

The Climate Registry

General Reporting Protocol

Version 1.1

Accurate, transparent, and consistent measurement of greenhouse gases across North America

May 2008

General Reporting Protocol
for the Voluntary Reporting Program



The Climate Registry

May 2008

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Leanne Tippett Mosby, Missouri
Leo Drozdoff, Nevada
Onis Glenn, Alabama
Renee Shealy, South Carolina
Richard Leopold, Iowa
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The Registry Protocol Workgroup

Angela Jenkins, Virginia
Anne Keach, Virginia
Bill Drumheller, Oregon
Bill Lamkin, Massachusetts
Brad Musick, New Mexico
Caroline Garber, Wisconsin
Chris Korleski, Ohio
Chris Nelson, Connecticut
Chris Sherry, New Jersey
Daniel Moring, Arizona
Drew Bergman, Ohio
Ed Jepsen, Wisconsin
Ed Kitchen, Ohio
Ethan Hinkley, Southern Ute
Gail Sandlin, Washington
Ira Domsky, Arizona
Joanne Morin, New Hampshire
Joe Sherrick, Pennsylvania
Juliane Schaible, Manitoba
Kevin MacDonald, Maine
Lany Weaver, New Mexico
Lee Alter, Arizona
Linda Murchison, California
Melissa Fazekas, Ohio
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Sincerely yours,



Gina McCarthy
Chairman of the Board of Directors
The Climate Registry

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ABBREVIATIONS AND ACRONYMS

Btu	British thermal unit(s)
CEMS	Continuous Emissions Monitoring System
CHP	combined heat and power
CH_4	methane
COP	coefficient of performance
CO_2	carbon dioxide
EU-ETS	European Union Emission Trading Scheme
GCV	gross caloric value
GHG	greenhouse gas
GWP	global warming potential
HFC	hydrofluorocarbon
HHV	higher heating value
IPCC	Intergovernmental Panel on Climate Change
kg	kilogram(s)
kWh	kilowatt-hour(s)
lb	pound
LHV	lower heating value
LPG	liquefied petroleum gas
MMBtu	one million British thermal units
MWh	megawatt-hour(s)
NOx	oxides of nitrogen
N_2O	nitrous oxide
PFC	perfluorocarbon
SF_6	sulfur hexafluoride
U.S. EPA	United States Environmental Protection Agency
WBCSD	World Business Council for Sustainable Development
WRI	World Resources Institute

Part I: Introduction

1 Background

In response to a scientific consensus linking greenhouse gas (GHG) emissions from human activities to global climate change,[1] governments, businesses, non-governmental organizations, and individuals increasingly agree that the risks to our physical environment and the global economy from climate change are both real and significant. The public debate now concerns the question of what can and should be done to reduce GHG emissions. Rather than waiting for final policy resolutions, many organizations are taking significant voluntary steps to reduce their own emissions. However, in order to develop and implement successful GHG emission reduction policies it is necessary to first have accurately quantified emissions data.

The growing interest in voluntary GHG reporting programs, and the need for high quality, consistent data to help manage business risk and inform regulatory programs, led to the creation of The Climate Registry (the Registry).

Through early regional efforts states, provinces, and tribal nations recognized that by pooling resources and establishing common measurement standards, they could reduce the costs of reporting while still supporting varied climate change policies and objectives.

In 2007, U.S. states, Canadian provinces, Mexican states, and Tribal Nations established a common GHG registry for North America: The Climate Registry. As members of the Registry, these jurisdictions agreed to:

- Establish and endorse a voluntary entity-wide GHG registry that collects GHG data consistently across jurisdictions
- Encourage entities in their jurisdictions to join the Registry
- Incorporate the Registry's GHG quantification methodologies into any future mandatory GHG programs or GHG emissions reduction programs in their jurisdictions.

The Registry is now the broadest based GHG initiative in North America; its membership covers 80 percent of the populations of the U.S. and Canada.

As of March 2008, the Registry's membership includes: thirty-nine U.S. states and the District of Columbia, seven Canadian provinces and territories, six Mexican states, and three tribal nations. The breadth of this collaboration enables organizations to streamline their GHG emission reporting across many jurisdictions.

For more information about the Registry, please refer to the Registry's website: www.theclimateregistry.org.

2 The Registry's Goals

The Registry seeks to achieve a number of goals through its voluntary reporting program. The Registry aims to:

- Develop and manage the premier voluntary GHG emissions registry in North America
- Utilize the technical and policy resources of the voluntary reporting program to support state, provincial, tribal, and federal mandatory GHG reporting programs
- Serve as a centralized repository of high quality, accurate, transparent, verified GHG emissions data for the public
- Engage stakeholders, including environmental groups, businesses, local governments, and other interested parties to

[1] See, for example, Intergovernmental Panel on Climate Change, *The Physical Science Basis*, Fourth Assessment, Working Group I Report, 2007, www.ipcc.ch/index.html.

assist in developing and improving the Registry's programs

- Promote lowest cost solutions whenever possible.

3 Voluntary Reporting Program Overview

Participation in the Registry's voluntary reporting program is voluntary. However, once a Reporter chooses to join the Registry, they must comply with the Registry's reporting requirements. All Reporters who choose to join the Registry must report:

- Their GHG emissions (CO_2, CH_4, N_2O, HFCs, PFCs, SF_6)
- From their operations in Canada, the U.S., and Mexico
- At the facility level

To ensure the accuracy and credibility of the reported emissions data, the Registry requires Reporters to use a third-party Verifier to assess their emission reports annually. Once verified, emission reports are shared with the public.

The Registry allows flexibility in reporting in the first two years a Reporter participates in the Registry.

The Registry's voluntary reporting program includes three tools that help Reporters calculate, report, and verify their emissions annually:

- **General Reporting Protocol (GRP):** Guidance to Reporters on how to calculate and report GHG emissions
- **General Verification Protocol (GVP):** Guidance to Verifiers on how to verify reported emissions
- **Climate Registry Information System (CRIS):** Online GHG software application through which Reporters calculate, report, and verify their annual GHG emissions

The purpose of this document, the GRP, is to ensure the complete, consistent, transparent, and accurate measurement and reporting of GHG emissions to the Registry's voluntary reporting program.

NOTE: Some states, provinces, and tribes have expressed interest in using a portion of the Registry's technical tools to support state, provincial, and regional mandatory GHG reporting programs. While the Registry plans to provide technical support and resources to mandatory programs, the requirements set forth in this document (GRP) pertain to participation exclusively in the Registry's voluntary reporting program.

4 Benefits of Reporting

Reporting is open to all legally constituted bodies (e.g., corporations, institutions, and organizations) recognized under U.S., Canadian, or Mexican law. In addition, cities, counties, and government agencies may also participate in the Registry.

The benefits of participating in the Registry are numerous and varied, and include:

- **Risk Management.** Voluntarily reporting GHG emissions may help organizations manage climate risk by documenting early actions to reduce GHG emissions. Such information has previously received recognition from mandatory GHG programs, and may be accepted by future state, provincial, federal or international regulatory GHG programs.
- **Competitive Advantage.** Accounting for emissions has helped many organizations gain better insights into the relationship between improving efficiency (reducing factor inputs and waste) and reducing emissions. As a result, organizations have redesigned business operations and processes, implemented technological

innovations, improved products and services, and ultimately built competitive advantage.

- **Readiness for Emissions Trading.** Utilizing credible, transparent calculation methodologies and reporting processes via the Registry will help to prepare organizations for participation in carbon trading markets. Many states are now developing emissions trading programs that may be based on the Registry's standards.

- **Readiness for a Carbon Constrained Future.** Identifying emissions sources to develop a GHG profile and management strategies may help organizations prepare for and respond to the potential impact of new regulations.

- **Recognition as an Environmental Leader.** Reporting GHG emissions to a voluntary registry provides organizations with a pathway to recognize, publicize, and promote their environmental stewardship.

- **Participation in Key Policy Discussions.** Reporters will be afforded the opportunity to participate in GHG policy discussions relevant to their industry. Furthermore, such discussions may help inform future decisions of policy makers throughout North America.

- **Access to Technical Resources.** Reporters will gain exclusive access to CRIS, the Registry's online calculation, reporting, and verification tool.

- **Comprehensive Reporting.** For those organizations that are required to report emissions to mandatory GHG reporting programs, but desire to assemble a more complete corporate GHG emissions footprint, the Registry provides a vehicle for comprehensive reporting.

- **Stakeholder Education** Assembling an annual GHG emissions inventory for the Registry can help inform management, customers, employees, and the public of a Reporter's carbon footprint.

5 Climate Registry Information System (CRIS)

CRIS is the Registry's online calculation, reporting and verification tool. CRIS will be used by:

- **Reporters:** To calculate and/or report annual GHG emissions

- **Verifiers:** To assess the accuracy of the reported data

- **The Public:** To access verified annual emission reports

- **The Registry:** To manage and administer its voluntary reporting program

CRIS is a user-friendly internet-based application that simplifies GHG emission calculations by automating many of the reporting requirements. CRIS tracks GHG data over time and produces useful emission reports for both Reporters and interested stakeholders.

Organizations that do not currently utilize Environmental Management Systems may use CRIS to track and manage their emissions. In early 2009, organizations that have comprehensive internal emissions tracking systems will be able to automatically transfer GHG data directly to CRIS, further streamlining the reporting process.

6 Reporter Services

The Registry is pleased to offer Reporters a variety of tools and services to help complete the Registry's annual emission reporting process. These services include:

- A toll-free hotline number to answer Reporter's technical reporting questions, including questions relating to the GRP, CRIS, and verification.

TECHNICAL SUPPORT HOTLINE:
866-523-0764

- An electronic newsletter with helpful tips, reporting reminders, and useful updates about climate change policy in North America.

- Regular orientation meetings and web-based trainings. These meetings and trainings will review the Registry's program, its tools (this Protocol, the *General Verification Protocol*, and CRIS), and help Reporters to successfully complete their annual emission reports.

- Conferences, meetings, and timely calls relating to GHG reporting and policy developments in North America.

7 Continuous Improvement

The Registry's protocols are intended to reflect the best practices associated with GHG accounting. As a result, the Registry is always interested in receiving stakeholder feedback from experts who feel that the Registry's protocols can be improved as new science or technical knowledge becomes available.

The Registry encourages all stakeholders to provide feedback on its protocols via the Registry's Protocol Feedback Form on its website: www.theclimateregistry.org.

The Registry will revise its protocols as necessary to ensure that they are both current and clear. Feedback will be reviewed and considered on a regular basis.

Part II: Determining What You Should Report

About Part II

All entities that report to The Climate Registry's voluntary reporting program should read Part II in its entirety. This section sets forth the general reporting requirements that pertain to all Reporters. Guidance for reporting GHG data that the Registry encourages you to report, but does not require you to report, will appear as *optional* in italics.

CHAPTER 1: INTRODUCTION

The General Reporting Protocol (GRP) is divided into several parts. These parts mirror the chronology of the reporting process:

- Determining what to report;
- Quantifying your emissions; and
- Reporting your emissions.

Figure 1.1 illustrates the reporting process, and explains where related guidance is contained in the GRP.

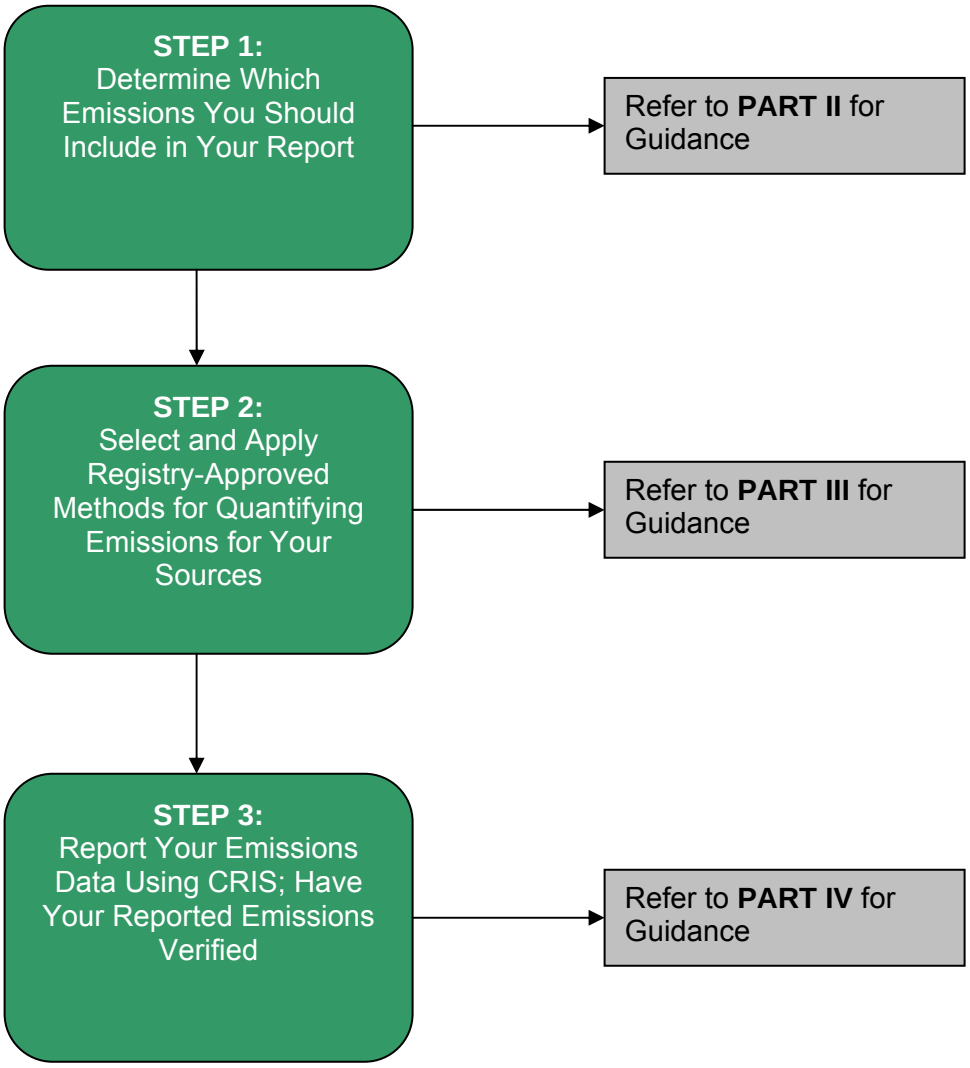
Part I provides an overview of the Registry's voluntary reporting program, history and benefits.

Part II provides guidance on determining the specific emissions sources you must report and how your emissions data should be categorized and consolidated for reporting purposes. The Registry requires that you read Part II in its entirety to ensure that you have identified all appropriate reporting requirements.

Part III provides the methodologies approved by the Registry for quantifying your emissions from various emission sources. Part III pertains to emissions sources likely to be pertinent to a wide variety of Reporters. You must read those chapters of Part III that provide quantification guidance for emission sources owned or operated by your organization, but you may skip over those chapters and/or sections that do not pertain to your organization's emission sources.

Part IV describes the process for reporting your emissions to the Registry once they have been quantified using the methodologies explained in Part III.

Figure 1.1 Basic Process for Reporting Emissions and Corresponding Protocol Guidance



1.1 GHG Accounting and Reporting Principles

The Registry has adopted five overarching accounting and reporting principles, which are intended to help you ensure that your GHG data represent a faithful, true, and fair account of your organization's GHG emissions. The principles are the same as those of the World Resource Institute / World Business Council for Sustainable Development (WRI/WBCSD) GHG Protocol *Corporate Accounting and Reporting Standard* (Revised Edition).

When you are deciding on data collection procedures or whether to report certain categories of emissions that are optional under the Registry's rules, you are encouraged to consult these accounting principles:

- **Relevance**: Ensure that your GHG inventory appropriately reflects your GHG emissions and serves the decision-making needs of users—both internal and external to your organization.

- **Completeness**: Account for and report all GHG emission sources and activities within the defined inventory boundary.

- **Consistency**: Use consistent methodologies to allow for meaningful comparisons of emissions over time. Clearly document any changes to the data, inventory boundary, methods, or any other relevant factors in the time series.

- **Transparency**: Address all relevant issues in a factual and coherent manner, based on a clear audit trail. Disclose any relevant assumptions and make appropriate references to the accounting and calculation methodologies and data sources used.

- **Accuracy**: Ensure that the quantification of GHG emissions is neither systematically overstating or understating your true emissions, and that uncertainties are reduced as much as practicable. Achieve sufficient accuracy enabling users of your data to be able to make decisions with reasonable assurance of the integrity of the reported information.

1.2 Origin of the Registry's GRP

The Registry's GRP embodies GHG accounting best practices. Thus, the Registry has drawn from the following existing GHG programs and protocols to create its GRP:

- The World Resources Institute and the World Business Council for Sustainable Development (WRI/WBCSD) GHG Protocol *Corporate Accounting and Reporting Standard* (Revised Edition)

- International Organization for Standardization (ISO) 14064-1, *Specification with guidance at the organization level for quantification and reporting of greenhouse gas emissions and removals*

- The California Climate Action Registry, *General Reporting Protocol* and various industry-specific protocols

- U.S. Environmental Protection Agency Climate Leaders *Greenhouse Gas Inventory Guidance*

The GRP will continue to be refined over time in order to add clarity and specificity and incorporate new developments in GHG accounting. The Registry is committed to continual improvement, and therefore welcomes feedback and suggestions from stakeholders. To submit feedback, please use the Protocol Feedback Form located on the Registry's website: www.theclimateregistry.org.

In addition, the Registry plans to develop sector-specific protocols to provide more detailed guidance for individual industry sectors. If you are interested in learning more about the current status of these sector-specific

protocols, please visit the Registry's website at www.theclimateregistry.org.

1.3 Reporting Requirements

Part II describes the Registry's requirements and options for accounting and categorizing the emissions you report to the Registry. Table 1.1 provides a concise summary of these requirements and options. Please note that users of the Climate Registry Information System (CRIS) will be prompted to report this information when generating their annual inventories and reports. CRIS also has the capability to calculate emissions in units of CO_2 equivalent and aggregate emissions data by facility, state, country and entity.

1.4 Annual Emissions Reporting

The Registry will begin accepting GHG data in July, 2008. The Registry requires you to report your emissions **annually** on a **calendar year basis**.

The Registry refers to a **reporting year** as the year in which the emissions occurred. The Registry refers to a **submitting year** as the year in which you submit your report to the Registry. For example, if you submit a report in 2010 for your 2009 emissions, your reporting year is 2009 and your submitting year is 2010. Because the Registry requires you to submit your report on emissions that occurred within a given year the following year, ***the reporting year always precedes the submitting year by one year.***

Reporters may join the Registry at any time. When Reporters join, they must commit to reporting their emissions for the following calendar year. This will allow Reporters to join the Registry in mid-year, even if they cannot report GHG emissions for that year (for example, because they do not have emissions data for the entire year).

You must report your emissions in CRIS each submitting year by June 30th, and successfully verify your emissions by December 15th of the same year.

Table 1.1 Key Registry Reporting Requirements and Options

Issue	Requirements	Options
Geographical Boundaries (Chapter 2)	Report all emissions in Canada, Mexico and the U.S.	• May report worldwide emissions • **Transitional Reporters only** may limit report to one or more states, provinces or territories
Greenhouse Gases (Chapter 3)	Report emissions of all six internationally recognized GHGs: CO_2, CH_4, N_2O, HFCs, PFCs, SF_6	• May report additional GHGs • **Transitional Reporters only** may report fewer GHGs, but must at a minimum report CO_2 emissions from stationary combustion
Organizational Boundaries (Chapter 4)	• Report on a control basis • Also report on an equity share basis *or* provide list of equity investments	• May report using operational or financial control • Encouraged to additionally report using equity share
Operational Boundaries (Chapter 5)	• Report all Scope 1 and Scope 2 emissions • Report direct emissions of CO_2 from biomass combustion separately	• May additionally report Scope 3 emissions
Facility-Level Reporting (Chapter 6)	Separately report emissions by facility	• May separately report emissions by unit for stationary combustion sources • May aggregate emissions from: a. Commercial buildings (e.g., office buildings) b. Mobile sources (fleets) c. Other special categories (e.g., oil and gas wells)
Base Year (Chapter 7)	• The first reporting year for which you submit a complete emissions report will be your base year. • Base year emissions must be updated to reflect subsequent organizational and methodology changes, ***if*** the impacts of such changes on total entity emissions cumulatively exceed five percent	• May update emissions for intervening years between the base year and the current reporting year • If you do not have the types of data needed to estimate base year emissions for an acquisition using a Registry-approved calculation method, you may use an alternative, simplified estimation method. (If you do not have ***any*** data with which to estimate base year emissions for an acquisition, you should not update your base year emissions to reflect the acquisition.)
Transitional Reporting (Chapter 8)	There is no requirement to report transitionally	• May report transitionally for your first two reporting years

Issue	Requirements	Options
Historical Reporting (Chapter 9)	There is no requirement to report historical emissions	• May report historical emissions data for any year preceding your first reporting year as long as: a) your data meets the minimum historical reporting requirements, and b) you provide consecutive years of historical data (no data gaps) • You may import historical data from other programs or registries to the Registry
Emissions Quantification Methods (Part III)	Use the Registry-approved methods described in Part III and Appendix E	• May use alternative, simplified estimation methods for small emission sources, but total emissions computed using simplified methods cannot exceed five percent of Reporter's total entity (Scope 1 and Scope 2) emissions
Performance Metrics (Chapter 17)	There is no requirement to report performance metrics	• May report performance metrics to show relevant, comparable data that enables tracking of emissions relative to indicators of performance (e.g., output). • May choose which performance metrics to report until sector-specific protocols provide further requirements and methodologies.

CHAPTER 2: GEOGRAPHIC BOUNDARIES

The first step in determining what to report to the Registry is to determine the geographic scope of your report. The Registry requires you to report your North American emissions (excluding Central America). You also have the option to report your worldwide emissions.

2.1 Required Geographic Boundaries

The Registry requires that at a minimum you must report your emission sources in all Canadian provinces and territories, Mexican states, and U.S. states and dependent areas.[2] You must also indicate if any of your facilities are located in lands designated to tribal nations that are members of the Registry.

2.2 *Optional Reporting*: Worldwide Emissions

The Registry encourages the most comprehensive reporting possible and therefore encourages you to report emissions associated with all of your organization's activities throughout the world. You may begin reporting your worldwide GHG emissions at any time.

There are several reasons why you may wish to complete a worldwide report of your organization's emissions:

- Your existing environmental management system already captures emissions at the global level;
- It will help you prepare for international regulatory programs (both Kyoto and post-Kyoto regimes);
- Corporate decision-making must look at the "big picture" when making efforts to improve efficiency and make cost-effective reductions in GHG emissions;
- It enhances your credibility to investors and customers; and
- Climate change is a global challenge requiring a global understanding of emission sources and profiles.

Reporting all of your international operations ensures the most comprehensive accounting of your entity-wide emissions and is strongly encouraged by the Registry. If you choose to report emissions beyond the three North American countries, you must report your GHG emissions from your entity's total global operations. You may not report your GHG emissions from a selected few countries.

A full accounting of all global sources helps to enhance the credibility of emission reports by demonstrating to data users that global Reporters have fully documented emissions in *all* regions and countries; not just in areas where emissions may be small or declining.

If you choose to report your worldwide emissions, they must be verified; however you are not required to use a Registry-approved Verifier to do so. As long as the Registry receives proof of verification of your worldwide emissions from a reputable Verifier, the Registry will accept your worldwide emissions.

If you do not have GHG emissions in North America, you may still join the Registry and report your worldwide emissions.

[2] U.S. dependent areas include American Samoa, Baker Island, Guam, Howland Island, Jarvis Island, Johnston Atoll, Kingman Reef, Midway Islands, Navassa Island, Northern Mariana Islands, Palmyra Atoll, Puerto Rico, Virgin Islands, and Wake Island.

CHAPTER 3: GASES TO BE REPORTED

3.1 Required Reporting of Six Internationally-Recognized Greenhouse Gases

You must report your emissions of all **six** internationally-recognized **greenhouse gases** regulated under the Kyoto Protocol:

- Carbon dioxide (CO_2);
- Methane (CH_4);
- Nitrous oxide (N_2O);
- Hydrofluorocarbons (HFCs);
- Perfluorocarbons (PFCs); and
- Sulfur hexafluoride (SF_6).

A complete list of the internationally-recognized GHGs, including individual HFCs and PFCs, is provided in Chapter 10. This list also includes the Global Warming Potential (GWP) of each GHG, which is used to calculate the carbon dioxide equivalence (CO_2e) of the individual gases.

You must account for emissions of each gas separately and report emissions in metric tons of each gas. CRIS will automatically convert your reported emissions to carbon dioxide equivalent. For more information on converting to units of carbon dioxide equivalent, refer to Appendix B.

3.2 *Optional Reporting:* Additional Greenhouse Gases

In addition to the six internationally-recognized GHGs, you have the option of reporting other GHGs.

The Registry has not developed approved calculation methods for GHGs beyond these internationally-recognized gases. In this case, as well as other cases in which the Registry does not establish guidelines for quantifying emissions of a particular gas from a particular emissions source, you should use existing industry best practice methods. Calculation methods should be based on internationally accepted best practices whenever possible, such as the Intergovernmental Panel on Climate Change's (IPCC) *Guidelines for National Greenhouse Gas Inventories* (2006). Please refer to Chapter 10 for more information.

CHAPTER 4: ORGANIZATIONAL BOUNDARIES

After determining the geographic boundaries of your entity and the gases that you will report, you must define your organizational boundaries according to the Registry's consolidation methods.

The Registry requires that you report entity-wide emissions for your organization. Your organization must be a legal entity, (e.g., a corporation, institution or organization) as defined by Canadian, Mexican or U.S. law. In addition, the Registry permits government agencies (city, county, state, provincial, etc.) to report as separate legal entities.

The Registry recognizes that your entity may be comprised of several legally defined entities, for example you may be a parent company of several subsidiaries. The Registry encourages you to report at the highest organizational level possible (such as the parent company level). Please refer to Section 4.4 of this chapter for more guidance on reporting for entities with multiple legal entities.

You must also determine which operations, facilities, and sources to include within your organizational boundary and how to account for the emissions from those sources. Business operations vary in their legal and organizational structures and include wholly owned operations, subsidiaries, and incorporated and non-incorporated joint ventures, among others. You must define an approach for setting your organizational boundaries to consistently define those businesses and operations that constitute your entity in order to account for and report your entity-wide GHG emissions.

If your entity wholly owns all its operations, its organizational boundary will be the same whichever consolidation approach is used; you must simply report all emissions from each of your wholly owned operations. For companies with jointly owned operations, however, the organizational boundary and the resulting emissions will differ depending on the consolidation approach used.

4.1 Two Approaches to Organizational Boundaries: Control and Equity Share

The Registry follows the WRI/WBSCD GHG Protocol *Corporate Accounting and Reporting Standard* (Revised Edition) in defining the boundaries and structure of the reporting entity. There are two general approaches to defining the organizational boundary, the "equity share" approach and the "control" approach, defined as follows:

- **Equity Share Approach:** If you choose the equity share approach, you must report all emissions sources that are wholly owned and partially owned according to your entity's equity share in each.

- **Control Approach**: If you choose the control approach, you must report 100 percent of the emissions from sources that are under your control, including both wholly owned and partially owned sources.

Control can be defined in either financial or operational terms. When using the control approach, you must choose either the operational control approach or financial control approach to consolidate your emissions, defined as follows:

- An entity has **operational control** over an operation if the entity or one of its subsidiaries has the full authority to introduce and implement its operating policies. The entity that holds the operating license for an operation typically has operational control.

- An entity has **financial control** over an operation if the entity has the ability to direct the financial policies of the operation with an interest in gaining economic benefits from its activities. Financial control usually exists

if the entity has the right to the majority of the benefits of the operation, however these rights are conveyed. An entity has financial control over an operation if the operation is considered a group company or subsidiary for the purpose of financial consolidation, i.e., if the operation is fully consolidated in financial accounts.

Each consolidation approach—equity share, operational control, and financial control—has advantages and disadvantages. The operational and financial control approaches may best facilitate performance tracking of GHG management policies and be most compatible with the majority of regulatory programs. However, these may not fully reflect the financial risks and opportunities associated with climate change, compromising financial risk management.

On the other hand, the equity share approach best facilitates financial risk management by reflecting the full financial risks and opportunities associated with climate change, but may be less effective at tracking the operational performance of GHG management policies.

Likewise, stakeholders may find each approach useful for different purposes.

Requirements for Setting Your Organizational Boundary

You have two options for defining your organizational boundary:

- ***Option 1:*** Report based on both the equity share approach and a control approach (either operational or financial control); or

- ***Option 2:*** Report based on a control approach (either operational or financial control)

    - Note on Option 2: To better promote GHG risk management and disclosure, if your entity is a publicly traded corporation, you must also submit a list of your entity's equity investments in your emission report. You are only required to report this information if it is already publicly available in your corporate financial reports (see Section 4.3 for more information).

The control and equity share approaches both yield a meaningful picture of entity-wide emissions. Therefore, the most comprehensive approach is to consolidate your emissions based on ***both*** the equity share and a control approach. The Registry strongly encourages you to report using both approaches (Option 1).

If you cannot report based on the equity share and control approach (Option 1)—for example, because you cannot obtain the necessary data from operations you do not control—you should report according to Option 2. Under Option 2, publicly traded companies must *identify* the entities in which they have an ownership interest and disclose the percent ownership for each entity, while Option 1 requires that they *report emissions* for those entities.

If you initially report on a control basis (Option 2) and later choose to additionally report on an equity share basis (Option 1), you will be required to report using Option 1 going forward. You must apply the same consolidation approach (or approaches) consistently throughout your organization.

Figure 4.1 is a decision tree that provides guidance on the reporting requirements for the equity share approach as well as for the control approaches. These requirements are described in the following sections.

4.2 Option 1: Reporting Based on Both Equity Share and Control

Equity Share Approach

Under the equity share approach, a company accounts for GHG emissions from operations according to its share of equity in the operation. The equity share reflects economic interest, which is the extent of rights a company has to

the risks and rewards flowing from an operation. Typically, the share of economic risks and rewards in an operation is aligned with the company's percentage ownership of that operation, and equity share will normally be the same as the ownership percentage. Where this is not the case, the economic substance of the relationship the company has with the operation always overrides the legal ownership form to ensure that equity share reflects the percentage of economic interest.

You should apply the equity share consolidation methodology to report emissions sources within each of your owned companies/subsidiaries, associated/affiliated companies, and joint ventures/partnerships/operations. You need not include emissions from fixed asset investments, where the parent company has neither significant influence nor financial control (see Table 4.3 for more information). Table 4.1 provides an illustration of prorating facility emissions using the equity share approach.

Table 4.1 Accounting for Equity Share Emissions

Percent of Ownership	Percent of Emissions Attributed to Entity
Wholly-owned	100%
90% owned, with control	90%
90% owned, without control	90%
10% owned, with control	10%
10% owned, without control	10%
Fixed asset investments	0%

Control Approach with Equity Share

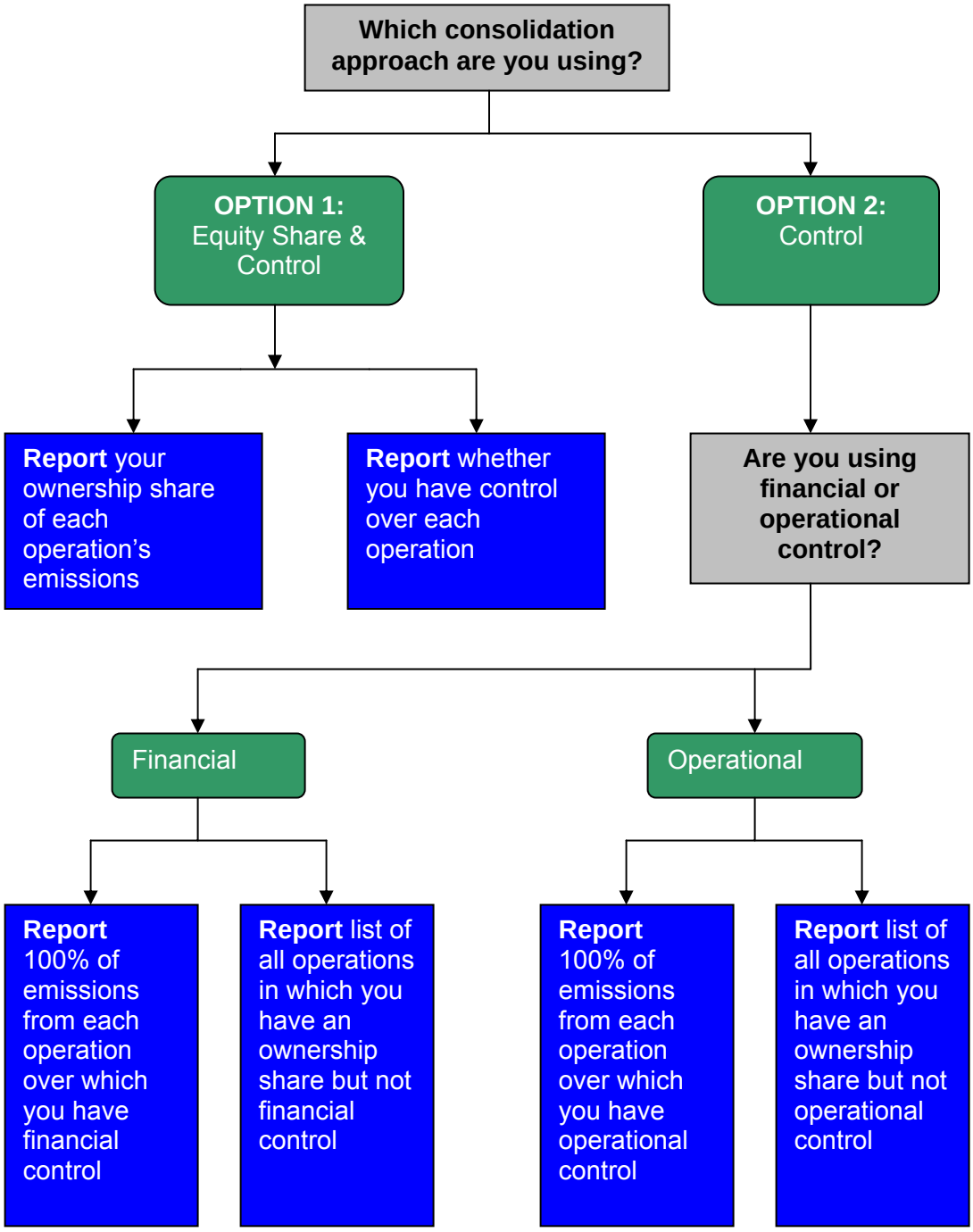
The Registry requires that when you report using the equity share approach, you also report your control-based emissions in order to provide the most comprehensive emission report. This requirement ensures that all Reporters report consistently using the same method (i.e., control) in order to enable comparability of emissions reports. Consistency across reports also avoids double counting when multiple emission reports are compared.

For Reporters choosing to report based on the equity share approach, additionally reporting based on a control approach is a simple exercise. Reporting based on equity share is similar to reporting based on the control approach, since control-based emissions totals can be easily derived from equity share emissions totals[3] and no additional emissions data needs to be collected.[4] To add the control approach, simply identify whether you have control over each of your facilities or operations, defined in terms of either operational or financial control. (A single control approach should be consistently applied throughout your organization).

CRIS, the Registry's online GHG calculation and reporting tool, will compute a subtotal of your entity-wide emissions based on both the equity share and the control approach.

[3] To obtain control-based emissions from equity share-based emissions, simply multiply each facility's total emissions by either 100% or 0% depending on whether you have control instead of multiplying each facility's emissions by your equity share.
[4] With the exception that you will have to collect data for leased assets if you choose the operational control approach.

Figure 4.1 Decision Tree for Determining Reporting Requirements for the Different Consolidation Methods



4.3 Option 2: Reporting Using the Control Consolidation

Control can be defined in either operational or financial terms. When using control to determine how to report GHG emissions associated with joint ventures and partnerships, you should first select between either the financial or operational approach and consistently apply the definitions below in determining how to report these emissions.

If you determine you have control over a particular joint venture or partnership, you should report 100 percent of the emissions from that entity, including all of its operations, facilities, and sources. If you determine you do not have control, you should not report any of the emissions associated with the entity.

In most cases, the organization that has financial control of an operation typically also has operational control.

However, in some sectors such as the oil and gas industry, complex joint ventures and ownership or operator structures can exist where financial and operational control are not vested with the same organization. In these cases, the choice to apply a financial or operational definition of control can be significant. In making this decision, you should take into account your individual situation and select a criterion that best reflects your actual level of control and the standard practice within your industry. Table 4.2 provides an illustration of the reporting responsibility under the two different control reporting options. One or more conditions from those listed below can be used to establish your choice of a control approach.

Financial Control Approach

Financial control is the ability to dictate or direct the financial policies of an operation or facility with the ability to gain the economic rewards from activities of the operation or the facility. One or more of the following conditions establishes financial control:

- Wholly owning an operation, facility, or source
- Considering an operation to be, for the purposes of financial accounting, a group company or subsidiary, and consolidating its financial accounts in your organization's financial statements
- Governing the financial policies of a joint venture under a statute, agreement or contract
- Retaining the rights to the majority of the economic benefits and/or financial risks from an operation or facility that is part of a joint venture or partnership (incorporated or unincorporated), however these rights are conveyed. These rights may be evident through the traditional conveyance of equity interest or working/participating interest or through nontraditional arrangements. The latter could include your organization casting the majority of votes at a meeting of the board of directors or having the right to appoint/remove a majority of the members of the board in the case of an incorporated joint venture.

Operational Control Approach

Operational control is the authority to develop and carry out the operating or health, safety and environmental (HSE) policies of an operation or at a facility. One or more of the following conditions establishes operational control:

- Wholly owning an operation, facility, or source
- Having the full authority to introduce and implement operational and health, safety and environmental policies (including both GHG- and non-GHG related policies). In many instances, the authority to introduce and implement operational and health, safety, and environmental (HSE) policies is explicitly conveyed in the contractual or

legal structure of the partnership or joint venture. In most cases, holding an operator's license is an indication of your organization's authority to implement operational and HSE policies. However, this may not always be so. If your organization holds an operating license and you believe you do not have operational control, you will need to explicitly demonstrate that your authority to introduce operational and HSE policies is significantly limited or vested with a separate entity.

It should be noted that your organization need not be able to control all aspects of operations within a joint venture to have operational control. For instance, an entity with operational control may not have the authority to make decisions on major capital investments without the approval of other parties in a venture.

Joint Control

In the case of joint control, two entities each have 50 percent equity ownership and no stipulations exist to demonstrate that either organization has control of the financial or operating policies of the venture. If you have joint financial control over a facility and are using financial control as your control criterion, you should report your emissions based on the equity share approach, that is, based on your economic interest in and/or benefit derived from the operation or activities at a facility. In this case, you would report 50 percent of the controlled entity's emissions. If you are using operational control as your control criterion, it may be that neither partner has operational control; a separate entity conducting the operation may implement its own operating policies. In such a case, neither partner would report the operation's emissions.

Providing a List of Equity Investments

If your entity is a publicly traded company and you choose one of the control approaches to consolidate your emissions (Option 2), you must also provide a list of entities in which your entity has an ownership interest but does not have control and the percent ownership interest you hold for each entity or operation. By providing this additional information, you will enhance disclosure of your entity's emissions profile by shedding light on operations that you would otherwise omit from a control-based emission report.

The intent of this requirement is to include supplementary financial information that is already publicly available elsewhere, such as in corporate financial reports.

You must submit the following information to the Registry to describe your equity investments:

- A list of all entities and jointly owned operations in which your entity has an equity share but does not have control, including subsidiaries, associated/ affiliated entities, and joint ventures/partnerships/ operations
- Your entity's percent ownership interest held for each entity or operation

In addition, you are encouraged to provide the following *optional* information:

- The identity of the legal entity that has control over each listed entity or operation
- A brief description of the emitting activities and emissions profile for each listed entity or operation

You must include all applicable entities and operations within the same geographic boundary used to define your consolidated emissions, though you are encouraged to include all entities and operations from your entire global operations. Because investment portfolios change over time, you should include those investments held by your entity on December 31 of the reporting year.

You may opt out of the equity share investment reporting requirement if the required data is not publicly available elsewhere and you wish to

keep this information confidential (as may be the case for privately held companies).

See Example 4.8 (Table 4.4) in this chapter for an example of information provided by an entity under this requirement.

Table 4.2 Reporting Based on Financial Versus Operational Control

Level of Control of Facility	Percent of Emissions to Report Under Financial Control	Percent of Emissions to Report Under Operational Control
Wholly owned	100%	100%
Partially owned with financial and operational control	100%	100%
Partially owned with financial control; no operational control	100%	0%
Partially owned with operational control; no financial control	0%	100%
Joint financial control with operational control	Based on equity share	100%
Joint financial control; no operational control	Based on equity share	0%
Subsidiary with operational control	100%	100%
Subsidiary; no operational control	100%	0%
Associated entity (not consolidated in financial accounts) with operational control	0%	100%
Associated entity (not consolidated in financial accounts); no operational control	0%	0%
Fixed asset investments	0%	0%
Not owned but have a capital or financial lease	100%	100%
Not owned but have an operating lease	0%	100%

Table 4.3 Reporting Based on Equity Share versus Financial Control

Accounting Category	Financial Accounting Definition	GHG Consolidation Approach	
		Equity Share	Financial Control
Group companies/ subsidiaries	The parent company has the ability to direct the financial and operating policies of the company with a view to gaining economic benefits from its activities. Normally, this category also includes incorporated and non-incorporated joint ventures and partnerships over which the parent company has financial control. Group companies/subsidiaries are fully consolidated, which implies that 100 percent of the subsidiary's income, expenses, assets, and liabilities are taken into the parent company's profit and loss account and balance sheet, respectively. Where the parent's interest does not equal 100 percent, the consolidated profit and loss account and balance sheet shows a deduction for the profits and net assets belonging to minority owners.	Equity share of GHG emissions	100% of GHG emissions
Associated/ affiliated companies	The parent company has significant influence over the operating and financial policies of the company, but does not have financial control. Normally, this category also includes incorporated and non-incorporated joint ventures and partnerships over which the parent company has significant influence, but not financial control. Financial accounting applies the equity share method to associated/ affiliated companies, which recognizes the parent company's share of the associate's profits and net assets.	Equity share of GHG emissions	0% of GHG emissions
Non-incorporated joint ventures/ partnerships/ operations where partners have joint financial control	Joint ventures/partnerships/operations are proportionally consolidated, i.e., each partner accounts for their proportionate interest of the joint venture's income, expenses, assets, and liabilities.	Equity share of GHG emissions	Equity share of GHG emissions
Fixed asset investments	The parent company has neither significant influence nor financial control. This category also includes incorporated and non-incorporated joint ventures and partnerships over which the parent company has neither significant influence nor financial control. Financial accounting applies the cost/dividend method to fixed asset investments. This implies that only dividends received are recognized as income and the investment is carried at cost.	0% of GHG emissions	0% of GHG emissions
Franchises	Franchises are separate legal entities. In most cases, the franchiser will not have equity rights or control over the franchise. Therefore, franchises should not be included in consolidation of GHG emissions data. However, if the franchiser does have equity rights or operational/financial control, then the same rules for consolidation under the equity or control approaches apply.	Equity share of GHG emissions	100% of GHG emissions

4.4 Corporate Reporting: Parent Companies and Subsidiaries

Parent companies or entities that participate in the Registry are required to report on behalf of all subsidiaries and group operations. You should consolidate the reported emissions data in a single report at the highest level possible.

While entities are strongly encouraged to report at the highest organizational level (such as the parent company level), subsidiaries *whose parent companies do not participate in the Registry* may report to the Registry on their own behalf. In other words, a subsidiary may report to the Registry as long as its parent company does *not* report to the Registry. However, should the parent company choose to begin reporting at a later date, the subsidiary may no longer report independently to the Registry. Instead, the subsidiary's GHG emissions will be subsumed into the parent company's annual emission report.

The requirement that subsidiaries cease reporting once parent companies begin to report is necessary to ensure that emissions are not double counted. A subsidiary with a non-participating parent company that chooses to report to the Registry must disclose its parent company and submit a corporate organizational chart that clearly defines the Reporter's relationship to its parent(s) and other subsidiaries.

If a corporate organizational chart is not already publicly available (as may be the case for privately held companies) subsidiaries may opt out of providing an organizational chart.

4.5 Government Agency Reporting

Similar to corporate reporting, the Registry strongly encourages government entities (local, county, state, provincial, etc.) to report at the highest organizational level possible (City, Province, or State). Individual government agencies and departments (municipal operations, state agencies, etc.) may report as their own entity, but as soon as the entire municipal, township, county, state or provincial government unit of which they are a part begins to report, all related agencies or departments within that government's jurisdiction and chosen consolidation methodology must be included in its emission report to the Registry.

For example, in the case of a municipal government, individual municipal agencies such as the municipal power provider or the municipal landfill may choose to report to the Registry as individual entities. However, if at a later date, the municipality as a whole begins to report to the Registry, it must assume responsibility for all the operations, agencies, and buildings within its jurisdiction, and the power provider and landfill must therefore consolidate their reports within that of the entire municipality. Other agencies that should be accounted for in a complete municipal government report might include:

- Municipal water and power utilities
- Waste water treatment facilities
- Airports or seaports
- Fire departments
- Fleets such as garbage trucks, transit buses, subway systems, or utility vehicles
- Office buildings such as city hall, schools, and public health facilities
- City parks operated by the municipality

Similarly, should a county government choose to report to the Registry, all of the individual departments and agencies (e.g., county roads departments) within the county government must be included in the county's report.

Should a state or provincial government choose to report to the Registry, all of the individual state/provincial agencies which report to that state/provincial government must be included in the state's report. However, local governments located within the state/province (e.g.,

municipalities, townships and counties) may continue to report separately from the state/province or county, as municipal government emission will not be rolled up into county and state/province emission reports.

Local Government Operations Protocol

The California Climate Action Registry, the Climate Registry, and the International Council for Local Environmental Initiatives (ICLEI) are currently collaborating to develop a Local Government Operations Protocol, which is scheduled to be completed by 2009. At that time, the Registry will provide more organizational and technical guidance to assist local government entities with their emission reporting, specifically with respect to organizational boundaries. Until this time, the Registry requires local government entities (cities, counties, state and provincial governments) to include their buildings and vehicle fleets in their organizational boundaries, at a minimum.

4.6 Leased Facilities/Vehicles and Landlord/Tenant Arrangements

You should account for and report emissions from leased facilities and vehicles according to the type of lease associated with the facility or source and the organizational boundary approach selected. This guidance applies to Reporters that rent office space (i.e., tenants), vehicles, and other facilities or sources (e.g., industrial equipment).

There are two types of leases:

Finance or capital lease. This type of lease enables the lessee to operate an asset and also gives the lessee all the risks and rewards of owning the asset. Assets leased under a capital or finance lease are considered wholly owned assets in financial accounting and are recorded as such on the balance sheet. If you have an asset under a finance or capital lease, the Registry considers this asset to be wholly owned by you.

Operating lease. This type of lease enables the lessee to operate an asset, like a building or vehicle, but does not give the lessee any of the risks or rewards of owning the asset. Any lease that is not a finance or capital lease is an operating lease. In most cases, operating leases cover rented office space and leased vehicles, whereas finance or capital leases are for large industrial equipment. If you have an asset under an operational lease, the Registry requires this asset be reported only if you are using the operational control approach.

Reporting Emissions from Leased Assets

You are required to account for and report emissions from a facility or source under a finance or capital lease as if it is an asset wholly owned and controlled by your entity or organization, regardless of the organizational boundary approach selected. Therefore, you should account for and report these emissions under the financial control, operational control, and equity share approaches.

With respect to facilities or sources under an operating lease (e.g., most office space rentals and vehicle leases), the organizational boundary approach selected (operational control, financial control, or equity share) will determine whether reporting the asset's associated emissions is required or optional.

When consolidating using the operational control approach, you are required to report emissions from assets for which you have an operating lease and these will be counted as Scope 1 or Scope 2 emissions. This follows from the fact that a lessee has operational control over an asset it leases under an operating lease. For example, the renter of office space has control over the office's lights, as well as the various office equipment (computers, copy machines, etc.) located in the office. Under the operational control approach, it is the lessee's control of these emission sources that makes the lessee responsible for reporting the emissions from these sources.

If you use either the equity share approach or the financial control approach, then reporting the emissions from a facility or source with an operating lease is optional. If you choose to report these emissions, they are counted as Scope 3 emissions (see the following chapter for a detailed discussion of the various scopes, including Scope 3).

Lessees of office space should report emissions from electricity use, heating and cooling of the space whenever possible. If you cannot report emissions from heating and cooling because it is not possible to obtain the necessary data, then you are only required to report emissions from electricity use.

Figure 4.2 is a decision tree designed to help *lessees* determine how to report emissions from leased assets.

Reporting Requirements for Lessors

Figure 4.3 is a decision tree providing guidance in determining reporting requirements for *lessors*. In general, the requirements for a lessor are the opposite of the lessee's reporting requirements. For example, the lessor is *not* required to report emissions for assets leased under a capital or finance lease regardless of the consolidation method applied by the lessor (although the lessor may *opt* to report these emissions as Scope 3 emissions). Similarly, the lessor is *not* required to report emissions for assets leased under an operating lease *if* the lessor is using the operational control consolidation method. However, the lessor *must* report such emissions *if* it is using the equity share or financial control approach.

4.7 Examples of Control versus Equity Share Reporting

Examples 4.1 through 4.8 are provided to assist you in determining which consolidation approach to use and how to implement each approach. You must apply your chosen consolidation approach consistently for every facility, source, and operation throughout your organization.

Figure 4.2 Decision Tree for Determining the Lessee's Reporting Requirements for a Leased Asset

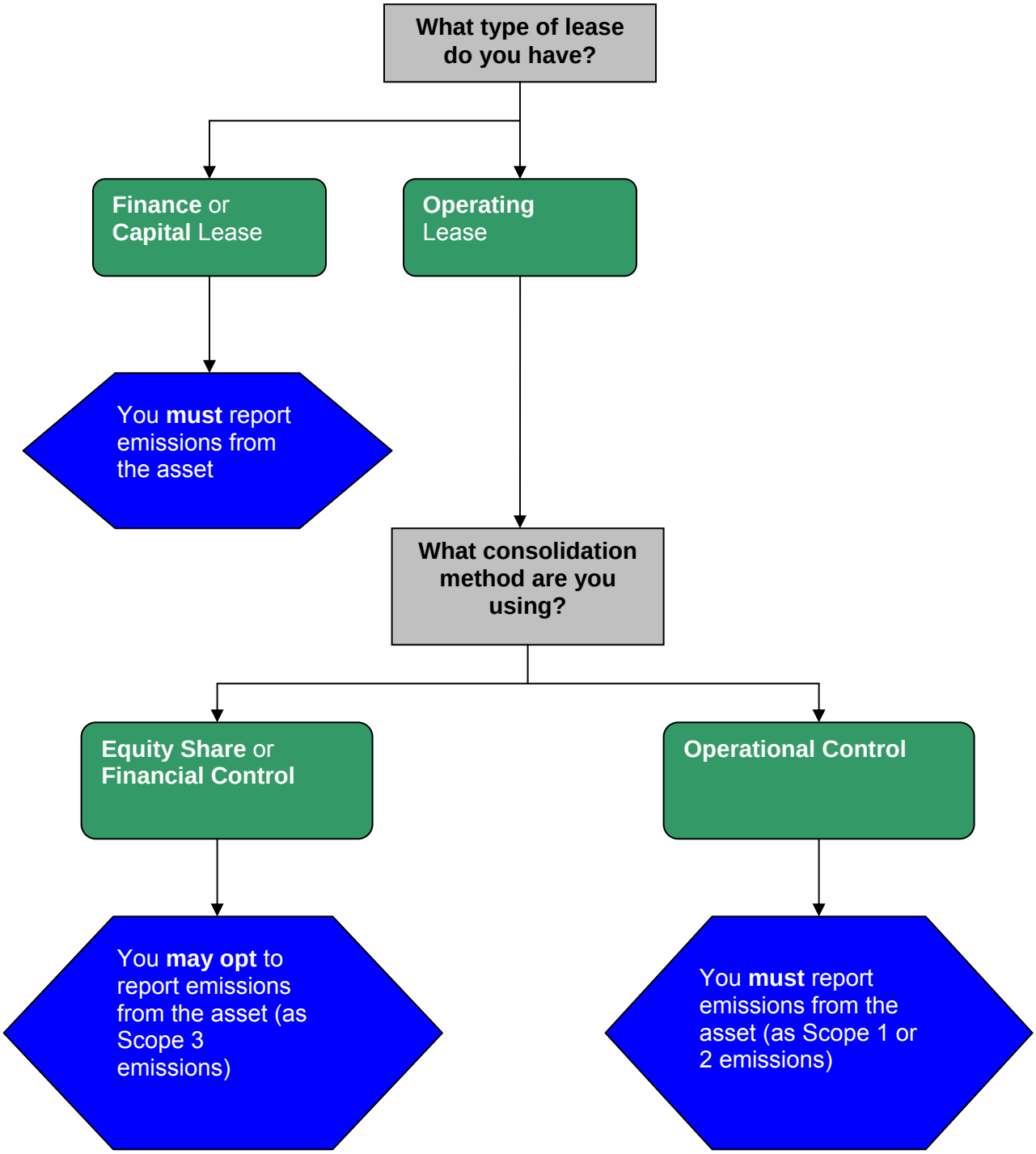
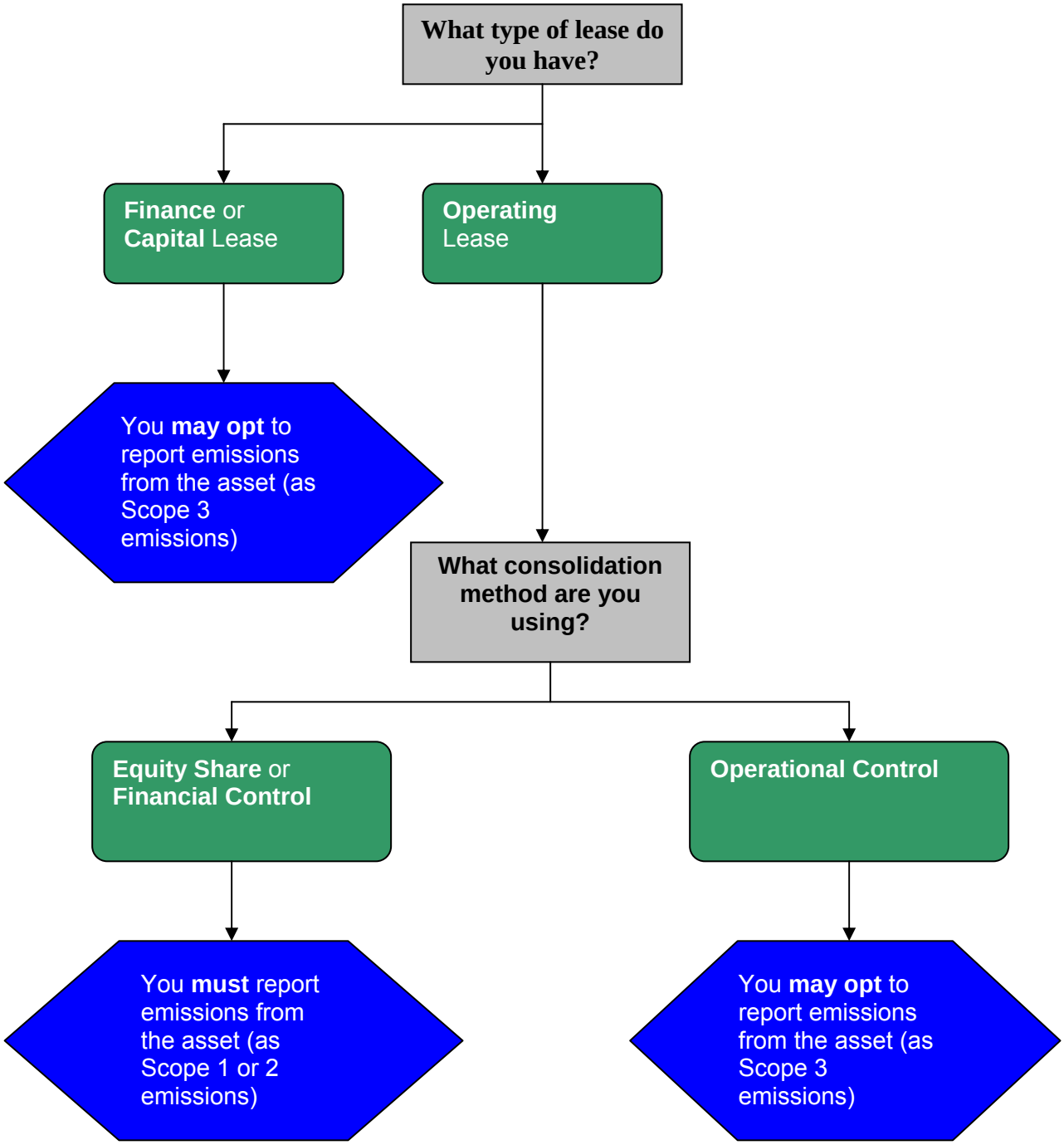


Figure 4.3 Decision Tree for Determining the Lessor's Reporting Requirements for a Leased Asset



Example 4.1 Responsibility for Reporting Emissions Under an Operating Lease

A real estate investment trust (REIT) owns a 10-story office building, and leases the 10th floor of the building to an environmental law firm under an operating lease. The law firm plans to report its emissions to the Registry using the operational control approach. In this situation, the law firm must include all of the direct and indirect emissions resulting from its use of the 10th floor space, because it has effective operational control over the space and all of the emissions sources within the space, and it is reporting on an operational control basis. However, if the law firm is unable to obtain data on the office's direct (Scope 1) emissions from the REIT (e.g., HFC emissions from the HVAC system, or emissions from a natural gas furnace), it may limit its report to the indirect (Scope 2) emissions associated with its electricity consumption.

However, if the law firm were reporting on an equity share or a financial control basis, it would *not* be required to report emissions associated with the office. This follows from the fact that the law firm does not *own* (or have a financial interest in) the office building, and under the equity share and financial control approaches *ownership* (or financial interest) is the criterion that determines reporting requirements. Although the law firm is not *required* to report emissions associated with the office when it uses the equity share or financial control approaches, it may *opt* to report these emissions. If it chooses to do so it must report the emissions as Scope 3 emissions (which is the category used to report optional indirect emissions from all sources).

Example 4.2 Reporting Responsibilities from the Lessor's Perspective

Let us now suppose that the REIT (the building owner) in the prior example also plans to report to the Registry. If the REIT reports using either the equity share or financial control approaches, it is required to report the building's emissions as Scope 1 (e.g., HFC emissions) and Scope 2 (electricity-related emissions). If, however, the REIT uses the operational control method to define its organizational boundaries, it would not be required to report the building's emissions, since effective control over the buildings emissions passes to the tenant under an operating lease. The REIT could still *opt* to report emissions from the building as Scope 3 emissions.

Example 4.3 Reporting Responsibilities Under a Capital or Finance Lease

With the passage of time, the environmental law firm (the tenant) in the prior examples expands its business until it occupies floors 2 through 10 of the 10-story office building; the first floor remains occupied by a number of retailers (e.g., a lunch café, a convenience store, a news stand, etc.). At this point the law firm signs a finance lease with the REIT for the entire building, thus giving the law firm not only operational control over floors 2 through 10, but the financial rights (and risks) associated with the rental space on the first floor. Under a finance lease (also known as a capital lease), the law firm is required to report all of the emissions associated with floors 2 through 10 of the building *regardless* of the consolidation method the firm uses (because the law firm both controls and effectively owns these floors under the terms of a finance lease). Furthermore, if the law firm is using the equity share or financial control approach, it must also report all emissions associated with the first floor. This follows from the fact that ownership or financial interest is the criterion used to determine reporting requirements under the equity share and financial control approaches, and the law firm holds the financial interest in the first floor space under the terms of a finance lease. However, the law firm would not be required to report emissions associated with the first floor if it reports using the operational control approach, because the first floor tenants, not the law firm, effectively control the first floor space. The law firm could, however, opt to report the first floor emissions as Scope 3 emissions.

Once the finance lease is signed, effective ownership of the building passes from the REIT to the law firm; hence the REIT would no longer be required to report emissions associated with the building. The REIT could, however, choose to report the buildings emissions as Scope 3 emissions.

Examples 4.1 through 4.3 Continued: Leased Office Space

The following tables summarize reporting responsibilities for the environmental law firm and the REIT under the various consolidation approaches and types of leases considered in the above examples.

Reporting Responsibilities of the Environmental Law Firm (Lessee)

Consolidation Approach	Type of Lease	
	Finance or Capital Lease	Operating Lease
Equity Share or Financial Control	**Must** report emissions from leased asset	**May opt** to report emissions from leased asset (as Scope 3)
Operational Control	**Must** report emissions from leased asset	**Must** report emissions from leased asset

Reporting Responsibilities of the REIT (Lessor)

Consolidation Approach	Type of Lease	
	Finance or Capital Lease	Operating Lease
Equity Share or Financial Control	**May opt** to report emissions from leased asset (as Scope 3)	**Must** report emissions from leased asset
Operational Control	**May opt** to report emissions from leased asset (as Scope 3)	**May opt** to report emissions from leased asset (as Scope 3)

It is possible that both the law firm and the REIT may report the same emissions in the same category. For example, if (1) an operating lease is signed, (2) the law firm reports on an operational control basis, and (3) the REIT reports on equity share basis, both the law firm and the REIT are required to report the electricity-related emissions from the leased space in the indirect (Scope 2) category. Other combinations of lease type and consolidation approach also exist which could require both the law firm and the REIT to report the same emissions in the same Scope category.

However, as long as the lessor and the lessee use the *same* consolidation approach, the same emissions will *not* be reported in the same Scope category. Therefore, in order to avoid double counting, users of the Registry's data should not add emissions across Reporters *unless* the summation includes only Reporters using the *same* consolidation method. For example, Scope 1 emissions from a Reporter(s) using the equity share approach should not be mixed with, or added to Scope 1 emissions from a Reporter(s) using the operational control approach. Similarly, emissions should not be mixed or summed across different scopes; e.g., Scope 3 emissions from one Reporter should never be added to Scope 1 or Scope 2 emissions from another Reporter. The Registry does not mix or add emissions across different consolidation methods or Scopes.

Example 4.4 Companies with Ownership Divided 60 percent-40 percent

Company A has 60 percent ownership and full control of Facility #1 under both the financial and operational control criteria. Company B has 40 percent ownership of the facility and does not have control.

Under either criterion for control, Company A would report 100 percent of GHG emissions for Facility #1 while Company B would report none. Under the equity share approach, Companies A and B would report 60 percent and 40 percent of GHG emissions, respectively, based on their share of ownership and voting interest.

Reporter	Ownership of Facility #1	Reporting Under Control Approaches		Reporting Under Equity Share Approach
		Financial Control	Operating Control	
Company A	60% ownership and voting interest	100%	100%	60%
Company B	40% ownership and voting interest	0%	0%	40%

Example 4.5 Companies with Ownership Divided 60 percent-40 percent and Voting Interests Divided 45 percent-55 percent

Company A has 60 percent ownership of Facility #1 and a 45 percent voting interest. Company B has 40 percent ownership of the facility and a 55 percent voting interest. Company B is also explicitly named as the operator and has the authority to implement its operational and HSE policies. Company B has control (according to both the financial and operational criteria).

Under the control approach (either financial or operational), Company B would report 100 percent of GHG emissions and Company A would report none, because Company B has a majority voting interest and operational control. Under equity share, Company A would report 60 percent of GHG emissions and Company B would report 40 percent, based on ownership share.

Reporter	Ownership of Facility #1	Reporting Under Control Approaches		Reporting Under Equity Share Approach
		Financial Control	Operating Control	
Company A	60% ownership and 45% voting interest	0%	0%	60%
Company B	40% ownership and 55% voting interest	100%	100%	40%

Example 4.6 Two Companies with 50 Percent Ownership Each

Company A and Company B each has 50 percent ownership of Facility #1. Company B has the authority to implement its operational and HSE policies, but all significant capital decisions require approval of both Company A and Company B since they have joint financial control. Each reports 50 percent of GHG emissions under the financial control and equity share approaches. Under the operational control approach, Company B reports 100 percent of the facility's emissions while Company A reports none.

Reporter	Ownership of Facility #1	Reporting Under Control Approaches		Reporting Under Equity Share Approach
		Financial Control	Operating Control	
Company A	50% ownership and voting interest	50%	0%	50%
Company B	50% ownership and voting interest	50%	100%	50%

Example 4.7 Three Companies with Ownership Divided 55 Percent-30 Percent-15 Percent

Company A has 55 percent ownership of Facility #1, Company B has 30 percent ownership of the facility, and Company C has 15 percent ownership. The majority owner has the authority to implement its operational and HSE policies.

Under either control approach, Company A would report 100 percent of GHG emissions because it holds financial and operational control of the facility, and Companies B and C would report no emissions. Under the equity share approach, each company would report according to its equity share of ownership and voting interests.

Reporter	Ownership of Facility #1	Reporting Under Control Approaches		Reporting Under Equity Share Approach
		Financial Control	Operating Control	
Company A	55% ownership and voting interest	100%	100%	55%
Company B	30% ownership and voting interest	0%	0%	30%
Company C	15% ownership and voting interest	0%	0%	15%

Example 4.8 Alpha, Inc.

Alpha, Inc. has five wholly owned or joint operations: Beta, Gamma, Delta, Pi, and Omega. The following table outlines the organizational structure of Alpha, Inc. and the percent of emissions from each of its sub-entities that it includes in the parent company's entity-wide emissions total using equity share, operational control, and financial control.

Wholly owned and joint operations of Alpha, Inc.	Legal structure and partners	Economic interest held by Alpha, Inc.	Control of operating policies	Treatment in Alpha, Inc.'s financial accounts	Percent of GHG emissions accounted for and reported by Alpha, Inc. under each consolidation approach		
					Equity Share	Operational Control	Financial Control
Beta	Incorporated company	100%	Alpha	Wholly owned subsidiary	100%	100%	100%
Gamma	Incorporated company	40%	Alpha	Subsidiary	40%	100%	100%
Delta	Non-incorporated joint venture; partners have joint financial control; other partner is Epsilon	50% by Beta	Epsilon	via Beta	50% (50% x 100%)	0%	50%
Pi	Subsidiary of Gamma	75% by Gamma	Gamma	via Gamma	30% (75% x 40%)	100%	100%
Omega	Incorporated joint venture; other partner is Lambda	56%	Lambda	Subsidiary	56%	0%	100%

The Registry also requires Alpha, Inc. to provide additional information about its entity-wide emissions profile, depending on the consolidation approach it chooses. The following table illustrates the information Alpha, Inc. must provide depending on whether it uses operational control, financial control, or equity share.

Consolidation Approach Used By Alpha, Inc.	Emissions Included in Alpha, Inc.'s Entity-Wide Total	Additional Information Provided
Operational control	100% of the emissions from Beta, Gamma, and Pi	The company includes additional information about Delta and Omega because they are entities in which Alpha, Inc. has an equity share but does not have control and are therefore not included in its entity-wide total (see the table below for the information Alpha, Inc. provides for Delta and Omega).
Financial control	100% of the emissions from Beta, Gamma, Pi, and Omega, and 50% of the emissions from Delta	The company does not need to include any additional information on equity investments, since the financial control approach captures all of its sub-entities and includes them all in its entity-wide emissions total.
Equity share	100% of the emissions from Beta; 40% of the emissions from Gamma; 50% of the emissions from Delta; 30% of the emissions from Pi; and 56% of the emissions from Omega	The company notes that it has operational control over Beta, Gamma, and Pi and that it does not have operational control over Delta and Omega. With this information, the Registry publishes supplementary information on Alpha, Inc.'s control-based profile in its emission report.

Example 4.8 Alpha, Inc. (Continued)

If Alpha Inc. reports based on a control approach, it must provide additional information about entities and operations in which it has an equity share but does not have control. In this case, Alpha must only provide this information if it reports based on operational control, because the operational control approach excludes some of its business activities, namely Delta and Omega. Therefore, provides the following information in addition to its total emissions based on operational control.

Table 4.4 Required and Optional Documentation of Equity Share Investments

Entity/ Operation *(Required)*	Description *(Required)*	Equity Share *(Required)*	Legal Entity with Operational Control *(Optional)*	Description of Emitting Activities *(Optional)*
Delta	Non-Incorporated Joint Venture	50%	Epsilon	Delta is an electric generating facility containing two coal-fired units with a total capacity of 1,600 MW
Omega	Incorporated Joint Venture	56%	Lambda	Omega is a cement manufacturing company with five U.S. facilities and significant emissions of carbon dioxide from stationary combustion and clinker calcination

CHAPTER 5: OPERATIONAL BOUNDARIES

5.1 Required Emission Reporting: Scope 1 and Scope 2

To separately account for direct and indirect emissions, to improve transparency, and to provide utility for different types of organizations and different types of climate policies and business goals, the Registry follows the WRI/WBCSD GHG Protocol *Corporate Standard* in categorizing direct and indirect emissions into "scopes" as follows:

- **Scope 1:** All direct GHG emissions (with the exception of direct CO_2 emissions from biomass combustion)
- **Scope 2:** Indirect GHG emissions associated with the consumption of purchased or acquired electricity, steam, heating, or cooling
- **Scope 3:** All other indirect emissions not covered in Scope 2, such as upstream and downstream emissions, emissions resulting from the extraction and production of purchased materials and fuels, transport-related activities in vehicles not owned or controlled by the reporting entity (e.g., employee commuting and business travel), use of sold products and services, outsourced activities, recycling of used products, waste disposal, etc.

Together the three scopes provide a comprehensive accounting framework for managing and reducing direct and indirect emissions. Figure 5.1 provides an overview of the relationship between the scopes and the activities that generate direct and indirect emissions along an entity's value chain.

For effective and innovative GHG management, setting operational boundaries that are comprehensive with respect to direct and indirect emissions will help better manage the full spectrum of GHG risks and opportunities that exist along your value chain.

The Registry requires that you report both Scope 1 and Scope 2 emissions data. Reporting of Scope 3 emissions is *optional*. Direct CO_2 emissions from the combustion of biomass shall not be included in Scope 1 and shall instead be reported separately from the scopes.

5.2 Direct Emissions: Scope 1

Direct GHG emissions are emissions from sources within the entity's organizational boundaries (see previous chapter) that the reporting entity owns or controls. These emissions must be further subdivided into emissions from four separate types of sources:

- *Stationary combustion* to produce electricity, steam, heat or power using equipment in a fixed location;
- *Mobile combustion* of fuels in transportation sources (e.g., cars, trucks, marine vessels and planes) and emissions from non-road equipment such as in construction, agriculture and forestry;
- *Physical and chemical processes* other than fuel combustion (e.g., for the manufacturing of cement, aluminum, adipic acid, ammonia, etc.); and
- *Fugitive sources*, i.e., unintentional releases from the production, processing, transmission, storage, and use of fuels and other substances, that do not pass through a stack, chimney, vent, exhaust pipe or other functionally-equivalent opening (such as releases of sulfur hexafluoride from electrical equipment; hydrofluorocarbon releases during the use of refrigeration and air conditioning equipment; and methane leakage from natural gas transport).

5.3 Indirect Emissions: Scope 2

Indirect GHG emissions are emissions that are a consequence of activities that take place within the organizational boundaries of the reporting entity, but that occur at sources owned or controlled by another entity. For example, emissions that occur at a utility's power plant as a result of electricity used by a manufacturing company represent the manufacturer's indirect emissions.

Scope 2 is a special category of indirect emissions and refers only to indirect emissions associated with the consumption of purchased or acquired electricity, steam, heating, or cooling. It typically represents one of the largest sources of emissions for an entity; therefore, it represents a significant opportunity for GHG management and reduction. Reporting of Scope 2 emissions enables transparent accounting and reporting of emissions and reductions associated with such opportunities. Also, in comparison to other indirect emissions, data for Scope 2 emissions can be gathered in a relatively consistent and verifiable manner.

The Registry recognizes that the indirect emissions reported by one entity may also be reported as direct emissions by another entity. For example, the indirect emissions from electricity use reported by a manufacturing entity may also be reported as direct emissions by the generating entity that produced the electricity. This dual reporting does not constitute double counting of emissions as the entities report the emissions associated with the electricity production and use in different scopes (Scope 1 for the generating entity and Scope 2 for the manufacturing entity). Emissions can only be aggregated meaningfully ***within*** a scope, not across scopes. By definition, Scope 2 emissions will always be accounted for by another entity as Scope 1 emissions. Therefore, Scope 1 and 2 emissions must be accounted for separately.

Requiring the reporting of both Scope 1 and Scope 2 emissions helps ensure that each Reporter provides a comprehensive emissions profile reflecting the decisions and activities of each reporting entity.

5.4 Reporting Emissions from Biomass Combustion

The combustion of biomass and biomass-based fuels (such as wood, wood waste, landfill gas, ethanol, etc.) emit GHGs. Unlike other fuels, you must track CO_2 emissions from biomass combustion separately from your other direct emissions. You must report CO_2 emissions from biomass combustion separately from the scopes.

CO_2 emissions from biomass combustion are reported separately because the carbon in biomass is of a biogenic origin—meaning that it was recently contained in living organic matter—while the carbon in fossil fuels has been trapped in geologic formations for millennia. Because of this biogenic origin, the Intergovernmental Panel on Climate Change (IPCC) *Guidelines for National Greenhouse Gas Inventories* requires that CO_2 emissions from biomass combustion be reported separately.

The requirement to report biogenic emissions applies only to stationary combustion and mobile combustion. Biogenic emissions related to forestry and land management need not be reported to the Registry. In the future, the Registry may develop a sector-specific protocol for forestry and land management that will provide guidance for reporting other biogenic emissions. Visit our website at www.theclimateregistry.org to check the current status of sector-specific protocols.

Because biofuels are often mixed with fossil fuels prior to combustion (e.g., wood waste with coal in a power plant, ethanol with gasoline in an automobile, or biomass with fossil-based materials in municipal solid waste), you must separately calculate your CO_2 emissions from biomass combustion from your CO_2 emissions from fossil fuel emissions. Chapters 12 and 13 in Part III of the Protocol provide methodologies

you can use to separate your biogenic CO_2 emissions from your other CO_2 emissions.

The separate reporting of CO_2 emissions from biomass combustion applies only to CO_2 and not to methane (CH_4) and nitrous oxide (N_2O), which are also emitted from biomass combustion. Unlike CO_2 emissions, the CH_4 and N_2O emitted from biomass combustion are not of a biogenic origin. Therefore, $CH_4$and N_2O emissions from biomass combustion must be reported as part of your Scope 1 emissions and should not be reported separately from your other CH_4 and N_2O emissions.

5.5 *Optional Reporting*: Scope 3 Emissions

Reporting of Scope 3 emissions is optional, but doing so provides an opportunity for innovation in GHG management. Scope 3 emissions for your organization may include the following:

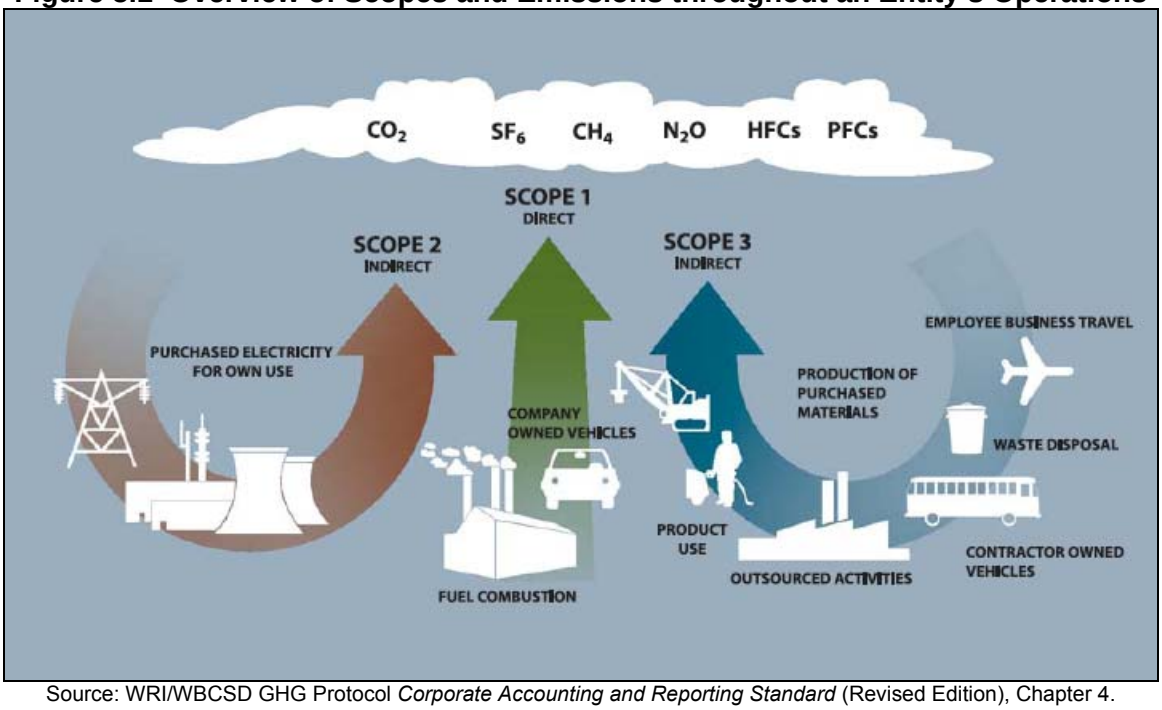
- Upstream emissions from the extraction and production of purchased materials and fuels
- Upstream emissions from the transportation of purchased materials or goods
- Upstream emissions from the transportation of purchased fuels
- Employee business travel
- Employees commuting to and from work
- Downstream emissions from the transportation of sold products
- Upstream emissions from the extraction, production and transportation of fuels consumed in the generation of electricity (either purchased or own generated by the reporting entity)
- Downstream emissions from the use of sold products and services
- Downstream emissions from the recycling of used products
- Downstream emissions from waste disposal

While data availability and reliability may influence which Scope 3 activities are included in the inventory, it is accepted that data accuracy may be lower than Scope 1 and Scope 2 data. It may be more important to understand the relative magnitude of and possible changes to Scope 3 activities. Emission estimates are acceptable as long as there is transparency with regard to the estimation approach, and the data used for the analysis are adequate to support the objectives of the inventory.

It is possible that the same Scope 3 emissions may be reported as Scope 3 emissions by more than one Reporter. For example, both an aluminum smelting company and an automobile manufacturer may choose to report the emissions associated with the mining of the raw materials (bauxite) used to produce aluminum that ultimately is utilized in the manufacturer's finished automobiles. For this reason, Scope 3 emissions should never be summed across Reporters or mixed with Scope 1 and Scope 2 emissions. The Registry does not add Scope 3 emissions together or mix Scope 3 with Scope 1 or 2 emissions.

While the GRP and CRIS do not currently include calculation methodologies for Scope 3 emissions, the Registry may provide such methodologies in the future to assist Reporters in measuring and managing these emissions. Reporters interested in computing their Scope 3 emissions are referred to the WRI/WBCSD GHG Protocol calculation tools and calculation guidance (available at www.ghgprotocol.org).

Figure 5.1 Overview of Scopes and Emissions throughout an Entity's Operations

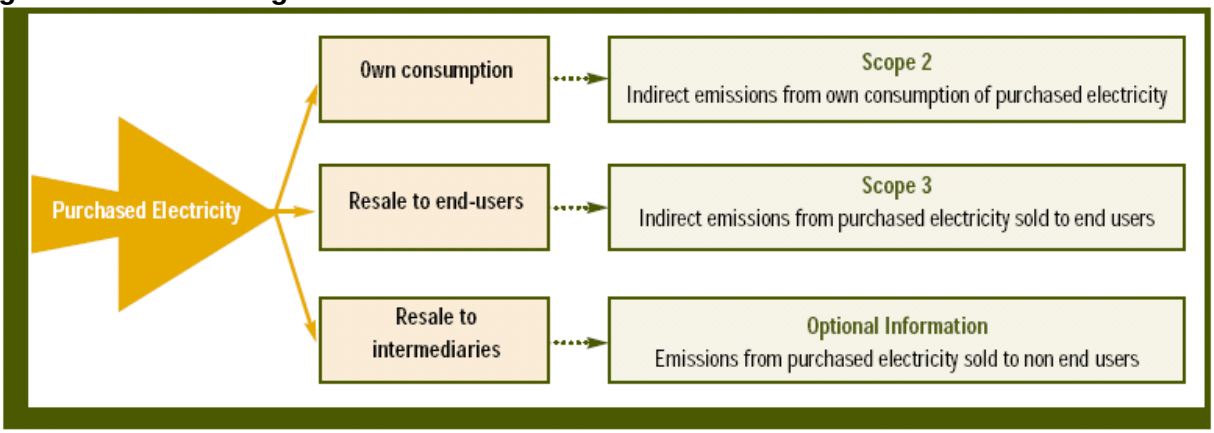


Source: WRI/WBCSD GHG Protocol *Corporate Accounting and Reporting Standard* (Revised Edition), Chapter 4.

Example 5.1 Categorizing Emissions from Electricity Generation by Scope

First we present general guidance pertaining to this example on how to categorize emissions from electricity generation by scope. Figure 5.2 provides an overview of possible transactions associated with purchased electricity and the corresponding emissions categories.

Figure 5.2 Accounting for the Indirect GHG Emissions Associated with Purchased Electricity



- **Purchased electricity for own consumption**: Emissions associated with the generation of purchased electricity that is consumed by the Reporter are reported in Scope 2. Scope 2 only accounts for the portion of the direct emissions from generating electricity that is actually consumed by the Reporter. A company that purchases electricity and transports it in a transmission and distribution (T&D) system that it owns or controls reports the emissions associated with T&D losses under Scope 2. However, if the reporting company owns or controls the T&D system but generates (rather than purchases) the electricity transmitted through its wires, the emissions associated with T&D losses are not reported under Scope 2, as they would already be accounted for under Scope 1. This is the case when generation, transmission, and distribution systems are vertically integrated and owned or controlled by the same company.

- **Purchased electricity for resale to end-users**: Emissions from the generation of purchased electricity for resale to end-users (for example purchases by a utility company) may be reported *optionally* under Scope 3. This reporting category is particularly relevant for utility companies that purchase wholesale electricity supplied by independent power producers for resale to their customers. Since utility companies and electricity suppliers often exercise choice over where they purchase electricity, this provides them with an important GHG reduction opportunity. Since Scope 3 is *optional*, companies that are unable to track their electricity sales in terms of end users and non-end users can choose not to report these emissions.

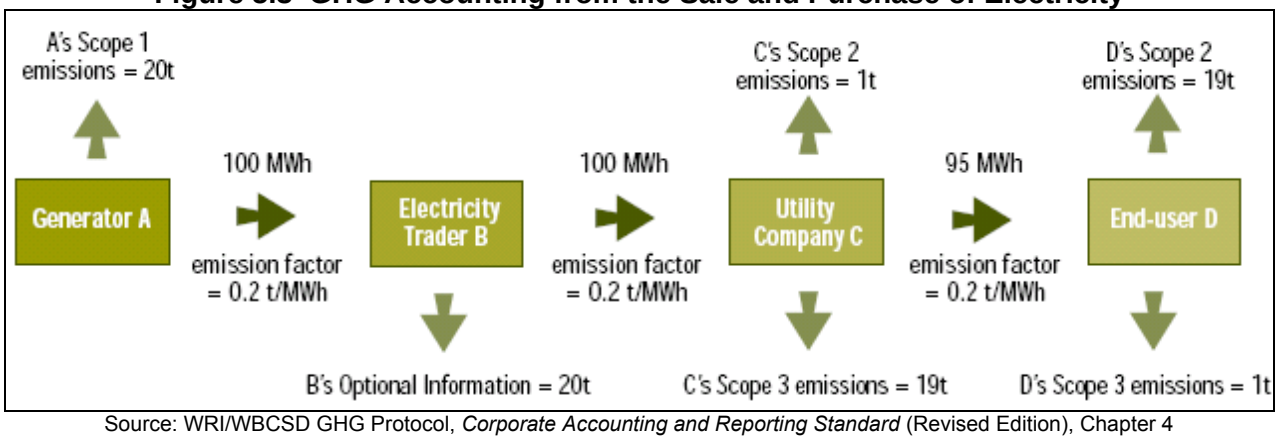
- **Purchased electricity for resale to intermediaries**: Emissions associated with the generation of purchased electricity that is resold to an intermediary (e.g., trading transactions) may be reported under *optional* information under the category "Generation of purchased electricity, heat, or steam for re-sale to non end users." Examples of trading transactions include brokerage/trading room transactions involving purchased electricity or any other transaction in which electricity is purchased directly from one source or the spot market and then resold to an intermediary (e.g., a non-end user). These emissions are reported under *optional* information separately from Scope 3 because there could be a number of trading transactions before the electricity finally reaches the end-user. This may cause duplicative reporting of indirect emissions from a series of electricity trading transactions for the same electricity.

For further information on how electric utilities and power generators should classify emissions by scope, refer to the WRI/WBCSD GHG Protocol, *Corporate Accounting and Reporting Standard* (Revised Edition), Chapter 4 and Appendix A (www.ghgprotocol.org).

Example 5.1 Categorizing Emissions from Electricity Generation by Scope (Continued)

To illustrate the application of the above classification rules, consider the following example. Company A is an independent power generator that owns a power generation plant. The power plant produces 100 MWh of electricity and releases 20 metric tons of emissions per year. Company B is an electricity trader and has a supply contract with Company A to purchase all its electricity. Company B resells the purchased electricity (100 MWh) to Company C, a utility company that owns / controls the T&D system. Company C consumes 5 MWh of electricity in its T&D system and sells the remaining 95 MWh to Company D. Company D is an end user who consumes the purchased electricity (95 MWh) in its own operations. Company A reports its direct emissions from power generation under Scope 1. Company C reports the indirect emissions from the generation of the part of the purchased electricity that is sold to the end-user under Scope 3 and the part of the purchased electricity that it consumes in its T&D system under Scope 2. This distinction is necessary because Scope 2 emissions are defined as emissions resulting from the *consumption* of electricity. Since Company C is *consuming* only the 5 MWh associated with its T&D system losses, only the emissions resulting from the generation of these 5 MWh qualify as Scope 2 emissions for Company C. Since Company C does *not* consume the remaining 95 MWh but rather resells this power, the emissions associated with the 95 MWh represents Scope 3 emissions for Company C. End user D reports the indirect emissions associated with its own consumption of purchased electricity under Scope 2 and can optionally report emissions associated with upstream T&D losses in Scope 3. Company B does not have emissions falling under any of the scopes in this example. Figure 4.3 shows the accounting of emissions associated with these transactions.

Figure 5.3 GHG Accounting from the Sale and Purchase of Electricity



Source: WRI/WBCSD GHG Protocol, *Corporate Accounting and Reporting Standard* (Revised Edition), Chapter 4

CHAPTER 6: FACILITY-LEVEL REPORTING

6.1 Required Facility-Level Reporting

Reporters are **required** to report emissions separately for each facility within an entity. Facility-level reporting enables tracking of GHG emissions at a disaggregated level, including emission changes associated with discrete business operations or facilities within your larger entity.

6.2 Defining Facility Boundaries

In general, a facility is defined as a single physical premises. Regulatory programs often define a facility as any stationary installation or establishment located on a single site or on contiguous or adjacent sites that are owned or operated by an entity. The Registry uses this definition for stationary sources as well. Guidelines for mobile combustion sources can be found Section 6.4 Categorizing Mobile Source Emissions section.

The Registry understands that some emission sources, such as pipelines and electricity transmission and distribution (T&D) systems, do not easily conform to this traditional definition of a facility. Please see Text Box called "Reporting Pipelines and T&D Systems" for information on reporting emissions from these sources.

Pipeline and T&D Systems

For purposes of reporting, each pipeline, pipeline system, or electricity T&D system should be treated as a single facility. If a pipeline or T&D system crosses a state or provincial boundary, you should subdivide the system into two separate facilities along the state/provincial boundary if it is possible to determine emissions separately for the two facilities thus defined.

If separate emissions estimates cannot be developed by state/province, you may treat the pipeline or T&D system as a single facility. In this case, the emissions for the single facility should be assigned to the *country* in which the facility is located. For example, emissions from a pipeline that extends from Alberta to Ontario would be assigned to Canada, rather than to a specific Canadian province.

If a pipeline or T&D system crosses national boundaries, again you should try to subdivide the system into two separate facilities and report the emissions from each facility thus defined. However, if you do not have the data necessary to estimate emissions from each national segment of a pipeline or T&D system, you may treat the pipeline or T&D system as a single facility. Emissions from such a facility must be reported in the "North American" geographic region, which is a separate geographic category provided by CRIS to handle this and other special situations (see Example 6.1).

Example 6.1 Interstate Natural Gas Pipeline

A pipeline transports natural gas from Alberta to a pipeline distribution system in Seattle, Washington. By comparing natural gas receipts at the supply source in Alberta with deliveries at the distribution point in Seattle, the company that owns the pipeline can determine the amount of natural gas (methane) that is lost due to leakage throughout the length of the pipeline. However, the company cannot break this total estimate down into emissions that occur in the Canada and U.S. segments of the pipeline. Therefore, emissions from the pipeline should be assigned to the North American category.

6.3 Optional Aggregation of Emissions from Stationary Facilities

In order to reduce the burden associated with reporting emissions separately for numerous small facilities, the Registry provides you with the *option* of aggregating emissions by facility type *within each state or province* rather than reporting at the facility level for certain qualifying facility types. Specifically, you may aggregate your emissions by facility type for the following types of stationary facilities *only*:

- **Commercial Buildings**: including, e.g., office buildings, retail stores, storage facilities, etc. You may aggregate your total emissions from all commercial buildings within a state/province, or, alternatively, you may aggregate these emissions by type of building within each state or province. Factories, mills, power plants and other industrial buildings are *not* considered commercial buildings, and may not be aggregated; emissions from industrial buildings must be reported separately for each such building.
- **Other special categories of facilities:** including oil and gas wells, pipelines and electricity transmission and distribution (T&D) systems. *If you are unsure of whether your facilities might qualify for inclusion in this special category, please contact the Registry at 866-523-0764.*

Emissions from all other types of stationary facilities besides the three categories listed above *must* be reported separately at the facility level.

6.4 Categorizing Mobile Source Emissions

The term "facility" generally refers to a single physical premises and therefore does not apply to mobile combustion sources such as automobiles, airplanes, and marine vessels. Criteria to guide the categorization of emissions from these sources are presented in the following subsections.

Ground-Based Mobile Combustion Sources

The Registry makes a distinction between ground-based mobile sources that operate exclusively on the grounds of a single facility, and ground-based mobile sources that operate beyond a single facility. Examples of the former mobile sources might include forklifts, front end-loaders, off-road trucks, mobile cranes, etc.

When mining, construction, and other equipment is assigned to a single facility and does not operate beyond that facility's premises, the equipment is considered to be part of the facility and the emissions from the equipment must be included in the facility's emissions. For example, emissions from mobile equipment that operate on a mine site must be included in the mine's emissions.

However, ground-based mobile sources that operate beyond the confines of a single facility (e.g., automobiles and on-road trucks) cannot be assigned to any single facility. The Registry provides you with flexibility in deciding how you

want to aggregate these sources. You have the option of aggregating emissions from mobile sources by:

- Geographic location (e.g., state/province, national or North American), or by
- Vehicle type (e.g., automobile, truck, train) within each geographic location.

Alternatively, you may report emissions from mobile sources at a more disaggregated level, including, e.g., by fleet or by individual vehicle.

Regardless of the level at which you choose to aggregate your mobile source emissions, it is necessary to assign these emissions (like all other emissions) to a geographic location. However, in some cases it is not possible to assign mobile source emissions to specific states or provinces, or even to specific countries. Therefore, the Registry has developed criteria and special geographic categories for accommodating mobile source emissions.

For *ground-based* mobile sources (automobiles, trucks, and trains), the criteria are as follows:

1. **State/Province Level Reporting:** Emissions from ground-based mobile sources that operate exclusively within a single state, province, or territory must be assigned to that state, province or territory. Mobile emissions can be aggregated within each state, province, or territory.

2. **National Level Reporting:** Emissions from ground-based mobile sources that operate across state or provincial boundaries but that operate exclusively within one country must be assigned to the *country* in which they operate. For example, an inter-provincial truck fleet that operates within Canada must be assigned to Canada, rather than any particular province. Likewise, a U.S. railroad that crosses state borders in the United States must be assigned to the United States, rather than a single state.

Example 6.2 NYC Limousine Company

A New York City limousine company owns a fleet of limousines that operate throughout the city and surrounding suburbs. Each limousine is assigned to one of five garages owned by the company, where the limousines are dispatched, serviced, fueled and parked when not in use. Four of the garages are located in New York City: one in Manhattan, one in Brooklyn, one in Queens, and one in the Bronx. The fifth garage is located across the Hudson River in Newark, New Jersey. The limousines assigned to the four New York City garages operate exclusively within the city boundaries; the limousines assigned to the Newark garage handle all trips between New York and New Jersey, and beyond. In addition to the limousines, each of the garages has a forklift which is used to move and stack spare auto parts stocked for limousine maintenance.

The limousine company wishes to report its emissions to the Registry. It has two different reporting options.

Option 1: The company may separate the limousines into two fleets—the fleet comprising the limousines assigned to the four New York City garages and a fleet including the limousines assigned to the Newark garage. This option would allow the company to separately report at least part of its fleet emissions at the state level (i.e., emissions assigned for the fleet assigned to New York City would be reported as New York state emissions). However, because the limousines assigned to the Newark garage are used for interstate trips, emissions from the Newark fleet would be assigned to the U.S. country category rather than a specific state. Should the company choose this option CRIS will aggregate the separately reported New York and U.S. emissions to provide a national fleet total at the entity level.

Option 2: The company could choose to report emissions from *all* of the limousines as a single fleet. In this case, since the fleet is used for both intra-state and interstate travel, the fleet emissions would have to be assigned to the U.S. rather than a single state. The Registry would encourage the use of the first option, as it provides greater detail, but the second option is allowed.

Using either option, the company will also need to calculate its emissions associated with electricity usage, as well as the forklifts to complete their emission report. The limousines are treated as being separate from the garages, because they operate beyond the physical boundaries of the garages.

3. **North America Level Reporting:** Emissions from ground-based mobile sources that cross national borders but that do *not* operate beyond Canada, Mexico and the United States must be assigned to a special "North American" category for mobile sources.

You are not required to report emissions from ground-based mobile sources that operate outside of Canada, Mexico, and the United States. For example, a trucking company with a fleet that operates in Mexico as well as in Belize and Guatemala is not required to report emissions from this fleet. However, the Registry encourages you to report worldwide emissions. If you choose to report emissions from such sources, the emissions should be assigned to the worldwide geographic category. Similarly, if you choose to report your worldwide emissions, including emissions from ground-based mobile sources operating entirely outside North America, these emissions should be included in the worldwide category.

Air- & Marine-Based Mobile Combustion Sources

Unlike ground-based vehicles, which often operate within state/province boundaries, air- and marine-based vehicles are often difficult to track at the state/province level. Therefore, the Registry allows air- and marine- based mobile combustion emissions to be tracked at the national level.

You must report emissions on a country basis whenever possible. However, in the case of cross-border flights or voyages, it is difficult to assign emissions by country, so the requirement to report at the national level does not apply.

Emissions from water and air based mobile sources are disaggregated by geographic location on a flight or voyage basis, rather than on an airplane or vessel basis. Thus, whereas the emissions from a single automobile or truck will always be assigned to a single geographic category (be it a state/province, country, or continent), the emissions from a single airplane or a marine vessel may be disaggregated and assigned to different geographic locations depending, e.g., on whether or not the airplane or marine vessel is used for both domestic and international transportation.

The criteria for assigning emissions to geographic categories for air and water based mobile sources are as follows:

1. **National Level Reporting:** Emissions occurring entirely within one country must be assigned to that country. Emissions from domestic flights and voyages must be assigned to the specific country in which the flight/voyage originated and terminated. For example, emissions from a flight from Montreal to Vancouver must be assigned to Canada, while emissions from a voyage from New York to Miami must be assigned to the United States. If an international flight or voyage includes a domestic stopover or port of call, the emissions from the domestic leg of the flight or voyage should be assigned to the country in which the domestic leg originates and terminates. For example, if a flight from Washington, D.C. to London includes a stopover in New York, the emissions from the Washington-to-New York leg of the flight should be assigned to the U.S. Similarly, if a ship sails from Los Angeles to Vancouver but has a port of call in Seattle, emissions from the Los Angeles to Seattle segment of the voyage should be assigned to the U.S.

2. **North America Level Reporting:** Emissions occurring entirely within North America (excluding Central America), but not entirely within a single country, must be assigned to North America. Emissions from international flights and voyages that originate and terminate within North America must be assigned to the North American category. For example, emissions from a flight that originates in Mexico City and terminates in Los Angeles would be assigned to the North American category, as would emissions from a voyage that originated in New York and

terminated in Cancun. If an intercontinental flight or voyage originating or terminating in one North American country includes a stopover or port of call in another North American country, the emissions from the North American leg of the flight or voyage should be assigned to the North American category. For example, if a flight from Houston to Caracas, Venezuela includes a stopover in Mexico City, the emissions from the Houston-to-Mexico City leg of the flight should be assigned to the North American category.

3. **Worldwide Reporting:** You are strongly encouraged, but not required, to report emissions from legs of flights or voyages that originate and/or terminate outside of Canada, the U.S., or Mexico. For example, emissions from a direct voyage from Los Angeles to Tokyo, or a non-stop flight from London to New York, need not be included in your emission report. However, you *may opt* to report such emissions if you so choose. If you do choose to report these emissions, they should be assigned to the worldwide geographic category. Similarly, if you choose to report your worldwide emissions, including emissions from legs of flights or voyages that both originate and terminate outside North America (e.g., London to Paris, or Hong Kong to Singapore) these emissions should be reported in the worldwide category.

Indirect emissions from electricity purchased for use by a vessel when it is in port should be treated as occurring while the vessel is in port. The emissions associated with this electricity consumption should be assigned to the state, province or territory in which the port is located. The owner/operator of the marine vessel, not the fueling facility, must report the vessel's emissions from in-port electricity use as well as fuel use during voyages.

6.5 *Optional Reporting*: Unit-Level Data

You are *encouraged* to report emissions data at the unit level for stationary combustion units, if data is available. A stationary combustion unit is defined as any individual non-mobile device designed to burn fuel. Stationary combustion units include boilers, burners, turbines, heaters, furnaces, incinerators, kilns, ovens, dryers, (stationary) internal combustion and diesel engines, catalytic oxidizers, flares, and thermal oxidizers.

6.6 Aggregation of Data to Entity Level

Once you report your facility level emissions to the Registry via CRIS, the system will automatically aggregate your emissions to create your entity-level emission report.

Please refer to Chapter 20 for more information about the public disclosure of entity and facility-level data.

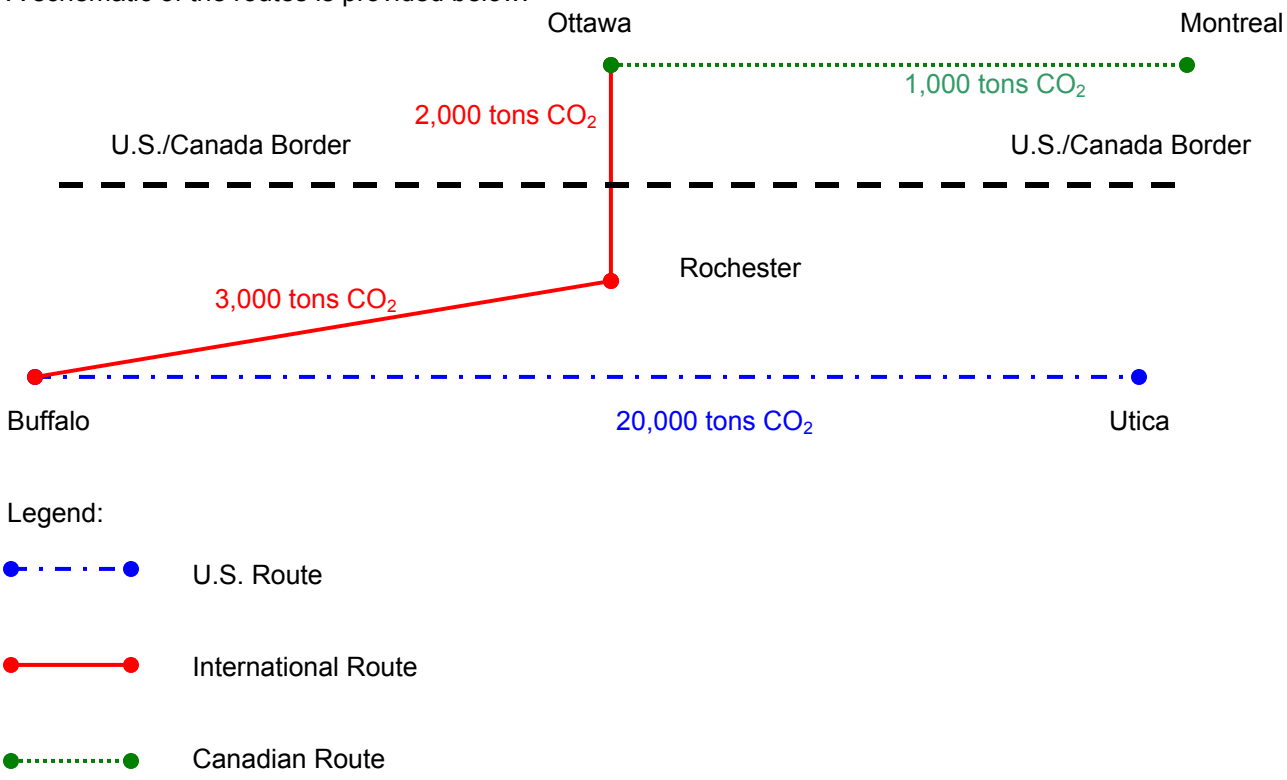
Example 6.3 Categorization of Airline Emissions

A small regional airline operates a fleet of 10 planes serving Buffalo, Rochester and Utica in upstate New York, as well as Ottawa and Montreal in Canada. Its fleet flies one U.S., one Canadian, and one international route. The Canadian route is Ottawa to Montreal (with a return). The U.S. route is Utica to Buffalo. Finally, the international route is Buffalo to Ottawa, with an intermediate stop in Rochester (and a return). The schematic below shows each of these routes.

The airline calculates and categorizes its emissions as follows:

- **Canadian Emissions:** Total of 1,000 tons CO_2 equivalent from all flights along the Ottawa-Montreal route
- **U.S. Emissions:** Total of 22,500 tons CO_2 equivalent, consisting of:
    a. 20,000 tons CO_2 equivalent from all flights along the Utica-Buffalo route
    b. 3,000 tons CO_2 equivalent, representing total emissions from the Buffalo-Rochester leg of the Buffalo-Ottawa flight.
- **North American Emissions:** Total of 2,000 tons CO_2 equivalent, representing emissions from the Rochester-Ottawa leg of the Buffalo-Ottawa flight.

A schematic of the routes is provided below:



Example 6.4 Categorization of Emissions from Marine Vessels

A shipping company owns and operates a fleet of seven container ships. These ships serve the ports of Los Angeles, Seattle, Vancouver, Tokyo, Hong Kong and Singapore. In order to report 2008 emissions for the fleet to the Registry, the shipping company first uses fuel purchasing records for each port of call to estimate total CO_2 emissions for its *direct* shipments (i.e., shipments without intermediate port calls) between each pair of ports, as follows:

Port Pairings		Number of Direct Shipments in 2008	CO_2 Emissions in Metric Tons
Port 1	Port 2		
United States:			
Los Angeles	Seattle	43	5,722
Total U.S.		43	5,722
North American:			
Los Angeles	Vancouver	22	3,121
Seattle	Vancouver	52	1,309
Total North American		74	4,430
Worldwide:			
Hong Kong	Los Angeles	2	1,823
Los Angeles	Singapore	35	14,750
Los Angeles	Tokyo	42	18,903
Total International		79	35,476
Fleet Grand Total Direct (Scope 1) Emissions		196	45,628

In addition to reporting emissions due to bunker fuel consumption while at sea, the shipping company must also report emissions resulting from the fleet's use of electricity while in port. These emissions must be assigned to the state or province in which each port is located, as follows:

Port	State or Province	Country	Indirect CO_2 Emissions from Fleet Electricity Use (Metric Tons)
Los Angeles	California	United States	452
Seattle	Washington	United States	214
Vancouver	British Columbia	Canada	311
Fleet Grand Total Indirect (Scope 2) Emissions			977

CHAPTER 7: ESTABLISHING AND UPDATING THE BASE YEAR

7.1 Required Base Year

Tracking GHG emissions over time enables Reporters to meet a variety of business goals, such as public reporting of GHG reductions, establishing and measuring progress towards GHG targets, managing risks and opportunities, and addressing the needs of investors and other stakeholders.

A "base year" is a benchmark against which an entity's emissions are compared over time. Setting and updating a base year provides a standardized benchmark that reflects an entity's evolving structure over time, allowing changes in organizational structure to be tracked in a meaningful fashion. Adjustments to base year emissions are generally made to reflect organizational changes such as mergers, acquisitions, or divestments.

Setting a base year allows Reporters to scale structural changes to their entity back to a benchmarked emission profile. For example, an acquisition of a facility could dramatically increase your entity's emissions relative to previous reporting years. To accurately describe the true impact the acquisition has on your emissions profile, you would adjust your base year emissions to incorporate the additional emissions associated with the acquired entity, thereby normalizing the real (organic) change in emissions from the base year (now accounting for the acquired facility) and the current year. Base year emissions may also need to be changed if there are significant changes in generally accepted GHG emissions accounting methodologies.

Your entity's base year is defined as the ***earliest reporting year*** you submit a "complete" emission report (a report that meets all of the Registry's reporting requirements, including the six internationally-recognized gases in three countries) to the Registry. You cannot designate your base year in a year that you are a *transitional reporter,* as your emissions will not be complete. If you choose to exercise your option to be a transitional reporter for the first two years of your participation in the Registry, then your base year will be your third reporting year.

You may set a historical year (refer to Chapter 9) as your base year, if you submit complete data for the historical year and all subsequent years. You may not set a historical year as your base year if you do not submit complete data to the Registry.

The purpose of having a base year in the Registry is simply to have a benchmark to illustrate the trends in your entity's emissions over time within the Registry. You may have already set an internal corporate/organizational base year or may have an existing regulatory baseline requirement that you must meet for a mandatory reporting program. These external benchmarks do not change or affect your base year with the Registry. The Registry's base year is for analysis of your emissions in the Registry over time only, and should not be confused with regulatory baselines.

7.2 Updating Your Base Year Emissions

To ensure that the comparison of your emissions over time is internally consistent, your base year emissions must closely reflect your current organizational structure.

For this reason, the Registry requires you to adjust (recalculate) your base year emissions when either:

1. A structural change in your organizational boundaries (i.e., merger, acquisition, or divestiture) triggers a significant cumulative change in your entity's base year emissions;

2. A change your entity's calculation methodologies or emission factors triggers a significant cumulative change in your entity's base year emissions; *or*

3. You discover a significant error or a number of cumulative errors that are collectively significant.

Significant is defined as a cumulative change of five percent or larger in your entity's total base year emissions (Scope 1 plus Scope 2, as well as Scope 3 if you are reporting Scope 3 emissions, on a CO_2 equivalent basis).

If you adjust your base year, you must have your third-party Verifier attest to the accuracy of your base year adjustment by including your base year adjustment verification in the scope of your current year's verification activities. For more information on verification, please refer to Chapter 19.

You should **not** adjust base year emissions in any of the following situations:

- Acquisition (or insourcing) or divestiture (or outsourcing) of a facility or business unit that did not exist in the base year(see Example 7.3);

- Structural changes due to 'outsourcing' if your entity is reporting its indirect emissions from relevant outsourced activities in the current reporting year (see Example 7.4);

- Structural changes due to 'insourcing' (the converse of outsourcing) if you already included the indirect emissions associated with the insourced activities in your base year report (see Example 7.5);

- Organic growth or decline, which refers to increases or decreases in production output, changes in product mix, and closures and openings of operating units owned or controlled by your entity.

If you have acquired or merged with a company, and you do not have the base year data from the new company needed to use any of the Registry's approved emission calculation methods (see Part III), you may instead use an alternative simplified method for updating your base year emissions using available data.

If you have absolutely no data for the new company, making it impossible to estimate the impact of the organizational change on your base year emissions, then you must redefine your base year to be your current reporting year (which would include your new acquisition, and thus, would reflect your current organizational structure.) You should also describe the structural change in your emission report to ensure transparency.

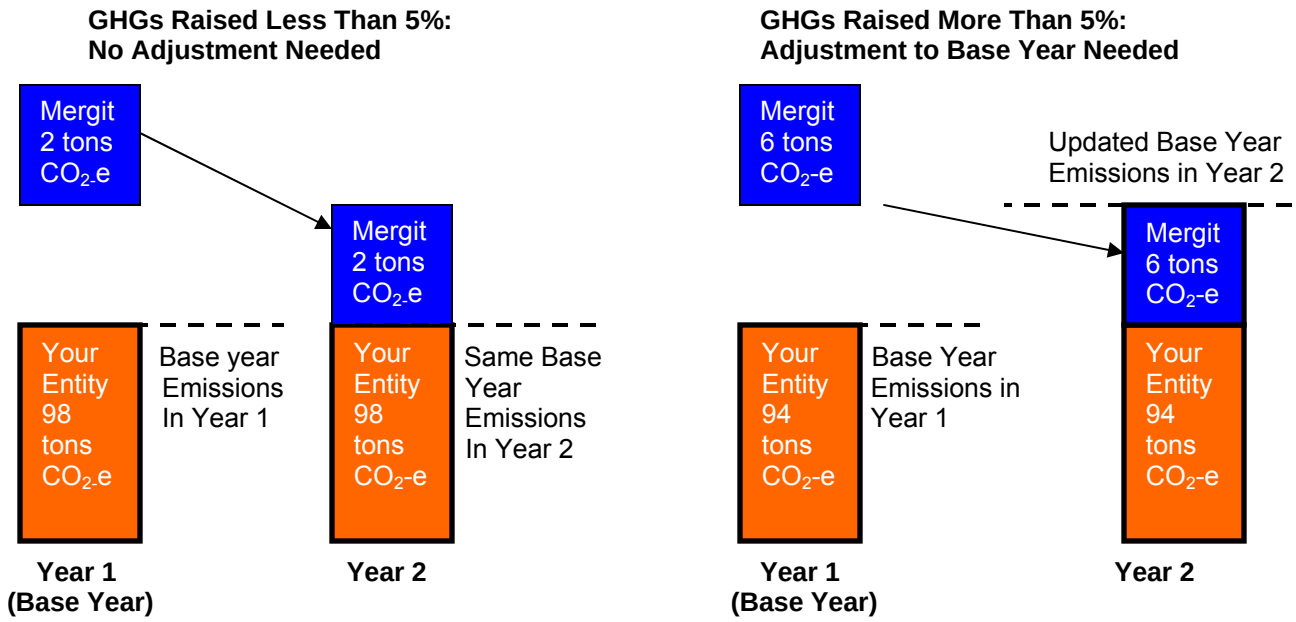
7.3 *Optional Reporting:* Updating Intervening Years

You are only *required* to update your *base year* emissions to reflect organizational and methodological changes. However, you may *opt* to update GHG emissions in the years between the base year and the reporting year along with the base year emissions, if you so choose.

The benefit of adjusting the intervening years (between your base year and current year) is that all of your GHG emission reports will be meaningful and comparable, rather than just the base year and the current year. This provides additional transparency to the public, and will provide more insight into your emissions trends for internal emissions management purposes.

Example 7.1 Mergers and Acquisitions

Your organization merges with Mergitrex. Depending on the percentage change in your total (Scope 1 and 2) base year emissions, you may need to adjust your base year report:



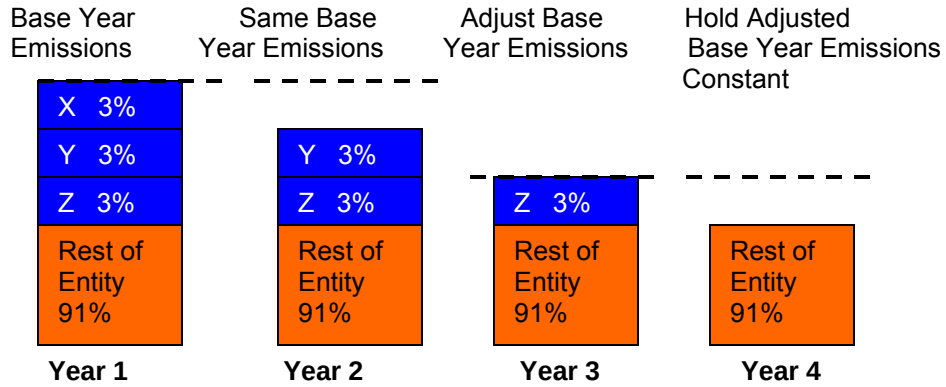
If, in the base year (Year 1), Mergitrex's emissions were less than 5 percent of your company's total base year (Scope 1 and 2) emissions (or if Mergitrex did not exist in the base year), then you would not adjust your base year emissions in Year 2 to reflect the merger. In the example above left, your total base year emissions would remain 98 tons CO_2 equivalent in Year 2.

If, in the base year (Year 1), Mergitrex's emissions were more than 5 percent of your company's total base year (Scope 1 and 2) emissions, then you must adjust your base year emissions in Year 2 to reflect the merger. Your emissions would be adjusted by adding Mergitrex's base year emissions (6 tons CO_2 equivalent in the example to the right) to your company's base year emissions (94 tons CO_2 equivalent), to obtain a new base year emission total (100 tons CO_2 equivalent).

Example 7.2 Divestitures

Your organization divests three divisions over the second, third and fourth reporting years. Each of these divisions account for 3% of your GHG emissions, for a 9% total reduction in emissions by year four.

GHGs Reduced by More than 5% in Year 3: Update in Base Year Emissions Required



Because the cumulative effect of these divestitures reduces what your base year emissions would have been by more than 5% in Year 3, in that year you will need to adjust your base year emissions by subtracting the base year emissions of Divisions X and Y from your originally-reported base year emissions.

Example 7.3 Acquisition of a Facility that Came into Existence After the Base Year Was Set

Your organization consists of two business units (A and B). In its base year, the company emits 50 tons of GHGs. In year two, the company undergoes organic growth, leading to an increase in emissions to 30 tons of GHGs per business unit, i.e., 60 tons CO_2 in total. The base year emissions should not be recalculated in this case, because the change in emissions was due to organic growth, not an acquisition.

At the beginning of year three, your organization acquires Production Facility C from another company. Facility C came into existence in year two, its emissions being 15 tons of GHGs in year two and 20 tons of GHGs in year three. The total emissions of your organization in year three, including facility C, are therefore 80 tons of GHGs. In this acquisition case, the base year emissions of your organization should not be updated, because the acquired facility C did not exist in the base year (or, in other words, the base year emissions of Facility C were zero).

Example 7.4 Outsourcing

If your organization contracts out activities previously included in your base year emissions estimate, you *may* need to adjust your base year report to reflect the outsourcing. If you continue to include the emissions associated with the outsourced activities as part of your indirect (Scope 2 or Scope 3) emissions, you should *not* adjust your base year emissions. If the emissions associated with the outsourced activities are classified as Scope 2, keep in mind that you are required to report these emissions. In meeting this requirement you will avoid the need for adjusting your base year emissions to reflect the outsourcing.

If, on the other hand, the outsourced activities generate Scope 3 emissions, you have the option to either report these emissions or exclude them from your report. If you choose to exclude them, and if the outsourced activities accounted for 5 percent or more of your base year emissions (either by themselves or in combination with other structural and methodological changes), you must adjust your base year emissions to reflect the outsourcing. Specifically, you should subtract the base year emissions caused by the activities now being outsourced from your previously-reported base year emissions to obtain an adjusted base year emissions total.

You should *not* adjust your base year report if the outsourced activities did not exist during your base year.

Example 7.5 Insourcing

Insourcing is the converse of outsourcing. If you did not include the emissions associated with insourced activities as indirect emissions in your base year report, then you must adjust your base year emissions to reflect the insourced activities (assuming that the 5 percent significance threshold has been exceeded). To adjust for insourcing, you would add the base year emissions for the insourced activities to your previously-reported base year emissions.

If the activities you are insourcing did not occur in the base year, you should not adjust your base year emissions. Base year emissions should not be adjusted for the insourcing of activities that did not occur in the base year.

For example, suppose that in the base year your company hired a delivery service to hand deliver proposals and deliverables to government clients located throughout Washington, DC. Suppose further that you included the delivery service's emissions associated with the delivery of your company's packages as indirect (Scope 3) emissions in your base year report. If, in a subsequent year, your company terminated its contract with the delivery service and used its own employees and vehicles to make the deliveries, no change in your base year report would be required because the emissions you 'insourced' were already included (as indirect emissions) in your base year report. Alternatively, if you did ***not*** include the delivery company's emissions in your base year report, upon insourcing the delivery activities you would have to revise your base year report to include the indirect emissions that were subsequently insourced.

However, if in the base year you did not submit any proposals or deliverables to clients in the Washington, DC area, but you subsequently hired the delivery service and then brought the delivery activities in house, you would not need to adjust your base year report because the insourced activities were not undertaken, either by your company or the delivery service, in the base year.

Example 7.6 Shifting the Location of Emissions Sources

If you shift operations outside of the U.S., Mexico and Canada, and this shift contributes to a total cumulative change in your base year emissions exceeding 5 percent, you must adjust your base year by subtracting the base year emissions of the shifted operations from your previously-reported base year total. Similarly if you shift operations into the U.S., Mexico, or Canada, you must increase your base year emissions by an amount equal to the base year emissions of the operations that were relocated. If you reported your worldwide emissions in the base year you will never need to adjust these emissions to reflect the relocation of your operations.

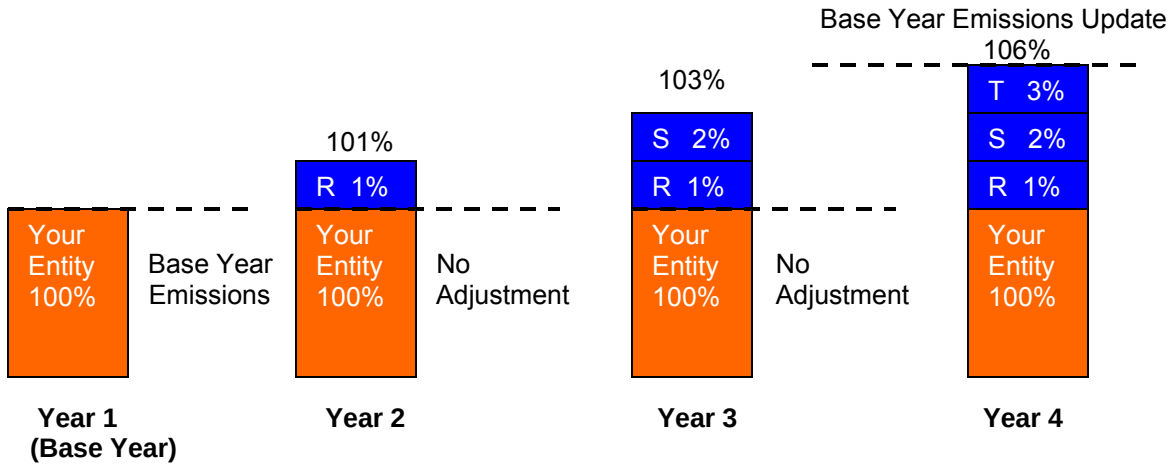
Example 7.7 Change in Emissions Accounting Methodologies

If you change emission calculation methodologies or data, for any reason (e.g., improvements in methodology/data or discovery of an error), and if application of the new methodologies would contribute to a cumulative total change in your base year emissions of more than 5 percent, you must recalculate your base year emissions using the new methodologies. This ensures that your base year emissions will remain comparable with your more recent emissions data.

Example 7.8 Cumulative Changes to Total Emissions

Your organization acquires three companies over three years, raising your total (Scope 1 and 2) base year GHG emissions by 6%.

GHGs Increased by More Than 5%: Updated Base Year



Your company acquires Reyes Rockets, Sierra Spaceworks, and Trinity Telescopes in reporting years two, three, and four, representing GHG base year emissions of 1%, 2% and 3% respectively of your company's base year emissions. While these acquisitions *individually* represent less than the required 5% increase for a base year adjustment, they amount to a 6% *cumulative* increase in total (Scope 1 and 2) base year emissions in CO_2 equivalent. Thus, you would be required to update your base year emissions in year four.

CHAPTER 8: TRANSITIONAL REPORTING *(OPTIONAL)*

8.1 Reporting Transitional Data

Completeness is one of the Registry's key accounting and reporting principles. Your emissions report must provide a complete account of all of your GHG emissions within North America. However, in addition to comprehensive reporting, the Registry also seeks to encourage broad participation in its voluntary reporting program, and recognizes that some entities may need additional time to develop a complete emissions inventory from all of their emission sources. For this reason, the Registry provides entities with an *option* to report less than comprehensive emissions data for their first one or two reporting years.

If you choose to use this option, you will be designated as a "Transitional Reporter" in the Registry until you submit a complete emission report for North America to the Registry. You are allowed to report as a Transitional Reporter for no more than two years. Your emission report in your third reporting year must be complete. For example, if you join the Registry in 2010, you may submit transitional data to the Registry for reporting years 2010 and 2011. However, beginning with reporting year 2012 you must report completely.

Complete emissions reports account for all emissions of the six internationally-recognized GHGs, from all operations within Canada, Mexico, and the U.S. These reporting requirements are relaxed for Transitional Reporters. If you opt to report on a transitional basis, the following options are available to you:

- **Geographic Boundaries:** You may opt to limit your emission report to one or more countries, states, or provinces, rather than reporting for all of North America.

- **Required Emissions:** You may opt to report fewer than the six internationally recognized GHGs normally required by the Registry and/or fewer than all your emission sources.

8.2 Minimum Reporting Requirements for Transitional Reporting

While the Registry is somewhat flexible with respect to transitional reporting, all Transitional Reporters must meet the following minimum reporting requirements.

A Transitional Reporter must report at a minimum all CO_2 emissions from stationary combustion for all of its operations in at least one state or province.

If you choose to report for several states/provinces, you must report, at a minimum, CO_2 from all stationary combustion sources within those states/provinces. However, you are encouraged to exceed the minimum requirements and report as comprehensively as possible.

All Transitional Reports must be third-party verified by a Registry-approved Verifier.

Transitional reports, like comprehensive reports, must be third-party verified by a Registry-approved Verifier. You may "import" or transfer transitional data from other GHG programs and registries to the Registry, as long as the data transferred meets the Registry's transitional reporting requirements. Transitional data transferred from other programs must be verified by a Registry-approved Verifier. Thus, if transitional data was previously verified by an un-approved third party prior to its transfer to the Registry, it will need to be re-verified.

8.3 Public Disclosure of Transitional Data

Like complete emission reports, transitional emission reports will be disclosed to the public after they are verified and submitted to the Registry. CRIS will include a report heading on your emission report that discloses that your report is "Transitional" to distinguish it from

complete emission reports. Please refer to Chapter 20 for more information about the public disclosure of emission reports.

Example 8.1 Transitional Reporting

Alpha Company is a diverse manufacturer with operations throughout North America and emissions of four of the six internationally recognized greenhouse gases (carbon dioxide, methane, nitrous oxide, and HFCs). Alpha is planning to provide its first annual report to the Registry in 2010; this report will cover Alpha's 2009 emissions. However, as Alpha has never conducted a full emissions inventory across all of its operations, it plans to report its 2009 emissions as a Transitional Reporter. For 2009, it limits its report to stationary combustion CO_2 emissions from all of its facilities in Texas, Oklahoma and Arkansas.

For 2010, Alpha expands its report to include CH_4 as well as CO_2, for *all* sources (mobile combustion, process and fugitive emission sources as well as stationary combustion sources) from all of its operations in the United States. For its 2011 emission report, Alpha may no longer report transitionally, and thus reports all of its emissions for all six internationally recognized GHGs, from all of its facilities and sources in the U.S., Canada and Mexico.

Note that the flexibility to report transitionally pertains *only* to gases, states/provinces and sources. Thus, while Alpha limits its 2009 report to one GHG and three states, it must still report comprehensively for the selected GHG and states. In other words, it must report *all* stationary combustion CO_2 emissions from *all* of its facilities and sources in these three states. Note also that while Transitional Reporters may opt to report fewer than all six internationally recognized GHGs, they *must* at a minimum report CO_2 emissions from stationary combustion.

The following table represents Alpha Company's GHG emissions inventory, and the portions of the inventory reported in each year:

Geographic Location of Facilities	CO_2 Emissions: Stationary Combustion	CO_2 Emissions: All Other Sources	CH_4 Emissions	N_2O Emissions	HFC Emissions	PFC Emissions	SF_6 Emissions
Texas, Oklahoma, and Arkansas	2009	2010	2010	2011	2011	N/A	N/A
All Other U.S. States	2010	2010	2010	2011	2011	N/A	N/A
Canada	2011	2011	2011	2011	2011	N/A	N/A
Mexico	2011	2011	2011	2011	2011	N/A	N/A

CHAPTER 9: HISTORICAL REPORTING *(OPTIONAL)*

9.1 Reporting Historical Data

You *may* opt to submit historical emissions data on a **calendar year basis**. **Historical data** is defined as all data for years prior to your **first reporting year**.

If your first reporting year in the Registry is 2009, any emission reports you submit prior to 2009 are considered historical. You may choose to report historical data beginning in any year as long as you report all subsequent years of data. For example, if your first reporting year is 2009, you may choose to report historical data starting in 1996. However, you must report your emissions for all subsequent years up to and including 2008 (1996 – 2008). You may not have gaps in your historical time series, or between your historical data and your first reporting year.

9.2 Minimum Reporting Requirements for Historical Data

While the Registry is flexible with respect to how many years of historical data you submit, all historical data must meet the following minimum reporting requirements for the Registry to accept it:

All historical emission reports must include at least:

- Entity-level emissions of CO_2 from stationary combustion for all operations in at least one state or province
- Third-party verified data (the data does NOT need to be verified by a Registry-approved Verifier if it has already been verified under another program; however, formal written attestation of verified data by a credible Verifier must be submitted to the Registry along with the historical emission report)

Data that does not meet the above reporting requirements will not be accepted by the Registry.

9.3 Importing Historical Data

You may "import" or transfer historical data from other GHG programs to the Registry. Like all other historical data, imported historical data that is transferred from other programs must meet the minimum requirements outlined in the above section. If the transferred historical data was verified by a third party as part of the other GHG program, this data need not and should not be re-verified. Historical data reported to the Registry that has not been verified by a third party (either because it was never reported under other GHG programs, or because the GHG program from which it was transferred did not require third-party verification) must be verified using a Registry-approved Verifier as outlined in Chapter 19 and the Registry's General Verification Protocol.

9.4 Public Disclosure of Historical Data

Like complete and transitional data, the Registry will disclose historical data to the public. If your historical emission report does not meet the Registry's requirements for completeness, it will be labeled "Historical Data" for transparency purposes. If your historical data was transferred from another GHG program, that program will also be cited on your historical emission report. For more information about the public disclosure of data, please refer to Chapter 20.

Part III: Quantifying Your Emissions

CHAPTER 10: INTRODUCTION TO QUANTIFYING YOUR EMISSIONS

After setting your entity's boundaries and identifying which sources to report, you must quantify your entity's emissions. In some cases, you may be able to directly measure GHG emissions by monitoring exhaust streams, such as for large stationary combustion units equipped with continuous emissions monitoring systems (CEMS). More often, you will apply calculation tools and methodologies to estimate GHG emissions using activity data such as fuel use. Part III provides emissions quantification guidelines that provide step-by-step guidance on how to quantify GHG emissions for your various sources of emissions.

Cross-Sector and Sector-Specific Sources

Chapters 12-16 of Part III provide guidelines for quantifying emissions from cross-sector sources, that is, sources that apply to a wide variety of reporting entities, regardless of industry sector. These sources include:

- Chapter 12: Stationary combustion
- Chapter 13: Mobile combustion
- Chapter 14: Electricity use
- Chapter 15: Use of imported steam, district heating, cooling, and electricity from combined heat and power (CHP)[5]
- Chapter 16: Use of refrigeration and air conditioning equipment

You will need to use some or all of these chapters to quantify emissions, depending on your entity's emissions sources.

Appendix E provides guidelines for quantifying various emissions from sector-specific sources—that is, sources that apply only to particular industry sectors. These sources are specific to the following industry sectors:

- Adipic acid production
- Aluminum production
- Ammonia production
- Cement production
- Electricity transmission and distribution
- HCFC-22 production
- Iron and steel production
- Lime production
- Nitric acid production
- Pulp and paper production
- Refrigeration and air condition equipment manufacturing
- Semiconductor manufacturing

Only reporting entities with emissions sources in these sectors will refer to these sections.

You will need to make use of all chapters and sections of Appendix E that are relevant to your organization. For example, an entity involved in iron and steel production may need to make use of each of the cross-sector chapters (Chapters 12-16) as well as Section E.7 of Appendix E, which provides methodologies specific to the iron and steel sector.

Calculation-Based Methodologies

Most Reporters will use calculation-based methodologies to quantify their organizations' GHG emissions. Calculation-based methodologies involve the calculation of emissions based on "activity data" and emission factors. Activity data can include data on fuel consumption, input material flow, or product output. Emission factors are determined by means of direct measurement and laboratory analyses or by using generalized default

[5] Combine heat and power (CHP) is also sometimes referred to as cogeneration.

factors. Calculations should be rounded up to one significant digit.

Tier levels (see below) are assigned based on the use and origin of different variables included in calculation methodologies, including activity data and emission factors. Tiers are included to provide greater transparency with respect to the accuracy of reported emissions.

Measurement-Based Methodologies

Measurement-based methodologies determine emissions by means of continuous measurement of the exhaust stream and the concentration of the relevant GHG(s) in the flue gas. Direct measurement will only be relevant to entities with facilities using existing continuous emission monitoring systems (CEMS), such as power plants or industrial facilities with large stationary combustion units. Reporters without existing monitoring systems will not need to install new monitoring equipment to comply with the Registry's quantification requirements. Those with CEMS should follow the guidance provided in Chapter 12.

Data Quality Tiers

The use of common quantification guidelines ensures that facilities and entities reporting to the Registry quantify their emissions consistently, such that a "ton of CO_2 is a ton of CO_2" throughout the Registry. The Registry uses a tiered quantification system to rank emissions quantification methodologies according to their levels of accuracy.

In this system, "Tier A" designates the preferred, or most accurate, approach for a given emissions source; "Tier B" represents an alternative second-best approach; and "Tier C" represents the least accurate, but still acceptable approach. Note that in some cases there may be multiple approaches given the same tiered ranking (such as A1 and A2), while for other sources there may only be one or two available quantification approaches for a given source (such as A and B).

Selecting a Tier

You are always encouraged to use the most accurate methodology for each emissions source, namely the Tier A method. If you cannot use the Tier A method—for example, due to technical constraints or excessive costs of data collection—you should use the next best available method, namely Tier B. In the event that the Tier A and Tier B methods are not technically possible or impose excessive costs for a particular source, you should use the Tier C method to quantify your emissions.

The use of higher tier methods is strongly encouraged by the Registry, but is not required. You may use the lowest tier methods provided in Part III for purposes of reporting. Note, however, that future regulatory programs may specify that higher accuracy methodologies be used. You may find that using the highest tier methods feasible also ensures the greatest likelihood that reported emissions data will be considered robust by stakeholders and reduces the risk that you will need to increase the stringency of data collection methodologies in the future.

Regardless of the approach employed, you must report consistently over time to ensure the comparability of your emissions data over time. However, if you develop the capability to use a higher tier method for a particular source (such as moving to a Tier A method from a Tier B method), you are encouraged to do so and should continue using the Tier A method consistently going forward (refer to Part II, Chapter 7 for requirements for updating your base year emissions due to methodological changes).

You must disclose the tiers and quantification approaches used for the various sources within each of your facilities. Reporters that quantify their emissions primarily using Tier A methods, thereby providing more robust emissions data, will have the advantage of publicly demonstrating their higher data quality to stakeholders.

Quantifying Emissions from Sources without Registry-Approved Methodologies

If the Registry has not endorsed guidelines for quantifying emissions from a particular emissions source, you should use existing industry best practice methods. Methods should be based on internationally accepted best practices whenever possible, such as the Intergovernmental Panel on Climate Change (IPCC) *Guidelines for National Greenhouse Gas Inventories* (2006); the WRI/WBCSD GHG Protocol calculation tools and calculation guidance (available at www.ghgprotocol.org); and other internationally recognized sources listed in the References section at the end of this Protocol.

No tier levels will be designated for sources not covered in Part III or Appendix E of the GRP. You should use the most accurate methods whenever possible.

The Registry plans to develop sector-specific protocols to provide more detailed guidance for individual industry sectors. If you are interested in learning more about the current status of these sector-specific protocols, please visit the Registry's website at www.theclimateregistry.org.

Using CRIS to Calculate and Report Your Emissions

CRIS is the Registry's GHG calculation, reporting, and verification tool, which you will use to report your emissions data to the Registry. The tool allows you to easily calculate and report your emissions data and generates user-friendly reports for both the Reporter and the public. You have two options for reporting data into CRIS:

- *Enter pre-calculated emissions data:* You may report emissions data into CRIS that you have already calculated on your own. CRIS will automatically convert your emissions to CO_2 equivalent. (You should also use this method to report continuous emissions monitoring data, if applicable.)

- *Use the built-in calculation tool*: You may use CRIS to calculate your emissions for you rather than calculating emissions data on your own. CRIS will automatically calculate your emissions based on the activity data you enter (e.g., energy use data) and convert your emissions to CO_2 equivalent.

If you enter pre-calculated emissions data, you must read all relevant sections of Part III to ensure that you have properly calculated your emissions. You will then use CRIS to report your emissions for each emitting activity. When you enter pre-calculated data, you must note which tier/method you have used to calculate your emissions as well as attach relevant documentation to support your calculations.

If you use CRIS's built-in calculation tool, you must read Part III to determine the data that you need to collect and enter into CRIS (such as energy use data or more specific emission factors, if applicable). CRIS will automatically calculate your emissions using the equations provided in Part III. CRIS also contains all of the Registry's default factors provided in Part III and automatically keeps track of the tiers and quantification methods you use to calculate your emissions.

CRIS provides you with flexibility when entering your emissions. You may use CRIS to enter different levels of raw and calculated data. For example, you may use CRIS to enter pre-calculated emissions for several of your stationary combustion sources, and also use CRIS' calculation tools to calculate your indirect emissions.

CHAPTER 11: SIMPLIFIED ESTIMATION METHODS

The rules, methodologies and standards in the GRP are designed to support the Registry's requirement of complete reporting of *all* of your entity's GHG emissions in North America. In addition to complete reporting of all emissions, you should calculate your emissions using the Registry-approved methodologies described in Part III and Appendix E as much as possible. However, the Registry understands that entities may have difficulty applying these methods to every source within their organizational boundaries—either because it is not possible or not efficient to use them.

Therefore, in order to reduce the reporting burden while retaining the requirement for complete emission reporting, you are allowed to use alternative, simplified estimation methods for any combination of individual emission sources (e.g., individual electricity generators, vehicles, furnaces, etc.) and/or gases, provided that the emissions from these sources and/or gases are less than or equal to 5 percent of your entity's total emissions (i.e., the sum of your Scope 1 and Scope 2 emissions, aggregated on a CO_2 equivalency basis). The remaining 95 percent of your emissions must be calculated using the methodologies specified in Part III and Appendix E, if possible. If this is not possible, please contact the Registry (866-523-0764) to discuss the situation.

If you cannot efficiently calculate your emissions using the Registry's quantification methodologies, then you may use alternative, simplified estimation methods to estimate up to 5 percent of your total emissions. Once estimated, you must include these emissions in your annual emission report. Therefore, your emission report will include 100 percent of your GHG emissions. You must document the simplified estimation methods that were used to arrive at these values. In addition, you must provide your Verifier with a list of the emission source(s) you used to estimate your emissions. Your estimated emissions will be aggregated and included in your entity-level emission report and your relevant facility-level emission reports, if appropriate.

Note that this requirement is similar to the *de minimis* concept used by other GHG registries and programs. When reporting to programs that employ *de minimis*, a small portion of an entity's emissions (such as 3 or 5 percent) may be considered eligible for exclusion from an emissions inventory.

The Registry allows Reporters to use rough, upper-bound, simplified methods to estimate emissions from small sources, but requires that those emissions estimates be included, rather than excluded, from your emissions inventory. The intent of this provision is to uphold the principle of completeness without adding significant additional costs compared to the *de minimis* exclusion approach.

Using Simplified Estimation Methods

The Registry does not provide a list of simplified estimation methods for you to use. No list would be comprehensive in accounting for all of the possible emissions sources. Instead, you may develop and implement simplified estimation methods as necessary and appropriate for your emissions inventory. In developing simplified estimation methods, you should always use upper-bound assumptions following the principle of conservativeness, i.e., erring on the side of overestimating rather than underestimating your emissions.

Example 11.1 Simplified Estimation of Mobile Combustion Emissions

The calculation of methane (CH_4) and nitrous oxide (N_2O) emissions from mobile combustion requires data on vehicle miles traveled by vehicle type (see Chapter 13). If you do not have data on distance traveled, but instead have data on fuel use, you may estimate distance traveled using fuel use data. However, this is already a Registry-approved method (Tier C), so this does not constitute a simplified estimation method.

If you do not have data on either distance traveled or fuel use, you could estimate CH_4 and N_2O emissions using some other proxy data, for example, the amount of time (e.g. hours) that a vehicle was operated. Using hours as a proxy for distance traveled constitutes a simplified estimation method because it gives only a rough estimate of actual emissions. As long as the estimated emissions from this source (and all other simplified estimation sources) fall below 5 percent of your entity's total emissions, you may use a simplified method. Be sure to always use upper-bound, conservative assumptions in developing simplified estimation methods (in this case, when estimating distance traveled based on hours operated).

Once you have completed your annual emissions report including simplified, upper-bound emissions estimates for a set of emission sources and/or gases, you do not have to re-estimate the emissions for this set of sources/gases in subsequent years unless your initial assumptions change. Instead, you may simply report your estimated emissions for each reporting year. However, if your initial assumptions change, you must recalculate your simplified emissions estimates using new assumptions.

Furthermore, if you find that your recalculated emissions now exceed 5 percent of your total entity-wide emissions, *or* if your total entity-wide emissions decline such that your originally estimated emissions no longer represent 5 percent or less of the total, you must re-select the sources and/or gases included in your simplified estimation calculations such that the resulting simplified estimates will once again sum to less than 5 percent of your total entity emissions (i.e. the sum of Scope 1 and Scope 2 emissions on a CO_2 equivalency basis).

Simplified Methods and Geographic Boundaries

If you are reporting your complete North American emissions, the 5 percent threshold for using simplified estimation methods refers to the sum of your total Scope 1 and Scope 2 emissions from all sources in these three countries.

Selecting Sources and Gases for the Application of Simplified Estimates

The sources and gases that may be estimated using simplified methods will vary from Reporter to Reporter. For example, fugitive GHG emissions may fall under the 5 percent threshold for some Reporters, but will likely exceed 5 percent for Reporters involved in the transmission and distribution of natural gas. Similarly, some Reporters may choose to apply simplified estimation methods for their non-CO_2 gases, if non-CO_2 emissions are less than 5 percent of the Reporter's total emissions.

You have some discretion in identifying which emissions to estimate using alternative, simplified methods. Example 11.2 provides guidance on the kinds of upper-bound methods that should be used as simplified alternatives to Registry-approved methods.

Example 11.2 Estimating Emissions Using Simplified Methods

A hotel chain with hotels located throughout the U.S. is planning to report its GHG emissions to the Registry. Using the Registry-approved methods in Part III, it has already calculated its GHG emissions for most of its sources, including:

- Indirect emissions from electricity purchases
- Direct emissions from fuel used in stationary combustion units
- Direct emissions from courtesy vans used at some of the hotels to shuttle customers to and from local airports
- Direct emissions of HFCs from the hotels' HVAC system.

Total emissions of all GHGs from these sources are calculated as 36,472 metric tons CO_2 equivalent.

There is one emissions source remaining to be quantified—the lawnmowers that are used to maintain the grounds at the hotels. There are 50 such lawnmowers in use at 47 different locations. However, only five of the hotels have kept fuel purchase records for their lawnmowers. Because data on all 50 lawnmowers are lacking, and the lawnmowers as a whole are likely to represent a very small source (less than 5 percent) of emissions relative to the other sources, the hotel chain decides to compute emissions for one lawnmower, and multiply the result by 50 to obtain a simplified estimate of emissions for all 50 lawnmowers. Recognizing the importance of developing a conservative emissions estimate, the hotel chain selects the lawnmower in use at its Miami, Florida location for three reasons. First, fuel consumption data is available for this lawnmower. Second, unlike the lawnmowers at its more northerly locations, this lawnmower is in use year round, and hence its emissions tend to be relatively high. And third, the grounds at the Miami hotel are extensive, and hence more fuel is required to mow the lawn at this hotel than at most of the other hotels owned by the chain.

The hotel chain calculates the emissions of the Miami lawnmower to be 0.32 metric tons CO_2 equivalent. Multiplying this result by 50, total lawnmower emissions for the chain as a whole are conservatively estimated as 16 metric tons CO_2 equivalent. Adding this value to the total emissions estimate for all of the other sources yields 36,488 metric tons CO_2 equivalent. The estimated lawnmower emissions represent less than 0.05 percent of this total—well below the 5 percent threshold for the use of simplified estimation methods. Therefore, the hotel chain's use of the simplified estimation method is allowable in this situation, and the chain reports the resulting 16-metric ton value as its estimate of emissions from its lawnmowers.

CHAPTER 12: DIRECT EMISSIONS FROM STATIONARY COMBUSTION

Who should read Chapter 12:

- Chapter 12 applies to Reporters who combust fuels to generate electricity, heat, steam, or power using equipment in a fixed location.

What you will find in Chapter 12:

- This chapter provides guidance on determining your direct emissions of CO_2, CH_4, and N_2O from stationary combustion, such as through power generation, manufacturing, or other industrial activities involving the combustion of fuels.

Information you will need:

- You will either need CEMS data or information about the type and quantity of fuels consumed.

Cross-References:

- If your organization imports steam or district heating or cooling, refer to Chapter 13 for guidance.

Data Quality Tiers: Direct CO_2 Emissions From Stationary Combustion

Tier	Method	Emission Factors
A1	Direct Monitoring	Continuous emissions monitoring (CEMS) in accordance with 40 CFR Part 75
A2	Calculation Based on Fuel Use	• Measured carbon content of fuels (per unit mass or volume), or • Measured carbon content of fuels (per unit energy) and measured heat content of fuels
B	Calculation Based on Fuel Use	• Measured heat content of fuels and default carbon content (per unit energy), or • Measured carbon content (per unit energy) and default heat content of fuels
C	Calculation Based on Fuel Use	Default CO_2 emission factors by fuel type

Data Quality Tiers: Direct CH_4 and N_2O Emissions From Stationary Combustion

Tier	Method	Emission Factors
A	Direct Measurement	Continuous emissions monitoring or periodic direct measurements
B	Calculation Based on Fuel Use	Default emission factors by sector and technology type
C	Calculation Based on Fuel Use	Default emission factors by sector and fuel type

Stationary combustion refers to the combustion of fuels to produce electricity, heat, or motive power using equipment in a fixed location. Typical large stationary sources include power plants, refineries, and manufacturing facilities. Smaller stationary sources include commercial and residential furnaces. Examples of stationary combustion units include boilers, burners, turbines, furnaces, and internal combustion engines. Figure 12.1 gives guidance on how to select a particular CO_2 emissions quantification methodology based on the data that is available to you. Figure 12.2 gives similar guidance for direct CH_4 and N_2O emissions from stationary combustion.

12.1 Measurement Using Continuous Emissions Monitoring System Data

Tier A1 Method: Direct Monitoring

Some facilities, such as power plants and large industrial plants, have continuous emissions monitoring systems (CEMS) that track their CO_2 emissions. Entities that report CO_2 emissions data to the U.S. EPA according to 40 CFR Part 75 and/or state/province or local environmental agencies should report the same CO_2 emissions information to the Registry. CO_2 data should be monitored in accordance with the requirements of the 40 CFR Part 75 rule, which includes requirements for installing, certifying, operating, and maintaining CEMS for measuring and reporting CO_2 as well as SO_2, NO_2, O_2, opacity, and volumetric flow. You may use either of the two following CEMS configurations to determine annual CO_2 emissions:

1. A monitor measuring CO_2 concentration percent by volume of flue gas and a flow monitoring system measuring the volumetric flow rate of flue gas can be used to determine CO_2 mass emissions. Annual CO_2 emissions are determined based on the operating time of the unit.

2. A monitor measuring O_2 concentration percent by volume of flue gas and a flow monitoring system measuring the volumetric flow rate of flue gas combined with theoretical CO_2 and flue gas production by fuel characteristics can be used to determine CO_2 flue gas emissions and CO_2 mass emissions. Annual CO_2 emissions are determined based on the operating time of the unit.

You must specify which CEMS configuration you use. Refer to U.S. EPA's resources on 40 CFR Part 75 at www.epa.gov/airmarkets/emissions/rules.html. Direct monitoring using CEMS in accordance with Part 75 is designated a Tier A1 method for measuring CO_2 emissions from stationary combustion.

If you do not own or operate a stationary combustion unit equipped with a CEMS, you should calculate your emissions from stationary combustion using the method outlined in Section 12.2. For whichever method or combination of methods you use to quantify your CO_2 emissions, you should use the same reporting methodology from year to year to maintain consistency and comparability between years.

For Reporters in the electric power sector, additional specifications on using CEMS will be developed in a forthcoming power/utility sector protocol.

Figure 12.1 Selecting Data Quality Tiers: Direct CO_2 Emissions from Stationary Combustion

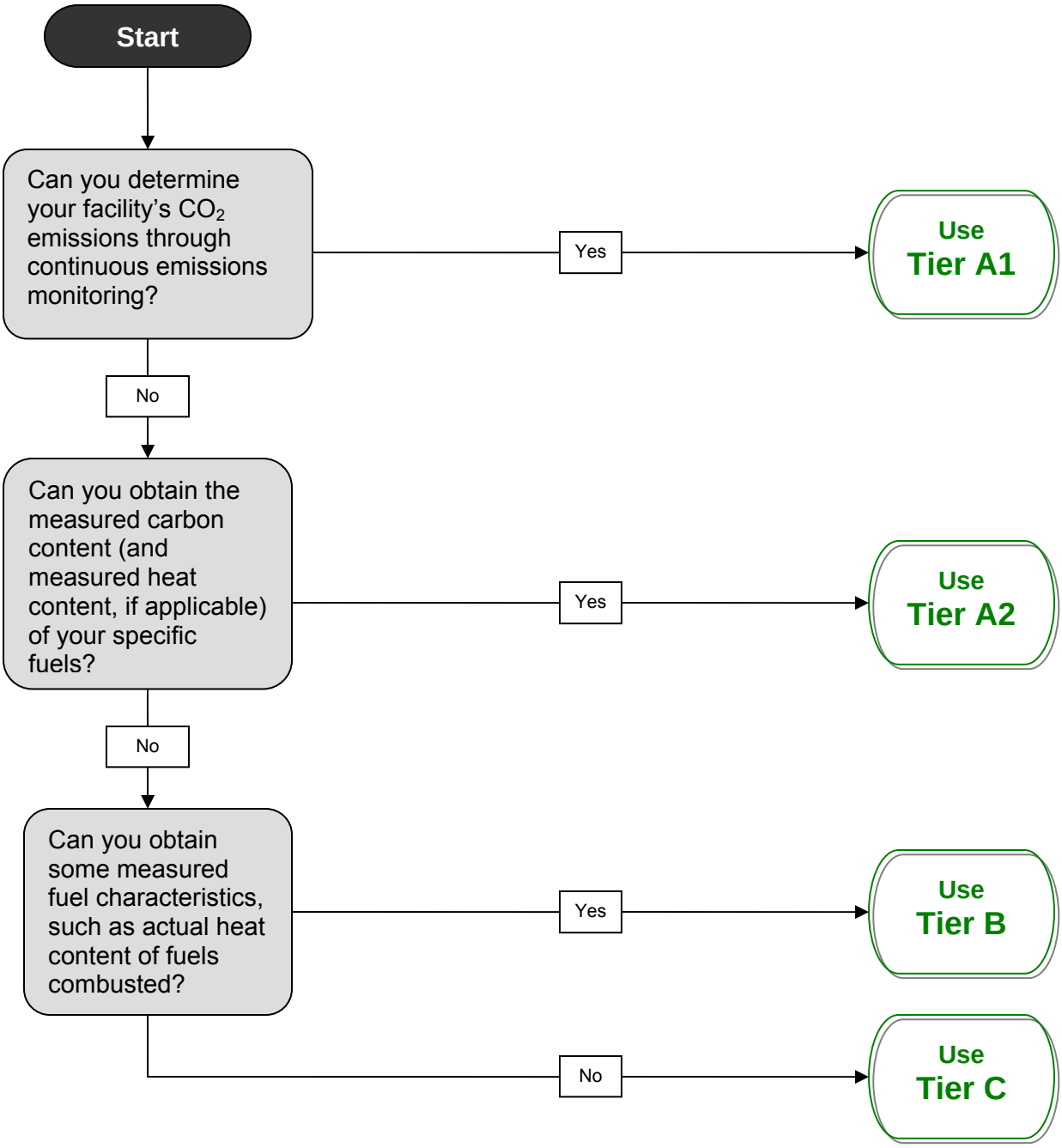
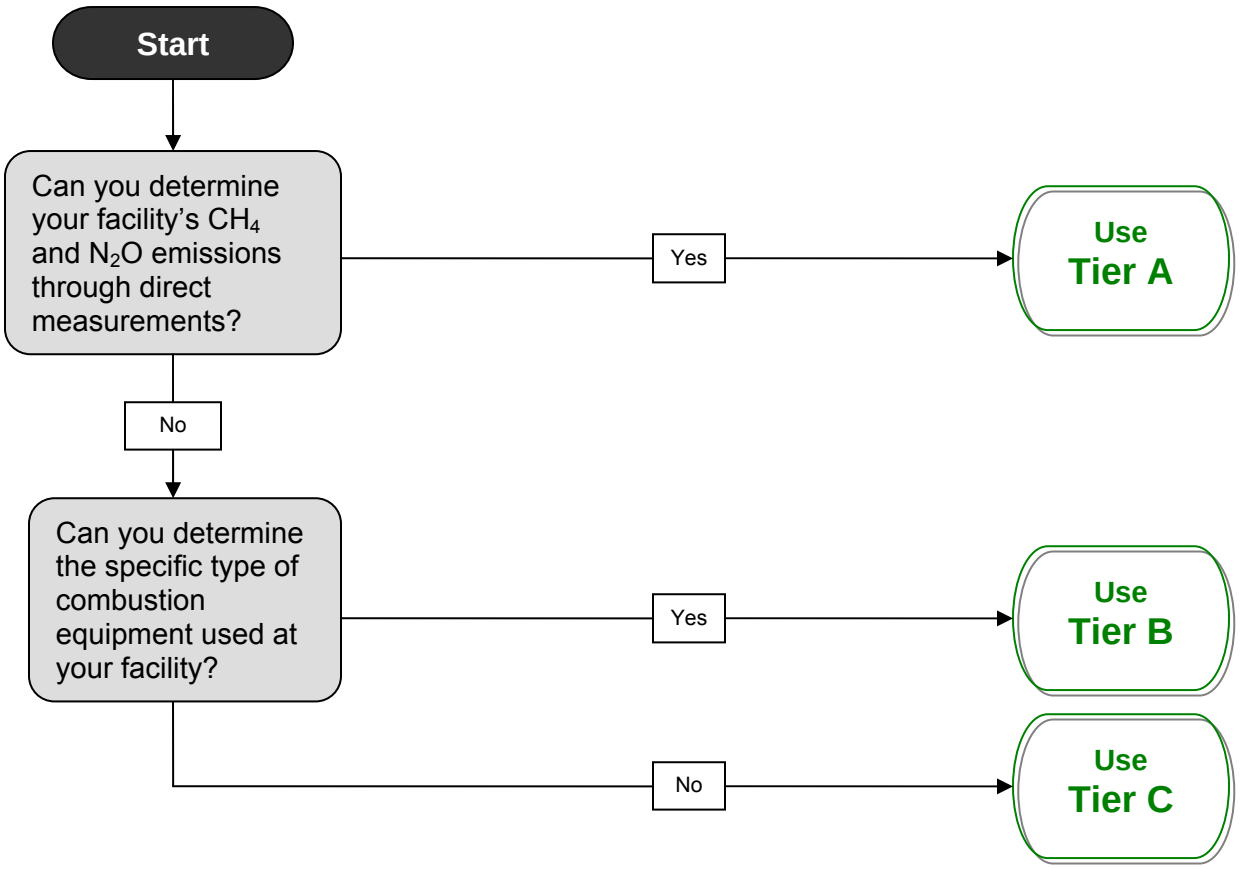


Figure 12.2 Selecting Data Quality Tiers: Direct CH_4 and N_2O Emissions from Stationary Combustion



Biofuels, Waste Fuels, and Biomass Co-Firing in a Unit with CEMS

Biofuels

Biofuels such as landfill gas, wood, and wood waste may be combusted in addition to fossil fuels. You must report your CO_2 emissions from fossil fuel combustion separately from your CO_2 emissions from biomass combustion. CO_2 emissions from fossil fuel combustion are reported in Scope 1, while CO_2 emissions from biomass combustion are reported separately from the scopes. The same step-by-step procedure for determining GHG emissions from fossil fuels applies to non-fossil fuels. Note that emissions of CH_4 and N_2O from biomass combustion are included in Scope 1 and are not treated differently from CH_4 and N_2O emissions from fossil fuel combustion.

Waste Fuels

For facilities that combust municipal solid waste (MSW), you must calculate or monitor your CO_2 emissions resulting from the incineration of waste of fossil fuel origin (e.g. plastics, certain textiles, rubber, liquid solvents, and waste oil) and include those emissions as direct CO_2 emissions (Scope 1). Your CO_2 emissions from combusting the biomass portion of MSW (e.g., yard waste, paper products, etc.) must be separately calculated and reported as biogenic CO_2 emissions (reported separately from the scopes). Information on the biomass portion of MSW will be site-specific and should be obtained from a local waste characterization study. You may also use the methodology described in ASTM D6866 (see below for more information).

Biomass Co-Firing in a Unit with CEMS

The Registry requires that participants identify and report biomass CO_2 emissions as "biogenic emissions," separate from fossil fuel emissions. Thus, if you combust biomass fuels in any of your units using CEMS to report CO_2 emissions, you must calculate the emissions associated with the biomass fuels (Equation 12a) and subtract this from your total measured emissions (Equation 12b). You must report these separately from your fossil fuel emissions, along with any other biogenic emissions.

The following example illustrates a case where biomass is co-fired and emissions are monitored through a CEMS. An electric utility company reports the CO_2 emissions from its major electric generating facilities using the CEMS already installed on those units. At one of its natural gas-fired units it co-fires with wood; the emissions associated with each combustion activity are mixed in the exhaust stack and measured collectively by the CEMS device. To report its CO_2 emissions from this unit, the utility must calculate the portion of CO_2 emissions from combusting wood, and subtract it from the measurement of total emissions. To do so, the entity must quantify the amount of biomass consumed by the unit, and multiply that value by the wood-specific CO_2 emission factor from Tables 12.2 – 12.3 (see Equation 12a). This value is then subtracted from the total CO_2 emissions measured by the CEMS (see Equation 12b).

Equation 12a	Calculating Biomass CO_2 Emissions (Fuel Consumption in MMBtu)

CO_2 from Biomass Combustion (metric tons) = Biomass Consumed (MMBtu) x Biomass Emission Factor (kg CO_2/MMBtu) x 0.001 (metric tons/kg)

Equation 12b	Backing Out Biomass CO_2 Emissions from CEMS

CO_2 from Fossil Fuel Combustion (metric tons) = Total CEMS CO_2 Emissions (metric tons) - Total Biomass CO_2 Emissions (metric tons)

Alternatively, instead of first calculating CO_2 from biomass combustion, you may first calculate CO_2 from fossil fuel combustion. To do this, multiply fossil fuel consumption by an appropriate fuel-specific emission factor from Tables 12.1 – 12.4 (see Section 12.2, Step 2 below). After deriving total CO_2 from fossil fuel combustion, subtract this value from total CEMS CO_2 emissions to obtain CO_2 from biomass combustion.

As a third option for separately calculating the portion of CO_2 emissions attributable to fossil fuel versus biomass, you may use the methodology described in ASTM D6866-06a, "Standard Test Methods for Determining the Biobased Content of Natural Range Materials Using Radiocarbon and Isotope Ratio Mass Spectrometry Analysis." For further specifications on using this method, see California Air Resources Board *Regulation for the Mandatory Reporting of Greenhouse Gas Emissions*, Section 95125(h)(2).

12.2 Calculating Emissions from Stationary Combustion Using Fuel Use Data

Estimating emissions from stationary combustion using fuel use data involves the following six steps:

1. Determine annual consumption of each fuel combusted at your facility;
2. Determine the appropriate CO_2 emission factors for each fuel;
3. Determine the appropriate CH_4 and N_2O emission factors for each fuel;
4. Calculate each fuel's CO_2 emissions;
5. Calculate each fuel's CH_4 and N_2O emissions; and
6. Convert CH_4 and N_2O emissions to CO_2 equivalent and determine total emissions.

Step 1: Determine annual consumption of each fuel combusted at your facility.

First identify all fuels combusted at your facility. Examples of fuel types include bituminous coal, residual fuel oil, distillate fuel (diesel), liquefied petroleum gas (LPG), and natural gas.

Then determine your annual fuel use by fuel type, measured in terms of physical units (mass or volume). For stationary combustion sources, the preferred method is to determine the amount of fuel combusted at each combustion unit by reading individual meters located at the fuel input point, if applicable. Alternatively, you may use fuel receipts or purchase records to calculate your total fuel usage. Convert fuel purchase and storage data to estimates of measured fuel use using Equation 12c.

Equation 12c	Accounting for Changes in Fuel Stocks
Total Annual Fuel Consumption = Annual Fuel Purchases - Annual Fuel Sales **+** Fuel Stock at Beginning of Year **-** Fuel Stock at End of Year	

Step 2: Determine the appropriate CO_2 emission factor for each fuel.

Tier A2 Method: Actual Fuel

The preferred method is to derive an emission factor for CO_2 using the measured characteristics of the fuels combusted. This method requires information on the heat content and/or carbon content of the fuels. This information can be determined either through fuel sampling and analysis or from data provided by fuel suppliers. Fuel sampling and analysis should be performed periodically, the frequency dependening on the type of fuel. In general, the sampling frequency should be greater for more variable fuels (e.g., coal, wood, solid waste) than for more homogenous fuels (e.g., natural gas, diesel fuel). You should collect and analyze fuel data according to applicable industry-approved, national, or international technical standards regarding sampling frequency, procedures, and preparation.

For additional resources on sampling rates and methods, refer to:

- 40 CFR Part 75, Appendix G
- California Air Resources Board Regulation for the Mandatory Reporting of Greenhouse Gas Emissions, Section 95125(c)-(e)
- European Union, Monitoring and Reporting Guidelines for the EU Emissions Trading Scheme (2006), Section 13, "Determination of Activity-Specific Data and Factors"
- WRI/WBCSD GHG Protocol Guidance: Direct Emissions from Stationary Combustion, Version 3.0 (July 2005), Annex D (http://www.ghgprotocol.org)

The carbon content of each fuel can be expressed in mass of carbon per mass of fuel (such as kg C/short ton), mass of carbon per volume of fuel (such as kg C/gallon), or mass of carbon per unit energy of fuel (such as kg C/MMBtu).

The heat content of each fuel is expressed in units of energy per unit mass or volume (such as

MMBtu/short ton or MMBtu/gallon) and should be calculated based on higher heating values (HHV). See the box "Estimating Emissions Based on Higher Heating Values" below if you have data based on lower heating values (LHV).

Multiply the heat content per unit mass or volume (such as Btu/ton or Btu/gallon) by the carbon content per unit energy (e.g., kg C/Btu) to determine the mass of carbon per physical unit of fuel (such as kg C/ton or kg C/gallon). If you have measured carbon content data expressed in mass of carbon per mass or volume of fuel, you do not need to multiply by a heat content factor, since your factor is already in physical units.

To account for the small fraction of carbon that may not be oxidized during combustion, multiply the carbon content in physical units by the fraction of carbon oxidized. If you do not have oxidation factors specific to the combustion source, use a default oxidation factor of 1.00 (100% oxidation). To convert from units of carbon to units of CO_2, multiply by 44/12, the molecular weight ratio of CO_2 to carbon (see Equation 12d).

Equation 12d	Calculating CO_2 Emission Factors Using Measured Fuel Characteristics (Fuel Consumption in Gallons)
Emission Factor (kg CO_2/gallon) = Heat Content × Carbon Content × % Oxidized × 44/12 (Btu/gallon) (kg C/Btu) (CO_2/C)	

Tier B Method: Combining Actual and Default Factors

You should use information on the measured fuel characteristics of the fuels you combust whenever possible. In some cases, you may be able to obtain measured heat content information (for example, from your fuel supplier), but unable to obtain measured carbon content data. Likewise, you may have measured carbon content data but no measured heat content data. In these cases, you should combine your more specific data with default factors from Tables 12.1 - 12.4. This method is considered Tier B.

Tier C Method: Default Emission Factors

If you cannot determine the measured heat content or measured carbon content of your specific fuels, use the default emission factors provided by fuel type in Tables 12.1 - 12.4. Emission factors are provided in units of CO_2 per unit energy and CO_2 per unit mass or volume. If you combust a fuel that is not listed in the table, you must derive an emission factor based on the specific properties of the fuel using the Tier A2 method.

Step 3: Determine the appropriate CH_4 and N_2O emission factors for each fuel.

Estimating CH_4 and N_2O emissions depends not only on fuel characteristics, but also on technology type and combustion characteristics; usage of pollution control equipment; and maintenance and operational practices. Due to this complexity, estimates of CH_4 and N_2O emissions from stationary sources are much more uncertain than estimates of CO_2 emissions. CH_4 and N_2O also account for much smaller quantities of emissions from stationary combustion than CO_2.

Tier A Method: Direct Monitoring

If your facilities use direct monitoring to obtain specific emission factors based on periodic exhaust sampling, use these emission factors.

Tier B Method: Default Emission Factors by Sector and Technology

If you can determine either the specific type of combustion equipment used at your facilities or your facilities' specific commercial sectors use factors from Tables 12.5 - 12.8 based on specific types of combustion equipment and sector.

Estimating Emissions Based on Higher Heating Values

When calculating CO_2 emissions, all fuel data and factors must be based on the same heating value basis. In the United States and Canada, higher heating values (HHV) are used to measure the heat content of fuels rather than lower heating values (LHV). Therefore, estimates of GHG emissions from fuel combustion should be based on HHV. However, LHV are typically used internationally, so you may be required to convert from LHV to HHV. Note that HHV are also referred to as gross calorific values (GCV) and LHV are also referred to as net calorific values (NCV). Converting from LHV to HHV is inexact and depends on the actual characteristics of fuels, but you can convert from a LHV to a HHV basis using the following "rule of thumb."

Equation 12e	Converting from LHV to HHV
$\mathbf{Btu}_{\mathbf{HHV}} = Btu_{LHV} \div 0.95$ for solid and liquid fuels	
$\mathbf{Btu}_{\mathbf{HHV}} = Btu_{LHV} \div 0.90$ for gaseous fuels	

Where Btu is fuel consumption data on an energy content basis (such as Btu or MMBtu) or a heat content factor (such as Btu/gallon). Note that to convert carbon content factors (such as kg C/Btu) from LHV to HHV, you must multiply by 0.95 or 0.90 rather than divide because the Btu factor is in the denominator.

For example, natural gas has a heat content of 924 Btu/standard cubic foot on an LHV basis and a heat content of 1,027 Btu/standard cubic foot on an HHV basis. Natural gas has a carbon content of 16.08 kg C/MMBtu on a LHV basis and a carbon content of 14.47 kg C/MMBtu on a HHV basis. To calculate a CO_2 emission factor for natural gas on the basis of both LHV and HHV, use Equation 12f.

Equation 12f	Example: Calculating CO_2 Emission Factors Using Measured Fuel Characteristics
Emission Factor (kg CO_2/gallon) = Heat Content (Btu/gallon) × Carbon Content (kg C/Btu) × % Oxidized × 44/12 (CO_2/C)	
LHV Emission Factor (kg CO_2/scf) = 924 (Btu/scf) × 16.08 (kg C/MMBtu) ÷ 1,000,000 × 1.0 (Btu/MMBtu) × 44/12 (CO_2/C) = 0.05448 (kg CO_2/scf)	
HHV Emission Factor (kg CO_2/gallon) = 1027 (Btu/scf) × 14.47 (kg C/MMBtu) ÷ 1,000,000 × 1.0 (Btu/MMBtu) × 44/12 (CO_2/C) = 0.05449 (kg CO_2/scf)	

Tier C Method: Default Emission Factors by Sector and Fuel

Use Table 12.9 to obtain emission factors by fuel type and sector.

Step 4: Calculate each fuel's CO_2 emissions and convert to metric tons.

To determine your facility's CO_2 emissions from stationary combustion, multiply your fuel use from Step 1 by the CO_2 emission factor from Step 2, and then convert kilograms to metric tons. Repeat the calculation for each fuel type, then sum (see Equation 12g). Note that Equation 12g expresses fuel use in gallons. If fuel use is expressed in different units (such as short tons, cubic feet, MMBtu, etc.), replace "gallons" in the equation with the appropriate unit of measure. Be sure that your units of measure for fuel use are the same as those in your emission factor.

Equation 12g	Calculating CO_2 Emissions From Stationary Combustion (Fuel use in gallons)
Fuel A CO_2 Emissions (metric tons) = Fuel Consumed (gallons) × Emission Factor (kg CO_2/gallon) ÷ 1,000 (kg/metric ton)	
Fuel B CO_2 Emissions (metric tons) = Fuel Consumed (gallons) × Emission Factor (kg CO_2/gallon) ÷ 1,000 (kg/metric ton)	
Total CO_2 Emissions (metric tons) = CO_2 from Fuel A (metric tons) + CO_2 from Fuel B (metric tons) + … (metric tons)	

Step 5: Calculate each fuel's CH_4 and N_2O emissions and convert to metric tons.

To determine your CH_4 emissions from stationary combustion at your facility, multiply your fuel use from Step 1 by the CH_4 emission factor from Step 3, and then convert grams to metric tons. Repeat the calculation for each fuel and technology type, then sum (see Equation 12h). Note that Equation 12h expresses fuel use in MMBtu. If fuel use is expressed in different units (such as gallons, short tons, cubic feet, etc.) you must convert your fuel use data to units of MMBtu. If you have a measured heat content factor for your specific fuels, use it to convert fuel data to energy units. Otherwise, use a default heat content factor by fuel from Tables 12.1 – 12.4. Be sure that your units of measure for fuel use are the same as those in your emission factor. Follow the same procedure, using Equation 12i, to calculate total emissions of N_2O at your facility.

Equation 12h	Calculating CH_4 Emissions From Stationary Combustion
Fuel/Technology Type A **CH_4 Emissions** (metric tons) = Fuel Use (MMBtu) × Emission Factor (g CH_4/MMBtu) ÷ 1,000,000 (g/metric ton)	
Fuel/Technology Type B **CH_4 Emissions** (metric tons) = Fuel Use (MMBtu) × Emission Factor (g CH_4/MMBtu) ÷ 1,000,000 (g/metric ton)	
Total CH_4 Emissions (metric tons) = CH_4 from Type A (metric tons) + CH_4 from Type B (metric tons) + … (metric tons)	

Equation 12i	Calculating N_2O Emissions From Stationary Combustion
Fuel/Technology Type A **N_2O Emissions** (metric tons) = Fuel Use (MMBtu) × Emission Factor (g N_2O/MMBtu) ÷ 1,000,000 (g/metric ton)	
Fuel/Technology Type B **N_2O Emissions** (metric tons) = Fuel Use (MMBtu) × Emission Factor (g N_2O/MMBtu) ÷ 1,000,000 (g/metric ton)	
Total N_2O Emissions (metric tons) = N_2O from Type A (metric tons) + N_2O from Type B (metric tons) + … (metric tons)	

Step 6: Convert CH_4 and N_2O emissions to units of CO_2 equivalent and determine total emissions from stationary combustion.

Use the IPCC global warming potential (GWP) factors provided in Equation 12j (and Appendix B) to convert CH_4 and N_2O emissions to units of CO_2 equivalent. Then sum your emissions of all three gases to determine your total emissions from stationary combustion at your facility (see Equation 12j).

Equation 12j	Converting to CO_2-Equivalent and Determining Total Emissions
CO_2 Emissions (metric tons CO_2e) = CO_2 Emissions (metric tons) × 1 (GWP)	
CH_4 Emissions (metric tons CO_2e) = CH_4 Emissions (metric tons) × 21 (GWP)	
N_2O Emissions (metric tons CO_2e) = N_2O Emissions (metric tons) × 310 (GWP)	
Total Emissions (metric tons CO_2e) = CO_2 + CH_4 + N_2O (metric tons CO_2e)	

12.3 Allocating Emissions from Combined Heat and Power (Optional)

Accounting for the GHG emissions from a Combined Heat and Power (CHP) facility is unique because it produces more than one useful product from the same amount of fuel combusted, namely, electricity and heat or steam. As such, apportionment of the GHG emissions between the two different energy streams may be useful.

Note that to comply with Registry reporting guidelines, Reporters must only determine absolute emissions from a CHP plant using the same procedure for non-CHP plants described in the previous section. However, Reporters may also allocate emissions according to each final product stream, i.e. electricity or steam, as described in this section.

Note that a CHP facility refers to a system that captures the waste-heat from the primary electricity generating pathway and uses it for non-electricity purposes. In contrast, a combined cycle power plant that uses waste-heat to generate electricity should be treated no differently from stationary combustion emissions as described in the previous section.

The most consistent approach for allocating GHG emissions in CHP applications is the efficiency method, which allocates emissions of CHP plants between electric and thermal outputs on the basis of the energy input used to produce the separate steam and electricity products. To use this method, you must know the total emissions from the CHP plant, the total steam (or heat) and electricity production, and the steam (or heat) and electricity efficiency of the facility. Use the following steps to determine the share of emissions attributable to steam (or heat) and electricity production.

Step 1: Determine the total direct emissions from the CHP system.

Calculate total direct GHG emissions using the methods described in the previous section. Like the guidance for non-CHP stationary combustion, calculating total emissions from CHP sources is based on either CEMS or fuel input data.

Step 2: Determine the total steam and electricity output for the CHP system.

To determine the total energy output of the CHP plant attributable to steam production, use published tables that provide energy content (enthalpy) values for steam at different temperature and pressure conditions (for example, the *Industrial Formulation 1997 for the Thermodynamic Properties of Water and Steam* published by the International Association for the Properties of Water and Steam (IAPWS)). Energy content values multiplied by the quantity of steam produced at the temperature and pressure of the CHP plant yield energy output values in units of MMBtu. Alternatively, determine net heat (or steam) production (in MMBtu) by subtracting the heat of return condensate (MMBtu) from the heat of steam export (MMBtu). To convert total electricity production from MWh to MMBtu, multiply by 3.412 MMBtu/MWh.

Step 3: Determine the efficiencies of steam and electricity production.

Identify steam (or heat) and electricity production efficiencies. If actual efficiencies of the CHP plant are not known, use a default value of 80 percent for steam and a default value of 35 percent for electricity. The use of default efficiency values may, in some cases, violate the energy balance constraints of some CHP systems. However, total emissions will still be allocated between the energy outputs. If the constraints are not satisfied, the efficiencies of the steam and electricity can be modified until constraints are met.

Step 4: Determine the fraction of total emissions allocated to steam and electricity production.

Allocate the emissions from the CHP plant to the steam and electricity product streams by using Equation 12k.

Equation 12k	Allocating CHP Emissions to Steam and Electricity
Step 1:	$E_H = (H \div e_H) \div [(H \div e_H) + (P \div e_P)] \times E_T$
Step 2:	$E_P = E_T - E_H$

where:
E_H = Emissions allocated to steam production;
H = Total steam (or heat) output (MMBtu);
e_H = Efficiency of steam (or heat) production;
P = Total electricity output (MMBtu);
e_P = Efficiency of electricity generation;
E_T = Total direct emissions of the CHP system; and
E_P = Emissions allocated to electricity production.

12.4 Example: Direct Emissions from Stationary Combustion

F&M Manufacturing

F&M is a manufacturing facility. It has two 10 MW generating units, one burning natural gas and one coal-fired unit. Neither is equipped with a CEMS device. F&M also has a commercial office building on-site that is heated with distillate fuel. In this example, the entity uses a Tier A2 method for estimating CO_2 emissions and Tier C for estimating CH_4 and N_2O emissions.

Step 1: Determine annual consumption of each fuel combusted at the facility.

F&M measures fuel used by its plants and purchases its heating fuel for commercial use in bulk by the barrel. Last year it consumed 769,921,800 standard cubic feet (scf) of natural gas and 43,039 short tons of coal. It also purchased 265 barrels of distillate fuel for heating and sold 15 barrels. F&M began the year with 12 barrels in storage and ended the year with 24 barrels in storage. Using Equation 12c, F&M determined distillate fuel consumption. The resulting total in barrels can be converted to gallons by multiplying by 42 (see Equation 12c below).

Step 2: Determine the appropriate emission factors for each fuel.

F&M calculates CO_2 emission factors for each of the three fuels using measured fuel characteristics it obtained from its fuel suppliers see Equation 12d below. F&M obtains emission factors for CH_4 and N_2O from Table 12.9 because it does not have monitoring data or available data on specific combustion technologies (see below).

Step 3: Calculate each fuel's CO_2 emissions and convert to metric tons.

See Equation 12g below.

Step 4: Calculate each fuel's CH_4 and N_2O emissions and convert to metric tons.

F&M first multiplies its fuel consumption in physical units by its fuel-specific heat content values to calculate fuel use in MMBtu for each fuel. See Equations 12h and 12i below.

Step 5: Convert CH_4 and N_2O emissions to units of CO_2 equivalent and determine total emissions from stationary combustion.

See Equation 12j below.

Equation 12c	Example: Accounting for Changes in Fuel Stocks
Total Annual Fuel Consumption = Annual Fuel Purchases - Annual Fuel Sales **+** Fuel Stock at Beginning of Year **-** Fuel Stock at End of Year	
Annual Distillate Fuel Use = 265 barrels - 15 barrels + 12 barrels - 24 barrels = 238 barrels × 42 gallons/barrel = 9,996 gallons	

Fuel Consumption by Fuel Type and Sector

Fuel Type	Sector	Annual Consumption
Natural Gas	Industrial	769,921,800 scf
Coal	Industrial	43,039 short tons
Distillate Fuel	Commercial	9,996 gallons

Equation 12d	Example: Calculating CO_2 Emission Factors Using Measured Fuel Characteristics
Emission Factor = Heat Content × Carbon Content × % Oxidized × 44/12 (kg CO_2/gallon) (MMBtu/gallon) (kg C/MMBtu) (CO_2/C)	
Natural Gas Emission Factor = 1,024 × 14.43 × 1.0 × 44/12 ÷ 1,000,000 = **0.054** (kg CO_2/scf) (Btu/scf) (kg C/MMBtu) (CO_2/C) (Btu/MMBtu) (kg CO_2/scf)	
Coal Emission Factor = 21.98 × 25.49 × 1.0 × 44/12 = **2,054.32** (kg CO_2/short ton) (MMBtu/short ton) (kg C/MMBtu) (CO_2/C) (kg CO_2/short ton)	
Distillate Emission Factor = 5.821 × 19.94 × 1.0 × 44/12 ÷ 42 = **10.13** (kg CO_2/gallon) (MMBtu/barrel) (kg C/MMBtu) (CO_2/C) (gallons/barrel) (kg CO_2/gallon)	

Emission Factors by Fuel Type and Sector

Fuel Type	Sector	CO_2 Emission Factor	CH_4 Emission Factor	N_2O Emission Factor
Natural Gas	Industrial	0.054 kg/scf	1 g/MMBtu	0.1 g/MMBtu
Coal	Industrial	2,054.32 kg/short ton	11 g/MMBtu	1.6 g/MMBtu
Distillate Fuel	Commercial	10.13 kg/gallon	11 g/MMBtu	0.6 g/MMBtu

Equation 12g	Example: Calculating CO_2 Emissions From Stationary Combustion
Fuel A CO_2 Emissions = Fuel Consumed × Emission Factor ÷ 1,000 (metric tons) (gallons) (kg CO_2/gallon) (kg/metric ton)	
Natural Gas CO_2 Emissions = 769,921,800 × 0.054 ÷ 1,000 = 41,714.2 metric tons (metric tons) (scf) (kg CO_2/scf) (kg/metric ton)	
Coal CO_2 Emissions = 43,039 × 2,054.32 ÷ 1,000 = 88,415.9 metric tons (metric tons) (short tons) (kg CO_2/short ton) (kg/metric ton)	
Diesel CO_2 Emissions = 9,996 × 10.13 ÷ 1,000 = 101.3 metric tons (metric tons) (gallons) (kg CO_2/gallon) (kg/metric ton)	
Total CO_2 Emissions = 41,714.2 + 88,415.9 + 101.3 = **130,231 metric tons** (metric tons) (metric tons) (metric tons) (metric tons)	

Equation 12h	Example: Calculating CH_4 Emissions From Stationary Combustion
Fuel A **CH_4 Emissions =** Fuel Use × Emission Factor ÷ 1,000,000 (metric tons) (MMBtu) (g CH_4/MMBtu) (g/metric ton)	
NG CH_4 **Emissions =** 788,399.92 × 1 ÷ 1,000,000 = 0.79 metric tons (metric tons) (MMBtu) (g CH_4/MMBtu) (g/metric ton)	
Coal CH_4 **Emissions =** 951,931.82 × 11 ÷ 1,000,000 = 10.47 metric tons (metric tons) (MMBtu) (g CH_4/MMBtu) (g/metric ton)	
Distillate Fuel **CH_4 Emissions =** 1,385.40 × 11 ÷ 1,000,000 = 0.02 metric tons (metric tons) (MMBtu) (g CH_4/MMBtu) (g/metric ton)	
Total CH_4 Emissions = 0.79 + 10.47 + 0.02 = **11.3 metric tons** (metric tons) (metric tons)	

Equation 12i	Example: Calculating N_2O Emissions From Stationary Combustion
Fuel A N_2O Emissions = Fuel Use × Emission Factor ÷ 1,000,000 (metric tons) (MMBtu) (g N_2O/MMBtu) (g/metric ton)	
NG N_2O **Emissions =** 788,399.92 × 0.1 ÷ 1,000,000 = 0.08 metric tons (metric tons) (MMBtu) (g N_2O/MMBtu) (g/metric ton)	
Coal **N_2O Emissions =** 951,931.82 × 1.6 ÷ 1,000,000 = 1.52 metric tons(metric tons) (MMBtu) (g N_2O/MMBtu) (g/metric ton)	
Distillate Fuel **N_2O Emissions =** 1,385.40 × 0.6 ÷ 1,000,000 = 0.001 metric tons(metric tons) (MMBtu) (g N_2O/MMBtu) (g/metric ton)	
Total N_2O Emissions = 0.08 + 1.52 + 0.001 = **1.6 metric tons** (metric tons) (metric tons)	

Equation 12j	Example: Converting to CO_2 Equivalent and Determining Total Emissions
CO_2 Emissions = 130,231 × 1 = 130,231 (metric tons CO_2e) (metric tons) (GWP)	
CH_4 Emissions = 11.3 × 21 = 237 (metric tons CO_2e) (metric tons) (GWP)	
N_2O Emissions = 1.6 × 310 = 496 (metric tons CO_2e) (metric tons) (GWP)	
Total Emissions = $CO_2 + CH_4 + N_2O$ = **130,964** (metric tons CO_2e) (metric tons CO_2e)	

Table 12.1 U.S. Default Factors for Calculating CO_2 Emissions from Fossil Fuel Combustion

Fuel Type	Tier B Method			Tier C Method	
	Heat Content	Carbon Content (Per Unit Energy)	Fraction Oxidized	CO_2 Emission Factor (Per Unit Energy)	CO_2 Emission Factor (Per Unit Mass or Volume)
Coal and Coke	**MMBtu / Short ton**	**kg C / MMBtu**		**kg CO_2 / MMBtu**	**kg CO_2 / Short ton**
Anthracite Coal	25.09	28.26	1.00	103.62	2,599.83
Bituminous Coal	24.93	25.49	1.00	93.46	2,330.04
Sub-bituminous Coal	17.25	26.48	1.00	97.09	1,674.86
Lignite	14.21	26.30	1.00	96.43	1,370.32
Unspecified (Residential/ Commercial)	22.05	26.00	1.00	95.33	2,102.29
Unspecified (Industrial Coking)	26.27	25.56	1.00	93.72	2,462.12
Unspecified (Other Industrial)	22.05	25.63	1.00	93.98	2,072.19
Unspecified (Electric Utility)	19.95	25.76	1.00	94.45	1,884.53
Coke	24.80	31.00	1.00	113.67	2,818.93
Natural Gas (By Heat Content)	**Btu / Standard cubic foot**	**kg C / MMBtu**		**kg CO_2 / MMBtu**	**kg CO_2 / Standard cub. ft.**
975 to 1,000 Btu / Std cubic foot	975 – 1,000	14.73	1.00	54.01	Varies
1,000 to 1,025 Btu / Std cubic foot	1,000 – 1,025	14.43	1.00	52.91	Varies
1,025 to 1,050 Btu / Std cubic foot	1,025 – 1,050	14.47	1.00	53.06	Varies
1,050 to 1,075 Btu / Std cubic foot	1,050 – 1,075	14.58	1.00	53.46	Varies
1,075 to 1,100 Btu / Std cubic foot	1,075 – 1,100	14.65	1.00	53.72	Varies
Greater than 1,100 Btu / Std cubic foot	> 1,110	14.92	1.00	54.71	Varies
Unspecified (Weighted U.S. Average)	1,029	14.47	1.00	53.06	0.0546
Petroleum Products	**MMBtu / Barrel**	**kg C / MMBtu**		**kg CO_2 / MMBtu**	**kg CO_2 / gallon**
Asphalt & Road Oil	6.636	20.62	1.00	75.61	11.95
Aviation Gasoline	5.048	18.87	1.00	69.19	8.32
Distillate Fuel Oil (#1, 2 & 4)	5.825	19.95	1.00	73.15	10.15
Jet Fuel	5.670	19.33	1.00	70.88	9.57
Kerosene	5.670	19.72	1.00	72.31	9.76
LPG (average for fuel use)	3.849	17.23	1.00	63.16	5.79
Propane	3.824	17.20	1.00	63.07	5.74
Ethane	2.916	16.25	1.00	59.58	4.14
Isobutene	4.162	17.75	1.00	65.08	6.45
n-Butane	4.328	17.72	1.00	64.97	6.70
Lubricants	6.065	20.24	1.00	74.21	10.72
Motor Gasoline	5.218	19.33	1.00	70.88	8.81
Residual Fuel Oil (#5 & 6)	6.287	21.49	1.00	78.80	11.80
Crude Oil	5.800	20.33	1.00	74.54	10.29
Naphtha (<401 deg. F)	5.248	18.14	1.00	66.51	8.31
Natural Gasoline	4.620	18.24	1.00	66.88	7.36
Other Oil (>401 deg. F)	5.825	19.95	1.00	73.15	10.15
Pentanes Plus	4.620	18.24	1.00	66.88	7.36
Petrochemical Feedstocks	5.428	19.37	1.00	71.02	9.18
Petroleum Coke	6.024	27.85	1.00	102.12	14.65
Still Gas	6.000	17.51	1.00	64.20	9.17
Special Naphtha	5.248	19.86	1.00	72.82	9.10
Unfinished Oils	5.825	20.33	1.00	74.54	10.34
Waxes	5.537	19.81	1.00	72.64	9.58
Waste Tires	**MMBtu / Short ton**	**kg C / MMBtu**		**kg CO_2 / MMBtu**	**kg CO_2 / Short ton**
Waste Tires	28.00	30.77	1.00	112.84	3,159.49

Source: U.S. EPA, *Inventory of Greenhouse Gas Emissions and Sinks: 1990-2005* (2007), Annex 2.1, Tables A-31, A-32, A-35, and A-36, except: heat content factors for Unspecified Coal (by sector), Naphtha (<401 deg. F), and Other Oil (>401 deg. F) (from U.S. Energy Information Administration, *Annual Energy Review 2006* (2007), Tables A-1 and A-5) and Carbon Content and Heat Content factors for Coke and LPG (from EPA Climate Leaders, Stationary Combustion Guidance (2007), Table B-1). A fraction oxidized value of 1.00 is from the Intergovernmental Panel on Climate Change (IPCC), *Guidelines for National Greenhouse Gas Inventories* (2006).
Note: Default CO_2 emission factors (per unit energy) are calculated as: Carbon Content × Fraction Oxidized × 44/12. Default CO_2 emission factors (per unit mass or volume) are calculated using Equation 12d: Heat Content × Carbon Content × Fraction Oxidized × 44/12 × Conversion Factor (if applicable). Heat content factors are based on higher heating values (HHV).

Table 12.2 U.S. Default Factors for Calculating CO_2 Emissions from Non-Fossil Fuel Combustion

Fuel Type	Tier B Method			Tier C Method	
	Heat Content	Carbon Content (Per Unit Energy)	Fraction Oxidized	CO_2 Emission Factor (Per Unit Energy)	CO_2 Emission Factor (Per Unit Mass or Volume)
Non-Fossil Fuels (Solid)	**MMBtu / Short ton**	**kg C / MMBtu**		**kg CO_2 / MMBtu**	**kg CO_2 / Short ton**
Wood and Wood Waste (12% moisture)	15.38	25.60	1.00	93.87	1,443.67
Kraft Black Liquor (North American hardwood)	11.98	25.75	1.00	94.41	1,130.76
Kraft Black Liquor (North American softwood)	12.24	25.95	1.00	95.13	1,164.02
Non-Fossil Fuels (Gas)	**Btu / Standard cubic foot**	**kg C / MMBtu**		**kg CO_2 / MMBtu**	**kg CO_2 / Standard cub. ft.**
Landfill Gas (50% CH_4 / 50% CO_2)	502.50	14.20	1.00	52.07	0.0262
Wastewater Treatment Biogas	Varies	14.20	1.00	52.07	Varies

Source: U.S. EPA Climate Leaders, Stationary Combustion Guidance (2007), Table B-2.
Note: Default CO_2 emission factors (per unit energy) are calculated as: Carbon Content × Fraction Oxidized × 44/12. Default CO_2 emission factors (per unit mass or volume) are calculated using Equation 12d: Heat Content × Carbon Content × Fraction Oxidized × 44/12 × Conversion Factor (if applicable). Heat content factors are based on higher heating values (HHV).

Table 12.3 Canadian Default Factors for Calculating CO_2 Emissions from Combustion of Natural Gas, Petroleum Products, and Biomass

Fuel Type	Tier B Method			Tier C Method
	Carbon Content (Per Unit Energy)	Heat Content	Fraction Oxidized	CO_2 Emission Factor (Per Unit Mass or Volume)
Natural Gas	**kg C / GJ**	**GJ / megalitre**		**g CO_2 / m^3**
Electric Utilities, Industry, Commercial, Pipelines, Agriculture, Residential	n/a	38.26	1.00	1901
Producer Consumption	n/a	n/a	1.00	2401
Natural Gas Liquids	**kg C / GJ**	**GJ / kilolitre**		**g CO_2 / L**
Propane	n/a	25.31	1.00	1518
Ethane	n/a	17.22	1.00	981
Butane	n/a	28.44	1.00	1739
Petroleum Products	**kg C / GJ**	**GJ / kilolitre**		**g CO_2 / L**
Light Fuel Oil	n/a	38.80	1.00	2873
Heavy Fuel Oil	n/a	42.50	1.00	3127
Kerosene	n/a	37.68	1.00	2589
Diesel	n/a	38.30	1.00	2772
Petroleum Coke from Upgrading Facilities	n/a	37.40	1.00	3547
Petroleum Coke from Refineries & Others	n/a	33.52	1.00	3884
Still Gas	**kg C / GJ**	**GJ / megalitre**		**g CO_2 / m^3**
Upgrading Facilities	n/a	43.24	1.00	2173
Refineries & Others	n/a	36.08	1.00	1777
Biomass	**kg C / GJ**	**GJ / ton**		**g CO_2 / kg**
Wood Fuel/Wood Waste	n/a	18.00	1.00	1000
Spent Pulping Liquor	n/a	14.00	1.00	1503

Source: Default CO_2 emission factors: Environment Canada, *National Inventory Report, 1990-2005: Greenhouse Gas Sources and Sinks in Canada* (April 2007), Annex 12: Emission Factors, Tables A12-1, A12-2, A12-3 (2005 data) and A12-22; Default Heat Content: Statistics Canada, *Report on Energy Supply-demand in Canada, 2005* (2007), Energy conversion factors, p. 116; Default Carbon Content: Canada-specific carbon content coefficients are not available. If you cannot obtain measured carbon content values specific to your fuels, you should use the Tier C Method (default CO_2 emission factor). Default Fraction Oxidized: Intergovernmental Panel on Climate Change (IPCC), *Guidelines for National Greenhouse Gas Inventories* (2006).
Note: CO_2 emission factors from Environment Canada originally included fraction oxidized factors of less than 100 percent. Values were converted to include a 100 percent oxidation rate using 99.5 percent for natural gas and NGLs; 98.5 percent for petroleum products; and 95 percent for biomass, based on the rates used to calculate the original factors.

Table 12.4 Canadian Default Factors for Calculating CO_2 Emissions from Combustion of Coal

Province and Coal Type	Tier B Method			Tier C Method
	Carbon Content	Heat Content	Fraction Oxidized	CO_2 Emission Factor (Per Unit Mass)
	kg C/GJ	GJ / ton		kg CO_2 / ton
Newfoundland and Labrador				
Canadian Bituminous	n/a	28.96	1.00	2272
Anthracite	n/a	27.70	1.00	2414
Prince Edward Island				
Canadian Bituminous	n/a	28.96	1.00	2272
Nova Scotia				
Canadian Bituminous	n/a	28.96	1.00	2272
U.S. Bituminous	n/a	28.99	1.00	2311
Sub-Bituminous	n/a	19.15	1.00	1751
New Brunswick				
Canadian Bituminous	n/a	26.80	1.00	2016
U.S. Bituminous	n/a	28.99	1.00	2334
Quebec				
Canadian Bituminous	n/a	28.96	1.00	2272
U.S. Bituminous	n/a	28.99	1.00	2367
Anthracite	n/a	27.70	1.00	2414
Ontario				
Canadian Bituminous	n/a	25.43	1.00	2277
U.S. Bituminous	n/a	28.99	1.00	2457
Sub-Bituminous	n/a	19.15	1.00	1751
Lignite	n/a	15.00	1.00	1491
Anthracite	n/a	27.70	1.00	2414
Manitoba				
Canadian Bituminous	n/a	26.02	1.00	2275
U.S. Bituminous	n/a	28.99	1.00	2457
Sub-Bituminous	n/a	19.15	1.00	1751
Lignite	n/a	15.00	1.00	1438
Anthracite	n/a	27.70	1.00	2414
Saskatchewan				
Canadian Bituminous	n/a	25.43	1.00	1871
Lignite	n/a	15.00	1.00	1441
Alberta				
Canadian Bituminous	n/a	25.43	1.00	1871
Sub-Bituminous	n/a	19.15	1.00	1783
Anthracite	n/a	27.70	1.00	2414
British Columbia				
Canadian Bituminous	n/a	26.02	1.00	2093
U.S. Bituminous	n/a	28.99	1.00	2457
Sub-Bituminous	n/a	19.15	1.00	1783
All Provinces				
Coke	n/a	28.83	1.00	2505
	kg C/GJ	GJ / megalitre		g/m^3
Coke Oven Gas	n/a	19.14	1.00	1616

Source: Default CO_2 Emission Factors: Environment Canada, *National Inventory Report, 1990-2005: Greenhouse Gas Sources and Sinks in Canada* (April 2007), Annex 12: Emission Factors, Table A12-5 (1998-2005 data); Default Heat Content: Statistics Canada, *Report on Energy Supply-demand in Canada, 2005* (2007), Energy conversion factors, p. 116, except value for U.S. Bituminous which was taken from Appendix C of this Protocol; Default Carbon Content: Canada-specific carbon content coefficients are not available. If you cannot obtain measured carbon content values specific to your fuels, you should use the Tier C Method. Default Fraction Oxidized: Intergovernmental Panel on Climate Change (IPCC), *Guidelines for National Greenhouse Gas Inventories* (2006). Note: CO_2 emission factors from Environment Canada originally included a fraction oxidized factor of 99 percent. Values were converted to instead include a 100 percent oxidation rate.

Table 12.5 Default CH_4 and N_2O Emission Factors by Technology Type for the Electricity Generation Sector (Tier B)

Fuel Type and Basic Technology	Configuration	CH_4 (g/MMBtu)	N_2O (g/MMBtu)
Liquid Fuels			
Residual Fuel Oil/Shale Oil Boilers	Normal Firing	0.8	0.3
	Tangential Firing	0.8	0.3
Gas/Diesel Oil Boilers	Normal Firing	0.9	0.4
	Tangential Firing	0.9	0.4
Large Diesel Oil Engines >600hp (447kW)		4.0	NA
Solid Fuels			
Pulverized Bituminous Combustion Boilers	Dry Bottom, wall fired	0.7	0.5
	Dry Bottom, tangentially fired	0.7	1.4
	Wet Bottom	0.9	1.4
Bituminous Spreader Stoker Boilers	With and without re-injection	1.0	0.7
Bituminous Fluidized Bed Combustor	Circulating Bed	1.0	61.1
	Bubbling Bed	1.0	61.1
Bituminous Cyclone Furnace		0.2	1.6
Lignite Atmospheric Fluidized Bed		NA	71.2
Natural Gas			
Boilers		0.9	0.9
Gas-Fired Gas Turbines >3MW		3.8	0.9
Large Dual-Fuel Engines		245	NA
Combined Cycle		0.9	2.8
Peat			
Peat Fluidized Bed Combustor	Circulating Bed	3.0	7.0
	Bubbling Bed	3.0	3.0
Biomass			
Wood/Wood Waste Boilers		9.3	5.9
Wood Recovery Boilers		0.8	0.8

Source: IPCC, Guidelines for National Greenhouse Gas Inventories (2006), Chapter 2: Stationary Combustion, Table 2.6. Values were converted back from LHV to HHV using IPCC's assumption that LHV are 5 percent lower than HHV for coal and oil, 10 percent lower for natural gas, and 20 percent lower for dry wood. (The IPCC converted the original factors from units of HHV to LHV, so the same conversion rates were used here to obtain the original values in units of HHV. For purposes of reporting, the conversion factor of 20 percent for wood should not be used to convert between LHV and HHV values; instead you should use a value of 5 percent. Refer to the box on "Estimating Emissions Based on Higher Heating Values" in Section 12.2.) Values were converted from kg/TJ to g/MMBtu using 1 kg = 1000 g and 1 MMBtu = 0.001055 TJ. NA = data not available.

Table 12.6 Default CH_4 and N_2O Emission Factors for Kilns, Ovens, and Dryers (Tier B)

Industry	Source	CH_4 (g / MMBtu)	N_2O (g / MMBtu)
Cement, Lime	Kilns - Natural Gas	1.04	NA
Cement, Lime	Kilns – Oil	1.00	NA
Cement, Lime	Kilns – Coal	1.00	NA
Coking, Steel	Coke Oven	1.00	NA
Chemical Processes, Wood, Asphalt, Copper, Phosphate	Dryer - Natural Gas	1.04	NA
Chemical Processes, Wood, Asphalt, Copper, Phosphate	Dryer – Oil	1.00	NA
Chemical Processes, Wood, Asphalt, Copper, Phosphate	Dryer – Coal	1.00	NA

Source: IPCC, Guidelines for National Greenhouse Gas Inventories (2006), Chapter 2: Stationary Combustion, Table 2.8. Values were converted back from LHV to HHV using IPCC's assumption that LHV are 5 percent lower than HHV for coal and oil and 10 percent lower for natural gas. Values were converted from kg/TJ to g/MMBtu using 1 kg = 1000 g and 1 MMBtu = 0.001055 TJ. NA = data not available.

Table 12.7 Default CH_4 and N_2O Emission Factors by Technology Type for the Industrial Sector (Tier B)

Fuel Type and Basic Technology	Configuration	CH_4 (g/MMBtu)	N_2O (g/MMBtu)
Liquid Fuels			
Residual Fuel Oil Boilers		3.0	0.3
Gas/Diesel Oil Boilers		0.2	0.4
Large Stationary Diesel Oil Engines >600hp (447 kW)		4.0	NA
Liquefied Petroleum Gases Boilers		0.9	4.0
Solid Fuels			
Other Bituminous/Sub-bit. Overfeed Stoker Boilers		1.0	0.7
Other Bituminous/Sub-bit. Underfeed Stoker Boilers		14.0	0.7
Other Bituminous/Sub-bituminous Pulverized	Dry Bottom, wall fired	0.7	0.5
	Dry Bottom, tangentially fired	0.7	1.4
	Wet Bottom	0.9	1.4
Other Bituminous Spreader Stokers		1.0	0.7
Other Bituminous/Sub-bit. Fluidized Bed Combustor	Circulating Bed	1.0	61.1
	Bubbling Bed	1.0	61.1
Natural Gas			
Boilers		0.9	0.9
Gas-Fired Gas Turbines >3MW		3.8	0.9
Natural Gas-fired Reciprocating Engines	2-Stroke Lean Burn	658.0	NA
	4-Stroke Lean Burn	566.9	NA
	4-Stroke Rich Burn	104.5	NA
Biomass			
Wood/Wood Waste Boilers		9.3	5.9

Source: IPCC, Guidelines for National Greenhouse Gas Inventories (2006), Chapter 2: Stationary Combustion, Table 2.7. Values were converted from LHV to HHV assuming that LHV are 5 percent lower than HHV for coal and oil, 10 percent lower for natural gas, and 20 percent lower for dry wood. (The IPCC converted the original factors from units of HHV to LHV, so the same conversion rates were used here to obtain the original values in units of HHV. For purposes of reporting, the conversion factor of 20 percent for wood should not be used to convert between LHV and HHV values; instead you should use a value of 5 percent. Refer to the box on "Estimating Emissions Based on Higher Heating Values" in Section 12.2.) Values were converted from kg/TJ to g/MMBtu using 1 kg = 1000 g and 1 MMBtu = 0.001055 TJ. NA = data not available.

Table 12.8 Default CH_4 and N_2O Emission Factors by Technology Type for the Commercial Sector (Tier B)

Fuel Type and Basic Technology	Configuration	CH_4 (g/MMBtu)	N_2O (g/MMBtu)
Liquid Fuels			
Residual Fuel Oil Boilers		1.4	0.3
Gas/Diesel Oil Boilers		0.7	0.4
Liquefied Petroleum Gases Boilers		0.9	4.0
Solid Fuels			
Other Bituminous/Sub-bit. Overfeed Stoker Boilers		1.0	0.7
Other Bituminous/Sub-bit. Underfeed Stoker Boilers		14.0	0.7
Other Bituminous/Sub-bit. Hand-fed Units		87.2	0.7
Other Bituminous/Sub-bituminous Pulverized Boilers	Dry Bottom, wall fired	0.7	0.5
	Dry Bottom, tangentially fired	0.7	1.4
	Wet Bottom	0.9	1.4
Other Bituminous Spreader Stokers		1.0	0.7
Other Bituminous/Sub-bit. Fluidized Bed Combustor	Circulating Bed	1.0	61.1
	Bubbling Bed	1.0	61.1
Natural Gas			
Boilers		0.9	0.9
Gas-Fired Gas Turbines >3MWa		3.8	1.3
Biomass			
Wood/Wood Waste Boilers		9.3	5.9

Source: IPCC, Guidelines for National Greenhouse Gas Inventories (2006), Chapter 2: Stationary Combustion, Table 2.10. Values were converted back from LHV to HHV using IPCC's assumption that LHV are 5 percent lower than HHV for coal and oil, 10 percent lower for natural gas, and 20 percent lower for dry wood. (The IPCC converted the original factors from units of HHV to LHV, so the same conversion rates were used here to obtain the original values in units of HHV. For purposes of reporting, the conversion factor of 20 percent for wood should not be used to convert between LHV and HHV values; instead you should use a value of 5 percent. Refer to the box on "Estimating Emissions Based on Higher Heating Values" in Section 12.2.) Values were converted from kg/TJ to g/MMBtu using 1 kg = 1000 g and 1 MMBtu = 0.001055 TJ.

Table 12.9 Default CH_4 and N_2O Emission Factors By Fuel Type and Sector (Tier C)

Fuel Type / End-Use Sector	CH_4 (g/MMBtu)	N_2O (g/MMBtu)
Coal		
Residential	316	1.6
Commercial	11	1.6
Industrial	11	1.6
Electric Power	1	1.6
Petroleum Products		
Residential	11	0.6
Commercial	11	0.6
Industrial	3	0.6
Electric Power	3	0.6
Natural Gas		
Residential	5	0.1
Commercial	5	0.1
Industrial	1	0.1
Electric Power	1	0.1
Wood		
Residential	316	4.2
Commercial	316	4.2
Industrial	32	4.2
Electric Power	32	4.2
Pulping Liquors		
Industrial	2.5	2.0

Source: EPA Climate Leaders, Stationary Combustion Guidance (2007), Table A-1, based on U.S. EPA, *Inventory of Greenhouse Gas Emissions and Sinks: 1990-2005* (2007), Annex 3.1.

CHAPTER 13: DIRECT EMISSIONS FROM MOBILE COMBUSTION

Who should read Chapter 13:

- Chapter 13 applies to all Reporters that own or operate motor vehicles or other forms of transportation.

What you will find in Chapter 13:

- This chapter provides guidance on calculating your direct emissions of CO_2, CH_4, and N_2O from mobile combustion.

Information you will need:

- You will need information about the types of vehicles your organization operates, fuel consumption data, and miles traveled for each type of vehicle. Fuel consumption data may be obtained from bulk fuel purchases, fuel receipts, or direct measurements of fuel use. Sources of annual mileage data include odometer readings, trip manifests or maintenance records.

Cross-References:

- Refer to Chapter 16 to determine any fugitive emissions you may have from motor vehicle air conditioning units, if applicable.

Data Quality Tiers: Direct CO_2 Emissions From Mobile Combustion

Tier	Activity Data	Emission Factors
A1	Fuel use	• Measured carbon content (per unit mass) and measured density of fuels, or • Measured carbon content (per unit energy) and measured heat content of fuels
A2	Fuel use	• Measured heat content of fuels and default carbon content (per unit energy), or • Measured carbon content (per unit energy) and default heat content of fuels
B	Fuel use	Default CO_2 emission factors by fuel type
C	Fuel use estimated using vehicle miles traveled and vehicle fuel economy	Default CO_2 emission factors by fuel type

Data Quality Tiers: Direct CH_4 & N_2O Emissions From Mobile Combustion (Non-Highway Vehicles)

Tier	Activity Data	Emission Factors
A	Fuel use	Default emission factors by vehicle type and fuel type
B	Fuel use estimated using vehicle miles traveled and vehicle fuel economy	Default emission factors by vehicle type and fuel type

Data Quality Tiers: Direct CH_4 & N_2O Emissions From Mobile Combustion (Highway Vehicles)

Tier	Activity Data	Emission Factors
A	Miles traveled by vehicle type	Default emission factors by vehicle type based on vehicle technology
B	Miles traveled by vehicle type	Default emission factors by vehicle type based on model year
C	Distance estimated using fuel use and vehicle fuel economy	Default emission factors by vehicle type based on vehicle technology or model year

Mobile combustion sources include both on-road and non-road vehicles such as automobiles, trucks, buses, trains, ships and other marine vessels, airplanes, tractors, and construction equipment. The combustion of fossil fuels in mobile sources emits carbon dioxide (CO_2), methane (CH_4) and nitrous oxide (N_2O).

Emissions from mobile combustion can be estimated based on vehicle fuel use and miles traveled data. CO_2 emissions, which account for the majority of emissions from mobile sources, are directly related to the quantity of fuel combusted and thus can be calculated using fuel consumption data. CH_4 and N_2O emissions depend more on the emission control technologies employed in the vehicle and distance traveled. Calculating emissions of CH_4 and N_2O requires data on vehicle characteristics (which takes into account emission control technologies) and vehicle miles traveled.

Figure 13.1 gives guidance on how to select a particular CO_2 emissions quantification methodology based on available data for direct CO_2 emission from mobile combustion. Figure 13.2 gives similar guidance for direct CH_4 and N_2O emissions from mobile combustion (highway vehicles only).

Mobile sources may also emit hydrofluorocarbons (HFCs) and perfluorocarbons (PFCs) from mobile air conditioning and transport refrigeration leaks. See Chapter 16 for guidance on estimating these additional mobile source emissions.

Figure 13.1 Selecting Data Quality Tiers: Direct CO_2 Emissions from Mobile Combustion

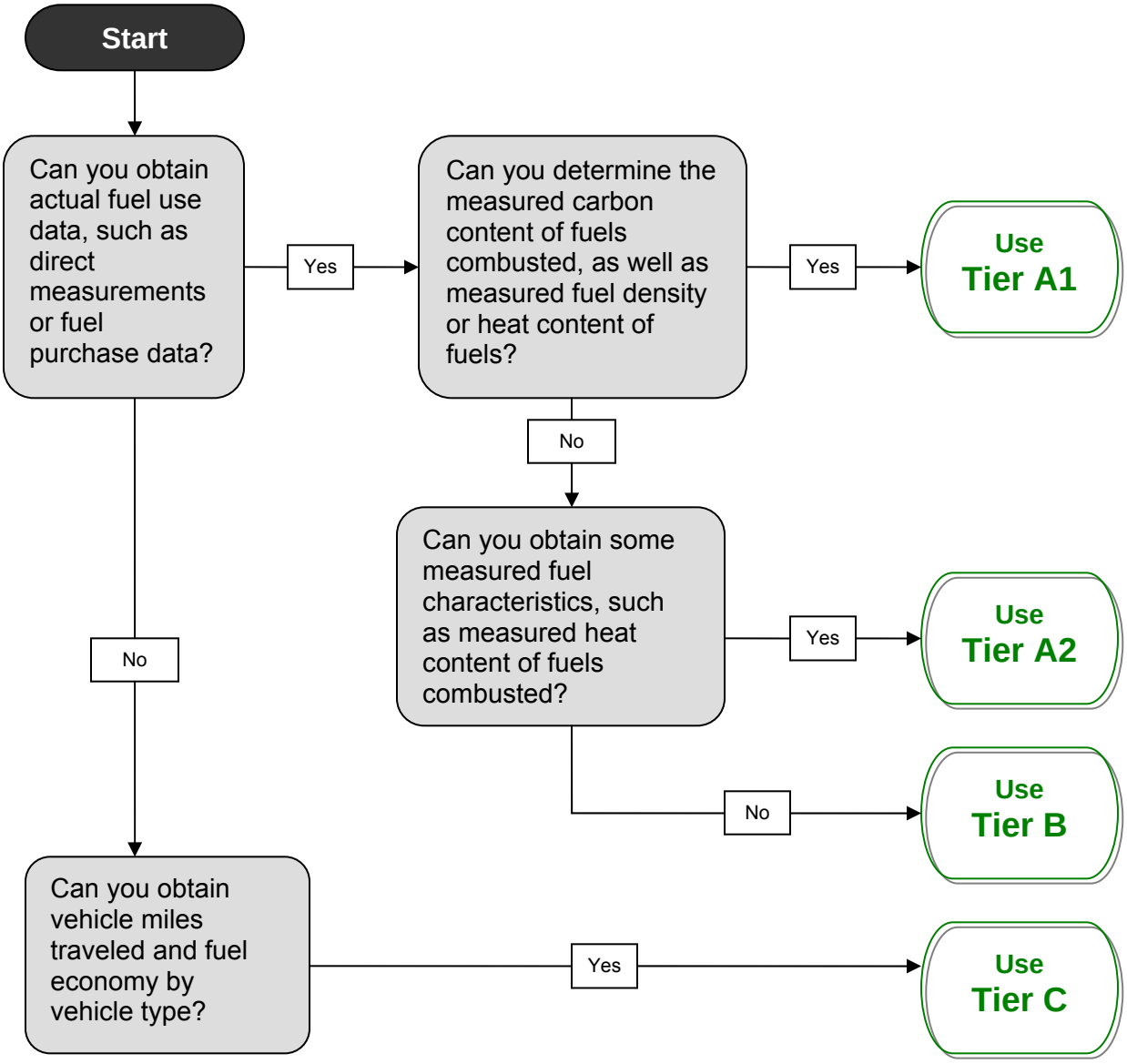
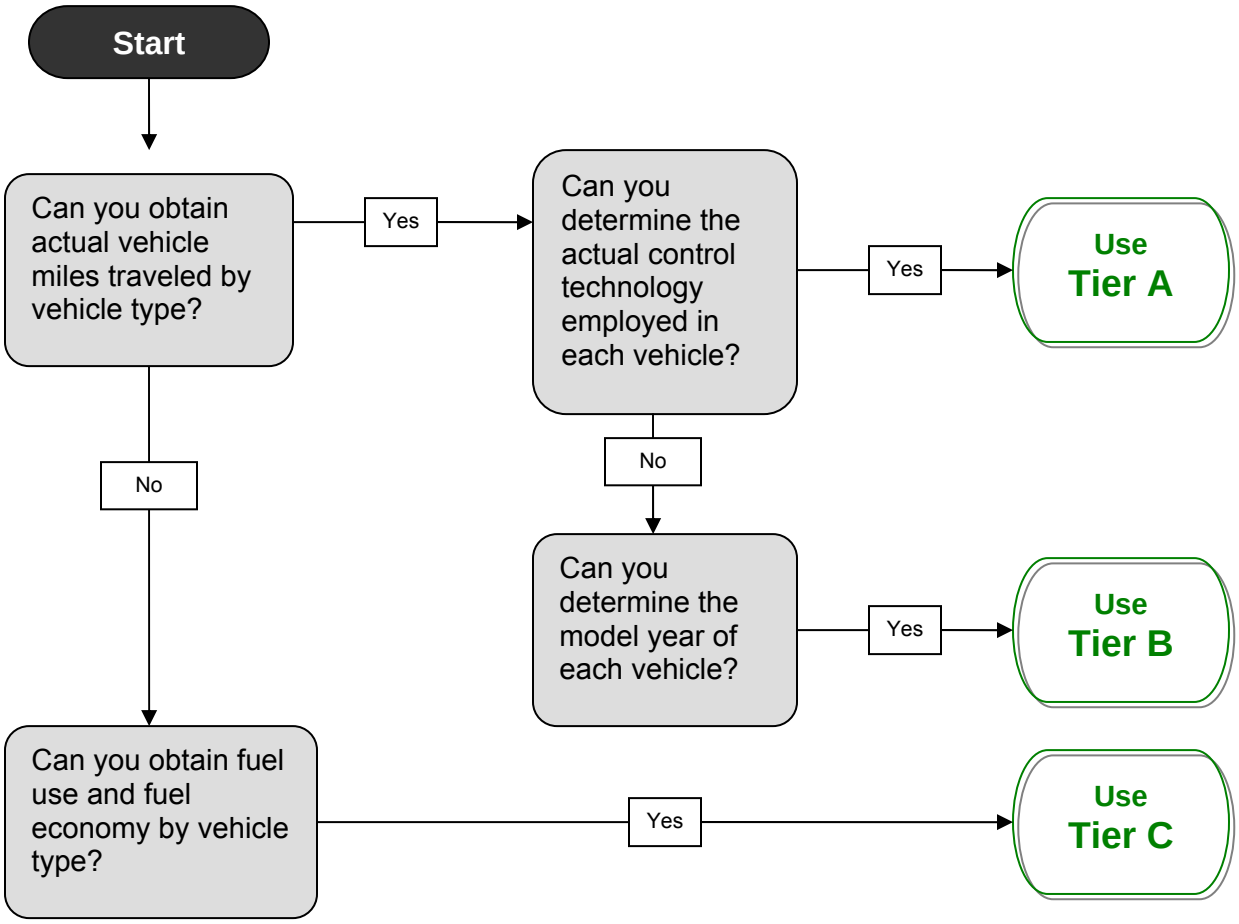


Figure 13.2 Selecting Data Quality Tiers: Direct CH_4 and N_2O Emissions from Mobile Combustion (Highway Vehicles Only)



13.1 Calculating CO_2 Emissions from Mobile Combustion

Estimating CO_2 emissions from mobile sources involves three steps:

1. Identify total annual fuel consumption by fuel type;
2. Determine the appropriate emission factor; and
3. Calculate total CO_2 emissions.

Step 1: Identify total annual fuel consumption by fuel type.

Tier A/B Method: Actual Use

The preferred approach is to obtain data on actual fuel consumption by fuel type. Methods include direct measurements of fuel use (official logs of vehicle fuel gauges or storage tanks); collected fuel receipts; and purchase records for bulk storage fuel purchases, (in cases where you operate a fleet and store fuel at a facility). For bulk purchase records, use Equation 13a to account for changes in fuel stocks when determining your annual fuel consumption. Total annual fuel purchases should include both fuel purchased for the bulk fueling facility and fuel purchased for vehicles at other fueling locations.

Equation 13a	Accounting for Changes in Fuel Stocks From Bulk Purchases
Total Annual Consumption = Total Annual Fuel Purchases + Amount Stored at Beginning of Year – Amount Stored at End of Year	

Tier C Method: Estimation Based on

If you cannot obtain fuel use data, but have information on annual mileage and fuel economy for the vehicles you operate, you may estimate your fuel consumption using the following procedure:

1. Identify the vehicle make, model, fuel type, and model years for all the vehicles you operate;
2. Identify the annual distance traveled by vehicle type;
3. Determine the fuel economy of each vehicle; and
4. Convert annual mileage to fuel consumption using Equation 13b.

Sources of annual mileage data include odometer readings or trip manifests that include distance to destinations. The preferred method for estimating fuel economy is to use company records by specific vehicle, such as the miles per gallon (mpg) values listed on the sticker when the vehicle was purchased, vehicle manufacturer documentation or other company records. If this data is not available, you may obtain fuel economy factors for passenger cars and light trucks from the EPA website www.fueleconomy.gov, which lists city, highway, and combined fuel economy factors by make, model, model year, and specific engine type. If you have accurate information about the driving patterns of your fleet, you should apply a specific mix of city and highway driving, using Equation 13b. Otherwise use the combined fuel economy factor, which assumes 45 percent of your vehicles' mileage is highway driving and 55 percent is city driving.

For heavy-duty trucks, fuel economy data may be available from vehicle suppliers, manufactures, or in company records. If no specific information is available, you should assume fuel economy factors of 8.0 mpg for medium trucks (10,000-26,000 lbs) and 5.8 mpg for heavy trucks (more than 26,000 lbs) (Source: U.S. Department of Energy, *Transportation Energy Data Book*, Ed. 26, 2007, Table 5.4).
If you operate more than one type of vehicle, you must calculate the fuel use for each of your vehicle types and then sum them together.

Equation 13b	Estimating Fuel Use Based on Distance
Fuel Use (gallons) = Distance (miles) ÷ [(City FE (mpg) × City %) + (Highway FE (mpg) × Hwy %)] FE = Fuel Economy	

Step 2: Select the appropriate CO_2 emission factor for each fuel.

Tier A1 Method: Actual Fuel

The preferred approach is to measure the fuel characteristics of the specific fuel consumed, or obtain this data from your fuel supplier. Site-specific emission factors can be determined from data on either: a) fuel density and carbon content of fuels, or b) heat content and carbon content per unit of energy of fuels.

Fuel Density Approach

Multiply the fuel density (mass/volume) by the carbon content per unit mass (mass C/mass fuel) to determine the mass of carbon per unit of volume of fuel (such as kg C/gallon). To account for the small fraction of carbon that may not be oxidized during combustion, multiply the carbon content by the fraction of carbon oxidized. If you do not have oxidation factors specific to the combustion source, use a default oxidation factor of 1.00 (100 percent oxidation). To convert from units of carbon to CO_2, multiply by 44/12 (see Equation 13c).

Equation 13c	Calculating CO_2 Emission Factors Using the Fuel Density Approach

Emission Factor (kg CO_2/gallon) =
Fuel Density × Carbon Content × % Oxidized × 44/12
(kg/gallon) (kg C/kg fuel) (CO_2/C)

Heat Content Approach

Use this approach if you can obtain the heat content and carbon content of each fuel from your fuel supplier. Multiply the heat content per unit volume (such as Btu/gallon) by the carbon content per unit energy (such as kg C/Btu) to determine the mass of carbon per unit volume (such as kg C/gallon). To account for the small fraction of carbon that may not be oxidized during combustion, multiply the carbon content by the fraction of carbon oxidized. If you do not have oxidation factors specific to the combustion source, use a default oxidation factor of 1.00 (100 percent oxidation). To convert from units of carbon to CO_2, multiply by 44/12 (see Equation 13d).

Equation 13d	Calculating CO_2 Emission Factors Using the Heat Content Approach

Emission Factor (kg CO_2/gallon) =
Heat Content × Carbon Content × % Oxidized × 44/12
(Btu/gallon) (kg C/Btu) (CO_2/C)

If you can obtain measured heat content data but not measured carbon content data, use your own heat content value and a default carbon content factor from Table 13.1 (U.S.) or Table 13.2 (Canada).

Tier A2 Method: Combining Actual and

If you can obtain measured carbon content data but not measured heat content data, use your own carbon content value and a default heat content factor from Table 13.1 (U.S.) or 13.2 (Canada).

Tier B/C Method: Default Emission

If you cannot determine the measured fuel density, heat content, or carbon content of your specific fuels, use the default CO_2 emission factors by fuel type in Table 13.1 (U.S.) and Table 13.2 (Canada). You are encouraged to use more specific values than those given in Tables 13.1 and 13.2 if available. For example, if you have data that provides information on specific gasoline used in terms of winter or summer grades, oxygenated vs. non-oxygenated fuels or other local fuel characteristics. If possible, you should also obtain specific fuel information for other fuels such as off-road diesel fuel and fuel used for locomotive, rail or marine transport.

Step 3: Calculate total CO_2 emissions and convert to metric tons.

To determine your CO_2 emissions from mobile combustion, first multiply your fuel use from Step 1 by the CO_2 emission factor from Step 2, and then convert kilograms to metric tons. Repeat the calculation for each fuel type, then sum (see Equation 13e).

Equation 13e	Calculating CO_2 Emissions From Mobile Combustion
Fuel A CO_2 Emissions (metric tons) = Fuel Consumed (gallons) × Emission Factor (kg CO_2/gallon) ÷ 1,000 (kg/metric ton)	
Fuel B CO_2 Emissions (metric tons) = Fuel Consumed (gallons) × Emission Factor (kg CO_2/gallon) ÷ 1,000 (kg/metric ton)	
Total CO_2 Emissions (metric tons) = CO_2 from Fuel A (metric tons) + CO_2 from Fuel B (metric tons) + … (metric tons)	

13.2 Calculating CH_4 and N_2O Emissions from Mobile Combustion

Estimating emissions of CH_4 and N_2O from mobile sources involves five steps:

1. Identify the vehicle type, fuel type, and technology type or model year of each vehicle you own and operate;
2. Identify the annual mileage by vehicle type;
3. Select the appropriate emission factor for each vehicle type;
4. Calculate CH_4 and N_2O emissions for each vehicle type and sum to obtain total CH_4 and N_2O emissions; and
5. Convert CH_4 and N_2O emissions to units of CO_2 equivalent and sum to determine total emissions.

Note that this procedure applies to highway vehicles and alternative fuel vehicles, but not to non-highway vehicles such as ships, locomotives, aircraft, and non-road vehicles. For these vehicles, estimation of CH_4 and N_2O emissions is based on fuel consumption rather than distance traveled. For these vehicles, use the same fuel consumption data used to estimate CO_2 emissions in the previous section. Then follow Steps 3-5 below to estimate emissions using default factors provided in Table 13.6. For non-highway vehicles, this is considered a Tier A method.

Figure 13.2 gives guidance on how to select a particular methodology based on the data that is available to you for your direct CH_4 and N_2O emissions from mobile combustion.

Step 1: Identify the vehicle type, fuel type, and technology type or model year of all the vehicles you own and operate.

You must first identify all the vehicles you own and operate, their vehicle type (such as passenger car or heavy-duty truck), their fuel type (such as gasoline or diesel), and either each vehicle's emission control technology or model year.

Tier A Method: Vehicle Technology

CH_4 and N_2O emissions depend on the emission control technologies employed. Therefore the preferred approach is to determine the actual control technology employed in each vehicle. Information on the control technology type for each vehicle is posted on an under-the-hood label. See Table 13.3 for a list of control technologies by vehicle type.

Tier B/C Method: Model Year

If determining the specific technologies of your vehicles is impossible or too labor intensive, you can estimate vehicle control technologies using each vehicle's model year. Table 13.4 provides emission factors by model year and vehicle type based on a weighted average of available control technologies for each model year.

Step 2: Identify the annual mileage by vehicle type.

Tier A/B Method: Distance Traveled

CH_4 and N_2O emissions depend more on distance traveled than volume of fuel combusted. Therefore, the preferred approach is to use vehicle miles traveled data by vehicle type. Sources of annual mileage data include odometer readings or trip manifests that include distance to destinations.

Tier C Method: Estimated Distance Traveled

If you do not have mileage data, but you do have fuel consumption data by vehicle type, you can estimate the vehicle miles traveled using fuel economy factors by vehicle type. See Step 1 in Section 13.1 for a discussion of determining appropriate fuel economy factors. If you operate more than one type of vehicle, you must separately calculate the fuel use for each of your vehicle types. If you have only bulk fuel purchase data, you should allocate consumption across vehicle types and model years in proportion to the fuel consumption distribution among vehicle type and model years, based on your usage data. Then use Equation 13f to estimate distance.

Equation 13f	Estimating Distance Based on Fuel Use
Distance (miles) = Fuel Use (gallons) × [(City FE (mpg) × City %) + (Highway FE (mpg) × Hwy %)] FE = Fuel Economy	

Step 3: Select the appropriate emission factor for each vehicle type.

Tier A Method: Vehicle Technology

If you have data on your vehicles' specific control technologies, obtain emission factors for highway vehicles from Table 13.3. Use Tables 13.5 and 13.6 for alternative fuel and non-highway vehicles.

Tier B/C Method: Model Year

If you have data on your vehicles' model years (rather than control technologies), obtain emission factors for highway vehicles from Table 13.4. Use Tables 13.5 and 13.6 for alternative fuel and non-highway vehicles.

Step 4: Calculate CH_4 and N_2O emissions by vehicle type and sum to obtain total CH_4 and N_2O emissions.

Use Equation 13g to calculate CH_4 emissions by vehicle type, convert to metric tons, and obtain total CH_4 emissions. Then repeat the procedure using Equation 13h to obtain total N_2O emissions.

Equation 13g	Calculating CH_4 Emissions From Mobile Combustion
Vehicle Type A **CH_4 Emissions** (metric tons) = Annual Distance (miles) × Emission Factor (g CH_4/mile) ÷ 1,000,000 (g/metric ton)	
Vehicle Type B **CH_4 Emissions** (metric tons) = Annual Distance (miles) × Emission Factor (g CH_4/mile) ÷ 1,000,000 (g/metric ton)	
Total CH_4 Emissions = CH_4 from Type A (metric tons) + CH_4 from Type B (metric tons) + … (metric tons)	

Equation 13h	Calculating N_2O Emissions From Mobile Combustion
Vehicle Type A **N_2O Emissions** (metric tons) = Annual Distance (miles) × Emission Factor (g N_2O/mile) ÷ 1,000,000 (g/metric ton)	
Vehicle Type B **N_2O Emissions** (metric tons) = Annual Distance (miles) × Emission Factor (g N_2O/mile) ÷ 1,000,000 (g/metric ton)	
Total N_2O Emissions = N_2O from Type A (metric tons) + N_2O from Type B (metric tons) + … (metric tons)	

Step 5: Convert CH_4 and N_2O emissions to units of CO_2 equivalent and determine total emissions from mobile combustion.

Use the IPCC global warming potential (GWP) factors in Equation 13i to convert CH_4 and N_2O emissions to units of CO_2 equivalent. Then sum your emissions of all three gases to determine your total emissions from mobile combustion (see Equation 13i).

Equation 13i	Converting to CO_2 equivalent and determining total emissions
CO_2 Emissions (metric tons CO_2e) = CO_2 Emissions (metric tons) × 1 (GWP)	
CH_4 Emissions (metric tons CO_2e) = CH_4 Emissions (metric tons) × 21 (GWP)	
N_2O Emissions (metric tons CO_2e) = N_2O Emissions (metric tons) × 310 (GWP)	
Total Emissions (metric tons CO_2e) = CO_2 + CH_4 + N_2O (metric tons CO_2e)	

Emissions from Alternative Fuel Vehicles

Emissions from Alternative Fuel Vehicles (AFV) are calculated in the same manner as other gasoline or diesel mobile sources, with the exception of electric vehicles. For instance, if you operate compressed natural gas or propane fueled vehicles, you must, as with gasoline or diesel, determine the total amount of fuel consumed and apply the appropriate emission factor to calculate your emissions. Electric vehicles are powered by internal batteries that receive a charge from the electricity grid. Therefore, using electric vehicles produces indirect emissions from purchased electricity. To calculate these emissions, you must determine the quantity of electricity consumed and apply an appropriate emission factor (see Chapter 14).

Emissions from Biofuels

Biofuels such as ethanol, biodiesel, and various blends of biofuels and fossil fuels may be combusted in mobile sources.

Due to their biogenic origin, you must report CO_2 emissions from the combustion of biofuels separately from your fossil fuel CO_2 emissions. For biofuel blends such as E85 (85 percent ethanol and 15 percent gasoline) and B20 (20 percent biodiesel and 80 percent diesel), combustion results in emissions of both fossil CO_2 and biomass CO_2. You must separately report both types of CO_2 emissions for each fuel.

When calculating emissions from mobile combustion, you are required to account only for emissions resulting from your own activities (i.e., tailpipe emissions from fuel combustion) rather than taking into account life cycle impacts, such as the CO_2 sequestered during the growing of crops or emissions associated with producing the fuels. The life cycle impacts of combusting fuels falls into Scope 3 for purposes of reporting.

13.3 Example: Direct Emissions from Mobile Combustion

GOFAST Vehicle Rental Agency

GOFAST Vehicle Rental is an independent vehicle renting company in the United States with a fleet of 200 model year 2000 passenger cars, 25 model year 2002 light duty trucks, and two model year 1998 heavy duty diesel powered trucks. GOFAST typically purchases its fuel in bulk.

Last year, the entity purchased 235,000 gallons of motor gasoline and 5,000 gallons of diesel fuel. GOFAST began the year with 20,000 gallons of motor gasoline in stock and ended with 10,000 gallons of motor gasoline in stock. The entity also began the year with 500 gallons of diesel fuel in stock and ended with 1,000 gallons of diesel fuel in stock. GOFAST also keeps odometer readings for each vehicle and determines total mileage by vehicle type as follows: 6,000,000 miles for passenger cars; 550,000 miles for light trucks; and 80,000 miles for heavy duty trucks. In this example, the entity follows Tier B methods for CO_2, CH_4, and N_2O.

CO_2 Emissions Calculation

Step 1: Identify the total annual fuel consumption by fuel type.

Vehicle Type	Fuel	Model Year	No. of Vehicles	Annual Mileage
Passenger Cars	Motor Gasoline	2000	200	6,000,000
Light Duty Trucks	Motor Gasoline	2002	25	550,000
Heavy Duty Trucks	Diesel	1998	2	80,000

GOFAST uses Equation 13a to determine annual fuel consumption by fuel type.

Equation 13a	Accounting for Changes in Fuel Stocks From Bulk Purchases
Total Annual Consumption = Total Annual Fuel Purchases + Amount Stored at Beginning of Year – Amount Stored at End of Year	
Total Gasoline Consumption (gallons) = 235,000 + 20,000 – 10,000 = 245,000 (gallons) (gallons) (gallons) (gallons)	
Total Diesel Consumption (gallons) = 5,000 + 500 – 1,000 = 4,500 (gallons) (gallons) (gallons) (gallons)	

Step 2: Determine the appropriate CO_2 emission factor for each fuel.

GOFAST uses Table 13.1 to obtain emission factors of 8.81 kilograms CO_2 per gallon of motor gasoline and 10.15 kilograms CO_2 per gallon of diesel fuel.

Step 3: Multiply fuel consumed by the emission factors to calculate total CO_2 emissions.

GOFAST uses Equation 13e to calculate CO_2 emissions for each fuel and then sums to determine total CO_2 emissions.

Equation 13e	Calculating CO_2 Emissions From Mobile Combustion
Gasoline CO_2 Emissions (metric tons) = 245,000 (gallons) × 8.81 (kg CO_2/gal) ÷ 1,000 (mt/kg) = **2,158.5** (metric tons CO_2)	
Diesel CO_2 Emissions (metric tons) = 4,500 (gallons) × 10.15 (kg CO_2/gal) ÷ 1,000 (mt/kg) = **45.7** (metric tons CO_2)	
Total CO_2 Emissions = **2,158.5 + 45.7 = 2,204** (metric tons) (mt) (mt) (metric tons CO_2)	

CH_4 and N_2O Emissions Calculation

Step 1: Identify the vehicle type, fuel, and vehicle technology or model year of all the vehicles GOFAST owns and operates.

Step 2: Identify the annual mileage by vehicle type.

GOFAST aggregates its vehicle odometer readings and enters the data in the table above.

Step 3: Select the appropriate emission factor for each vehicle type.

The entity uses Table 13.4 to obtain the emission factors by model year.

Vehicle Type	Fuel	Model Year	g N_2O/ mile	g CH_4/ mile
Passenger Cars	Motor Gasoline	2000	0.0273	0.0178
Light Duty Trucks	Motor Gasoline	2002	0.0228	0.0178
Heavy Duty Trucks	Diesel	1998	0.0048	0.0051

Step 4: Calculate CH_4 and N_2O emissions by vehicle type and sum to obtain total CH_4 and N_2O emissions.

Use Equation 13g to calculate CH_4 emissions by vehicle type, convert to metric tons, and obtain total CH_4 emissions. Then repeat the procedure using Equation 13h to obtain total N_2O emissions.

Equation 13g	Calculating CH_4 Emissions From Mobile Combustion
Passenger Cars **CH_4 Emissions** = 6,000,000 × 0.0178 ÷ 1,000,000 = **0.11** (metric tons) (miles) (g CH_4/mile) (g/metric ton)	
Light Duty Trucks **CH_4 Emissions** = 550,000 × 0.0178 ÷ 1,000,000 = **0.01** (metric tons) (miles) (g CH_4/mile) (g/metric ton)	
Heavy Duty Trucks **CH_4 Emissions** = 80,000 × 0.0051 ÷ 1,000,000 = **0.0004** (metric tons) (miles) (g CH_4/mile) (g/metric ton)	
Total CH_4 Emissions = 0.11 + 0.01 + 0.0004 = **0.12** (metric tons) (metric tons)	

Equation 13h	Calculating N_2O Emissions From Mobile Combustion
Passenger Cars **N_2OEmissions** = 6,000,000 × 0.0273 ÷ 1,000,000 = **0.16** (metric tons) (miles) (g N_2O/mile) (g/metric ton)	
Light Duty Trucks **N_2O Emissions** = 550,000 × 0.0228 ÷ 1,000,000 = **0.01** (metric tons) (miles) (g N_2O /mile) (g/metric ton)	
Heavy Duty Trucks **N_2O Emissions** = 80,000 × 0.0048 ÷ 1,000,000 = **0.0004** (metric tons) (miles) (g N_2O /mile) (g/metric ton)	
Total N_2O Emissions = 0.16 + 0.01 + 0.0004 = **0.18** (metric tons) (metric tons)	

Step 5: Convert CH_4 and N_2O emissions to units of CO_2 equivalent and determine total emissions from mobile combustion.

The entity uses Equation 13i to convert emissions to units of CO_2 equivalent and sum to obtain total GHG emissions from mobile combustion.

Equation 13i	Converting to CO_2 Equivalent and Determining Total Emissions
CO_2 Emissions = 2,204 × 1 = **2,204** (metric tons CO_2e) (metric tons) (GWP)	
CH_4 Emissions = 0.12 × 21 = **2.5** (metric tons CO_2e) (metric tons) (GWP)	
N_2O Emissions = 0.18 × 310 = **55.8** (metric tons CO_2e) (metric tons) (GWP)	
Total Emissions = CO_2 + CH_4 + N_2O = **2,262** (metric tons CO_2e) (metric tons CO_2e)	

Table 13.1 U.S. Default CO_2 Emission Factors for Transport Fuels

Fuel Type	Tier A2 Method			Tier B/C Method
	Carbon Content (Per Unit Energy)	Heat Content	Fraction Oxidized	CO_2 Emission Factor (Per Unit Volume)
Fuels Measured in Gallons	**kg C / MMBtu**	**MMBtu / barrel**		**kg CO_2 / gallon**
Motor Gasoline	19.33	5.218	1.00	8.81
Diesel Fuel No.1 and 2	19.95	5.825	1.00	10.15
Aviation Gasoline	18.87	5.048	1.00	8.32
Jet Fuel (Jet A or A-1)	19.33	5.670	1.00	9.57
Kerosene	19.72	5.670	1.00	9.76
Residual Fuel Oil (#5,6)	21.49	6.287	1.00	11.80
Crude Oil	20.33	5.80	1.00	10.29
Biodiesel (B100)*	NA	NA	1.00	9.46
Ethanol (E100)*	17.99	3.539	1.00	5.56
Methanol**	NA	NA	1.00	4.10
Liquefied Natural Gas (LNG)*	NA	NA	1.00	4.46
Liquefied Petroleum Gas (LPG)*	17.23	3.849	1.00	5.79
Propane	17.20	3.824	1.00	5.74
Ethane	16.25	2.916	1.00	4.14
Isobutane	17.75	4.162	1.00	6.45
n-Butane	17.72	4.328	1.00	6.70
Fuels Measured in Standard Cubic Feet	**kg C / MMBtu**	**Btu / Standard cubic foot**		**kg CO_2 / Standard cubic foot**
Compressed Natural Gas (CNG)*	14.47	1,027	1.00	0.054

Source: U.S. EPA, *Inventory of Greenhouse Gas Emissions and Sinks: 1990-2005* (2007), Annex 2.1, Tables A-31, A-34, A-36, A-39, except those marked * (from EPA Climate Leaders, Mobile Combustion Guidance, 2007) and ** (from California Climate Action Registry *General Reporting Protocol* Version 2.2, 2007, Table C.3). A fraction oxidized value of 1.00 is from the IPCC, *Guidelines for National Greenhouse Gas Inventories* (2006). Note: Default CO_2 emission factors are calculated using Equation 12d: Heat Content × Carbon Content × Fraction Oxidized × 44/12 × Conversion Factor. Heat content factors are based on higher heating values (HHV). NA = data not available.

Table 13.2 Canadian Default CO_2 Emission Factors for Transport Fuels

Fuel Type	Tier A2 Method			Tier B/C Method
	Carbon Content	Heat Content	Fraction Oxidized	CO_2 Emission Factors
		GJ / kiloliter		g CO_2 / L
Gasoline	n/a	35.00	1.00	2396
Diesel	n/a	38.30	1.00	2772
Light Fuel Oil	n/a	38.80	1.00	2873
Heavy Fuel Oil	n/a	42.50	1.00	3127
Aviation Gasoline	n/a	33.52	1.00	2365
Aviation Turbo Fuel	n/a	37.40	1.00	2589
Propane	n/a	25.31	1.00	1518
Ethanol	n/a	n/a	1.00	1513
		GJ / megaliter		g CO_2 / L
Natural Gas	n/a	38.26	1.00	1.9

Source: Default CO_2 Emission Factors: Environment Canada, *National Inventory Report, 1990-2005: Greenhouse Gas Sources and Sinks in Canada* (April 2007), Annex 12: Emission Factors, Table A12-7. Default Heat Content: Statistics Canada, *Report on Energy Supply-demand in Canada, 2005* (2007), Energy conversion factors, p. 116; Default Carbon Content: Canada-specific carbon content coefficients are not available. If you cannot obtain measured carbon content values specific to your fuels, you should use the Tier C Method. Default Fraction Oxidized: A value of 1.00 is used following the Intergovernmental Panel on Climate Change (IPCC), *Guidelines for National Greenhouse Gas Inventories* (2006).
Note: CO_2 emission factors from Environment Canada originally included fraction oxidized factors of less than 100 percent. Values were converted to 100 percent oxidation rate using 98.5 percent for all fuels except natural gas and propane, where a value of 99.5 percent was used, based on the rates used to calculate the original factors.

Table 13.3 Default CH_4 and N_2O Emission Factors for Highway Vehicles by Technology Type

Vehicle Type/Control Technology	N_2O (g/mi)	CH_4 (g/mi)
Gasoline Passenger Cars		
EPA Tier 2	0.0036	0.0173
Low Emission Vehicles	0.0150	0.0105
EPA Tier 1	0.0429	0.0271
EPA Tier 0	0.0647	0.0704
Oxidation Catalyst	0.0504	0.1355
Non-Catalyst Control	0.0197	0.1696
Uncontrolled	0.0197	0.1780
Gasoline Light Trucks (Vans, Pickup Trucks, SUVs)		
EPA Tier 2	0.0066	0.0163
Low Emission Vehicles	0.0157	0.0148
EPA Tier 1	0.0871	0.0452
EPA Tier 0	0.1056	0.0776
Oxidation Catalyst	0.0639	0.1516
Non-Catalyst Control	0.0218	0.1908
Uncontrolled	0.0220	0.2024
Gasoline Heavy-Duty Vehicles		
EPA Tier 2	0.0134	0.0333
Low Emission Vehicles	0.0320	0.0303
EPA Tier 1	0.1750	0.0655
EPA Tier 0	0.2135	0.2630
Oxidation Catalyst	0.1317	0.2356
Non-Catalyst Control	0.0473	0.4181
Uncontrolled	0.0497	0.4604
Diesel Passenger Cars		
Advanced	0.0010	0.0005
Moderate	0.0010	0.0005
Uncontrolled	0.0012	0.0006
Diesel Light Trucks		
Advanced	0.0015	0.0010
Moderate	0.0014	0.0009
Uncontrolled	0.0017	0.0011
Diesel Heavy-Duty Vehicles		
Advanced	0.0048	0.0051
Moderate	0.0048	0.0051
Uncontrolled	0.0048	0.0051
Motorcycles		
Non-Catalyst Control	0.0069	0.0672
Uncontrolled	0.0087	0.0899

Source: U.S. EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2005* (2007), Annex 3.2, Table A-99.
Note: The categories "EPA Tier 0" and "EPA Tier 1" were substituted for the early three-way catalyst and advanced three-way catalyst categories, respectively.

Table 13.4 Default CH_4 and N_2O Emission Factors for Highway Vehicles by Model Year

Vehicle Type and Year	N_2O (g/mi)	CH_4 (g/mi)
Gasoline Passenger Cars		
Model Years 1984-1993	0.0647	0.0704
Model Year 1994	0.0560	0.0531
Model Year 1995	0.0473	0.0358
Model Year 1996	0.0426	0.0272
Model Year 1997	0.0422	0.0268
Model Year 1998	0.0393	0.0249
Model Year 1999	0.0337	0.0216
Model Year 2000	0.0273	0.0178
Model Year 2001	0.0158	0.0110
Model Year 2002	0.0153	0.0107
Model Year 2003	0.0135	0.0114
Model Year 2004	0.0083	0.0145
Model Year 2005	0.0079	0.0147
Gasoline Light Trucks (Vans, Pickup Trucks, SUVs)		
Model Years 1987-1993	0.1035	0.0813
Model Year 1994	0.0982	0.0646
Model Year 1995	0.0908	0.0517
Model Year 1996	0.0871	0.0452
Model Year 1997	0.0871	0.0452
Model Year 1998	0.0728	0.0391
Model Year 1999	0.0564	0.0321
Model Year 2000	0.0621	0.0346
Model Year 2001	0.0164	0.0151
Model Year 2002	0.0228	0.0178
Model Year 2003	0.0114	0.0155
Model Year 2004	0.0132	0.0152
Model Year 2005	0.0101	0.0157
Gasoline Heavy-Duty Vehicles		
Model Years 1985-1986	0.0515	0.4090
Model Year 1987	0.0849	0.3675
Model Years 1988-1989	0.0933	0.3492
Model Years 1990-1995	0.1142	0.3246
Model Year 1996	0.1680	0.1278
Model Year 1997	0.1726	0.0924
Model Year 1998	0.1693	0.0641
Model Year 1999	0.1435	0.0578
Model Year 2000	0.1092	0.0493
Model Year 2001	0.1235	0.0528
Model Year 2002	0.1307	0.0546
Model Year 2003	0.1240	0.0533
Model Year 2004	0.0285	0.0341
Model Year 2005	0.0177	0.0326

Source: Gasoline vehicle factors from EPA Climate Leaders, Mobile Combustion Guidance (2007) based on U.S. EPA, *Inventory of U.S. Greenhouse Gas Emissions and* Sinks: 1990-2005 (2007). Diesel vehicle factors based on U.S. EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2005* (2007), Annex 3.2, Table A-98.

Table 13.4 (continued) Default CH_4 and N_2O Emission Factors for Highway Vehicles by Model Year

Vehicle Type and Year	N_2O (g/mi)	CH_4 (g/mi)
Diesel Passenger Cars		
Model Years 1960-1982	0.0012	0.0006
Model Years 1983-2004	0.0010	0.0005
Diesel Light Trucks		
Model Years 1960-1982	0.0017	0.0011
Model Years 1983-1995	0.0014	0.0009
Model Years 1996-2004	0.0015	0.0010
Diesel Heavy-Duty Vehicles		
All Model Years	0.0048	0.0051

Source: Gasoline vehicle factors from EPA Climate Leaders, Mobile Combustion Guidance, (2007) based on U.S. EPA, *Inventory of U.S. Greenhouse Gas Emissions and* Sinks: 1990-2005 (2007). Diesel vehicle factors based on U.S. EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2005* (2007), Annex 3.2, Table A-98.

Table 13.5 U.S. Default CH_4 and N_2O Emission Factors for Alternative Fuel Vehicles

Vehicle Type	N_2O (g/mi)	CH_4 (g/mi)
Light Duty Vehicles		
Methanol	0.067	0.018
CNG	0.050	0.737
LPG	0.067	0.037
Ethanol	0.067	0.055
Heavy Duty Vehicles		
Methanol	0.175	0.066
CNG	0.175	1.966
LNG	0.175	1.966
LPG	0.175	0.066
Ethanol	0.175	0.197
Buses		
Methanol	0.175	0.066
CNG	0.175	1.966
Ethanol	0.175	0.197

Source: U.S. EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2005* (2007), Annex 3.2, Table A-100.

Table 13.6 Default CH_4 and N_2O Emission Factors for Non-Highway Vehicles

Vehicle Type / Fuel Type	N_2O (g / gallon fuel)	CH_4 (g / gallon fuel)
Ships and Boats		
Residual Fuel Oil	0.30	0.86
Diesel Fuel	0.26	0.74
Gasoline	0.22	0.64
Locomotives		
Diesel Fuel	0.26	0.80
Agricultural Equipment		
Gasoline	0.22	1.26
Diesel Fuel	0.26	1.44
Construction		
Gasoline	0.22	0.50
Diesel Fuel	0.26	0.58
Other Non-Highway		
Snowmobiles (Gasoline)	0.22	0.50
Other Recreational (Gasoline)	0.22	0.50
Other Small Utility (Gasoline)	0.22	0.50
Other Large Utility (Gasoline)	0.22	0.50
Other Large Utility (Diesel)	0.26	0.58
Aircraft		
Jet Fuel	0.31	0.27
Aviation Gasoline	0.11	7.04

Data Source: U.S. EPA Climate Leaders, Mobile Combustion Guidance (2007) based on U.S. EPA *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2005* (2007), Annex 3.2, Table A-101.

CHAPTER 14: INDIRECT EMISSIONS FROM ELECTRICITY USE

Who should read Chapter 14:
- Chapter 14 applies to all Reporters that purchase and consume electricity.

What you will find in Chapter 14:
- This chapter provides guidance on calculating indirect emissions of CO_2, CH_4, and N_2O from electricity consumption.

Information you will need:
- You will need to refer to monthly electricity bills for information on electricity consumed.

Cross-References:
- This chapter may be useful in completing Chapter 15 when quantifying indirect emissions from CHP, steam, or district heating or cooling.

Data Quality Tiers: Indirect CO_2, CH_4 and N_2O Emissions From Electricity

Tier	Activity Data	Emission Factors
A	Known electricity use (Metered readings or utility bills)	Generator-specific emission factors
B	Known electricity use (Metered readings or utility bills)	eGRID power pool-specific factors
C	Estimated electricity use (Area method)	Generator-specific or eGRID power pool-specific factors

14.1 Calculating Indirect Emissions from Electricity Use

Nearly all entities are likely to have indirect emissions associated with the purchase and use of electricity. In some cases, indirect emissions from electricity use may comprise the majority of an entity's GHG emissions.

The generation of electricity through the combustion of fossil fuels typically yields carbon dioxide, and to a smaller extent, nitrous oxide and methane. The GRP provides annual emission factors for all three gases. To calculate indirect emissions from electricity use, follow these three steps:

1. Determine your annual electricity use from each facility;
2. Select the appropriate emission factors that apply to the electricity used; and
3. Determine your total annual emissions in metric tons of carbon dioxide equivalent.

Figure 14.1 gives guidance on how to select a particular quantification methodology based on the data that is available to you.

Step 1: Determine annual electricity consumption.

Reporting indirect emissions from electricity consumption begins with determining annual electricity use at each facility.

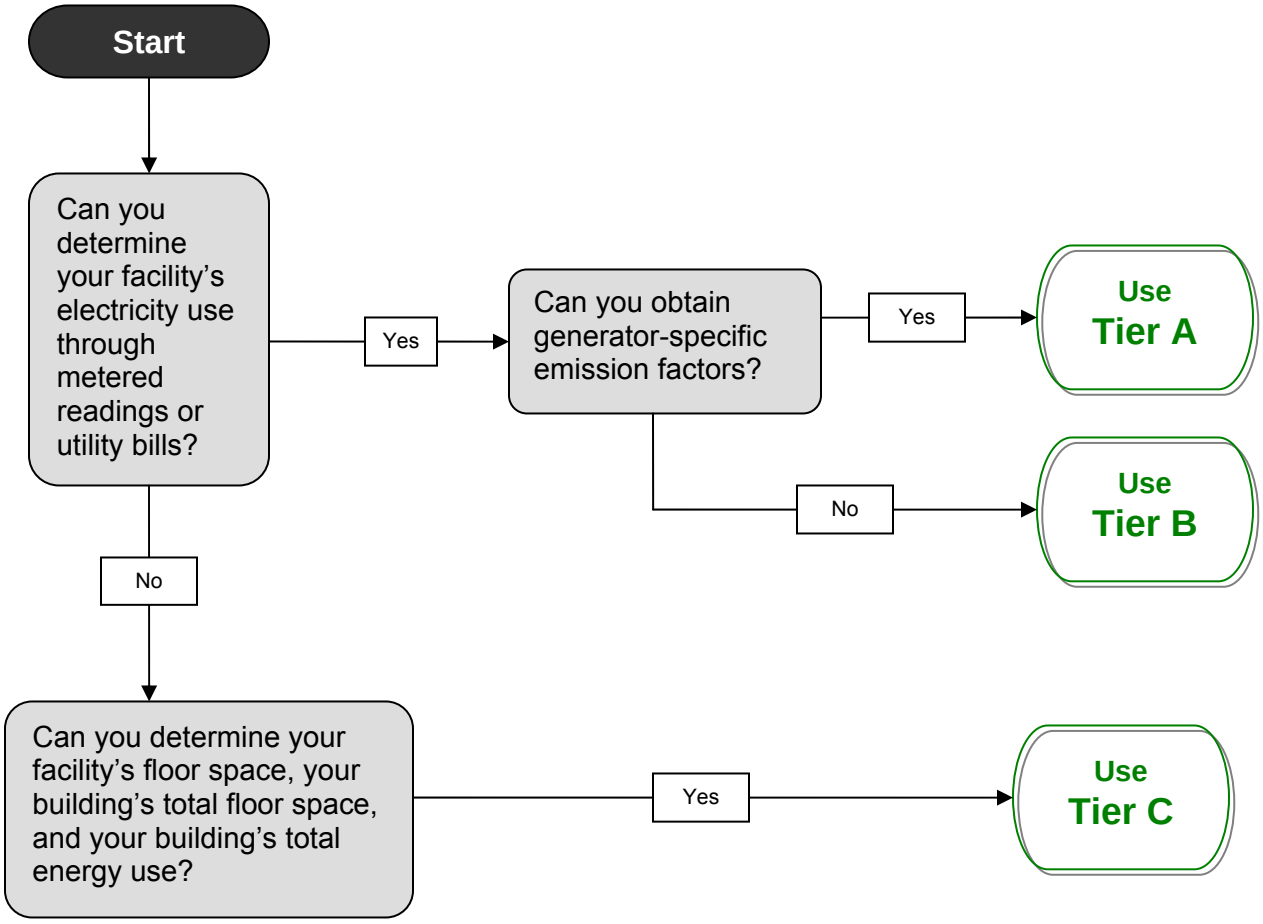
Tier A/B Method: Known Electricity Use

The preferred sources for determining annual electricity use are monthly electric bills or electric meter records. Both sources provide the number of kilowatt-hours (kWh) or megawatt-hours (MWh) of electricity consumed, giving a measure of the energy used by electric loads,

such as lights, office equipment, air conditioning, or machinery.

Record the electricity consumed each month at each facility. Then aggregate monthly bills to determine annual electricity use (in kWh or MWh) for each facility.

Figure 14.1 Selecting Data Quality Tiers: Indirect CO_2, CH_4 and N_2O Emissions from Electricity Use



Tier C Method: Area Method

If purchase records, electricity bills, or meter readings are not available or applicable, for example if you lease office space in a building owned by another entity, the next best method is to estimate energy use based on your entity's share of the building's floor space and total electricity consumption.

This method yields less accurate estimates than the known electricity use method because it is not specific to the particular space in the building used by the reporting entity and assumes that all occupants of the building have similar energy consuming habits. You should first be certain that you are unable to obtain electric bills to determine your actual electricity use.

To follow this method, you will need the following information, which should be available from your building's property manager:

- Total building area (square feet);
- Area of entity's space (square feet);
- Total building annual electricity use (kWh); and
- Building occupancy rate (e.g., if 75 percent of the building is occupied, use 0.75)

Use this information and Equation 14a to estimate your facility's share of the building's electricity use.

Equation 14a	Estimating Electricity Consumption Using the Area Method

Electricity Use (kWh) =
Entity's Area (sq ft) ÷ Building Area (sq ft) × Building Electricity Use (kWh) ÷ Occupancy Rate

Step 2: Select appropriate emission factors.

An electricity emission factor represents the amount of GHGs emitted per unit of electricity consumed. It is usually reported in units of pounds of GHG per kilowatt-hour or megawatt-hour.

Tier A Method: Generator-Specific Emission Factors

In some cases, entities may purchase electricity directly from a known "off-grid" electric generation source, that can be specifically identified, rather than from the electric grid. In such a case and if data is available, you should use emission rates specific to the known generation source as your facility's emission factors. If you consume power both from a known "off-grid" electric generation source as well as from the grid, you should pro-rate your emissions using the generator-specific emission factors for the portion of your power taken from the known "off-grid" source and the appropriate grid average emission factors for the portion of your electricity consumption taken from the grid. (For purchases from combined heat and power plants, refer to Chapter 15).

Tier B/C Method: Default Emission

Many Reporters will be unable to obtain generator-specific emission factors. In this case, you should use published emission factors based on each facility's geographic location, corresponding to the average emissions rate of electric generators supplying power to the grid. Because emission factors vary by location, you should be sure to use appropriate region-specific factors for each facility. For facilities in the U.S., you should use emission factors specific to your regional power pool rather than your state/province because transmission and distribution grids do not adhere to state/province boundaries.

To find the appropriate emission factors for a facility in the U.S., determine your eGRID subregion from the map in Figure 14.2. If you are unsure of your facility's subregion, use the EPA Power Profiler tool, available at: www.epa.gov/cleanenergy/powerprofiler.html to find your facility's subregion based on its zip code. Then, based on your subregion, find the appropriate emission factors for each gas in Table 14.1.

Note: The emission factors in Table 14.1 represent 2004 emission factors, which are currently the most recent data available from eGRID. When possible, use emission factors that correspond to the calendar year of data you are reporting. Use the 2004 emission factors provided in Table 14.1 as a proxy for more recent years until new eGRID emission factors become available.

For Canadian and Mexican facilities, use emission factors from Tables 14.2 and 14.3 for your reporting year (or the most recent year if no data are available).

If you are reporting emissions from facilities outside of North America, refer to the WRI/WBCSD GHG Protocol Calculation Tool, *Indirect CO_2 Emissions from Purchased Electricity, Heat, or Steam*, for emission factors by country, available at www.ghgprotocol.org.

Step 3: Determine total annual emissions and convert to metric tons of carbon dioxide equivalent.

To determine annual emissions, multiply annual electricity use (in megawatt-hours) from Step 1 by the emission factors for CO_2, CH_4, and N_2O (in pounds per MWh) from Step 2. [Note: If your electricity use data is in units of kilowatt-hours, divide by 1,000 to convert to megawatt-hours.] Then convert pounds into metric tons by dividing the total by 2,204.62 lbs/metric ton. To convert kilograms into metric tons, divide by 1,000 kg/metric ton (see Equation 14b). Repeat this step for each gas.

To convert CH_4 and N_2O into units of carbon dioxide equivalent, multiply total emissions of each gas (in metric tons) by its IPCC global warming potential (GWP) factor provided in Equation 14c. Then sum the emissions of each of the three gases in units of CO_2e to obtain total greenhouse gas emissions (see Equation 14c).

Equation 14b	Calculating Indirect Emissions from Electricity Use
CO_2 Emissions (metric tons) = Electricity Use (MWh) × Emission Factor (lbs CO_2/MWh) ÷ 2,204.62 (lbs/metric ton)	
CH_4 Emissions (metric tons) = Electricity Use (MWh) × Emission Factor (lbs CH_4/MWh) ÷ 2,204.62 (lbs/metric ton)	
N_2O Emissions (metric tons) = Electricity Use (MWh) × Emission Factor (lbs N_2O/MWh) ÷ 2,204.62 (lbs/metric ton)	

Equation 14c	Converting to CO_2-Equivalent and Determining Total Emissions
CO_2 Emissions (metric tons CO_2e) = CO_2 Emissions (metric tons) × 1 (GWP)	
CH_4 Emissions (metric tons CO_2e) = CH_4 Emissions (metric tons) × 21 (GWP)	
N_2O Emissions (metric tons CO_2e) = N_2O Emissions (metric tons) × 310 (GWP)	
Total Emissions (metric tons CO_2e) = CO_2 + CH_4 + N_2O (metric tons CO_2e)	

Green Power and Contractual Purchases

Some Reporters may be engaged in a green power purchasing contract (offered by an electric utility or an independent power provider) or may independently purchase renewable energy credits (RECs). These purchases are encouraged and should be reported as supplemental information in your entity-wide emission report. These purchases may not be deducted from your Scope 2 emissions. Scope 2 emissions result from the power you consume directly, either from a dedicated plant or from the grid, and represent your actual indirect emissions.

Similarly, you may choose to purchase your electricity from a utility that generates or distributes power from less GHG-intensive sources than the grid average emissions rate. If you know the average emissions rate of your utility's electricity supply, you may calculate an alternate Scope 2 total based on your supplier's specific emissions rate rather than the grid average emission factor. However, since you draw power from the grid as a whole, your actual Scope 2 emissions are those calculated using the grid average emission factor. The alternate total based on a supplier-specific emissions rate may be provided as supplementary information.

The Registry recognizes the need to develop a specific accounting framework for green power purchases in order to encourage and incentivize emission reduction efforts. There is not yet consensus on how to accurately and credibly track green power purchases in an accounting framework, beyond allowing Reporters to provide supplementary information about their green power purchases in annual emission reports. As the Registry develops an industry specific protocol for the power and utility sector (planned for 2008), it will incorporate a framework for accounting for contractual purchases of electricity, such as green power and RECs.

Prorating Monthly Electricity Use

When your electric bill does not begin exactly on January 1 or end on December 31, you must prorate your January and December electricity bills (for those two months only) to determine annual electricity use. To calculate your emissions for January from an electric bill spanning part of December and part of January, first divide total kilowatt-hours used in the period by the number of days in your billing cycle. Then, determine the number of days from your bill that fall in January. Multiply the electricity use per day by the number of days in January. Add this amount to any other electric bill that includes days in January.

Accounting for Transmission and Distribution Losses
Some electricity is lost during the transmission and distribution (T&D) of power from electric generators to end users. T&D losses should be reported by the entity that owns or controls the T&D lines. If your entity does not own or control the T&D system, you should not account for T&D losses in your entity's GHG inventory. In this case, you should only report the emissions associated with the amount of electricity you consume within your facilities (and report them as Scope 2 emissions; see Chapter 5 for more information). Emission factors presented in this chapter do not account for T&D losses and are therefore appropriate for end users who do not own or operate T&D lines. If your entity owns or controls the T&D system but generates (rather than purchases) the electricity transmitted through the system, you should not report the emissions associated with T&D losses under Scope 2, as they would already be accounted for under Scope 1. This is the case when generation, transmission, and distribution systems are vertically integrated and owned or controlled by the same entity. However, if you purchase (rather than generate) electricity and transport it through a T&D system that you own or control, you should report the emissions associated with T&D losses under Scope 2. To estimate these emissions, follow the same procedure described in Section 14.1 of this chapter for estimating indirect emissions from electricity use. In Step 1, use the electricity consumed in the T&D system (T&D losses) as your quantity of electricity consumed. In Step 2, use either a generator-specific emission factor (if the purchased electricity comes directly from a known generation source rather than the grid) or a grid-average emission factor from the appropriate eGRID subregion if the power comes from the grid.

Figure 14.2 Map of U.S. eGRID Subregions, 2004

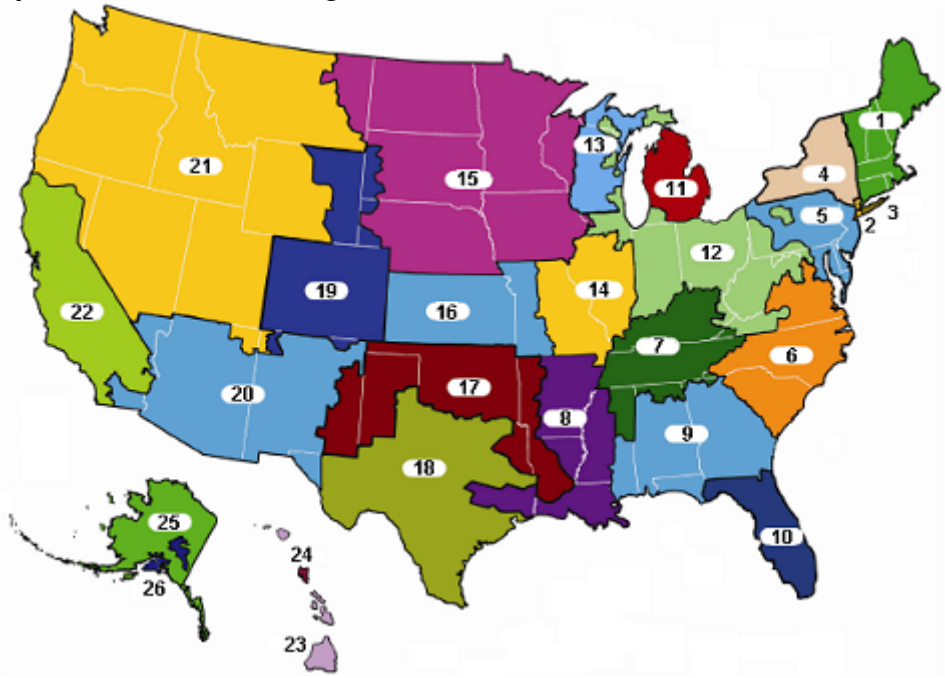


Table 14.1 U.S. Emission Factors for Grid Electricity by eGRID Subregion

Map No.	eGRID 2006 Subregion	eGRID 2006 Subregion Name	2004 Emission Rates		
			(lbs CO_2/MWh)	(lbs CH_4/MWh)	(lbs N_2O/MWh)
1	NEWE	NPCC New England	908.90	0.080	0.015
2	NYCW	NPCC NYC/Westchester	922.22	0.038	0.006
3	NYLI	NPCC Long Island	1,412.20	0.102	0.016
4	NYUP	NPCC Upstate NY	819.68	0.024	0.011
5	RFCE	RFC East	1,095.53	0.028	0.017
6	SRVC	SERC Virginia/Carolina	1,146.39	0.029	0.019
7	SRTV	SERC Tennessee Valley	1,494.89	0.023	0.024
8	SRMV	SERC Mississippi Valley	1,135.46	0.042	0.013
9	SRSO	SERC South	1,490.37	0.040	0.025
10	FRCC	FRCC All	1,327.66	0.054	0.016
11	RFCM	RFC Michigan	1,641.41	0.035	0.025
12	RFCW	RFC West	1,556.39	0.020	0.024
13	MORE	MRO East	1,858.72	0.041	0.030
14	SRMW	SERC Midwest	1,844.34	0.021	0.029
15	MROW	MRO West	1,813.81	0.028	0.029
16	SPNO	SPP North	1,971.42	0.024	0.030
17	SPSO	SPP South	1,761.14	0.030	0.023
18	ERCT	ERCOT All	1,420.56	0.021	0.015
19	RMPA	WECC Rockies	2,035.81	0.024	0.030
20	AZNM	WECC Southwest	1,254.02	0.018	0.015
21	NWPP	WECC Northwest	921.10	0.022	0.014
22	CAMX	WECC California	878.71	0.036	0.008
23	HIMS	HICC Miscellaneous	1,456.17	0.101	0.018
24	HIOA	HICC Oahu	1,728.12	0.0911	0.0212
25	AKMS	ASCC Miscellaneous	480.10	0.0239	0.0044
26	AKGD	ASCC Alaska Grid	1,257.19	0.0266	0.0064
U.S. Average (Note: This factor should not be used for reporting)			1,363.00	0.0305	0.0198

Source: U.S. EPA eGRID2006 Version 2.1 (2004 data); CH_4 and N_2O factors provided by EPA Climate Leaders based on eGRID2006 fuel consumption and electricity generation data and U.S. EPA's *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2005,* April 2007 (Annex 3, Table A-69). Factors do not include emissions from transmission and distribution losses.

Table 14.2 Canadian Emission Factors for Grid Electricity by Province

Province	Emission Rates (kg CO_2-equivalent / MWh)					
	2000	2001	2002	2003	2004	2005
Alberta	928	899	893	963	892	882
British Columbia	33	50	13	15	17	17
Manitoba	30	14	16	37	14	14
New Brunswick	454	518	495	440	426	394
Newfoundland & Labrador	19	42	43	38	32	31
Nova Scotia	775	731	608	686	805	771
Ontario	277	264	260	273	197	220
Prince Edward Island	1138	1014	742	669	373	252
Quebec	2.2	2.5	1.6	9.7	8.6	9.1
Saskatchewan	848	907	874	841	886	822
Yukon, Northwest Territories & Nunavut	54	59	39	38	40	30

Note: Emission rates include emissions of CO_2, CH_4, and N_2O. Factors do not include transmission and distribution losses.
Source: Environment Canada, National Inventory Report, 1990-2005: Greenhouse Gas Sources and Sinks in Canada (April 2007), Annex 9: Electricity Intensity Tables.

Table 14.3 Mexican Emission Factors for Grid Electricity

Year	Emission Rates (kg CO_2-equivalent / MWh)
2000	604.1
2001	625.0
2002	600.0
2003	571.2
2004	549.6
2005	550.1

Note: Emission rates include emissions of CO_2, CH_4, and N_2O. Factors are a national average of all the power plants operating and delivering electricity to the National Electric System and do not include transmission and distribution losses. Factors for 2002 to 2005 were not calculated with actual data but instead estimated using the Electricity Outlooks published by Mexico's Ministry of Energy.
Source: Asociación de Técnicos y Profesionistas en Aplicación Energética (ATPAE), 2003, *Metodologías para calcular el Coeficiente de Emisión Adecuado para Determinar las Reducciones de GEI Atribuibles a Proyectos de EE/ER – Justificación para la selección de la Metodología*, versión final 4.1 (junio de 2003), proyecto auspiciado por la Agencia Internacional de Estados Unidos para el Desarrollo Internacional, México, D.F., México.

14.2 Example: Indirect Emissions from Electricity Use

Cost-lo Clothing Distributors

Cost-lo is a discount retail clothing chain with one outlet in Los Angeles, California, one in Portland, Oregon, and one in Tucson, Arizona. In this example, the entity applies the Tier B method to calculate their indirect emissions.

Step 1: Determine annual electricity consumption.

Cost-lo records its annual electricity purchases in megawatt-hours (MWh): 1,600 MWh at its Los Angeles store, 600 MWh at its Portland store, and 800 MWh at its Tucson store.

Step 2: Select electricity emission factors that apply to the electricity purchased.

The company finds the appropriate emission factors for CO_2, CH_4, and N_2O from Table 14.1 for each facility and records them in the table below..

Step 3: Determine total annual emissions and convert to metric tons of CO_2 equivalent.

See Equations14b and 14c below.

Annual Electricity Use and Emission Factors

Facility	eGRID Subregion	Annual Electricity Purchases (MWh)	CO_2 (lbs / MWh)	CH_4 (lbs / MWh)	N_2O (lbs / MWh)
Los Angeles, CA	CAMX	1,600	878.71	0.036	0.008
Portland, OR	NWPP	600	921.10	0.022	0.014
Tucson, AZ	AZNM	800	1,254.02	0.018	0.015

Equations 14b and c			
Facility	**Calculating Indirect Emissions from Electricity Use**		**Converting to CO_2-equivalent**
Los Angeles	CO_2 Emissions	1,600 × 878.71 ÷ 2,204.62 = 637.72 (MWh) (lbs CO_2/MWh) (lbs/mt) (mt CO_2)	× 1 = 637.72 (GWP) (metric tons CO_2e)
	CH_4 Emissions	1,600 × 0.036 ÷ 2,204.62 = 0.026 (MWh) (lbs CH_4/MWh) (lbs/mt) (mt CH_4)	× 21 = 0.55 (GWP) (metric tons CO_2e)
	N_2O Emissions	1,600 × 0.008 ÷ 2,204.62 = 0.006 (MWh) (lbs N_2O/MWh) (lbs/mt) (mt N_2O)	× 310 = 1.80 (GWP) (metric tons CO_2e)
	Total Los Angeles Emissions		**= 640.07 metric tons CO_2-e**
Portland	CO_2 Emissions	600 × 921.10 ÷ 2,204.62 = 250.68 (MWh) (lbs CO_2/MWh) (lbs/mt) (mt CO_2)	× 1 = 250.68 (GWP) (metric tons CO_2e)
	CH_4 Emissions	600 × 0.022 ÷ 2,204.62 = 0.006 (MWh) (lbs CH_4/MWh) (lbs/mt) (mt CH_4)	× 21 = 0.13 (GWP) (metric tons CO_2e)
	N_2O Emissions	600 × 0.014 ÷ 2,204.62 = 0.004 (MWh) (lbs N_2O/MWh) (lbs/mt) (mt N_2O)	× 310 = 1.18 (GWP) (metric tons CO_2e)
	Total Portland Emissions		**= 251.99 metric tons CO_2e**
Tucson	CO_2 Emissions	800 × 1,254.02 ÷ 2,204.62 = 455.05 (MWh) (lbs CO_2/MWh) (lbs/mt) (mt CO_2)	× 1 = 455.05 (GWP) (metric tons CO_2e)
	CH_4 Emissions	800 × 0.018 ÷ 2,204.62 = 0.007 (MWh) (lbs CH_4/MWh) (lbs/mt) (mt CH_4)	× 21 = 0.14 (GWP) (metric tons CO_2e)
	N_2O Emissions	800 × 0.015 ÷ 2,204.62 = 0.005 (MWh) (lbs N_2O/MWh) (lbs/mt) (mt N_2O)	× 310 = 1.69 (GWP) (metric tons CO_2e)
	Total Tucson Emissions		**= 456.88 metric tons CO_2e**
Total Indirect Emissions From Electricity Use = 640.07 + 251.99 + 456.88 = **1,348.94 metric tons CO_2e**			

CHAPTER 15: INDIRECT EMISSIONS FROM IMPORTED STEAM, DISTRICT HEATING, COOLING, AND ELECTRICITY FROM A CHP PLANT

Who should read Chapter 15:

- Chapter 15 applies to organizations that purchase electricity, steam, or heat from a CHP plant or import steam, heating, or cooling from a conventional boiler that they do not own or operate.

What you will find in Chapter 15:

- This chapter provides guidance on estimating indirect emissions from a CHP facility, imported steam, and district heating or cooling. The chapter includes the quantification methodology for CHP and an example addressing indirect emissions from district heating.

Information you will need:

- You will need information about the type of CHP, imported steam and heat, and imported cooling your organization uses, and the types and amounts of fuel consumed by the plant to generate that electricity, heating, or cooling. For example, for heat or electricity from a CHP facility, you will need information about the plant's net heat production and net electricity production, in addition to your organization's own consumption of that power.

Cross-References:

- Refer to Chapter 14 for guidance on calculating indirect emissions from electricity use and Chapter 12 for guidance on calculating direct emissions from fuel combustion from a CHP or conventional boiler plant you own or operate.

Data Quality Tiers: Indirect Emissions From Combined Heat and Power

Tier	Method
A	CHP plant emissions calculated using a Tier A method from Chapter 12 (Stationary Combustion)
B	CHP plant emissions calculated using a Tier B method from Chapter 12
C	CHP plant emissions calculated using a Tier C method from Chapter 12

Data Quality Tiers: Indirect Emissions From Imported Steam or Heat

Tier	Method
A	Measured emission factors obtained directly from the supplier
B	Efficiency approach using source-specific efficiency factor
C	Efficiency approach using default efficiency factor

Data Quality Tiers: Indirect Emissions From District Cooling

Tier	Method
A	Detailed approach
B	Simplified approach with source-specific COP
C	Simplified approach with default COP

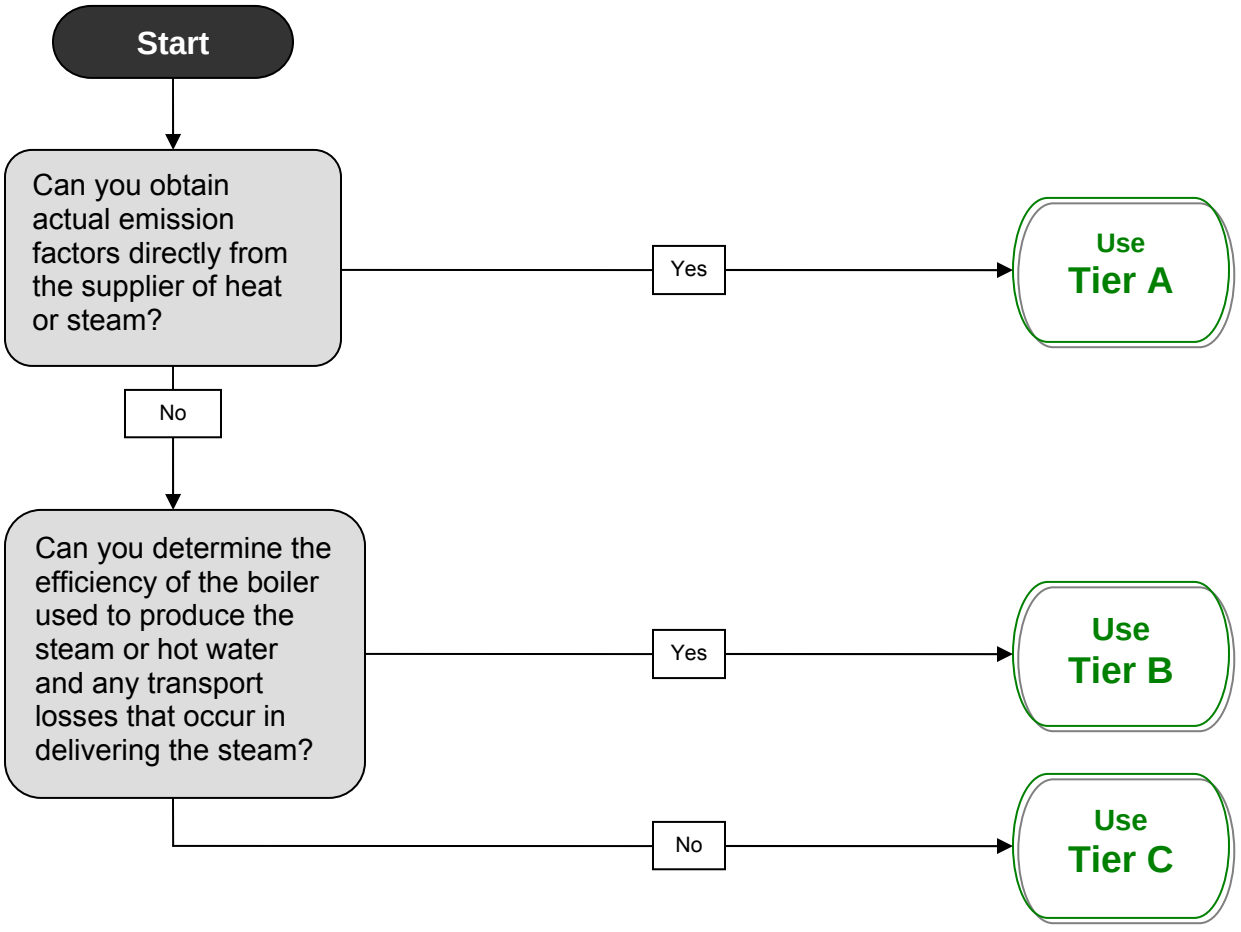
This chapter applies to organizations that purchase steam, district heat, cooling or electricity from a CHP or conventional boiler plant that they do not own or operate. Emissions associated with these sources are considered to be indirect. If you own or operate a CHP or conventional boiler plant, you should

Figure 15.1 gives guidance on how to select a particular emissions quantification methodology based on the data that is available to you.

15.1 Calculating Indirect Emissions from Heat and Power Produced at a CHP Facility

Emissions from CHP facilities represent a special case for estimating indirect emissions. Because CHP simultaneously produces electricity and heat (or steam), attributing total GHG emissions to each product stream would result in double counting. Thus, when two or more parties receive the energy streams from CHP plants, GHG emissions must be determined and allocated separately for heat production and electricity production.

Figure 15.1 Selecting Data Quality Tiers: Indirect CO_2, CH_4 and N_2O Emissions from Imported Steam or Heat



Since the output from CHP results simultaneously in heat and electricity, you can determine what "share" of the total emissions is a result of electricity and heat by using a ratio based on the Btu content of heat and/or electricity relative to the CHP plant's total output.

The process for estimating indirect emissions from heat and power produced at a CHP facility involves the following four steps:

1. Obtain total emissions and power and heat generation information from CHP facility;
2. Determine emissions attributable to net heat production and electricity production;
3. Calculate emissions attributable to your portion of heat and electricity consumed;
4. Convert to units of carbon dioxide equivalent and determine total emissions.

Step 1: Obtain emissions and power and heat information from the CHP facility.

You will need to obtain the following information from the CHP plant owner or operator to estimate indirect GHG emissions:

- Total emissions of carbon dioxide, methane, and nitrous oxide from the CHP facility, based on fuel input information;
- Total electricity production from the CHP plant, based on generation meter readings; and
- Net heat production from the CHP plant.

Net heat production refers to the useful heat that is produced in CHP, minus whatever heat returns to the boiler as steam condensate, as shown in Equation 15a. (Alternatively, refer to Step 2 in Section 12.3 for guidance on determining net heat production from steam temperature and pressure data.)

Equation 15a	Calculating Net Heat Production
Net Heat Production (MMBtu) =	Heat of Steam Export (MMBtu) - Heat of Return Condensate (MMBtu)

Step 2: Determine emissions attributable to net heat production and electricity production for the CHP plant.

Refer to Section 12.3 to calculate emissions attributable to net heat and electricity production.

Step 3: Calculate emissions attributable to your portion of heat and electricity consumed.

Once you have determined total emissions attributable to heat (or steam) and electricity production, you will need to determine your portion of heat or electricity consumed, and thus your indirect GHG emissions associated with heat or electricity use. First, obtain your electricity and heat (or steam) consumption information, then use Equations 15b and 15c to calculate your share of emissions, as appropriate.

Equation 15b	Calculating Indirect Emissions Attributable To Electricity Consumption
Indirect Emissions Attributable to Electricity Consumption (*metric tons*) =	Total CHP Emissions Attributable to Electricity Production (*metric tons*) × (Your Electricity Consumption (*kWh*) ÷ Total CHP Electricity Production (*kWh*))

Equation 15c	Calculating Indirect Emissions Attributable To Heat (or Steam) Consumption
Indirect Emissions Attributable to Heat Consumption (*metric tons*) =	Total CHP Emissions Attributable to Heat Production (*metric tons*) × (Your Heat Consumption (*MMBtu*) ÷ CHP Net Heat Production (*MMBtu*))

Step 4: Convert to units of CO_2 equivalent and determine total emissions.

Finally, use the IPCC global warming potential (GWP) factors provided in Equation 15d to convert methane and nitrous oxide emissions to units of carbon dioxide equivalent. Then sum your emissions of all three gases to determine your total emissions from stationary combustion (see Equation 15d).

Equation 15d	Converting to CO_2 Equivalent and Determining Total Emissions
CO_2 Emissions (metric tons CO_2e) = CO_2 Emissions (metric tons) × 1 (GWP)	
CH_4 Emissions (metric tons CO_2e) = CH_4 Emissions (metric tons) × 21 (GWP)	
N_2O Emissions (metric tons CO_2e) = N_2O Emissions (metric tons) × 310 (GWP)	
Total Emissions (metric tons CO_2e) = $CO_2 + CH_4 + N_2O$ (metric tons CO_2e)	

15.2 Calculating Indirect GHG Emissions from Imported Steam or District Heating from a Conventional Boiler Plant

Some facilities purchase steam or district heating, such as to provide space heating in the commercial sector or process heating in the industrial sector. This section provides guidance on calculating emissions from imported steam or district heating that is produced at a conventional boiler plant (i.e., not a CHP facility).

To estimate your facility's GHG emissions from imported steam or district heating, follow these four steps:

1. Determine energy obtained from steam or district heating;
2. Determine appropriate emission factors for the steam or district heating;
3. Calculate emissions from imported steam or district heating; and
4. Convert to units of carbon dioxide equivalent, and determine total emissions.

Step 1: Determine energy obtained from steam or district heating.

First, determine the quantity of acquired steam or district heating. You may use metered records of energy use, purchase records, or utility/supplier energy bills to determine annual consumption. Monthly energy bills must be summed over the year to give annual consumption.

Consumption data should be expressed in units of million British thermal units (MMBtu). If your consumption data is expressed in therms, you can convert the values to units of MMBtu by multiplying by 0.1, as shown in Equation 15e.

Equation 15e	Converting Steam Consumption from Therms to MMBtu
Energy Consumption (MMBtu) = Energy Consumption (therms) x 0.1 (MMBtu/therm)	

If your steam consumption is measured in pounds (lbs), you either need to monitor the temperature and pressure of the steam you have received, or request it from the steam supplier. This information can be used with standard steam tables to calculate the steam's energy content.

Calculate the thermal energy of the steam using saturated water at 212°F as the reference (Source: American Petroleum Institute, *Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Gas Industry*, 2001). The thermal energy consumption is calculated as the difference between the enthalpy of the steam at the delivered conditions and the enthalpy (or heat content) of the saturated water at the reference conditions (or heat content).

The enthalpy of the steam can be found in standard steam tables (for example, the *Industrial Formulation 1997 for the Thermodynamic Properties of Water and Steam* published by the International Association for the Properties of Water and Steam (IAPWS)). The enthalpy of saturated water at the reference conditions is 180 Btus per pound. The thermal energy consumption for the steam can then be calculated as shown in Equation 15f.

Equation 15f	Converting Steam Consumption from Pounds to MMBtu
Energy Consumption *(MMBtu)* = [Enthalpy of Delivered Steam *(Btu/lb)* - 180 *(Btu/lb)*] × Steam Consumed *(lbs)* ÷ 1,000,000 *(Btu/MMBtu)*	

Step 2: Determine the appropriate emission factors for the steam or district heating.

Tier A Method: Actual Emission Factors

Supplied steam or heat is usually generated from direct, known sources of energy. In this case, you should obtain measured emission factors directly from the supplier of heat or steam. Emission factors should be in units of mass per unit of energy (such as tons of CO_2 emitted per MMBtu of heat generated). See Chapter 12, Section 12.2, for information on deriving CO_2 emission factors.

Tier B Method: Efficiency Approach Using Specific Efficiency Factor

If you cannot obtain emission factors directly from suppliers of heat or steam, you can estimate emission factors based on boiler efficiency, fuel mix, and fuel-specific emission factors.

Because emissions vary with fuel type, you must know the type of fuels that are burned in the plant supplying your steam or hot water. You can obtain this information from the plant's energy supplier. Once you know the fuels combusted to generate the steam or hot water, determine the appropriate emission factors for each fuel combusted. The preferred approach is to obtain CO_2 emission factors based on measured characteristics of the fuels combusted, including measured heat content and measured carbon content, from your supplier. If this data is not available, use default emission factors for CO_2, CH_4, and N_2O from Tables 12.1 – 12.9.

Next, you must determine the efficiency of the boiler used to produce the steam or hot water and any transport losses that occur in delivering the steam, and calculate a total efficiency factor using Equation 15g. Boiler efficiency is the ratio of steam output to fuel input, in units of energy, which you should obtain from your steam or heat supplier. If transport losses or boiler efficiency vary seasonally, these factors should be calculated on a monthly or seasonal basis and summed to yield total annual factors.

Equation 15g	Calculating System Efficiency
Total Efficiency Factor (%) = Boiler Efficiency x (100% - Transport Losses) (%) (%)	

Calculate carbon dioxide, methane, and nitrous oxide emission factors that reflect the efficiency and fuel mix of the boiler employed to generate your steam or hot water using Equation 15h.

Tier C Method: Efficiency Approach Using Default Efficiency Factor

If you are unable to obtain the specific system efficiency of the boiler that generated your steam or heat, apply a default total efficiency factor—boiler efficiency and transport losses combined—of 75 percent in Equation 15h.

Equation 15h	Calculating Emission Factors
CO_2 Emission Factor (kg CO_2 / MMBtu) = Fuel-Specific Emission Factor ÷ Total Efficiency Factor (kg CO_2 / MMBtu) (%)	
CH_4 Emission Factor (kg CH_4 / MMBtu) = Fuel-Specific Emission Factor ÷ Total Efficiency Factor (kg CH_4 / MMBtu) (%)	
N_2O Emission Factor (kg N_2O / MMBtu) = Fuel-Specific Emission Factor ÷ Total Efficiency Factor (kg N_2O / MMBtu) (%)	

Step 3: Calculate emissions from imported steam or district heating.

Once you have both the value of total energy consumed from Step 1 and the appropriate emission factors from Step 2, use Equation 15i to calculate GHG emissions from imported steam or hot water.

Equation 15i	Calculating Emissions From Imported Steam or Heat
Total CO_2 Emissions (metric tons) = Energy Consumed x Emission Factor x 0.001 (MMBtu) (kg CO_2 / MMBtu) (metric tons/kg)	
Total CH_4 Emissions (metric tons) = Energy Consumed x Emission Factor x 0.001 (MMBtu) (kg CH_4 / MMBtu)) (metric ton/kg)	
Total N_2O Emissions (metric tons) = Energy Consumed x Emission Factor x 0.001 (MMBtu) (kg N_2O / MMBtu) (metric ton/kg)	

Step 4: Convert to units of carbon dioxide equivalent and determine total emissions.

Use the IPCC global warming potential factors provided in Equation 15d to convert CH_4 and N_2O emissions to units of CO_2 equivalent. Then sum your emissions of all three gases to determine your total indirect emissions from imported heat or steam (see Equation 15d).

Equation 15d	Converting to CO_2 Equivalent and Determining Total Emissions
CO_2 Emissions = CO_2 Emissions × 1 (metric tons CO_2e) (metric tons) (GWP)	
CH_4 Emissions = CH_4 Emissions × 21 (metric tons CO_2e) (metric tons) (GWP)	
N_2O Emissions = N_2O Emissions × 310 (metric tons CO_2e) (metric tons) (GWP)	
Total Emissions = $CO_2 + CH_4 + N_2O$ (metric tons CO_2e) (metric tons CO_2e)	

15.3 Calculating Indirect GHG Emissions from District Cooling

Some facilities purchase cooling, such as chilled water, for either cooling or refrigeration when they do not operate cooling compressors on-site. Conceptually, purchased chilled water is similar to purchased heat or steam, with the primary difference being the process used to generate the chilled water. When you purchase cooling services using district cooling, the compressor system that produces the cooling is driven by either electricity or fossil fuel combustion. Your indirect emissions from district cooling represent your share of the total cooling demand from the cooling plant, multiplied by the total GHG emissions generated by that plant.

You must first determine your total cooling use by summing the total cooling from your monthly cooling bills. Once you have determined your total cooling, you can use either the detailed approach (Tier A) or simplified approach (Tier B or C) to estimate your GHG emissions from district cooling. Figure 15.2 gives guidance on how to select a particular approach based on the data that is available to you.

Tier A Method: Detailed Approach

The detailed approach allows you to determine the total cooling-related emissions from the district cooling plant and your facility's fraction of total cooling demand.

Step 1: Determine total cooling-related emissions from the district cooling plant.

District cooling plants take a variety of forms and may produce electricity, hot water, or steam for sale in addition to cooling.

Where Cooling Plant Produces Only Cooling. In the simplest case, all of the fuel consumed by the plant is used to provide cooling. In that case, you will be able to determine total cooling emissions based on (1) total indirect emissions from cooling plant electricity and heat consumption (metric tons), and (2) total direct emissions from cooling plant fuel combustion (metric tons).

The process for calculating direct and indirect emissions is described in Chapters 12 and 13. You will need to obtain the emission values from the district cooling plant, or calculate the emissions based on the fuel consumption, as well as electricity and steam consumption information, provided by the plant.

Where Cooling Plant Produces More Than Cooling. In many cases, the simple situation described above will not apply. Instead, the cooling plant will be integrated into a combined heat and power plant, where some of the steam and electricity produced by the plant may be used for cooling, and some may be used for other purposes. In this case, the emissions from the combined heat and power plant will need to be allocated between heating and electricity production (or shaft work in the case of internal combustion engines), and these emissions will have to be scaled by the fraction of the heat or electricity that is used for cooling, as shown in Equation 15k (see the following page). This equation assumes 90 percent efficiency for boiler emissions and allocates all other waste heat to electrical efficiency.

Step 2: Determine fraction of cooling emissions attributable to your operations.

The next step in calculating your GHG emissions from cooling is to scale the total plant cooling emissions by the percentage of your share of the cooling load. Equation 15j demonstrates how the total cooling load on the plant is scaled to determine your cooling emissions.

Equation 15j	Calculating Annual Cooling Emissions
Your Cooling Emissions (metric tons) = Total Plant Cooling Emissions *(metric tons)* × [Your Cooling Load *(ton-hour)* ÷ Total Cooling Load *(ton-hour)*]	

Step 3: Determine total yearly emissions.

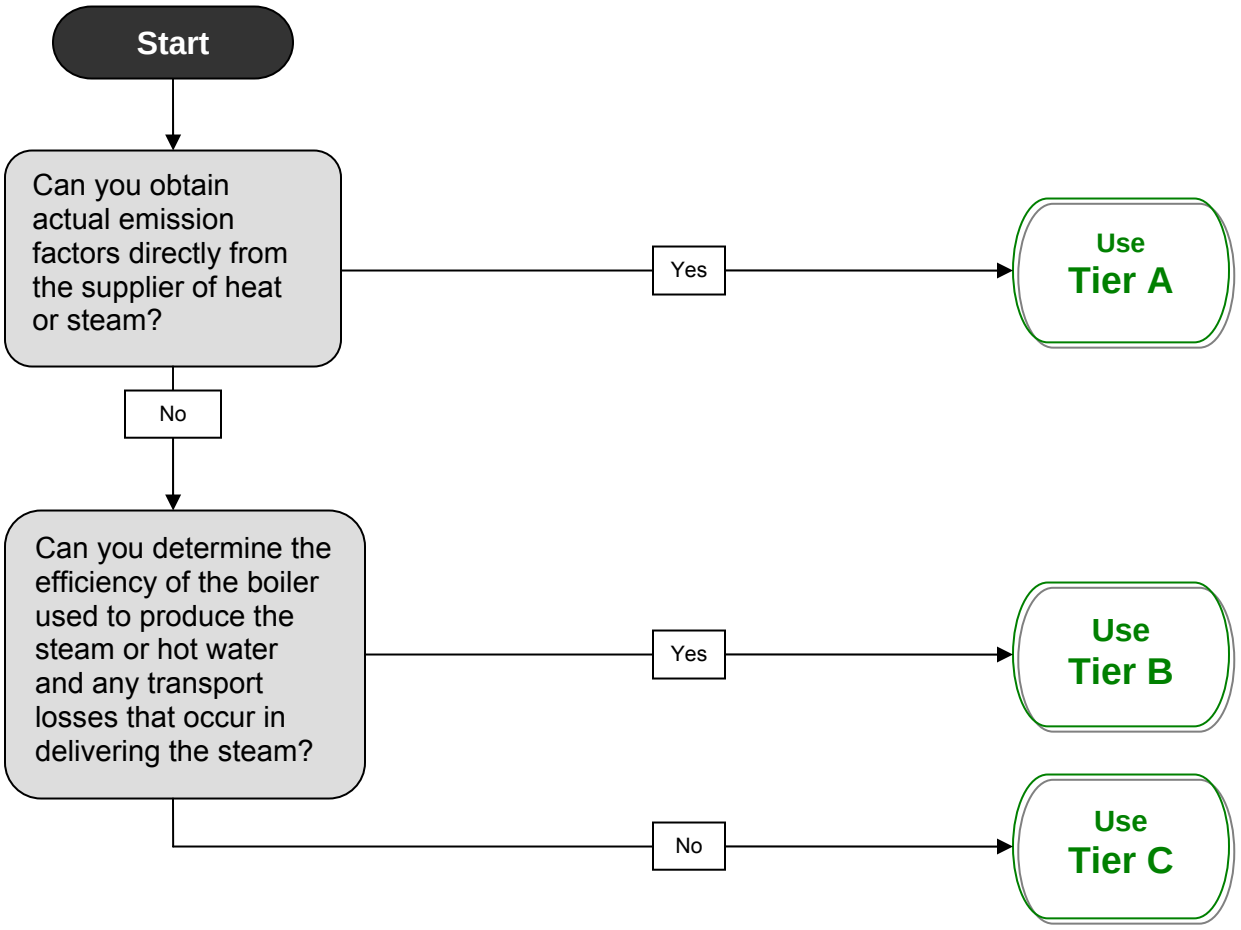
For each month (or longer period) of the year, cooling emissions should be calculated as

described in Steps 1 and 2, above. The duration of the periods for which the emissions are calculated will depend on the data available. Ideally, calculations would be made monthly for cooling plants integrated with CHPs, as emissions associated with cooling will depend on how the CHP outputs are distributed. If data for making these calculations are not available on a monthly basis, then longer periods will need to be used. In either case, the emissions for each period must be summed over the year to obtain the annual total.

Equation 15k	Calculating Cooling Emissions From Plant with Multiple Product Streams

Total Cooling Emissions (metric tons) =
[% of CHP Electricity Prod. Used for Cooling × ((Total Fuel Heat Input *(MMBtu)* - Net Heat Production *(MMBtu)*) ÷ 0.9) ÷ Total Fuel Heat Input *(MMBtu)*] +
[% of CHP Heat Prod. Used for Cooling × (Net Heat Production *(MMBtu)* ÷ (0.9 × Total Fuel Heat Input *(MMBtu)*))] × Total CHP Emissions *(metric tons)*

Figure 15.2 Selecting Data Quality Tiers: Indirect CO_2, CH_4 and N_2O Emissions from District Cooling



Tier B/C Method: Simplified Approach

The simplified approach uses an estimated value for the ratio of cooling demand to energy input for the cooling plant, known as the "coefficient of performance" (COP). Thus, this approach allows you to estimate the portion of energy used at the district cooling plant directly attributable to your cooling.

Step 1: Determine your annual cooling demand.

While your cooling bill may be reported in terms of million Btu (MMBtu), it will typically report cooling demand in ton-hours. You can convert ton-hours of cooling demand to MMBtu using Equation 15l. If you are billed monthly, sum together your monthly cooling demand to yield an annual total.

Equation 5l	Calculating Annual Cooling Demand
Cooling Demand = Cooling Demand × 12,000 ÷ 1,000,000 (MMBtu) (ton-hour) (Btus/ton-hour) (MMBtu/Btu)	

Step 2: Estimate COP for the plant's cooling system.

Tier B: Source-Specific COP

The preferred approach is to obtain the source-specific COP for your cooling plant. This method is designated as Tier B. If you can obtain the COP for the cooling plant, proceed to Step 3.

Tier C: Default COP

If you cannot obtain the COP for the plant itself, determine the type of chiller used by the district cooling plant. With that information, a rough estimate of the COP may be selected from the default values shown in Table 15.1.

Table 15.1. Typical Chiller Coefficients of Performance

Chiller Type	COP	Energy Source
Absorption Chiller	0.8	Natural Gas
Engine-Driven Compressor	1.2	Natural Gas
Electric-Driven Compressor	4.2	Electricity

Step 3: Determine energy input.

To determine the energy input to the system resulting from your cooling demand, use Equation 15m. For an electric driven compressor, convert the energy input in MMBtu into kWh by multiplying by 293.1.

Equation 15m	Calculating Energy Input
Energy Input = Cooling Demand ÷ COP (MMBtu) (MMBtu)	

Step 4: Calculate GHG emissions resulting from cooling, convert to units of carbon dioxide equivalent, and determine total emissions.

Where Cooling Plant Uses Absorption Chillers or Combustion Engine-Driven Compressors. In this case, calculate the compressor's emissions using the stationary combustion methods outlined in Chapter 12. If you can determine what type of fuel is being used, multiply the energy input by source-specific or default emission factors for CO_2, CH_4, and N_2O from Tables 12.1 – 12.9 in Chapter 12. If the fuel type cannot be determined, assume the fuel used is natural gas. Use Equation 15n to calculate emissions.

Equation 15n	Calculating Total Cooling Emissions
Total CO_2 Emissions (metric tons) = Energy Input x Emission Factor x 0.001 (MMBtu) (kg CO_2 / MMBtu) (metric tons/kg)	
Total CH_4 Emissions (metric tons) = Energy Input x Emission Factor x 0.001 (MMBtu) (kg CH_4 / MMBtu) (metric tons/kg)	
Total N_2O Emissions (metric tons) = Energy Input x Emission Factor x 0.001 (MMBtu) (kg N_2O / MMBtu) (metric tons/kg)	

Where Cooling Plant Uses Electric-Driven Compressors. In this case, calculate emissions using the procedures for estimating indirect emissions from electricity use described in Chapter 14.

Finally, convert emissions to units of carbon dioxide equivalent using Equation 15d and sum

Equation 15d	Converting to CO_2-equivalent and Determining Total Emissions
CO_2 Emissions (metric tons CO_2e)	= CO_2 Emissions (metric tons) × 1 (GWP)
CH_4 Emissions (metric tons CO_2e)	= CH_4 Emissions (metric tons) × 21 (GWP)
N_2O Emissions (metric tons CO_2e	= N_2O Emissions (metric tons) × 310 (GWP)
Total Emissions (metric tons CO_2e)	= CO_2 + CH_4 + N_2O (metric tons CO_2e)

to determine total emissions from cooling.

15.4 Example: Indirect Emissions from District Heating

Socal Manufacturing Company

The Socal Manufacturing Company imports steam at its California facility. The steam is imported from a conventional natural gas-fired boiler. The boiler efficiency is 85 percent and the loss factor is 6 percent. The entity uses a Tier B method to calculate emissions.

Step 1: Determine energy obtained from steam or district heating.

Since its energy consumption is provided in therms on its monthly billing, Socal uses Equation 15e to determine energy consumption. Socal consumed 6,000 therms in

Equation 15e	Converting Steam Consumption from Therms to MMBtu
Energy Consumption (MMBtu)	= Energy Consumption (therms) x 0.1 (MMBtu/therm)
Steam Energy Consumption (MMBtu)	= 6,000 (therms) x 0.1 = **600 MMBtu** (MMBtu/therm)

the past year.

Step 2: Determine appropriate emission factors.

Socal cannot obtain emission factors directly from the supplier of steam. However, the entity can obtain source-specific efficiency factors from the supplier, namely a boiler efficiency of 85 percent and a loss factor of 6 percent. It also knows that the boiler combusts natural gas. The entity uses Equation 15g to calculate a total efficiency factor and Equation 15h to calculate emission factors for CO_2, CH_4, and N_2O, using emission factors for natural gas from Chapter 12 (represented in the Table below).

Emission Factors for Natural Gas

Fuel	Gas Emitted	Emission Factor
Natural Gas	Carbon Dioxide	53.06 kg/MMBtu
Natural Gas	Methane	0.001 kg/MMBtu
Natural Gas	Nitrous Oxide	0.0001 kg/MMBtu

Equation 15g	Calculating System Efficiency
Total Efficiency Factor (%)	= Boiler Efficiency (%) x (100% - Transport Losses (%))
Total Efficiency Factor = 85% x (100% - 6%) = **0.799**	

Equation 15h	Calculating Emission Factors
Emission Factor (kg / MMBtu)	= Fuel-Specific Emission Factor (kg / MMBtu) ÷ Total Efficiency Factor (%)
CO_2 Emission Factor (kg CO_2 / MMBtu)	= 53.06 (kg CO_2 / MMBtu) ÷ 0.799 (kg CO_2 / MMBtu) = **66.4** (kg CO_2 / MMBtu)
CH_4 Emission Factor (kg CH_4 / MMBtu)	= 0.001 (kg CH_4 / MMBtu) ÷ 0.799 (kg CH_4 / MMBtu) = **0.001** (kg CH_4 / MMBtu)
N_2O Emission Factor (kg N_2O / MMBtu)	= 0.0001 (kg N_2O / MMBtu) ÷ 0.799 (kg N_2O / MMBtu) = **0.0001** (kg N_2O / MMBtu)

Step 3: Calculate Total Emissions.

Socal uses the steam consumption from Step 1, the emission factors from Step 2, and Equation 15i to calculate emissions from steam consumption. Then the entity converts to units of carbon dioxide equivalent using Equation 15d and sums to determine total emissions.

Equation 15i	Calculating Emissions From Imported Steam or Heat
Total Emissions (metric tons) = Energy Consumed x Emission Factor x 0.001 (MMBtu) (kg / MMBtu) (metric ton/kg)	
Total CO_2 Emissions (metric tons) = 600 x 66.4 x 0.001 = **39.8** (MMBtu) (kg CO_2 /MMBtu) (metric ton/kg)	
Total CH_4 Emissions (metric tons) = 600 x 0.001 x 0.001 = **0.0006** (MMBtu) (kg CH_4/MMBtu) (metric ton/kg)	
Total N_2O Emissions (metric tons) = 600 x 0.0001 x 0.001 = **0.00006** (MMBtu) (kg N_2O/MMBtu) (mt/kg)	

Equation 15d	Converting to CO_2-equivalent and Determining Total Emissions
CO_2 Emissions = 39.8 × 1 = 39.8 (metric tons CO_2-e) (metric tons)	
CH_4 Emissions = 0.0006 × 21 = 0.01 (metric tons CO_2-e) (metric tons) GWP	
N_2O Emissions = 0.00006 × 310 = 0.02(metric tons CO_2-e) (metric tons) GWP	
Total Emissions = $CO_2 + CH_4 + N_2O$ = **39.8** metric tons CO_2-e(metric tons CO_2-e) (metric tons CO_2-e)	

CHAPTER 16: DIRECT FUGITIVE EMISSIONS FROM THE USE OF REFRIGERATION AND AIR CONDITIONING EQUIPMENT

Who should read Chapter 16:

- Chapter 16 applies to organizations that use refrigeration and air conditioning equipment, including household, commercial, industrial, and motor vehicle refrigeration and air conditioning systems.

What you will find in Chapter 16:

- This chapter provides guidance on determining direct fugitive emissions of HFCs and PFCs from refrigeration and air conditioning systems.

Information you will need:

- To complete this chapter you will need information on the types and quantities of air conditioning equipment, total refrigerant charge, annual leak rates, and the types of refrigerant, as applicable.

Cross-References:

- See Chapter 13 for guidance on calculating combustion emissions from motor vehicles and see Appendix E.11 for calculating emissions from the manufacturing of refrigeration and air conditioning equipment.

Data Quality Tiers: Direct Fugitive Emissions From the Use of Refrigeration and Air Conditioning Equipment

Tier	Method
A	Mass balance method
B	Simplified mass balance method

16.1 Calculating Direct Fugitive Emissions from Refrigeration Systems

Leakage from refrigeration systems, such as air conditioners and refrigerators, is common across a wide range of entities. Refrigeration and air conditioning systems include household refrigeration, domestic air conditioning and heat pumps, motor vehicle air conditioning, chillers, retail food refrigeration, cold storage warehouses, refrigerated transport, industrial process refrigeration, and commercial air conditioning systems.

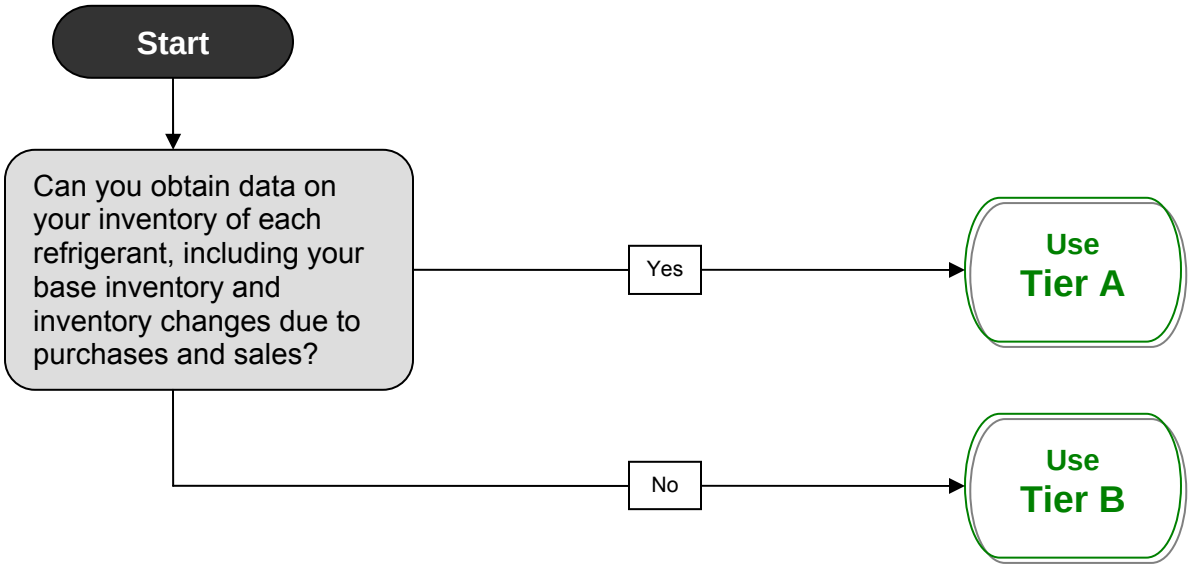
Emissions of hydrofluorocarbons (HFCs) and perfluorocarbons (PFCs) from refrigeration and air conditioning equipment result from the manufacturing process, leakage over the operational life of the equipment, and disposal at the end of the useful life of the equipment. This chapter addresses emissions from use of equipment only (including installation, use, and disposal). For guidance on calculating emissions from the manufacturing of refrigeration and air condition equipment, see Section E.11 of Appendix E.

There are three methods for estimating emissions of HFCs and PFCs from refrigeration and air conditioning equipment:

1. Mass balance approach (designated as Tier A);
2. Simplified mass balance approach (designated as Tier B); and
3. Screening method, which can only be used to determine whether emissions fall below 5 percent of your total entity-wide emissions, and if so, may be used as a simplified estimation method (see Chapter 11). The screening method cannot be used as a method for quantifying and reporting emissions if these emissions sources exceed 5 percent of your total emissions.

Figure 16.1 gives guidance on how to select a particular emissions quantification methodology based on the data that is available to you. Emissions from refrigeration and air conditioning equipment should be calculated and reported separately for each of your facilities.

Figure 16.1 Selecting Data Quality Tiers: Fugitive Emissions from the Use of Refrigeration and Air Conditioning Equipment



Tier A Method: Mass Balance Approach

The mass balance approach is the most accurate method for determining HFC and PFC emissions. This method is particularly recommended for equipment manufacturers and for equipment users who service their own equipment. To calculate HFC and PFC emissions using the mass balance approach, follow these three steps:

1. Determine the base inventory for each refrigerant in use at each facility;
2. Calculate changes to the base inventory for each refrigerant based on purchases and sales of refrigerants and changes in total capacity of the equipment; and
3. Calculate annual emissions of each type of refrigerant, convert to units of carbon dioxide equivalent, and determine total HFC and PFC emissions for each facility.

Step 1: Determine the base inventory for each HFC and PFC.

For each facility, first determine the quantity of the refrigerant in storage at the beginning of the year **(A)** and the quantity in storage at the end of the year **(B)**, as shown in Table 16.1. Refrigerant in storage (or in inventory) is the total stored on site in cylinders or other storage containers and does not include refrigerants contained within equipment.

Step 2: Calculate changes to the base inventory.

Next, include any purchases or acquisitions of each refrigerant, sales or disbursements of each refrigerant, and any changes in capacity of refrigeration equipment. Additions and subtractions refer to refrigerants placed in or removed from the stored inventory, respectively.

Purchases/Acquisitions of Refrigerant. This is the sum of all the refrigerants acquired during the year either in storage containers or in equipment (item **C** in Table 16.1). Purchases and other acquisitions may include refrigerant:

- Purchased from producers or distributors,
- Provided by manufactures or inside equipment,
- Added to equipment by contractors or other service personnel (but not if that refrigerant is from your inventory), and
- Returned after off-site recycling or reclamation.

Sales/Disbursements of Refrigerant. This is the sum of all the refrigerants sold or otherwise disbursed during the year either in storage containers or in equipment (item **D** in Table 16.1). Sales and disbursements may include refrigerant:

- In containers or left in equipment that is sold,
- Returned to suppliers, and
- Sent off-site for recycling, reclamation, or destruction.

Net Increase in Total Full Charge of Equipment. This is the net change to the total equipment volume for a given refrigerant during the year (item **E** in Table 16.1). Note that the net increase in total full charge of equipment refers to the full and proper charge of the equipment rather than to the actual charge, which may reflect leakage. It accounts for the fact that if new equipment is purchased, the refrigerant that is used to charge that new equipment should not be counted as an emission.

It also accounts for the fact that if the amount of refrigerant recovered from retiring equipment is less than the full charge, then the difference between the full charge and the recovered amount has been emitted. Note that this quantity will be negative if the retiring equipment has a total full charge larger than the total full charge of the new equipment.

If the beginning and ending total capacity values are not known, this factor can be calculated based on known changes in equipment. The total full charge of new equipment (including equipment retrofitted to use the refrigerant in question) minus the full charge of equipment that is retired or sold (including full charge of refrigerant in question from equipment that is retrofit to use a different refrigerant) also provides the change in total capacity.

Step 3: Calculate annual emissions of each type of HFC and PFC, convert to units of carbon dioxide equivalent, and determine total HFC and PFC emissions.

For each type of refrigerant or refrigerant blend, use Equation 16a and your data from Table 16.1 to calculate total annual emissions of each type of HFC and PFC at each of your facilities.

Equation 16a	Calculating Emissions of Each Type of HFC and PFC Using the Mass Balance Method

Total Annual Emissions (metric tons of HFC or PFC) **=**
(A - B + C - D - E **)** ÷ 1,000
(kg) (kg) (kg) (kg) (kg) (kg/metric tons)

Next, use Equation 16b and the appropriate global warming potential factors from Appendix B (or Table 16.2 for refrigerant blends) to convert each HFC and PFC to units of carbon dioxide equivalent.

Equation 16b	Converting to CO_2-equivalent

HFC Type A Emissions = HFC Type A Emissions × GWP
(mt CO_2e) (metric tons HFC Type A) (HFC A)

PFC Type A Emissions = PFC Type A Emissions × GWP
(mt CO_2e) (metric tons PFC Type A) (PFC A)

Finally, sum the totals of each type of HFC, in units of carbon dioxide equivalent, to determine total HFC emissions (see Equation 16c) at each facility. Likewise, sum the totals of each type of PFC to determine total PFC emissions.

Equation 16c	Determining total HFC and PFC emissions

Total HFC Emissions = HFC Type A + HFC Type B + …
(mt CO_2e) (mt CO_2-e) (mt CO_2e)

Total PFC Emissions = PFC Type A + PFC Type B + …
(mt CO_2e) (mt CO_2-e) (mt CO_2e)

Table 16.1 Base Inventory and Inventory Changes

Inventory		Amount (kg)
Base Inventory		
A	Refrigerant in inventory (storage) at the beginning of the year	
B	Refrigerant in inventory (storage) at the end of the year	
Additions to Inventory		
1	Purchases of refrigerant (including refrigerant in new equipment)	
2	Refrigerant returned to the site after off-site recycling	
→ **C**	Total Additions (1+2)	
Subtractions from Inventory		
3	Returns to supplier	
4	HFCs taken from storage and/or equipment and disposed of	
5	HFCs taken from storage and/or equipment and sent off-site for recycling or reclamation	
→ **D**	Total Subtractions (3+4+5)	
Net Increase in Full Charge/Nameplate Capacity		
6	Total full charge of new equipment	
7	Total full charge of retiring equipment	
→ **E**	Change to nameplate capacity (6-7)	

Table 16.2 Global Warming Potentials of Refrigerant Blends

Refrigerant Blend	Global Warming Potential
R-401A	18
R-401B	15
R-401C	21
R-402A	1,680
R-402B	1,064
R-403A	1,400
R-403B	2,730
R-404A	3,260
R-406A	0
R-407A	1,770
R-407B	2,285
R-407C	1,526
R-407D	1,428
R-407E	1,363
R-408A	1,944
R-409A	0
R-409B	0
R-410A	1,725
R-410B	1,833
R-411A	15
R-411B	4
R-412A	350
R-413A	1,774
R-414A	0
R-414B	0
R-415A	25
R-415B	105
R-416A	767
R-417A	1,955
R-418A	4
R-419A	2,403
R-420A	1,144
R-500	37
R-501	0
R-502	0
R-503	4,692
R-504	313
R-505	0
R-506	0
R-507 or R-507A	3,300
R-508A	10,175
R-508B	10,350
R-509 or R-509A	3,920
Source: ASHRAE Standard 34	

Tier B Method: Simplified Mass Balance Approach

If you do not have the necessary data to use the mass balance approach outlined above, you should use the simplified mass balance approach. This method may be used either by entities that service their own equipment or by entities that have contractors service their equipment. This method requires information on the quantity of refrigerant used to charge new equipment during installation, the quantity of refrigerant used to service equipment, the quantity of refrigerant recovered from retiring equipment, and the total full charges of new and retiring equipment.

To calculate HFC and PFC emissions using the simplified mass balance approach, follow these three steps:

1. Determine the types and quantities of refrigerants used at each facility;
2. Calculate annual emissions of each type of HFC and PFC; and
3. Convert to units of carbon dioxide equivalent and determine total HFC and PFC emissions at each facility.

Step 1: Determine the types and quantities of refrigerants used.

For each type of refrigerant used, determine the following quantities used or recovered during the reporting year, if applicable:

- Quantity of refrigerant used to charge new equipment during installation (if you installed new equipment that was not pre-charged by the manufacturer)
- Total full charge (capacity) of new equipment using this refrigerant (if you installed new equipment that was not pre-charged by the manufacturer)
- Quantity of refrigerant used to service equipment.
- Total full charge (capacity) of retiring equipment (if you disposed of equipment during the reporting year)
- Quantity of refrigerant recovered from retiring equipment (if you disposed of equipment during the reporting year)

If you have contractors that service your equipment, you should obtain the required information from the contractor. Always track and maintain the required information carefully in order to obtain accurate estimates of emissions.

Note that "total full charge" refers to the full and proper charge of the equipment rather than to the actual charge, which may reflect leakage. For more information, see the description of "Net Increase in Total Full Charge of Equipment" from Step 2 in the Mass Balance Approach above.

Step 2: Calculate annual emissions of each type of HFC and PFC.

Next, use Equation 16d to calculate emissions for each type of refrigerant used at your facility. Repeat Equation 16d for each type of refrigerant used.

Equation 16d **Calculating Emissions of Each Type of Refrigerant**

Total Annual Emissions (metric tons) =
$(P_N - C_N + P_S + C_D - R_D) \div 1{,}000$
(kg) (kg) (kg) (kg) (kg) (kg/metric tons)

Where:
P_N = purchases of refrigerant used to charge new equipment *
C_N = total full charge of the new equipment *
P_S = quantity of refrigerant used to service equipment
C_D = total full charge of retiring equipment
R_D = refrigerant recovered from retiring equipment

* Omitted if the equipment has been pre-charged by the manufacturer

Step 3: Convert to units of carbon dioxide equivalent and determine total annual HFC and PFC emissions.

Use Equation 16b and the appropriate global warming potential factors from Table12.1 (or Table 16.2 for refrigerant blends) to convert each HFC and PFC to units of carbon dioxide equivalent.

Equation 16b	Converting to CO_2-equivalent
HFC Type A Emissions (metric tons CO_2e)	= HFC Type A Emissions (metric tons HFC Type A) × GWP (HFC A)
PFC Type A Emissions (metric tonsCO_2e)	= PFC Type A Emissions (metric tons PFC Type A) × GWP (PFC A)

Finally, sum the totals of each type of HFC, in units of carbon dioxide equivalent, to determine total HFC emissions at each facility (see Equation 16c). Likewise, sum the totals of each type of PFC to determine total PFC emissions.

Equation 16c	Determining total HFC and PFC emissions
Total HFC Emissions (metric tons CO_2e)	= HFC Type A (mt CO_2e) + HFC Type B (mt CO_2e) + …
Total PFC Emissions (metric tons CO_2e)	= PFC Type A (mt CO_2e) + PFC Type B (mt CO_2e) + …

Screening Method

Consistent with the Registry's voluntary reporting requirements, any combination of emissions that total less than or equal to 5 percent of a Reporter's total entity-wide emissions may be estimated with simplified methods (and reported to the Registry). The Screening Method is intended to help you roughly estimate your emissions and determine whether HFC and PFC emissions from refrigeration and air conditioning systems may be estimated with simplified methods.

If the Screening Method determines that your emissions from refrigeration and air conditioning systems represent less than 5 percent of your total entity-wide emissions, you may use the Screening Method to estimate and report these emissions. Note that you may only use simplified methods to estimate up to 5 percent of your total entity-wide emissions. If emissions from refrigeration and air conditioning represent 5 percent of your total emissions and you use the Screening Method to estimate those emissions, you are not eligible to use simplified methods to estimate other sources within your inventory. See Chapter 11 for more information.

If the Screening Method determines that emissions from refrigeration and air conditioning are greater than 5 percent of your total entity-wide emissions, you must use either the Mass Balance Approach or Simplified Mass Balance Approach outlined above to accurately quantify and report your emissions. In this case, you may not use the Screening Method to report your emissions.

The Screening Method estimates emissions by multiplying the quantity of refrigerants used by default emission factors. Because default emission factors are highly uncertain, the resulting emissions estimates are not considered accurate.

To estimate emissions using the Screening Method, follow these three steps:

1. Determine the types and quantities of refrigerants used;
2. Estimate annual emissions of each type of HFC and PFC; and
3. Convert to units of carbon dioxide equivalent and determine total HFC and PFC emissions.

Step 1: Determine the types and quantities of refrigerants used.

To estimate emissions, you must determine the number and types of refrigeration and air conditioning equipment, by equipment category; the types of refrigerant used; and the refrigerant charge capacity of each piece of equipment (see Table 16.3). If you do not know the refrigerant charge capacity of each piece of equipment, use the upper bound of the range provided by equipment type in Table 16.3.

Step 2: Estimate annual emissions of each type of refrigerant.

For each type of refrigerant, use Equation 16e to estimate annual emissions. Default emission factors are provided in Table 16.3 by equipment type. The equation includes emissions from

installation, operation, and disposal of equipment. If you did not install or dispose of equipment during the reporting year, do not include emissions from these activities in your estimation.

Note that refrigerants may be blends of HFCs or PFCs. Table 16.2 lists the global warming potential factors for selected blends.

Equation 16e	Estimating Emissions of Each Type of Refrigerant using the Screening Method

For each type of refrigerant:

Total Annual Emissions = [$(C_N \times k) + (C \times x \times T) + (C_D \times y \times (1 - z))$ **]** ÷ 1,000

(metric tons) (kg) (%) (kg) (%) (years) (kg) (%) (%) (kg/metric ton)

Where:

C_N = quantity of refrigerant charged into the new equipment [1]

C = total full charge (capacity) of the equipment

T = time in years equipment was in use (e.g., 0.5 if used only during half the year and then disposed)

C_D = total full charge (capacity) of equipment being disposed of [2]

k = installation emission factor [1]

x = operating emission factor

y = refrigerant remaining at disposal [2]

z = recovery efficiency [2]

[1] Omitted if no equipment was installed during the reporting year or the installed equipment was pre-charged by the manufacturer

[2] Omitted if no equipment was disposed of during the reporting year

Table 16.3 Default Emission Factors for Refrigeration / Air Conditioning Equipment

Type of Equipment	Capacity (kg)	Installation Emission Factor k (% of capacity)	Operating Emission Factor x (% of capacity / year)	Refrigerant Remaining at Disposal y (% of capacity)	Recovery Efficiency z (% of remaining)
Domestic Refrigeration	0.05 - 0.5	1 %	0.5 %	80 %	70 %
Stand-alone Commercial Applications	0.2 - 6	3 %	15 %	80 %	70 %
Medium & Large Commercial Refrigeration	50 - 2,000	3 %	35 %	100 %	70 %
Transport Refrigeration	3 - 8	1 %	50 %	50 %	70 %
Industrial Refrigeration including Food Processing and Cold Storage	10 - 10,000	3 %	25 %	100 %	90 %
Chillers	10 - 2,000	1 %	15 %	100 %	95 %
Residential and Commercial A/C including Heat Pumps	0.5 - 100	1 %	10 %	80 %	80 %
Mobile Air Conditioning	0.5 – 1.5	0.5 %	20 %	50 %	50 %

Source: IPCC, *Guidelines for National Greenhouse Gas Inventories* (2006), Volume 3: Industrial Processes and Product Use, Table 7.9.
Note: Emission factors above are the most conservative of the range provided by the IPCC. The ranges in capacity are provided for reference. You should use the actual capacity of your equipment. If you do not know your actual capacity, you should use the high end of the range provided (e.g., use 2,000 kg for chillers).

Step 3: Convert to units of carbon dioxide equivalent and determine total HFC and PFC emissions.

Equation 16b	Converting to CO_2 Equivalent
HFC Type A Emissions (metric tons CO_2e)	= HFC Type A Emissions (metric tons HFC Type A) × GWP (HFC A)
PFC Type A Emissions (metric tons CO_2e)	= PFC Type A Emissions (metric tons PFC Type A) × GWP (PFC A)

Use Equation 16b and the appropriate global warming potential factors from Table 12.1 (or Table 16.2 for refrigerant blends) to convert each type of refrigerant to units of carbon dioxide equivalent.

Finally, sum the totals of each type of HFC, in units of carbon dioxide equivalent, to determine total HFC emissions (see Equation 16c). Likewise, sum the totals of each type of PFC to determine total PFC emissions.

If the sum of your HFC and PFC emissions, in units of carbon dioxide equivalent, is less than 5 percent of your total entity-wide emissions, you may use these estimates to report HFC and PFC emissions from refrigeration and air conditioning use, provided you estimate no more than 5 percent of your total emissions using a simplified estimation method such as this screening method. If you determine HFC and PFC emissions to be more than 5 percent of your total emissions (or you are using

simplified estimation methods to estimate other sources that together constitute 5 percent of your total emissions), you must use a Tier A or B method outlined in this chapter to estimate these emissions.

16.2 Example: Direct Fugitive Emissions from Refrigeration Systems

Produce Chillers, Inc.

Produce Chillers, Inc. operates five large commercial chillers to refrigerate vegetable produce shortly after harvest, using HFC-23. During the reporting year, the entity increased its total vegetable produce refrigeration capacity by 18 percent with new equipment, decommissioned one refrigeration unit for recycling, and recharged several of its refrigeration units. Its inventory at the beginning of the year is 412.6 kg and at the end of the year it is 405.1 kg. The entity chooses to use the Tier A method.

Step 1: Determine the base inventory for each refrigerant.

Produce Chillers records its base inventory for HFC-23 in the table below.

Step 2: Calculate changes to the base inventory.

The entity records its additions, subtractions, and changes to full charge in the table below and calculates the values C, D, and E.

Step 3: Calculate annual emissions of each type of HFC and PFC, convert to units of carbon dioxide equivalent, and determine total HFC and PFC emissions.

The entity uses Equation 16a and the data from the table below to calculate emissions of HFC-23, and then converts the total to units of carbon dioxide equivalent using Equation 16b and the appropriate global warming potential value from Table 12.1. Because Produce Chillers uses only one type of HFC, it does not need to sum emissions for multiple HFCs using Equation 14c. Instead, the entity's total emissions of HFCs result from Equation 16b.

Equation 16c	Determining total HFC and PFC emissions
Total HFC Emissions (metric tons CO_2e)	= HFC Type A + HFC Type B + … (metric tons CO_2e)
Total PFC Emissions (metric tons CO_2e)	= PFC Type A + PFC Type B + … (metric tons CO_2e)

Equation 16a	Calculating Emissions of Each Type of HFC and PFC
HFC-23 Emissions (metric tons of HFC-23)	= (412.6 (kg) – 405.1 (kg) + 197.5 (kg) – 53.3 (kg) - 90 (kg)) ÷ 1,000 (kg/metric ton) = 0.062

Equation 16b	Converting to CO_2 equivalent
HFC-23 Emissions (metric tons CO_2e)	= 0.062 (metric tons) × 11,700 (HFC-23 GWP) = **725.4** metric tons CO_2e

Inventory for HFC-23 from Commercial Chillers		Amount (kg)
Base Inventory		
A	Beginning of year	412.6
B	End of year	405.1
Additions to Inventory		
1	Purchases of HFCs (including HFCs in new equipment)	197.5
2	HFCs returned to the site after off-site recycling	0
→ **C**	Total Additions (1+2)	197.5
Subtractions from Inventory		
3	Returns to supplier	0
4	HFCs taken from storage and/or equipment and disposed of	0
5	HFCs taken from storage and/or equipment and sent off-site for recycling or reclamation	53.3
→ **D**	Total Subtractions (3+4+5)	53.3
Net Increase in Full Charge/Nameplate Capacity		
6	Total full charge of new equipment	100
7	Total full charge of retiring equipment	10
→ **E**	Change to nameplate capacity (6-7)	90

Part IV: Reporting Your Emissions

About Part IV

All entities that report to The Climate Registry's voluntary reporting program should read Part IV in its entirety. This section sets forth the procedures that all Reporters must follow once they have completed their emissions calculations and are ready to submit their data to the Registry. Specifically, Part IV provides information on how to report your data using the Registry's software, the supplemental information you need to report (or may report optionally), and how to have your report verified. Part IV also provides you with the Registry's deadlines for reporting and for having your report verified by a Registry-approved Verifier.

CHAPTER 17: COMPLETING YOUR ANNUAL EMISSION REPORT

Now that you have defined and calculated your GHG emissions, you are ready to complete your annual emission report. In addition to calculating your North American emissions, you must also provide the Registry with some information about your entity. Finally, you have the ability to include optional information in your emission report. You may keep optional information private to use for internal purposes, or it can be disclosed to the Registry's stakeholders via your public emission report.

As you compile your complete emission report, please adhere to the following reporting and verification deadlines:

- **Reporting Deadline** (Data must be submitted into CRIS): **June 30th**
- **Verification Deadline** (Data must be successfully verified by a TCR approved verifier): **December 15th**

For example, if you are reporting your 2008 data, you must report this data in CRIS by June 30, 2009 and must verify your data by December 15th, 2009.

17.1 Additional Reporting Requirements

The primary information that you must report to the Registry is your GHG emissions data. However, the Registry also requires that you provide the following additional information:

- Information about your entity (address, key contacts, etc.)
- Name and address of each facility
- Whether your entity is participating in the Registry as a Transitional Reporter or a Complete Reporter
- The consolidation approach(es) employed (i.e., operational control, financial control, equity share) by your entity
- Quantification methodologies and "tiers" employed for each source (see Part III for more information), including disclosure of all relevant assumptions made, data sources used, and identification of any changes to the data, inventory boundary, methods, or other relevant factors relative to prior-year reports. Note: If you use CRIS to calculate your emissions, the quantification

methodologies and tiers will be automatically generated for you.

- If you are reporting as a subsidiary, the identity of your parent company and an organizational chart that makes clear your relationship to your parent(s) and other subsidiaries

17.2 *Optional Data*

The Registry encourages you to *exceed* its reporting requirements by providing optional data in addition to the required data and information described above. Reporting optional data will enhance the value of your report to the Registry's stakeholders, and it may also further demonstrate both the transparency of your emission report and your environmental leadership. You may include whatever additional data or information you believe would be helpful for your stakeholders to review with your emission report. You may either enter this data or information in numerous text boxes in CRIS designated for optional data, or you may upload documents to your entity's document library within CRIS (for either internal purposes or public disclosure).

You may submit a wide array of optional data to the Registry, however the Registry encourages you to consider including the following:

- Your organization's entire worldwide emissions (in addition to your North American emissions)
- Your organization's unit-level emissions (for stationary combustion units)
- Your organization's historical emissions, for a time period of your choosing providing consecutive years are reported through your first year of participation in the Registry
- Your organization's emissions based on more than one of the consolidation approaches described in Chapter 4 (e.g., you may choose to report your emissions on both an equity share and operational control basis, or both an equity share and financial control basis)
- Your organization's emissions of other GHGs beyond the six internationally recognized GHGs
- Your organization's Scope 3 emissions
- Information on any GHG management or reduction programs or strategies, including green power purchases (e.g., RECs), purchases of offsets (including information on whether they are verified or certified), etc.
- Descriptions of unique environmental practices employed by your entity

Performance Metrics for Your Entity

Performance metrics provide information about an entity's direct and indirect emissions relative to a unit of business activity, input, or output. You may use performance metrics to serve a range of objectives, including:

- Evaluation of emissions over time in relation to targets or industry benchmarks;
- Facilitation of comparisons between similar businesses, process or products; and
- Improving public understanding of your entity's emissions profile over time, even as your business activity changes, expands or decreases.

Many companies track environmental performance with intensity ratios. Intensity ratios measure GHG emissions per unit of physical activity or economic unit. For example, an electricity generating company may use a GHG intensity indicator that specifically measures pounds of emissions per total megawatt-hour generated (lbs/MWH). In the power sector, some examples of performance metrics include generation emission intensity (e.g., tons of CO_2 emissions per unit of electricity consumed); and sales emissions

intensity (e.g., emissions per unit of electricity sold).

Currently, the reporting of relevant performance metrics is optional. However, in the future the Registry may develop and require the reporting of sector-specific performance metrics that assist in fully capturing a company's emissions in a way that is most relevant to users. For example, because some provinces, states or tribal nations are contemplating future load-based electricity sector regulatory programs in their regions, the Registry may decide to require Reporters in the electric power sector to report emissions associated with the electricity they deliver to customers (i.e., sales emissions intensity data).

CHAPTER 18: REPORTING YOUR DATA USING CRIS

18.1 CRIS Overview

The Registry has developed a sophisticated GHG calculation, reporting, and verification tool to centralize the GHG data submitted to the Registry. The Climate Registry Information System (CRIS) allows Reporters to easily calculate and report their GHG emissions annually, and produces user-friendly reports for both the Reporter and the public.

Reporters may use CRIS to assemble their emissions inventory from the ground up by using its automatic calculation functions to enter activity-level data for facilities, or simply enter their pre-calculated facility-level data by emissions type into CRIS. This decision will likely depend on whether or not a Reporter currently utilizes a robust corporate Environmental Management System (EMS), or if they are aggregating and assembling their inventory for the first time.

By early 2009, the Registry plans to offer a data exchange mechanism that will ease the automated transfer of GHG emissions data from existing corporate EMS and between GHG emissions reporting programs. The Registry is currently partnering with several programs and the U.S. EPA to develop this standardized schema to exchange GHG information. For updates on the status of the data exchange standard, please visit the Registry's website: www.theclimateregistry.org.

Public Emissions Reports

Stakeholders will be able to print and download public emissions reports from CRIS as well as view them online. Once the Registry collects multiple years of data, stakeholders will also be able to produce reports in CRIS that track GHG emissions over time.

18.2 Help with CRIS

The Registry's technical staff is available to help you with any questions you may have about using CRIS to calculate, report, or verify your emissions. Please call **866-523-0764** if you need technical support.

Reporting Deadline Reminder

The deadline for reporting your emissions is **June 30th** of the year following your reporting year.

CHAPTER 19: THIRD-PARTY VERIFICATION

This chapter provides an overview of the Registry's verification process, focusing primarily on those aspects that are a Reporter's responsibilities. As such, it is designed to provide you with a comprehensive, yet concise, overview of the steps in the verification process that require your direct participation. If you are interested in reading a more detailed description of the verification process, including the responsibilities and activities of the Verification Bodies, Accreditation Bodies, the Registry's Verification Oversight Panel, please refer to the Registry's *General Verification Protocol*.

19.1 Background: The Purpose of the Registry's Verification Process

One of the Registry's guiding principles is to establish a high level of environmental integrity in the GHG data it collects. In part, the measurement, estimation, and reporting requirements articulated in this GRP will assure the quality and integrity of the data. Equally important, however, is the independent evaluation of the accuracy of emission reports and their conformity with the GRP's requirements. Third-party verification is defined as an independent expert assessment of the accuracy and conformity of a Reporter's emission report based on the reporting requirements contained in this GRP and the verification requirements described in the Registry's *General Verification Protocol.*

The purpose of third-party verification is to provide confidence to users (state regulatory agencies, tribal authorities, investors, suppliers, customers, local governments, the Registry, the public, etc.) that your emission report represents a faithful, true, and fair account of your emissions—free of material misstatements and conforming to the Registry's accounting and reporting rules.

Third-party verification is becoming a widely accepted practice for ensuring accurate emissions data. Verification has been employed in the context of a number of GHG reporting programs. It is required by the California Climate Action Registry and is recommended by the Department of Energy's 1605(b) reporting program.

Third-party verification has also been relied upon successfully by several GHG regulatory programs, including the European Union's Emissions Trading System (EU ETS), the United Kingdom's GHG Emissions Trading System, and Alberta's Specified Gas Emitters Program.

In the U.S., the Environmental Protection Agency (EPA) requires third-party verification for Title IV components of the 1990 Clean Air Act Amendments. The California Air Resources Board also plans to use third-party verification in its mandatory GHG reporting program.

19.2 Activities To Be Completed by the Reporter in Preparation for Verification

The remaining sections of this chapter walk you through the steps that you must take to initiate and complete the Registry's verification process.

Selecting a Verification Body

Each year, once you have completed compiling your emissions inventory and have entered this information into CRIS, you must have your emissions report verified. The Registry has adopted a rigorous verification process to ensure the accuracy and credibility of the reported emissions data. To initiate this process, you must select a Verification Body from the list of Registry-approved Verification Bodies available on the Registry's website (www.theclimateregistry.org).

To select a Verification Body, the Registry recommends that you discuss they type and scope of your emissions with at least two Verification Bodies and request that they submit a verification proposal including cost and time estimate to you.

To do so, you should first review the list of approved Verification Bodies and select some (or all) as prospective bidders. Due to the possibility of access to proprietary information, you may want to send each prospective bidder a non-disclosure agreement.

In order to help your selected Verification Bodies prepare accurate verification proposals for you, you may want to provide them with the following information:

1. The expected contract duration;
2. A general description of your organization;
3. Whether or not you are a Transitional Reporter;
4. The geographic boundaries of your emissions report; and
5. The password to a read-only version of your emission report in CRIS.

Once you have received and evaluated verification proposals and have chosen the Verification Body you would like to work with, you may *begin* negotiating contract terms. However, the Registry requires all Verification Bodies to submit a Case Specific Conflict of Interest (COI) Assessment Form to the Registry, and await the Registry's confirmation of this Assessment prior to finalizing a verification contrace.

The COI Assessment Form evaluates the potential conflicts between your organization and the Verification Body. Verification contracts may **not** be finalized until the Registry authorizes a Verification Body to proceed.

The Registry screens all COI Assessments, and will periodically conduct a more thorough review of COI. If the Registry chooses your COI Assessment to review, you may not proceed with your verification contract until the Registry authorizes the Verification Body to do so.

If a Verification Body or the Registry finds that the risk of COI between you and the Verification Body is high, they will inform you. At this point, you will either need to select a different Verification Body to work with (where the risk for COI is lower), or direct the Verification Body to submit a Mitigation Plan to the Registry demonstrating how they have reduced the COI risk to an acceptable level. The process and criteria used by Verification Bodies to assess COI is described in Part 3 of the *General Verification Protocol.*

Finalizing the Verification Contract

Assuming that there is no finding of a high risk COI, you may finalize your contract with a Verification Body once they receive confirmation from the Registry. This contract is exclusively between you and the Verification Body. The particulars of any given contract are at the discretion of the two parties. However, contracts for verification services typically include the following components:

- **Scope of the Verification Process.** This component of the contract should outline the exact geographic and organizational boundaries of your emissions inventory. In addition, you should clarify the type of emissions you have reported (simple, specific industrial, etc.) and confirm that the Verification Body is approved to verify such types of emission activity. Finally, you must define the total scope of the Verification Body's activities. The scope will likely be the emissions required to be reported by the Registry, however, it may include also include additional boundaries or activities (verification of historical emissions, verification of change in base year, etc.) as well.
- **Confirmation of Accredited Verification Body.** This is a simple statement that the Verification Body has been approved by the

Registry to verify emission reports covering the scope listed above.

- **Verification Standard.** Verification Bodies must verify your emission reports against the Registry's requirements (defined in this GRP) using the process outlined in the Registry's *General Verification Protocol*. ISO 14064-3 should also be indicated as a standard for verification. However in cases where its requirements could prohibit the Verification Body from complying with the *General Verification Protocol*, the latter will take precedence. If you plan to use your emissions report for additional purposes such as submitting data to another registry, satisfying mandatory reporting requirements, participating in emissions trading schemes, etc., you may want to add additional verification standards to your contract.

- **Non-disclosure Terms.** You should reach agreement with your Verification Body in advance on methods for identifying and protecting proprietary and confidential business data that may be revealed during verification.

- **Facility Access.** You should reach agreement in advance to the conditions of your Verification Body's facility visits.

- **Documentation and Data Requirements.** You should reach agreement in advance on how and when you will provide activity and emissions data to your Verification Body. The range of required documentation will largely be determined by the size and complexity of your operations, and whether you have used the online calculation tools available through CRIS.

- **Period of Performance.** The period of performance for verification services may be up to five years. However, you have discretion as to whether you sign a one- or multi-year contract.

- **Performance Schedule.** You may wish to reach agreement on a schedule to complete the verification process and for the Verification Body to deliver a Verification Report and Verification Statement to you by the deadline of **December 15** of the year following the reporting year.

- **Payment Terms.** Typical payment terms include total value, schedule of payments, and method of payment (e.g., electronic funds transfer).

- **Re-verification Terms.** If the Verification Body identifies material misstatements in your emission report, you must revise your report. Upon completion of your revisions, you may ask your Verification Body to re-verify the portions of your emission report that you corrected. Contracts should also specify the length of time you will have to correct misstatements. *It is important to note that Verification Bodies may **not** provide guidance, technical assistance, or implementation work on the remediation of misstatements, as this constitutes consulting services, which the Registry prohibits.*

- **Liability.** All Verification Bodies are subject to minimum liability associated with completing the verification per the terms of the verification contract. You may require, and the Verification Body may agree to, additional liability under your contract.

- **Contacts.** You should identify technical leads for your organization and your Verification Body, as well as responsible corporate officials of both parties.

- **Dispute Resolution.** Both parties must state their consent to submit irreconcilable differences for review to the appropriate Accreditation Body.

- **Acknowledgement of Registry Personnel and Registry-Authorized Representative Site Visits.** Both you and your Verification Body must sign an acknowledgement that Registry/Accreditation Body personnel and/or Registry-authorized representatives may occasionally accompany the

verification team on visits to your facilities for purposes of monitoring the verification process.

Kickoff Meeting with the Verification Body

Once your verification contract is in place, your verification team will meet with you to discuss the planned verification activities. At a minimum, the agenda for this meeting should include:

1. Introduction of the verification team;
2. Review of verification activities and scope;
3. Transfer of background information; and
4. Review and confirmation of the verification process schedule.

Although the specific needs of the verification team will vary from Reporter to Reporter, you will typically be asked to provide access to documents and data related to your emission report (supporting data, information about control systems, management plans, etc.) as well as to individual employees involved in the preparation of your report. In addition, most Reporters will be asked to provide verification team members with physical access to a sample of facilities selected by the Verification Body. Occasionally Registry personnel and/or Registry-authorized representatives may accompany verification team members on site visits, in order to monitor the verification team's efforts.

Following the initial kickoff meeting, your Verification Body will begin the technical work involved in verifying your emissions, and will contact you on as needed basis to obtain documents and other materials, contacts, site access permissions, etc.

19.3 Batch Verification Option

In an effort to minimize the transaction costs of verification for small office-based organizations with relatively simple emissions, the Registry offers a batch verification option to eligible Reporters. The Registry will select at least one Batch Verification Body to conduct batch verification each year. Reporters that meet the following eligibility criteria will be able to seek batch verification.

Eligible Reporters include those with:

- **Less than 1000 metric tons total CO_2e per year**

And only emissions from the following sources:

- Scope 2 Indirect Emissions
- Scope 1 Direct Emissions from stationary combustion for heating or cooling; and
- Scope 1 Direct Emissions from mobile sources
- No significant fugitive emissions

Any Reporter with significant process or fugitive emissions is not eligible for batch verification. *Note: If you have any questions about your eligibility for batch verification, the Registry encourages you to contact the Batch Verification Body directly. The Batch Verification Body will be listed on the Registry's website:* **www.TheClimateRegistry.org.**

If you are eligible for Batch Verification, and choose to elect this option for verification, the Registry will select the Verification Body and negotiate a flate fee for service. The Registry will also provide you with a standard verification contract template. You will sign your own contract with the Batch Verification Body. If you require non-standard contract language, you will not be able to participate in batch verification.

Once the standard contract is signed, the batch verification process is essentially the same as

the standard (non-batch) verification process. However, facility visits, which are conducted as part of the standard verification process, are not required or expected for batch verifications.

Reporters interested in batch verification should notify the Batch Verification Body prior to the deadline for submitting emission reports (6/30). The Batch Verification Body selected by the Registry is responsible for determining the eligibility of Reporters.

19.4 Verification Concepts

Materiality

Verification Bodies use the concept of materiality to determine if omitted or misstated GHG emissions information will lead to significant misrepresentation of your emissions, thereby influencing conclusions or decisions made on the basis of those emissions by intended users. A material misstatement is the aggregate of errors, omissions, non-compliance with program requirements, and/or misrepresentations that could affect the decisions of intended users.

The Registry sets this threshold at 5 percent (on an absolute value basis) of a Reporter's direct (Scope 1)[6] and indirect (Scope 2) emissions. Thus, the Registry requires Verification Bodies to assess the accuracy of your direct and indirect emissions separately. Your direct and indirect emissions must both be deemed as accurate (within 5 percent) for a Verification Body to issue a successful Verification Statement for your entity.

> **Material Misstatement:** A discrepancy is considered to be material if the collective magnitude of compliance and reporting errors in a Reporter's emission report alters a Reporter's direct or indirect emissions by plus or minus 5 percent.

As illustrated in Figure 19.1, the Registry requires Verification Bodies to assess the positive and negative errors outside of an inherent uncertainty band surrounding the true value of a Reporter's emissions. Due to the inherent uncertainty associated with CEMs and other metering equipment, emission factors, and some of the Registry's approved emission calculation methodologies, a Reporter's emissions will more than likely deviate to some extent from the "true" emissions. The Registry recognizes and accepts the inherent uncertainty surrounding reported emissions.[7]

The Registry defines inherent uncertainty as the uncertainty associated with: 1) the inexact nature of calculating GHG emissions (rounding errors, significant digits, etc.) and 2) the inexact nature of the calculations associated with the Registry's permitted use of simplified estimation methods (for up to 5 percent of a Reporter's entity wide emissions).

Mitigating Misstatements

If during the course of conducting the verification activities, a Verification Body discovers a discrepancy (either material or not), it must inform you of the error in a timely fashion, so that you may work to correct the error or discrepancy. The Registry requires Reporters to correct as many misstatements as is possible; however, it realizes that some misstatements may not be able to be corrected in a timely manner or at all (missing data, etc.). As a result, the Registry allows non-material misstatements to remain in your emission reports.

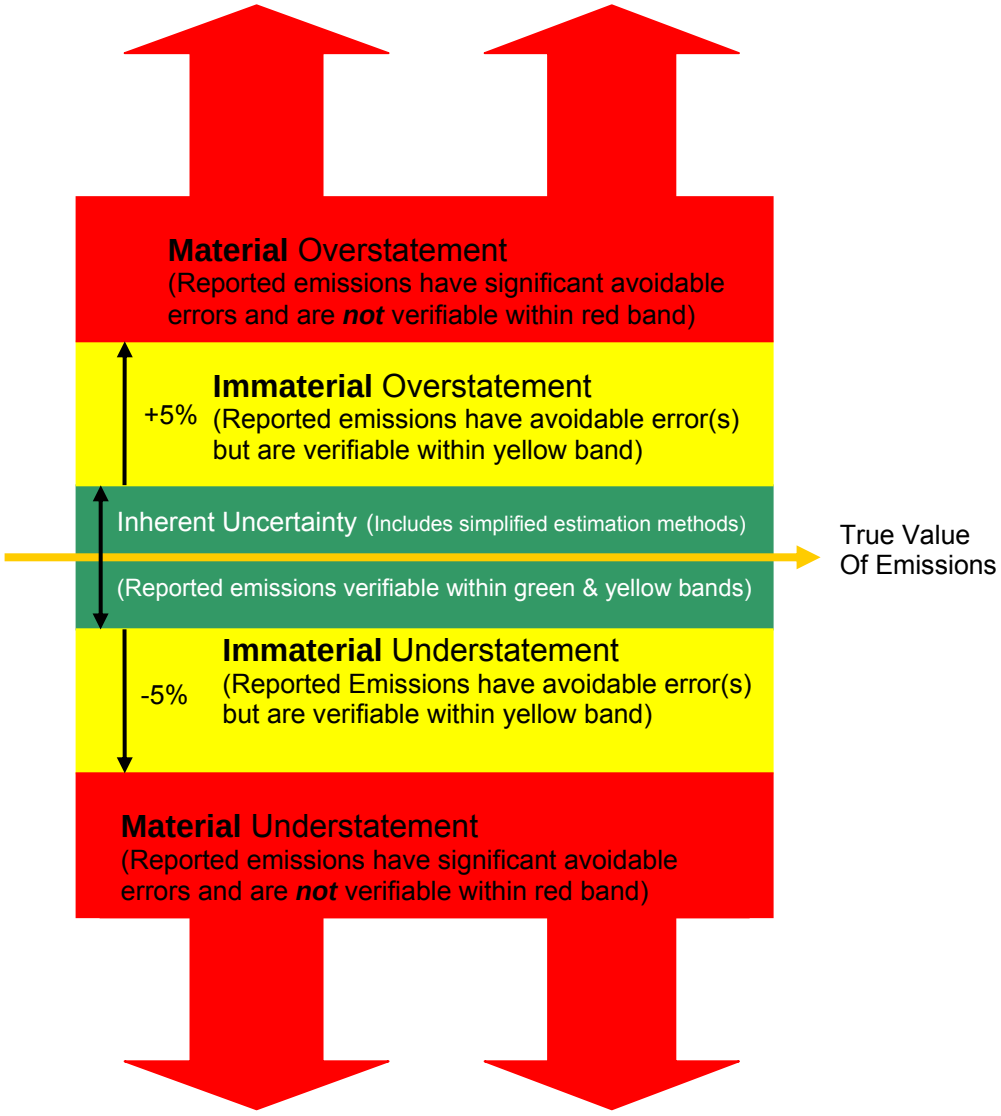
Verification Bodies must communicate with you to determine how much time you will require to correct any discovered misstatements, so that they can plan another assessment of the corrected misstatements accordingly.

While the Registry requires Verification Bodies to inform you of discrepancies and encourages the correction of errors before completing a final Verification Statement, the Registry strictly prohibits Verification Bodies from providing any consulting activities to you to help you correct the discovered error or discrepancy. In summary, Verification Bodies must clearly

[6] Including any reported biogenic emissions.

[7] The Registry accepts as inherent uncertainty both the uncertainty associated with emission calculations (emi

Figure 19.1 Conceptual Application of the Materiality Threshold



explain the error to you, but cannot help you correct the error. Verification Bodies should agree to a typical and reasonable response that will allow for ample time for you to correct discrepancies before completing the Verification Statement.

Risk-Based Approach to Verification

Given the impossibility of assessing and confirming the accuracy of every piece of GHG information that goes into an emission report, the Registry has adopted ISO 14064-3's risk-based approach to verification. This approach directs Verification Bodies to focus their attention on those data systems, processes, emissions sources, and calculations that pose the greatest risk of generating a material discrepancy in an effort to locate systemic reporting errors.

The main objective of the verification effort is to confirm that your stated emissions comply with the Registry's materiality threshold of 5 percent (on an absolute value basis). Thus, a Verification Body's risk assessment of your emissions will focus on those reporting errors that might materially affect your stated emissions.

Verification Bodies must perform risk assessments at the entity-level. This means that Verification Bodies must survey your emission sources, facilities, GHG gases, processes, policies, and operations and identify those that pose the greatest threat to causing material misstatements in your emission report. From this entity-level risk assessment, Verification Bodies will identify certain facilities, sources, policies, etc. to sample for errors. Thus, a Verification Body will visit some individual facilities and they will be assessing the overall entity-level risk of your emissions.

19.5 Verification Cycle

The Registry requires annual verification of all GHG data. This means that you must contract for verification services every year you report your emissions to the Registry. However, if your management systems and/or emissions sources do not change from year to year, then the Registry allows Verification Bodies to use their professional judgment to determine the appropriate level of a verification assessment in order to issue a Verification Statement with reasonable assurance for your stated emissions.

At a minimum, each year a Verification Body must conduct an entity-wide risk assessment and visit a number of facilities to check for reporting errors and misstatements.

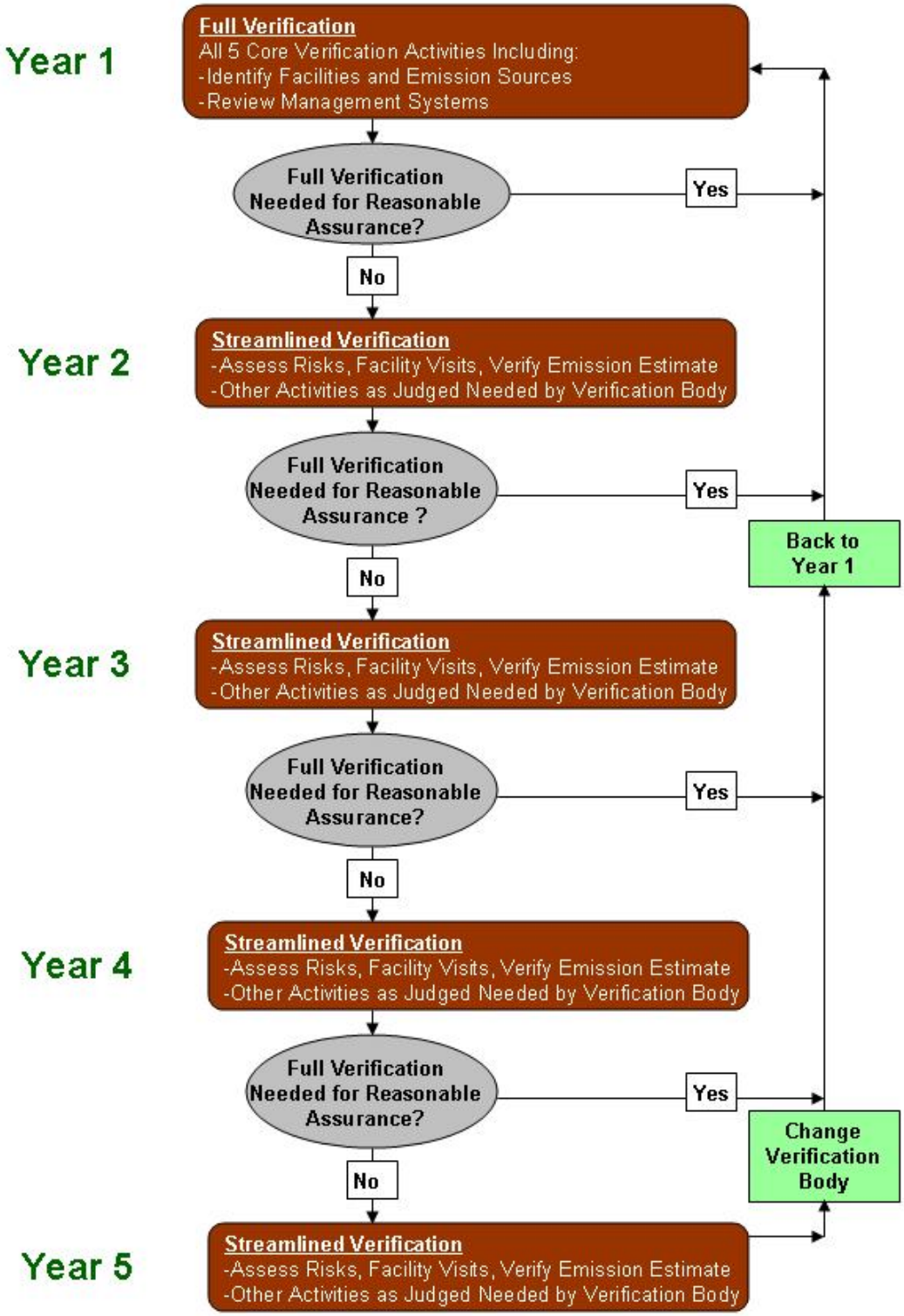
The Registry allows Verification Bodies to streamline verification activities for Reporters in the years following a successful comprehensive verification process in order to minimize verification costs whenever this is possible without compromising the integrity and credibility of the reported GHG data. To this end, the Registry allows for a five-year verification cycle, which permits a streamlined verification process in the second through fifth years of the cycle, assuming a Reporter does not experience any significant changes to their organizational structure or GHG emissions (see Figure 19.2 below).

In Year 1 of the five-year cycle, a Verification Body must comprehensively assess your emission report and your compliance with Registry requirements; confirm your emissions sources and GHGs; review your management policies and systems; and sample data for systematic calculation and reporting errors in order to gain a detailed understanding of your operations and resulting GHG emissions.

If your organizational structure and GHG emissions have not changed significantly, and you hire the same Verification Body to verify your emissions the next year, then your Verification Body may choose to streamline their verification activities, as long as the Verification Body can still provide a reasonable assurance that you have accurately reported your emissions within 5 percent.

While the Registry largely defers to a Verification Body's professional judgment to

Figure 19.2 Five-Year Verification Cycle



assess if your organizational structure or emissions have changed significantly after the first year of the verification cycle, the Registry deems the following changes as being significant; and therefore requires your Verification Body to conduct more comprehensive (or more substantial) verification activities than the minimum risk assessment. Significant changes that will require more than streamlined verification activities include:

- A new Verification Body is selected to assess a Reporter's emissions
- Base Year emissions are changed or adjusted
- A Reporter becomes a "complete" reporter (no longer a Transitional Reporter)
- A Reporter's emissions change by more than 5 percent from the previous year's emissions
- Other issues as deemed appropriate by the Verification Body

While some of the above changes (e.g., the selection of a new Verification Body) might necessitate a complete verification (the first year of the five-year verification cycle), other changes may still be addressed as part of a streamlined process, depending on the professional judgment of the Verification Body.

The specific activities that constitute streamlined verification will vary depending on the circumstances, but in all cases the Verification Body must perform the minimum set of activities that will allow it to conduct a risk-based assessment of materiality and to attain reasonable assurance in the findings presented in its Verification Statement. The minimum required activities include the risk-based assessment, the facility visits, and the verification of emission estimates against the verification criteria.

Beyond these three required activities, the Verification Body should use its professional judgment to determine the set of verification activities that will be required to meet the reasonable assurance goal.

In short, the Registry does not prescribe the specific activities that should constitute a streamlined verification (beyond the three activities noted above), but rather encourages Verification Bodies to use professional judgment in tailoring a verification process appropriate to the specific circumstances of each Reporter.

This latitude to tailor the verification process to the circumstances applies *only* to streamlined verifications; not to the full verification that the Verification Body *must* conduct at least once every five years.

NOTE: The Registry's articulates this process to serve as guidance for ways to streamline the verification process. Verification Bodies are not required to follow this five-year cycle, but are allowed to do so, as long as they can meet the intent of the verification process, appropriately manage their own risks, and thus are able to provide reasonable assurance that a Reporter's emissions contain no material errors, omissions or misrepresentations.

Verifying Multiple Years of Data

If you need to update your base year (a historical year), or correcting a previously reported and verified year of data, a Verification Body may verify this information together with your current emission report. This will count as one year in the five year verification cycle.

Alternatively, if you request that your Verification Body verify multiple years of historical data along with your current emission report, each year of historical data verified by your Verification Body will count toward the five year verification cycle. For example, if a Verification Body verifies three years of your historical data along with your current year's emission report, this will count as four years of a verification cycle. Thus, the Verification Body could only verify your emissions for one additional year.

19.6 Conducting Verification Activities

The heart of the verification process lies in conducting the verification activities. While this process is customized for each Reporter, Verification Bodies will take the following actions to complete the verification process. They will:

- Develop a Verification Plan
- Implement the Verification Plan
- Conduct the Core Verification Activities

The five core verification activities involved in the verification effort are:

1. Assessing conformance with the Registry's requirements
2. Assessing completeness of emission report
3. Performing risk assessment based on review of information systems and controls
4. Selecting a sample/developing a sampling plan
5. Evaluating GHG information systems and controls and emission estimates against verification criteria

Following the completion of the verification activities, you Verification Body will complete the required verification documentation and discuss their findings with you.

19.7 Activities To Be Completed After the Verification Body Reports Its Findings

Upon completion of the verification activities, your Verification Body will provide you with a Verification Report and Verification Statement that document its findings. At a minimum, the Verification Report should include the following elements:

- The scope of the verification process undertaken and description of the verification plan employed for your organization;
- The standard used to verify emissions (this is the Registry's GRP, but may also include other protocols or methodologies for those sources for which the Registry has yet to provide detailed guidance);
- A description of the verification activities, based on the size and complexity of your operations;
- A list of facilities and emissions sources identified, including sources estimated using simplified methods not prescribed in the GRP;
- A description of the sampling plan as well as techniques and risk assessment methodologies employed for each source;
- An evaluation of whether your annual GHG report is in compliance with the GRP;
- A comparison of your overall emission estimates with the Verification Body's overall emission estimates;
- A list of misstatements, if any; and
- A Verification Statement that contains its overall findings, which you must forward to the Registry.

The Verification Report is typically shared only between you and the Verification Body. In some cases Registry personnel or Registry-authorized representatives may request to review the Verification Report. In these cases, the Verification Report will be treated as a confidential document. No part of it will be made available to the public or to any person or organization outside of the Registry and its authorized representatives.

The Verification Statement is an official documentation of the outcome of the

verification activities. The Registry makes this document available to the public upon completion of the verification process. The standard format used for the Verification Statement is shown in Figure 19.3.

Exit Meeting with your Verification Body

Your Verification Body must prepare a brief summary presentation of its verification findings and provide this presentation during an Exit Meeting with you. This meeting may be conducted in person, or via phone.

At a minimum, the goals of this meeting should be:

- Your acceptance of the Verification Report and Verification Statement
- Your authorization for the Verification Body to communicate its findings to the Registry via CRIS
- If the same Verification Body is under contract for verification activities in future years, you may wish to establish a schedule for the next year's verification activities
- In addition, you might exchange lessons learned about the verification process and share your thoughts with the Registry for improving the verification process in the future.

19.8 Unverified Emission Reports

If your Verification Body determines your emission report is not verifiable due to material misstatements, you must correct your report and have it re-verified.

The Registry will retain your unverified emission report in the Registry database for up to one year pending correction and re-verification. You must pass the re-verification process within a year to remain an active Reporter to the Registry. Upon completion of a successful re-verification, the Registry will formally accept your revised report into CRIS.

Dispute Resolution Process

There may be instances where you and your Verification Body cannot agree on the findings expressed in the Verification Report or Verification Statement. In such instances, you should attempt to reach a resolution with the Verification Body, relying first on the Verification Body's internal dispute resolution process. In the event that you cannot reach a resolution, either party can initiate a dispute resolution process by submitting a request to the Accreditation Body via the Registry by sending an email to:

verification@theclimateregistry.org.

The Accreditation Body will review the dispute and reach a unanimous, binding decision concerning verifiability. In doing so it may interview you and the Verification Body and/or request documentation related to the dispute. The Accreditation Body will notify you and the Verification Body and of its decision.

Errors Discovered After the Completion of Verification

In some cases, errors in your emission report may be discovered after the completion of the verification process, either by you, your Verification Body, the Registry, or another party (e.g., a user of the data).

If such errors result in a cumulative change in total reported emissions of less than 5 percent, the Registry encourages you to correct the error. However, if the reporting errors cause a material misstatement of more than 5 percent, the Registry requires you to correct the error and re-verify your emission report.

If the Registry decides that a material misstatement exists in one of your previously verified emission reports, the Registry will change the verification status of your emission report to "unverified," and will notify you of the change in status. The Registry provides you with one year to correct the report and have the

report re-verified (either by the original Verification Body or a new Verification Body).

You must successfully complete the re-verification process within a year to remain an active Reporter in the Registry. Upon completion of a successful re-verification, the Registry will formally accept the revised emission report into CRIS.

Verification Deadline Reminder

The deadline for verifying your emissions is **December 15th** of your submitting year (the year following your reporting year).

Figure 19.3 Verification Statement Template

[Insert Verifier Logo]

The Climate Registry Verification Statement

Name of Verification Body: _____

This Verification Statement documents that ____(insert Verification Body) has conducted verification activities in compliance with ISO 14064-3 and the Registry's General Verification Protocol. This statement also attests to the fact that ____ (Verification Body) provides ____ (insert level of assurance: reasonable or limited) that ____ (insert Reporter) reported greenhouse gas emissions from January 1 ____ (insert reporting year) through December 31 ____ (insert reporting year) are verifiable and meet the requirements of The Climate Registry.

Date Verification was completed (from CRIS): _____

Reporting Classification: ☐ Transitional ☐ Complete ☐ Historical

Type of Verification: ☐ Batch ☐ Streamlined ☐ Full Verification

GHG Reporting Standards Used to Verify Emissions:

☐ The Climate Registry's *General Reporting Protocol*

☐ Others (specify): _____

Reporter's Organizational Boundaries:

☐ Control Only: (☐ Financial **or** ☐ Operational)

☐ Equity Share and Control (☐ Financial **or** ☐ Operational)

Geographic Scope of Verification: ☐ Transitional ☐ North American ☐ Worldwide

Base Year (if applicable): _____

Total Entity-Wide Emissions Verified:

Total Scope 1 Emissions: _____ CO_2-e

_____ CO_2 _____CH_4 _____ N_2O _____HFCs _____ PFCs _____SF_6

Percent of Scope 1 Emissions covered by site visits: _____ %

Total Scope 2 Emissions: _____ CO_2E

_____ CO_2 _____CH_4 _____ N_2O _____HFCs _____ PFCs _____SF_6

Percent of Scope 2 Emissions covered by site visits: _____ %

Verification Statement:

☐ Verified without Qualification

☐ Verified with Qualification

Explain Qualifications: _____

☐ Unable to Verify (include reason, e.g., "due to data errors" or "due to non-compliance with the Registry's reporting requirments):

_____

Figure 19.1 Verification Statement Template (continued)

[Insert Verifier Logo]

The Climate Registry Verification Statement (Continued)

Attestation:

_____ _____
[*Insert Name*], Lead Verifier Date

_____ _____
[*Insert Name*], Internal Peer Reviewer Date

Authorization:

I _____ [*Name of Reporter Representative*] accept the findings in this Verification Statement and authorize the submission of this Verification Statement to The Climate Registry on behalf of _____ [*Name of Reporter*].

_____ _____
[Reporter Representative Signature] Date

The Remainder of this Form is for Use by Registry Staff Only:

☐ The Registry has reviewed this Verification Statement for completeness and has accepted it.

Dispute Resolution:

☐ If this box is checked, this Verification Statement has been disputed and submitted to an Accreditation Body to conduct a dispute resolution process. Upon review, the Accreditation Body:

☐ Upholds the original Verification Statement

☐ Overturns the original Verification Statement and issues the following revised Verification Statement:

☐ Verified without Qualification

☐ Verified with Qualification
Explain qualifications:_____

☐ Unable to Verify (include reason, e.g., "due to data errors" or "due to non-compliance with the Registry's reporting requirements).

_____

Accreditation Body Authorization:

_____ _____
[Committee Chairperson's Signature] Date

_____ _____
[Verification Oversight Panel Member's Signature] Date

_____ _____
[Panel Member's Signature] Date

CHAPTER 20: PUBLIC EMISSION REPORTS

20.1 Required Public Disclosure

Your verified annual emission reports are accessible to the public through the Registry's website. These reports describe your annual emissions and serve as useful tools for various stakeholders, such as shareholders, regulators, non-governmental organizations, and the general public, to better understand your entity's GHG emissions (and reductions).

The Registry requires Reporters to disclose their entity-and facility-level GHG emission reports to the public. Specifically, the Registry requires that the following information be disclosed annually to the public for each Reporter:

- **Entity-level emissions, by gas and emissions category**
- **Facility-level emissions, by gas and emissions category**

  Note: If disclosing facility-level data publicly will jeopardize your confidential business information, you may apply for an exemption from this reporting requirement. Please refer to Section 20.2 for more information.

Stakeholders can query CRIS via the Registry's website to access public emission reports for each Reporter with verified emissions data. A Reporter's public annual entity emission report contains the following information:

- Direct emissions of each GHG by source type (stationary combustion, mobile combustion, process, and fugitive emissions) with CO_2 emissions from biomass combustion reported separately
- Indirect emissions of each GHG (Scope 2)
- Consolidation approach employed
- Base year (if applicable) and description of any structural changes in the reporting entity (mergers, acquisitions, divestitures, etc.)
- A summary statistic of data quality tiers used
- Information on parent companies for reporting entities that are subsidiaries
- Information about a Reporter's third-party Verifier
- Indication of historical, transitional or imported data when applicable
- Optional data, if provided (performance metrics, GHG reduction goals, etc.)

A Reporter's facility-level emission report will include the same information listed above, for each facility.

In addition, the public may query CRIS to produce emission reports that describe emissions data:

- By geographic area, including worldwide (*optional*), North America, national, state/province/territory and tribal areas
- Over multiple years

20.2 Confidential Business Information

As indicated above, if the release of your facility-level emissions data will jeopardize your entity's confidential business information (CBI), then you may apply to the Registry for an exemption from this reporting requirement.

To do so, please download the Public Disclosure Exemption Request Form from the Registry's website: www.theclimateregistry.org, and either mail or email the completed form, which must include a detailed explanation of your need for confidentiality, to the Registry at the address listed below:

The Climate Registry
P.O. Box 712545
Los Angeles, CA 90071

Or

Exemption@theclimateregistry.org

The Registry will review exemption requests within 14 business days of their submittal. You will be notified by email regarding the status of your exemption request and instructions for how to proceed with your emission reporting in CRIS.

While Reporters who are granted exemptions will not be required to disclose their facility-level emissions to the public, they will be required to disclose the following emissions information to the public:

- **Entity-level emissions, by gas and emissions category**
- **State/province-level emissions, by CO2e**

If you have questions regarding the public release of data, please contact the Registry at 1-866-523-0764 or help@theclimateregistry.org

GLOSSARY OF TERMS

Term	Definition
Activity data	Data on the magnitude of a human activity resulting in emissions or reductions taking place during a given period of time. Data on energy use, miles traveled, input material flow, and product output are all examples of activity data that might be used to compute GHG emissions.
Base Year	A specific year against which an entity's emissions are tracked over time. For the purposes of the Registry, the Reporter's base year is defined as the ***earliest year*** for which a complete emissions inventory is submitted.
Base Year Emissions	GHG emissions in the base year.
Biofuel	Fuel made from biomass, including wood and wood waste, sulphite lyes (black liquor), vegetal waste (straw, hay, grass, leaves, roots, bark, crops), animal materials/waste (fish and food meal, manure, sewage sludge, fat, oil and tallow), turpentine, charcoal, landfill gas, sludge gas, and other biogas, bioethanol, biomethanol, bioETBE, bioMTBE, biodiesel, biodimethylether, fischer tropsch, bio oil, and all other liquid biofuels which are added to, blended with, or used straight as transportation diesel fuel. Biomass also includes the plant or animal fraction of flotsam from waterbody management, mixed residues from food and beverage production, composites containing wood, textile wastes, paper, cardboard and pasteboard, municipal and industrial waste, and processed municipal and industrial wastes.
Biogenic Carbon	Carbon derived from biogenic (plant or animal) sources excluding fossil carbon.
Biomass	Non-fossilized and biodegradable organic material originating from plants, animals, and micro-organisms, including products, byproducts, residues and waste from agriculture, forestry and related industries as well as the non-fossilized and biodegradeable organic fractions of industrial and municipal wastes, including gases and liquids recovered from the decomposition of non-fossilized and biodegradeable organic material.
Boundaries	GHG accounting and reporting boundaries can have several dimensions, i.e.,organizational, operational and geographic. These boundaries determine which emissions are accounted for and reported by the entity.

Capital Lease	A lease which transfers substantially all the risks and rewards of ownership to the lessee and is accounted for as an asset on the balance sheet of the lessee. Also known as a finance lease or financial lease. Leases other than capital or finance leases are operating leases. Consult an accountant for further detail as definitions of lease types differ between various accepted financial standards.
Calculation-Based	Any of various emission quantification methodologies that involve the calculation of emissions based on emission factors and activity data such as input material flow, fuel consumption, or product output.
Cogeneration	An energy conversion process in which more than one useful product (e.g., electricity and heat or steam) is generated from the same energy input stream. Also referred to as combined heat and power (CHP).
Combined Heat and Power	(CHP) Same as cogeneration.
Complete Emissions Inventory	For purposes of the Registry, a complete accounting of an entity's emissions meets all of the requirements specified in this General Reporting Protocol.
Control Approach	An emissions accounting approach for defining organizational boundaries in which an entity reports 100 percent of the GHG emissions from operations under its financial or operational control.
CO_2 Equivalent	The universal unit for comparing emissions of different GHGs expressed in terms of the GWP of one unit of carbon dioxide.
Data Quantification System	The system used by the Registry to rank emissions quantification methodologies according to their levels of accuracy. In this system "Tier A" designates the preferred, or most accurate, approach, "Tier B" represents an alternative second-best approach, and "Tier C" represents the least accurate but still acceptable approach.
Direct Emissions	Emissions from sources within the reporting entity's organizational boundaries that are owned or controlled by the reporting entity, including stationary combustion emissions, mobile combustion emissions, process emissions, and fugitive emissions.
Emission Factor	GHG emissions expressed on a per unit activity basis (for example, metric tons of CO_2 emitted per million Btus of coal combusted, or metric tons of CO_2 emitted per kWh of electricity consumed).
Entity	Any business, corporation, institution, organization, government agency, etc., recognized under U.S., Canadian, or Mexican law. A reporting entity is comprised of all the facilities and emission sources delimited by the organizational boundary developed by the entity, taken in their entirety.

Equity Share Approach	An emissions accounting approach for defining organizational boundaries in which an entity accounts for GHG emissions from each operation according to its share of economic interest in the operation, which is the extent of rights an entity has to the risks and rewards flowing from an operation.
Facility	Any installation or establishment located on a single site or on contiguous or adjacent sites that are owned or operated by an entity. A facility includes not only all of the stationary installations and equipment located at the site, but all mobile equipment that is under the control of the reporting entity and operates exclusively on a particular facility's premises. Examples of such site-specific mobile equipment include forklifts, front-end loaders, off-road trucks, mobile cranes, etc. Similarly, pipelines, pipeline systems, and electricity transmission and distribution systems are considered discrete facilities for reporting purposes.
Finance Lease	Same as capital lease.
Financial Control	The ability to direct the financial and operating policies of an operation with an interest in gaining economic benefits from its activities. Financial control is one of two ways to define the control approach.
Fugitive Emissions	Uncontrolled emissions including emissions from the production, processing, transmission, storage, and use of fuels and other substances, not emitted through an exhaust pipe, stack, chimney, vent or other functionally equivalent opening. Examples include releases of sulfur hexafluoride (SF6) from electrical equipment, hydrofluorocarbon (HFC) releases during the use of refrigeration and air conditioning equipment, process equipment leaks, etc.
Global Warming Potential	(GWP) The ratio of radiative forcing (degree of warming to the atmosphere) that would result from the emission of one unit of a given GHG compared to one unit of carbon dioxide (CO_2).
Greenhouse Gases	(GHG) For the purposes of the Registry, GHGs are the six internationally recognized gases identified in the Kyoto Protocol: carbon dioxide (CO_2), nitrous oxide (N_2O), methane (CH_4), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6).
Hydrofluorocarbons	(HFC) A group of manmade chemicals with various commercial uses (e.g., refrigerants) composed of one or two carbon atoms and varying numbers of hydrogen and fluorine atoms. Most HFCs are highly potent GHGs with 100-year GWPs in the thousands.

Indirect Emissions	Emissions that are a consequence of activities that take place within the organizational boundaries of the reporting entity, but that occur at sources owned or controlled by another entity. For example, emissions of electricity used by a manufacturing entity that occur at a power plant represent the manufacturer's indirect emissions.
Insourcing	The administration of ancillary business activities, formally performed outside of the company, using resources within a company.
Intergovernmental Panel on Climate Change	(IPCC) International body of climate change scientists. The role of the IPCC is to assess the scientific, technical and socio-economic information relevant to the understanding of the risk of human-induced climate change (www.ipcc.ch).
Inventory	A comprehensive, quantified list of an organization's GHG emissions and sources.
Inventory Boundary	An imaginary line that encompasses the direct and indirect emissions included in the inventory. It results from the chosen organizational and operational boundaries.
Measurement-Based	Any of the various emission quantification methodologies that involve the determination of emissions by means of direct measurement of the flue gas flow, as well as the concentration of the relevant GHG(s) in the flue gas.
Mobile Combustion Emissions	Emissions from the combustion of fuels in transportation sources (e.g., cars, trucks, buses, trains, airplanes, and marine vessels) and emissions from non-road equipment such as equipment used in construction, agriculture, and forestry. A piece of equipment that cannot move under its own power but that is transported from site to site (e.g., an emergency generator) is a stationary, not a mobile, combustion source.
Operating Lease	A lease which does not transfer the risks and rewards of ownership to the lessee and is not recorded as an asset in the balance sheet of the lessee. Leases other than operating leases are capital, finance, or financial leases. Consult an accountant for further detail as definitions of lease types differ between various accepted financial standards.
Operational Control	Full authority to introduce and implement operating policies at an operation. Operational control is one of two ways to define the control approach.
Operational Boundaries	The boundaries that determine the direct and indirect emissions associated with operations within the Reporter's organizational boundaries.

Organic Growth (or Decline)	Increases or decreases in GHG emissions as a result of changes in production output, product mix, plant closures, and the opening of new plants.
Organizational Boundaries	The boundaries that determine the operations owned or controlled by the reporting entity, depending on the consolidation approach taken (either the equity share or control approach).
Outsourcing	The contracting out of activities to other businesses.
Perfluorocarbons	(PFC) A group of man-made chemicals composed of one or two carbon atoms and four to six fluorine atoms, containing no chlorine. PFCs have no commercial uses and are emitted as a byproduct of aluminum smelting and semiconductor manufacturing. PFCs have very high GWPs and are very long-lived in the atmosphere.
Process Emissions	Emissions resulting from physical or chemical processes rather than from fuel combustion. Examples include emissions from manufacturing cement, aluminum, adipic acid, ammonia, etc.
Reporter	An entity that submits an emissions inventory based on the requirements in the General Reporting Protocol to the Registry.
Reporting Year	The year in which the emissions you are reporting to the Registry occurred. For example, in 2010, you would report for the 2009 reporting year (emissions that occurred in 2009).
Scope 1 Emissions	All direct GHG emissions, with the exception of direct CO_2 emissions from biogenic sources.
Scope 2 Emissions	Indirect GHG emissions associated with the consumption of purchased or acquired electricity, heating, cooling, or steam.
Scope 3 Emissions	All indirect emissions not covered in Scope 2. Examples include upstream and downstream emissions, emissions resulting from the extraction and production of purchased materials and fuels, transport-related activities in vehicles not owned or controlled by the reporting entity, use of sold products and services, outsourced activities, recycling of used products, waste disposal, etc.
Submitting Year	The year in which you are submitting your emission report. For example, when submitting a report in 2015 for emissions that occurred in 2014, your submitting year would be 2015. The submitting year is always the year following the reporting year.

Simplified Estimation Methods	For purposes of the Registry, rough, upper-bound methods for estimating emissions that are not found in Part III or Appendix E of the GRP. Simplified estimation methods may be used to calculate emissions from one or more sources, for one or more gases, that, when aggregated, equal no more than five percent of an entity's total Scope 1 and Scope 2 emissions, as determined on a CO_2 equivalent basis.
Stationary Combustion Emissions	Emissions from the combustion of fuels to produce electricity, steam, heat, or power using equipment (boilers, furnaces, etc.) in a fixed location.
Structural Change	A change in the organizational or operational boundaries of a company that result from a transfer of ownership or control of emissions from one company to another. Structural changes usually result from a transfer of ownership of emissions, such as mergers, acquisitions, divestitures, but can also include insourcing and outsourcing.
Transitional Reporter	A Reporter that opts to provide a partially complete emission report, covering fewer than the six internationally recognized GHGs (but CO_2 from stationary combustion at a minimum) and/or one or more states or provinces. The transitional reporting option is available only during a Reporter's first two reporting years.
Verification	An independent assessment of the reliability (considering completeness and accuracy) of a GHG inventory.

Appendix A: Managing Inventory Quality

Note: The guidance in this appendix is taken directly from the WRI/WBCSD *GHG Protocol Corporate Standard* (Revised Edition), Chapter 7.

A corporate GHG inventory program includes all institutional, managerial, and technical arrangements made for the collection of data, preparation of the inventory, and implementation of steps to manage the quality of the inventory. The guidance in this appendix is intended to help companies develop and implement a quality management system for their inventory.

Given an uncertain future, high quality information will have greater value and more uses, while low quality information may have little or no value or use and may even incur penalties. For example, a company may currently be focusing on a voluntary GHG program but also want its inventory data to meet the anticipated requirements of a future when emissions may have monetary value. A quality management system is essential to ensuring that an inventory continues to meet the principles of the *GHG Protocol Corporate Standard* and anticipates the requirements of potential future GHG emissions programs.

Even if a company is not anticipating a future regulatory mechanism, internal and external stakeholders will demand high quality inventory information. Therefore, the implementation of some type of quality management system is important. However, the *GHG Protocol Corporate Standard* recognizes that companies do not have unlimited resources, and, unlike financial accounting, corporate GHG inventories involve a level of scientific and engineering complexity. Therefore, companies should develop their inventory program and quality management system as a cumulative effort in keeping with their resources, the broader evolution of policy, and their own corporate vision.

A quality management system provides a systematic process for preventing and correcting errors, and identifies areas where investments will likely lead to the greatest improvement in overall inventory quality. However, the primary objective of quality management is ensuring the credibility of a company's GHG inventory information. The first step towards achieving this objective is defining inventory quality.

Defining Inventory Quality

The *GHG Protocol Corporate Standard* outlines five accounting principles that set an implicit standard for the faithful representation of a company's GHG emission through its technical, accounting, and reporting efforts (Chapter 1). Putting these principles into practice will result in a credible and unbiased treatment and presentation of issues and data. For a company to follow these principles, quality management needs to be an integral part of its corporate inventory program. The goal of a quality management system is to ensure that these principles are put into practice.

An Inventory Program Framework

A practical framework is needed to help companies conceptualize and design an integrated corporate inventory program and quality management system and to help plan for future improvements (Figure A.1). This framework focuses on the following institutional, managerial, and technical components of an inventory:

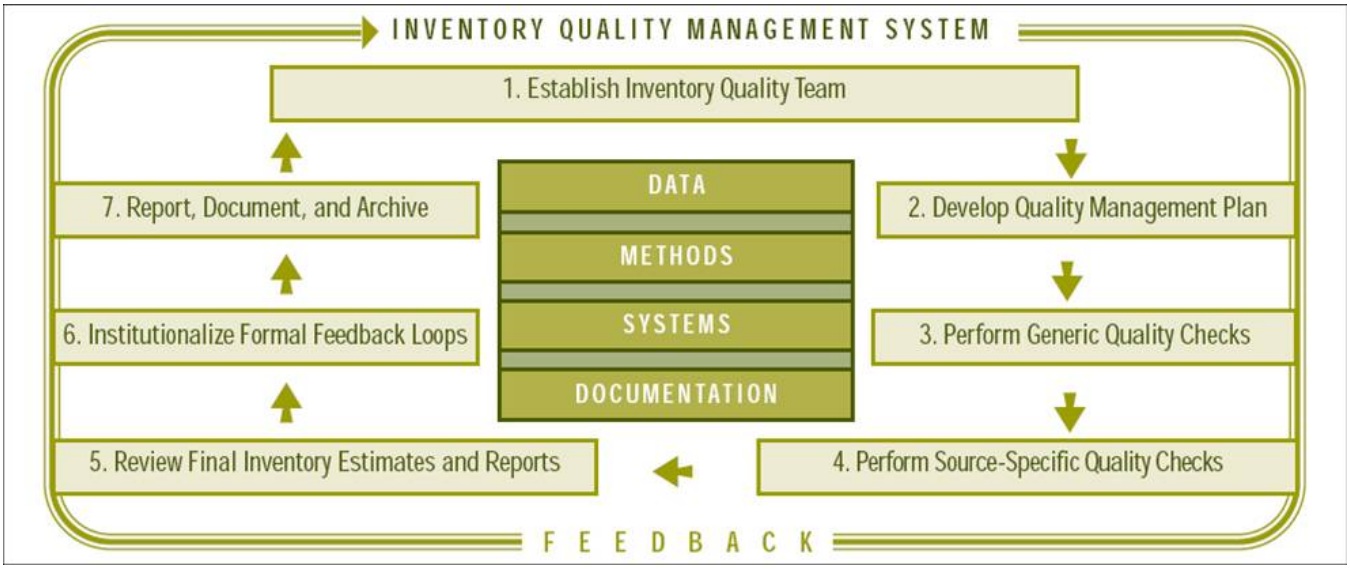
Methods: These are the technical aspects of inventory preparation. Companies should select or develop methodologies for estimating emissions that accurately represent the characteristics of their source categories. The *GHG Protocol* provides many default methods and calculation tools to help with this effort. The design of an inventory program and quality management system should provide for the selection, application, and updating of inventory methodologies as new research becomes available, changes are made to business

operations, or the importance of inventory reporting is elevated.

Data: This is the basic information on activity levels, emission factors, processes, and operations. Although methodologies need to be appropriately rigorous and detailed, data quality is more important. No methodology can compensate for poor quality input data. The design of a corporate inventory program should facilitate the collection of high quality inventory data and the maintenance and improvement of collection procedures.

Inventory processes and systems: These are the institutional, managerial, and technical procedures for preparing GHG inventories. They include the team and processes charged with the goal of producing a high quality inventory. To streamline GHG inventory quality management, these processes and systems may be integrated, where appropriate, with other corporate processes related to quality.

Figure A.1 Inventory Quality Management System



Documentation: This is the record of methods, data, processes, systems, assumptions, and estimates used to prepare an inventory. It includes everything employees need to prepare and improve a company's inventory. Since estimating GHG emissions is inherently technical (involving engineering and science), high quality, transparent documentation is particularly important to credibility. If information is not credible, or fails to be effectively communicated to either internal or external stakeholders, it will not have value.

Companies should seek to ensure the quality of these components at every level of their inventory design.

Implementing an Inventory Quality Management System

A quality management system for a company's inventory program should address all four of the inventory components described above. To implement the system, a company should take the following steps:

1. *Establish an inventory quality team. This team should be responsible for the company's GHG inventory program, implementing a quality management system, and continually improving inventory quality.* This team or manager should coordinate interactions between relevant business units, facilities and external entities such as government agency programs, research institutions, verifiers, or consulting firms.

2. *Develop a quality management plan.* This plan describes the steps a company is taking to implement its quality management system, which should be incorporated into the design of its inventory program from the beginning, although further rigor and coverage of certain procedures may be phased in over multiple years. The plan should include procedures for all organizational levels and inventory development processes—from initial data collection to final reporting of accounts. For efficiency and comprehensiveness, companies should integrate (and extend as appropriate) existing quality systems to cover GHG management and reporting, such as any ISO procedures. To ensure accuracy, the bulk of the plan should focus on practical measures for implementing the quality management system, as described in steps three and four.

3. *Perform generic quality checks*. These apply to data and processes across the entire inventory, focusing on appropriately rigorous quality checks on data handling, documentation, and emission calculation activities (e.g., ensuring that correct unit conversions are used). Guidance on quality checking procedures is provided in the section on implementation below.

4. *Perform source-category-specific quality checks*. This includes more rigorous investigations into the appropriate application of boundaries, adjustment procedures, and adherence to accounting and reporting principles for specific source categories, as well as the quality of the data input used (e.g., whether electricity bills or meter readings are the best source of consumption data) and a qualitative description of the major causes of uncertainty in the data. The information from these investigations can also be used to support a quantitative assessment of uncertainty. Guidance on these investigations is provided in the section on implementation below.

5. *Review final inventory estimates and reports.* After the inventory is completed, an internal technical review should focus on its engineering, scientific, and other technical aspects. Subsequently, an internal managerial review should focus on securing official corporate approval of and support for the inventory.

6. *Institutionalize formal feedback loops*. The results of the reviews in step five, as well as the results of every other component of a company's quality management system, should be fed back via formal feedback procedures to the person or team identified in step one. Errors should be corrected and

improvements implemented based on this feedback.

7. *Establish reporting, documentation, and archiving procedures*. The system should contain record keeping procedures that specify what information will be documented for internal purposes, how that information should be archived, and what information is to be reported for external stakeholders. Like internal and external reviews, these record keeping procedures include formal feedback mechanisms.

A company's quality management system and overall inventory program should be treated as evolving, in keeping with a company's reasons for preparing an inventory. The plan should address the company's strategy for a multi-year implementation (i.e., recognize that inventories are a long-term effort), including steps to ensure that all quality control findings from previous years are adequately addressed.

Practical Measures for Implementation

Although principles and broad program design guidelines are important, any guidance on quality management would be incomplete without a discussion of practical inventory quality measures. A company should implement these measures at multiple levels within the company, from the point of primary data collection to the final corporate inventory approval process. It is important to implement these measures at points in the inventory program where errors are mostly likely to occur, such as the initial data collection phase and during calculation and data aggregation. While corporate-level inventory quality may initially be emphasized, it is important to ensure quality measures are implemented at all levels of disaggregation (e.g., facility, process, geographical, according to a particular scope, etc) to be better prepared for possible GHG markets or regulatory rules in the future.

Companies also need to ensure the quality of their historical emission estimates and trend data. They can achieve time series consistency by employing inventory quality measures to minimize biases that can arise from changes in the characteristics of the data or methods used to calculate historical emission estimates and by following the standards and guidance of Chapter 7.

The third step of a quality management system, as described above, is to implement generic quality checking measures. These measures apply to all source categories and all levels of inventory preparation. Table A.1 provides a sample list of such measures.

The fourth step of a quality management system is source category-specific data quality investigations. The information gathered from these investigations can also be used for the quantitative and qualitative assessment of data uncertainty (see section on uncertainty). Addressed below are the types of source-specific quality measures that can be employed for emission factors, activity data, and emission estimates.

Emission Factors and Other Parameters. For a particular source category, emissions calculations will generally rely on emission factors and other parameters (e.g., utilization factors, oxidation rates, methane conversion factors). These factors and parameters may be published or default factors, based on company-specific data, site-specific data, or direct emission or other measurements. For fuel consumption, published emission factors based on fuel energy content are generally more accurate than those based on mass or volume, except when mass or volume based factors have been measured at the company- or site-specific level. Quality investigations need to assess the representativeness and applicability of emission factors and other parameters to the specific characteristics of a company. Differences between measured and default values need to be qualitatively explained and justified based upon the company's operational characteristics.

Activity data. The collection of high quality activity data will often be the most significant limitation for corporate GHG inventories. Therefore, establishing robust data collection procedures needs to be a priority in the design of

any company's inventory program. The following are useful measures for ensuring the quality of activity data:

- Develop data collection procedures that allow the same data to be efficiently collected in future years.

- Convert fuel consumption data to energy units before applying carbon content emission factors, which may be better correlated to a fuel's energy content than its mass.

- Compare current year data with historical trends. If data do not exhibit relatively consistent changes from year to year then the causes for these patterns should be investigated (e.g., changes of over 10 percent from year to year may warrant further investigation).

- Compare activity data from multiple reference sources (e.g., government survey data or data compiled by trade associations) with corporate data when possible. Such checks can ensure that consistent data is being reported to all parties. Data can also be compared among facilities within a company.

- Investigate activity data that is generated for purposes other than preparing a GHG inventory. In doing so, companies will need to check the applicability of this data to inventory purposes, including completeness, consistency with the source category definition, and consistency with the emission factors used. For example, data from different facilities may be examined for inconsistent measurement techniques, operating conditions, or technologies. Quality control measures (e.g., ISO) may have already been conducted during the data's original preparation. These measures can be integrated with the company's inventory quality management system.

- Check that base year adjustment procedures have been followed consistently and correctly (see Chapter 7).

- Check that operational and organizational boundary decisions have been applied correctly and consistently to the collection of activity data (see Chapters 4 and 5).

- Investigate whether biases or other characteristics that could affect data quality have been previously identified (e.g., by communicating with experts at a particular facility or elsewhere). For example, a bias could be the unintentional exclusion of operations at smaller facilities or data that do not correspond exactly with the company's organizational boundaries.

- Extend quality management measures to cover any additional data (sales, production, etc.) used to estimate emission intensities or other ratios.

Emission Estimates. Estimated emissions for a source category can be compared with historical data or other estimates to ensure they fall within a reasonable range. Potentially unreasonable estimates provide cause for checking emission factors or activity data and determining whether changes in methodology, market forces, or other events are sufficient reasons for the change. In situations where actual emission monitoring occurs (e.g., power plant CO_2 emissions), the data from monitors can be compared with calculated emissions using activity data and emission factors.

If any of the above emission factor, activity data, emission estimate, or other parameter checks indicate a problem, more detailed investigations into the accuracy of the data or appropriateness of the methods may be required. These more detailed investigations can also be utilized to better assess the quality of data. One potential measure of data quality is a quantitative and qualitative assessment of their uncertainty.

Inventory Quality and Inventory Uncertainty

Preparing a GHG inventory is inherently both an accounting and a scientific exercise. Most applications for company-level emissions and removal estimates require that these data be

reported in a format similar to financial accounting data. In financial accounting, it is standard practice to report individual point estimates (i.e., single value versus a range of possible values). In contrast, the standard practice for most scientific studies of GHG and other emissions is to report quantitative data with estimated error bounds (i.e., uncertainty). Just like financial figures in a profit and loss or bank account statement, point estimates in a corporate emission inventory have obvious uses. However, how would or should the addition of some quantitative measure of uncertainty to an emission inventory be used?

In an ideal situation, in which a company had perfect quantitative information on the uncertainty of its emission estimates at all levels, the primary use of this information would almost certainly be comparative. Such comparisons might be made across companies, across business units, across source categories, or through time. In this situation, inventory estimates could even be rated or discounted based on their quality before they were used, with uncertainty being the objective quantitative metric for quality. Unfortunately, such objective uncertainty estimates rarely exist.

Types of Uncertainties. Uncertainties associated with GHG inventories can be broadly categorized into scientific uncertainty and estimation uncertainty. Scientific uncertainty arises when the science of the actual emission and/or removal process is not completely understood. For example, many direct and indirect factors associated with GWP values that are used to combine emission estimates for various GHGs involve significant scientific uncertainty. Analyzing and quantifying such scientific uncertainty is extremely problematic and is likely to be beyond the capacity of most company inventory programs.

Estimation uncertainty arises any time GHG emissions are quantified. Therefore all emissions or removal estimates are associated with estimation uncertainty. Estimation uncertainty can be further classified into two types: *model* uncertainty and *parameter* uncertainty.

Model uncertainty refers to the uncertainty associated with the mathematical equations (i.e., models) used to characterize the relationships between various parameters and emission processes. For example, model uncertainty may arise either due to the use of an incorrect mathematical model or inappropriate input into the model. As with scientific uncertainty, estimating model uncertainty is likely to be beyond most company's inventory efforts; however, some companies may wish to utilize their unique scientific and engineering expertise to evaluate the uncertainty in their emission estimation models.

Parameter uncertainty refers to the uncertainty associated with quantifying the parameters used as inputs (e.g., activity data and emission factors) into estimation models. Parameter uncertainties can be evaluated through statistical analysis, measurement equipment precision determinations, and expert judgment. Quantifying parameter uncertainties and then estimating source category uncertainties based on these parameter uncertainties will be the primary focus of companies that choose to investigate the uncertainty in their emission inventories.

Limitations of Uncertainty Estimates. Given that only parameter uncertainties are within the feasible scope of most companies, uncertainty estimates for corporate GHG inventories will, of necessity, be imperfect. Complete and robust sample data will not always be available to assess the statistical uncertainty in every parameter. For most parameters (e.g., liters of gasoline purchased or metric tons of limestone consumed), only a single data point may be available. In some cases, companies can utilize instrument precision or calibration information to inform their assessment of statistical uncertainty. However, to quantify some of the systematic uncertainties associated with parameters and to supplement statistical uncertainty estimates, companies will usually have to rely on expert judgment. The problem with expert judgment, though, is that it is difficult to obtain in a comparable (i.e., unbiased) and consistent

manner across parameters, source categories, or companies.

For these reasons, almost all comprehensive estimates of uncertainty for GHG inventories will be not only imperfect but also have a *subjective* component and, despite the most thorough efforts, are themselves considered highly uncertain. In most cases, uncertainty estimates cannot be interpreted as an objective measure of quality. Nor can they be used to compare the quality of emission estimates between source categories or companies.

Exceptions to this include the following cases in which it is assumed that either statistical or instrument precision data are available to objectively estimate each parameter's statistical uncertainty (i.e., expert judgment is not needed):

- When two operationally similar facilities use identical emission estimation methodologies, the differences in scientific or model uncertainties can, for the most part, be ignored. Then quantified estimates of statistical uncertainty can be treated as being comparable between facilities. This type of comparability is what is aimed for in some trading programs that prescribe specific monitoring, estimation, and measurement requirements. However, even in this situation, the degree of comparability depends on the flexibility that participants are given for estimating emissions, the homogeneity across facilities, as well as the level of enforcement and review of the methodologies used.

- Similarly, when a single facility uses the same estimation methodology each year, the systematic parameter uncertainties—in addition to scientific and model uncertainties—in a source's emission estimates for two years are, for the most part, identical. Because the systematic parameter uncertainties then cancel out, the uncertainty in an emission trend (e.g., the difference between the estimates for two years) is generally less than the uncertainty in total emissions for a single year. In such a situation, quantified uncertainty estimates can be treated as being comparable over time and used to track relative changes in the quality of a facility's emission estimates for that source category. Such estimates of uncertainty in emission trends can also be used as a guide to setting a facility's emissions reduction target. Trend uncertainty estimates are likely to be less useful for setting broader (e.g., company-wide) targets (see Chapter 11) because of the general problems with comparability between uncertainty estimates across gases, sources, and facilities.

Given these limitations, the role of qualitative and quantitative uncertainty assessments in developing GHG inventories include:

- Promoting a broader learning and quality feedback process.

- Supporting efforts to qualitatively understand and document the causes of uncertainty and help identify ways of improving inventory quality. For example, collecting the information needed to determine the statistical properties of activity data and emission factors forces one to ask hard questions and to carefully and systematically investigate data quality.

- Establishing lines of communication and feedback with data suppliers to identify specific opportunities to improve quality of the data and methods used.

- Providing valuable information to reviewers, verifiers, and managers for setting priorities for investments into improving data sources and methodologies.

The *GHG Protocol Corporate Standard* has developed a supplementary guidance document on uncertainty assessments ("Guidance on uncertainty assessment in GHG inventories and calculating statistical parameter uncertainty") along with an uncertainty calculation tool, both of which are available on the GHG Protocol website. The guidance document describes how to use the calculation tool in aggregating uncertainties. It also discusses in more depth different types of

uncertainties, the limitations of quantitative uncertainty assessment, and how uncertainty estimates should be properly interpreted.

Additional guidance and information on assessing uncertainty—including optional approaches to developing quantitative uncertainty estimates and eliciting judgments from experts—can also be found in EPA's *Procedures Manual for Quality Assurance/Quality Control and Uncertainty Analysis* and in Chapter 6 of the IPCC's *Good Practice Guidance*.

Table A.1 Generic Quality Checking Measures

Data Gathering, Input, and Handling Activities
✔ Check a sample of input data for transcription errors
✔ Identify spreadsheet modifications that could provide additional controls or checks on
✔ Ensure that adequate version control procedures for electronic files have been
✔ Others
Data Documentation
✔ Confirm that bibliographical data references are included in spreadsheets for all primary
✔ Check that copies of cited references have been archived
✔ Check that assumptions and criteria for selection of boundaries, base years, methods, activity data, emission factors, and other parameters are documented
✔ Check that changes in data or methodology are documented
✔ Others
Calculating Emissions and Checking Calculations
✔ Check whether emission units, parameters, and conversion factors are appropriately
✔ Check if units are properly labeled and correctly carried through from beginning to end of
✔ Check that conversion factors are correct
✔ Check the data processing steps (e.g., equations) in the spreadsheets
✔ Check that spreadsheet input data and calculated data are clearly differentiated
✔ Check a representative sample of calculations, by hand or electronically
✔ Check some calculations with abbreviated calculations (i.e., back of the envelope checks)
✔ Check the aggregation of data across source categories, business units, etc.
✔ Check consistency of time series inputs and calculations
✔ Others

Appendix B: Global Warming Potentials

If you report emissions of non-CO_2 gases, CRIS will convert the mass estimates of these gases to a CO_2 equivalent basis. Converting emissions of non-CO_2 gases to units of CO_2 equivalent allows GHGs to be compared on a common basis, i.e., on the ability of each greenhouse gas to trap heat in the atmosphere. Global Warming Potential (GWP) factors represent the ratio of the heat-trapping ability of each greenhouse gas relative to that of carbon dioxide. For example, the GWP of methane is 21 because one metric ton of methane has 21 times more ability to trap heat in the atmosphere than one metric ton of carbon dioxide. To convert emissions of non-CO_2 gases to units of CO_2 equivalent, multiply the emissions of each gas in units of mass (e.g., metric tons) by the appropriate GWP factors in the following table.

Table B.1 Global Warming Potential Factors for Required Greenhouse Gases

Common Name	Formula	Chemical Name	GWP
Carbon dioxide	CO_2		1
Methane	CH_4		21
Nitrous oxide	N_2O		310
Sulfur hexafluoride	SF_6		23,900
Hydrofluorocarbons (HFCs)			
HFC-23	CHF_3	trifluoromethane	11,700
HFC-32	CH_2F_2	difluoromethane	650
HFC-41	CH_3F	fluoromethane	150
HFC-43-10mee	$C_5H_2F_{10}$	1,1,1,2,3,4,4,5,5,5-decafluoropentane	1,300
HFC-125	C_2HF_5	pentafluoroethane	2,800
HFC-134	$C_2H_2F_4$	1,1,2,2-tetrafluoroethane	1,000
HFC-134a	$C_2H_2F_4$	1,1,1,2-tetrafluoroethane	1,300
HFC-143	$C_2H_3F_3$	1,1,2-trifluoroethane	300
HFC-143a	$C_2H_3F_3$	1,1,1-trifluoroethane	3,800
HFC-152	$C_2H_4F_2$	1,2-difluoroethane	43*
HFC-152a	$C_2H_4F_2$	1,1-difluoroethane	140
HFC-161	C_2H_5F	fluoroethane	12*
HFC-227ea	C_3HF_7	1,1,1,2,3,3,3-heptafluoropropane	2,900
HFC-236cb	$C_3H_2F_6$	1,1,1,2,2,3-hexafluoropropane	1,300*
HFC-236ea	$C_3H_2F_6$	1,1,1,2,3,3-hexafluoropropane	1,200*
HFC-236fa	$C_3H_2F_6$	1,1,1,3,3,3-hexafluoropropane	6,300
HFC-245ca	$C_3H_3F_5$	1,1,2,2,3-pentafluoropropane	560
HFC-245fa	$C_3H_3F_5$	1,1,1,3,3-pentafluoropropane	950*
HFC-365mfc	$C_4H_5F_5$	1,1,1,3,3-pentafluorobutane	890*
Perfluorocarbons (PFCs)			
Perfluoromethane	CF_4	tetrafluoromethane	6,500
Perfluoroethane	C_2F_6	hexafluoroethane	9,200
Perfluoropropane	C_3F_8	octafluoropropane	7,000
Perfluorobutane	C_4F_{10}	decafluorobutane	7,000
Perfluorocyclobutane	c-C_4F_8	octafluorocyclobutane	8,700
Perfluoropentane	C_5F_{12}	dodecafluoropentane	7,500
Perfluorohexane	C_6F_{14}	tetradecafluorohexane	7,400

Source: Intergovernmental Panel on Climate Change (IPCC) Second Assessment Report published in 1995, unless no value was assigned in the document. In that case, the GWP values are from the IPCC Third Assessment Report published in 2001 (those marked with *). GWP values are from the Second Assessment Report (unless otherwise noted) to be consistent with international practices. Values are 100-year GWP values.

Example Calculation: Convert 10 metric tons of HFC-134a to CO_2 equivalent (CO_2e)				
10 (metric tons HFC-134a)	*	1,300 (GWP of HFC-134a)	=	13,000 (metric tons CO_2e)

Note: Since the Second Assessment Report (SAR) was published in 1995, the Intergovernmental Panel on Climate Change (IPCC) has published updated GWP values in its Third Assessment Report (TAR) and Fourth Assessment Report (AR4) that reflect new information on atmospheric lifetimes of greenhouse gases and an improved calculation of the radiative forcing of CO_2. However, GWP values from the SAR are still used by international convention to maintain consistency in GHG reporting, including by the United States and Canada when reporting under the United Nations Framework Convention on Climate Change. TAR GWP values are often used for gases that were not reported in the SAR. To maintain consistency with international practices, the Registry requires participants to use the GWP values in Table B.1. If more recent GWP values are adopted as standard practice by the international community, the Registry will likewise update its GWP requirements to reflect international practices.

Appendix C: Standard Conversion Factors

Table C.1 Conversion Factors

Mass			
1 pound (lb) =	453.6 grams (g)	0.4536 kilograms (kg)	0.0004536 metric tons (tonnes)
1 kilogram (kg) =	1,000 grams (g)	2.2046 pounds (lb)	0.001 metric tons (tonnes)
1 short ton (ton) =	2,000 pounds (lb)	907.18 kilograms (kg)	0.9072 metric tons (tonnes)
1 metric ton (tonne) =	2,204.62 pounds (lb)	1,000 kilograms (kg)	1.1023 short tons (tons)
Volume			
1 cubic foot (ft^3) =	7.4805 US gallons (gal)	0.1781 barrels (bbl)	
1 cubic foot (ft^3) =	28.32 liters (L)	0.02832 cubic meters (m^3)	
1 US gallon (gal) =	0.0238 barrels (bbl)	3.785 liters (L)	0.003785 cubic meters (m^3)
1 barrel (bbl) =	42 US gallons (gal)	158.99 liters (L)	0.1589 cubic meters (m^3)
1 liter (L) =	0.001 cubic meters (m^3)	0.2642 US gallons (gal)	0.0063 barrels (bbl)
1 cubic meter (m^3) =	6.2897 barrels (bbl)	264.17 US gallons (gal)	1,000 liters (L)
Energy			
1 kilowatt hour (kWh) =	3,412 Btu (Btu)	3,600 kilojoules (KJ)	
1 megajoule (MJ) =	0.001 gigajoules (GJ)		
1 gigajoule (GJ) =	0.9478 million Btu (MMBtu)	277.8 kilowatt hours (kWh)	
1 British thermal unit (Btu) =	1,055 joules (J)	1.055 kilojoules (KJ)	
1 million Btu (MMBtu) =	1.055 gigajoules (GJ)	293 kilowatt hours (kWh)	
1 therm =	100,000 Btu	0.1055 gigajoules (GJ)	29.3 kilowatt hours (kWh)
Other			
kilo =	1,000		
mega =	1,000,000		
giga =	1,000,000,000		
tera =	1,000,000,000,000		
peta =	1,000,000,000,000,000		
1 mile =	1.609 kilometers		
1 metric ton carbon (C) =	$^{44}/_{12}$ metric tons CO_2		

Example Calculation: Convert 1,000 lb C/kWh into metric tons CO_2 /GJ

$$1{,}000\ \frac{\text{lb C}}{\text{kWh}} \times 277.8\ \frac{\text{kWh}}{\text{GJ}} \times 0.0004536\ \frac{\text{metric tons}}{\text{lb}} \times 44/12\ \frac{CO_2}{C} = 462.04\ \frac{\text{metric tons } CO_2}{\text{GJ}}$$

Appendix D: GHG Emission Sources by Industry Sector[8]

Sector	Scope 1 Emission Sources	Scope 2 Emission Sources	Scope 3 Emission Sources[9]
Energy			
Energy Generation	• Stationary combustion (boilers and turbines used in the production of electricity, heat or steam, fuel pumps, fuel cells, flaring) • Mobile combustion (trucks, barges and trains for transportation of fuels) • Fugitive emissions (CH_4 leakage from transmission and storage facilities, HFC emissions from LPG storage facilities, SF_6 emissions from transmission and distribution equipment)	Stationary combustion (consumption of purchased electricity, heat or steam)	• Stationary combustion (mining and extraction of fuels, energy for refining or processing fuels) • Process emissions (production of fuels, SF_6 emissions) • Mobile combustion (transportation of fuels/waste, employee business travel, employee commuting) • Fugitive emissions (CH_4 and CO_2 from waste landfills, pipelines, SF_6 emissions)
Oil and Gas	• Stationary combustion (process heaters, engines, turbines, flares, incinerators, oxidizers, production of electricity, heat and steam) • Process emissions (process vents, equipment vents, maintenance/turnaround activities, non-routine activities) • Mobile combustion (transportation of raw materials/products/waste; company owned vehicles) • Fugitive emissions (leaks from pressurized equipment, wastewater treatment, surface impoundments)	Stationary combustion (consumption of purchased electricity, heat or steam)	• Stationary combustion (product use as fuel or combustion for the production of purchased materials) • Mobile combustion (transportation of raw materials/products/waste, employee business travel, employee commuting, product use as fuel) • Process emissions (product use as feedstock or emissions from the production of purchased materials) • Fugitive emissions (CH_4 and CO_2 from waste landfills or from the production of purchased materials)

[8] This appendix is taken directly from WRI/WBCSD GHG Protocol *Corporate Accounting and Reporting Standard* (Revised Edition), Appendix D.
[9] Scope 3 activities of outsourcing, contract manufacturing & franchises are not addressed in this table as specific GHG sources depend on the nature of the outsource activity.

Coal Mining	• Stationary combustion (methane flaring and use, use of explosives, mine fires) • Mobile combustion (mining equipment, transportation of coal) • Fugitive emissions (CH_4 emissions from coal mines and coal piles)	Stationary combustion (consumption of purchased electricity, heat or steam)	• Stationary combustion (product use as fuel) • Mobile combustion (transportation of coal/waste, employee business travel, employee commuting) • Process emissions (gasification)
Metals			
Aluminum	• Stationary combustion (bauxite to aluminum processing, coke baking, lime, soda ash and fuel use, on-site CHP) • Process emissions (carbon anode oxidation, electrolysis, PFC) • Mobile combustion (pre- and post-smelting transportation, ore haulers) • Fugitive emissions (fuel line CH_4, HFC and PFC, SF_6 cover gas)	Stationary combustion (consumption of purchased electricity, heat or steam)	• Stationary combustion (raw material processing and coke production by second party suppliers, manufacture of production line machinery) • Mobile Combustion (transportation services, business travel, employee commuting) • Process emissions (during production of purchased materials) • Fugitive emissions (mining and landfill CH_4 and CO_2, outsourced process emissions)
Iron and Steel	• Stationary combustion (coke, coal and carbonate fluxes, boilers, flares) • Process emissions (crude iron oxidation, consumption of reducing agent, carbon content of crude iron/ferroalloys) • Mobile combustion (on-site transportation) • Fugitive emissions (CH_4, N_2O)	Stationary combustion (consumption of purchased electricity, heat or steam)	• Stationary combustion (mining equipment, production of purchased materials) • Process emissions (production of ferroalloys) • Mobile combustion (transportation of raw materials/products/waste and intermediate products) • Fugitive emissions (CH_4 and CO_2 from waste landfills)

Chemicals			
Nitric acid, Ammonia, Adipic acid, Urea, and Petrochemicals	• Stationary combustion (boilers, flaring, reductive furnaces, flame reactors, steam reformers) • Process emissions (oxidation/reduction of substrates, impurity removal, N_2O byproducts, catalytic cracking, myriad other emissions individual to each process) • Mobile combustion (transportation of raw materials/products/waste) • Fugitive emissions (HFC use, storage tank leakage)	Stationary combustion (consumption of purchased electricity, heat or steam)	• Stationary combustion (production of purchased materials, waste combustion) • Process emissions (production of purchased materials) • Mobile combustion (transportation of raw materials/products/waste, employee business travel, employee commuting) • Fugitive emissions (CH_4 and CO_2 from waste landfills and pipelines)
Minerals			
Cement and Lime	• Process emissions (calcination of limestone) • Stationary combustion (clinker kiln, drying of raw materials, production of electricity) • Mobile combustion (quarry operations, on-site transportation)	Stationary combustion (consumption of purchased electricity, heat or steam)	• Stationary combustion (production of imported materials, waste combustion) • Process emissions (production of purchased clinker and lime) • Mobile combustion (transportation of raw materials/products/waste, employee business travel, employee commuting) • Fugitive emissions (mining and landfill CH_4 and CO_2, outsourced process emissions)
Waste			
Landfills, Waste combustion, Water services	• Stationary combustion (incinerators, boilers, flaring) • Process emissions (sewage treatment, nitrogen loading) • Fugitive emissions (CH_4 and CO_2 emissions from waste and animal product decomposition) • Mobile combustion (transportation of waste/products)	Stationary combustion (consumption of purchased electricity, heat or steam)	• Stationary combustion(recycled waste used as a fuel) • Process emissions (recycled waste used as a feedstock) • Mobile combustion (transportation of waste/products, employee business travel, employee commuting)

Pulp & Paper			
Pulp and Paper	• Stationary combustion (production of steam and electricity, fossil fuel-derived emissions from calcination of calcium carbonate in lime kilns, drying products with infrared dryers fired with fossil fuels) • Mobile combustion (transportation of raw materials, products, and wastes, operation of harvesting equipment) • Fugitive emissions (CH_4 and CO_2 from waste)	Stationary combustion (consumption of purchased electricity, heat or steam)	• Stationary combustion (production of purchased materials, waste combustion) • Process emissions (production of purchased materials) • Mobile combustion (transportation of raw materials/products/waste, employee business travel, employee commuting) • Fugitive emissions (landfill CH_4 and CO_2 emissions)
HFC, PFC, SF_6 & HCFC 22 Production			
HCFC 22 production	• Stationary combustion (production of electricity, heat or steam) • Process emissions (HFC venting) • Mobile combustion (transportation of raw materials/products/waste) • Fugitive emissions (HFC use)	Stationary combustion (consumption of purchased electricity, heat or steam)	• Stationary combustion (production of purchased materials) • Process emissions (production of purchased materials) • Mobile combustion (transportation of raw materials/products/waste, employee business travel, employee commuting) • Fugitive emissions (fugitive leaks in product use, CH_4 and CO_2 from waste landfills)

Semiconductor Production			
Semiconductor production	• Process emissions (C_2F_6, CH_4, CHF_3, SF_6, NF_3, C_3F_8, C_4F_8, N_2O used in wafer fabrication, CF_4 created from C_2F_6 and C_3F_8 processing) • Stationary combustion (oxidation of volatile organic waste, production of electricity, heat or steam) • Fugitive emissions (process gas storage leaks, container remainders/heel leakage) • Mobile combustion (transportation of raw materials/products/waste	Stationary combustion (consumption of purchased electricity, heat or steam)	• Stationary combustion (production of purchased materials, waste combustion, upstream T&D losses of purchased electricity) • Process emissions (production of purchased materials, outsourced disposal of returned process gases and container remainder/heel) • Mobile combustion (transportation of raw materials/products/waste, employee business travel, employee commuting) • Fugitive emissions (landfill CH_4 and CO_2 emissions, downstream process gas container remainder/heel leakage)
Other Sectors			
Service sector/ Office based organizations	• Stationary combustion (production of electricity, heat or steam) • Mobile combustion (transportation of raw materials/waste) • Fugitive emissions (mainly HFC emissions during use of refrigeration and air-conditioning equipment)	Stationary combustion (consumption of purchased electricity, heat or steam)	• Stationary combustion (production of purchased materials) • Process emissions (production of purchased materials) • Mobile combustion (transportation of raw materials/products/waste, employee business travel, employee commuting)

Appendix E: Direct Emissions from Sector-Specific Sources

Who should read Appendix E:

- Appendix E applies to Reporters that have direct process or fugitive emissions from industry-specific emission sources.

What you will find in Appendix E:

- Appendix E provides a framework for determining direct process or fugitive emissions from selected sector-specific sources. Each section in this chapter provides the methods, data quality tiers, and default emission factors to be used for quantifying emissions for each source type.

Information you will need:

- To complete this chapter you will need information pertaining to the relevant industry-specific processes outlined in each section.

Cross-References:

- See Part III: Chapters 12-16 for guidance on calculating emissions from sources that are not specific to your industry, such as stationary combustion, mobile combustion, electricity use, imported steam, and refrigeration systems.

Appendix E contains a framework for quantifying emissions from the following sources:

- Adipic acid production (Section E.1)
- Aluminum production (Section E.2)
- Ammonia production (Section E.3)
- Cement production (Section E.4)
- Electricity transmission and distribution (Section E.5)
- HCFC-22 production (Section E.6)
- Iron and steel production (Section E.7)
- Lime production (Section E.8)
- Nitric acid production (Section E.9)
- Pulp and paper production (Section E.10)
- Refrigeration and air condition equipment manufacturing (Section E.11)
- Semiconductor manufacturing (Section E.12).

E.1 Adipic Acid Production (N_2O Emissions)

Direct Process N_2O Emissions from Adipic Acid Production

Tier	Method	Emission Factors
A1	Continuous emissions monitoring	n/a
A2	Mass Balance	Plant-specific factors: • Measured destruction and utilization factors for an abatement technology • Measured N_2O emissions factor based on direct measurements
B	Mass Balance	Mix of default and plant-specific factors
C	Mass Balance	Default factors: • Default destruction and utilization factors for an abatement technology • Default N_2O emissions factor

Mass Balance Method
Source: WRI/WBCSD, *Calculating N_2O Emissions from the Production of Adipic Acid*, 2001 (Consistent with IPCC 2006, Equation 3.8, N_2O Emissions from Adipic Acid Production, Tier 2)

N_2O Emissions = (Adipic Acid Production x N_2O Emission Factor) x (1 - Destruction factor x Abatement system utilization factor)

Where:
N_2O emissions = N_2O emissions, metric tons
N_2O emissions factor = N_2O emission factor by technology type, metric tons of N_2O/metric ton of adipic acid produced
N_2O destruction factor = fraction of emissions abated by reduction technologies
Abatement system utilization factor = fraction of time the abatement system was in use

Default Emission Factors
Source: IPCC 2006

TABLE 3.4 DEFAULT FACTORS FOR ADIPIC ACID PRODUCTION		
Production Process	**N_2O Generation Factor[a,d]**	**Uncertainty Estimate**
Nitric Acid Oxidation	300 kg/tonne adipic acid (uncontrolled)	± 10% (based on expert judgement). The range of 300 kg ± 10% encompasses the variability from pure ketone to pure alcohol feedstocks, with most manufacturers somewhere in the middle.[a]
Abatement Technology	**N_2O Destruction Factor[b]**	**Uncertainty Estimate**
Catalytic Destruction	92.5%	90-95% (based on expert judgement). Manufacturers known to employ this technology include: BASF (Scott, 1998), and DuPont (Reimer, 1999b).
Thermal Destruction	98.5%	98-99% (based on expert judgement). Manufacturers known to employ this technology include: Asahi, DuPont, Bayer, and Solutia (Scott, 1998).
Recycle to Nitric Acid	98.5%	98-99% (based on expert judgement). Manufacturers known to employ this technology include: Alsachemie (Scott, 1998).
Recycle to feedstock for Adipic Acid	94%	90-98% (based on expert judgement). Solutia implemented this technology around 2002.
Abatement System	**Utilisation Factor[d]**	**Uncertainty Estimate**
Catalytic Destruction	89%	80-98% (based on expert judgement)[c].
Thermal Destruction	97%	95-99% (based on expert judgement)[c].
Recycle to Nitric Acid	94%	90-98% (based on expert judgement)[c].
Recycle to Adipic Acid	89%	80-98% (based on expert judgement)[c].

E.2 Aluminum Production (CO_2 and PFC Emissions)

Direct Process CO_2 Emissions from Aluminum Production

Tier	Method	Emission Factors
A	Process-Specific Mass Balance	Plant-specific factors • For each applicable parameter listed in IPCC Tables 4.11 – 4.14
B	Process-Specific Mass Balance	Default factors: • Industry-typical values in IPCC Tables 4.11 – 4.14 (Tier 2 column)

Process-Specific Mass Balance Method
Source: IPCC 2006 Equations 4.21 – 4.24 (Tier 2/3 Methods)

CO2 EMISSIONS FROM PREBAKED ANODE CONSUMPTION

$$E_{CO2} = NAC \bullet MP \bullet \frac{100 - S_a - Ash_a}{100} \bullet \frac{44}{12}$$

Where:
E_{CO2} = CO_2 emissions from prebaked anode consumption, metric tons CO_2
MP = total metal production, metric tons Al
NAC = net prebaked anode consumption per metric ton of aluminum, metric tons C/ metric ton Al
S_a = sulphur content in baked anodes, wt %
Ash_a = ash content in baked anodes, wt %
44/12 = CO_2 molecular mass: carbon atomic mass ratio, dimensionless

CO2 EMISSIONS FROM PITCH VOLATILES COMBUSTION

$$E_{CO2} = (GA - H_w - BA - WT) \bullet \frac{44}{12}$$

Where:
E_{CO2} = CO_2 emissions from pitch volatiles combustion, metric tons CO_2
GA = initial weight of green anodes, metric tons
H_w = hydrogen content in green anodes, metric tons
BA = baked anode production, metric tons
WT = waste tar collected, metric tons

CO2 EMISSIONS FROM BAKE FURNACE PACKING MATERIAL

$$E_{CO2} = PCC \bullet BA \bullet \frac{100 - S_{pc} - Ash_{pc}}{100} \bullet \frac{44}{12}$$

Where:
E_{CO2} = CO_2 emissions from bake furnace packing material, metric tons CO_2
PCC = packing coke consumption, metric tons / metric ton BA
BA = baked anode production, metric tons
S_{pc} = sulphur content in packing coke, wt %
Ash_{pc} = ash content in packing coke, wt %

CO_2 EMISSIONS FROM PASTE CONSUMPTION (for Søderberg cells (VSS and HSS))

$$E_{CO2} = \left(PC \bullet MP - \frac{CSM \bullet MP}{1000} - \frac{BC}{100} \bullet PC \bullet MP \bullet \frac{S_p + Ash_p + H_p}{100} \right.$$
$$\left. - \frac{100 - BC}{100} \bullet PC \bullet MP \bullet \frac{S_c + Ash_c}{100} - MP \bullet CD \right) \bullet \frac{44}{12}$$

Where:
E_{CO2} = CO_2 emissions from paste consumption, metric tons CO_2
MP = total metal production, metric tons Al
PC = paste consumption, metric tons / metric ton Al
CSM = emissions of cyclohexane soluble matter, kg/ metric ton Al
BC = binder content in paste, wt %
S_p = sulphur content in pitch, wt %
Ash_p = ash content in pitch, wt %
H_p = hydrogen content in pitch, wt %
S_c = sulphur content in calcined coke, wt %
Ash_c = ash content in calcined coke, wt %
CD = carbon in skimmed dust from Søderberg cells, metric tons C/ metric ton Al
44/12 = CO_2 molecular mass : carbon atomic mass ratio, dimensionless

Default Emission Factors
Source: IPCC 2006

TABLE 4.11
DATA SOURCES AND UNCERTAINTIES FOR PARAMETERS USED IN TIER 2 OR 3 METHOD FOR CO_2 EMISSIONS FROM PREBAKE CELLS (CWPB AND SWPB), SEE EQUATION 4.21

Parameter	Tier 2 Method		Tier 3 Method	
	Data Source	Uncertainty (+/-%)	Data Source	Uncertainty (+/-%)
MP: total metal production (tonnes aluminium per year)	Individual facility records	2	Individual facility records	2
NAC: net anode consumption per tonne of aluminium (tonnes per tonne Al)	Individual facility records	5	Individual facility records	5
S_a: sulphur content in baked anodes (wt %)	Use industry typical value, 2	50	Individual facility records	10
Ash_a: ash content in baked anodes (wt %)	Use industry typical value, 0.4	85	Individual facility records	10

Source: IAI (2005b).

TABLE 4.12
DATA SOURCES AND UNCERTAINTIES FOR PARAMETERS USED IN TIER 2 OR 3 METHOD FOR CO_2 EMISSIONS FROM PITCH VOLATILES COMBUSTION (CWPB AND SWPB), SEE EQUATION 4.22

Parameter	Tier 2 Method		Tier 3 Method	
	Data Source	Uncertainty (+/-%)	Data Source	Uncertainty (+/-%)
GA: initial weight of green anodes processed (tonnes green anode per year)	Individual facility records	2	Individual facility records	2
H_w: Hydrogen content in green anodes (tonnes)	Use industry typical value, 0.005 • GA	50	Individual facility records	10
BA: Baked anode production (tonnes per year)	Individual facility records	2	Individual facility records	2
WT: Waste tar collected (tonnes) a) Riedhammer furnaces b) All other furnaces	Use industry typical value, a) 0.005 • GA b) insignificant	50	Individual facility records	20

Source: IAI (2005b).

TABLE 4.13
DATA SOURCES AND UNCERTAINTIES FOR PARAMETERS USED IN TIER 2 OR 3 METHOD FOR CO_2 EMISSIONS FROM BAKE FURNACE PACKING MATERIAL (CWPB AND SWPB), SEE EQUATION 4.23

Parameter	Tier 2 Method		Tier 3 Method	
	Data Source	Uncertainty (+/-%)	Data Source	Uncertainty (+/-%)
PCC: Packing coke consumption (tonnes per tonne BA)	Use industry typical value, 0.015	25	Individual facility records	2
BA: Baked anode production (tonnes per year)	Individual facility records	2	Individual facility records	2
S_{pc}: Sulphur content in packing coke (wt %)	Use industry typical value, 2	50	Individual facility records	10
Ash_{pc}: Ash content in packing coke (wt %)	Use industry typical value, 2.5	95	Individual facility records	10

Source: IAI (2005b).

TABLE 4.14
DATA SOURCES AND UNCERTAINTIES FOR PARAMETERS USED IN TIER 2 OR 3 METHOD FOR CO_2 EMISSIONS FROM SØDERBERG CELLS (VSS AND HSS)

Parameter	Tier 2 Method		Tier 3 Method	
	Data Source	Data Uncertainty (+/-%)	Data Source	Data Uncertainty (+/-%)
MP: total metal production (tonnes Al/year)	Individual facility records	2	Individual facility records	2
PC : paste consumption (tonnes per tonne Al)	Individual facility records	2-5	Individual facility records	2-5
CSM: emissions of cyclohexane soluble matter (kg per tonne Al)	Use industry typical value, HSS – 4.0 VSS – 0.5	30	Individual facility records	15
BC: binder content in paste (wt %)	Use industry typical value, Dry Paste – 24 Wet Paste – 27	25	Individual facility records	5
S_p: sulphur content in pitch (wt %)	Use industry typical value, 0.6	20	Individual facility records	10
Ash_p: ash content in pitch (wt %)	Use industry typical value, 0.2	20	Individual facility records	10
H_p: hydrogen content in pitch (wt %)	Use industry typical value, 3.3	50	Individual facility records	10
S_c: sulphur content in calcined coke (wt %)	Use industry typical value, 1.9	20	Individual facility records	10
Ash_c: ash content in calcined coke (wt %)	Use industry typical value, 0.2	50	Individual facility records	10
CD: carbon in dust from anode (tonnes of carbon in skim per tonne Al)	Use industry typical value, 0.01	99	Individual facility records	30

Direct Process PFC Emissions from Aluminum Production

Tier	Method	Emission Factors
A	Slope method or Overvoltage method	Plant-specific factors • Plant-specific Slope or Overvoltage coefficients based on representative measurements • Plant-specific weight fraction
B	Slope method or Overvoltage method	Default factors: • Default Slope or Overvoltage coefficients by technology type from IPCC Table 4.16 • Default weight fraction from IPCC Table 4.16
C	Simplified method	Default factors: • Default factors by technology type from IPCC Table 4.15

Slope Method
Source: IPCC 2006 Equation 4.26 (PFC Emissions by Slope Method, Tier 2 and 3 Methods)

$$E_{CF4} = S_{CF4} \bullet AEM \bullet MP$$

and

$$E_{C2F6} = E_{CF4} \bullet F_{C2F6/CF4}$$

Where:
E_{CF4} = emissions of CF_4 from aluminum production, kg CF_4
E_{C2F6} = emissions of C_2F_6 from aluminum production, kg C_2F_6
S_{CF4} = slope coefficient for CF_4, (kg CF_4/tonne Al)/(AE-Mins/cell-day)
AEM = anode effect minutes per cell-day, AE-Mins/cell-day
MP = metal production, metric tons Al
$F_{C2F6/CF4}$ = weight fraction of C_2F_6/CF_4, kg C_2F_6/kg CF_4

Overvoltage Method
Source: IPCC 2006 Equation 4.27 (PFC Emissions by Overvoltage Method, Tier 2 and 3 Methods)

$$E_{CF4} = OVC \bullet \frac{AEO}{CE/100} \bullet MP$$

and

$$E_{C2F6} = E_{CF4} \bullet F_{C2F6/CF4}$$

Where:
E_{CF4} = emissions of CF_4 from aluminum production, kg CF_4
E_{C2F6} = emissions of C_2F_6 from aluminum production, kg C_2F_6
OVC = Overvoltage coefficient for CF_4, (kg CF_4/tonne Al)/mV
AEO = anode effect overvoltage, mV
CE = aluminum production process current efficiency expressed, percent (e.g., 95 percent)
MP = metal production, metric tons Al
$F_{C2F6/CF4}$ = weight fraction of C_2F_6/CF_4, kg C_2F_6/kg CF_4

Simplified Method
Source: IPCC 2006 Equation 4.25 (PFC Emissions, Tier 1 Method)

$$E_{CF4} = \sum_i \left(EF_{CF4,i} \bullet MP_i \right)$$

and

$$E_{C2F6} = \sum_i \left(EF_{C2F6,i} \bullet MP_i \right)$$

Where:
E_{CF4} = emissions of CF_4 from aluminum production, kg CF_4
E_{C2F6} = emissions of C_2F_6 from aluminum production, kg C_2F_6
$EF_{CF4,i}$ = default emission factor by cell technology type *i* for CF_4, kg CF_4/ metric ton Al
$EF_{C2F6,i}$ = default emission factor by cell technology type *i* for C_2F_6, kg C_2F_6/ metric ton Al
MP_i = metal production by cell technology type *i*, metric tons Al

Default Emission Factors
Source: IPCC 2006

TABLE 4.15
DEFAULT EMISSION FACTORS AND UNCERTAINTY RANGES FOR THE CALCULATION OF PFC EMISSIONS FROM ALUMINIUM PRODUCTION BY CELL TECHNOLOGY TYPE (TIER 1 METHOD)

Technology	CF_4		C_2F_6	
	EF_{CF4} (kg/tonne Al)[a]	Uncertainty Range (%)[b]	EF_{C2F6} (kg/tonne Al)[c]	Uncertainty Range (%)[d]
CWPB	0.4	-99/+380	0.04	-99/+380
SWPB	1.6	-40/+150	0.4	-40/+150
VSS	0.8	-70/+260	0.04	-70/+260
HSS	0.4	-80/+180	0.03	-80/+180

[a] Default CF_4 values calculated from median anode effect performance from 1990 IAI survey data (IAI, 2001).
[b] Uncertainty based on the range of calculated CF_4 specific emissions by technology from 1990 IAI anode effect survey data (IAI, 2001).
[c] Default C_2F_6 values calculated from global average C_2F_6:CF_4 ratios by technology, multiplied by the default CF_4 emission factor.
[d] Uncertainty range based on global average C_2F_6:CF_4 ratios by technology, multiplied by calculated minimum and maximum specific CF_4 emissions from 1990 IAI survey data (IAI, 2001).
Note: These default emission factors should only be used in the absence of Tier 2 or Tier 3 data.

TABLE 4.16
TECHNOLOGY SPECIFIC SLOPE AND OVERVOLTAGE COEFFICIENTS FOR THE CALCULATION OF PFC EMISSIONS FROM ALUMINIUM PRODUCTION (TIER 2 METHOD)

Technology[a]	Slope Coefficient[b, c] [(kg $_{PFC}/t_{Al}$) / (AE-Mins/cell-day)]		Overvoltage Coefficient[b, c, d] [(kg $_{CF4}/t_{Al}$) / (mV)]		Weight Fraction C_2F_6 / CF_4	
	CF_4	Uncertainty (+/-%)	CF_4	Uncertainty (+/-%)	C_2F_6/CF_4	Uncertainty (+/-%)
CWPB	0.143	6	1.16	24	0.121	11
SWPB	0.272	15	3.65	43	0.252	23
VSS	0.092	17	NR	NR	0.053	15
HSS	0.099	44	NR	NR	0.085	48

[a] Centre Worked Prebake (CWPB), Side Worked Prebake (SWPB), Vertical Stud Soderberg (VSS), Horizontal Stud Soderberg (HSS).

[b] Source: Measurements reported to IAI, US EPA sponsored measurements and multiple site measurements (U.S. EPA and IAI, 2003).

[c] Embedded in each Slope and Overvoltage coefficient is an assumed emissions collection efficiency as follows: CWPB 98%, SWPB 90%, VSS 85%, HSS 90%. These collection efficiencies have been assumed based on measured PFC collection fractions, measured fluoride gas collection efficiencies and expert opinion.

[d] The noted coefficients reflect measurements made at some facilities recording positive overvoltage and others recording algebraic overvoltage. No robust relationship has yet been established between positive and algebraic overvoltage. Positive overvoltage should provide a better correlation with PFC emissions than algebraic overvoltage. Overvoltage coefficients are not relevant (NR) to VSS and HSS technologies.

E.3 Ammonia Production (CO_2 Emissions)

Direct Process CO_2 Emissions from Ammonia Production

Tier	Method	Emission Factors
A1	Direct measurement, either continuous emissions monitoring or periodic direct measurements	n/a
A2	Mass Balance	Plant-specific carbon content of feedstock fuels
B	Mass Balance	Default carbon content of feedstock fuels by fuel type

Mass Balance Method

Source: Adapted from IPCC 2006 Equation 3.3 (CO_2 Emissions from Ammonia Production, Tier 2 and 3)

$$CO_2\ Emissions = \sum_i (FC_i \times CC_i \times OF_i \times 44/12) - R_{CO2}$$

Where:
CO_2 Emissions = emissions of CO_2, kg
FC_i = total feedstock fuel consumption of fuel type *i* (MMBtu)
CC_i = carbon content factor of the fuel type *i*, kg C/MMBtu
OF_i = carbon oxidation factor of the fuel type *i*, fraction
R_{CO2} = CO_2 recovered for downstream use (urea production, CO_2 capture and storage), kg

Default Emission Factors

Carbon content and oxidation factors are provided for U.S. natural gas below by heat content. For other fuels, refer to Tables 12.1 – 12.4 in Chapter 12 (*Direct Emissions from Stationary Combustion*).

Heat Content (HHV Btu per Standard Cubic Foot)	Carbon Content (kg C / MMBtu)	Oxidation Factor
975 – 1,000	14.73	1.0
1,000 – 1,025	14.43	1.0
1,025 – 1,050	14.47	1.0
1,050 – 1,075	14.58	1.0
1,075 – 1,100	14.65	1.0
Greater than 1,100	14.92	1.0
Unspecified (Weighted U.S. Average)	14.47	1.0
Source: U.S. EPA, *Inventory of Greenhouse Gas Emissions and Sinks: 1990-2005* (2007), Annex 2.1, A-35.		

E.4 Cement Production (CO_2 Emissions)

Direct Process CO_2 Emissions Using Clinker Method

Tier	Method	Emission Factors
Process CO_2 emissions from Clinker Calcination		
A	Clinker Method	Plant-specific clinker emission factor: • Measured CaO- and MgO content of a plant's clinker • Measured non-carbonate fractions of CaO and MgO
B	Clinker Method	Default clinker emission factor: • Default clinker EF = 525 kg CO_2/ metric tons clinker
Process CO_2 emissions from Discarded Cement Kiln Dust		
A1	Direct Measurement	n/a
A2	Mass Balance	Plant-specific CKD emission factor: • Plant-specific clinker emission factor • Plant-specific CKD calcination rate
B	Mass Balance	Default CKD emission factor: • CKD calcination rate (d) = 1 • Default clinker EF = 525 kg CO_2/ metric tons clinker
Process CO_2 emissions from Organic Carbon in Raw Meal		
A	Mass Balance	Measured organic carbon content
B	Mass Balance	Default organic carbon content = 0.2%

Direct Process CO_2 Emissions Using Carbonate Input Method

Tier	Method	Emission Factors
A	Carbonate Input Method	Plant-specific factors
B	Carbonate Input Method	Default factors: • Fi = 1.00 • Fd = 1.00 • Cd = the calcium carbonate ratio in the raw material feed to the kiln • EFd = the emission factor for calcium carbonate • CO2 emissions from non-carbonate carbon in the non-fuel raw materials can be ignored (set Mk • Xk • EFk = 0) if the heat contribution from the non-carbonate carbon is < 5% of total heat (from fuels).

Clinker Method

Source: Cement Sustainability Initiative, *The Cement CO_2 Protocol: CO_2 Accounting and Reporting Standard for the Cement Industry* (2005) Version 2.0, consistent with California Air Resources Board, *Draft Regulation for the Mandatory Reporting of Greenhouse Gas Emissions*, 2007, and the California Climate Action Registry's *Cement Reporting Protocol*, 2005

$$\text{Process } CO_2 \text{ Emissions} = CO_{2\ (\text{clinker})} + CO_{2\ (\text{cement kiln dust})} + CO_{2\ (\text{non-carbonate carbon})} = (Cli \times EF_{Cli}) + (CKD \times EF_{CKD}) + (TOC_{RM} \times RM \times 44/12)$$

Where:
Cli = Quantity of clinker produced, metric tons
EF_{Cli} = Clinker emission factor, metric tons CO2/metric tons clinker
CKD = Quantity CKD discarded
EF_{CKD} = CKD emission factor
TOC_{RM} = Organic carbon content of raw material (%)
RM = Amount of raw material consumed (metric tons/year)
44/12 = The CO_2 to carbon molar ratio

Clinker Emission Factor

EF_{Cli} = [(CaO content – non-carbonate CaO) x Molecular ratio of CO_2/CaO] + [(MgO Content – non-carbonate MgO) x Molecular Ratio of CO_2/MgO]

Where:
CaO Content (by weight) = CaO content of Clinker (%)
MgO Content (by weight) = MgO content of Clinker (%)
Molecular Ratio of CO_2/CaO = 44g/56g = 0.785
Molecular Ratio of CO_2/MgO = 44g/40g = 1.092

CKD Emission Factor

$$EF_{CKD} = \frac{\frac{EF_{Cli}}{1+EF_{Cli}} \times d}{1 - \frac{EF_{Cli}}{1+EF_{Cli}} \times d}$$

Where:
EF_{CKD} = CKD Emission Factor
EF_{Cli} = Clinker Emission Factor
d = CKD Calcination Rate:

$$d = 1 - \frac{fCO_{2CKD} \times (1 - fCO_{2RM})}{(1 - fCO_{2CKD}) \times fCO_{2RM}}$$

Where:
fCO_{2CKD} = weight fraction of carbonate CO_2 in the CKD
fCO_{2RM} = weight fraction of carbonate CO_2 in the raw meal

Carbonate Input Method

Source: IPCC 2006 (Tier 3 Method)

EQUATION 2.3
TIER 3: EMISSIONS BASED ON CARBONATE RAW MATERIAL INPUTS TO THE KILN

$$CO_2\ Emissions = \sum_i (EF_i \bullet M_i \bullet F_i) - M_d \bullet C_d \bullet (1 - F_d) \bullet EF_d + \sum_k (M_k \bullet X_k \bullet EF_k)$$

Emissions from carbonates

Emissions from uncalcined CKD not recycled to the kiln

Emissions from carbon-bearing non-fuel materials

Where:
CO_2 Emissions = emissions of CO_2 from cement production, metric tons
EF_i = emission factor for the particular carbonate *i*, metric tons CO_2/tonne carbonate
M_i = weight or mass of carbonate *i* consumed in the kiln, metric tons
F_i = fraction calcination achieved for carbonate *i*, fraction
M_d = weight or mass of CKD not recycled to the kiln (= 'lost' CKD), metric tons
C_d = weight fraction of original carbonate in the CKD not recycled to the kiln, fraction
F_d = fraction calcination achieved for CKD not recycled to kiln, fraction
EF_d = emission factor for the uncalcined carbonate in CKD not recycled to the kiln, metric tons CO_2/tonne carbonate
M_k = weight or mass of organic or other carbon-bearing nonfuel raw material *k*, metric tons
X_k = fraction of total organic or other carbon in specific nonfuel raw material *k*, fraction
EF_k = emission factor for kerogen (or other carbon)-bearing nonfuel raw material *k*, metric tons CO_2/ metric ton carbonate

Default CO_2 Emission Factors for Carbonate Inputs

Source: IPCC 2006

TABLE 2.1
FORMULAE, FORMULA WEIGHTS, AND CARBON DIOXIDE CONTENTS OF COMMON CARBONATE SPECIES*

Carbonate	Mineral Name(s)	Formula Weight	Emission Factor (tonnes CO_2/tonne carbonate)**
$CaCO_3$	Calcite*** or aragonite	100.0869	0.43971
$MgCO_3$	Magnesite	84.3139	0.52197
$CaMg(CO_3)_2$	Dolomite***	184.4008	0.47732
$FeCO_3$	Siderite	115.8539	0.37987
$Ca(Fe,Mg,Mn)(CO_3)_2$	Ankerite****	185.0225–215.6160	0.40822–0.47572
$MnCO_3$	Rhodochrosite	114.9470	0.38286
Na_2CO_3	Sodium carbonate or soda ash	106.0685	0.41492

Source: CRC Handbook of Chemistry and Physics (2004)

* Final results (i.e., emission estimates) using these data should be rounded to no more than two significant figures.

** The fraction of emitted CO_2 assuming 100 percent calcination; e.g., 1 tonne calcite, if fully calcined, would yield 0.43971 tonnes of CO_2.

*** Calcite is the principal mineral in limestone. Terms like high-magnesium or dolomitic limestones refer to a relatively small substitution of Mg for Ca in the general $CaCO_3$ formula commonly shown for limestone.

**** Formulae weight range shown for ankerite assumes that Fe, Mg, and Mn are present in amounts of at least 1.0 percent.

E.5 Electricity Transmission and Distribution (SF_6 Emissions)

Direct Fugitive SF_6 Emissions from Electricity Transmission and Distribution Systems

Tier	Method	Emission Factors
A	Mass Balance	n/a

Mass Balance Method

Source: IPCC 2006 Equation 8.10 (Utility-Level Mass Balance Approach, Tier 3), consistent with California Air Resources Board, *Draft Regulation for the Mandatory Reporting of Greenhouse Gas Emissions*, 2007, the California Climate Action Registry's *Power/Utility Reporting Protocol*, 2005, and U.S. EPA's SF_6 Emission Reduction Partnership for Electric Power Systems, *Emissions Inventory Reporting Protocol*

$$SF_6 \text{ Emissions} = (I_B - I_E + P - S - C)$$

Where:

SF_6 Emissions = annual fugitive SF_6 emissions

I_B = the quantity of SF_6 in inventory at the beginning of the year (in storage containers, not in equipment)

I_E = the quantity of SF_6 in inventory at the end of the year (in storage containers, not in equipment)

P = purchases/acquisitions of SF_6. This is the sum of all the SF_6 acquired from other entities during the year either in storage or in equipment, including SF_6 purchased from chemical producers or distributors in bulk, SF_6 purchased from equipment manufacturers or distributors with or inside of equipment, and SF_6 returned to site after off-site recycling.

S = sales/disbursements of SF_6. This is the sum of all the SF_6 sold or otherwise disbursed to other entities during the year either in storage containers or in equipment, including SF_6 returned to suppliers, SF_6 sent off-site for recycling, and SF_6 that is destroyed.

C = Change in total nameplate capacity of equipment (Nameplate Capacity of New Equipment – Nameplate Capacity of Retiring Equipment). This is the net increase in the total volume of SF_6-using equipment during the year. Note that "total nameplate capacity" refers to the full and proper charge of the equipment rather than to the actual charge, which may reflect leakage. This term accounts for the fact that if new equipment is purchased, the SF_6 that is used to charge that new equipment should not be counted as an emission. On the other hand, it also accounts for the fact that if the amount of SF_6 recovered from retiring equipment is less than the nameplate capacity, then the difference between the nameplate capacity and the recovered amount has been emitted.

E.6 HCFC-22 Production (HFC-23 Emissions)

Direct Process HFC-23 Emissions from HCFC-22 Production

Tier	Method	Emission Factors
A	Direct measurement, either continuous emissions monitoring or periodic direct measurements	n/a
B	Mass Balance based on process efficiencies	Plant-specific factors
C	Mass Balance based on production data	Default HFC-23 emission factor

Mass Balance Based on Process Efficiencies
Source: IPCC 2006, Equations 3.31 – 3.33 (Tier 2 Method)

$$E_{HFC-23} = EF_{calculated} \bullet P_{HCFC-22} \bullet F_{released}$$

Where:
E_{HFC-23} = by-product HFC-23 emissions from HCFC-22 production, kg
$EF_{calculated}$ = HFC-23 calculated emission factor, kg HFC-23/kg HCFC-22
$P_{HCFC-22}$ = total HCFC-22 production, kg
$F_{released}$ = Fraction of the year that this stream was released to atmosphere untreated, fraction

The calculated emission factor can be calculated from both the carbon efficiency and the fluorine efficiency (equations below). The value used in the above equation should be the average of these two values.

$$EF_{carbon_balance} = \frac{(100 - CBE)}{100} \bullet F_{efficiency\ loss} \bullet FCC$$

Where:
$EF_{carbon_balance}$ = HFC-23 emission factor calculated from carbon balance efficiency, kg HFC-23/kg HCFC-22
CBE = carbon balance efficiency, percent
$F_{efficiency\ loss}$ = factor to assign efficiency loss to HFC-23, fraction
FCC = factor for the carbon content of this component (= 0.81), kg HFC-23/kg HCFC-22

$$EF_{fluorine_balance} = \frac{(100 - FBE)}{100} \bullet F_{efficiency\ loss} \bullet FFC$$

Where:
$EF_{fluorine_balance}$ = HFC-23 emission factor calculated from fluorine balance efficiency, kg HFC-23/kg HCFC-22
FBE = fluorine balance efficiency, percent
$F_{efficiency\ loss}$ = factor to assign efficiency loss to HFC-23, fraction
FFC = factor for the fluorine content of this component (= 0.54), kg HFC-23/kg HCFC-22

Mass Balance Based on Production Data
Source: WRI/WBCSD, *Calculating HFC-23 Emissions from the Production of HCFC-22*, 2001.

HFC-23 Emissions = (HCFC-22 Production x HFC-23 Emission Factor) x (1 - Fraction Abated x Utilization Factor)

Where:
HCFC-22 Production - total amount of HCFC-22 produced by the facility in metric tons
HFC-23 Emission Factor – EF from HCFC-22 production (metric tons of HFC-23/metric ton of HCFC-22 produced)
Fraction Abated (%) – percent of emissions abated by reduction technologies and practices (if applicable)
Utilization Factor (%) – percent of time the abatement technology was in use (if applicable)

Default Emission Factors
Source: IPCC 2006, Table 3.28

HFC-23 Emission Factor (kg HFC-23/kg HCFC-22 produced) by Type	
Old, un-optimized plants (e.g., 1940s to 1995)	0.04
Plants of recent design, not specifically optimized	0.03

E.7 Iron and Steel Production (CO_2 Emissions)

Direct Process CO_2 Emissions from Iron and Steel Production

Tier	Method	Emission Factors
A	Mass Balance	Plant-specific carbon content factors
B	Mass Balance	Default carbon content factors (IPCC Table 4.3)

Mass Balance Method
Source: IPCC 2006 Equations 4.9 – 4.11 (Tier 2/3 Method)

$$\text{Process } CO_2 \text{ Emissions} = CO_{2\,(\text{Iron \& Steel Prod})} + CO_{2\,(\text{Sinter Prod})} + CO_{2\,(\text{Direct Reduced Iron Prod})}$$

EQUATION 4.9
CO_2 EMISSIONS FROM IRON & STEEL PRODUCTION (TIER 2)

$$E_{CO2,non-energy} = \left[PC \bullet C_{PC} + \sum_a (COB_a \bullet C_a) + CI \bullet C_{CI} + L \bullet C_L + D \bullet C_D + CE \bullet C_{CE} + \sum_b (O_b \bullet C_b) + COG \bullet C_{COG} - S \bullet C_S - IP \bullet C_{IP} - BG \bullet C_{BG} \right] \bullet \frac{44}{12}$$

Where:
$E_{CO2,\ non\text{-}energy}$ = process emissions of CO_2, metric tons
PC = quantity of coke consumed in iron and steel production (not including sinter production), metric tons
COB_a = quantity of onsite coke oven by-product *a*, consumed in blast furnace, metric tons
CI= quantity of coal directly injected into blast furnace, metric tons
L = quantity of limestone consumed in iron and steel production, metric tons
D = quantity of dolomite consumed in iron and steel production, metric tons
CE = quantity of carbon electrodes consumed in EAFs, metric tons
O_b = quantity of other carbonaceous and process material *b*, consumed in iron and steel production, such as sinter or waste plastic, metric tons
COG= quantity of coke oven gas consumed in blast furnace in iron and steel production, m^3 (or other unit such as metric tons or GJ)
S = quantity of steel produced, metric tons
IP = quantity of iron production not converted to steel, metric tons
BG = quantity of blast furnace gas transferred offsite, m^3 (or other unit such as metric tons or GJ)
C_x = carbon content of material input or output *x*, metric tons C/(unit for material *x*) [e.g., metric tons C/ metric ton]

EQUATION 4.10
CO_2 EMISSIONS FROM SINTER PRODUCTION (TIER 2)

$$E_{CO2,non-energy} = \left[CBR \bullet C_{CBR} + COG \bullet C_{COG} + BG \bullet C_{BG} + \sum_a (PM_a \bullet C_a) - SOG \bullet C_{SOG} \right] \bullet \frac{44}{12}$$

Where:
$E_{CO2,\ non\text{-}energy}$ = process emissions of CO_2, metric tons
CBR = quantity of purchased and onsite produced coke breeze used for sinter production, metric tons
COG= quantity of coke oven gas consumed in blast furnace in sinter production, m^3 (or other unit such as metric tons or GJ)
BG = quantity of blast furnace gas consumed in sinter production, m^3 (or other unit such as metric tons or GJ)
PM_a = quantity of other process material *a*, other than those listed as separate terms, such as natural gas and fuel oil, consumed for coke and sinter production in integrated coke production and iron an steel production facilities, metric tons

SOG = quantity of sinter off gas transferred offsite either to iron and steel production facilities or other facilities, m^3 (or other unit such as metric tons or GJ)
C_x = carbon content of material input or output *x*, metric tons C/(unit for material *x*) [e.g., metric tons C/ metric ton]

EQUATION 4.11
CO_2 EMISSIONS FROM DIRECT REDUCED IRON PRODUCTION (TIER 2)

$$E_{CO2,non-energy} = \left(DRI_{NG} \bullet C_{NG} + DRI_{BZ} \bullet C_{BZ} + DRI_{CK} \bullet C_{CK}\right) \bullet \frac{44}{12}$$

Where:
$E_{CO2, non-energy}$ = process emissions of CO_2, metric tons
DRI_{NG} = amount of natural gas used in direct reduced iron production, GJ
DRI_{BZ} = amount of coke breeze used in direct reduced iron production, GJ
DRI_{CK} = amount of metallurgical coke used in direct reduced iron production, GJ
C_{NG} = carbon content of natural gas, metric tons C/GJ
C_{BZ} = carbon content of coke breeze, metric tons C/GJ
C_{CK} = carbon content of metallurgical coke, metric tons C/GJ

Default Emission Factors
Source: IPCC 2006

TABLE 4.3
TIER 2 MATERIAL-SPECIFIC CARBON CONTENTS FOR IRON & STEEL AND COKE PRODUCTION (kg C/kg)

Process Materials	Carbon Content
Blast Furnace Gas	0.17
Charcoal*	0.91
Coal[1]	0.67
Coal Tar	0.62
Coke	0.83
Coke Oven Gas	0.47
Coking Coal	0.73
Direct Reduced Iron (DRI)	0.02
Dolomite	0.13
EAF Carbon Electrodes[2]	0.82
EAF Charge Carbon[3]	0.83
Fuel Oil[4]	0.86
Gas Coke	0.83
Hot Briquetted Iron	0.02
Limestone	0.12
Natural Gas	0.73
Oxygen Steel Furnace Gas	0.35
Petroleum Coke	0.87
Purchased Pig Iron	0.04
Scrap Iron	0.04
Steel	0.01

Source: Default values are consistent with the those provided in Vol 2 and have been calculated with the assumptions below. Complete references for carbon content data are included in Table 1.2 and 1.3 in Volume 2, Chapter 1.

Notes:

[1] Assumed other bituminous coal

[2] Assumed 80 percent petroleum coke and 20 percent coal tar

[3] Assumed coke oven coke

[4] Assumed gas/diesel fuel

* The amount of CO_2 emissions from charcoal can be calculated by using this carbon content value, but it should be reported as zero in national greenhouse gas inventories. (See Section 1.2 of Volume 1.)

E.8 Lime Production (CO_2 Emissions)

Direct Process CO_2 Emissions from Lime Production

Tier	Method	Emission Factors
A1	Mass balance based on carbonate inputs	Plant-specific factors
A2	Mass balance based on production	Plant-specific factors • Measured CaO and MgO content factors • Measured correction factor for LKD • Measured correction factor for hydrated lime
B	Mass balance based on carbonate inputs	Default factors • Fi = 1.00 • Fd = 1.00 • EFd = emission factor for calcium carbonate • Cd = the calcium carbonate ratio in the raw material feed to the kiln
C	Mass balance based on production	Default factors • Default CaO and MgO content factors • Default inputs to correction factor for LKD • Default correction factor for hydrated lime, 0.97

Mass Balance Based on Carbonate Inputs
IPCC 2006 Equation 2.7 (Tier 3: Emissions Based on Carbonate Inputs)

$$CO_2\ Emissions = \sum_i (EF_i \bullet M_i \bullet F_i) - M_d \bullet C_d \bullet (1 - F_d) \bullet EF_d$$

Where:
CO_2 Emissions = emissions of CO_2 from lime production, metric tons
EF_i = emission factor for carbonate *i*, metric tons CO_2/ metric ton carbonate (see Table 2.1)
M_i = weight or mass of carbonate i consumed, metric tons
F_i = fraction calcination achieved for carbonate *i*, fraction
M_d = weight or mass of LKD, metric tons
C_d = weight fraction of original carbonate in the LKD, fraction. This factor can be accounted for in a similar way as CKD from cement manufacturing.
F_d = fraction calcination achieved for LKD, fraction
EF_d = emission factor for the uncalcined carbonate in LKD, metric tons CO_2/ metric ton carbonate

Mass Balance Based on Production
IPCC 2006 Equations 2.6 (Tier 2: Emissions Based on National Lime Production Data by Type), 2.9 (Tier 2 Emission Factors for Lime Production), and 2.5 (Correction Factor for CKD Not Recycled to the Kiln). IPCC Equation 2.5 has been modified to be applicable to lime production, following the recommendation of the 2006 IPCC guidelines.

$$CO_2\ Emissions = \sum_i (EF_{lime,i} \bullet M_{l,i} \bullet CF_{lkd,i} \bullet C_{h,i})$$

Where:

CO_2 Emissions = emissions of CO_2 from lime production, metric tons
$EF_{lime,i}$ = emission factor for lime of type *i*, metric tons CO_2/tonne lime
$M_{l,i}$ = lime production of type *i*, metric tons
$CF_{lkd,i}$ = correction factor for LKD for lime of type *i*, dimensionless
$C_{h,i}$ = correction factor for hydrated lime of the type *i* of lime, dimensionless
(Calculated as 1 – (x • y) where x is the proportion of hydrated lime and y is the water content in it. Since the vast majority of hydrated lime produced is high-calcium (90 percent), the default values are x=0.10 and y = 0.28 (default water content), resulting in a default correction factor of 0.97)
i = each of the specific lime types listed in Table 2.4

$$EF_{lime,a} = SR_{CaO} \bullet CaO\ Content$$

$$EF_{lime,b} = SR_{CaO \cdot MgO} \bullet CaO \cdot MgO\ Content$$

$$EF_{lime,c} = SR_{CaO} \bullet CaO\ Content$$

Where:
$EF_{lime\ a}$ = emission factor for quicklime (high-calcium lime), metric tons CO_2/tonne lime
$EF_{lime\ b}$ = emission factor for dolomitic lime, metric tons CO_2/ metric ton lime
$EF_{lime\ c}$ = emission factor for hydraulic lime, metric tons CO_2/ metric ton lime
SR_{CaO} = stoichiometric ratio of CO_2 and CaO (see Table 2.4), metric tons CO_2/ metric ton CaO
$SR_{CaO \cdot MgO}$ = stoichiometric ratio of CO_2 and CaO·MgO (see Table 2.4), metric tons CO_2/tonne CaO·MgO
CaO Content = CaO content (see Table 2.4 for default factors), metric tons CaO/ metric ton lime
CaO·MgO Content = CaO·MgO content (see Table 2.4 for default factors), metric tons CaO·MgO/ metric ton lime

$$\boldsymbol{CF_{lkd} = 1 + (M_d / M_l) \times C_d \times F_d}$$

Where:
CF_{lkd} = emissions correction factor for LKD, dimensionless
M_d = weight of LKD not recycled to the kiln, metric tons
M_l = weight of lime produced, metric tons
C_d = fraction of original carbonate in the LKD (i.e., before calcination), fraction*
F_d = fraction calcination of the original carbonate in the LKD, fraction*
* Default values: Assume that the original carbonate is all $CaCO_3$ and that the proportion of original carbonate in the LKD is the same as that in the raw mix kiln feed.

Default Emission Factors
Source: IPCC 2006

TABLE 2.4
BASIC PARAMETERS FOR THE CALCULATION OF EMISSION FACTORS FOR LIME PRODUCTION

Lime Type	Stoichiometric Ratio [tonnes CO_2 per tonne CaO or CaO·MgO] (1)	Range of CaO Content [%]	Range of MgO Content[d] [%]	Default Value for CaO or CaO·MgO Content [fraction] (2)	Default Emission Factor [tonnes CO_2 per tonne lime] (1) • (2)
High-calcium lime[a]	0.785	93-98	0.3-2.5	0.95	0.75
Dolomitic lime[b]	0.913	55-57	38-41	0.95 or 0.85[c]	0.86 or 0.77[c]
Hydraulic lime[b]	0.785	65-92[e]	NA	0.75[e]	0.59

Source:

[a] Miller (1999b) based on ASTM (1996) and Schwarzkopf (1995).

[b] Miller (1999a) based on Boynton (1980).

[c] This value depends on technology used for lime production. The higher value is suggested for developed countries, the lower for developing ones.

[d] There is no exact chemical formula for each type of lime because the chemistry of the lime product is determined by the chemistry of the limestone or dolomite used to manufacture the lime.

[e] Total CaO content (including that in silicate phases).

TABLE 2.1
FORMULAE, FORMULA WEIGHTS, AND CARBON DIOXIDE CONTENTS OF COMMON CARBONATE SPECIES*

Carbonate	Mineral Name(s)	Formula Weight	Emission Factor (tonnes CO_2/tonne carbonate)**
$CaCO_3$	Calcite*** or aragonite	100.0869	0.43971
$MgCO_3$	Magnesite	84.3139	0.52197
$CaMg(CO_3)_2$	Dolomite***	184.4008	0.47732
$FeCO_3$	Siderite	115.8539	0.37987
$Ca(Fe,Mg,Mn)(CO_3)_2$	Ankerite****	185.0225–215.6160	0.40822–0.47572
$MnCO_3$	Rhodochrosite	114.9470	0.38286
Na_2CO_3	Sodium carbonate or soda ash	106.0685	0.41492

Source: CRC Handbook of Chemistry and Physics (2004)

* Final results (i.e., emission estimates) using these data should be rounded to no more than two significant figures.

** The fraction of emitted CO_2 assuming 100 percent calcination; e.g., 1 tonne calcite, if fully calcined, would yield 0.43971 tonnes of CO_2.

*** Calcite is the principal mineral in limestone. Terms like high-magnesium or dolomitic limestones refer to a relatively small substitution of Mg for Ca in the general $CaCO_3$ formula commonly shown for limestone.

**** Formulae weight range shown for ankerite assumes that Fe, Mg, and Mn are present in amounts of at least 1.0 percent.

E.9 Nitric Acid Production (N_2O Emissions)

Direct Process N_2O Emissions from Nitric Acid Production

Tier	Method	Emission Factors
A1	Continuous emissions monitoring	n/a
A2	Mass Balance	Plant-specific factors: • Measured destruction and utilization factors for an abatement technology • Measured N_2O emission factor based on direct measurements
B	Mass Balance	Default N_2O emission factor by technology type from Table 3.3

Mass Balance Method
Source: WRI/WBCSD, *Calculating N_2O Emissions from the Production of Nitric Acid*, 2001 (Consistent with IPCC 2006 Equation 3.6: N_2O Emissions from Nitric Acid Production, Tier 2)

N_2O Emissions = Nitric Acid Production x N_2O Emissions Factor x (1 – N_2O Destruction factor x Abatement system utilization factor)

Where:
N_2O emissions factor = metric tons of N2O / metric tons of nitric acid produced
N_2O destruction factor = fraction of emissions abated by reduction technologies
Abatement system utilization factor = fraction of time the abatement system was in use

Default Emission Factors

Source: IPCC 2006

Note: The default emission factors in Table 3.3 include the impact on emissions of abatement technology where relevant (i.e. for plants with NSCR and plants with process-integrated or tailgas N_2O destruction). If you are using default emission factors from Table 3.3 for plants with these abatement technologies (NSCR or process-integrated or tailgas N_2O destruction), you should use a simplified version of the Mass Balance method that does include the N_2O destruction factor or abatement system utilization factor. In this case, use the equation:

N_2O Emissions = Nitric Acid Production x N_2O Emission Factor.

For plants without abatement technologies (e.g. atmospheric pressure plants (low pressure), medium pressure combustion plants, and high pressure plants), use the full Mass Balance equation above, incorporating an N_2O destruction factor and abatement system utilization factor if applicable.

TABLE 3.3
DEFAULT FACTORS FOR NITRIC ACID PRODUCTION

Production Process	N_2O Emission Factor (relating to 100 percent pure acid)
Plants with NSCR[a] (all processes)	2 kg N_2O/tonne nitric acid ±10%
Plants with process-integrated or tailgas N_2O destruction	2.5 kg N_2O/tonne nitric acid ±10%
Atmospheric pressure plants (low pressure)	5 kg N_2O/tonne nitric acid ±10%
Medium pressure combustion plants	7 kg N_2O/tonne nitric acid ±20%
High pressure plants	9 kg N_2O/tonne nitric acid ±40%

[a]Non-Selective Catalytic Reduction (NSCR).

Source: van Balken (2005).

E.10 Pulp and Paper Production (CO_2 Emissions)

Direct Process CO_2Emissions from Make-Up Carbonates Used in the Pulp Mill

Tier	Method	Emission Factors
A	Mass Balance	Default stoichiometric emission factors

Mass Balance Method
Source: IPCC 2006, Section 2.5 (Consistent with International Council of Forest and Paper Associations (ICFPA), *Calculation Tools for Estimating Greenhouse Gas Emissions from Pulp and Paper Mills*, Version 1.1, 2005, and European Union, *Guidelines for the monitoring and reporting of greenhouse gas emissions*, 2006, Annex XI).

$$CO_2 \text{ emissions} = \sum_i (\text{Carbonate Used}_i \times \text{Emission Factor}_i)$$

Where:
Carbonate Used$_i$ = the amount of carbonate *i* ($CaCO_3$ and Na_2CO_3) used in the pulp mill (metric tons)
Emission Factor$_i$ = the stoichiometric ratio for make-up carbonate *i* (metric tons CO/metric tons $CaCO_3$ and metric tons CO_2/metric tons Na_2CO_3)

Direct Process CO_2Emissions from Limestone or Dolomite Used in Flue Gas Desulfurization Systems

Tier	Method	Emission Factors
A	Mass Balance	Default stoichiometric emission factors

Mass Balance Method
Source: IPCC 2006, Section 2.5

$$CO_2 \text{ emissions} = \sum_i (\text{Carbonate Used}_i \times \text{Emission Factor}_i)$$

Where:
Carbonate Used$_i$ = the amount of carbonate *i* (limestone or dolomite) consumed in the flue gas desulfurization system (tonnes)
Emission Factor$_i$ = the stoichiometric ratio for carbonate *i* (metric tons CO_2/metric ton limestone and metric tons CO_2/metric ton dolomite)

Default Emission Factors for Pulp and Paper Production
Source: IPCC 2006

TABLE 2.1
FORMULAE, FORMULA WEIGHTS, AND CARBON DIOXIDE CONTENTS OF COMMON CARBONATE SPECIES*

Carbonate	Mineral Name(s)	Formula Weight	Emission Factor (tonnes CO_2/tonne carbonate)**
$CaCO_3$	Calcite*** or aragonite	100.0869	0.43971
$MgCO_3$	Magnesite	84.3139	0.52197
$CaMg(CO_3)_2$	Dolomite***	184.4008	0.47732
$FeCO_3$	Siderite	115.8539	0.37987
$Ca(Fe,Mg,Mn)(CO_3)_2$	Ankerite****	185.0225–215.6160	0.40822–0.47572
$MnCO_3$	Rhodochrosite	114.9470	0.38286
Na_2CO_3	Sodium carbonate or soda ash	106.0685	0.41492

Source: CRC Handbook of Chemistry and Physics (2004)

* Final results (i.e., emission estimates) using these data should be rounded to no more than two significant figures.

** The fraction of emitted CO_2 assuming 100 percent calcination; e.g., 1 tonne calcite, if fully calcined, would yield 0.43971 tonnes of CO_2.

*** Calcite is the principal mineral in limestone. Terms like high-magnesium or dolomitic limestones refer to a relatively small substitution of Mg for Ca in the general $CaCO_3$ formula commonly shown for limestone.

**** Formulae weight range shown for ankerite assumes that Fe, Mg, and Mn are present in amounts of at least 1.0 percent.

E.11 Refrigeration and A/C Equipment Manufacturing (HFC and PFC Emissions)

Direct Process HFC and PFC Emissions from Manufacturing Refrigeration and A/C Equipment

Tier	Method	Emission Factors
A	Mass Balance using measured refrigerant data	n/a

Mass Balance Method

Source: WRI/WBCSD, *Calculating HFC and PFC Emissions from the Manufacturing, Installation, Operation and Disposal of Refrigeration & Air-conditioning Equipment* (Version 1.0) 2005, consistent with U.S. EPA Climate Leaders, *Direct HFC and PFC Emissions from Manufacturing Refrigeration and Air Conditioning Units*, 2003

$$\text{Emissions} = \sum_i [(I_{Bi} - I_{Ei} + P_i - S_i) \times GWP_i]$$

Where:

Emissions = Total HFC and PFC emissions from manufacturing refrigeration and A/C equipment, in CO_2-equivalent

I_{Bi} = amount of refrigerant *i* in inventory at the beginning of reporting period (in storage, not equipment)

I_{Ei} = amount of refrigerant *i* in inventory at the end of reporting period (in storage, not equipment)

P_i = Purchases/Acquisitions of Refrigerant *i*. This is the sum of all the refrigerant acquired from other entities during the year, including refrigerant purchased from producers/distributors; refrigerant acquired in either storage containers or equipment; refrigerant returned after off-site reclamation or recycling; and refrigerant returned by equipment users.

S_i = Sales/Disbursements of Refrigerant *i*. This is the sum of all the refrigerant sold or otherwise disbursed to other entities during the year, including refrigerant sold, delivered, or disbursed in storage containers or charged into equipment; refrigerant recovered and sent off-site for recycling, reclamation, or destruction; and refrigerant returned to refrigerant producers.

GWP_i = global warming potential factor for refrigerant *i* from IPCC Second Assessment Report

Global Warming Potentials of Refrigerant Blends

Refrigerant Blend	Global Warming Potential
R-401A	18
R-401B	15
R-401C	21
R-402A	1,680
R-402B	1,064
R-403A	1,400
R-403B	2,730
R-404A	3,260
R-406A	0
R-407A	1,770
R-407B	2,285
R-407C	1,526
R-407D	1,428
R-407E	1,363
R-408A	1,944
R-409A	0
R-409B	0
R-410A	1,725
R-410B	1,833
R-411A	15
R-411B	4
R-412A	350
R-413A	1,774
R-414A	0
R-414B	0
R-415A	25
R-415B	105
R-416A	767
R-417A	1,955
R-418A	4
R-419A	2,403
R-420A	1,144
R-500	37
R-501	0
R-502	0
R-503	4,692
R-504	313
R-505	0
R-506	0
R-507 or R-507A	3,300
R-508A	10,175
R-508B	10,350
R-509 or R-509A	3,920
Source: ASHRAE Standard 34	

E.12 Semiconductor Manufacturing (PFC and SF_6 Emissions)

Direct Process PFC and SF_6 Emissions from Plasma Etching and Chemical Vapor Deposition (CVD)

Tier	Method	Emission Factors
A	Mass Balance Using Process-Specific Parameters	Plant-specific factors: • For each parameter used in Equations 6.7 – 6.11 for each individual process • 'p' in the equations is a specific 'process' (e.g., silicon nitride etching or plasma enhanced chemical vapor deposition (PECVD) tool chamber cleaning), not a 'process type' (e.g. etching vs. CVD chamber cleaning)
B	Mass Balance Using Process Type-Specific Parameters	Plant-specific factors: • For each parameter used in Equations 6.7 – 6.11 for each process type • 'p' in the equations is a 'process type' (etching vs. CVD chamber cleaning)
C	Mass Balance Using Process Type-Specific Parameters	Default factors: Industry-wide default values used for any or all of the following parameters: • h = 0.10 • Ui,p (IPCC Table 6.3, Tier 2b) • BCF4,i,p, BC2F6,i,p, BC3F8,i,p (IPCC Table 6.3, Tier 2b) • di,p, dCF4,p, dC2F6,p, dCHF3,p and dC3F8,p (IPCC Table 6.6) • ai,p = 0 (unless emission control technologies are installed)

Mass Balance Method
Source: IPCC 2006, Equations 6.7 - 6.11 (Tier 2b and 3)

Total Emissions of Gas *i* = $E_i + BPE_{CF4,i} + BPE_{C2F6,i} + BPE_{CHF3,i} + BPE_{C3F8,i}$

EQUATION 6.7
TIER 2b METHOD FOR ESTIMATION OF FC EMISSIONS

$$E_i = (1-h) \bullet \sum_p \left[FC_{i,p} \bullet (1-U_{i,p}) \bullet (1-a_{i,p} \bullet d_{i,p}) \right]$$

Where:
E_i = emissions of gas *i*, kg
p = process or process type
$FC_{i,p}$ = mass of gas *i* fed into process or process type *p* (e.g., CF_4, C_2F_6, C_3F_8, c-C_4F_8, c-C_4F_8O, C_4F_6, C_5F_8, CHF_3, CH_2F_2, NF_3, SF_6), kg
h = fraction of gas remaining in shipping container (heel) after use, fraction
$U_{i,p}$= use rate for each gas *i* and process or process type *p* (fraction destroyed or transformed), fraction
$a_{i,p}$ = fraction of gas *i* volume fed into process or process type *p* with emission control technologies, fraction

$d_{i,p}$ = fraction of gas *i* destroyed by the emission control technology used in process or process type *p* (If more than one emission control technology is used in process or process type *p*, this is the average of the fraction destroyed by those emission control technologies, where each fraction is weighted by the quantity of gas fed into tools using that technology), fraction

EQUATION 6.8
BY-PRODUCT EMISSIONS OF CF_4

$$BPE_{CF4,i} = (1-h) \bullet \sum_{p} \left[B_{CF4,i,p} \bullet FC_{i,p} \bullet \left(1 - a_{i,p} \bullet d_{CF4,p}\right) \right]$$

Where:

$BPE_{CF4,i}$ = by-product emissions of CF_4 converted from the gas *i* used, kg

$B_{CF4,i,p}$ = emission factor for by-product emissions of CF_4 converted from gas *i* in process or process type *p*, kg CF_4 created/kg gas *i* used

$d_{CF4,p}$ = fraction of CF_4 by-product destroyed by the emission control technology used in process or process type *p* (e.g., control technology type listed in Table 6.6), fraction

EQUATION 6.9
BY-PRODUCT EMISSIONS OF C_2F_6

$$BPE_{C2F6,i} = (1-h) \bullet \sum_{p} \left[B_{C2F6,i,p} \bullet FC_{i,p} \bullet \left(1 - a_{i,p} \bullet d_{C2F6,p}\right) \right]$$

Where:

$BPE_{C2F6,i}$ = by-product emissions of C_2F_6 converted from the gas *i* used, kg

$B_{C2F6,i,p}$ = emission factor for by-product emissions of C_2F_6 converted from gas *i* in process or process type *p*, kg C_2F_6 created/kg gas *i* used

$d_{C2F6,p}$ = fraction of C_2F_6 by-product destroyed by the emission control technology used in process or process type *p* (e.g., control technology type listed in Table 6.6), fraction

EQUATION 6.10
BY-PRODUCT EMISSIONS OF CHF_3

$$BPE_{CHF3,i} = (1-h) \bullet \sum_{p} \left[B_{CHF3,i,p} \bullet FC_{i,p} \bullet \left(1 - a_{i,p} \bullet d_{CHF3,p}\right) \right]$$

Where:

$BPE_{CHF3,i}$ = by-product emissions of CHF_3 converted from the gas *i* used, kg

$B_{CHF3,i,p}$ = emission factor for by-product emissions of CHF_3 converted from gas *i* in process or process type *p*, kg CHF_3 created/kg gas *i* used

$d_{CHF3,p}$ = fraction of CHF_3 by-product destroyed by the emission control technology used in process or process type *p* (e.g., control technology type listed in Table 6.6), fraction

EQUATION 6.11
BY-PRODUCT EMISSIONS OF C_3F_8

$$BPE_{C3F8,i} = (1-h) \bullet \sum_{p} \left[B_{C3F8,i,p} \bullet FC_{i,p} \bullet \left(1 - a_{i,p} \bullet d_{C3F8,p}\right) \right]$$

Where:

$BPE_{C3F8,i}$ = by-product emissions of C_3F_8 from the gas *i* used, kg

$B_{C3F8,i,p}$ = emission factor for by-product emissions of C_3F_8 converted from gas *i* in process or process type *p*, kg C_3F_8 created/kg gas *i* used

$d_{C3F8,p}$ = fraction of C_3F_8 by-product destroyed by the emission control technology used in process or process type *p* (e.g., control technology type listed in Table 6.6), fraction

Default Emission Factors

Source: IPCC 2006

TABLE 6.6
TIER 2a & 2b DEFAULT EFFICIENCY PARAMETERS FOR ELECTRONICS INDUSTRY FC EMISSION REDUCTION TECHNOLOGIES[a,b,e]

Emission Control Technology	CF_4	C_2F_6	CHF_3	C_3F_8	c-C_4F_8	NF_3[f]	SF_6
Destruction[c]	0.9	0.9	0.9	0.9	0.9	0.95	0.9
Capture/Recovery[d]	0.75	0.9	0.9	NT	NT	NT	0.9

[a] Values are simple (unweighted) averages of destruction efficiencies for all abatement technologies. Emission factors do not apply to emission control technologies which cannot abate CF_4 at destruction or removal efficiency (DRE) ≥ 85 percent when CF_4 is present as an input gas or by-product and all other FC gases at DRE ≥ 90 percent. If manufacturers use any other type of emission control technology, its destruction efficiency is 0 percent when using the Tier 2 methods.

[b] Tier 2 emission control technology factors are applicable only to electrically heated, fuelled-combustion, plasma, and catalytic devices that

- are specifically designed to abate FCs,
- are used within the manufacturer's specified process window and in accordance with specified maintenance schedules and
- have been measured and has been confirmed under actual process conditions, using a technically sound protocol, which accounts for known measurement errors including, for example, CF_4 by-product formation during C_2F_6 as well as the effect of dilution, the use of oxygen or both in combustion abatement systems

[c] Average values for fuelled combustion, plasma, and catalytic abatement technologies.

[d] Average values for cryogenic and membrane capture and recovery technologies.

[e] Vendor data verified by semiconductor manufacturers. Factors should only be used when an emission control technology is being utilised and maintained in accordance with abatement manufacturer specifications.

[f] Use of NF_3 in the etch process is typically small compared to CVD. The aggregate emissions of NF_3 from etch and CVD under Tier 2b will usually not be greater than estimates made with Tier 2a or Tier 1 methods.

NT = not tested.

TABLE 6.3
TIER 2 DEFAULT EMISSION FACTORS FOR FC EMISSIONS FROM SEMICONDUCTOR MANUFACTURING

	Greenhouse Gases with TAR GWP									Greenhouse Gases without TAR GWP			Non-GHGs Producing FC By-products[‡]	
Process Gas (i)	CF_4	C_2F_6	CHF_3	CH_2F_2	C_3F_8	c-C_4F_8	NF_3 Remote	NF_3	SF_6	C_4F_6	C_5F_8	C_4F_8O	F_2	COF_2
Tier 2a														
1-Ui	0.9	0.6	0.4	0.1	0.4	0.1	0.02	0.2	0.2	0.1	0.1	0.1	NA	NA
B_{CF4}	NA	0.2	0.07	0.08	0.1	0.1	0.02[†]	0.09	NA	0.3	0.1	0.1	0.02[†]	0.02[†]
B_{C2F6}	NA	NA	NA	NA	NA	0.1	NA	NA	NA	0.2	0.04	NA	NA	NA
B_{C3F8}	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.04	NA	NA
Tier 2b														
Etch 1-Ui	0.7[*]	0.4[*]	0.4[*]	0.06[*]	NA	0.2[*]	NA	0.2	0.2	0.1	0.2	NA	NA	NA
CVD 1-Ui	0.9	0.6	NA	NA	0.4	0.1	0.02	0.2	NA	NA	0.1	0.1	NA	NA
Etch B_{CF4}	NA	0.4[*]	0.07[*]	0.08[*]	NA	0.2	NA	NA	NA	0.3[*]	0.2	NA	NA	NA
Etch B_{C2F6}	NA	NA	NA	NA	NA	0.2	NA	NA	NA	0.2[*]	0.2	NA	NA	NA
CVD B_{CF4}	NA	0.1	NA	NA	0.1	0.1	0.02[†]	0.1[†]	NA	NA	0.1	0.1	0.02[†]	0.02[†]
CVD B_{C2F6}	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
CVD B_{C3F8}	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.04	NA	NA

Notes: NA denotes not applicable based on currently available information

[‡] The default emission factors for F_2 and COF_2 may be applied to cleaning low-k CVD reactors with ClF_3.

[*] Estimate includes multi-gas etch processes

[†] Estimate reflects presence of low-k, carbide and multi-gas etch processes that may contain a C-containing FC additive

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