare estimates with previous estimates.	• For each source category, current inventory estimates should be compared with previous estimates. If there are significant changes or departures from expected trends, recheck estimates and explain any difference.
QA Activity	**Procedures**
Undertake an expert review of emission estimates.	• Arrange to have experts in relevant technical fields conduct a review of the documentation, calculations and assumptions. Use reviewers that have not been involved in preparing the emissions.

[1] Adapted from Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories (IPCC, 2000).

5.2 Data Management

Internal documentation and archiving are key activities that should be completed as part of general QC procedures. All information that was used to produce the emission estimates for the facility in question should be documented and archived such that the estimates are transparent and can be reviewed or reproduced.[24] This generally includes:

- assumptions and criteria for selection of activity data and emission factors;
- EFs used, including full references to the sources of default factors used;
- activity data or sufficient information to enable activity data to be traced to the referenced source;
- information on the uncertainty associated with activity data, EFs or other parameters used;

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[24] A period of seven years is recommended as an archiving period. This is the period for which worksheets and underlying data should be maintained for future review. This period is consistent with that used by financial accounting systems.

- rationale for choice of methods;
- methods used, including those used to estimate uncertainty;
- changes in data inputs or methods from previous years;
- identification of individuals providing expert judgement for uncertainty estimates and their qualifications to do so;
- details of electronic databases or software used in the production of the emission estimates, including versions, operating manuals, hardware requirements and any other information required to enable their later use;
- worksheets and interim calculations for emission source category estimates and aggregated estimates and any recalculations of previous estimates;
- final inventory report and any analysis of trends from previous years; and
- QA/QC plans and outcomes of QA/QC procedures.

Some examples of specific documentation that pertain to the stationary and mobile fuel combustion and process-related emission estimates covered here include:

- sources of the fuel data used and observations on how complete this data set is;
- sources of calorific values that may have been used;
- sources of EFs used or data used to develop facility-specific EFs, including details on the methodology used to collect these data (e.g. CEMS, stack sampling techniques, lab analysis procedures, etc.);
- sources of annual production data, feed material usage or consumption data, material composition analyses performed or collected (e.g. carbon content, % impurities), etc.
- sampling, measurement method and measured results for composition analysis that may have been performed, HFC use, etc.; and
- appropriate explanation of the linkage with fuel combustion emission estimates to demonstrate that double-counting or missing emissions have not occurred.

It is good practice to maintain such documentation for every annual set of emission estimates produced. Also, it is important to maintain and archive this documentation in such a way that every emission estimate can be fully documented and reproduced if necessary (IPCC, 2000).

Section 6: Verification

To complement the QA/QC procedures implemented, you may wish to consider options for verification of your emission estimates, which may include third-party audit and/or periodic spot checks. With a third-party audit, it is important that the auditor be independent of your facility or organization to ensure an objective assessment of the processes and data evaluated. You should also consider the professional qualifications of the verifier and the experience that the verifier may have with your particular operations and the types of emissions. Periodic spot checks may involve direct emissions testing of the source categories (e.g. periodic stack test measurements) and comparison with the emission estimates that have been calculated.

You should identify and document any verification processes that you have undertaken to verify the emission estimates for your facility, including the verification results.

Section 7: Reporting Emissions

Once you have completed the process of calculating the emission estimates from the stationary and mobile fuel combustion and process-related sources at your facility, the results should be compiled, using a summary report similar to the one presented in Table G.1 in Appendix G. It is necessary to include total estimates in mass of individual gas and in mass of CO_2 equivalents for the GHGs being emitted for all source categories to ensure completeness. Trends in the emission estimates should also be reported where estimates from one inventory year to the next are compared. A tabular format similar to that presented in Table G.2 is suggested for this purpose.

Various templates have been included in this guidance manual to assist you in the development of your estimates. As previously mentioned, it is important to retain completed copies of all worksheets used to calculate the emissions and record all relevant data and information. Specific information that should be recorded has been identified in various sections throughout this document.

Other factors to consider when reporting emissions are as follows:

- Estimates of CO_2 emissions from the combustion of biomass fuels are calculated and documented for information purposes but are not included in overall CO_2 emission totals (since these would be accounted for under biomass stocks under a separate guidance manual); however, emissions of CH_4 and N_2O from biomass fuel combustion should be reported and included in overall facility emission totals.
- GHG emission estimates should be reported in common mass units. Table G.1 uses gigagrams (Gg),[25] as this is the unit of measure used in the national inventory to meet international reporting guidelines.
- The time period for the estimates should be on a calendar-year basis.
- The methodology and results from uncertainty assessments, QA/QC procedures and any verification processes used should be clearly and transparently documented.
- Emissions should be reported at a sufficiently disaggregated level to ensure adequate transparency. Any areas where data have been aggregated or omitted for reasons of confidentiality should be documented.
- If you have completed a key source assessment, the results of this process should be documented.
- Any changes in methodologies since the last inventory and how this has affected absolute emissions and the emissions trend in a particular area should be documented.
- It is important to document the main activities contributing to increases or decreases in emissions and why these occurred

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[25] One gigagram = 1 kilotonne (or 1000 metric tons).

Section 8: Appendices

Appendix A: Templates and Default Values for Use in the Detailed Fuels-based Approach

This appendix presents sample data and calculation templates and default values for various parameters to be used in the Detailed Fuels-based Approach (Section 3.4.1.1) for estimating stationary fuel combustion emissions. The EFs presented in Tables A.4–A.8 are the national EFs used in the preparation of the National GHG Inventory (except where otherwise noted). Default gross calorific (or higher heating) values for various fuel types are provided in Table A.9 if conversion is necessary from energy units to physical units (e.g. mass, volume).

Table A.1: Detailed Fuels-based Approach — Stationary Fuel Combustion Data Entries and Calculations for CO_2 Emissions

Source Category[a]	Fuel Type Combusted[b]	(1) Quantity of Fuel Combusted (Original Units)	(2) CO_2 Emission Factor[c] (g / Original Units)	(3) CO_2 Emissions[d] (g)	(4) CO_2 Emissions[e] (Gg)
1. __________________	______________	input	input	calc	calc
__________________	______________	input	input	calc	calc
….	….	….	….	….	….
2. __________________	______________	input	input	calc	calc
__________________	______________	input	input	calc	calc
….	….	….	….	….	….
3. __________________	______________	input	input	calc	calc
__________________	______________	input	input	calc	calc
….	….	….	….	….	….
4. __________________	______________	input	input	calc	calc
__________________	______________	input	input	calc	calc
….	….	….	….	….	….
TOTAL[f]		sum		sum	sum
For Information Purposes:					
Biomass Fuels					
(i) __________________	______________	input	input	calc	calc
(ii) __________________	______________	input	input	calc	calc
….	….	….	….	….	….
		sum		sum	sum

Explanatory Notes:

(a) List categories used in Section 2.3 for the combustion sources (this may be by fuel category, combustion technology, primary end purpose of combustion, etc.).

(b) Specify type(s) of fuel(s) combusted in each source category.

(c) Details on any conversions performed on the EF are to be reported.

(d) CO_2 emissions calculated based on equation in Section 3.4.1.1.

(e) Report CO_2 emissions in units of gigagrams.

(f) Total is not to include subtotal from Biomass Fuels (Biomass subtotals are for reference purposes only).

Table A.2: Detailed Fuels-based Approach — Stationary Fuel Combustion Data Entries and Calculations for CH_4 Emissions

Source Category[(a)]	Fuel Type Combusted[(b)]	(1) Quantity of Fuel Combusted (Original Units)	(2) CH_4 Emission Factor[(c)] (g / Original Units)	(3) CH_4 Emissions[(d)] (g)	(4) CH_4 Emissions[(e)] (Gg)
1. ________________	______________	input	input	calc	calc
________________	______________	input	input	calc	calc
….	….	….	….	….	….
2. ________________	______________	input	input	calc	calc
________________	______________	input	input	calc	calc
….	….	….	….	….	….
3. ________________	______________	input	input	calc	calc
________________	______________	input	input	calc	calc
….	….	….	….	….	….
4. ________________	______________	input	input	calc	calc
________________	______________	input	input	calc	calc
….	….	….	….	….	….
TOTAL		sum		sum	sum

Explanatory Notes:

(a) List categories used in Section 2.3 for the combustion sources (this may be by fuel category, combustion technology, primary end purpose of combustion, etc.).

(b) Specify the type(s) of fuel(s) combusted in each source category.

(c) Details on any conversions performed on the EF are to be documented.

(d) CH_4 emissions calculated based on equation in Section 3.4.1.1.

(e) Report CH_4 emissions in units of gigagrams.

Table A.3: Detailed Fuels-based Approach — Stationary Fuel Combustion Data Entries and Calculations for N_2O Emissions

Source Category[a]	Fuel Type Combusted[b]	(1) Quantity of Fuel Combusted (Original Units)	(2) N_2O Emission Factor[c] (g / Original Units)	(3) N_2O Emissions[d] (g)	(4) N_2O Emissions[e] (Gg)
1. ________________	______________	input	input	calc	calc
________________	______________	input	input	calc	calc
….	….	….	….	….	….
2. ________________	______________	input	input	calc	calc
________________	______________	input	input	calc	calc
….	….	….	….	….	….
3. ________________	______________	input	input	calc	calc
________________	______________	input	input	calc	calc
….	….	….	….	….	….
4. ________________	______________	input	input	calc	calc
________________	______________	input	input	calc	calc
….	….	….	….	….	….
TOTAL		sum		sum	sum

Explanatory Notes:

(a) List categories used in Section 2.3 for the combustion sources (this may be by fuel category, combustion technology, primary end purpose of combustion, etc.).

(b) Specify the type(s) of fuel(s) combusted in each source category.

(c) Details on any conversions performed on the EF are to be documented.

(d) N_2O emissions calculated based on equation in Section 3.4.1.1.

(e) Report N_2O emissions in units of gigagrams.

Table A.4: Refined Petroleum Products — Emission Factors

	Emission Factor			Representative Technology(a) *(for CH_4 and N_2O EFs only)*	
	CO_2	CH_4	N_2O	CH_4	N_2O
	(g/L)	**(g/L)**	**(g/L)**		
Light Fuel Oil					
Electric Utilities	2830(1)	0.18(2)	0.031(2)	Utility turbine	Distillate fired boiler
Industry	2830(1)	0.006(2)	0.031(2)	Generic industrial boiler	Same as CH_4
Producer Consumption(b)	2830(1)	0.006(2)	0.031(2)	Generic industrial boiler	Same as CH_4
Residential	2830(1)	0.026(2)	0.006(2)	Residential combustor (i.e. boiler, furnace, water heater)	Same as CH_4
Other Small Combustion(c)	2830(1)	0.026(2)	0.031(2)	Generic commercial boiler	Utility/industrial boilers
	(g/L)	**(g/L)**	**(g/L)**		
Heavy Fuel Oil					
Electric Utilities	3090(1)	0.034(2)	0.064(2)	Utility boiler	Same as CH_4
Industry	3090(1)	0.12(2)	0.064(2)	Generic industrial boiler	Same as CH_4
Producer Consumption(b)	3090(1)	0.12(2)	0.064(2)	Generic industrial boiler	Same as CH_4
Residential etc.(d)	3090(1)	0.057(2)	0.064(2)	Generic commercial / residential boilers	Utility / industrial boilers
	(g/L)	**(g/L)**	**(g/L)**		
Kerosene					
Electric Utilities	2550(1)	0.006(2)	0.031(2)	Utility turbine	Distillate fired boiler
Industry	2550(1)	0.006(2)	0.031(2)	Generic industrial boiler	Same as CH_4
Producer Consumption(b)	2550(1)	0.006(2)	0.031(2)	Generic industrial boiler	Same as CH_4
Residential etc.(d)	2550(1)	0.026(2)	0.006(2)	Residential combustor (i.e. boiler, furnace, water heater)	Same as CH_4
Other Small Combustion(c)	2550(1)	0.026(2)	0.031(2)	Generic commercial boiler	Utility/industrial boilers
	(g/L)	**(g/L)**	**(g/L)**		
Diesel					
Electric Utilities	2730(1)	0.133(2)	0.4(2)	Reciprocating diesel engine	–
Producer Consumption(b)	2730(1)	0.133(2)	0.4(2)	Reciprocating diesel engine	–
	(g/L)	**(g/L)**	**(g/L)**		
Petroleum Coke					
Petroleum Coke Others	4200(3)	0.12(2)	0.064(2)	Generic industrial boiler	Same as CH_4
Producer Consumption(b)	4200(3)	0.12(2)	0.064(2)	Generic industrial boiler	Same as CH_4
Coke from Catalytic Crackers	3800(3)	0.12(2)	0.064(2)	Generic industrial boiler	Same as CH_4
	(g/m^3)	**(g/m^3)**	**(g/m^3)**		
Still Gas	2000(1)	0.037(2)	0.002(2)	Generic industrial boiler	All boilers

Explanatory Notes:

(a) The national EFs for CH_4 and N_2O are based on the typical or representative combustion technology(ies) listed for each EF.

(b) Producer Consumption — includes consumption by oil and gas producers.

(c) Other Small Combustion — includes commercial and small industrial subsectors (i.e. forestry, construction, agriculture, public administration, commercial and other institutional).

(d) Residential etc. — includes commercial, residential and small industrial subsectors (i.e. forestry, construction, agriculture, residential, public administration, commercial and other institutional).

Sources:

(1) Jaques, A. (1992), *Canada's Greenhouse Gas Emissions: Estimates for 1990,* Environmental Protection, Conservation and Protection, Environment Canada, EPS 5/AP/4, December.

(2) SGA Energy Limited (2000), *Emission Factors and Uncertainties for CH_4 & N_2O from Fuel Combustion,* prepared for Environment Canada, August.

(3) Nyboer, J. (1996), Personal communication with P. Boileau, Greenhouse Gas Division, Environment Canada, January.

Table A.5: Coal and Coal Products — CO_2 Emission Factors

Province/Coals	Emission Factors 1990–1994 (g/kg)	Emission Factors 1995–2000 (g/kg)	Province/Coals	Emission Factors 1990–1994 (g/kg)	Emission Factors 1995–2000 (g/kg)
Nova Scotia			**Manitoba**		
Canadian Bituminous	2300(1)	2249(2)	Canadian Bituminous	2520(1)	2252(2)
U.S. Bituminous	2330(1)	2288(2)	Sub-Bituminous(a)	2520(1)	1733(2)
			Lignite	1520(1)	1424(2)
New Brunswick					
Canadian Bituminous	2230(1)	1996(2)	**Saskatchewan**		
U.S. Bituminous	2500(1)	2311(2)	Lignite	1340(1)	1427(2)
Quebec			**Alberta**		
U.S. Bituminous	2500(1)	2343(2)	Canadian Bituminous	1700(1)	1852(2)
Anthracite	2390(1)	2390(1)	Sub-Bituminous(a)	1740(1)	1765(2)
			Anthracite	2390(1)	2390(1)
Ontario					
Canadian Bituminous	2520(1)	2254(2)	**British Columbia**		
U.S. Bituminous	2500(1)	2432(2)	Canadian Bituminous	1700(1)	2072(2)
Sub-Bituminous(a)	2520(1)	1733(2)			
Lignite	1490(1)	1476(2)			
Anthracite	2390(1)	2390(1)			
All Provinces					
	(g/kg)	(g/kg)			
Metallurgical Coke	3100(3)	3100(3)			
	(g/m^3)	(g/m^3)			
Coke Oven Gas	1600(1)	1600(1)			

Explanatory Notes:

(a) Represents both domestic and imported sub-bituminous.

Sources:

(1) Jaques, A. (1992), *Canada's Greenhouse Gas Emissions: Estimates for 1990,* Environmental Protection, Conservation and Protection, Environment Canada, EPS 5/AP/4, December.

(2) Adapted from McCann, T.J. (2000), *1998 Fossil Fuel and Derivative Factors,* prepared for Environment Canada by T.J. McCann and Associates, March.

(3) IPCC (Intergovernmental Panel on Climate Change) (1997), *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories*, IPCC, Bracknell, UK.

Table A.6: Coals — CH_4 and N_2O Emission Factors

	Emission Factors		
All Coals	**CH_4**	**N_2O**	**Combustion Technology[(a)]**
	(g/kg)	**(g/kg)**	
Utility	0.022(1)	0.032(1)	Pulverized coal dry bottom (wall or tangentially fired) / pulverized coal wet bottom boilers
Industry	0.03(1)	0.02(1)	Overfeed / spreader stoker boilers
Residential	4(1)	0.02(1)	Hand-fired boiler
Metallurgical Coke	0.03(1)	0.02(1)	Overfeed / spreader stoker boilers
	(g/m^3)	**(g/m^3)**	
Coke Oven Gas	0.037(1)	0.035(1)	Generic natural gas boiler

Explanatory Notes:

(a) The national EFs for CH_4 and N_2O are based on the typical or representative combustion technology(ies) listed in the table.

Sources:

(1) SGA Energy Limited (2000), *Emission Factors and Uncertainties for CH_4 & N_2O from Fuel Combustion,* prepared for Environment Canada, August.

Table A.7: Natural Gas and Natural Gas Liquids — Emission Factors

	Emission Factors			Representative Technology(a) *(for CH_4 and N_2O EFs only)*	
	CO_2	**CH_4**	**N_2O**	**CH_4**	**N_2O**
	(g/m^3)	**(g/m^3)**	**(g/m^3)**		
Natural Gas					
Electric Utilities	1891(1)	0.49(2)	0.049(2)	Simple / combined cycle utility gas turbines	Same as CH_4
Industrial	1891(1)	0.037(2)	0.033(2)	Generic industrial boiler (conventional or low NOx burner)	Same as CH_4
Producer Consumption(b)	2389(1)	6.5(3,4)	0.033(2)	–	Generic industrial boiler (conventional or low NOx burner)
Pipelines	1891(1)	1.9(2)	0.05(2)	Gas turbine / engine-driven compressor	Same as CH_4
Residential, Commercial, Agriculture	1891(1)	0.037(2)	0.035(2)	Generic boiler, conventional burner (no controls)	Same as CH_4
	(g/L)	**(g/L)**	**(g/L)**		
Natural Gas Liquids					
Ethane	976(1)	n/a	n/a	n/a	n/a
Propane	1500(1)	0.024(2)	0.108(2)	Industrial/commercial boilers	Same as CH_4
Butane	1730(1)	0.024(2)	0.108(2)	Industrial/commercial boilers	Same as CH_4

Explanatory Notes:

(a) The national EFs for CH_4 and N_2O are based on the typical or representative combustion technology(ies) listed for each EF.

(b) Producer Consumption — includes consumption by oil and gas producers.

Sources:

(1) Adapted from McCann, T.J. (2000), *1998 Fossil Fuel and Derivative Factors,* prepared for Environment Canada by T.J. McCann and Associates, March.

(2) SGA Energy Limited (2000), *Emission Factors and Uncertainties for CH_4 & N_2O from Fuel Combustion*, prepared for Environment Canada, August.

(3) U.S. EPA (1995), *Compilation of Air Pollutant Emission Factors, AP-42, 5th Edition, Volume 1: Stationary Point and Area Sources*, U.S. Environmental Protection Agency.

(4) CAPP (1999), *CH_4 and VOC Emissions from Upstream Oil and Gas Operations in Canada, Volume 2*, Canadian Association of Petroleum Producers, CAPP Publication No. 1999-0010.

Table A.8: Biomass Emission Factors

Source	Description	Emission Factors CO_2 (g/kg fuel)	 CH_4 (g/kg fuel)	 N_2O (g/kg fuel)
Wood Fuel / Wood Waste	Industrial Combustion	950(1)	0.05(1)	0.02(5,6)
Accidental Forest Fires	Open Combustion	1630(2)	3(2)	1.75(2)
Prescribed Burns	Open Combustion	1620(2)	6.2(2)	1.3(2)
Spent Pulping Liquor	Industrial Combustion	1428(3)	0.05(1)	0.02(5,6)
Stoves & Fireplaces	Residential Combustion			
Conventional Stoves		1500(4)	15(1)	0.16(1)
Conventional Fireplaces and Inserts		1500(4)	15(1)	0.16(1)
Stoves/Fireplaces with Catalytic Advanced Technology or Catalytic Control		1500(4)	6.9(1)	0.16(1)
Other Wood-burning Equipment		1500(4)	15(1)	0.16(1)

Note: CO_2 emissions from biomass sources are not to be included in facility totals here. CH_4 and N_2O emissions are included, except for accidental forest fires and prescribed burns, which would be reported under Land Use Change and Forestry.

Sources:

(1) U.S. EPA (1996), *Compilation of Air Pollutant Emission Factors, AP-42, 5th Edition, Volume 1: Stationary Point and Area Sources*, Supplementary B, January, U.S. Environmental Protection Agency.

(2) Taylor, S.W. & Sherman, K.L. (1996), *Biomass Consumption and Smoke Emissions from Contemporary and Prehistoric Wildland Fires in British Columbia*, prepared by the Pacific Forestry Centre, Canadian Forest Service, Natural Resources Canada, FDRA Report, March.

(3) Jaques, A.P. (1992), *Canada's Greenhouse Gas Emissions: Estimates for 1990*, Environment Canada, Report EPS 5/AP/4, December.

(4) ORTECH Corporation (1994), *Inventory Methods Manual for Estimating Canadian Emissions of Greenhouse Gases*, Report to Environment Canada, April.

(5) Radke, L.F., Hegg, D.A., Hobbs, P.V., Nance, J.D., Lyons, J.H., Laursen, K.K., Weiss, R.E., Riggan, P.J. & Ward, D.E. (1991), Particulate and trace gas emissions from large biomass fires in North America, in *Global Biomass Burning: Atmospheric Climatic and Biospheric Implications*, J.S. Levine (ed.), Massachusetts Institute of Technology, Cambridge, Massachusetts.

(6) Rosland, A. & Steen, M. (1990), *Klimgass-Regnshap For Norge*, Statens Forurensningstilsyn, Oslo, Norway.

Table A.9: Gross Calorific Values for Various Fuel Types (1990–2000)

		Gross Calorific Values										
Fuel Type	**Units(a)**	**1990**	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**1998**	**1999**	**2000**
Coal												
Anthracite	TJ/kt	27.70	27.70	27.70	27.70	27.70	27.70	27.70	27.70	27.70	27.70	27.70
Imported bituminous	TJ/kt	29.00	29.00	29.00	29.00	29.00	29.00	29.00	29.00	29.82	29.82	29.82
Canadian bituminous												
NF, PE, NS and QC	TJ/kt	28.50	28.50	28.50	28.50	28.50	28.50	28.50	28.50	28.96	28.96	28.96
NB	TJ/kt	27.00	27.00	27.00	27.00	27.00	27.00	27.00	27.00	26.80	26.80	26.80
ON	TJ/kt	30.40	30.40	30.40	30.40	30.40	30.40	30.40	30.40	25.43	25.43	25.43
MB	TJ/kt	30.40	30.40	30.40	30.40	30.40	30.40	30.40	30.40	26.02	26.02	26.02
SK, AB, YT, NT & NU	TJ/kt	30.40	30.40	30.40	30.40	30.40	30.40	30.40	30.40	25.43	25.43	25.43
BC	TJ/kt	30.50	30.50	30.50	30.50	30.50	30.50	30.50	30.50	26.02	26.02	26.02
Sub-bituminous	TJ/kt	18.30	18.30	18.30	18.30	18.30	18.30	18.30	18.30	19.15	19.15	19.15
Lignite	TJ/kt	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00
Coal coke	TJ/kt	28.83	28.83	28.83	28.83	28.83	28.83	28.83	28.83	28.83	28.83	28.83
Coke oven gas	TJ/GL	18.61	18.61	18.61	18.61	18.61	18.61	18.61	18.61	19.14	19.14	19.14
Propane	TJ/ML	25.53	25.53	25.53	25.53	25.53	25.53	25.53	25.53	25.31	25.31	25.31
Butane	TJ/ML	28.62	28.62	28.62	28.62	28.62	28.62	28.62	28.62	28.44	28.44	28.44
Ethane	TJ/ML	18.36	18.36	18.36	18.36	18.36	18.36	18.36	18.36	17.22	17.22	17.22
Crude Oil	TJ/ML	38.92	38.92	38.96	38.92	38.93	38.98	39.03	39.11	39.11	39.08	39.13
Light and medium	TJ/ML	38.51	38.51	38.51	38.51	38.51	38.51	38.51	38.51	38.51	38.51	38.51
Heavy	TJ/ML	40.90	40.90	40.90	40.90	40.90	40.90	40.90	40.90	40.90	40.90	40.90
Pentanes plus	TJ/ML	35.17	35.17	35.17	35.17	35.17	35.17	35.17	35.17	35.17	35.17	35.17
Still gas from refineries	TJ/GL	37.28	37.28	37.28	37.28	37.28	37.28	37.28	37.28	33.70	36.08	36.08
Still gas from upgraders	TJ/GL	43.13	43.13	43.13	43.13	43.13	43.13	43.13	43.13	44.03	43.24	43.24
Motor gasoline	TJ/ML	34.66	34.66	34.66	34.66	34.66	34.66	34.66	34.66	35.00	35.00	35.00
Kerosene & stove oil	TJ/ML	37.68	37.68	37.68	37.68	37.68	37.68	37.68	37.68	37.68	37.68	37.68
Diesel	TJ/ML	38.68	38.68	38.68	38.68	38.68	38.68	38.68	38.68	38.30	38.30	38.30
Light fuel oil	TJ/ML	38.68	38.68	38.68	38.68	38.68	38.68	38.68	38.68	38.80	38.80	38.80
Heavy fuel oil	TJ/ML	41.73	41.73	41.73	41.73	41.73	41.73	41.73	41.73	42.50	42.50	42.50
Petroleum coke from refineries	TJ/ML	44.48	44.48	44.48	44.48	44.48	44.48	44.48	44.48	46.44	46.35	46.35
Petroleum coke from upgraders	TJ/ML	39.64	39.64	39.64	39.64	39.64	39.64	39.64	39.64	40.45	40.57	40.57
Aviation gasoline	TJ/ML	33.52	33.52	33.52	33.52	33.52	33.52	33.52	33.52	33.52	33.52	33.52
Aviation turbo fuel	TJ/ML	36.37	36.37	36.37	36.37	36.37	36.37	36.37	36.37	37.40	37.40	37.40
Petrochemical feedstock	TJ/ML	35.17	35.17	35.17	35.17	35.17	35.17	35.17	35.17	35.17	35.17	35.17
Naphtha specialities	TJ/ML	35.17	35.17	35.17	35.17	35.17	35.17	35.17	35.17	35.17	35.17	35.17
Asphalt	TJ/ML	44.46	44.46	44.46	44.46	44.46	44.46	44.46	44.46	44.46	44.46	44.46
Lubricating oils and grease	TJ/ML	39.16	39.16	39.16	39.16	39.16	39.16	39.16	39.16	39.16	39.16	39.16
Other petroleum products	TJ/ML	39.82	39.82	39.82	39.82	39.82	39.82	39.82	39.82	39.82	39.82	39.82
Natural gas	TJ/GL	37.78	37.83	37.88	38.01	38.55	38.06	38.10	38.12	38.17	38.13	37.99
Solid wood waste	TJ/kt	18.00	18.00	18.00	18.00	18.00	18.00	18.00	18.00	18.00	18.00	18.00
Spent pulping liquor	TJ/kt	14.00	14.00	14.00	14.00	14.00	14.00	14.00	14.00	14.00	14.00	14.00

Adapted from Statistics Canada (2001), *Quarterly Report on Energy Supply-Demand in Canada*, Catalogue No. 57-003-XPB, Vol. 25, No. 5, December 2001.

Explanatory Notes:

(a) Units: TJ/kt = terajoules per kilotonne; TJ/GL = terajoules per gigalitre; TJ/ML = terajoules per megalitre.

Appendix B: Templates and Default Values for Use in the Detailed Source-based Approach

This appendix presents data and calculation templates and default values for various EFs to be used in the Detailed Source-based Approach (Section 3.4.1.2) for estimating stationary fuel combustion emissions. The EFs presented in Tables B.4–B.6 have been compiled from the U.S. EPA's *Compilation of Air Pollutant Emission Factors* (AP-42) (U.S. EPA, 1995). AP-42 EFs are revised and updated on an ongoing basis. The tables presented here were compiled in November 2002. Refer to the U.S. EPA's website (http://www.epa.gov/ttn/chief/ap42/index.html) if you wish to check for future updates to these EFs.

Table B.1: Detailed Source-based Approach — Stationary Fuel Combustion Data Entries and Calculations for CO_2 Emissions

Source Category[a]	**Fuel Type Combusted**[b]	**Combustion Technology Used**[c]	**(1) Quantity of Fuel Combusted (Original Units)**	**(2) CO_2 Emission Factor**[d] **(g / Original Units)**	**(3) CO_2 Emissions**[e] **(g)**	**(4) CO_2 Emissions**[f] **(Gg)**
1. ____________	__________	___________	input	input	calc	calc
____________	__________	___________	input	input	calc	calc
....	....	....	....	....	....	....
2. ____________	__________	___________	input	input	calc	calc
____________	__________	___________	input	input	calc	calc
....	....	....	....	....	....	....
3. ____________	__________	___________	input	input	calc	calc
____________	__________	___________	input	input	calc	calc
....	....	....	....	....	....	....
4. ____________	__________	___________	input	input	calc	calc
____________	__________	___________	input	input	calc	calc
....	....	....	....	....	....	....
TOTAL[g]			sum		sum	sum
For Information Purposes:						
Biomass Fuels						
(i) ____________	__________	___________	input	input	calc	calc
(ii) ____________	__________	___________	input	input	calc	calc
....	....	....	....	....	....	....
			sum		sum	sum

Explanatory Notes:

(a) List categories used in Section 2.3 for the combustion sources (this may be by fuel category, combustion technology, primary end purpose of combustion, etc.).

(b) Type of fuel(s) combusted in each source category is to be specified.

(c) Type of combustion technology unit used with each source category is to be identified.

(d) Details on any conversions performed on the EF are to be reported.

(e) CO_2 emissions calculated based on equation in Section 3.4.1.2.

(f) Report CO_2 emissions in units of gigagrams.

(g) Total is not to include subtotal from Biomass Fuels (Biomass subtotals are for reference purposes only).

Table B.2: Detailed Source-based Approach — Stationary Fuel Combustion Data Entries and Calculations for CH_4 Emissions

Source Category[a]	Fuel Type Combusted[b]	Combustion Technology Used[c]	(1) Quantity of Fuel Combusted (Original Units)	(2) CH_4 Emission Factor[d] (g / Original Units)	(3) CH_4 Emissions[e] (g)	(4) CH_4 Emissions[f] (Gg)
1.______________	______________	____________________	input	input	calc	calc
______________	______________	____________________	input	input	calc	calc
….	….	….	….	….	….	….
2.______________	______________	____________________	input	input	calc	calc
______________	______________	____________________	input	input	calc	calc
….	….	….	….	….	….	….
3.______________	______________	____________________	input	input	calc	calc
______________	______________	____________________	input	input	calc	calc
….	….	….	….	….	….	….
4.______________	______________	____________________	input	input	calc	calc
______________	______________	____________________	input	input	calc	calc
….	….	….	….	….	….	….
TOTAL			sum		sum	sum

Explanatory Notes:

(a) List categories used in Section 2.3 for the combustion sources (this may be by fuel category, combustion technology, primary end purpose of combustion, etc.).

(b) Type of fuel(s) combusted in each source category is to be specified.

(c) Type of combustion technology unit used with each source category is to be identified.

(d) Details on any conversions performed on the EF are to be reported.

(e) CH_4 emissions calculated based on equation in Section 3.4.1.2.

(f) Report CH_4 emissions in units of gigagrams.

Table B.3: Detailed Source-based Approach — Stationary Fuel Combustion Data Entries and Calculations for N_2O Emissions

Source Category[(a)]	Fuel Type Combusted[(b)]	Combustion Technology Used[(c)]	(1) Quantity of Fuel Combusted (Original Units)	(2) N_2O Emission Factor[(d)] (g / Original Units)	(3) N_2O Emissions[(e)] (g)	(4) N_2O Emissions[(f)] (Gg)
1. ______________	____________	________________	input	input	calc	calc
______________	____________	________________	input	input	calc	calc
….	….	….	….	….	….	….
2. ______________	____________	________________	input	input	calc	calc
______________	____________	________________	input	input	calc	calc
….	….	….	….	….	….	….
3. ______________	____________	________________	input	input	calc	calc
______________	____________	________________	input	input	calc	calc
….	….	….	….	….	….	….
4. ______________	____________	________________	input	input	calc	calc
______________	____________	________________	input	input	calc	calc
….	….	….	….	….	….	….
TOTAL			sum		sum	sum

Explanatory Notes:

(a) List categories used in Section 2.3 for the combustion sources (this may be by fuel category, combustion technology, primary end purpose of combustion, etc.).

(b) Type of fuel(s) combusted in each source category is to be specified.

(c) Type of combustion technology unit used with each source category is to be identified.

(d) Details on any conversions performed on the EF are to be reported.

(e) N_2O emissions calculated based on equation in Section 3.4.1.2.

(f) Report N_2O emissions in units of gigagrams.

Table B.4: Default Carbon Dioxide (CO_2) Emission Factors for Various Combustion Technology Types

Source/Sector	Fuel Type	Combustion Technology		CO_2 Emission Factor	Units(a)
External Combustion Boilers					
Electric Generation	Anthracite Coal	Travelling Grate (Overfeed) Stoker	Uncontrolled	2.84E+03(1)	kg/tonne
	Lignite	Pulverized Coal: Dry Bottom, Wall Fired	Uncontrolled	7.26E1 * (C) * 5.0001E-1(b) (2)	kg/tonne
		Pulverized Coal: Dry Bottom, Tangential Fired	Uncontrolled	7.26E1 * (C) * 5.0001E-1(b) (2)	kg/tonne
		Cyclone Furnace	Uncontrolled	7.26E1 * (C) * 5.0001E-1(b) (2)	kg/tonne
		Travelling Grate (Overfeed) Stoker	Uncontrolled	7.26E1 * (C) * 5.0001E-1(b) (2)	kg/tonne
		Spreader Stoker	Uncontrolled	7.26E1 * (C) * 5.0001E-1(b) (2)	kg/tonne
		Atmospheric Fluidized Bed Combustion: Bubbling Bed	Uncontrolled	7.26E1 * (C) * 5.0001E-1(b) (2)	kg/tonne
		Atmospheric Fluidized Bed Combustion: Circulating Bed	Uncontrolled	7.26E1 * (C) * 5.0001E-1(b) (2)	kg/tonne
	Natural Gas	Boilers >100 Million Btu/h except Tangential	Uncontrolled	1.92E+06(c) (3)	kg/10^6 m^3
		Boilers <100 Million Btu/h except Tangential	Uncontrolled	1.92E+06(c) (3)	kg/10^6 m^3
		Tangentially Fired Units	Uncontrolled	1.92E+06(c) (3)	kg/10^6 m^3
	Wood/Bark Waste	Wood Residue Boiler	Uncontrolled	8.38E+01(d) (4)	kg/GJ
	Solid Waste	Specify Waste Material in Comments	Electrostatic Precipitator	8.08E-03(5)	kg/GJ
Industrial	Anthracite Coal	Travelling Grate (Overfeed) Stoker	Uncontrolled	2.84E+03(1)	kg/tonne
	Natural Gas	Boilers >100 Million Btu/h	Uncontrolled	1.92E+06(c) (3)	kg/10^6 m^3
		Boilers 10–100 Million Btu/h	Uncontrolled	1.92E+06(c) (3)	kg/10^6 m^3
	Wood/Bark Waste	Wood Residue Boiler	Uncontrolled	8.38E+01(d) (4)	kg/GJ
	Liquified Petroleum Gas (LPG) - Butane	Boilers 10–100 Million Btu/h	Uncontrolled	1.71E+03(e) (6)	kg/m^3
	Liquified Petroleum Gas (LPG) - Propane	Boilers 10–100 Million Btu/h	Uncontrolled	1.50E+03(e) (6)	kg/m^3
	Bagasse	All Boiler Sizes	Uncontrolled	7.80E+02(f) (1)	kg/tonne
Commercial / Institutional	Anthracite Coal	Travelling Grate (Overfeed) Stoker	Uncontrolled	5.68E+03(1)	lb/tons
	Natural Gas	Boilers >100 Million Btu/h	Uncontrolled	1.92E+06(c) (3)	kg/10^6 m^3
		Boilers 10–100 Million Btu/h	Uncontrolled	1.92E+06(c) (3)	kg/10^6 m^3
		Boilers <10 Million Btu/h	Uncontrolled	1.92E+06(c) (3)	kg/10^6 m^3
	Wood/Bark Waste	Wood Residue Boiler	Uncontrolled	8.38E+01(d) (4)	kg/GJ
	Liquified Petroleum Gas (LPG) - Butane	Boilers 0.3–10 Million Btu/h	Uncontrolled	1.71E+03(e) (6)	kg/m^3
	Liquified Petroleum Gas (LPG) - Propane	Boilers 0.3–10 Million Btu/h	Uncontrolled	1.50E+03(e) (6)	kg/m^3
	Liquid Waste Oil	Small Boilers	Uncontrolled	2.64E+03(6)	kg/m^3
Industrial	Waste Oil	Space Heater: Air Atomized Burner	Uncontrolled	2.64E+03(6)	kg/m^3
Commercial / Institutional	Waste Oil	Space Heater: Air Atomized Burner	Uncontrolled	2.64E+03(6)	kg/m^3
		Space Heater: Vaporizing Burner	Uncontrolled	2.64E+03(6)	kg/m^3
Internal Combustion Engines					
Electric Generation	Distillate Oil (Diesel)	Turbine	Uncontrolled	6.75E+01(g) (7)	kg/GJ
Industrial	Distillate Oil (Diesel)	Turbine	Uncontrolled	6.75E+01(g) (7)	kg/GJ
		Reciprocating	Uncontrolled	2.71E+03(h) (6)	kg/m^3

Source/Sector	Fuel Type	Combustion Technology		CO_2 Emission Factor	Units(a)
		Turbine: Cogeneration	Uncontrolled	6.75E+01(g) (7)	kg/GJ
	Natural Gas	Turbine	Uncontrolled	4.73E+01(j) (7)	kg/GJ
		Turbine: Cogeneration	Uncontrolled	4.73E+01(j) (7)	kg/GJ
		Two-cycle Lean Burn	Uncontrolled	4.73E+01(k) (7)	kg/GJ
		Four-cycle Rich Burn	Uncontrolled	4.73E+01(k) (7)	kg/GJ
		Four-cycle Lean Burn	Uncontrolled	4.73E+01(k) (7)	kg/GJ
	Gasoline	Reciprocating	Uncontrolled	2.34E+03(l) (6)	kg/m^3
	Diesel	Large Bore Engine	Uncontrolled	2.71E+03(h) (6)	kg/m^3
	Dual Fuel (Oil/Gas)	Large Bore Engine	Uncontrolled	3.50E+02(6)	kg/hp-h
Commercial / Institutional	Distillate Oil (Diesel)	Reciprocating	Uncontrolled	2.71E+03(h) (6)	kg/m^3
		Turbine	Uncontrolled	6.75E+01(g) (7)	kg/GJ
	Natural Gas	Turbine	Uncontrolled	4.73E+01(j) (7)	kg/GJ
		Turbine: Cogeneration	Uncontrolled	4.73E+01(j) (7)	kg/GJ
	Gasoline	Reciprocating	Uncontrolled	2.34E+03(l) (6)	kg/m^3
	Digester Gas	Turbine	Uncontrolled	1.16E+01(m) (7)	kg/GJ
	Landfill Gas	Turbine	Uncontrolled	2.15E+01(n) (7)	kg/GJ
Stationary Source Fuel Combustion					
Residential	Natural Gas	Total: All Combustor Types	Uncontrolled	2.08E+06(1)	kg/10^6 m^3
		Residential Furnaces	Uncontrolled	1.92E+06(c) (3)	kg/10^6 m^3
	Wood	Fireplaces	Uncontrolled	1.70E+03(1)	kg/tonne
		Non-catalytic Woodstoves: Pellet Fired	Uncontrolled	1.48E+03(o) (1)	kg/tonne
		Non-catalytic Woodstoves: Pellet Fired	Uncontrolled	1.84E+03(p) (1)	kg/tonne

Explanatory Notes:

(a) Sources of the EFs list the EFs in imperial units. For use under this guidance manual, these EFs have been converted to metric units.

(b) C = % carbon content. If the carbon percentage is not known, a default value of 4600 lb/ton may be used as the EF.

(c) Based on approximately 100% conversion of fuel carbon to CO_2.

(d) Factors are for boilers with no controls or with particulate matter controls. Units of kg of pollutant / gigajoule (GJ) of heat input.

(e) Assuming 99.5% conversion of fuel carbon to CO_2.

(f) CO_2 emissions will increase following a wet scrubber in which CO_2-generating reagents (such as sodium carbonate or calcium carbonate) are used. Wet, as-fired bagasse containing approximately 50% moisture by weight.

(g) Based on 99% conversion of fuel carbon to CO_2. EFs based on an average distillate oil heating value of 139 MMBtu/1000 gallons.

(h) The heating value for diesel fuel is 137 000 Btu/gallon. This was used to convert from lbs/MBtu.

(j) Based on 99.5% conversion of fuel carbon to CO_2. EF based on an average natural gas heating value (HHV) of 1020 Btu/scf at 60°F.

(k) Based on 99.5% of fuel carbon converted to CO_2. EFs were calculated in units of lb/MMBtu based on procedures in EPA Method 19.

(l) The heating value for gasoline fuel is 126 000 Btu/gallon. This was used to convert from lbs/MBtu.

(m) EF based on an average digester gas heating value (HHV) of 600 Btu/scf at 60°F.

(n) EF based on an average landfill gas heating value (HHV) of 400 Btu/scf at 60°F.

(o) Pellet Stove Type. Units certified pursuant to 1988 NSPS.

(p) Pellet Stove Type. Exempt from 1988 NSPS (i.e., air-to-fuel ratio > 35:1).

Sources:

(1) U.S. EPA (1995), *Compilation of Air Pollutant Emission Factors, AP-42, 5th Edition, Volume 1: Stationary Point and Area Sources*, U.S. Environmental Protection Agency.

(2) U.S. EPA (September 1998), *Compilation of Air Pollutant Emission Factors, AP-42, 5th Edition, Volume 1: Stationary Point and Area Sources*, Supplement E, U.S. Environmental Protection Agency.

(3) U.S. EPA (March 1998), *Compilation of Air Pollutant Emission Factors, AP-42, 5th Edition, Volume 1: Stationary Point and Area Sources*, Supplement D, U.S. Environmental Protection Agency.

(4) U.S. EPA (July 2001), *Compilation of Air Pollutant Emission Factors, AP-42, 5th Edition, Volume 1: Stationary Point and Area Sources,* Supplement G, U.S. Environmental Protection Agency.

(5) Baltimore Resco Company (1992), *Stationary Source Sampling Final Report*, Reference No. 10759, Baltimore, Maryland, May 12–15 (Confidential Report No. ERC-103).

(6) U.S. EPA (October 1996), *Compilation of Air Pollutant Emission Factors, AP-42, 5th Edition, Volume 1: Stationary Point and Area Sources*, Supplement B, U.S. Environmental Protection Agency.

(7) U.S. EPA (2000), *Compilation of Air Pollutant Emission Factors, AP-42, 5th Edition, Volume 1: Stationary Point and Area Sources*, Supplement F, U.S. Environmental Protection Agency.

Table B.5: Default Methane (CH_4) Emission Factors for Various Combustion Technology Types

Source/Sector	Fuel Type	Combustion Technology		CH_4 Emission Factor	Units(a)
External Combustion Boilers					
Electric Generation	Bituminous Coal	Pulverized Coal: Dry Bottom	Uncontrolled	2.00E-02(1)	kg/tonne
		Cyclone Furnace	Uncontrolled	5.00E-03(1)	kg/tonne
		Spreader Stoker	Uncontrolled	3.00E-02(1)	kg/tonne
		Spreader Stoker	Multiple Cyclone without Fly Ash Re-injection	3.00E-02(1)	kg/tonne
		Spreader Stoker	Multiple Cyclone with Fly Ash Re-injection	3.00E-02(1)	kg/tonne
		Travelling Grate (Overfeed) Stoker	Uncontrolled	3.00E-02(1)	kg/tonne
		Travelling Grate (Overfeed) Stoker	Multiple Cyclones	3.00E-02(1)	kg/tonne
		Pulverized Coal: Dry Bottom (Tangential)	Uncontrolled	2.00E-02(1)	kg/tonne
		Atmospheric Fluidized Bed Combustion: Bubbling Bed	Uncontrolled	3.00E-02(1)	kg/tonne
		Atmospheric Fluidized Bed Combustion: Circulating Bed	Uncontrolled	3.00E-02(1)	kg/tonne
	Sub-bituminous Coal	Pulverized Coal: Wet Bottom	Uncontrolled	2.500E-02(1)	kg/tonne
		Pulverized Coal: Dry Bottom	Uncontrolled	2.00E-02(1)	kg/tonne
		Cyclone Furnace	Uncontrolled	5.00E-03(1)	kg/tonne
		Spreader Stoker	Uncontrolled	3.00E-02(1)	kg/tonne
		Spreader Stoker	Multiple Cyclone without Fly Ash Re-injection	3.00E-02(1)	kg/tonne
		Spreader Stoker	Multiple Cyclone with Fly Ash Re-injection	3.00E-02(1)	kg/tonne
		Travelling Grate (Overfeed) Stoker	Uncontrolled	3.00E-02(1)	kg/tonne
		Travelling Grate (Overfeed) Stoker	Multiple Cyclones	3.00E-02(1)	kg/tonne
		Pulverized Coal: Dry Bottom Tangential	Uncontrolled	2.00E-02(1)	kg/tonne
	Residual Oil	Grade 6 Oil: Normal Firing	Uncontrolled	3.36E-02(b) (1)	kg/m^3
		Grade 5 Oil: Tangential Firing	Uncontrolled	3.36E-02(b) (1)	kg/m^3
	Distillate Oil	Grade 4 Oil: Normal Firing	Uncontrolled	3.36E-02(b) (1)	kg/m^3
		Grade 4 Oil: Tangential Firing	Uncontrolled	3.36E-02(b) (1)	kg/m^3
	Natural Gas	Boilers >100 Million Btu/h except Tangential	Uncontrolled	3.68E+01(2)	$kg/10^6\ m^3$
		Boilers <100 Million Btu/h except Tangential	Uncontrolled	3.68E+01(2)	$kg/10^6\ m^3$
		Tangentially Fired Units	Uncontrolled	3.68E+01(2)	$kg/10^6\ m^3$
	Wood/Bark Waste	Wood/Bark-fired Boiler	Miscellaneous Control Devices	5.60E-03(c) (3)	kg/tonne
Industrial	Bituminous Coal	Cyclone Furnace	Uncontrolled	5.00E-03(1)	kg/tonne
		Spreader Stoker	Uncontrolled	3.00E-02(1)	kg/tonne
		Spreader Stoker	Multiple Cyclones without Fly Ash Re-injection	3.00E-02(1)	kg/tonne
		Spreader Stoker	Multiple Cyclone with Fly Ash Re-injection	3.00E-02(1)	kg/tonne
		Overfeed Stoker	Uncontrolled	3.00E-02(1)	kg/tonne
		Overfeed Stoker	Multiple Cyclones	3.00E-02(1)	kg/tonne
		Underfeed Stoker	Uncontrolled	4.00E-01(1)	kg/tonne
		Underfeed Stoker	Multiple Cyclones	4.00E-01(1)	kg/tonne
		Atmospheric Fluidized Bed Combustion: Bubbling Bed	Uncontrolled	3.00E-02(1)	kg/tonne
	Sub-bituminous Coal	Pulverized Coal: Wet Bottom	Uncontrolled	2.50E-02(1)	kg/tonne
		Pulverized Coal: Dry Bottom	Uncontrolled	2.00E-02(1)	kg/tonne
		Cyclone Furnace	Uncontrolled	5.00E-03(1)	kg/tonne

Source/Sector	Fuel Type	Combustion Technology		CH_4 Emission Factor	Units(a)
		Spreader Stoker	Uncontrolled	3.00E-02(1)	kg/tonne
		Spreader Stoker	Multiple Cyclone without Fly Ash Re-injection	3.00E-02(1)	kg/tonne
		Travelling Grate (Overfeed) Stoker	Uncontrolled	3.00E-02(1)	kg/tonne
		Travelling Grate (Overfeed) Stoker	Multiple Cyclones	3.00E-02(1)	kg/tonne
		Pulverized Coal: Dry Bottom Tangential	Uncontrolled	2.00E-02(1)	kg/tonne
	Residual Oil	Grade 6 Oil	Uncontrolled	1.20E-01(b) (1)	kg/m^3
		10–100 Million Btu/h	Uncontrolled	1.20E-01(b) (1)	kg/m^3
		<10 Million Btu/h	Uncontrolled	1.20E-01(b) (1)	kg/m^3
		Grade 5 Oil	Uncontrolled	1.20E-01(b) (1)	kg/m^3
	Distillate Oil	Grades 1 and 2 Oil	Uncontrolled	6.23E-03(b) (1)	kg/m^3
		10–100 Million Btu/h	Uncontrolled	6.23E-03(b) (1)	kg/m^3
		<10 Million Btu/h	Uncontrolled	6.23E-03(b) (1)	kg/m^3
		Grade 4 Oil	Uncontrolled	6.23E-03(b) (1)	kg/m^3
	Natural Gas	>100 Million Btu/h	Uncontrolled	3.68E+01(2)	$kg/10^6\ m^3$
	Wood/Bark Waste	Bark-fired Boiler (>50 000 lb Steam)	Miscellaneous Control Devices	5.60E-03(c) (3)	kg/tonne
		Wood/Bark-fired Boiler (>50 000 lb Steam)	Miscellaneous Control Devices	5.60E-03(c) (3)	kg/tonne
		Bark-fired Boiler (<50 000 lb Steam)	Miscellaneous Control Devices	5.60E-03(c) (3)	kg/tonne
		Wood/Bark-fired Boiler (<50 000 lb Steam)	Miscellaneous Control Devices	5.60E-03(c) (3)	kg/tonne
		Wood-fired Boiler (<50 000 lb Steam)	Miscellaneous Control Devices	5.60E-03(c) (3)	kg/tonne
		Wood Cogeneration	Miscellaneous Control Devices	5.60E-03(c) (3)	kg/tonne
		Stoker boilers	Uncontrolled	5.00E-02(d) (4)	kg/tonne
Commercial / Institutional	Bituminous Coal	Pulverized Coal: Dry Bottom	Uncontrolled	2.00E-02(1)	kg/tonne
		Overfeed Stoker	Multiple Cyclones	3.00E-02(1)	kg/tonne
		Underfeed Stoker	Multiple Cyclones	4.00E-01(1)	kg/tonne
		Spreader Stoker	Uncontrolled	3.00E-02(1)	kg/tonne
		Spreader Stoker	Multiple Cyclone with Fly Ash Re-injection	3.00E-02(1)	kg/tonne
		Atmospheric Fluidized Bed Combustion: Bubbling Bed	Uncontrolled	3.00E-02(1)	kg/tonne
		Atmospheric Fluidized Bed Combustion: Circulating Bed	Uncontrolled	3.00E-02(1)	kg/tonne
	Sub-bituminous Coal	Pulverized Coal: Wet Bottom	Uncontrolled	2.50E-02(1)	kg/tonne
		Spreader Stoker	Multiple Cyclone with Fly Ash Re-injection	3.00E-02(1)	kg/tonne
		Travelling Grate (Overfeed) Stoker	Multiple Cyclones	3.00E-02(1)	kg/tonne
		Pulverized Coal: Dry Bottom Tangential	Uncontrolled	2.00E-02(1)	kg/tonne
	Residual Oil	Grade 6 Oil	Uncontrolled	5.69E-02(b) (1)	kg/m^3
		10–100 Million Btu/h	Uncontrolled	5.69E-02(b) (1)	kg/m^3
		<10 Million Btu/hr	Uncontrolled	5.69E-02(b) (1)	kg/m^3
		Grade 5 Oil	Uncontrolled	5.69E-02(b) (1)	kg/m^3
	Distillate Oil	Grades 1 and 2 Oil	Uncontrolled	2.59E-02(b) (1)	kg/m^3
		10–100 Million Btu/h	Uncontrolled	2.59E-02(b) (1)	kg/m^3
		<10 Million Btu/h	Uncontrolled	2.59E-02(b) (1)	kg/m^3
		Grade 4 Oil	Uncontrolled	2.59E-02(b) (1)	kg/m^3
	Natural Gas	>100 Million Btu/h	Uncontrolled	3.68E+01(2)	$kg/10^6\ m^3$
		10–100 Million Btu/h	Uncontrolled	3.68E+01(2)	$kg/10^6\ m^3$
		<10 Million Btu/h	Uncontrolled	3.68E+01(2)	$kg/10^6\ m^3$

Source/Sector	Fuel Type	Combustion Technology		CH_4 Emission Factor	Units(a)
	Wood/Bark Waste	Bark-fired Boiler	Miscellaneous Control Devices	5.60E-03(c) (3)	kg/tonne
		Wood/Bark-fired Boiler	Miscellaneous Control Devices	5.60E-03(c) (3)	kg/tonne
		Wood-fired Boiler	Miscellaneous Control Devices	5.60E-03(c) (3)	kg/tonne
		Stoker Boilers	Uncontrolled	5.00E-02(d) (4)	kg/tonne
	Liquified Petroleum Gas (LPG) - Butane	All Boiler Types	Uncontrolled	2.40E-02(5)	kg/m^3
	Liquified Petroleum Gas (LPG) - Propane	All Boiler Types	Uncontrolled	2.40E-02(5)	kg/m^3
Internal Combustion Engines					
Electric Generation	Natural Gas	Turbine	Uncontrolled	3.70E-03(e) (6)	kg/GJ
Industrial	Natural Gas	Turbine	Uncontrolled	3.70E-03(e) (6)	kg/GJ
		Turbine: Cogeneration	Uncontrolled	3.70E-03(e) (6)	kg/GJ
		Two-cycle Lean Burn	Uncontrolled	6.23E-01(f) (6)	kg/GJ
		Four-cycle Rich Burn	Uncontrolled	9.89E-02(f) (6)	kg/GJ
	Large Bore Engine	Diesel	Uncontrolled	1.33E-01(g) (5)	kg/m^3
		Dual Fuel (Oil/Gas)	Uncontrolled	1.80E+00(5)	kg/hp-h
Commercial / Institutional	Natural Gas	Turbine	Uncontrolled	3.70E-03(e) (6)	kg/GJ
Stationary Source Fuel Combustion					
Residential	Anthracite Coal	Total: All Combustor Types	Uncontrolled	4.00E+00(5)	kg/tonne
	Distillate Oil	Total: All Combustor Types	Uncontrolled	2.13E-01(b) (1)	kg/m^3
	Natural Gas	Residential Furnaces	Uncontrolled	3.68E+01(2)	$kg/10^6\ m^3$
	Wood	Catalytic Woodstoves: General	Uncontrolled	4.30E+00(7)	kg/tonne
		Non-catalytic Woodstoves: Conventional	Uncontrolled	2.40E+00(7)	kg/tonne
	Kerosene	Total: All Heater Types	Uncontrolled	2.13E-01(b) (1)	kg/m^3

Explanatory Notes:

(a) Sources of the EFs list the EFs in imperial units. For use under this guidance manual, these EFs have been converted to metric units.

(b) Volatile organic compound (VOC) emissions can increase by several orders of magnitude if the boiler is improperly operated or is not well maintained.

(c) Units are lb of pollutant / ton of wood waste burned. EFs are based on wet, as-fired wood waste with average properties of 50 weight% moisture and 4500 Btu/lb higher heating value. EF represents measurements from wood waste combustion.

(d) Units are lb of pollutant / ton of wood waste burned. EFs are based on wet, as-fired wood waste with average properties of 50 weight% moisture and 4500 Btu/lb higher heating value.

(e) EF based on an average natural gas heating value (HHV) of 1020 Btu/scf at 60°F. Also, this EF may be converted to other natural gas heating values.

(f) EF for methane is determined by subtracting the VOC and ethane EFs from the total organic carbon (TOC) EF. Measured EF for methane compares well with the calculated EF, 1.48 lb/MMBtu vs. 1.45 lb/MMBtu, respectively.

(g) The heating value for diesel fuel is 137 000 Btu/gallon. This was used to convert from lbs/MMBTU.

Sources:

(1) U.S. EPA (1998), *Compilation of Air Pollutant Emission Factors, AP-42, 5th Edition, Volume 1: Stationary Point and Area Sources*, Supplement E, U.S. Environmental Protection Agency, September.

(2) U.S. EPA (1998), *Compilation of Air Pollutant Emission Factors, AP-42, 5th Edition, Volume 1: Stationary Point and Area Sources*, Supplement D, U.S. Environmental Protection Agency, March.

(3) U.S. EPA (1999), *Compilation of Air Pollutant Emission Factors, AP-42, 5th Edition, Volume 1: Stationary Point and Area Sources*, Supplement E, U.S. Environmental Protection Agency, February.

(4) U.S. EPA (1998), *Compilation of Air Pollutant Emission Factors, AP-42, 5th Edition, Volume 1: Stationary Point and Area Sources*, Supplement D, U.S. Environmental Protection Agency, February.

(5) U.S. EPA (1996), *Compilation of Air Pollutant Emission Factors, AP-42, 5th Edition, Volume 1: Stationary Point and Area Sources*, Supplement B, U.S. Environmental Protection Agency, October.

(6) U.S. EPA (2000), *Compilation of Air Pollutant Emission Factors, AP-42, 5th Edition, Volume 1: Stationary Point and Area Sources*, U.S. Environmental Protection Agency.

(7) U.S. EPA (1995), *Compilation of Air Pollutant Emission Factors, AP-42, 5th Edition, Volume 1: Stationary Point and Area Sources*, U.S. Environmental Protection Agency.

Table B.6: Default Nitrous Oxide (N_2O) Emission Factors for Various Combustion Technology Types

Source/Sector	Fuel Type	Combustion Technology		N_2O Emission Factor	Units(a)
External Combustion Boilers					
Electric Generation	Bituminous Coal	Pulverized Coal: Wet Bottom	Uncontrolled	4.00E-02(1)	kg/tonne
		Pulverized Coal: Dry Bottom	Uncontrolled	1.50E-02(1)	kg/tonne
		Spreader Stoker	Uncontrolled	2.00E-02(1)	kg/tonne
		Spreader Stoker	Multiple Cyclone without Fly Ash Re-injection	2.00E-02(1)	kg/tonne
		Spreader Stoker	Multiple Cyclone with Fly Ash Re-injection	2.00E-02(1)	kg/tonne
		Travelling Grate (Overfeed) Stoker	Uncontrolled	2.00E-02(1)	kg/tonne
		Travelling Grate (Overfeed) Stoker	Multiple Cyclones	2.00E-02(1)	kg/tonne
		Pulverized Coal: Dry Bottom (Tangential)	Uncontrolled	4.00E-02(1)	kg/tonne
		Atmospheric Fluidized Bed Combustion: Circulating Bed	Uncontrolled	1.75E+00(1)	kg/tonne
	Sub-bituminous Coal	Pulverized Coal: Wet Bottom	Uncontrolled	4.00E-02(1)	kg/tonne
		Pulverized Coal: Dry Bottom	Uncontrolled	1.50E-02(1)	kg/tonne
		Cyclone Furnace	Uncontrolled	4.50E-02(1)	kg/tonne
		Spreader Stoker	Uncontrolled	2.00E-02(1)	kg/tonne
		Spreader Stoker	Multiple Cyclone without Fly Ash Re-injection	2.00E-02(1)	kg/tonne
		Spreader Stoker	Multiple Cyclone with Fly Ash Re-injection	2.00E-02(1)	kg/tonne
		Travelling Grate (Overfeed) Stoker	Uncontrolled	2.00E-02(1)	kg/tonne
		Travelling Grate (Overfeed) Stoker	Multiple Cyclones	2.00E-02(1)	kg/tonne
	Lignite	Atmospheric Fluidized Bed	Uncontrolled	1.25E+00(2)	kg/tonne
		Atmospheric Fluidized Bed Combustion: Bubbling Bed	Uncontrolled	1.25E+00(1)	kg/tonne
		Atmospheric Fluidized Bed Combustion: Circulating Bed	Uncontrolled	1.25E+00(1)	kg/tonne
	Residual Oil	Grade 6 Oil: Normal Firing	Uncontrolled	1.32E-02(1)	kg/m^3
	Distillate Oil	Grades 1 and 2 Oil	Uncontrolled	1.32E-02(1)	kg/m^3
	Natural Gas	Boilers >100 Million Btu/h except Tangential	Uncontrolled	3.52E+01(3)	$kg/10^6\ m^3$
		Boilers <100 Million Btu/h except Tangential	Uncontrolled	3.52E+01(3)	$kg/10^6\ m^3$
		Boilers <100 Million Btu/h except Tangential	Low NOx Burners	1.03E+01(3)	$kg/10^6\ m^3$
		Tangentially Fired Units	Uncontrolled	3.52E+01(3)	$kg/10^6\ m^3$
		Tangentially Fired Units	Low NOx Burners	1.03E+01(3)	$kg/10^6\ m^3$
Industrial	Bituminous Coal	Pulverized Coal: Wet Bottom	Uncontrolled	4.00E-02(1)	kg/tonne
		Pulverized Coal: Dry Bottom (Tangential)	Uncontrolled	4.00E-02(1)	kg/tonne
		Cyclone Furnace	Uncontrolled	4.50E-02(1)	kg/tonne
		Spreader Stoker	Uncontrolled	2.00E-02(1)	kg/tonne
		Spreader Stoker	Multiple Cyclone without Fly Ash Re-injection	2.00E-02(1)	kg/tonne

Source/Sector	Fuel Type	Combustion Technology		N_2O Emission Factor	Units(a)
		Spreader Stoker	Multiple Cyclone with Fly Ash Re-injection	2.00E-02(1)	kg/tonne
		Overfeed Stoker	Uncontrolled	2.00E-02(1)	kg/tonne
		Overfeed Stoker	Multiple Cyclones	2.00E-02(1)	kg/tonne
		Underfeed Stoker	Uncontrolled	2.00E-02(1)	kg/tonne
		Underfeed Stoker	Multiple Cyclones	2.00E-02(1)	kg/tonne
		Atmospheric Fluidized Bed Combustion: Bubbling Bed	Uncontrolled	1.75E+00(1)	kg/tonne
		Atmospheric Fluidized Bed Combustion: Circulating Bed	Uncontrolled	1.75E+00(1)	kg/tonne
	Sub-bituminous Coal	Pulverized Coal: Wet Bottom	Uncontrolled	4.00E-02(1)	kg/tonne
		Pulverized Coal: Dry Bottom	Uncontrolled	1.50E-02(1)	kg/tonne
		Pulverized Coal: Dry Bottom (Tangential)	Uncontrolled	4.00E-02(1)	kg/tonne
		Cyclone Furnace	Uncontrolled	4.50E-02(1)	kg/tonne
		Spreader Stoker	Uncontrolled	2.00E-02(1)	kg/tonne
		Spreader Stoker	Multiple Cyclone without Fly Ash Re-injection	2.00E-02(1)	kg/tonne
		Spreader Stoker	Multiple Cyclone with Fly Ash Re-injection	2.00E-02(1)	kg/tonne
		Travelling Grate (Overfeed) Stoker	Uncontrolled	2.00E-02(1)	kg/tonne
		Travelling Grate (Overfeed) Stoker	Multiple Cyclones	2.00E-02(1)	kg/tonne
		Underfeed Stoker	Uncontrolled	2.00E-02(1)	kg/tonne
		Underfeed Stoker	Multiple Cyclones	2.00E-02(1)	kg/tonne
	Residual Oil	Grade 6 Oil	Uncontrolled	1.32E-02(1)	kg/m^3
	Distillate Oil	Grades 1 and 2 Oil	Uncontrolled	1.32E-02(1)	kg/m^3
	Natural Gas	>100 Million Btu/h	Uncontrolled	3.52E+01(3)	kg/10^6 m^3
		>100 Million Btu/h	Low NOx Burners	1.03E+01(3)	kg/10^6 m^3
		10–100 Million Btu/h	Uncontrolled	3.52E+01(3)	kg/10^6 m^3
		10–100 Million Btu/h	Low NOx Burners	1.03E+01(3)	kg/10^6 m^3
	Wood/Bark Waste	Stoker Boilers	Uncontrolled	2.00E-02(b) (4)	kg/tonne
Commercial / Institutional	Bituminous Coal	Cyclone Furnace	Uncontrolled	4.50E-02(1)	kg/tonne
		Pulverized Coal: Dry Bottom	Uncontrolled	1.50E-02(1)	kg/tonne
		Overfeed Stoker	Uncontrolled	2.00E-02(1)	kg/tonne
		Overfeed Stoker	Multiple Cyclones	2.00E-02(1)	kg/tonne
		Underfeed Stoker	Uncontrolled	2.00E-02(1)	kg/tonne
		Underfeed Stoker	Multiple Cyclones	2.00E-02(1)	kg/tonne
		Spreader Stoker	Uncontrolled	2.00E-02(1)	kg/tonne
		Spreader Stoker	Multiple Cyclone with Fly Ash Re-injection	2.00E-02(1)	kg/tonne
		Atmospheric Fluidized Bed Combustion: Bubbling Bed	Uncontrolled	1.75E+00(1)	kg/tonne
		Atmospheric Fluidized Bed Combustion: Circulating Bed	Uncontrolled	1.75E+00(1)	kg/tonne
	Sub-bituminous Coal	Cyclone Furnace	Uncontrolled	4.50E-02(1)	kg/tonne
		Travelling Grate (Overfeed) Stoker	Uncontrolled	2.00E-02(1)	kg/tonne
		Pulverized Coal: Dry Bottom Tangential	Uncontrolled	4.00E-02(1)	kg/tonne
	Residual Oil	Grade 6 Oil	Uncontrolled	1.32E-02(1)	kg/m^3

Source/Sector	Fuel Type	Combustion Technology		N_2O Emission Factor	Units(a)
	Distillate Oil	Grades 1 and 2 Oil	Uncontrolled	1.32E-02(1)	kg/m^3
	Natural Gas	>100 Million Btu/h	Uncontrolled	3.52E+01(3)	kg/10^6 m^3
		10–100 Million Btu/h	Uncontrolled	3.52E+01(3)	kg/10^6 m^3
		<10 Million Btu/h	Uncontrolled	3.52E+01(3)	kg/10^6 m^3
		<10 Million Btu/h	Low NOx Burners	1.03E+01(3)	kg/10^6 m^3
	Wood/Bark Waste	Stoker Boilers	Uncontrolled	2.00E-02(b) (4)	kg/tonne
		Fluidized Bed Combustion Boilers	Uncontrolled	1.00E-01(b) (4)	kg/tonne
Internal Combustion Engines					
Electric Generation	Natural Gas	Turbine	Steam or Water Injection	1.29E-03(c) (5)	kg/GJ
Industrial	Natural Gas	Turbine: Cogeneration	Steam or Water Injection	1.29E-03(c) (5)	kg/GJ
Commercial / Institutional	Natural Gas	Turbine	Steam or Water Injection	1.29E-03(c) (5)	kg/GJ
		Turbine: Cogeneration	Steam or Water Injection	1.29E-03(c) (5)	kg/GJ
Stationary Source Fuel Combustion					
Residential	Distillate Oil	Total: All Combustor Types	Uncontrolled	5.99E-03(d) (1)	kg/m^3
	Natural Gas	Residential Furnaces	Uncontrolled	3.52E+01(3)	kg/10^6 m^3
		Residential Furnaces	Low NOx Burners	1.03E+01(3)	kg/10^6 m^3
	Kerosene	Total: All Heater Types	Uncontrolled	5.99E-03(1)	kg/m^3

Explanatory Notes:

(a) Sources of the EFs list the EFs in imperial units. For use under this guidance manual, these EFs have been converted to metric units.

(b) Units are lb of pollutant/ton of wood waste burned. EFs are based on wet, as-fired wood waste with average properties of 50 weight% moisture and 4500 Btu/lb higher heating value.

(c) Based on limited source tests on a single turbine with water-steam injection. EF based on an average natural gas heating value (HHV) of 1020 Btu/scf at 60°F. Also, this EF can be converted to other natural gas heating values.

(d) Corrected in Supplement A.

Sources:

(1) U.S. EPA (1998), *Compilation of Air Pollutant Emission Factors, AP-42, 5th Edition, Volume 1: Stationary Point and Area Sources*, Supplement E, U.S. Environmental Protection Agency, September.

(2) U.S. EPA (1995), *Compilation of Air Pollutant Emission Factors, AP-42, 5th Edition, Volume 1: Stationary Point and Area Sources*, U.S. Environmental Protection Agency.

(3) U.S. EPA (1998), *Compilation of Air Pollutant Emission Factors, AP-42, 5th Edition, Volume 1: Stationary Point and Area Sources*, Supplement D, U.S. Environmental Protection Agency, March.

(4) U.S. EPA (1998), *Compilation of Air Pollutant Emission Factors, AP-42, 5th Edition, Volume 1: Stationary Point and Area Sources*, Supplement D, U.S. Environmental Protection Agency, February.

(5) U.S. EPA (2000), *Compilation of Air Pollutant Emission Factors, AP-42, 5th Edition, Volume 1: Stationary Point and Area Sources*, U.S. Environmental Protection Agency.

Appendix C: Templates and Default Values for Use in the Estimation of Mobile Fuel Combustion Emissions

This appendix presents sample data and calculation templates and default EF values for estimating mobile fuel combustion emissions. The EFs presented in Table C.4 are the national EFs used in the preparation of the National GHG Inventory (except where otherwise noted). Default gross calorific (or higher heating) values for various fuel types are provided in Table A.9 if conversion is necessary from energy units to physical units (e.g. mass, volume).

Table C.1: Mobile Fuel Combustion — Data Entries and Calculations for CO_2 Emissions

Source Category[a]	Fuel Type Combusted[b]	(1) Quantity of Fuel Combusted (Original Units)	(2) CO_2 Emission Factor[c] (g / Original Units)	(3) CO_2 Emissions[d] (g)	(4) CO_2 Emissions[e] (Gg)
1. ____________________	_______________	input	input	calc	calc
____________________	_______________	input	input	calc	calc
….	….	….	….	….	….
2. ____________________	_______________	input	input	calc	calc
____________________	_______________	input	input	calc	calc
….	….	….	….	….	….
3. ____________________	_______________	input	input	calc	calc
____________________	_______________	input	input	calc	calc
….	….	….	….	….	….
4. ____________________	_______________	input	input	calc	calc
____________________	_______________	input	input	calc	calc
….	….	….	….	….	….
TOTAL[f]		sum		sum	sum

Explanatory Notes:

(a) List categories used in Section 2.3 for the combustion sources (this may be by fuel category, mode of transport/vehicle type).

(b) Specify type(s) of fuel(s) combusted in each source category.

(c) Details on any conversions performed on the EF are to be reported.

(d) CO_2 emissions calculated based on equation in Section 3.4.2.

(e) Report CO_2 emissions in units of gigagrams.

Table C.2: Mobile Fuel Combustion — Data Entries and Calculations for CH_4 Emissions

Source Category[a]	Fuel Type Combusted[b]	(1) Quantity of Fuel Combusted (Original Units)	(2) CH_4 Emission Factor[c] (g / Original Units)	(3) CH_4 Emissions[d] (g)	(4) CH_4 Emissions[e] (Gg)
1. ________________	______________	input	input	calc	calc
________________	______________	input	input	calc	calc
….	….	….	….	….	….
2. ________________	______________	input	input	calc	calc
________________	______________	input	input	calc	calc
….	….	….	….	….	….
3. ________________	______________	input	input	calc	calc
________________	______________	input	input	calc	calc
….	….	….	….	….	….
4. ________________	______________	input	input	calc	calc
________________	______________	input	input	calc	calc
….	….	….	….	….	….
TOTAL		sum		sum	sum

Explanatory Notes:

(a) List categories used in Section 2.3 for the combustion sources (this may be by fuel category, mode of transport/vehicle type).

(b) Specify the type(s) of fuel(s) combusted in each source category.

(c) Details on any conversions performed on the EF are to be documented.

(d) CH_4 emissions calculated based on equation in Section 3.4.2.

(e) Report CH_4 emissions in units of gigagrams.

Table C.3: Mobile Fuel Combustion Data Entries and Calculations for N_2O Emissions

Source Category[(a)]	Fuel Type Combusted[(b)]	(1) Quantity of Fuel Combusted (Original Units)	(2) N_2O Emission Factor[(c)] (g / Original Units)	(3) N_2O Emissions[(d)] (g)	(4) N_2O Emissions[(e)] (Gg)
1. ________________	______________	input	input	calc	calc
________________	______________	input	input	calc	calc
….	….	….	….	….	….
2. ________________	______________	input	input	calc	calc
________________	______________	input	input	calc	calc
….	….	….	….	….	….
3. ________________	______________	input	input	calc	calc
________________	______________	input	input	calc	calc
….	….	….	….	….	….
4. ________________	______________	input	input	calc	calc
________________	______________	input	input	calc	calc
….	….	….	….	….	….
TOTAL		sum		sum	sum

Explanatory Notes:

(a) List categories used in Section 2.3 for the combustion sources (this may be by fuel category, mode of transport/vehicle type).

(b) Specify the type(s) of fuel(s) combusted in each source category.

(c) Details on any conversions performed on the EF are to be documented.

(d) N_2O emissions calculated based on equation in Section 3.4.2.

(e) Report N_2O emissions in units of gigagrams.

Table C.4: Mobile Combustion Sources — Emission Factors

	Emission Factor(a)		
Use(b)	**CO_2**	**CH_4**	**N_2O**
	(g/L)	**(g/L)**	**(g/L)**
Diesel			
Heavy-Duty Diesel Vehicles(c)			
- Advance Control	2730(1)	0.12(2)	0.08(2)
- Moderate Control	2730(1)	0.13(2)	0.08(2)
- Uncontrolled	2730(1)	0.15(2)	0.08(2)
Other Diesel Vehicles(d)	2730(1)	0.14(2)	1.1(2)
	(g/L)	**(g/L)**	**(g/L)**
Gasoline			
Heavy-Duty Gasoline Vehicles(c)			
- Three-way Catalyst	2360(1)	0.17(2)	1(2)
- Non-Catalyst	2360(1)	0.29(2)	0.046(2)
- Uncontrolled	2360(1)	0.49(2)	0.08(2)
Other Gasoline Vehicles(d)	2360(1)	2.7(2)	0.05(2)
	(g/L)	**(g/L)**	**(g/L)**
Diesel Rail Transportation	2730(1)	0.15(2)	1.1(2)
Marine Transportation			
Gasoline Boats	2360(1)	1.3(2)	0.06(2)
Diesel Ships	2730(1)	0.15(2)	1.00(2)
Light Fuel Oil Ships	2830(1)	0.3(2)	0.07(2)
Heavy Fuel Oil Ships	3090(1)	0.3(2)	0.08(2)
Pipeline Transport(e)	**(g/L)**	**(g/L)**	**(g/L)**
Diesel	2730(1)	0.133(2)	0.4(2)
	(g/m^3)	**(g/m^3)**	**(g/m^3)**
Natural Gas	1891(3)	1.9(2)	0.05(2)

Explanatory Notes:

(a) CO_2 EFs for mobile combustion are dependent on fuel properties and are the same as those used for stationary combustion for all fuels. EFs for CH_4 and N_2O are technology dependent and are based on combustion technologies typically used in Canada.

(b) The fuels and transport modes listed above are typical types that are expected to be used on-site at industrial facilities in mobile combustion activities.

(c) This category of vehicle includes on-road heavy duty vehicles that may be equipped with emission control devices..

(d) This category of vehicle includes off-road vehicles that are not licensed to operate on roads or highways (e.g. tracked construction vehicles, mobile mining vehicles, tractors, etc.). This category of vehicle does not generally employ emission control devices.

(e) Pipelines consist of both oil and gas types that may use fossil fueled combustion engines to power motive compressors and other equipment which propel their contents (e.g. fuels used may be natural gas or diesel). The fuel EFs listed here are those used in stationary combustion applications.

Sources:

(1) Jaques, A. (1992), *Canada's Greenhouse Gas Emissions: Estimates for 1990,* Environmental Protection, Conservation and Protection, Environment Canada, EPS 5/AP/4, December.

(2) SGA Energy Limited (2000), *Emission Factors and Uncertainties for CH_4 & N_2O from Fuel Combustion,* prepared for Environment Canada, August.

(3) Adapted from McCann, T.J. (2000), *1998 Fossil Fuel and Derivative Factors*, prepared for Environment Canada, March.

Appendix D: Template and Default Values for Use in the Estimation of Process-related Emissions

This appendix presents a data collection template and default values that may be used in the estimation of process-related emissions (Section 3.4.3).

Table D.1: Process-related Emissions — Process Source Entries and Calculated Emissions

		GHG Emissions(e,f)	
Process Description(a)	**Source Occurring at Facility?(a) (Yes / No)**	**CO_2 (Gg)**	**HFCs (Gg)**
1. Use of Reducing Agents(b)			
______________________	__________	calc	
______________________	…	…	
2. Use of Other Blast Furnace Additives(c)			
______________________	__________	calc	
______________________	…	…	
3. Limestone Use	__________	calc	
4. Steel Production in BOF	__________	calc	
5. Steel Production in EAF	__________	calc	
6. Consumption of Electrodes (EAF)	__________	calc	
7. Carbon Use in Foamy Slag	____________	calc	
8. On-site Lime Production	____________	calc	
9. Soda Ash Use	____________	calc	
10. HFC Use(d)			
______________________	__________		calc
______________________	__________		calc
….	….		…
TOTAL		sum	N/A

Explanatory Notes:

(a) Confirm list of process-related sources occurring at the facility in question; use chosen categories from Section 2.3 if applicable.

(b) It is important to identify the reducing agent(s) used and also what type of technology is used to produce crude iron (e.g. blast furnace, direct reduction).

(c) List the type of additive(s) used in the process).

(d) List the equipment type that makes use of HFCs (e.g. refrigeration unit, air conditioning system); also, list the specific HFC that is used in each system.

(e) Emissions calculated based on relevant equations in Section 3.4.3.

(f) Report emissions in units of gigagrams.

Table D.2: Default CO_2 Emission Factor for Various Reducing Agents used in Blast Furnace Operations (Pig Iron Production)

Reducing Agent (RA)	EF (tonne CO_2 / tonne RA)
Coal	(see Table A.5 in Appendix A)(1)
Metallurgical Coke	3.1(2)
Petroleum Coke	4.2(1)
Natural Gas	(see Table A.7 in Appendix A)(1)

Sources:

(1) Olsen, K., Collas, P., Boileau, P., Blain, D., Ha, C., Henderson, L., Liang, C., McKibbon, S., & Morel-a-l'Hussier, L. (2002), *Canada's Greenhouse Gas Inventory, 1990–2000*, Environment Canada, June.

(2) IPCC (Intergovernmental Panel on Climate Change) (1997), *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories*, IPCC, Bracknell, UK.

Table D.3: Default Carbon Content for Various Input and Output Materials in Raw Iron and Steel Production

Material	Carbon Content(b) (%)
Iron Ore	0(1)
Raw (or Pig) Iron	4(1)
Direct Reduced Iron(a)	1.5(2)
Raw Steel	1.25(1)

Explanatory Notes:

(a) The value listed is for direct reduced iron produced using the Midrex process.

(b) Where a range of values was given in the source, the midpoint of the range is listed above.

Sources:

(1) IPCC (Intergovernmental Panel on Climate Change) (2000), *Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories,* Global Environmental Strategies, Kanagawa, Japan.

(2) European Integrated Pollution Prevention and Control (IPPC) Bureau (2000), *Best Available Techniques Reference Document on the Production of Iron and Steel,* European Commission, March..

Table D.4: Default CO_2 Emission Factor for Other Blast Furnace Additives

Material	EF (tonnes CO_2 / tonne material)
PVC	1.62
PET	2.24
PE	2.85

Explanatory Notes:

PVC = polyvinyl chloride; PET = polyethylene terephthalate; PE = polyethylene.

Source:

World Resources Institute and World Business Council on Sustainable Development (WRI/WBCSD) (2002), *Calculating Direct GHG Emissions from the Production of Iron and Steel, Calculation Worksheets, Version 1.0*, June.

Table D.5: Default Annual Leakage Rate for Different Categories of Equipment Using HFCs

Equipment Category	LR Value (% of total HFC charge)
Residential Refrigeration	1.0
Commercial Refrigeration	17.0
Stationary Air Conditioning	17.0

Source:

Olsen, K., Wellisch, M., Boileau, P., Blain, D., Ha, C., Henderson, L., Liang, C., McCarthy, J. & McKibbon, S. (2003), *Canada's Greenhouse Gas Inventory, 1990–2001*, Environment Canada, August.

Appendix E: Templates of Spreadsheet Calculations for Use in the Key Source Assessment Process

This appendix presents templates of spreadsheet calculations for use in the key source assessment process (Section 3.5).

Table E.1: Spreadsheet for Level Assessment

Source Categories[a]	Direct Greenhouse Gas[b]	(1) Base Year Estimate[c]	(2) Current Year Estimate[d]	(3) Level Assessment[e]	(4) Cumulative Total[f]
Stationary Combustion					
1. _______________		input	input	calc	calc
		input	input	calc	calc
		…	…	…	…
2. _______________		input	input	calc	calc
	(e.g. CO_2, CH_4, N_2O)	input	input	calc	calc
		…	…	…	…
3. _______________		input	input	calc	calc
		input	input	calc	calc
… … … …		…	…	…	…
Mobile Combustion					
1. _______________		input	input	calc	calc
		input	input	calc	calc
		…	…	…	…
2. _______________	(e.g. CO_2, CH_4, N_2O)	input	input	calc	calc
		input	input	calc	calc
… … … …		…	…	…	…
Process-related					
1. _______________		input	input	calc	calc
		…	…	…	…
2. _______________	(e.g. CO_2, HFCs, SF_6, etc.)	input	input	calc	calc
		…	…	…	…
3. _______________		input	input	calc	calc
		…	…	…	…
… … … …		…	…	…	…
Total		calc	calc		

Explanatory Notes:

(a) List the emission sources identified for your facility using categories selected (e.g. by fuel type, combustion technology, transport mode, specific process type).

(b) List each GHG that is a contributor to the facility inventory (e.g. CO_2, CH_4, N_2O, HFCs, SF_6, etc.). It is necessary to consider each GHG separately for each emission source, since estimating methods, EFs and related uncertainties differ for each gas.

(c) Base year emission estimates from inventory data, in CO_2-equivalent units. Convert non-CO_2 GHG emissions to CO_2 equivalents (eqs) by multiplying the emissions of the GHGs by their respective GWPs (see Appendix H for a list of GWPs).

(d) Current year emission estimates from the most recent inventory, in CO_2-equivalent units. See note (c) for appropriate conversions.

(e) Level Assessment calculated using the equation in Section 3.5.1.1. The calculated numbers here for the emission source categories are to be listed in descending order of magnitude (from greatest to least).

(f) Cumulative total of column 3.

Table E.2: Spreadsheet for Trend Assessment

Source Categories(a)	Direct Greenhouse Gas(b)	(1) Base Year Estimate(c)	(2) Current Year Estimate(d)	(3) Trend Assessment(e)	(4) Cumulative Total(f)
Stationary Combustion					
1. ______________	(e.g. CO_2, CH_4, N_2O)	input	input	calc	calc
		input	input	calc	calc
		....	....	....	....
2. ______________		input	input	calc	calc
		input	input	calc	calc
		....	....	....	....
3. ______________		input	input	calc	calc
		input	input	calc	calc
…		....	....	....	....
Mobile Combustion					
1. ______________	(e.g. CO_2, CH_4, N_2O)	input	input	calc	calc
		input	input	calc	calc
		....	....	....	....
2. ______________		input	input	calc	calc
		input	input	calc	calc
…		....	....	....	....
Process-related					
1. ______________	(e.g. CO_2, HFCs, SF_6, etc.)	input	input	calc	calc
		....	....	....	....
2. ______________		input	input	calc	calc
		....	....	....	....
3. ______________		input	input	calc	calc
		....	....	....	....
…		....	....	....	....
Total		calc	calc		

Explanatory Notes:

(a) List the emission sources identified for your facility using categories selected (e.g. by fuel type, combustion technology, specific process type).

(b) List each GHG that is a contributor to the facility inventory (e.g. CO_2, CH_4, N_2O, HFCs, SF_6, etc.). It is necessary to consider each GHG separately for each emission source, since estimating methods, EFs and related uncertainties differ for each gas.

(c) Base year emission estimates from inventory data, in CO_2-equivalent units. Convert non-CO_2 GHG emissions to CO_2 equivalents (eqs) by multiplying the emissions of the GHGs by their respective GWPs (see Appendix H for a list of GWPs).

(d) Current year emission estimates from most recent inventory, in CO_2-equivalent units. See note (c) for appropriate conversions.

(e) Trend Assessment calculated using equation in Section 3.5.1.2. The calculated numbers here for the emission source categories are to be listed in descending order of magnitude (from greatest to least).

(f) Cumulative total of column 3.

Appendix F: Template and Default Values for Use in the Uncertainty Assessment Process

This appendix presents a template and tables with default uncertainties for some default emission factors for use in the uncertainty assessment process (Section 4). The following table should be completed for each GHG type being emitted (e.g. CO_2, CH_4, N_2O, SF_6, etc.).

Table F.1: Uncertainty Assessment for ________ Emissions (specify CO_2, CH_4, N_2O, SF_6 or HFCs) — Data Entries and Calculations

Source Category (a)	(1) GHG Emissions (Gg)	(2) Uncertainty of GHG Emissions (b) (Confidence Interval, expressed in ± %)	(3) Variable 1 (c) (Col. 1)^2	(4) Variable 2 (c) (Col. 2)^2	(5) Variable 3 (c) (Col. 3 x Col. 4)
Stationary Combustion					
1. ___________________	calc	calc	calc	calc	calc
	....	....	....	....	....
2. ___________________	calc	calc	calc	calc	Calc
	....	....	....	....	....
3. ___________________	calc	calc	calc	calc	calc
....	....	....	....	....	...
Mobile Combustion					
1. ___________________	calc	calc	calc	calc	calc
	...	...	...	...	...
2. ___________________	calc	calc	calc	calc	calc
	....	....	....	....	....
3. ___________________	calc	calc	calc	calc	calc
....	....	....	....	....	...
Process-Related					
1. ___________________	calc	calc	calc	calc	calc
	....	....	....	....	....
2. ___________________	calc	calc	calc	calc	calc
	....	....	....	....	....
3. ___________________	calc	calc	calc	calc	calc
....	....	....	....	....	....
Total Emissions (d) =	__________ Gg				
Cumulated Uncertainty for Total Emissions (e) =	± __________ %				

Explanatory Notes:

(a) List the source categories used if applicable and a description of the emission source(s) for the GHG type being addressed.

(b) Uncertainty of GHG emissions is calculated using the first equation listed in Section 4.

(c) These variables are calculated in order to be used in the equation for determining the Cumulated Uncertainty for Total Emissions (see note (e) below).

(d) Total emissions = Sum of emissions from all source categories (sum of Col. 1).

(e) Cumulated Uncertainty for Total Emissions is calculated using the second equation listed in Section 4; Cumulated Uncertainty = ± [square root (sum of Col. 5)] / Total Emissions.

Table F.2: Uncertainties due to National Emission Factors

Gas	EF Uncertainty
CO_2	4%
CH_4	30%
N_2O	40%

Olsen, K., Collas, P., Boileau, P., Blain, D., Ha, C., Henderson, L., Liang, C., McKibbon, S. & Morel-a-l'Hussier, L. (2002), *Canada's Greenhouse Gas Inventory, 1990–2000*, Environment Canada, June.

Note: These uncertainties are in fact the overall uncertainties that were derived for the national GHG emission estimates prepared for the 1990 inventory. These uncertainties are being applied to the EF component as it can be expected that the EF is the greatest contributor to the overall uncertainty of the fuel combustion emission estimates. The level of uncertainty associated with the national energy activity data used is considered to be relatively low in comparison. Future efforts need to be conducted to obtain revised up-to-date uncertainties for the national inventory.

Appendix G: Template for a Summary GHG Emissions Table and Emission Trends Report

This appendix presents a template for a summary emissions table to document the total GHG emissions from the stationary and mobile fuel combustion and process-related source categories at your facility for the identified inventory year. A template for documenting trends in GHG emissions from the same sources over several inventory periods is also presented.

Table G.1: Summary Report for Facility GHG Emissions from Fuel Combustion and Process-Related Sources

Facility Name: ______________________________

Inventory Year: ______________________________

Facility Address: ______________________________
____
____

Source Categories(a)	Emissions(b,c)									
						HFCs (specify)				
	CO_2 (Gg)	CH_4 (Gg)	CH_4 (Gg CO_2 eqs)	N_2O (Gg)	N_2O (Gg CO_2 eqs)	____ (Gg)	______ (Gg CO_2 eqs)	____ (Gg)	______ (Gg CO_2 eqs)	Total (Gg CO_2 eqs)
Stationary Combustion										
1. __________________	input	input	calc	input	calc					calc
....	…	…	…	…	…					…
2. __________________	input	input	calc	input	calc					calc
....	…	…	…	…	…					…
3. __________________	input	input	calc	input	calc					calc
....	…	…	…	…	…					…
Mobile Combustion										
1. __________________	input	input	calc	input	calc					calc
....	…	…	…	…	…					…
2. __________________	input	input	calc	input	calc					calc
....	…	…	…	…	…					…
3. __________________	input	input	calc	input	calc					calc
....	…	…	…	…	…					…
Process-related										
1. __________________	input									calc
2. __________________	input									calc
3. __________________						input	calc			calc
4. _________________								input	calc	calc
....	…					…	…	…	…	…
TOTAL:	sum	sum	sum	sum	sum	sum	sum	sum	sum	sum

Explanatory Notes:

(a) List categories used if applicable (e.g. for stationary combustion activities, this may be by fuel category, combustion technology, primary end purpose of combustion, etc.).

(b) When necessary, use the notation key below for the appropriate emission estimates.

(c) Convert non-CO_2 emissions to CO_2 equivalents (eqs) by multiplying the non-CO_2 emissions by their appropriate GWPs (listed in Appendix H).

Notation Key for Emission Estimates:

NA - Not available	NE - Not estimated	NO - Not occurring	0 - An estimate is made but the figure is too small to display

Table G.2: Emission Trends Report for Facility GHG Emissions from Fuel Combustion and Process-related Sources

Facility Name:	______________________________
Facility Address:	______________________________ ______________________________

	Emissions (All Gases)[b,c] **(Gg CO_2 equivalents)**				
Source Categories[a]	_______ **(base year)**	_______ **(base year + 1)**	_______ **(base year + 2)**	_______ **(base year + ..)**	_______ **(base year + n)**
Stationary Combustion					
1. ____________________	input	input	input	input	input
____________________	input	input	input	input	input
2. ____________________	input	input	input	input	input
____________________	…	…	…	…	…
3. ____________________	…	…	…	…	…
… ____________________	…	…	…	…	…
Mobile Combustion					
1. ____________________	input	input	input	input	input
____________________	input	input	input	input	input
2. ____________________	input	input	input	input	input
____________________	…	…	…	…	…
3. ____________________	…	…	…	…	…
… ____________________	…	…	…	…	…
Process-related					
1. ____________________	input	input	input	input	input
2. ____________________	input	input	input	input	input
3. ____________________	input	input	input	input	input
4. ____________________	…	…	…	…	…
… ____________________	…	…	…	…	…
Total:	sum	sum	sum	sum	sum

Explanatory Notes:

(a) List categories used if applicable (e.g. for stationary combustion activities, this may be by fuel category, combustion technology, primary end purpose of combustion, etc.).

(b) Input the total estimate for all GHGs (e.g. CO_2, CH_4, N_2O, HFCs) in units of gigagrams of CO_2 equivalents for the given source category and the given year.

(c) When necessary, use the notation key below for the appropriate emission estimates.

Notation Key for Emission Estimates:

NA - Not available	NE - Not estimated	NO - Not occurring	0 - An estimate is made but the figure is too small to display

Appendix H: Global Warming Potential

"The concept of 'global warming potential' (GWP) has been developed to allow scientists and policy-makers to compare the ability of each GHG to trap heat in the atmosphere relative to another gas. By definition, a GWP is the time-integrated change in radiative forcing[26] due to the instantaneous release of 1 kg of the gas expressed relative to the radiative forcing from the release of 1 kg of CO_2. In other words, a GWP is a relative measure of the warming effect that the emission of a radiative gas (i.e., GHG) might have on the surface troposphere. The GWP of a GHG takes into account both the instantaneous radiative forcing due to an incremental concentration increase and the lifetime of the gas."[27]

The following table provides the 100-year GWPs for various GHGs. These GWPs are recommended by the Intergovernmental Panel on Climate Change and are used in the development of the National GHG Inventory.

Table H.1: Global Warming Potentials

GHG	Formula	100-year GWP	Atmospheric Lifetime
Carbon Dioxide	CO_2	1	Variable
Methane	CH_4	21	12 ± 3
Nitrous Oxide	N_2O	310	120
Sulfur Hexafluoride	SF_6	23 900	3200
Hydrofluorocarbons (HFCs)			
HFC-23	CHF_3	11 700	264
HFC-32	CH_2F_2	650	5.6
HFC-41	CH_3F	150	3.7
HFC-43-10mee	$C_5H_2F_{10}$	1 300	17.1
HFC-125	C_2HF_5	2 800	32.6
HFC-134	$C_2H_2F_4$ (CHF_2CHF_2)	1 000	10.6
HFC-134a	$C_2H_2F_2$ (CH_2FCF_3)	1 300	14.6
HFC-143	$C_2H_3F_3$ (CHF_2CH_2F)	300	1.5
HFC-143a	$C_2H_3F_3$ (CF_3CH_3)	3 800	3.8
HFC-152a	$C_2H_4F_2$ (CH_3CHF_2)	140	48.3
HFC-227ea	C_3HF_7	2 900	36.5
HFC-236fa	$C_3H_2F_6$	6 300	209
HFC-245ca	$C_3H_3F_5$	560	6.6
Perfluorocarbons (PFCs)			
Perfluoromethane	CF_4	6 500	50 000
Perfluoroethane	C_2F_6	9 200	10 000
Perfluoropropane	C_3F_8	7 000	2 600
Perfluorobutane	C_4F_{10}	7 000	2 600
Perfluorocyclobutane	c-C_4F_8	8 700	3 200
Perfluoropentane	C_5F_{12}	7 500	4 100
Perfluorohexane	C_6F_{14}	7 400	3 200

GWP Source: IPCC (1996a), *1995 Summary for Policy Makers — A Report of Working Group I of the Intergovernmental Panel on Climate Change.*

Lifetime Source: IPCC (1995), *Second Assessment Report* Table 2.9, p. 121, Intergovernmental Panel on Climate Change.

Note: The CH_4 GWP includes the direct effect and those indirect effects due to the production of tropospheric ozone and stratospheric water vapour. Not included is the indirect effect due to the production of CO_2.

Source: Olsen, K., Wellisch, M., Boileau, P., Blain, D., Ha, C., Henderson, L., Liang, C., McCarthy, J. & McKibbon, S. (2003), *Canada's Greenhouse Gas Inventory, 1990–2001*, Environment Canada, August.

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[26] The term "radiative forcing" refers to the amount of heat-trapping potential for any given GHG. It is measured in units of power (watts) per unit of area (metres squared). The radiative forcing effect of a gas within the atmosphere is a reflection of its ability to cause atmospheric warming.

[27] Olsen, K., Wellisch, M., Boileau, P., Blain, D., Ha, C., Henderson, L., Liang, C., McCarthy, J. & McKibbon, S. (2003), Canada's Greenhouse Gas Inventory, 1990–2001, Environment Canada, August.

Appendix I: Common Unit Prefixes and Conversions

Table I.1: Unit Prefixes

SI Units		Multiple	U.S. Designation	
Unit	Symbol		Unit	Symbol
kilo-	k	10^3	thousand	k or M
mega-	M	10^6	million	MM
giga-	G	10^9	billion	B
tera-	T	10^{12}	trillion	T
peta-	P	10^{15}	quadrillion	Q

Table I.2: Unit Conversions

Volume		
1 cubic metre (m^3)	=	1000 litres (L)
	=	264.2 U.S. gallons (gal)
	=	6.29 barrels (bbl)
	=	35.315 cubic feet (ft^3)
	=	1.308 cubic yards (yd^3)
Mass		
1 kilogram (kg)	=	2.2046 pounds (lbs)
	=	1000 grams (g)
1 tonne (t)	=	1000 kilograms (kg)
	=	2204.6 pounds (lbs)
	=	1.1023 U.S. tons (short tons)
	=	0.98421 imperial tons (long tons)
Energy		
1 gigajoule (GJ)	=	947 817 British thermal units (Btu)
	=	0.947817 million Btu (MMBtu)

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