



**THE CLIMATE
REGISTRY**

**GENERAL REPORTING
PROTOCOL**

VERSION 3.0

MAY 2019

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ABBREVIATIONS AND ACRONYMS

GLOSSARY OF TERMS

A. INTRODUCTION

ABOUT THE CLIMATE REGISTRY

The Climate Registry (TCR) designs and operates voluntary and compliance greenhouse gas (GHG) reporting programs globally, and assists organizations in measuring, reporting, and verifying (MRV) the carbon in their operations in order to manage and reduce it. TCR also consults with governments nationally and internationally on all aspects of GHG measurement, reporting, and verification.

TCR's Carbon Footprint Registry is aligned with international standards and provides a nexus between business, government, and non-governmental organizations to share policy information and exchange best practices.

For more information, please visit:
www.theclimateregistry.org.



About This Document

The Climate Registry's General Reporting Protocol (GRP) Version 3.0 outlines GHG accounting policies and calculation methods for reporting an organizational carbon footprint, or GHG inventory. The GRP was developed through a comprehensive public stakeholder process that included over 1,275 individual comments from 124 respondents representing industry, environmental non-governmental organizations, regulatory agencies, and consulting firms.

TCR's GRP embodies GHG accounting best practices drawn from the following existing GHG standards and guidance:

- » The World Resources Institute and the World Business Council for Sustainable Development (WRI/WBCSD) GHG Protocol Corporate Accounting and Reporting Standard (Revised Edition);
 - » The GHG Protocol Scope 2 Guidance: An amendment to the GHG Protocol Corporate Standard; and,
 - » The GHG Protocol Corporate Value Chain (Scope 3) Accounting and Reporting Standard: Supplement to the GHG Protocol Corporate Accounting and Reporting Standard.
- » International Organization for Standardization (ISO) 14064-1:2018, Greenhouse Gases – Part 1: Specification with guidance at the organization level for quantification and reporting of greenhouse gas emissions and removals; and,
- » U.S. Environmental Protection Agency Center for Corporate Climate Leadership Greenhouse Gas Inventory Guidance.

GHG Accounting and Reporting Principles

The GRP adheres to five overarching accounting and reporting principles that are intended to help ensure that GHG data represent a faithful, true, and fair account of an organization's GHG emissions. These principles are the basis for the requirements and guidance in the GRP.

- » **Relevance:** Ensure that the GHG inventory appropriately reflects an organization's GHG emissions and serves the decision-making needs of users—both internal and external to the organization.
- » **Completeness:** Account for and report all relevant GHG emissions and activities within the defined inventory boundary.
- » **Consistency:** Use consistent methods to allow for meaningful comparisons of emissions over time. Clearly document any changes to the data, inventory boundary, methods, or any other relevant factors.
- » **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 quantification methods and data sources used to allow intended users to make decisions with reasonable confidence.
- » **Accuracy:** Ensure that the quantification of GHG emissions is neither systematically overstating nor understating true emissions, and that uncertainties are reduced as much as practicable. Achieve sufficient accuracy to enable users of the data to make decisions with reasonable assurance of the integrity of the reported information.

GRP Structure

The GRP is presented as a series of individual topic-specific modules, which may be viewed separately or downloaded together as a combined document. The GRP modules provide the key reporting requirements for TCR's Carbon Footprint Registry and are designed to be used as a set.

The GRP is comprised of the following modules, which mirror the chronology of the reporting process:

Modules	
A.	<u>Introduction</u> (this module) <i>Provides an overview of the GRP.</i>
B.	<u>Inventory Boundaries</u> <i>Outlines the GHGs and types of GHG sources that may be included in the inventory, provides requirements for defining organizational and reporting boundaries, and describes various levels of granularity at which emissions data may be publicly reported.</i>
C.	<u>GHG Emissions Quantification Methods</u> <i>Provides methods for quantifying emissions for the following source categories:</i> <ul style="list-style-type: none">» <i>Direct emissions from stationary combustion;</i>» <i>Direct emissions from mobile combustion;</i>» <i>Indirect emissions from non-electric energy use; and,</i>» <i>Direct fugitive emissions.</i>
D.	<u>Advanced Methods</u> <i>Provides advanced methods for quantifying emissions. References to advanced methods are available throughout the GHG Emissions Quantification Methods Module.</i>
E.	<u>Reporting an Inventory</u> <i>Provides additional required and optional information to include alongside GHG emissions quantification to complete and report a GHG inventory.</i>

All GRP modules are available to download at www.theclimateregistry.org.

Additional sector-specific protocols and metrics are available for certain sectors at www.theclimateregistry.org and contain additional methods and requirements to the GRP. Supplemental guidance documents will provide further examples, background material, or tips for reporting. Members should report emissions to the Carbon Footprint Registry following a step-wise reporting process, starting with the GRP, progressing to sector-specific protocols and metrics if relevant, and referring to guidance documents as needed.

Updates to the GRP

TCR may update this document in the future to reflect changes in international best practices and to provide additional clarity and guidance.

Updates to the GRP will be incorporated into the relevant GRP module(s) as needed. TCR will inform stakeholders of changes to the GRP in a timely manner, and will provide explicit direction for when new reporting and verification policies or procedures will be required.



B. INVENTORY BOUNDARIES

DEFINING OPERATIONS

The greenhouse gas (GHG) emitting activities within an inventory are based on the intersection of the selected organizational boundary and reporting boundary as defined below. While an organizational boundary encompasses all of an organization's business activities, organizations may define their own reporting boundary to include all activities (matching the organizational boundary), or a subset of activities.

Organizational Boundaries

Businesses, government agencies and non-profits can utilize a range of organizational structures to define the degree of ownership or control they exert over different activities. Some examples of these structures include wholly owned operations, divisions, subsidiaries and joint ventures. When added together, the activities within these structures define the organizational boundary.

GHG emissions inventories can be constructed to reflect three different views of an organizational boundary: operational control, financial control, or equity share.

- » **Operational Control:** Reflects the activities where the organization or its subsidiaries has the full authority to introduce and implement operating policies. The organization that holds the operating license for an activity typically has operational control.
- » **Financial Control:** Reflects activities where the organization has the ability to direct the financial policies of the activity with an interest in gaining economic benefits from the activity. An organization has financial control over an activity if the activity is fully consolidated in the organization's financial accounts.
- » **Equity Share:** Reflects activities that are wholly owned and partially owned according to the organization's equity share in each.

Organizations must apply the same organizational boundary approach consistently to all activities. If an organization wholly owns and controls all of its activities, its organizational boundary will be the same using each approach.

Organizations with more complex owner or operator structures should take into account their individual situation and select an approach that best reflects

the actual level of control and the standard practice within the industry. Organizations may also elect to compile separate inventory reports reflecting different approaches.

Operational Control

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

- » Wholly owning and controlling an activity, operation, facility, or source; or,
- » Having the full authority to introduce and implement operational and HSE (including both GHG- and non-GHG related policies). The authority to introduce and implement operational and HSE policies is often explicitly conveyed in the contractual or legal structure of the partnership or joint venture. In most cases, holding an operating license is an indication of the organization's authority to implement operational and HSE policies. If an organization holds an operating license and believes it does not have operational control, it must explicitly demonstrate that the organization's authority to introduce operational and HSE policies is significantly limited or vested with a separate entity.

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

Financial Control

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

- » Wholly owning an activity, operation, facility, or source;
- » Considering an activity to be, for the purposes of financial accounting, a group company or subsidiary, and consolidating its financial accounts in an organization's financial statements;
- » Governing the financial policies of a joint venture under a statute, agreement or contract; or,
- » Retaining the rights to the majority of the economic benefits and/or financial risks from an activity or facility that is part of a joint venture or partnership (incorporated or unincorporated), however these rights are conveyed.¹

Equity Share

Under the equity share approach, an organization accounts for GHG emissions from activities according to its share of equity in each activity.²

The equity share reflects economic interest, which is the extent of rights an organization has to the risks and rewards flowing from an activity. Typically, the share of economic risks and rewards in an activity is aligned with the organization's ownership percentage of that activity, 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 organization has with the activity always overrides the legal ownership form to ensure that equity share reflects the percentage of economic interest.

1 These rights may be evident through the traditional conveyance of equity interest or working/participating interest or through nontraditional arrangements. The latter could include an 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.

2 Organizations need not include emissions from fixed asset investments, where the parent company has neither significant influence nor financial control.

Reporting Boundaries

Organizations may define their own reporting boundary to include the GHG sources that are relevant to their operational and sustainability goals in accordance with the principles of GHG accounting. The reporting boundary may match the organizational boundary (i.e., all the emission sources within the organizational boundary are included), or may be a subset of the organizational boundary.

Organizations must publicly define and disclose their own inventory reporting boundary using the following parameters, which are described in the following sections:

- » GHGs;
- » GHG Sources;
- » Reporting Period; and,
- » Geography/business units.

GEOGRAPHY

Organizations may use geography as a parameter in defining their reporting boundary. For example, organizations can choose to include specific countries, states, provinces or territories in their reporting boundary. Similarly, parameters can include specific business units or facilities. When organizations are defining their reporting boundary to include a subset of facilities in their operational boundary, they must disclose any facilities that are excluded from the reporting boundary. Members will make this disclosure in the *Self-Defined Boundary Form*.

RELEVANT GHG SOURCES

To fulfill the GHG accounting principle of completeness, the inventory must include all relevant direct and indirect emissions within the defined reporting boundary. For the purposes of reporting to The Climate Registry (TCR), all Scope 1 and Scope 2 emissions, combustion-based direct biogenic emissions, and combustion-based indirect biogenic emissions associated with the consumption of energy are relevant³, and must be included within the reporting boundary for TCR to consider the inventory “complete.”

However, all members reporting to TCR have the flexibility to define their reporting boundary to report specific GHG sources that they deem relevant to their individual business and sustainability goals. Thus, members may decide that some sources deemed relevant by TCR are not relevant for their organization, or that additional sources beyond TCR’s criteria are relevant for their organization. Members reporting in conformance with TCR’s program that exclude GHG sources that TCR has defined as relevant from the reporting boundary must identify the excluded sources and explain the reason for their exclusion.⁴

Members may also refer to TCR’s guidance on conforming to ISO 14064-1: 2018 and the GHG Protocol if they are seeking to conform to these standards.

³ TCR does not consider the following emission sources relevant: approved miniscule sources, biogenic emissions other than those associated with the combustion of biomass, and emission sources identified as optional in the protocols.

⁴ TCR provides an explanation for the exclusion of miniscule sources included on the *Exclude Miniscule Sources Form*.

GREENHOUSE GASES (GHGs)

Organizations may define their reporting boundary to include all internationally-recognized GHGs regulated under the Kyoto Protocol, or a subset of these gases. These are:

- » Carbon dioxide (CO₂);
- » Methane (CH₄);
- » Nitrous oxide (N₂O);
- » Hydrofluorocarbons (HFCs);
- » Perfluorocarbons (PFCs);
- » Sulfur hexafluoride (SF₆); and,
- » Nitrogen trifluoride (NF₃).

Organizations must disclose whether they are excluding any of the gases above from the reporting boundary. Members will make this disclosure in the *Self-Defined Boundary Form*.

A complete list of the Kyoto GHGs, including individual HFCs and PFCs, is provided in Tables 5.1 and 5.2.⁵

Organizations must account for emissions of each gas separately, in metric tons of each gas.⁶

Reporting Emissions in Carbon Dioxide Equivalent (CO₂e)

In addition to reporting GHG emissions by gas, organizations must also report emissions from non-CO₂ gases in units of carbon dioxide equivalent (CO₂e). Converting emissions of non-CO₂ gases to units of CO₂e allows the ability of each GHG to trap heat in the atmosphere to be compared on a common basis.

Tables 5.1 and 5.2 include the Global Warming Potential (GWP) of each GHG, which is used to calculate the carbon dioxide equivalent of the individual gases.^{7,8} GWP factors represent how much heat each GHG is able to trap in the atmosphere relative to the heat-trapping ability of CO₂.

GWP defaults are published by the Intergovernmental Panel on Climate Change (IPCC.) As part of its activities, the IPCC revisits and updates these defaults in periodic Assessment Reports. Organizations may use GWPs from the Assessment Report that is most relevant to their operations providing the following conditions are met:

1. All GWPs must be 100 year values;
2. Where possible within an inventory, all GWPs must come from a single Assessment Report. If a GWP for a particular gas is not provided in the chosen Assessment Report, organizations must select the more recent GWP for that gas; and,
3. The source of all GWP values must be disclosed publicly.⁹

It is best practice to use GWP values from the most recent Assessment Report.¹⁰ However, when a base year has been set, it is best practice to use the same GWP values for the current inventory and the base year inventory.

⁵ Emission factor tables are available at www.theclimateregistry.org.

⁶ Emissions totals of the HFC and PFC categories are reported in metric tons of carbon dioxide equivalents (CO₂e) of each respective category.

⁷ Ibid.

⁸ Emission factor tables are available at www.theclimateregistry.org.

⁹ Organizations must also publicly disclose whether GWPs from multiple Assessment Reports have been used.

¹⁰ Organizations that select a GWP that is not from the most recent Assessment Report must justify their selection in order to conform with ISO 14064-1: 2018.

GHG SOURCES

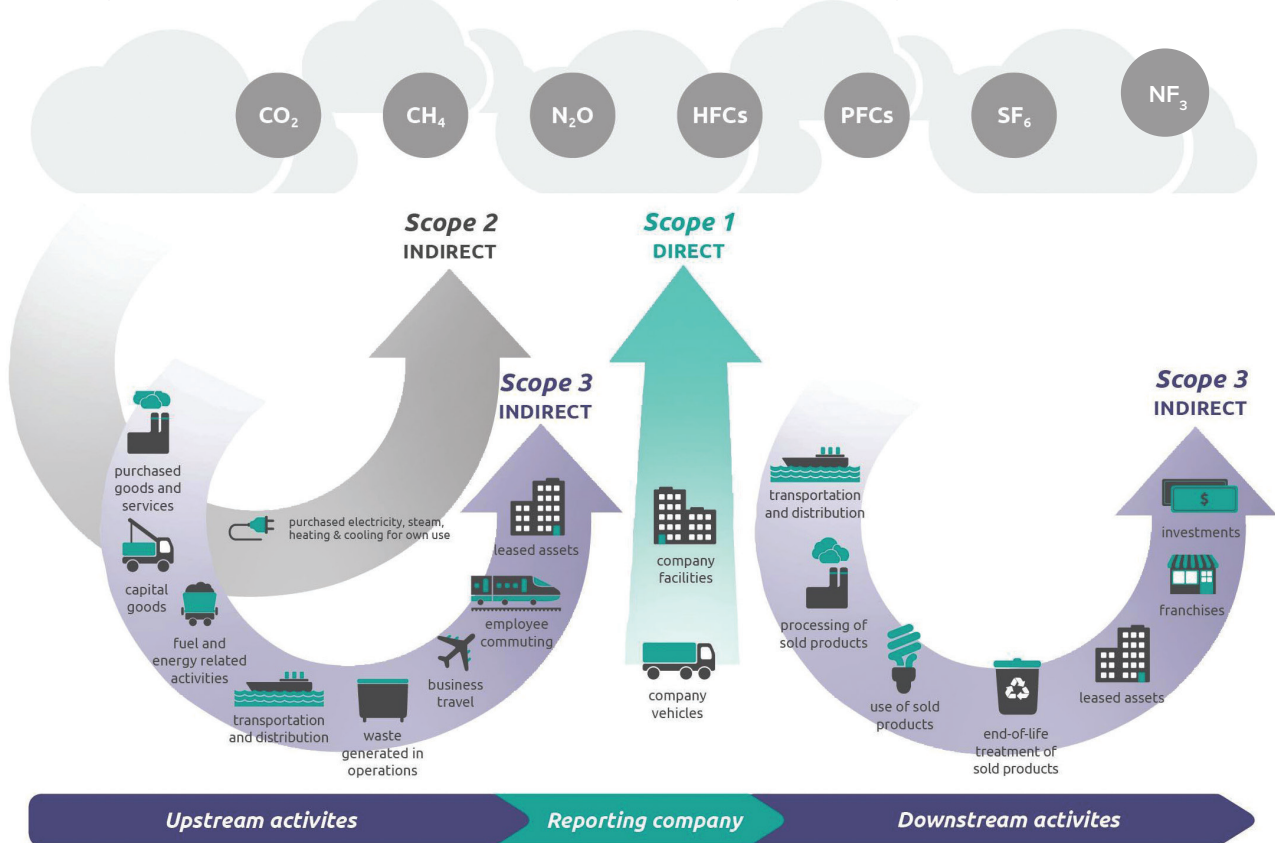
Direct and indirect emissions are categorized as follows:¹¹

- » **Scope 1:** Direct anthropogenic GHG emissions.
- » **Scope 2:** Indirect anthropogenic GHG emissions associated with the consumption of purchased or acquired electricity, steam, heating, or cooling (collectively referred to as consumed energy).
- » **Scope 3:** All other (non-Scope 2) indirect anthropogenic GHG emissions that occur in the value chain.¹²
- » **Additional GHGs:** Biogenic GHG emissions are excluded from the scope categories and are reported separately. Non-Kyoto GHG emissions are also outside of the scopes.

Together these categories provide a comprehensive accounting framework for managing and reducing direct and indirect emissions.

Figure 1 below provides an overview of the relationship between the scopes and the activities that generate direct and indirect emissions along the value chain. An organization reports anthropogenic emissions within its organizational boundary directly in Scope 1, and anthropogenic emissions that result indirectly from its activities in Scope 2 and Scope 3.

Figure 1: Overview of Scopes and Emissions throughout an Organization's Operations



Source: Adapted from WRI/WBCSD GHG Protocol Corporate Value Chain (Scope 3) Accounting and Reporting Standard.

¹¹ Scopes 1, 2, and 3 align with WRI/WBCSD's GHG Protocol Corporate Standard. ISO 14064-1: 2018 categorizes emissions into direct and indirect emissions.

¹² Examples of Scope 3 emissions include emissions resulting from employee commuting and business travel, use of sold products and services, and waste disposal.

Direct Emissions: Scope 1

Direct GHG emissions are emissions from sources within the organizational boundary.

Scope 1 emissions are all direct emissions resulting from the impact of human beings on nature. These generally result from the use of fossil fuels or other man-made chemicals and must be subdivided within the inventory into the four types of sources they result from:

- » **Stationary combustion** of fuels in any stationary equipment including boilers, furnaces, burners, turbines, heaters, incinerators, engines, flares, etc.;
- » **Mobile combustion** of fuels in transportation sources (e.g., cars, trucks, marine vessels and planes) and emissions from non-road equipment such as those 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., intentional or 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 SF₆ from electrical equipment; HFC releases during the use of refrigeration and air conditioning equipment; and CH₄ leakage from natural gas transport or landfills).

Indirect Emissions: Scope 2

Indirect GHG emissions are a consequence of activities that take place within the organizational boundary of the reporting organization, but occur at sources owned or controlled by another organization. For example, emissions that occur at a natural gas power plant as a result of providing electricity to a local manufacturing

company contribute to the manufacturer's indirect emissions. Scope 2 is a special category of indirect emissions and refers only to indirect anthropogenic emissions associated with consumed energy.

Scope 2 emissions are reported in two ways, using the location-based method and the market-based method.

- » The **location-based method** reflects the GHG emissions from locally-generated energy delivered through the grid. It transparently demonstrates local conditions and the impacts of energy conservation.
- » The **market-based method** reflects the GHG emissions associated with choices an organization makes about its energy supply or product. It allows organizations to claim the specific emission rate associated with their energy purchases, as well demonstrate the impacts of energy conservation.¹³

Indirect emissions reported by one organization may also be reported as direct emissions by another. For example, the company that owns and operates the power plant described above would report the emissions resulting from the generation of the electricity it provided to the manufacturing company as its own direct emissions. This dual reporting does not constitute double counting because the organizations report the emissions associated with the electricity production and its consumption in different scopes (Scope 1 for the power provider and Scope 2 for the manufacturing organization). The scope framework allows for a broader assessment of an organization's GHG emissions impact within an inventory, but emissions can only be aggregated meaningfully across organizations *within* a single scope.¹⁴

¹³ Refer to the [GHG Emissions Quantification Module](#), Indirect Emissions from Electricity Use section for more information about using the location-based and market-based methods.

¹⁴ Reporting of direct and indirect biogenic emissions mirrors the scopes framework (e.g., emissions from the combustion of biogas to produce electricity would be reported as direct biogenic emissions for the power generator and indirect biogenic emissions for the power consumer).

Indirect Emissions: Scope 3

Scope 3 is a broad category of indirect emissions that includes all anthropogenic indirect emissions other than emissions associated with consumed energy. Reporting Scope 3 emissions provides opportunities for identifying and reducing emissions across the value chain, and communicating innovation in GHG management. Members are encouraged to report Scope 3 emissions in accordance with the [GHG Protocol Corporate Value Chain \(Scope 3\) Accounting and Reporting Standard](#). TCR provides guidance for calculating sources of Scope 3 emissions in many of our sector-specific resources.

Additional Gases

Emissions from Biomass

Biogenic CO₂ emissions are generated during the combustion or decomposition of biologically-based material. Organizations must track and report biogenic CO₂ emissions separately from other emissions because the carbon in biomass was recently contained in living organic matter. This sets it apart from the carbon in fossil fuels that has been trapped in geologic formations for millennia, the release of which can be attributed directly to human activities.¹⁵

Only combustion-based direct biogenic emissions and combustion-based indirect biogenic emissions associated with the consumption of energy are relevant for the purposes of reporting to TCR, and must be included within the reporting boundary for TCR to consider the inventory “complete.” TCR does not include other biogenic emissions in its definition for relevance due to a lack of scientific consensus around the methods used to quantify these emissions.

The separate reporting of CO₂ emissions from biomass combustion applies only to CO₂ and not to CH₄ and N₂O, which are also emitted during biomass combustion. Unlike CO₂ emissions, the CH₄ and N₂O emitted from biomass combustion are not of a biogenic origin and are therefore classified as Scope 1 or Scope 2 emissions. When biomass is combined with fossil fuel combustion, the biomass-based CH₄ and N₂O emissions should be reported together with fossil-fuel based CH₄ and N₂O emissions.

Non-Kyoto GHGs

Non-Kyoto GHG emissions may be disclosed alongside the inventory, outside the scopes, as part of a separate public document.¹⁶

REPORTING PERIOD

Organizations must disclose the period for which emissions are reported. Members must report emissions on an *annual basis* (i.e., calendar year or fiscal year).¹⁷

The year in which the emissions occurred is known as the reporting year (RY). For example, if an inventory is reported in 2019 for an organization’s 2018 emissions, the reporting year is 2018.

Organizations must include emissions from the activities within their organizational boundary for the part of the year each activity is within its control. For most activities, this will be the total annual emissions from the operation.

¹⁵ Because of this difference, the *IPCC Guidelines for National Greenhouse Gas Inventories* requires that CO₂ emissions from biogenic sources be reported separately.

¹⁶ Organizations seeking to conform with the Greenhouse Gas Protocol Corporate Standard may report non-Kyoto GHGs outside of the inventory provided that the organization includes a list of these gases, and provided that 100-year Global Warming Potential (GWP) values for these GHGs have been defined in IPCC Assessment Reports.

¹⁷ The fiscal year may be defined by the member.

MINISCULE SOURCES

Miniscule sources are very small sources of emissions in a member's inventory that represent a high reporting burden, such as hand-held fire extinguishers, refrigerant in office water coolers, or CO₂ from soda fountains. Miniscule sources should not:

- » Compromise the relevance of the reported inventory;
- » Significantly reduce the combined quantity of Scope 1, Scope 2,¹⁸ and biogenic CO₂e emissions reported;
- » Impact the ability to identify the member's viable opportunities for emissions reduction projects;
- » Impact the ability to ascertain whether the member has achieved a reduction (of five percent or greater) in total entity emissions from one year to the next;
- » Impact the ability to assess the member's climate change-related risk exposure; or,
- » Impact the decision-making needs of users (i.e., is not expected to be deemed critical by key stakeholders).

Whenever possible, members are encouraged to report emissions from miniscule sources using TCR approved methods or Simplified Estimation Methods (SEMs). However, members may opt to exclude miniscule sources from their inventory by completing and publicly disclosing TCR's *Exclude Miniscule Sources Form* for each reporting year.

Sources identified on the form can be excluded without further action. Information on how to request the exclusion of a new miniscule source is available at www.theclimateregistry.org.

CRITERIA ICON



The Criteria Icon identifies criteria that must be met to use a particular quantification method or reporting option.

SEMS ICON



The SEMs Icon identifies emission sources commonly calculated with SEMs and methods that must be reported as SEMs.

¹⁸ The higher Scope 2 total.

DATA GRANULARITY FOR REPORTING TO TCR

Members may enter their GHG data at the source, facility, or entity level in the Climate Registry Information System (CRIS), and choose whether to report publicly at the facility-level or entity-level.¹⁹

Source-Level Reporting

Members are encouraged to report emissions data at the source level, if data is available. Reporting data at this level of granularity is valuable for internal data management and can help streamline verification. Source-level data is not made available publicly through TCR, but members will have access to this information in private reports.

Facility-Level Reporting

Reporting of facility-level information enables tracking of GHG emissions at a disaggregated level, including emission changes associated with discrete business operations or facilities. It is also typically the required reporting boundary for mandatory GHG reporting programs. Emissions information will be presented in public reports at the facility-level by GHG type and source category.²⁰

Entity-Level Reporting

Entity-level reporting provides a public summary of the inventory emissions totals by GHG type and source category. Members may choose to enter pre-calculated entity-wide emissions totals, or may enter facility-level or source-level data, which will be available to the member in private reports.

¹⁹ In public reports, source-level data is aggregated to the facility-level. Members seeking verification must be prepared to provide source-level information for each sampled facility to their verification body upon request.

²⁰ Source categories include stationary combustion, mobile combustion, process emissions, fugitive emissions, Scope 1 purchased electricity, Scope 2 purchased heating, direct combustion-based biogenic emissions, and indirect combustion-based biogenic emissions associated with consumed energy.



C. GHG EMISSIONS QUANTIFICATION METHODS

INTRODUCTION TO QUANTIFYING EMISSIONS

Greenhouse gas (GHG) emissions are quantified using either direct measurement or calculation methods. The selection of a quantification method will depend on the information that is available for each source. Once a method has been chosen, it is best practice to use it year after year to ensure the comparability of emissions data over time.¹

This module provides step-by-step methods to calculate emissions from common activities within the following source categories:²

- » Stationary combustion;³
- » Mobile combustion;
- » Electricity use;
- » Non-electric energy use; and,
- » Fugitive emissions.

Within each section, the most commonly used methods are listed first.

Guidelines for using [Simplified Estimation Methods \(SEMs\)](#) to conservatively calculate emissions from small sources are provided in this module. Additional quantification methods for less common sources are provided in the [Advanced Methods Module](#) and TCR's sector specific protocols. If TCR has not provided guidelines for quantifying emissions from a particular emission source, organizations may use existing international or industry best practice methods, which are published, peer reviewed methods or emission factors.⁴

TCR also accepts GHG emission quantification methods mandated by a state, provincial, or federal GHG reporting program that conform to the principles of corporate GHG accounting.⁵

1 A change in the employed method could trigger a base year recalculation. View the [Tracking Emissions Over Time Guidance](#) for more information on base year recalculation.

2 Refer to the [Inventory Boundaries Module](#) section on GHG sources for descriptions of the types of direct and indirect emissions.

3 Direct measurement methods for stationary combustion are available in the [Advanced Methods Module](#).

4 Emission factors must be gas-specific (i.e., not in units of carbon dioxide equivalent (CO₂e)).

5 Please note: where mandatory requirements exclude certain emission sources, members may quantify emissions from those sources in accordance with TCR's reporting requirements, or may exclude them from the reporting boundary, provided the exclusion is documented and justified.

Calculation-Based Methods

Most organizations will use calculation methods to quantify their GHG emissions. Calculation methods use activity data and emission factors to estimate GHG emissions. Activity data is a measure of a level of activity that results in GHG emissions (e.g., gallons of fuel or kWh of electricity consumed). Emission factors reflect the average GHG intensity per unit of activity data for a given source. Most organizations will use default emission factors to estimate emissions. Organizations may also develop their own site-specific emission factors based on the specific characteristics of the GHG source and fuel or unit of energy consumption.

Calculating emissions from GHG sources generally involves the following six steps:⁶

1. Determine annual consumption of each combusted fuel or annual energy consumption;
2. Determine the CO₂ emission factor for each fuel or unit of energy consumption;
3. Determine CH₄ and N₂O emission factors for each fuel or unit of energy consumption;⁷
4. Calculate CO₂ emissions by multiplying the emission factor by annual fuel or energy consumption;
5. Calculate CH₄ and N₂O emissions by multiplying emission factors by annual fuel or energy consumption;⁸ and,
6. Convert CH₄ and N₂O emissions to CO₂e.

DEFAULT EMISSION FACTORS

Default emission factors may be updated when the attributes of energy (electricity, fuel, etc.) change and as emission factor quantification methods are refined. TCR publishes up-to-date emission factors on an annual basis. Organizations reporting emissions data from previous years must use the most recent emission factors available⁹ when the inventory is being reported, except when quantifying emissions associated with electricity use. For electricity, organizations must use the factor corresponding to the reporting year, or when unavailable, the most recent previous year.^{10 11}

Measurement-Based Methods

Emissions may be measured directly through systems that monitor the concentration of the GHGs and output flow rate. Direct measurement may be relevant to entities with facilities using Continuous Emissions Monitoring System (CEMS), such as power plants, industrial facilities with large stationary combustion units, or landfills with landfill gas collection systems.

+ ADVANCED METHOD

» [Quantifying direct CO₂ emissions with site-specific data](#)

6 Different processes are used to calculate fugitive and process emissions. Guidance on calculating emissions from refrigeration systems is outlined in the section on fugitive emissions.

7 CH₄ and N₂O emissions from mobile combustion are calculated using mileage data rather than fuel consumption data.

8 Ibid.

9 From TCR's annual update or a more recent peer-reviewed publication.

10 The most recent supplier-specific emission factor (meeting [TCR's eligibility criteria for electricity](#)) may be used in lieu of a more recent residual mix or grid-average emission factor to calculate market-based Scope 2 emissions, provided the supplier-specific emission factor is no more than five years older than the most recent residual mix or grid-average emission factor.

11 Members may elect to use eGRID2012 or eGRID2014 for EY 2014 through EY 2016.

Simplified Estimation Methods

Organizations must quantify emissions using TCR-accepted methods. However, in some cases organizations may have difficulty applying these methods to every source within their boundaries—either because it is not possible or not efficient to use them.

Therefore, TCR accepts emissions estimated using simplified methods in certain cases. Members may use Simplified Estimation Methods (SEMs) for any combination of emission sources and/or gases, provided that corresponding emissions do not exceed 10% of the CO₂e sum of reported Scope 1, Scope 2,¹² combustion-based direct biogenic emissions and combustion-based indirect biogenic emissions associated with consumed energy¹³ (hereafter referred to as the 10% SEMs threshold). In developing SEMs, members should follow the principle of conservativeness (i.e., erring on the side of overestimating rather than underestimating emissions). Members must document emissions that have been estimated using SEMs for verification. Refer to the [Accounting for Small Emission Sources Guidance](#) for more information.

DIRECT EMISSIONS FROM STATIONARY COMBUSTION

Stationary combustion refers to the combustion of anthropogenic or biogenic-based fuels or biomass in any stationary equipment.¹⁴ Common large stationary sources exist in power plants, refineries, and manufacturing facilities. Examples of stationary combustion units include boilers, burners, turbines, furnaces, and internal combustion engines.

SEMS ICON



The SEMs Icon identifies emission sources commonly calculated with SEMs and methods that must be reported as SEMs.

10% SEMS THRESHOLD

Emissions calculated with SEMs must not exceed 10% of the CO₂e sum of reported Scope 1, Scope 2, combustion-based direct biogenic emissions and combustion-based indirect biogenic emissions associated with consumed energy.

+ ADVANCED METHODS

- » [Quantifying CO₂ emissions with direct measurement systems](#)
- » [Quantifying biogenic emissions from co-firing units](#)
- » [Quantifying direct CO₂ emissions with measured fuel characteristics](#)
- » [Optional: Allocating emissions from combined heat and power](#)
- » [Eligibility of contractual instruments for renewable fuels](#)

¹² The higher Scope 2 total must be used to total Scope 1, Scope 2, combustion-based direct biogenic emissions and combustion-based indirect biogenic emissions associated with consumed energy. See the section on [Indirect Emissions from Electricity Use](#) for more information on the location-based and market-based methods.

¹³ Consumed energy refers to purchased or acquired electricity, steam, heating, or cooling.

¹⁴ Due to their biogenic origin, organizations must report CO₂ emissions from the combustion of biomass or biogenic-based fuels separately from fossil fuel CO₂ emissions. Refer to the advanced method for determining the eligibility of contractual instruments for renewable fuels.

Emissions may be quantified through direct measurement, or calculated based on fuel use data. This section provides a calculation method using fuel use data. The [Advanced Methods Module](#) provides methods for quantifying emissions with direct measurement systems and using measured fuel characteristics. It also includes methods for allocating biogenic emissions from co-firing units, an optional method to allocate emissions from combined heat and power, and guidance on determining eligibility of contractual instruments for renewable fuels.

Calculating Emissions from Stationary Combustion Using Fuel Use Data

To calculate emissions from stationary combustion using fuel use data, organizations will need to:

1. Determine annual consumption of each fuel combusted at the facility, and
2. Determine the CO₂, CH₄, and N₂O emission factors for each fuel.

1. Determine Annual Consumption of Each Fuel Combusted at the Facility

For each type of fuel,¹⁵ determine the actual annual consumption, measured in units of energy, mass, or volume. The most accurate method is to read individual meters located at the fuel input point of each combustion unit. For solid fuels, fuel use may be back calculated from steam generation rates.¹⁶ If self-producing fuels, such as biomass, organizations may rely on internal records that identify the site-specific methods used, the measurements made, and the calculations performed to quantify fuel usage. Alternatively, organizations may use fuel receipts, or purchase and storage records.

Use the equation below to estimate annual fuel consumption based on fuel purchase and storage data.

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

2.a. Determine the CO₂ Emission Factor for Each Fuel

Use the default CO₂ emission factors provided by fuel type in Tables 1.1 to 1.3.¹⁷ Emission factors are provided in units of CO₂ per unit energy and CO₂ per unit mass or volume. For fuels that are combusted in small quantities, it may be acceptable to use [SEMs](#).



If heat content and/or carbon content is known or can be directly measured, organizations may use an [advanced method](#) to derive an emission factor for CO₂ based on that information. If combusting a fuel that is not listed in the tables, organizations may use a relevant published, peer-reviewed emission factor.

Organizations that have purchased a contractual instrument that includes the environmental attributes of a biofuel (e.g., biogas for thermal use) should refer to the [advanced method](#) to determine eligibility for claiming the emission attributes of the contractual instrument.

¹⁵ Examples of common fuels used for stationary combustion include natural gas, diesel, and wood.
¹⁶ For example, as indicated in U.S. Greenhouse Gas Reporting Program §98.33(a)(2)(iii) corresponding to Tier 2 methodology, Equation C-2c.
¹⁷ Emission factor tables are available at www.theclimaterestory.org.

2.b. Determine the CH₄ and N₂O Emission Factors for Each Fuel

Estimating CH₄ and N₂O emissions from fuel combustion depends not only on fuel characteristics, but also on technology type and combustion characteristics; usage of pollution control equipment; and maintenance and operational practices.

Facilities that use direct monitoring to obtain specific emission factors based on periodic exhaust sampling should use these emission factors. If either the specific type of combustion equipment used at a facility or a facility's specific sector can be determined, use factors from Tables 1.4 to 1.8.¹⁸ If only the type of fuel is known, use Tables 1.9 and 1.10 to obtain emission factors by fuel type and sector.¹⁹ For example, emission factors for natural gas-fired turbines greater than 3 MW for the electricity sector are available in Table 1.5. Less specific emission factors for natural gas used in the energy sector are available in Table 1.9.

+ ADVANCED METHOD

» [Eligibility of contractual instruments for renewable fuels](#)

REPORTING EMISSIONS FROM BIOFUELS

Biofuels such as ethanol, biodiesel, and various blends of biofuels and fossil fuels are frequently combusted in mobile sources. Due to their biogenic origin, organizations must report CO₂ emissions from the combustion of biofuels separately from fossil fuel CO₂ emissions. For biofuel blends such as E85 (85% ethanol and 15% gasoline), E10 (10% ethanol and 90% gasoline) and B20 (20% biodiesel and 80% diesel), organizations must apportion emissions as fossil CO₂ and biogenic CO₂ based on the blend composition.

In many cases, standard gasoline is blended with some biofuel. However, fuel mixes can vary with location and the time of year. When using default emission factors to quantify CO₂ emissions, unless documentation of specific information about the particular gasoline blend is available, organizations should use TCR's default emission factor for motor gasoline. This will result in all CO₂ emissions being reported in Scope 1.

Refer to the [advanced method](#) for determining the eligibility of contractual instruments for renewable fuels.



¹⁸ Ibid.

¹⁹ Ibid.

DIRECT EMISSIONS FROM MOBILE COMBUSTION

Mobile emissions come from sources capable of emitting GHGs while moving from one location to another. These include both on-road and non-road vehicles such as automobiles, trucks, buses, trains, ships and other marine vessels, airplanes, tractors, construction equipment, forklifts, ride-on lawn mowers, snowmobiles, snow blowers, chainsaws, and lawn care equipment. The combustion of fuels in mobile sources emits CO₂, CH₄ and N₂O.

CO₂ emissions, which account for the majority of emissions from mobile sources, can be calculated using fuel consumption data. CH₄ and N₂O emissions depend more on the emission control technologies employed in the vehicle and the distance traveled. Mobile sources may also emit HFCs and PFCs from mobile air conditioning and transport refrigeration leaks. See the [fugitive emissions](#) section for guidance on estimating these refrigerant emissions.

Calculating CO₂ Emissions from Mobile Combustion

To calculate CO₂ emissions from mobile combustion, organizations will need to:

1. Determine annual fuel consumption for each type of fuel used, and
2. Select the appropriate CO₂ emission factor.

1. Determine Annual Fuel Consumption by Fuel Type

For each type of fuel, determine actual annual consumption, or estimate the annual consumption based on distance traveled.

Method A: Actual Fuel Use

Using data on actual fuel consumption for each type of fuel will result in the most accurate emissions quantifications. These data include direct measurements of fuel use (e.g., official logs of vehicle fuel gauges or storage tanks); collected fuel receipts; and purchase records for bulk fuel purchases.

Method B: Estimation Based on Distance

Organizations that cannot obtain fuel use data, but have information on annual mileage and fuel economy, may estimate fuel consumption using the following procedure:

1. Identify the vehicle make, model, fuel type, and model year for all operated vehicles;
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 the equation below.

ESTIMATING FUEL USE BASED ON DISTANCE

Fuel Use (gallons)	=	$\frac{\text{Distance (miles)}}{(\text{City FE} \times \text{City percentage}) (\text{mpg}) + (\text{Highway FE} \times \text{Highway percentage}) (\text{mpg})}$
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FE = Fuel Economy

City percentage = percentage a vehicle's annual mileage that is city driving

Hwy percentage = percentage of a vehicle's annual mileage that is highway driving

Sources of annual mileage data include odometer readings or trip manifests that include distance to destinations.

The most accurate 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.²⁰

For heavy-duty trucks, fuel economy data may be available from vehicle suppliers, manufacturers, or in company records. If no specific information is available, organizations should assume fuel economy factors of 8.0 mpg for medium trucks (10,000-26,000 pounds (lb)) and 5.8 mpg for heavy trucks (more than 26,000 lbs).²¹

Organizations must calculate the fuel use for each vehicle type separately and then sum them together by fuel.

2. Select CO₂ Emission Factor

Most organizations will use the default CO₂ emission factors by fuel type in Table 2.1 (U.S.) and Table 2.2 (Canada).²² If information on actual fuel characteristics is available, organizations may use an [advanced method](#) based on heat content or fuel density.

USING DEFAULT FUEL ECONOMY EMISSION FACTORS

If direct access to fuel economy information for vehicles is unavailable, organizations may obtain fuel economy factors for passenger cars and light trucks from the U.S. EPA website www.fueleconomy.gov, which lists city, highway, and combined fuel economy factors by make, model, model year, and specific engine type. If accurate information about the driving patterns of the fleet is available, organizations should apply a specific mix of city and highway driving, using the equation above. Otherwise use the combined fuel economy factor, which assumes 45% of a vehicle's mileage is highway driving and 55% is city driving.

+ ADVANCED METHOD

» [Quantifying direct CO₂ emission factors for mobile combustion based on actual fuel characteristics, fuel density and heat content](#)

20 This method should be used to determine fuel economy for non-road vehicles, since default fuel economy information for non-road vehicles is not available.

21 Source: U.S. Department of Energy, *Transportation Energy Data Book*, Ed. 36, 2018, Table 5.4

22 Emission factor tables are available at www.theclimaterestory.org.

Calculating CH₄ and N₂O Emissions from Mobile Combustion

To calculate emissions of CH₄ and N₂O from mobile sources, organizations will need to:

1. Identify the vehicle type, fuel type, and technology type or model year of each operated vehicle;
2. Identify the annual mileage by vehicle type;
3. Select the emission factor for each vehicle type; and,
4. For each vehicle type, multiply the annual mileage by the emission factor for CH₄ and N₂O to estimate CH₄ and N₂O emissions.

There are several possible methods to complete the steps above, based on available information. Emissions calculations will be most accurate if there is data on the type of emissions control technology actually used for each vehicle, but organizations can also use the vehicle's make and model year to determine which control technology is typically used. Organizations will also need mileage data for each vehicle type, but if this is not available, mileage can be estimated based on fuel consumption. Default emission factors are provided in Tables 2.4 to 2.7 based on the available data (e.g., specific control technologies or model years).²³

When mobile emissions of CH₄ and N₂O are sufficiently small, organizations may consider using a **SEM** to estimate those emissions based on annual fuel consumption.

SEM FOR MOBILE CH₄ AND N₂O EMISSIONS FROM GASOLINE AND DIESEL PASSENGER CARS AND LIGHT DUTY TRUCKS



This SEM estimates CH₄ and N₂O emissions by applying an emission factor that describes a default ratio of CH₄ or N₂O to corresponding CO₂ emissions.²⁴

1. Determine the total annual quantity of gasoline and diesel fuel gallons consumed, by fuel-type;
2. Calculate the CO₂ emissions using the methods above;
3. To calculate the CH₄ and N₂O emissions, multiply the metric tons of CO₂ by the CH₄ and N₂O emission factor from Table 2.9.²⁵

CALCULATING CH₄ AND N₂O FOR NON-HIGHWAY VEHICLES

The procedure described in this section applies to highway vehicles and alternative fuel vehicles, but not to non-highway vehicles such as ships, locomotives, aircraft, and agricultural equipment. For these types of vehicles, use the same fuel consumption data used to estimate CO₂ emissions in the previous section, along with default emission factors for CH₄ and N₂O provided in Table 2.7.²⁶ Organizations reporting emissions from jet fuel combustion in jet aircraft can also quantify CH₄ and N₂O emissions using the number of landing and takeoff (LTO) cycles by aircraft type provided in Table 2.8.²⁷

²³ Ibid.

²⁴ The default ratio is based on GHG emission trend data reported as part of the *U.S. National Inventory of Greenhouse Gas Emissions and Sinks* every year to estimate CH₄ and N₂O emissions.

²⁵ Emission factor tables are available at www.theclimateregistry.org.

²⁶ Ibid.

²⁷ Ibid.

1. Identify the Vehicle Type, Fuel Type, and Technology Type or Model Year of All Owned and Operated Vehicles

Organizations must identify all owned and operated vehicles, their vehicle type (e.g., passenger car or heavy-duty truck), their fuel type (e.g., gasoline or diesel), and either the emission control technology or model year for each vehicle.

The most accurate approach is to determine the actual control technology employed in each vehicle. Table 2.4 provides the names of control technologies for each vehicle type.²⁸ Information on the control technology type for each vehicle is posted on an under-the-hood label.

ESTIMATING VEHICLE CONTROL TECHNOLOGY

If it is not feasible to check each vehicle's under-the-hood label, organizations can estimate vehicle control technologies using each vehicle's model year. Table 2.5 provides emission factors for highway vehicles by model year and vehicle type based on a weighted average of available control technologies for each model year.²⁹

2. Determine Annual Mileage for Each Vehicle Type

Unlike CO₂ emissions, CH₄ and N₂O emissions depend more on distance traveled than volume of fuel combusted. Therefore, organizations will need to identify vehicle miles traveled by vehicle type.

If mileage data is unavailable, but fuel consumption data for each highway vehicle type is available, organizations can estimate the vehicle miles traveled using **fuel economy factors** by vehicle type. (This is the reverse of the method to estimate fuel consumption based on mileage data to quantify CO₂ emissions.) If more than one type of vehicle is operated, organizations must separately calculate the fuel use for each vehicle type. If only bulk fuel purchase data is available, organizations should allocate consumption across vehicle types and model years based on usage data. Then use the equation below to estimate distance.

ESTIMATING DISTANCE BASED ON FUEL USE

$$\text{Distance (miles)} = \text{Fuel use (gallons)} \times [(\text{City FE} \times \text{City percentage})(\text{mpg}) + (\text{Highway FE} \times \text{Highway percentage})(\text{mpg})]$$

FE = Fuel Economy

City percentage = percentage a vehicle's annual mileage that is city driving

Hwy percentage = percentage of a vehicle's annual mileage that is highway driving

²⁸ Ibid.

²⁹ Ibid.

3. Select the Emission Factor for Each Vehicle Type

Next, select an emission factor for each vehicle type based on the vehicle's model year or control technology.

If data on vehicles' model years is available, obtain emission factors for highway vehicles from Table 2.5. Use Tables 2.6 and 2.7 for alternative fuel and non-highway vehicles.³⁰

If data on vehicles' specific control technologies is available, obtain emission factors for highway vehicles from Table 2.4. Use Tables 2.6 and 2.7 for alternative fuel and non-highway vehicles.³¹

Organizations reporting emissions associated with jet fuel combustion in jet aircraft can use the emission factors based on LTO cycles by aircraft type in Table 2.8 to quantify CH₄ and N₂O emissions.³²

4. Calculate CH₄ and N₂O Emissions by Vehicle Type

For each vehicle type, multiply the total annual mileage by the emission factors for CH₄ and N₂O to calculate CH₄ and N₂O emissions.

Please note: When calculating Scope 1 or direct biogenic emissions from mobile combustion, organizations must only account for emissions resulting from their own activities (e.g., tailpipe emissions from fuel combustion) rather than taking into account the indirect emissions that are part of a fuel's life cycle, such as the CO₂ sequestered during the growing of crops or emissions associated with producing the fuels. The life cycle impacts of combusting fuels are Scope 3 emissions.

³⁰ Ibid.

³¹ Ibid.

³² Ibid.

INDIRECT EMISSIONS FROM ELECTRICITY USE

The generation of electricity through the combustion of fossil fuels typically yields CO₂, and to a smaller extent, CH₄ and N₂O. To calculate indirect emissions from electricity use, organizations will determine annual electricity consumption and calculate a location-based Scope 2 total and a market-based Scope 2 total for electricity.

Emissions from purchased or imported energy are reported in two ways as follows:

- » **Location-based method:** The location-based method quantifies the average emissions from electricity generated and consumed in an organization's geographic region(s) of operations within the organization's defined boundaries, primarily using grid-average emission factors. This method reflects the GHG emissions from locally-generated electricity delivered through the grid and transparently demonstrates local conditions and the impacts of energy conservation. It does not reflect any purchasing choice(s) made by an organization.
- » **Market-based method:** The market-based method quantifies emissions from electricity generated and consumed that organizations have purposefully purchased, using emission factors conveyed through contractual instruments between the organization and the electricity or product provider.³³ This method reflects the GHG emissions associated with the choices an organization makes about its electricity supply or product. It allows organizations to claim the specific emission

rate associated with these purchases, for instance, a utility-specific emission factor from [TCR's Electric Power Sector \(EPS\) delivery metrics](#). Energy conservation (i.e., reduced energy consumption) also impacts the GHG emissions reflected in the market-based method.

These two methods are referred to throughout the GRP as the Scope 2 methods.³⁴

1. Determine Annual Electricity Consumption

There are several methods to determine electricity consumption depending on available information:

- » Known electricity use method;
- » Area method;
- » Cost method; or,
- » Average intensity method.

+ ADVANCED METHOD

- » [Sample data method](#)
- » [Proxy data method](#)

Method A: Known Electricity Use

Monthly electric bills or electric meter records provide the number of kilowatt-hours (kWh) or megawatt-hours (MWh) of electricity consumed. 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.³⁵

³³ Examples of markets with contractual instruments include the U.S., the European Union, Australia, most Latin American countries, Japan, and India. The market-based method is applicable when contractual instruments are present in the market.

³⁴ The Scope 2 methods also apply to combustion-based indirect biogenic emissions that are reported outside the scopes.

³⁵ When an electric bill does not begin exactly on the first day of the reporting year and end on the last day of the reporting year, members must prorate utility data in the first and last month's electricity bills (for those two months only) to determine annual electricity use.

Method B: Area

The area method allows organizations to estimate energy use based on their share of the building's floor space and total electricity consumption. This method is less accurate than the known electricity use method.

Organizations will need to collect the following information from the building's property manager:

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

+ ADVANCED METHOD

» [Using energy audit data to estimate electricity consumption](#)

Use this information and the equation below to estimate the organization's share of the building's electricity use.

ESTIMATING ELECTRICITY CONSUMPTION USING THE AREA METHOD

$$\text{Electricity Use (kWh)} = \frac{\text{Organization's Area (ft}^2\text{)} \times \text{Building Electricity Use (kWh)}}{\text{Building Area (ft}^2\text{)} \times \text{Occupancy Rate}}$$

Method C: Cost (U.S. Commercial Facilities and Warehouses Only)

If it is not feasible to obtain kWh data for commercial facilities and warehouses,³⁶ organizations can estimate electricity consumption using electricity expenditures and average kWh costs.³⁷

To use this method, first determine annual electricity expenditures for each facility. This data is often found in utility bills or financial records. Then, to estimate annual kWh, divide the annual facility-level electricity expenditures by the average electricity cost by U.S. state from Table 3.5, as shown in the equation below.³⁸

ESTIMATING ELECTRICITY CONSUMPTION USING THE EXPENDITURE RECORDS

$$\text{Electricity Use (kWh)} = \frac{\text{Facility Expenditures (dollars)} \times 100}{\text{Average Kilowatt Hour (} \frac{\text{cents}}{\text{kWh}} \text{)}}$$

Method D: Average Intensity

Organizations may need to use the average intensity method for calculating indirect emissions from leased space if they do not receive information about electricity use from an electric utility and they are unable to obtain information about the building's electricity use from the landlord/property manager. The average intensity method is less accurate than methods A-C.

+ ADVANCED METHOD

» [Developing an operation-specific electricity use model to estimate electricity use](#)

³⁶ This method is accepted for commercial facilities and warehouses only. It is not accepted for industrial facilities.

³⁷ The cost method may not be used to calculate indirect emissions for on-site generation in which energy attributes are sold to another organization.

³⁸ Emission factor tables are available at www.theclimateregistry.org.

This method involves the following steps:

1. Determine the leased space's square footage;
2. Determine the average annual electricity intensity for the building space; and,
3. Estimate electricity consumption.

1. Determine the Leased Space's Square Footage

First, review the lease to determine the leased space's usable square footage. Usable square footage is the space contained within the walls of the leased space, including storage space. It does not include other 'rentable' areas such as building bathrooms, common areas, etc.

2. Determine the Average Annual Electricity Intensity for Building Space

Next, select the most appropriate average electricity intensity according to the operations of the building space using Table 3.6 (Canada) and Table 3.7 (U.S).^{39,40}

3. Calculate Electricity Consumption

Use the equation below to estimate the electricity consumption for each leased space.

ESTIMATING ANNUAL ELECTRICITY CONSUMPTION		
Annual Electricity Consumption	=	$\text{Leased Space (useable space) (ft}^2\text{)} \times \text{Annual Electricity Intensity (kWh/ft}^2\text{)}$ <p style="text-align: center;"><small>(from landlord) (from table)</small></p>

Select Emission Factor to Calculate Location-Based Emissions

An electricity emission factor represents the amount of GHGs emitted per unit of electricity consumed. Emission factors for the location-based method reflect the GHG emissions intensity from locally-generated electricity delivered either through the grid or through a direct line transfer.

Organizations must select an emission factor for each unit of electricity consumed. Three categories of location-based emission factors are listed in order from most specific to least specific in the location-based hierarchy and are described in the sections that follow. Organizations should use the most specific emission factors available.⁴¹

Please note: When a standalone biogenic CO₂ emission factor is not available for combustion-based indirect biogenic emissions (e.g., when relying on grid average factors), the member must publicly disclose that indirect biogenic emissions are or may have been excluded.⁴²

GUIDANCE

- » [Alternative accounting methods if certificates are transferred to a third party](#)
- » [Choosing a default emission factor when the generator does not provide an emissions rate](#)
- » [Prorating emissions when power is received from both a direct line generation source and the electric grid](#)

³⁹ Ibid.

⁴⁰ Members with facilities in another country may submit a Member-Developed Methodology Approval Request Form to TCR for review if they are able to find a similar default electricity intensity.

⁴¹ Location-based emission factor hierarchy is from WRI's GHG Protocol Scope 2 Guidance, Table 6.2.

⁴² Members that demonstrate that no biomass was combusted to generate consumed electricity are not subject to this requirement.

LOCATION-BASED EMISSION FACTOR HIERARCHY

1. **Location-A:** Direct line emission factors (if available)
2. **Location-B:** Regional or subnational emission factors
3. **Location-C:** National production emission factors

Location-A: Direct Line Emission Factors (If Applicable)

Direct line emission factors represent emissions from electricity purchased directly from a generation source with no grid transfers. The emissions factor is ineligible to be claimed when energy attribute certificates are transferred to a third-party.

Examples:

- » Landfill waste-to-energy generator that sends power to nearby organization without connecting to the grid; and,
- » Solar or wind generator that sends power to organization without connecting to the grid.

Location-B: Regional or Subnational Emission Factors

Regional or subnational emission factors represent average emissions from all electricity produced in a defined grid distribution region. These emission factors should reflect net physical energy imports and exports across the grid boundary.⁴³

To find the appropriate emission factors for a facility in the U.S., use the U.S. EPA Power Profiler tool, available at: www.epa.gov/cleanenergy/powerprofiler.html to determine the facility's Emissions & Generation Resource Integrated Database (eGRID) subregion. Then, based on the subregion, find the emission factors for each gas in Table 3.1.⁴⁴

For Canadian facilities, use emission factors for each province from Tables 3.2.⁴⁵

Location-C: National Production Emission Factors

National production emission factors represent average emissions from all energy produced within state or national borders.

If applying national production emission factors, use the value for the reporting year, or the most recent year available.

For Mexican facilities, use emission factors from Table 3.3.⁴⁶

Country-specific Scope 2 emission factors can be obtained from the International Energy Agency (IEA) for operations outside of North America.^{47, 48}

43 Members with facilities in the U.S. using this approach should use emission factors specific to each facility's regional power pool rather than the state it is located in, because transmission and distribution grids do not adhere to state boundaries. However, state-specific emission factors that reflect net imports and exports across the grid boundary are acceptable.

44 Emission factor tables are available at www.theclimateregistry.org.

45 Ibid.

46 Ibid.

47 See: <http://www.iea.org/statistics/onlinedataservice/>.

48 International Energy Agency (IEA) emission factors do not adjust for imports/exports of energy across national boundaries.

Select Emission Factor to Calculate Market-Based Emissions

Emission factors for the market-based method reflect the emission factor from electricity that organizations have purposefully purchased, through the use of contractual instruments between the organization and the electricity or product provider.

Types of contractual instruments that convey specific emissions factors for the market-based method are listed in order from most specific to least specific in the hierarchy below and are described in the sections that follow. Organizations should select the most specific emission factor available to them given their eligible contractual instruments for each unit of electricity that they consume.^{49, 50, 51}

Organizations must publicly disclose the category or categories of contractual instruments used to calculate emissions using the market-based method (e.g., energy attribute certificates, contracts, utility-specific emission factors). Organizations are encouraged to specify the energy generation technologies (e.g., coal, solar, nuclear).

Please note: As with the location-based method, when a standalone biogenic CO₂ emission factor is not available for combustion-based indirect biogenic emissions (e.g., when relying on grid average factors), the member must publicly disclose that indirect biogenic emissions are or may have been excluded.⁵²

Contractual instruments for electricity, such as renewable energy certificates (RECs), can only be used to calculate Scope 2 emissions or combustion-based indirect biogenic emissions associated with consumed energy, and not Scope 1 or 3 emissions.⁵³

MARKET-BASED EMISSION FACTOR HIERARCHY

1. **Market-A:** Energy attribute certificates (or equivalent instruments)
2. **Market-B:** Contracts
3. **Market-C:** Supplier/utility-specific emission factors
4. **Market-D:** Residual mix
5. **Market-E:** Other grid-average emission factors

GUIDANCE

- » [Role of energy attribute certificates in the market-based method](#)
- » [Renewable Energy Certificates in the market-based method](#)

49 Organizations centrally purchasing energy attribute certificates on behalf of all their operations in a single country or region should indicate how they match these purchases to individual site consumption.

50 Organizations must ensure that any contractual instrument from which an emission factor is derived meets the TCR Eligibility Criteria outlined in the next section. Where contractual instruments do not meet these criteria, emission factors from either Market-D or Market-E must be used.

51 Market-based method emission factor hierarchy adapted from WRI's GHG Protocol Scope 2 Guidance, Table 6.3

52 Members that demonstrate that no biomass was combusted to generate consumed electricity are not subject to this requirement.

53 With the exception of Scope 3 or biogenic end-use electricity consumption.

Market-A: Energy Attribute Certificates (or Equivalent Instruments)

Energy attribute certificates convey information about energy generation to organizations involved in the sale, distribution, consumption, or regulation of electricity. They provide proof of electricity generation from a specific energy source and represent the rights to claim the environmental, social, and low or zero emissions characteristics resulting from the use of that electricity generation. Certificates can be unbundled, bundled with electricity, conveyed in a contract, or delivered by a utility. Where energy attribute certificates are issued, the certificates themselves serve as the emission factor for the market-based method.⁵⁴

Examples include:

- » Renewable Energy Certificates (RECs) (U.S., Canada, Australia, others);
- » Electricity contracts that convey RECs;
- » Certificates for non-renewable generation in regions where all-generation tracking systems are in operation;⁵⁵ and,
- » Any other energy certificates that meet the [TCR Eligibility Criteria](#).

Market-B: Contracts

Contracts can convey electricity generation attributes where energy attribute certificates do not exist or where attributes or certificates are not required to claim use.⁵⁶ These may apply to specified sources of electricity, from both renewable and fossil fuels.

Contracts are also commonly present when electricity is conveyed from a specific source through a direct line transfer. The guidance on direct line emission factors for the [location-based method](#) also applies to the market-based method.

Examples:

- » Power purchase agreements (PPAs) or contracts for electricity from specific nonrenewable sources (e.g., coal, nuclear) outside of regions where all-generation tracking systems are in operation;
- » Direct line transfers;⁵⁷
- » Contracts that convey attributes to the power consumer where certificates do not exist; and,
- » Contracts for power that are silent on attributes, but where attributes are not otherwise tracked or claimed.

54 Most contractual instruments for renewable energy will have an emission factor of zero. However, depending on the renewable resource employed, some may have non-biogenic emissions that must be reflected in Scope 2 or indirect biogenic emissions totals. In cases where a contractual instrument employs a biomass fuel type but does not provide a corresponding emission factor for biogenic CO₂, members must publicly disclose that indirect biogenic emissions are or may have been excluded from their emissions inventory.

55 In the U.S., the New England Power Pool Generation Information System (NEPOOL GIS), New York Generation Attribute Tracking System (NYGATS), and the Pennsylvania, Jersey, Maryland (PJM) regional transmission organization have all-attribute tracking systems. Therefore, in these regions, certificates are needed to convey the attributes (emission rates) of all specified purchases. If certificates that meet the TCR eligibility criteria are not available for specified purchases, organizations must use emission factors from either Market-D or Market-E.

56 This may also refer to cases where attribute ownership is not explicit but where the contract can nevertheless serve as a proxy for attributes due to reasonable certainty that the attributes are not otherwise conveyed.

57 See Location-A in the location-based method section for more information on direct line transfers.

Market-C: Supplier/Utility-Specific Emission Factors

Supplier/utility-specific emission factors quantify indirect emissions associated with a standard product offer, green power program, or a customized power product.

Organizations may use electric delivery metrics reported and verified in accordance with [TCR's EPS Protocol](#),⁵⁸ or other publicly certified delivery metrics developed by a supplier or utility as described in the advanced methods.

Examples:

- » Retail emission factor, representing a delivered energy product (e.g., TCR EPS delivery metrics, Table 3.8),⁵⁹
- » Special power product (SPP, also known as green power products or green energy tariffs); and,
- » Voluntary renewable electricity program or product.

+ ADVANCED METHOD

- » [Using supplier-specific delivery metrics that are publicly disclosed or certified](#)

Market-D: Residual Mix

Residual mix emission factors quantify subnational or national energy production, factoring out voluntary purchases to prevent double counting of these claims.

Many organizations will either be unable to obtain supplier-specific or utility-specific emission factors and/or will purchase some electricity exclusively from the grid. In these cases, organizations should use a residual mix emission factor, or must publicly disclose if a residual mix emission factor is not available.⁶⁰

Refer to the [advanced method](#) for requirements for use of residual mix emission factors.

+ ADVANCED METHOD

- » [Validating residual mix emission factors](#)

Market-E: Other Grid-Average Emission Factors

Refer to the location-based emission factor hierarchy for the subnational/regional or national production emission factors. Organizations using a grid-average emission factor in the market-based method must publicly disclose the lack of an available residual mix emission factor if one is not available.

Examples:

- » Regional or subnational emission factors (Tables 3.1, 3.2).⁶¹
- » National production emission factors (Table 3.3).⁶²

⁵⁸ Emission factor tables are available at www.theclimateregistry.org.

⁵⁹ Ibid.

⁶⁰ Members may contact TCR at help@theclimateregistry.org to assess the applicability of a residual mix emission factor.

⁶¹ Emission factor tables are available at www.theclimateregistry.org.

⁶² Ibid.

ENSURE CONTRACTUAL INSTRUMENTS MEET TCR ELIGIBILITY CRITERIA FOR ELECTRICITY



TCR defines certain eligibility criteria that are designed to ensure that emission factors used to calculate the market-based method Scope 2 total are consistent with GHG accounting best practices. Only emission factors that meet the criteria in the table below are eligible to be claimed.

Where contractual instruments do not meet these criteria, emission factors from either Market-D or Market-E must be used.

Members must upload a public document identifying the contractual instrument certification program(s) or other documentation that demonstrates clear and explicit ownership and TCR eligibility in CRIS (e.g., REC certification document, self-attestation form).

TCR Eligibility Criteria for Electricity⁶³

CRITERIA	DESCRIPTION
Contractual instruments must:	
1. Convey GHG information	» Convey the direct GHG emission rate attribute associated with produced electricity.
2. Prevent double counting	» Be the only instrument that carries the GHG emission rate attribute claim associated with that quantity of electricity generation. Clear and explicit ownership must be demonstrated by either third-party verification that includes a chain of custody audit, or documentation of permanent retirement in an electronic tracking system in a dedicated, named retirement subaccount for a particular TCR reporting year. » Be distinct from offsets. A MWh generated by a renewable energy project and claimed as an offset cannot also be claimed as a contractual instrument (e.g., REC).
3. Be retired	» Be tracked, redeemed, retired, or canceled by or on behalf of the reporting organization.
4. Be of recent vintage	» Have been generated within a period of six months before the reporting year to up to three months after the reporting year.
5. Be sourced from same market as operations	» Be sourced from the same market in which the reporting organization's electricity consuming operations are located and to which the instrument is applied. Market boundaries are assumed to match national boundaries, except where international grids are closely tied.
Utility-specific emission factors must be:	
6. Calculated based on delivered electricity	» Calculated based on contractually-delivered electricity, incorporating RECs or other instruments sourced and retired on behalf of customers.
Direct line generation or organizations consuming on-site generation must:	
7. Convey GHG claims to the organization	» Ensure that all emission claims are transferred to the reporting organization only.
All contractual instruments must operate in markets with a:	
8. Residual mix	» Adjusted, residual mix emission factor characterizing the GHG intensity of unclaimed or publicly shared electricity. Organizations must disclose the lack of an available residual mix emission factor if one is not available.

⁶³ TCR's Eligibility Criteria are based on the Scope 2 Quality Criteria in the *GHG Protocol Scope 2 Guidance* and additional international best practices.

INDIRECT EMISSIONS FROM NON-ELECTRIC ENERGY USE

The consumption of non-electric energy such as imported steam, heat, and cooling is another category of Scope 2 emission sources and is reported similarly to electricity consumption. Emissions from non-electric energy consumption are calculated in two ways, using the location-based and market-based methods.

Some facilities purchase steam or heating, for example, to provide space heating in the commercial sector or process heating in the industrial sector. An [advanced method](#) is provided for calculating emissions from imported steam or heating transferred on a direct line from a conventional boiler plant.

An [advanced method](#) is also provided for estimating indirect emissions from heat and power produced at a combined heat and power (CHP) plant. 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.

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 organizations purchase cooling, the compressor system that produces the cooling is driven by either electricity, fossil fuel, or biofuel combustion. An [advanced method](#) is provided for calculating emissions from imported cooling.

In many cases, organizations that lease space (such as office space) use heat, steam, or cooling that is generated within the facility in which they are located, where the heat or cooling generation unit is outside of their organizational boundary. The rest of the methods in this section estimate indirect emissions resulting from non-electric energy consumption in leased spaces.

+ ADVANCED METHODS

- » [Calculating indirect emissions from imported steam or heating from a conventional boiler plant](#)
- » [Calculating indirect emissions from heat and power produced at a CHP facility](#)
- » [Calculating indirect emissions from cooling](#)

Calculating Indirect Energy Use from Imported Steam, Heating, or Cooling in Leased Spaces

Imported Heating or Steam

Organizations who lease space that is heated by units located outside of their organizational boundaries must report anthropogenic emissions associated with consumed energy in Scope 2 (imported heat). Combustion-based indirect biogenic emissions associated with consumed energy must be reported separately outside of the scopes.⁶⁴ In both cases, organizations must use the [area method](#) or [average intensity method](#) to calculate emissions.

Organizations with operational control of heating units in leased space (typically those with heating units located within the leased space, or organizations who pay their own gas bill directly to the utility) are required to report the emissions from such heating units as [Scope 1 \(stationary combustion\) emissions](#).

⁶⁴ When a standalone biogenic CO₂ emission factor is not available for combustion-based indirect biogenic emissions (e.g., when relying on grid average factors), the member must publicly disclose that indirect biogenic emissions are or may have been excluded. Members that demonstrate that no biomass was combusted to generate consumed electricity are not subject to this requirement.

Often in leased spaces, tenants do not separately contract for imported heat and are unable to obtain that information from their landlords. In these cases, organizations can utilize default consumption rates such as the natural gas consumption defaults from the [U.S. Energy Information Administration Commercial Building Energy Consumption Survey](#) or the [Natural Resources Canada Commercial and Institutional Building Energy Use Survey](#) to determine the energy used to generate the heat they consume and use the [average intensity method](#) to calculate emissions.

Imported Cooling

Organizations who lease space with air conditioning or cooling units that are located within their organizational boundaries are required to report the emissions from such cooling units as [Scope 1 \(fugitive\) emissions](#) and [Scope 2 \(electricity use\)](#). Anthropogenic emissions associated with consumed energy must be reported in Scope 2. Combustion-based indirect biogenic emissions associated with consumed energy must be reported separately outside of the scopes.⁶⁵

DIRECT FUGITIVE EMISSIONS

This section provides guidance on calculating direct fugitive emissions of HFCs and PFCs from refrigeration and air conditioning systems. Refrigeration and air conditioning systems include motor vehicle air conditioning, chillers, retail food refrigeration, cold storage warehouses, refrigerated transport, industrial process refrigeration, commercial air conditioning systems, household refrigeration, and domestic air conditioning and heat pumps.

Emissions of HFCs and 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 section addresses emissions from the use of refrigeration and air conditioning equipment only (including installation, use, and disposal).

Two methods for estimating emissions of HFCs and PFCs from refrigeration and air conditioning equipment are provided in this section:

- » Simplified mass balance method; and
- » Screening method, which may be used as a SEM provided that total emissions estimated with SEMs fall below the 10% SEMs threshold.

An [advanced mass balance method](#) is provided for organizations that have access to detailed data on refrigerant purchases, sales, storage, and changes in total equipment capacity.

ADVANCED METHOD

- » [Quantification of direct fugitive emissions using the advanced mass balance method](#)

⁶⁵ Ibid.

REPORTING HFC AND PFC BLENDS

Please note: some refrigerant blends include both HFCs and PFCs. When reporting emissions associated with these blends, the HFC and PFC components must be reported by gas. To report the emissions from these blends, organizations must multiply the amount of each refrigerant used by the percent composition of each HFC and PFC listed in Table 5.2. Use the equation below and the GWP factors from Table 5.2 to convert each HFC and PFC to units of CO₂e.⁶⁶

CONVERTING HFC AND PFC EMISSIONS TO CO ₂ e	
HFC Type A Emissions (mt CO ₂ e)	= $HFC\ Type\ A\ Emissions\ (mt\ HFC\ Type\ A) \times GWP\ (HFC\ A)$
PFC Type A Emissions (mt CO ₂ e)	= $PFC\ Type\ A\ Emissions\ (mt\ PFC\ Type\ A) \times GWP\ (PFC\ A)$

REPORTING MONTREAL PROTOCOL REFRIGERANTS

Common refrigerants R-2, R-12, and R-11 are not part of the GHGs required to be reported to TCR because they are either HCFCs or chlorofluorocarbons (CFCs). The production of HCFCs and CFCs is being phased out under the Montreal Protocol and as a result, HCFCs and CFCs are not defined as GHGs under the Kyoto Protocol. Emissions of non-Kyoto-defined GHGs must not be reported as emission sources in the inventory, regardless of the GWP of the gas. Members that opt to disclose emissions of these refrigerants must include that information in a supplemental document.

⁶⁶ Emission factor tables are available at www.theclimaterestry.org.

Method A: Simplified Mass Balance

If the necessary data to use the advanced mass balance method is not available, organizations should use the simplified mass balance method. This method may be used either by organizations that service their own equipment or by organizations that have contractors service their equipment.

1. Determine the Types and Quantities of Refrigerants Used

For each 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 new equipment was installed that was not pre-charged by the manufacturer);
- » Total full charge (capacity) of new equipment using this refrigerant (if new equipment was installed that was not pre-charged by the manufacturer);
- » Quantity of refrigerant used to service equipment;
- » Total full charge (capacity) of retiring equipment (if equipment was disposed during the reporting year); and,
- » Quantity of refrigerant recovered from retiring equipment (if equipment was disposed during the reporting year).

Organizations who have contractors that service refrigeration equipment should obtain the required information from the contractor. Always track and maintain the required information carefully in order to obtain accurate emissions data.

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” in the [advanced mass balance method](#).

2. Calculate Annual Emissions of Each HFC and PFC Gas

Use the equation below to calculate emissions for each refrigerant used.

CALCULATING EMISSIONS OF EACH REFRIGERANT USING THE SIMPLIFIED MASS BALANCE METHOD	
Total Annual Emissions (mt)	$= \frac{(P_N - C_N + P_S - P_R + C_D - R_D)(kg)}{1,000 \left(\frac{kg}{mt}\right)}$
Where: P_N = Purchases of refrigerant used to charge new equipment* C_N = Total full charge (capacity) of the new equipment* P_S = Quantity of refrigerant used to service equipment	P_R = Quantity of refrigerant recycled C_D = Total full charge (capacity) of retiring equipment R_D = Refrigerant recovered from retiring equipment * Omitted if the equipment has been pre-charged by the manufacturer

Method C: Screening



The screening method is a SEM which may be used to estimate HFC and PFC emissions from refrigeration and air conditioning systems 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.

Organizations may only use the screening method if total, entity-wide emissions estimated with SEMs do not exceed 10% of the CO₂e sum of reported Scope 1, Scope 2, combustion-based direct biogenic emissions and combustion-based indirect biogenic emissions associated with consumed energy (i.e., the 10% SEMs threshold).

1. Determine the Types and Quantities of Refrigerants Used

To estimate emissions, organizations 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 4.1).⁶⁷ If the refrigerant charge capacity of each piece of equipment is unknown, use the upper bound of the range provided by equipment type in Table 4.1.⁶⁸

2. Estimate Annual Emissions of Each Refrigerant

For each refrigerant, use the equation below to estimate annual emissions. Default emission factors are provided in Table 4.1 by equipment type.⁶⁹ The equation includes emissions from installation, operation, and disposal of equipment. If an organization did not install or dispose of equipment during the reporting year, it should not include emissions from these activities in the estimation.

ESTIMATING EMISSIONS OF EACH REFRIGERANT USING THE SCREENING METHOD	
For each refrigerant: Total Annual Emissions (mt)	= $\frac{(C_N \times k) + (C \times w \times T) + [C_D \times y \times (1 - z)] (kg)}{1,000 \left(\frac{kg}{mt}\right)}$
<p>Where:</p> <p>C_N = Quantity of refrigerant charged into the new equipment*</p> <p>C = Total full charge (capacity) of the equipment</p> <p>T = Time in years equipment was in use (e.g., 0.5 if used only during half the year and then disposed)</p> <p>C_D = Total full charge (capacity) of equipment being disposed of**</p> <p>k = Installation emission factor*</p> <p>w = Operating emission factor</p> <p>y = Refrigerant remaining at disposal**</p> <p>z = Recovery efficiency**</p> <p>* Omitted if no equipment was installed during the reporting year or the installed equipment was pre-charged by the manufacturer</p> <p>** Omitted if no equipment was disposed of during the reporting year</p>	

If the sum of HFC and PFC emissions, in units of CO₂e, plus any other emissions estimated with SEMs, do not exceed the 10% SEMs threshold, organizations may use these estimates to report HFC and PFC emissions from the use of refrigeration and air conditioning equipment. Members must mark these emissions as SEMs in CRIS.

⁶⁷ Emission factor tables are available at www.theclimateregistry.org.

⁶⁸ Ibid.

⁶⁹ Ibid.



D. ADVANCED METHODS FOR QUANTIFYING EMISSIONS

This module provides advanced methods to measure or calculate greenhouse gas (GHG) emissions from less common emission sources and calculation methods that use measured or site-specific data. Advanced methods for calculating the following categories of emissions are provided:

- » Direct carbon dioxide (CO₂) emissions from stationary combustion using site-specific data or measured fuel characteristics;
- » Direct CO₂ emissions from mobile combustion using actual fuel characteristics;
- » Indirect emissions from electricity use using sample, proxy, or energy audit data or an operation-specific electricity use model;
- » Indirect emissions from heat and power produced at a combined heat and power (CHP) system;
- » Indirect emissions from imported heat, steam, and cooling; and,

- » Direct fugitive emissions from refrigeration using purchase, retirement, and storage data.

The module also provides a method to allocate biogenic and anthropogenic emissions from co-firing stationary combustion units, and an optional method to allocate emissions from CHP. Detailed guidance is provided for selecting emission factors to calculate market-based Scope 2 emissions, and determining the eligibility of contractual instruments for renewable fuels combusted in stationary and mobile equipment.

More common quantification methods for many sources are available in the [GHG Emissions Quantification Methods Module](#). If TCR has not provided guidelines for quantifying emissions from a particular emission source, organizations may use existing international or industry best practice methods, which are published, peer-reviewed calculation and measurement methods or emission factors.¹

¹ Emission factors must be gas-specific (i.e., not in units of carbon dioxide equivalent (CO₂e)).

QUANTIFYING DIRECT CO₂ EMISSIONS WITH SITE-SPECIFIC DATA

GHG emissions are quantified using either direct measurement or calculation methods. Direct measurement systems monitor GHG concentration and flow rates. Calculation-based methods use activity data and emission factors to estimate GHG emissions. Most organizations will use default emission factors, but organizations with more specific data available may also develop their own site-specific emission factors based on the specific characteristics of the GHG source and fuel.

This section provides instruction for measuring direct emissions using the following advanced methods:

- » Direct measurement of CO₂ emissions;
- » Allocating anthropogenic and biogenic CO₂ emissions from co-firing units;
- » Developing site-specific CO₂ emission factors to quantify emissions with calculation-based methods; and,
- » Optionally allocating emissions from combined heat and power.

Quantifying CO₂ Emissions with Direct Measurement Systems

CO₂ emissions may be measured directly with Continuous Emissions Monitoring Systems (CEMS), that monitor GHG concentration and flow rates based on periodic exhaust sampling. CEMS can be found in facilities such as power plants,² industrial facilities with large stationary combustion units, or landfills with sensors to monitor emissions from landfill gas collection systems.

Organizations may use either of the two following CEMS methods to measure and calculate annual CO₂ emissions:³

1. A monitor measuring CO₂ concentration percent by volume of flue gas and a flow monitoring system measuring the volumetric flow rate of flue gas can be used to determine CO₂ mass emissions. Annual CO₂ emissions are then determined based on the operating time of the unit.
2. A monitor measuring CO₂ concentration percent by volume of flue gas and a flow monitoring system measuring the volumetric flow rate of flue gas, combined with theoretical CO₂ and flue gas production by fuel characteristics, can be used to determine CO₂ flue gas emissions and CO₂ mass emissions. Annual CO₂ emissions are then determined based on the operating time of the unit.

Direct measurement may be used to quantify and report both anthropogenic and biogenic emissions, depending on the activity being monitored.

Quantifying Biogenic Emissions from Co-Firing Units

For facilities that combust blended fuels, such as municipal solid waste (MSW) treatment facilities, organizations must calculate or monitor CO₂ 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 CO₂ emissions (Scope 1). CO₂ emissions from combusting the biomass portion of the fuel or feedstock (e.g., yard waste or paper products for MSW) must be separately calculated and reported as biogenic CO₂ emissions (reported separately from the scopes). Methods are provided for the allocation of emissions from blended fuels in units without CEMS and in units with CEMS below.

Allocating Emissions from Blended Fuels in Units Without CEMS

Information on the biomass portion of fuels and feedstocks are often site-specific. MSW facilities

² For organizations in the electric power sector, additional specifications on using CEMS can be found in TCR's [EPS Protocol](#).

³ All methods of direct monitoring using CEMS pursuant to 40 CFR Parts 60, 75, 98 or Environment Canada's Report EPS 1/PG/7 (Revised) are consistent with the method in this section.

without CEMS should obtain biomass/fossil fuel breakdown information from a local waste characterization study. Organizations may also use the method 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 CARB *Regulation for the Mandatory Reporting of Greenhouse Gas Emissions*, Section 95125(h)(2).

Allocating Emissions from Blended Fuels in Units with CEMS

Where biomass and fossil fuels are co-fired and emissions are monitored through a CEMS, the emissions associated with each combustion activity may be mixed in the exhaust stack and measured collectively by the same CEMS device. To determine the share of biogenic CO₂ emissions measured by the CEMS, calculate the CO₂ emissions from fossil fuel or biomass combustion by using a fuel-specific emission factor applied to the amount of fuel or biomass combusted.⁴ After calculating these CO₂ emissions from either fossil fuel or biomass combustion, subtract the calculated value from the total CEMS measured CO₂ value to identify the remaining (anthropogenic or biogenic) CO₂ emissions.

Alternatively, organizations may use the method described in ASTM D6866-06a (see above for more information).

Quantifying Direct CO₂ Emissions with Measured Fuel Characteristics

Organizations that have access to measured characteristics of combusted fuels may derive an emission factor for CO₂. 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 depending 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). Organizations 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 Parts 86, 87, 89 et al. *Mandatory Reporting of Greenhouse Gases*;
- » 40 CFR Part 75, Appendix G *Continuous Emissions Monitoring, Determination of CO₂ Emissions*;
- » *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;” and,
- » WRI/WBCSD *GHG Protocol Guidance: Direct Emissions from Stationary Combustion*, Version 3.0 (July 2005), Annex D (www.ghgprotocol.org).

The carbon content of each fuel can be expressed in mass of carbon per mass of fuel (e.g., kilogram (kg) C/short ton), mass of carbon per volume of fuel (e.g., kg C/gallon), or mass of carbon per unit energy of fuel (e.g., 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).⁵

If carbon content is expressed in mass of carbon per unit energy (e.g., kg C/Btu), multiply by the

4 Emission factors may be derived using measured fuel characteristics or default values from Tables 1.1 to 1.3. Emission factor tables are available at www.theclimateregistry.org.

5 Outside of the U.S. and Canada, lower heating values (LHV) are more commonly used. Refer to TCR’s guidance on converting from LHV to HHV.

heat content of that fuel per unit mass or volume (such as Btu/ton or Btu/gallon) to determine the mass of carbon per physical unit of fuel (such as kg C/ton or kg C/gallon).⁶

To account for the small fraction of carbon that may not be oxidized during combustion, multiply the carbon content in physical units of fuel by the fraction of carbon oxidized. Organizations may use a site-specific oxidation factor, or where site-specific data is not available, apply a default oxidation factor of 1.00 (100% oxidation). Then convert from units of carbon to units of CO₂ by applying the molecular weight ratio of CO₂ to carbon (44/12) as shown in the equation below.

CALCULATING CO ₂ EMISSION FACTORS USING MEASURED FUEL CHARACTERISTICS	
Emission Factor	= $Heat\ Content \times Carbon\ Content \times Percent\ Oxidized \times \frac{44}{12}$

Combining Measured Data and Default Factors

Organizations should use measured fuel characteristics of combusted fuels to quantify emissions whenever possible. In some cases, heat content information may be available (for example, from the fuel supplier), while measured carbon content data is not, and vice versa. In these cases, organizations should combine the more specific data with default emission factors from Tables 1.1 to 1.3.⁷

Optional: Allocating Emissions from Combined Heat and Power

Accounting for the GHG emissions from a Combined Heat and Power (CHP) system that captures the waste heat from the primary electricity generating pathway and uses it for non-electricity purposes is unique because the system produces more than one useful product from the same amount of fuel combusted, namely, electricity and heat or steam.⁸ As such, apportionment of the GHG emissions between the two different energy streams may be useful.

Please note: While allocating the emissions generated by a CHP system between the two energy product streams is optional, absolute emissions from CHP systems included within the reporting boundary must be reported.

The most consistent approach for allocating GHG emissions from CHP systems is the efficiency method, which allocates emissions of CHP systems 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, the organization must know the total emissions from the CHP system, the total steam (or heat) and electricity production, and the steam (or heat) and electricity production efficiency of the system.

Use the following steps to determine the share of emissions attributable to steam (or heat) and electricity production.

1. Determine the total direct emissions from the CHP system;
2. Determine the total steam (or heat) and electricity output for the CHP system;
3. Determine the efficiencies of steam (or heat) and electricity production; and,
4. Determine the fraction of total emissions allocated to steam (or heat) and electricity production.

⁶ If carbon content data is expressed in mass of carbon per mass or volume of fuel, skip this step.
⁷ Emission factor tables are available at www.theclimateregistry.org.
⁸ Note that a combined cycle (or bottoming cycle) system that uses waste heat to generate electricity should be treated no differently from stationary combustion emissions as described in the previous section.

1. Determine the Total Direct Emissions from the CHP System

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

2. Determine the Total Steam and Electricity Output for the CHP System

To determine the total energy output of the CHP system attributable to steam production, use published tables that provide energy content (enthalpy) values for steam at different temperature and pressure conditions.⁹ Energy content values multiplied by the quantity of steam produced at the temperature and pressure of the CHP system 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.

3. Determine the Efficiencies of Steam and Electricity Production

Identify steam (or heat) and electricity production efficiencies. If actual efficiencies of the CHP system are not known, use a default value of 80% for steam and a default value of 35% 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.

4. Determine the Fraction of Total Emissions Allocated to Steam and Electricity Production

Allocate the emissions from the CHP system to the steam (or heat) and electricity product streams by using the equation below.

ALLOCATING CHP EMISSIONS TO STEAM AND ELECTRICITY	
Step 1:	$E_H = \frac{\frac{H}{e_H} \times E_T}{\frac{H}{e_H} + \frac{P}{e_P}}$
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 E _P = Emissions allocated to electricity production	

⁹ E.g., 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).

QUANTIFYING CO₂ EMISSION FACTORS FOR MOBILE COMBUSTION BASED ON ACTUAL FUEL CHARACTERISTICS, FUEL DENSITY, AND HEAT CONTENT

To calculate CO₂ emissions from mobile combustion, organizations will need to determine annual fuel consumption for each type of fuel used in the fleet and select the appropriate CO₂ emission factor. Most organizations will use the default CO₂ emission factors by fuel type in Table 2.1 (U.S.) and Table 2.2 (Canada) to calculate emissions from mobile combustion.¹⁰ More accurate CO₂ emission factors can be derived by measuring the fuel characteristics of the specific fuel consumed, or obtaining this data from the fuel supplier. Specific emission factors can be determined from data on either the fuel density and carbon content of fuels, or heat content and carbon content per unit of energy of fuels.

If only measured heat content data is available and measured carbon content data is missing (or vice versa), organizations may use a combination of their own data and a default heat content or carbon content factor from Table 2.1 (U.S.) or Table 2.2 (Canada).¹¹

Fuel Density Method

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 oxidation factors specific to the combustion source are not available, use a default oxidation factor of 1.00 (100% oxidation). To convert from units of carbon to CO₂, multiply by 44/12. Refer to the equation below.

CALCULATING CO ₂ EMISSION FACTORS USING THE FUEL DENSITY APPROACH	
Emission Factor (kg CO ₂ /gallon)	= Fuel Density (kg/gallon) × Carbon Content (kg C/kg fuel) × Percent Oxidized × $\frac{44}{12}$ (CO ₂ /C)

Heat Content Method

If the heat content and carbon content of each fuel can be obtained from the fuel supplier, multiply the heat content per unit volume (e.g., Btu/gallon) by the carbon content per unit energy (e.g., kg C/Btu) to determine the mass of carbon per unit volume (e.g., 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 oxidation factors specific to the combustion source are not available, use a default oxidation factor of 1.00 (100% oxidation). To convert from units of carbon to CO₂, multiply by 44/12. Refer to the equation below.

CALCULATING CO ₂ EMISSION FACTORS USING THE HEAT CONTENT APPROACH	
Emission Factor (kg CO ₂ /gallon)	= Heat Content (Btu/gallon) × Carbon Content (kg C/kg f) × Percent Oxidized × $\frac{44}{12}$ (CO ₂ /C)

¹⁰ Emission factor tables are available at www.theclimateregistry.org.

¹¹ Ibid.

ELIGIBILITY OF CONTRACTUAL INSTRUMENTS FOR RENEWABLE FUELS COMBUSTED IN STATIONARY OR MOBILE EQUIPMENT

Organizations that have purchased a contractual instrument that includes the environmental attributes of a biofuel (e.g., biogas) should consult the [TCR Eligibility Criteria for Steam and Heating](#) in the advanced method for [Calculating Indirect Emissions from Imported Steam or Heating from a Conventional Boiler Plant](#) to evaluate if the instrument may be claimed in the inventory.¹² If eligible, the most specific market-based emission factors available should be used to report biogenic CO₂ and Scope 1 methane (CH₄) and nitrous oxide (N₂O) emissions. If the contractual instrument is ineligible, organizations should report using the appropriate default emission factor of the fuel consumed.¹³

QUANTIFYING INDIRECT EMISSIONS FROM ELECTRICITY USE

To calculate indirect emissions from electricity use, organizations will determine annual electricity consumption and calculate a location-based Scope 2 total and a market-based Scope 2 total for electricity.

Determining Electricity Consumption

There are several advanced methods to determine electricity consumption depending on available information. These methods involve the following types of information:

- » Sample data method
- » Proxy data method
- » Using Energy Audit Data to Estimate Electricity Consumption
- » Developing an Operation-Specific Electricity Use Model to Estimate Electricity Use

Sample Data Method

Organizations can use sample data to estimate total electricity consumption if they can demonstrate that:

- » Hours of use of the equipment have been metered or tracked; and,
- » The equipment is operating continuously (or on a schedule that they can account for) at a constant rate.

To use the sample data method to estimate electricity consumption, multiply the sample by the amount of time the equipment was in use.

Proxy Data Method

Organizations can use existing data on equipment operations as a proxy for unavailable data at another site as long as they can demonstrate that:

- » The equipment is identical;
- » Equipment operations where site-specific data is unavailable consume the same amount of energy as identical equipment where site-specific data is available;

¹² [The Eligibility Criteria for Steam and Heating](#) also apply to contractual instruments for other renewable technologies, such as solar thermal and geothermal.

¹³ If TCR does not provide a default emission factor for the consumed fuel, organizations may use existing international or industry best practice methods, which are published, peer-reviewed calculation and measurement methods or emission factors. Emission factors must be gas-specific (i.e., not in units of carbon dioxide equivalent (CO₂e)).

- » The equipment operates on the same schedule; and,
- » The same maintenance procedures are followed.

Organizations may use make and model information, manufacturer specifications, or testing to determine that both pieces of equipment consume the same amount of electricity.

Using Energy Audit Data to Estimate Electricity Consumption

As an alternative to the area method to estimate electricity use (see the [GHG Emissions Quantification Methods Module](#), Indirect Emissions from Electricity Use section), organizations with access to a comprehensive energy audit can use the audit findings to apportion total building electricity use to the organization’s space, provided electricity use has been consistent since the date of the audit. Organizations may also use a combination of energy audit findings and the area method to allocate total emissions to different operations.

Developing an Operation-Specific Electricity Use Model to Estimate Electricity Use

In certain circumstances, organizations may have sufficient information to develop operation-specific electricity use models for their operations. For example, if an organization has several retail stores where they use a consistent lighting design and lighting makes up the majority of the electricity load, they may develop a member-specific electricity consumption model to estimate electricity use based on square footage. Members should contact TCR if they are interested in developing their own operation-specific electricity use model to estimate electricity use.

Emissions estimated using these approaches will not contribute to the Simplified Estimation Methods (SEMs) threshold.

Selecting Emission Factors to Calculate Market-Based Emissions

Emission factors for the market-based method reflect the emission rate from electricity that organizations have purposefully purchased, through the use of contractual instruments between the organization and the electricity or product provider.

The [GHG Emissions Quantification Methods Module](#), Indirect Emissions from Electricity Use section describes five categories of emission factors that could be applied to each unit of electricity consumed to calculate market-based emissions. In this section, advanced methods are provided for organizations that use supplier-specific emission factors that are publicly disclosed and certified (from the Market-C: Supplier/utility-specific emissions rate category), and for validating residual mix emission factors (from the Market-D: Residual mix category).

Using Supplier-Specific Delivery Metrics That Are Publicly Disclosed or Certified

Supplier-specific and utility-specific emission factors quantify indirect emissions associated with a standard product offer, green power program, or a customized power product.

Organizations may use electric delivery metrics reported and verified in accordance with [TCR’s EPS Protocol](#),¹⁴ or other publicly certified delivery metrics developed by a supplier or utility. To demonstrate the validity of factors that are not reported and verified through TCR, members must upload a public document in CRIS that identifies where the emission factor is publicly disclosed or the utility’s certification of the emission factor. The utility’s certification must describe the methodology used to develop the emission factor and, as applicable, include references to publicly available data used in its development.¹⁵

¹⁴ Emission factor tables are available at www.theclimateregistry.org.

¹⁵ These emission factors are expected to be compiled in a manner comparable to TCR’s requirements in the [EPS Protocol](#). Specifically, these factors must reflect purchased power delivered to customers and treatment of RECs should be consistent with the TCR Eligibility Criteria.

Validating Residual Mix Emission Factors

Residual mix emission factors quantify subnational or national energy production, factoring out voluntary purchases to prevent double counting of these claims.

TCR accepts residual mix emission factors that are publicly documented and are industry expert-developed or have been through a regulatory or peer review process. To validate these emission factors, members must upload public documentation of the source data in CRIS. This should include the methodology used to calculate the residual mix and where the data is publicly available.

QUANTIFYING INDIRECT EMISSIONS FROM IMPORTED STEAM, HEATING, COOLING, AND A CHP SYSTEM

This section provides advanced methods for quantifying indirect emissions from imported steam, heating, cooling, and a CHP system.

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

Some facilities purchase steam or heating, for example, 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 heating that is produced with a conventional boiler.¹⁶

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

1. Determine energy obtained from steam or heating;
2. Calculate location-based Scope 2 total for steam or heating; and,
3. Calculate market-based Scope 2 total for steam or heating.

1. Determine Energy Obtained from Steam or Heating

First, determine the quantity of acquired steam or heating. 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 obtain annual consumption.

Consumption data should be expressed in units of million British thermal units (MMBtu). If consumption data is expressed in therms, convert the values to units of MMBtu by multiplying by 0.1, as shown in the equation below.

If steam consumption is measured in pounds, either monitor the temperature and pressure of the steam received, or request this data 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.¹⁷ 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.

¹⁶ If heating is generated using electricity, refer to the advanced method on Calculating Indirect Emissions from Cooling to calculate emissions from heating.

¹⁷ Source: American Petroleum Institute, Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Gas Industry, 2001.

CONVERTING STEAM CONSUMPTION FROM THERMS TO MMBTU

Energy Consumption (MMBtu)	=	$Energy\ Consumption\ (therms) \times 0.1\ (MMBtu/therm)$
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The enthalpy of the steam can be found in standard steam tables.¹⁸ The enthalpy of saturated water at the reference conditions is 180 Btus/lb. The thermal energy consumption for the steam can then be calculated as shown in the equation below.

CONVERTING STEAM CONSUMPTION FROM POUNDS TO MMBTU

Energy Consumption (MMBtu)	=	$\frac{[Enthalpy\ of\ Delivered\ Steam - 180](\frac{Btu}{lb}) \times Steam\ consumed\ (lb)}{1,000,000\ (\frac{Btu}{MMBtu})}$
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2. Calculate Location-Based Scope 2 Total for Steam or Heating

Organizations must publicly report Scope 2 emissions for imported steam or heating in two ways, using both the location-based method and the market-based method.

A. Select a Location-Based Emission Factor

First, select the emission factors that apply to the location-based method. For steam or heating, an emission factor represents the amount of GHGs emitted per unit of energy consumed. It is usually reported in amount of GHG (in metric tons or pounds) per MMBtu of heat generated.

Organizations must select an emission factor for each unit of energy consumption, as identified in step one. Two categories of location-based emission factors are listed in order from most specific to least specific in the location-based emission factor hierarchy. Organizations should use the most specific emission factors available.¹⁹ A description of each category is described in the sections that follow.

Anthropogenic emissions associated with consumed energy must be reported in Scope 2. Combustion-based indirect biogenic emissions associated with consumed energy must be reported separately outside of the scopes.²⁰

¹⁸ E.g., Industrial Formulation 1997 for the Thermodynamic Properties of Water and Steam published by IAPWS.

¹⁹ Location-based emission factor hierarchy is adapted from WRI's GHG Protocol Scope 2 Guidance, Table 6.2.

²⁰ When a standalone biogenic CO₂ emission factor is not available for combustion-based indirect biogenic emissions (e.g., when relying on grid average factors), the member must publicly disclose that indirect biogenic emissions are or may have been excluded. Members that demonstrate that no biomass was combusted to generate consumed electricity are not subject to this requirement.

LOCATION-BASED EMISSION FACTOR HIERARCHY

1. **Location-A:** Direct line emission factors (if available)
2. **Location-B:** Regional or subnational emission factors

Location-A: Direct Line Emission Factors

Direct line emission factors represent emissions from steam or heat purchased directly from a generation source, from direct line transfers where the organization receives energy directly from a generator with no grid transfers. Emission factors may be obtained directly by the supplier, or may be estimated based on boiler efficiency, fuel mix, heat content, and carbon content.

Examples include:

- » Connected facilities where one facility creates heat or steam and transfers it directly to a facility owned or operated by an organization; and,
- » Heat or steam produced by a central boiler within a multi-tenant leased building and sold to organizations that are tenants who do not own or operate the building or equipment.²¹

Direct line emission factors should be in units of mass per unit of energy (e.g., metric tons of CO₂ emitted per MMBtu of heat generated). See the advanced method for [Quantifying Direct CO₂ Emissions with Measured Fuel Characteristics](#) for information on deriving CO₂ emission factors.

Refer to the [GHG Emissions Quantification Module](#), Indirect Emissions from Electricity Use section and the [Accounting for Renewable Energy Guidance](#) for more detail on direct

line emission factors and for guidance on their applicability to the location-based Scope 2 total.

If emission factors are not available from suppliers of heat or steam, organizations can estimate an emission factor based on boiler efficiency, fuel mix, and emission factors specific to the fuel type using a source-specific efficiency factor. Organizations should proceed to [Location-B](#) if they cannot obtain heat and carbon content from the supplier and are not able to estimate the emission factor.

Efficiency Approach Using a Source-Specific Efficiency Factor

Because emissions vary with fuel type, organizations must know the type of fuels that are burned in the plant supplying the steam or hot water or, for leased spaces, in the boiler supplying the natural gas. This information can be obtained from the plant's energy supplier. Once the fuels combusted to generate the steam or hot water are known, determine the appropriate emission factors for each fuel combusted. The most accurate approach, assuming a direct line, is to obtain CO₂ emission factors based on measured characteristics of the fuels combusted, including measured heat content and measured carbon content, from the supplier.

Next, 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 the equation below. Boiler efficiency is the ratio of steam output to fuel input, in units of energy, which should be obtained from the 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.

CALCULATING SYSTEM EFFICIENCY

Total Efficiency Factor (percentage)	=	<i>Boiler Efficiency</i> × (100 Percent × <i>Transport Losses</i>)
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²¹ The [GHG Emissions Quantification Methods Module, Indirect Emissions from Non-Electric Energy Use](#) section provides methods for calculating indirect energy use from imported steam, heating, and cooling in leased spaces.

Calculate CO₂, CH₄, and N₂O emission factors that reflect the efficiency and fuel mix of the boiler employed to generate the steam or hot water or, for leased spaces, in the boiler supplying the natural gas, using the equation below.

CALCULATING EMISSION FACTORS	
CO ₂ Emission Factor (kg CO ₂ /MMBtu)	$= \frac{\text{Fuel Specific Emission Factor } (\frac{\text{kg CO}_2}{\text{MMBtu}})}{\text{Total Efficiency Factor (percent)}}$
CH ₄ Emission Factor (kg CH ₄ /MMBtu)	$= \frac{\text{Fuel Specific Emission Factor } (\frac{\text{kg CH}_4}{\text{MMBtu}})}{\text{Total Efficiency Factor (percent)}}$
N ₂ O Emission Factor (kg N ₂ O/MMBtu)	$= \frac{\text{Fuel Specific Emission Factor } (\frac{\text{kg N}_2\text{O}}{\text{MMBtu}})}{\text{Total Efficiency Factor (percent)}}$

Efficiency approach using a default efficiency factor

If the specific system efficiency of the boiler that generated the steam or heat is unavailable, apply a default total efficiency factor—boiler efficiency and transport losses combined—of 75% in the equation above.²²

Location-B: Fuel-Specific Emission Factors

If measured heat content and measured carbon content from the supplier is not available, use the appropriate default fuel-specific emission factors for CO₂, CH₄, and N₂O from Tables 1.1 to 1.9.²³ Refer to [Location-A](#) above and use the equations in that section to calculate emission factors.

B. Calculate Emissions from Imported Steam and Heating Using the Location-Based Method

Next, use the equation below to calculate GHG emissions from imported steam or hot water or, for leased spaces, from the natural gas supplying the boiler, for the location-based method.

CALCULATING EMISSIONS FROM IMPORTED STEAM OR HEAT				
Total CO ₂ Emissions (mt)	=	Energy Consumed (MMBtu)	x	Emission Factor (kg CO ₂ / MMBtu) x 0.001 (mt/kg)
Total CH ₄ Emissions (mt)	=	Energy Consumed (MMBtu)	x	Emission Factor (kg CH ₄ / MMBtu) x 0.001 (mt/kg)
Total N ₂ O Emissions (mt)	=	Energy Consumed (MMBtu)	x	Emission Factor (kg N ₂ O / MMBtu) x 0.001 (mt/kg)

22 When using the CRIS calculator to report emissions from heating in leased spaces in CRIS, the default efficiency factor will automatically be applied.
 23 Ibid.

3. Calculate Market-Based Scope 2 Total for Imported Steam or Heating

A. Select the Appropriate Emission Factors that Apply to the Market-Based Method

If only direct line transfers are used for steam or heating, the location-based and market-based Scope 2 totals will be the same. In this case, report the location-based Scope 2 total for the market-based method.

Each unit of energy consumption must be matched with an emission factor appropriate for each facility's market.²⁴ Four types of contractual instruments that convey specific emissions rates for steam or heating are listed in order from most specific to least specific in the hierarchy below and are described in the sections that follow. Organizations should use the most specific emission factor available given the contractual instruments in their inventory.^{25,26}

MARKET-BASED EMISSION FACTOR HIERARCHY

1. **Market-A:** Energy attribute certificates (or equivalent instruments)
2. **Market-B:** Contracts
3. **Market-C:** Supplier/utility-specific emission factors
4. **Market-D:** Residual mix

These contractual instruments can only be used to calculate market-based Scope 2 emissions, and not Scope 1 or Scope 3 emissions.

Anthropogenic emissions associated with consumed energy must be reported in Scope 2. Combustion-based indirect biogenic emissions associated with consumed energy must be reported separately outside of the scopes.²⁷

Organizations must publicly disclose the category or categories of contractual instruments used to calculate emissions under the market-based method (e.g., energy attribute certificates, contracts), where possible specifying the energy generation technologies (e.g., natural gas, coal, solar, nuclear).

Market-A: Energy Attribute Certificates (or Equivalent Instruments)

Energy attribute certificates convey information about energy generation to organizations involved in the sale, distribution, consumption, or regulation of steam or heating. Refer to the [GHG Emissions Quantification Module](#), Indirect Emissions from Electricity Use section for more detail on energy attribute certificates and for guidance on their applicability to the market-based Scope 2 total.

Examples include:

- » Heat or steam contracts that convey attributes, or certificates for non-renewable generation in regions where all-generation tracking systems are in operation; and,
- » Any other energy certificates that meet the TCR Eligibility Criteria for steam or heating.

Market-B: Contracts

Contracts include direct contracts between two parties for steam or heating as well as contracts from specific sources, where energy attribute certificates do not exist or are not required for a usage claim and are not transacted or claimed in any other way, either for that resource or in that market.

Contracts are also commonly present when steam or heat is conveyed from a specific source through a direct line transfer. Organizations that have a direct line transfer for a portion of their emissions from steam or heating should refer to the [location-based emission factor categories](#).

²⁴ Organizations centrally purchasing energy attribute certificates on behalf of all their operations in a single country or region should indicate how they match these purchases to individual site consumption.

²⁵ Organizations must ensure that any contractual instrument from which an emission factor is derived meets the TCR Eligibility Criteria. Where contractual instruments do not meet these criteria, emission factors from either Market-C or Market-D must be used.

²⁶ Market-based method emission factor hierarchy adapted from WRI's *GHG Protocol Scope 2 Guidance*, Table 6.3.

²⁷ When a standalone biogenic CO₂ emission factor is not available for combustion-based indirect biogenic emissions (e.g., when relying on grid average factors), the member must publicly disclose that indirect biogenic emissions are or may have been excluded. Members that demonstrate that no biomass was combusted to generate consumed electricity are not subject to this requirement.

Refer to the [GHG Emissions Quantification Module](#), Indirect Emissions from Electricity Use section for more detail on contracts and for guidance on their applicability to the market-based Scope 2 total.



Examples include:

- » Direct line transfers; and,
- » PPAs or contracts for energy from specific non-renewable sources (e.g., coal, nuclear) outside of regions where all-generation tracking systems are in operation.

Market-C: Residual Mix

Residual mix emission factors quantify subnational or national energy production, factoring out voluntary purchases to prevent double counting of these claims.²⁸

Organizations must publicly disclose the lack of an available residual mix emission factor if one is not available. Refer to the [GHG Emissions Quantification Module](#), Indirect Emissions from Electricity Use section for more detail on residual mix emission factors and for guidance on their applicability to the market-based Scope 2 total.

Market-D: Fuel-Specific Emission Factors

If none of the preferred market-based emission factors are available, refer to the [location-based emission factor categories for steam or heating](#). Examples of fuel-specific emission factors include:

- » U.S. fuel-specific default emission factors (Tables 1.1, 1.9);²⁹
- » Canadian fuel-specific default emission factors (Tables 1.2-1.4); and,³⁰
- » International sector-specific default emission factors by fuel type (Tables 2.5-2.8, 1.10).³¹

B. Ensure Contractual Instruments Meet TCR Eligibility Criteria for Steam and Heating

TCR defines certain eligibility criteria that are designed to ensure that emission factors used to calculate the market-based Scope 2 total for steam and heating are consistent with GHG accounting best practices.

Members must upload a public document identifying the contractual instrument certification program(s) or other documentation that demonstrates clear and explicit ownership and TCR eligibility in CRIS (e.g., self-attestation form).

²⁸ No annual, grid-average third-party developed residual mix emission factors were available at the time GRP v. 3.0 was published. Members may contact TCR at help@theclimateregistry.org for updated information or to assess the applicability of a regional residual mix emission factor.

²⁹ Emission factor tables are available at www.theclimateregistry.org.

³⁰ Ibid.

³¹ Ibid.

TCR Eligibility Criteria for Steam and Heating³²

CRITERIA	DESCRIPTION
Contractual instruments must:	
1. Convey GHG information	<ul style="list-style-type: none"> » Convey the direct GHG emission rate attribute associated with produced steam or heat, to be calculated based on its characteristics.
2. Prevent double counting	<ul style="list-style-type: none"> » Be the only instrument that carries the GHG emission rate attribute claim associated with that quantity of produced steam or heat. Clear and explicit ownership must be demonstrated by either third-party verification that includes a chain of custody audit, or documentation of permanent retirement in an electronic tracking system in a dedicated, named retirement subaccount for a particular TCR reporting year. » Be distinct from offsets. A MWh generated by a renewable energy project and claimed as an offset cannot also be claimed as a contractual instrument.
3. Be retired	<ul style="list-style-type: none"> » Be tracked, redeemed, retired, or canceled by or on behalf of the reporting organization.
4. Be of recent vintage	<ul style="list-style-type: none"> » Have been generated within a period of six months before the reporting year to up to three months after the reporting year.
5. Be sourced from same market as operations	<ul style="list-style-type: none"> » Be sourced from the same market in which the reporting organization's steam or heat consuming operations are located and to which the instrument is applied. Market boundaries are assumed to match national boundaries, except where international grids are closely tied.
Direct line generation or organizations consuming on-site generation must:	
6. Convey GHG claims to the member	<ul style="list-style-type: none"> » Ensure that all emission claims are transferred to the reporting organization only.
All contractual instruments must:	
7. Residual mix	<ul style="list-style-type: none"> » Operate in markets with an adjusted, residual mix emission factor characterizing the GHG intensity of unclaimed energy. Organizations must disclose the lack of an available residual mix emission factor if one is not available.

³² TCR's Eligibility Criteria for steam and heating are based on the Scope 2 Quality Criteria in the *GHG Protocol Scope 2 Guidance* and have been adapted for steam, heating, and gas transactions. They may also reflect additional requirements from international best practice.

C. Calculate Emissions from Imported Steam or Heating for the Market-Based Method

Refer to the [location-based method](#) for guidance on calculating emissions using total energy consumed and the appropriate emission factors.

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

Combined heat and power (CHP) systems simultaneously produce electricity and heat (or steam). When two or more parties receive the energy streams from CHP systems, indirect GHG emissions must be determined and allocated separately for heat production and electricity production. Allocation avoids double counting of the same GHG emissions in each product stream.

Since the output from CHP results simultaneously in heat and electricity, organizations can determine what “share” of the total emissions is a result of electricity and heat by using a ratio based on the energy content of heat and/or electricity relative to the CHP system’s total output.

The process for estimating indirect emissions from heat and power produced by a CHP system involves the following three steps:

1. Obtain total emissions and power and heat generation information from CHP system;
2. Determine emissions attributable to net heat production and electricity production; and,
3. Calculate emissions attributable to the portion of heat and electricity consumed according to the location-and market-based methods.

1. Obtain Emissions and Power and Heat Information from the CHP System

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

- » Total emissions of CO₂, CH₄, and N₂O from the CHP system, based on fuel input information;
- » Total electricity production from the CHP system, based on generation meter readings; and,
- » Net heat production from the CHP system.

Net heat production refers to the useful heat that is produced in the CHP system, minus whatever heat returns to the boiler as steam condensate, as shown in the equation below. (Alternatively, refer to Step 2 of the advanced method for [Allocating Emissions from Combined Heat and Power](#) for guidance on determining net heat production from steam temperature and pressure data.)

CALCULATING NET HEAT PRODUCTION	
Net Heat Production (MMBtu)	= $Heat\ of\ Steam\ Export\ (MMBtu) - Heat\ of\ Return\ Condensate\ (MMBtu)$

2. Determine Emissions Attributable to Net Heat Production and Electricity Production

Refer to the [GHG Emissions Quantification Module](#), Direct Emissions from Stationary Combustion section and the advanced method for [Quantifying Direct CO₂ Emissions with Site-specific Data](#).

Refer to the advanced method for [Allocating Emissions from Combined Heat and Power](#) to calculate emissions attributable to net heat and electricity production.

3. Calculate Emissions Attributable to the Portion of Heat and Electricity Consumed According to the Location-Based and Market-Based Methods

Once the total emissions attributable to heat (or steam) and electricity production have been determined, organizations will need to determine the portion of heat or electricity they have consumed, and thus their indirect GHG emissions associated with heat or electricity use. Indirect emissions associated with this heat or electricity use must be reported according to both the location-based and market-based methods (refer to the [GHG Emissions Quantification Module](#), Indirect Emissions from Electricity Use section).

This section assumes there is a direct line transfer between the generator and the user. When this is the case, methods in the [GHG Emissions Quantification Module](#), Direct Emissions from Stationary Combustion section or the advanced methods for [Quantifying Direct CO₂ Emissions with Site-specific Data](#) section in this module will be sufficient for calculating indirect emissions associated with the generation according to both the location-based and market-based methods. In the case of grid-connected CHP, refer to the location-based and market-based emission factor categories for electricity in the [GHG Emissions Quantification Module](#), Indirect Emissions from Electricity Use section.

First, obtain electricity and heat (or steam) consumption information, and then use the equations below to calculate the share of emissions according to both the location-based and market-based methods, as appropriate.

CALCULATING INDIRECT EMISSIONS ATTRIBUTABLE TO ELECTRICITY CONSUMPTION

Indirect Emissions Attributable to Electricity Consumption (mt)	=	$\frac{\text{Total CHP Emissions Attributable to Electricity Production (mt)} \times \text{Your Electricity Consumption (kWh)}}{\text{Total CHP Electricity Production (kWh)}}$
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CALCULATING INDIRECT EMISSIONS ATTRIBUTABLE TO HEAT (OR STEAM) CONSUMPTION

Indirect Emissions Attributable to Heat Consumption (mt)	=	$\frac{\text{Total CHP Emissions Attributable to Heat Production (mt)} \times \text{Your Heat Consumption (MMBtu)}}{\text{CHP Net Heat Production (MMBtu)}}$
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If contractual instruments are purchased and eligible to be claimed, these may only be applied to the portion of the facility's emissions that are consumed by the organization.

Calculating Indirect Emissions from 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 organizations purchase cooling services using cooling, the compressor system that produces the cooling is driven by either electricity, fossil fuel combustion, or biofuel combustion.

Organizations reporting emissions from purchased cooling must report Scope 2 emissions in two ways, using both the location-based and market-based methods.

Anthropogenic emissions associated with consumed energy must be reported in Scope 2. Combustion-based indirect biogenic emissions associated with consumed energy must be reported separately outside of the scopes.³³

Organizations must first determine the total cooling use by summing the total cooling from monthly cooling bills. Then, use either the detailed approach or simplified approach to estimate GHG emissions from cooling based on the data that is available.

Detailed Approach to Calculate Indirect Emissions from Cooling

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

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

The process for calculating combustion emissions from cooling plants is described in the [GHG Emissions Quantification Module](#), Direct Emissions from Stationary Combustion section and the advanced methods for [Quantifying Direct CO₂ Emissions with Site-specific Data](#) in this module. Organizations will need to obtain the emission values from the cooling plant, or calculate the emissions based on the fuel consumption or any contractual instruments using emission factors from the location-based and market-based emission factor categories (refer to the GHG Emissions Quantification Methods Module, Indirect Emissions from Electricity Use section. If only direct line transfers are used for cooling and any certificates are retained, the location-based and market-based Scope 2 totals will be the same.

In the simplest case, all of the fuel consumed by the plant is used to provide cooling. In that case, organizations will be able to determine Scope 2 cooling emissions based on total direct emissions from cooling plant fuel combustion (metric tons).

³³ When a standalone biogenic CO₂ emission factor is not available for combustion-based indirect biogenic emissions (e.g., when relying on grid average factors), the member must publicly disclose that indirect biogenic emissions are or may have been excluded. Members that demonstrate that no biomass was combusted to generate consumed electricity are not subject to this requirement.

Simplified Approach to Calculating Indirect Emissions from Cooling

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).³⁴ This approach allows organizations to estimate the portion of energy used at the cooling plant directly attributable to the organization’s cooling. This involves the following steps:

1. Determine annual cooling demand;
2. Estimate COP for the plant’s cooling system;
3. Determine energy input; and,
4. Calculate GHG emissions resulting from cooling.

1. Determine Annual Cooling Demand

Cooling demand is typically reported in ton-hours. Convert ton-hours of cooling demand to MMBtu using the equation below. If billed monthly, sum together monthly cooling demand to yield an annual total.

CALCULATING ANNUAL COOLING DEMAND	
Cooling Demand (MMBtu)	$= \frac{\text{Cooling Demand (ton – hour)} \times 12,000 \left(\frac{\text{Btu}}{\text{ton-hour}} \right)}{1,000,000 \left(\frac{\text{MMBtu}}{\text{Btu}} \right)}$

2. Determine COP for the Plant’s Cooling System

The most accurate approach is to obtain the source-specific COP for the cooling plant. Organizations that can obtain the COP for the cooling plant should proceed to Step 3. If organizations cannot obtain the COP for the plant itself, determine the type of chiller used by the cooling plant. With that information, a rough estimate of the COP may be selected from the default values shown in Table 1.

Table 1. Typical Chiller Coefficients of Performance

CHILLER TYPE	COP	ENERGY SOURCE
Absorption Chiller	0.8	Natural Gas
Engine-Driven Compressor	1.2	Natural Gas

Source: California Climate Action Registry General Reporting Protocol Version 3.1, January 2009.

3. Determine Energy Input

To determine the energy input to the system resulting from cooling demand, use the equation below.

CALCULATING ENERGY INPUT	
Energy Input (MMBtu)	$= \frac{\text{Cooling Demand (MMBtu)}}{\text{COP}}$

³⁴ Note that this approach is not considered a Simplified Estimation Method (SEM).

4. Calculate GHG Emissions Resulting from Cooling

To calculate the location-based and market-based Scope 2 totals for indirect emissions using the simplified approaches, refer to [GHG Emissions Quantification Module](#), Indirect Emissions from Electricity Use section.

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 the [GHG Emissions Quantification Module](#), Direct Emissions from Stationary Combustion section and the advanced methods for [Quantifying Direct CO₂ Emissions with Site-specific Data](#). If the type of fuel used is known, multiply the energy input by source-specific or default emission factors for CO₂, CH₄, and N₂O from Tables 1.1 to 1.9.³⁵ If the fuel type cannot be determined, assume the fuel used is natural gas. Use the equation below to calculate emissions.

CALCULATING TOTAL COOLING EMISSIONS						
Total CO₂ Emissions (mt)	=	<i>Energy Input (MMBtu)</i>	x	<i>Emission Factor (kg CO₂ / MMBtu)</i>	x	<i>0.001 (mt/kg)</i>
Total CH₄ Emissions (mt)	=	<i>Energy Input (MMBtu)</i>	x	<i>Emission Factor (kg CH₄ / MMBtu)</i>	x	<i>0.001 (mt/kg)</i>
Total N₂O Emissions (mt)	=	<i>Energy Input (MMBtu)</i>	x	<i>Emission Factor (kg N₂O / MMBtu)</i>	x	<i>0.001 (mt/kg)</i>

³⁵ Emission factor tables are available at www.theclimateregistry.org.

QUANTIFICATION OF DIRECT FUGITIVE EMISSIONS USING THE ADVANCED MASS BALANCE METHOD

The advanced mass balance method is the most accurate method for determining HFC and PFC emissions. To calculate HFC and PFC emissions using this method, organizations will need to determine the amount of refrigerant in storage at the beginning of the year, and account for any changes based on refrigerant purchases and sales and changes in total equipment capacity. Table 2 is a template that lists various aspects of changes to the base year inventory.

Table 2. 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)	

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 2. 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.

2. Calculate Any 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 2). 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 the organization’s 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 2). 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 2). 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.

3. Calculate Annual Emissions of Each HFC and PFC Gas

For each refrigerant or refrigerant blend, use the equation below and data from Table 2 to calculate total annual emissions of each HFC and PFC gas at each facility.

CALCULATING EMISSIONS OF EACH OF HFC OR PFC GAS USING THE ADVANCED MASS BALANCE METHOD

Total Annual Emissions (mt of HFC or PFC)	=	$\frac{[A - B + C - D - E] (kg)}{1,000 \frac{kg}{mt}}$
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E. REPORTING AN INVENTORY

This module describes additional information that members must include with their emissions to complete their greenhouse gas (GHG) inventory. Members may also report optional information to better illustrate their emissions management strategy, goals and achievements. Optional information can include purchased offsets, a net inventory, performance metrics, or other supplemental information.

Members interested in publicly disclosing their inventory must have their inventories third-party verified. Members can choose which optional information to disclose to stakeholders and which they would like to keep private to use for internal purposes, and can choose to report with different levels of granularity in The Climate Registry Reporting System (CRIS).

ADDITIONAL REPORTING REQUIREMENTS

GHG emissions data is the primary information that members report to the Carbon Footprint Registry. However, TCR also requires members to publicly disclose the following additional information:

- » Information about the entity (address, key contacts, etc.);
- » Any member-defined criteria for defining relevant indirect emissions, if different from TCR's criteria for relevance;^{1,2}
- » A description of the reporting boundary, including any excluded emissions and explanation of the reason for their exclusion;³

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- 1 For the purposes of reporting to TCR, all Scope 1 and Scope 2 emissions as well as combustion-based biogenic direct emissions and combustion-based biogenic indirect CO₂ emissions associated with energy consumption are relevant. The following emission sources are not relevant: approved miniscule sources, biogenic emissions other than those associated with the combustion of biomass, and emission sources identified as optional in the protocols.
 - 2 Members seeking to conform to ISO 14064-1:2018 should refer to TCR's guidance on the meeting additional requirements of the ISO standard, since ISO 14064-1: 2018 criteria for relevant emissions includes significant Scope 3 emissions.
 - 3 Members are not required to include a description of the reporting boundary and/or an explanation of why TCR-approved miniscule sources are excluded for inventories that include all relevant emissions.

- » If combustion-based indirect biogenic emissions associated with energy consumption are included in the reporting boundary but are not reported, a statement that a standalone biogenic CO₂ emission factor is not available;
- » The reporting year (e.g., calendar year or fiscal year);
- » The set of Global Warming Potential (GWPs) applied;⁴
- » The consolidation approach(es) employed (e.g., operational control, financial control, equity share);
- » Industry type based on North American Industry Classification System (NAIC) Code;
- » If the member is reporting as a subsidiary and the parent company is also reporting, the identity of the parent company as it appears in CRIS; and,
- » Explanation of any change to or recalculation of a base-year or previous GHG inventory.⁵

OPTIONAL REPORTING

TCR encourages members to exceed reporting requirements by providing optional data in addition to the required data in the Additional Reporting Requirements section. Reporting optional data enhances the value of the inventory to stakeholders and the transparency of the emission report and the member's environmental leadership.

Offsets

Offsets represent the reduction, removal, or avoidance of GHG emissions from a specific project that is used to compensate for (i.e., offset) GHG emissions occurring elsewhere, for example, to meet a voluntary GHG target. A carbon offset represents one ton of carbon

dioxide equivalent. Some regulatory and voluntary programs generate carbon credits from certified carbon offsets projects, which can then be tracked, traded and retired for compliance or voluntary purposes. The purchase and retirement of offset credits may be disclosed as additional information items.⁶ Offsets may be applied to Scope 1, Scope 2, Scope 3 or biogenic emissions in a net inventory, separately from the primary inventory totals. If offsets are applied to Scope 2 emissions, the same offsets must be applied to both the location-based emissions and market-based emissions totals.

Offset credits applied to an adjusted inventory must meet TCR's offset requirements, below:

- » **Real:** GHG reductions must represent actual emission reductions quantified using comprehensive accounting methods.
- » **Additional:** GHG reductions or removals must be surplus to regulation and beyond what would have happened in the absence of the incentive provided by the offset credit.⁷
- » **Permanent:** GHG reductions must be permanent or have guarantees to ensure that any losses are replaced in the future.
- » **Transparent:** Offset projects must be publicly and transparently registered to clearly document offset generation, transfers and ownership.
- » **Verified:** GHG reductions must result from projects whose performance has been appropriately validated and verified to a standard that ensures reproducible results by an independent third-party that is subject to a viable and trustworthy accreditation system.
- » **Owned Unambiguously:** No parties other than the project developer, must be able to reasonably claim ownership of the GHG



4 Members seeking to conform to ISO 14064-1:2018 must provide justification for the GWP selected if the latest IPCC GWP is not used.
 5 Members seeking to conform to ISO 14064-1:2018 must also document any limitations to comparability resulting from a recalculation of a base year or previous GHG inventory.
 6 Members seeking to report in accordance with ISO 14064-1 should refer to TCR's guidance on the treatment of offsets in ISO 14064-1:2018.
 7 Offsets quantified using a project vs. performance standard methodology may establish slightly different requirements for demonstrating additionally.

reductions represented by the offset credits.

Offset credits that are applied to a net inventory total or disclosed as additional information can only be used once and must be retired prior to the date they are reported to TCR. Members that wish to apply offset credits to a net inventory total or disclose offsets as additional information must also disclose the offset program or GHG scheme under which the offsets were generated.

TCR recognizes offset credits that have been issued or recognized by the following offset programs:

- » State, province, territorial, or federal regulatory agencies in North America;
- » American Carbon Registry;
- » Clean Development Mechanism;
- » Climate Action Reserve;
- » The Gold Standard;
- » Joint Implementation;
- » Verified Carbon Standard; and,
- » Other programs meeting equivalent standards upon TCR staff evaluation.⁸

Members purchasing carbon offsets in the retail market can gain assurance about the validity of their purchases by seeking out retail offset certification. One such certification program is Green-e.

Performance Metrics

Performance metrics provide information about an organization's direct and indirect emissions relative to a unit of business activity, input, or output. Members may use performance metrics to serve a range of objectives, including:

- » Evaluating emissions over time in relation to targets or industry benchmarks;
- » Facilitating comparisons between similar organizations, process or products; and,
- » Improving public understanding of the emissions profile over time, even as an organization's activity changes.

Many organizations track environmental performance with GHG intensity metrics, which measure GHG emissions per economic unit or unit of physical activity.

TCR currently has standards for several performance metrics specific to different sectors. These metrics can sometimes be used as inputs to the GHG inventories of other organizations in the supply chain, including customers or suppliers. For example, an electric utility customer may use a power delivery metric from their utility (e.g., emissions per megawatt hour of electricity product sold) as the emission factor to calculate and report market-based Scope 2 emissions.

Electric Power Generation and Deliveries Metrics

The [Electric Power Sector \(EPS\) Protocol](#) contains requirements for developing both electricity generation and delivery metrics, which provide helpful information for other members working to better quantify market-based Scope 2 emissions. Load serving entities (e.g., electric power utilities) publicly reporting to TCR are required to quantify and report generation metrics and may opt to develop delivery metrics. Published delivery metrics are available at www.theclimateregistry.org, and published generation metrics are available in the Public Reports section of <https://www.cris4.org> within supporting documents.

⁸ Contact TCR at help@theclimateregistry.org to request evaluation of additional offset programs.

Transit Agency Performance Metrics

TCR has developed a set of performance metrics that provide transit agencies with a reliable, transparent, and clear communication tool that can be used to explain carbon efficiency to policymakers, the public and other stakeholders. Reporting of these metrics are optional. For more information on the transit agency performance metrics, visit www.theclimateregistry.org.

Water and Wastewater Agency Performance Metrics

TCR has developed two sets of reporting guidance for members of the water sector in California. The Water-Energy Nexus Registry (WEN Registry) Protocol includes standards and guidance for WEN Registry participants to report their entity-wide carbon footprint and water-related performance metrics. *Water-Energy GHG (WEG) Metrics: Performance Metrics for Water Managers in Southern California* provides additional guidance to water managers with operations in Southern California. These documents define system average and product-specific metrics that measure the GHG intensity of water-related operations or deliveries. Product-specific metrics may be used to communicate the emissions associated with water-related products purchased by distinct customer groups, while the system average reflects the total emissions related to water management across the system. Members may elect to report some or all of the water-related performance metrics alongside their GHG inventory.

Optional Data

Members may include supplemental data or information with the emissions report. Among a wide array of optional data, TCR encourages members to consider including the following:

- » Unit-level emissions (for stationary combustion units);
- » Emissions based on more than one of the consolidation approaches described in the [Inventory Boundaries Module](#) (i.e., report emissions on both an equity share and operational control basis, or both an equity share and financial control basis);
- » Scope 2 disclosure;
 - » Key features of contractual instruments, such as instrument certification labels, characteristics of energy generation facilities, GHG type reported that does not have a specific emission rate under a contractual instrument (e.g., CH₄ or N₂O), and policy context;
 - » Total annual energy consumption reported separately from the scopes (e.g., in kWh, BTU), including any energy consumed from owned/operated energy producing facilities;
 - » Percentage of overall electricity consumption reported in the market-based method that reflects markets *without* contractual information available;
 - » Scope 2 totals for each method disaggregated by country;
 - » Estimation of avoided emissions from contractual instrument purchases, reported separately from the scopes;
 - » Advanced grid studies or real-time information if it is available, reported separately from the Scope 2 totals as a comparison to the location-based method;
 - » Contractual instrument purchases that do not meet TCR Eligibility Criteria, including details on which criteria were not met and why;
 - » Relationship to emission trading programs (e.g., cap-and-trade or emission rate trading),

if applicable, and Scope 2 totals calculated by other regulatory methods;

- » Additional certificate or other instrument retirements performed in conjunction with a member's voluntary claim (e.g., certificate multipliers or pairing undertaken for regulatory or voluntary purposes);
 - » Scope 2 method used to calculate Scope 3 emissions from fuel- and energy-related emissions not included in Scopes 1 and 2 (if this is reported); and,
 - » Role of member's procurement practices in driving new projects.
- » Scope 3 emissions and description of relevant Scope 3 calculation methods;
 - » Information on any GHG management or reduction programs or strategies, such as purchases of offsets (including information on whether they are verified or certified); and,
 - » Descriptions of unique environmental practices.

THIRD-PARTY VERIFICATION

Third-party verification is defined as an independent expert assessment of the accuracy and conformity of an emissions inventory based on the reporting requirements contained in the GRP, and the verification requirements described in TCR's [General Verification Protocol](#).

Third-party verification provides confidence to users that the emission report represents a faithful, true, and fair account of emissions—free of material misstatements and conforming to the accounting and reporting rules in the documents listed above. Verification ensures that all data published by The Climate Registry is accurate, consistent and transparent.

Verification is optional for members, but is required for publication of emissions inventories in CRIS.

Members can refer to TCR's guidance for more information on the member's role in the verification process.

REPORTING DATA IN CRIS

CRIS is TCR's proprietary online platform for members to calculate, report, verify, and disclose GHG emissions. CRIS provides multiple options to calculate and report GHG emissions on an annual basis, and produces user-friendly reports for both TCR members and the public. Since organizations have different approaches for collecting and tracking GHG emissions data, CRIS provides a number of data entry options to allow organizations to easily report GHG data in a way that aligns with their own internal processes.

Getting Started in CRIS

User Accounts

TCR members are able to create two different types of user accounts with distinct permissions, an Entity Editor or an Entity Administrator account. More information on the features and permission levels for each user type can be found in the CRIS User Guide available in [CRIS](#).

Inventory Details

Each year, members will update information about their organization and the annual emission inventory being reported. These updates include selection of the Global Warming Potentials (GWPs) used to calculate carbon dioxide equivalents, the public base year or period used for tracking emissions over time, addresses and contact information, and the TCR-recognized verification body that will review the inventory.

Global Warming Potential

Members may choose which IPCC Assessment Report and associated GWP set will be applied to each inventory reported in CRIS. The default GWP standard at the time of publication is "AR5," the IPCC's Fifth Assessment Report. The GWP standard will have a direct impact on the calculations that are completed in CRIS and members may update the standard at any time.

Data Entry

Members can report data at three different levels of granularity in CRIS: entity level, facility level and source level. Entity-level reporting refers to total organization-wide emissions. Facility-level emissions are total emissions for a given facility. Members may report emissions for individual sources within a facility (e.g., electricity and natural gas for offices or gasoline and diesel for vehicles) at the source level. Members have the option to report pre-calculated data or enter raw activity data in the emissions calculator, or a combination of each. The sections that follow describe the different approaches that organizations can take when reporting emissions in CRIS.

Entity-Level Reporting

Members that decide to report emissions at the entity level submit either raw activity data or pre-calculated data for one or more facilities in CRIS. If the inventory is reported according to both a control and entity share consolidation methodology, the member must report additional facilities to accurately reflect the equity share. Public reports contain only aggregated entity-level data.

Facility-Level Reporting

Members also have the option to report pre-calculated data at the individual facility level, or by aggregating like facilities. This provides more transparency to public stakeholders than entity-level reporting. Public reports will display the emissions totals of each emission source category for each facility.⁹

Source-Level Reporting

Members may choose from the following options to report GHG emissions at the source-level:

- » Use the CRIS emissions calculator to perform GHG emissions calculations. This involves

inputting activity data (e.g., kWh of electricity consumed or gallons of fuel combusted) and selecting the appropriate default emission factor supplied by the CRIS calculator to calculate emissions. TCR compiles default emission factors from publicly available sources and updates the factors in CRIS annually. Emission factors can also be customized in the emissions calculator if a more specific factor is available.

- » Perform emissions calculations offline and submit pre-calculated data at the source level.
- » Submit emissions from sources monitored with CEMS, PART 70 CEMS, and PART 60 CEMS as pre-calculated data.

Public reports will only display the emissions totals by emission source category for each facility, not raw activity data.

Forms and Documents

CRIS contains built-in forms designed to disclose supplemental information and provide more context about an inventory. Depending upon a member's inventory, certain forms will be required and made public after verification. Members can submit optional forms for internal tracking purposes, which will remain private.

Self-Defined Boundary Form

Members that choose to define their own reporting boundary (i.e., define a reporting boundary that does not meet TCR's criteria for relevance¹⁰) must document the activities included in their inventory by completing the *Self-Defined Boundary Form*. Members can disclose the selected geographic boundary of the inventory, the GHGs included, and which activity types are included or excluded from the inventory. Once the inventory has been verified, this form will be made publicly available.

⁹ Emission source categories include stationary combustion; mobile combustion; process emissions; fugitive emissions; indirect emissions from consumed energy; combustion-based direct biogenic emissions and combustion-based indirect biogenic emissions associated with consumed energy.

¹⁰ For the purposes of reporting to TCR, all Scope 1 and Scope 2 emissions as well as combustion-based direct biogenic emissions and combustion-based indirect biogenic emissions associated with consumed energy are relevant. The following emission sources are not relevant for reporting to TCR: approved miniscule sources, biogenic emissions other than those associated with the combustion of biomass, and emission sources identified as optional in the protocols.

Exclude Miniscule Sources Form

TCR has designated a list of small sources of emissions that represent a high reporting burden for particular sectors. Members may exclude miniscule emission sources relevant to their sector by disclosing that the sources exist, but are not quantified and reported, using the *Exclude Miniscule Sources Form*. Once the inventory has been verified, this form will be publicly available.

Apply Purchased Offsets Form

Members may apply purchased carbon offset credits to Scope 1, Scope 2, Scope 3 and biogenic emissions in an adjusted inventory by using the *Apply Purchased Offsets Form*. When reported, offsets will appear as a line item in the member's entity emissions summary grids (mt CO₂e) on both public and private reports. Adjusted emissions totals for each scope are displayed separately from the primary emissions totals.

Indirect Emissions Disclosure Form

The *Indirect Emissions Disclosure Form* is required for members undergoing verification and communicates additional information about the contractual instruments associated with specific facilities and sources, the availability of residual mix emission factors, and the inclusion or exclusion of indirect biogenic emissions in an inventory. The form also allows members to disclose either the market-based or location-based Scope 2 total for an inventory if they have chosen exclude either category of emissions from the public emissions report. Once the inventory has been verified, this form will be publicly available.

Supporting Documents

Members may upload additional required and optional documentation to CRIS, such as sector-specific reports (e.g., EPS report, LGO standard inventory report, transit agency metrics), spreadsheets of calculations performed offline, energy attribute certificates or contracts for contractual instruments (e.g., power purchase agreements), and inventory management plans. Documents should be marked as public if they provide supporting information for the public

emissions inventory, or marked as private if they are for internal tracking and verification body review only.

Submitting an Inventory

Once a member has finished reporting an inventory, they may submit it to a verification body to complete verification and make the emissions report public. The following tools are available to assist members prior to submitting inventories for verification.

Inventory Submission Checklist

The Inventory Submission Checklist is a tool that members can use to check that they have completed all of the required steps in the reporting process and uploaded all necessary supporting documentation. Completing the checklist is optional, and is only intended to assist members in preparing their submission. Verification bodies can review this list, but will not make any assessments about the accuracy of an inventory based on the member's responses on the checklist.

Activity History Log

The Activity History Log contains information on each step of the inventory submission process, including who changed the workflow and when, and the date that the inventory reporting process initially began.

Quality Assurance Check

As a part of the inventory submission process, CRIS runs a number of checks on an inventory to identify any potential issues with the reported data. CRIS checks whether or not a member has:

- » reported emissions for each of the active sources and facilities;
- » included all of the sources from the previous reporting year in the current inventory;
- » added any new facilities;
- » reported CH₄ and N₂O for all of the combustion sources;
- » exceeded the 10% limit for estimating emissions using simplified estimation methods (SEMs); and/or,
- » selected a verification body.

There are two types of notifications that the Quality Assurance Check may generate: warnings and errors. Warnings are non-critical messages notifying a member that there may be potential issues with the inventory. Members are advised to address the warnings before submitting an inventory, but they will not prevent members from moving to the verification process. Errors are critical issues that must be addressed before members can submit an inventory to the verification body.

Verification

Once a member has selected a verification body and submitted an inventory, the verification body is automatically notified of the submission. Verification bodies have access to all reported data, supporting documentation and forms, and are able to submit requests for members to make corrections directly in CRIS.

Generating Reports

CRIS allows both members and the general public to generate reports on emissions data. Members can view their own reported emissions data in CRIS at any time by running private reports. Any member of the public with a CRIS login can access reports that have been verified and published.

Please view the CRIS Terms of Use for more information on the storage of reported data in CRIS (public and private). The Terms of Use can be viewed by selecting “Register for a new account” on the [CRIS](#) home page.

Public Reports

After an emissions inventory is successfully verified by a third-party verification body, it is published in CRIS. Verified reports are available to the general public and display emissions totals at either the entity- or facility-level. CRIS users can customize the information included in public reports by selecting a specific Region (Global or North America Only), Level of Detail (Detail or Summary), and the Organizational Boundary (Control, Equity Share and Control, or Equity Share Only).

Private Reports

Members have the ability to generate reports containing more information about an inventory than the public reports. The Detail Report—Control (Private) and the Data Extract Report are the most comprehensive reports available. Members can customize the information included in reports by selecting a specific Region (Global or North America Only), Level of Detail (Detail or Summary), and the Organizational Boundary (Control, Equity Share and Control, or Equity Share Only).

Detail Report—Control (Private)

The Private Detail Report provides a summary of entity-level emissions totals, as well as emissions at the facility- and source-levels if that level of data granularity is reported in CRIS. It is best to download this report from CRIS as a PDF file.

Data Extract

A Data Extract provides a line-by-line spreadsheet of all of the data a member has entered into CRIS, which can then be filtered and sorted using Excel. It is best to download this report from CRIS as an Excel file.

ABBREVIATIONS AND ACRONYMS

AR5	Intergovernmental Panel on Climate Change Fifth Assessment Report
Btu	British thermal unit(s)
C	Carbon
CARB	California Air Resources Board
CEMS	Continuous Emissions Monitoring System
CFC	Chlorofluorocarbon
CHP	Combined heat and power
CH₄	Methane
COP	Coefficient of performance
CO₂	Carbon dioxide
CO₂e	Carbon dioxide equivalent
CRIS	Climate Registry Information System
eGRID	Emissions and Generation Resource Integrated Database
EPS	Electric Power Sector
EU ETS	European Union Emission Trading Scheme
FE	Fuel economy
GCV	Gross caloric value
GHG	Greenhouse gas
GPP	Green Power Product
GRP	General Reporting Protocol
GVP	General Verification Protocol

GWP	Global warming potential
HCFC	Hydrochlorofluorocarbon
HFC	Hydrofluorocarbon
HHV	Higher heating value
HSE	Health, safety, and environmental
HVAC	Heating, ventilation, and air conditioning
IAPWS	International Association for the Properties of Water and Steam
ICLEI	International Council for Local Environmental Initiatives
IPCC	Intergovernmental Panel on Climate Change
IEA	International Energy Agency
ISO	International Organization for Standardization
kg	Kilogram(s)
kWh	Kilowatt-hour(s)
lb	Pound
LGO	Local Government Operations
LHV	Lower heating value
LPG	Liquefied petroleum gas
LTO	Landing and takeoff
MMBtu	One million British thermal units
mpg	Miles per gallon
MRV	Measurement, reporting and verification

MSW	Municipal solid waste
mt	Metric ton
MWh	Megawatt-hour(s)
NAIC	North American Industry Classification System
NCV	Net calorific value
NEPOOL GIS	New England Power Pool Generation Information System
NERC	North American Electric Reliability Corporation
NF₃	Nitrogen trifluoride
N₂O	Nitrous oxide
NYGATS	New York Generation Attribute Tracking System
PFC	Perfluorocarbon
PPA	Power purchase agreement
PJM GATS	Pennsylvania, Jersey, Maryland Generation Attribute Tracking System

RECs	Renewable energy certificates
RY	Reporting year
scf	Standard cubic foot
SEM	Simplified Estimation Method
SF₆	Sulfur hexafluoride
T&D	Transmission & distribution
TCR	The Climate Registry
U.S.	United States
U.S. EPA	United States Environmental Protection Agency
VB	Verification Body
WBCSD	World Business Council for Sustainable Development
WEG	Water-Energy Greenhouse Gas
WEN	Water-Energy Nexus
WRI	World Resources Institute

GLOSSARY OF TERMS

ACTIVITY DATA

Measure of a level of activity that results in greenhouse gas (GHG) emissions (e.g., gallons of fuel or kWh of electricity consumed).

ANTHROPOGENIC EMISSIONS

GHGs emitted into the atmosphere as a direct result of human activities (i.e., the burning of fossil fuels).

BASE YEAR (OR BASE PERIOD)

A benchmark against which an organization's current or future emissions are compared. A base period is referred to as a base year for simplicity.

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 topsch, 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 water body 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 EMISSIONS

Carbon dioxide (CO₂) generated during the combustion or decomposition of biologically-based material.

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 biodegradable organic fractions of industrial and municipal wastes, including gases and liquids recovered from the decomposition of non-fossilized and biodegradable organic material.

CALCULATION-BASED

Emission quantification methods that involve the calculation of emissions based on emission factors and activity data such as input material flow, fuel consumption, or product output.

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.

CARBON DIOXIDE EQUIVALENT

(CO₂e) The universal unit for comparing emissions of different GHGs expressed in terms of the global warming potential (GWP) of one unit of carbon dioxide.

COMBINED HEAT AND POWER

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.

CONSUMED ENERGY

Purchased or acquired electricity, steam, heating, or cooling.

CONTINUOUS EMISSION MONITORING SYSTEM (CEMS)

Monitors installed in energy and industrial operations to continuously collect, record and report emissions data.

CONTRACTUAL INSTRUMENT

Any type of contract between two parties for the sale and purchase of energy bundled with energy generation attributes, or for unbundled attribute claims. Contractual instruments applied to an inventory must meet the TCR Eligibility Criteria.

CONTROL APPROACH

An emissions accounting approach for defining organizational boundaries in which an organization reports the GHG emissions from operations under its financial or operational control.

DIRECT EMISSIONS

Emissions from sources within the reporting organization's organizational boundaries that are owned or controlled by the reporting organization, including stationary combustion emissions, mobile combustion emissions, process emissions, and fugitive emissions.

DIRECT LINE

Energy purchased and received directly from a generation source, with no grid transfers.

EMISSION FACTOR

GHG emissions expressed on a per unit activity basis (e.g., metric tons of CO₂ emitted per million Btus of coal combusted, or metric tons of CO₂ emitted per kWh of electricity consumed).

ENERGY ATTRIBUTE CERTIFICATE

A category of contractual instruments that conveys information about energy generation to organizations involved in the sale, distribution, consumption, or regulation of electricity (e.g., renewable energy certificates).

EQUITY SHARE APPROACH

An emissions accounting approach for defining organizational boundaries that reflects activities that are wholly owned and partially owned according to the organization's equity share in each.

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

Intentional or 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; landfill gas emissions; and CH₄ leakage from natural gas transport).

GEOGRAPHY

A physical parameter that is used to define the reporting boundary.

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 (CO₂).

GREENHOUSE GASES

(GHG) For the purposes of TCR, GHGs are the internationally recognized gases identified in the Kyoto Protocol: carbon dioxide (CO₂), nitrous oxide (N₂O), methane (CH₄), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), sulfur hexafluoride (SF₆) and nitrogen trifluoride (NF₃).

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 organization, but that occur at sources owned or controlled by another organization. For example, emissions of electricity used by a manufacturing company that occur at a power plant represent the manufacturer's indirect emissions.

INDUSTRY BEST PRACTICE

Existing international or industry best practice methods, which are published, peer reviewed calculation and measurement methods or emission factors.

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 REPORT

The summary of emissions and related information reported as part of an inventory.

LOCATION-BASED METHOD

Scope 2 method that quantifies the average emissions from energy generated and consumed in an organization's geographic region(s) of operations within the organization's defined boundaries, primarily using grid average emission factors.

MARKET-BASED METHOD

Scope 2 method that quantifies emissions from energy generated and consumed within the organization's defined boundaries, that the organization has purposefully purchased, using emission factors conveyed through contractual instruments between the organization and the electricity or product provider.

MEASUREMENT-BASED

Emission quantification methods 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.

MEMBER

An organization that submits an emissions inventory based on the requirements in the General Reporting Protocol to TCR.

MINISCULE SOURCES

Emissions sources listed on TCR's Exclude Miniscule Sources Form which TCR has deemed may be excluded from an inventory without:

- » Compromising the relevance of the reported inventory;
- » Significantly reducing the combined quantity of Scope 1, Scope 2, and biogenic CO₂e emissions reported;
- » Impacting ability to identify the member's viable opportunities for emissions reductions projects;
- » Impacting the ability to ascertain whether the member has achieved a reduction (of five percent or greater) in total entity-wide emissions from one year to the next;
- » Impacting ability to assess the member's climate change related risk exposure; or,
- » Impacting the decision-making needs of users.

MOBILE EMISSIONS

Emissions from the combustion of fuels in transportation sources (e.g., cars, trucks, buses, trains, airplanes, and marine vessels), emissions from non-road equipment such as equipment used in construction, agriculture, and forestry and other mobile sources.

MOBILE SOURCE

Emissions sources designed and capable of emitting GHGs while moving from one location to another. An emissions source is not a mobile source if it is a piece of equipment that is designed and capable of being moved from one location to another but does not combust fuel while it is being moved (e.g., an emergency generator).

NITROGEN TRIFLUORIDE

NF₃ is used as a replacement for PFCs (mostly C₂F₆) and SF₆ in the electronics industry. It is typically used in plasma etching and chamber cleaning during the manufacture of semi-conductors and LCD panels (Liquid Crystal Display). NF₃ is broken down into nitrogen and fluorine gases in situ, and the resulting fluorine radicals are the active cleaning agents that attack the poly-silicon. NF₃ is also used in the photovoltaic industry (thin-film solar cells) for “texturing, phosphorus silicate glass (PSG) removal, edge isolation and reactor cleaning after deposition of silicon nitrate or film silicon.” NF₃ is further used in hydrogen fluoride and deuterium fluoride lasers, which are types of chemical lasers.

NON-ELECTRIC ENERGY USE

Consumption of energy other than electricity (i.e., steam, heat, cooling).

OFFSETS

Represent the reduction, removal, or avoidance of GHG emissions from a specific project that is used to compensate for (i.e., offset) GHG emissions occurring elsewhere.

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.

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.

ORGANIZATION

A business, corporation, institution, organization, government agency, etc., recognized under national law. A reporting organization is comprised of all the facilities and emission sources delimited by the organizational boundary developed by the organization, taken in their entirety.

ORGANIZATIONAL BOUNDARIES

The boundaries that determine the operations owned or controlled by the reporting organization, depending on the consolidation approach taken (either the equity share or control approach).

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 other than from fuel combustion. Examples include emissions from manufacturing cement, aluminum, adipic acid, ammonia, etc.

PURCHASE POWER AGREEMENT

(PPA) A type of contract that allows a consumer, typically a large industrial or commercial entity, to form an agreement with a specific energy generating unit. The contract itself specifies the commercial terms including delivery, price, payment, etc. In many markets, these contracts secure a long-term stream of revenue for an energy project. In order for the consumers to say they are buying the electricity of the specific generator, attributes must be contractually transferred to the consumer with the electricity.

RELEVANT GHG SOURCES

Categories of emission sources that must be included within the reporting boundary for TCR to consider the inventory “complete” for the purposes of reporting to TCR. Relevant emissions consist of Scope 1 and Scope 2 emissions, combustion-based direct biogenic emissions, and combustion-based indirect biogenic emissions associated with the consumption of energy. Approved miniscule sources, biogenic emissions other than those associated with the combustion of biomass, and emission sources identified as optional in the protocols are not considered relevant.

RENEWABLE ENERGY CERTIFICATE

(REC) A type of energy attribute certificate. In the U.S. a REC represents the property rights to the environmental, social and other non-power qualities of renewable electricity generation.

REPORTING BOUNDARY

The boundary that determines the direct and indirect emissions associated with activities within the inventory.

REPORTING YEAR

The year in which the emissions occurred. Members must report emissions on an annual basis (i.e., calendar year or fiscal year).

RESIDUAL MIX

Subnational or national emission factor that uses energy production data and factors out voluntary purchases.

SCOPE 1 EMISSIONS

Direct anthropogenic GHG emissions.

SCOPE 2 EMISSIONS

Indirect anthropogenic GHG emissions associated with the consumption of purchased or acquired electricity, steam, heating, or cooling (collectively referred to as consumed energy).

SCOPE 3 EMISSIONS

All other (non-Scope 2) indirect anthropogenic GHG emissions that occur in the value chain. 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 organization, use of sold products and services, outsourced activities, recycling of used products, and waste disposal.

SIMPLIFIED ESTIMATION METHODS

(SEMs) Rough, upper-bound methods for estimating emissions. Members may use SEMs for any combination of emission sources and/or gases, provided that corresponding emissions do not exceed 10% of the CO₂e sum of reported Scope 1, Scope 2, combustion-based direct biogenic emissions and combustion-based indirect biogenic emissions associated with consumed energy. The higher Scope 2 total must be used to total Scope 1, Scope 2, combustion-based direct biogenic emissions and combustion-based indirect biogenic emissions associated with consumed energy.

SPECIAL POWER PRODUCT

(SPP) A consumer option offered by an energy supplier distinct from the standard offering. The electricity associated with SPPs is often derived from renewable or other low-carbon energy sources, demonstrated by energy attribute certificates or other contracts.

STATIONARY COMBUSTION EMISSIONS

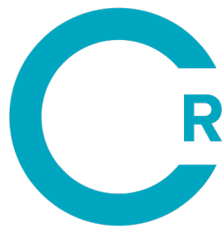
Emissions from the combustion of fuels in any stationary equipment including boilers, furnaces, burners, turbines, heaters, incinerators, engines, flares, etc.

STATIONARY SOURCE

An emissions source that is confined to a distinct geographic location and is not designed to operate while in motion.

VERIFICATION

The process used to ensure that an organization's greenhouse gas emissions inventory has met a minimum quality standard and complied with TCR's procedures and protocols for calculating and reporting GHG emissions.



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