The Climate Registry

Electric Power Sector Protocol for the Voluntary Reporting Program

Annex I to the General Reporting Protocol

June 2009
Version 1.0

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ABOUT THIS PROTOCOL

This protocol was developed with substantial input from The Climate Registry's Electric Power Sector Workgroup (see below for a list of workgroup members and organizations) which was composed of a broad range of individuals with expertise in reporting in this sector. The Registry also wishes to acknowledge Ryerson, Master and Associates, Inc. and its staff for their important role in developing this protocol, particularly the leadership of Ivor John. Additionally, the protocol reflects significant contributions from a Technical Expert Panel assembled by The Registry, consisting of over 130 stakeholders and electric power sector greenhouse gas reporting experts. Finally, The Registry's Protocol Committee, its chair Eileen Tutt, and Registry staff members Sam Hitz, Peggy Foran, Adam Regele and Jill Gravender all provided critical input throughout the process.

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ABBREVIATIONS AND ACRONYMS

ASTM	American Society for Testing and Materials
Btu	British thermal unit(s)
CCAR	California Climate Action Registry
CEMS	Continuous Emission Monitoring System
CHP	Combined Heat and Power
DG	Digester Gas
eGRID	Emissions & Generation Resource Integrated Database
EIA	United States Energy Information Administration
EPA	United States Environmental Protection Agency
EPS	Electric Power Sector
EWG	Exempt Wholesale Generator
FERC	United States Federal Energy Regulatory Commission
GHG	Greenhouse Gas
GRP	General Reporting Protocol
GVP	General Verification Protocol
HFC	Hydrofluorocarbon
HHV	Higher Heating Value
IPCC	Intergovernmental Panel on Climate Change
IPP	Independent Power Producer
ISO	Independent System Operator
J	joule
kg	kilogram(s)
kW	kilowatt(s)
kWh	kilowatt-hour(s)
LDCs	Local Distribution Company
LHV	Lower Heating Value
LSE	Load Serving Entity
MMBtu	million British thermal units
MSW	Municipal Solid Waste
MT	Metric Ton
MW	megawatt
MWh	megawatt-hour
NAICS	North American Industry Classification System
NERC	North American Electric Reliability Corporation
PFC	Perfluorocarbon
POD	Point of Delivery
POR	Point of Receipt
RATA	Relative Accuracy Test Audit
RECs	Renewable Energy Certificates
RPS	Renewable Portfolio Standard
T&D	Transmission and Distribution
WDF	Waste Derived Fuel

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PART I: INTRODUCTION

The Climate Registry's (The Registry) General Reporting Protocol (GRP) describes The Registry's voluntary reporting program and provides the basic framework for participating businesses, government agencies, and non-profit organizations to report their emissions of greenhouse gases (GHGs) to The Registry's voluntary program.

The GRP is designed to support the complete, transparent, and accurate reporting of an organization's GHG emissions in a fashion that minimizes the reporting burden and maximizes the benefits associated with understanding the connection between fossil fuel consumption, energy production, and GHG emissions in a quantifiable manner. By joining The Registry, participants agree to report their GHG emissions according to the guidelines in the GRP and its appendices. The reporting requirements of the GRP are the governing requirements for all Members.[1]

In order to support the unique GHG emissions sources of many of the industrial sectors participating in The Registry's reporting program, The Registry develops sector-specific reporting protocols. These protocols address sector-specific issues, and provide methodologies for calculating emissions from unique industry GHG emissions sources. This document (hereafter referred to as the "EPS Protocol") was developed by The Registry as a supplemental annex to the GRP for the electric power sector (EPS). It defines the additional reporting requirements for EPS organizations reporting to The Registry's voluntary program and in some instances provides alternative provisions to those of the GRP. It also provides specific interpretation of the GRP reporting requirements for the EPS' unique operations. As such it is intended to be used in conjunction with the GRP. Members will still need to use the GRP as the primary source document in understanding The Registry's basic reporting requirements and in quantifying and reporting emissions from many of their sources. In order to facilitate coordinated use of the GRP and this protocol, the EPS Protocol structure closely parallels that of the GRP.

The EPS involves all aspects of the electricity supply system, including power generation, transmission, and distribution.

The text box at the end of this introduction (Applicability: Who Must Use the EPS Protocol) gives a description of the operations included in the EPS Protocol, and the types of organizations that are required to use the EPS Protocol.

[1] *The Registry changed its nomenclature from "Reporters" to "Members" in the fall of 2008 to reflect the leadership Members demonstrate by reporting their emissions to The Registry and to highlight that its Members are part of a community of organizations committed to the application of best practices in GHG reporting.*

APPLICABILITY: WHO MUST USE THE EPS PROTOCOL?

The EPS Protocol must be used by Members that own or control:

- electric power generating facilities;
- transmission systems that convey electricity from a generation facility to a distribution system; or
- distribution systems that convey electric power received from a generation facility or a transmission system to the final consumer.

These entities usually have facilities with the following root code in the North American Industry Classification System (NAICS):

2211 Electric Power Generation, Transmission and Distribution

This industry group is comprised of entities primarily engaged in generating, transmitting, and/or distributing electric power.

However more generally, the protocol applies to two main groups of entities – those involved with **power generation** and those involved with **power delivery** (transmission and/or distribution of electricity). As such the applicability of the protocol extends to the following types of entities:[2]

Power Generation

- Electric Utilities that operate generating facilities – including Investor-Owned Utilities (IOUs), federally-owned utilities, and other publicly-owned utilities.
- Electricity Power Generators – including Independent Power Producers (IPPs), Qualifying Facilities (QFs), Exempt Wholesale Generators (EWGs), and Non-Utility Generators (NUGs).
- Electric Cooperatives with generating facilities.

Power Delivery

- Transmission and Distribution (T&D) System Operators – including utilities, distribution cooperatives, and other Local Distribution Companies (LDCs).
- Bulk Power Transmission Operators – including utilities, Transmission Companies (or "Transcos"), Balancing Authorities, Independent System Operators (ISOs), Regional Transmission Organizations (RTOs), and transmission cooperatives.
- Power Marketers, Energy Service Companies, or Retail Electricity Providers that do not own or operate power generation, transmission or distribution facilities. (These entities have the option report power deliveries metrics.)

A single entity –such as a vertically integrated utility – may have operations that are represented in more than one of the above categories. These entities will need to meet the reporting requirements for all of the categories in which they have operations. Refer to Figure 10.1 to identify the components of your operations covered by the EPS Protocol.

The EPS Protocol also extends to Members that deliver power to the grid in any amount that may not be covered by the 2211 classification, including renewable and other low or zero-emissions generation.[3] Certain sections of this protocol apply to Members that own or control power generating facilities that have no anthropogenic GHG emissions. This is because Members are required to calculate and report emissions metrics for all power generating facilities that deliver electricity to the grid. The data required for these facilities is primarily net power generated.

Entities that generate electricity, heat or steam for their own use and even for sale to outside entities whose facilities are not classified under 2211 and do not deliver electricity to the grid are not required to use the EPS Protocol. These entities should report using the GRP.

The EPS Protocol does not have any specific Scope 1 or Scope 2 reporting requirements for Power Marketers, Energy Service Companies or Retail Electricity Providers that do not own or control power generation, transmission or distribution facilities or systems. If these entities choose to develop power deliveries metrics for the electricity they provide to others (Chapter 19), then they must also calculate Scope 3 emissions for the electricity they deliver. (Refer to Section 5.5 for more details.)

The EPS Protocol does not contain guidance for reporting emissions from natural gas transmission and distribution operations, thus it does not provide a complete reporting methodology for electric utilities that also have natural gas operations.

The glossary included at the end of the EPS Protocol includes definitions and descriptions for many of the entities that participate in the EPS.

[2]Note that a single entity may operate and report as both a power generator and as a power deliverer.

[3]For those entities that export relatively small amounts of electricity, the burden of reporting under this protocol is expected to be minimal, consisting mainly of reporting emissions associated with energy generation and data related to power exported to the grid.

PART II: DETERMINING WHAT YOU SHOULD REPORT

Chapter 1: Introduction

1.1 GHG Accounting and Reporting Principles

REFER TO GRP.

1.2 Origin of The Registry's GRP

REFER TO GRP.

1.3 Reporting Requirements

REFER TO GRP.

1.4 Annual Emissions Reporting

You must report your emissions in The Registry's reporting software by **June 30th** of the year following the emissions year. You must successfully verify your emissions by **December 15th** of that same year. These dates are consistent with those in the GRP.

Chapter 2: Geographic Boundaries

2.1 Required Geographic Boundaries

REFER TO GRP.

The EPS Protocol requires Members to conform to the geographic boundary requirements articulated in the GRP (i.e. you must report all emissions sources in all Canadian provinces and territories, Mexican states, and U.S. states and dependent areas as well as indicate if any of your facilities are located in lands designated as Native Sovereign Nations).

Geographic boundary considerations for this sector within regional cap and trade systems can be complex, if those systems attempt to account for emissions associated with power imports that may be generated beyond the state or provincial borders of the region. For The Registry however, the relevant geographic region is North America and therefore boundary considerations are relatively straightforward. Where the EPS Protocol focuses on power purchases (Chapter 14), the frame of reference is the reporting entity's organizational boundaries, regardless of geographic boundaries, national or otherwise.

2.2 Optional Reporting: Worldwide Emissions

REFER TO GRP.

Chapter 3: Gases to Be Reported

3.1 Required Reporting of All Six Internationally-Recognized Greenhouse Gases

REFER TO GRP.

3.2 Optional Reporting: Additional Greenhouse Gases

REFER TO GRP.

Chapter 4: Organizational Boundaries

4.1 Two Approaches to Organizational Boundaries: Control and Equity Share

Section 4.1 of the GRP describes two approaches that can be employed to define the organizational boundaries of an entity for the purposes of emissions reporting:

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

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

The GRP requires that if a Member selects Option 2 and is a publicly traded corporation, it must also submit a list of its equity investment as part of its emissions report. (More information on this requirement is presented in the GRP, Section 4.3). The GRP also provides a discussion of some considerations to bear in mind when setting organizational boundaries.

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

If GRP Option 1 is selected, the entire entity's emissions must be reported on both an equity share and control basis. In using the equity share consolidation approach, it should be recognized that the EPS is characterized by complex organizational structures and assets that are shared in a variety of ways, including but not limited to equity positions, long-term purchase agreements, transmission rights, etc. In applying the equity share consolidation approach, it is important to distinguish a bona fide equity share from other kinds of joint financing or asset sharing.[4] In the CRIS reporting tool, separate entity-level emission totals will be consolidated using both methods. Members should refer to the GRP (Section 4.2 and Table 4.3) for more information, and consult The Registry's Member Services Department at (866) 523-0764 ext. 3 or help@theclimateregistry.org to further discuss the requirements for reporting according to equity share.

4.3 Option 2: Reporting Using the Control Consolidation

Section 4.3 of the GRP provides instructions on how Members generally apply GRP Option 2 for organizational boundaries. The EPS Protocol places one additional requirement on Members selecting GRP Option 2 – emissions from any electric generating facilities that the Member has an equity share in must be reported, whether they control the facility or not.[5] This supplemental requirement applies only to emissions associated with electric generation units at the facility (i.e. combustion emissions and related process and fugitive emissions) and not to other types of ancillary operations (e.g. associated mobile sources or

[4] Reporting indirect emissions for transmission systems and for transmission and distribution systems can be complex, especially when there are multiple owners involved. EPS Members are advised to consider this carefully before selecting Option 1 with complete equity share reporting.
[5] The requirement to report emissions associated with equity share in generating facilities is additional to the organizational boundary requirements of Option 2. However, this additional information will not be consolidated into the organization's overall emissions totals if Option 2 is selected.

indirect emissions from electricity consumption).

This additional equity share information allows The Registry to compile a complete and comparable inventory of power generation emissions, the most significant source of emissions within this sector. This supplemental requirement is largely consistent with industry practice and it provides a way for vertically integrated utilities to report the equity share of their power generation facilities while still reporting emissions for transmission and distribution systems solely on a control basis.[6]

Emission reports of Members that select GRP Option 2 for organizational boundaries will be aggregated to the entity level using control as the consolidation approach. While the supplemental equity share emissions for power generation will not be aggregated as part of an entity's total emissions, The Registry's reporting software will generate an emissions report that separately shows these equity share emissions for each electric generating facility.

[6] Without this provision, Members wishing to provide power generation emissions according to the equity share consolidation approach would be required to report all other emission sources according to equity share. This is especially challenging for transmission systems, which are often characterized by complex ownership arrangements.

4.4 Examples: Applying Organizatonal Boundaries to Power Generating Operations

4.1

EXAMPLE 4.1

A power plant operated by Company A has four electric generating units. The first three units are owned by Company A, and the fourth Unit is owned by Company B. Each unit has 100,000 metric tons of emissions (CO_2e). The facility also has a fleet of three vehicles with an aggregate of 100 metric tons of CO_2e emissions, a facility-wide fire suppression system (10 metric tons, CO_2e), and a central control room with an HVAC unit (five metric tons CO_2e). How are the direct (Scope 1) emissions divided up between the two entities?

It is determined that Company A has operational control of the facility, and as such, all emissions are assigned to this entity under the control option (400,115 metric tons CO_2e). The emissions associated with power generation (400,000 metric tons CO_2e) are identified as such and reported separately from the non-generation emissions (115 metric tons CO_2e). Company B reports zero emissions under the control approach.

The EPS Protocol also requires supplemental equity share emissions reporting for power generation. In this example, the equity share of power generation emissions for Company A would be 300,000 metric tons CO_2e, and 100,000 metric tons CO_2e for Company B. The vehicle, fire suppressions system and HVAC unit emissions are not included in the supplemental equity reporting of emissions because they are not associated directly with power generation.

The allocation of power generation emissions is summarized below for both consolidation approaches.

	Ownership	Control Consolidation		Equity Share Consolidation	
		Company A	Company B	Company A	Company B
Unit 1	Company A (100%)	100,000 MT	0 MT	100,000 MT	0 MT
Unit 2	Company A (100%)	100,000 MT	0 MT	100,000 MT	0 MT
Unit 3	Company A (100%)	100,000 MT	0 MT	100,000 MT	0 MT
Unit 4	Company B (100%)	100,000 MT	0 MT	0 MT	100,000 MT
Total Power Generation	**Company A (75%), Company B (25%)**	**400,000 MT**	**0 MT**	**300,000 MT**	**100,000 MT**

4.2

EXAMPLE 4.2
Entity Aggregation of CO_2 Emissions from Power Generating Facilities

An entity has an ownership interest in five power plants that emit CO_2 emissions as shown in the table below. The entity consolidation of emissions for control and equity share based reporting are also shown in this table.

	CO_2 Emissions (MT)	Equity Share	Control (Y/N)	Control-Based Report CO_2 Emissions (MT)	Equity Share Report CO_2 Emissions (MT)
Plant 1	5,000,000	100%	Y	5,000,000	5,000,000
Plant 2	3,600,000	33%	N	0	1,200,000
Plant 3	160,000	75%	Y	160,000	120,000
Plant 4	500,000	50%	Y	500,000	250,000
Plant 5	250,000	20%	N	0	50,000
Total	**9,510,000**			**5,660,000**	**6,620,000**

4.5 Corporate Reporting: Parent Companies & Subsidiaries

In cases where a parent company reports to The Registry, the EPS Protocol requires the holding/parent company to disaggregate emissions by subsidiary (i.e. apply this protocol separately to each subsidiary), for any subsidiary that operates a distinct retail electricity provision business (i.e. a Local Distribution Company).[7] Emissions from these key subsidiaries will ultimately be consolidated at the parent level in entity-level reports, but reporting in this disaggregated fashion will allow for the calculation of emissions (and metrics, if applicable) that are meaningful at the local subsidiary level.

While the GRP encourages entities to report at the highest level, it is recognized that in some cases a subsidiary chooses to join The Registry, and its parent company (or holding company) chooses not to report. If a parent company reports to The Registry using the GRP, the separate emissions for each subsidiary would not typically be reported separately.

In the EPS, parent companies often have subsidiaries that are distinct retail providers of electricity and some parent companies may deem it important for their subsidiaries to be able to report separately. Because of this, The Registry recognizes that a parent company may decide not to report, but instead encourage or require its subsidiaries to report as distinct entities. This may be another transparent way to coordinate reporting to The Registry.

4.6 Government Agency Reporting

Most Municipal Utilities and many other local, state, and federal utilities are affiliated in some way with a city, county or other general-purpose local government that has operations in addition to electricity power supply. For the municipalities that own or control these utilities, The Registry has adopted the Local Government Operations (LGO) Protocol, which provides guidance on how to report all of a local government's emissions at the facility level. All local governments will need to use the LGO Protocol as their principle reporting protocol. However, the LGO Protocol instructs public electric utilities that are part of a larger local government entity to report their EPS emissions using this EPS Protocol and indicate which emissions sources are associated with their electric utility within CRIS. This public utility data will be aggregated separately from the rest of the local government's operations. Requiring the public or municipal utility component of a local government to report using the EPS protocol will facilitate comparison between public and private electric utility entities. However, a public utility's emissions will also be aggregated into the emissions report corresponding to the larger local government of which it is a part.

[7]The Registry permits holding companies to choose to disaggregate their reporting in an even more detailed manner by choosing to apply the EPS Protocol to other subsidiaries such as wholesale electricity supply subsidiaries. However, disaggregation to the subsidiary level is required only for the subsidiaries which are Local Distribution Companies. In such cases, The Registry's requirements for material accuracy (GVP) and limitation, on the use of simplified methodologies (Chapter 11) will be applied at the subsidiary level as well as the entity level.

4.7 Reporting Emissions Associated with Bulk Power Transmission Losses

When applying an organizational boundary approach consistent with GRP Option 1, Members should treat the emissions associated with bulk transmission system losses as they would any other source (i.e. report emissions associated with your equity share of the source).

With GRP Option 2, the responsibility for reporting the indirect emissions associated with losses on bulk power transmission systems belongs with the entity that controls the system. Consequently, the entity responsible for reporting depends on the selected control consolidation methodology (operational or financial).

With financial control, it is likely that the primary owner of the asset will be the controlling party. This entity will have the most at stake when financial decisions are made concerning capital improvements and maintenance.

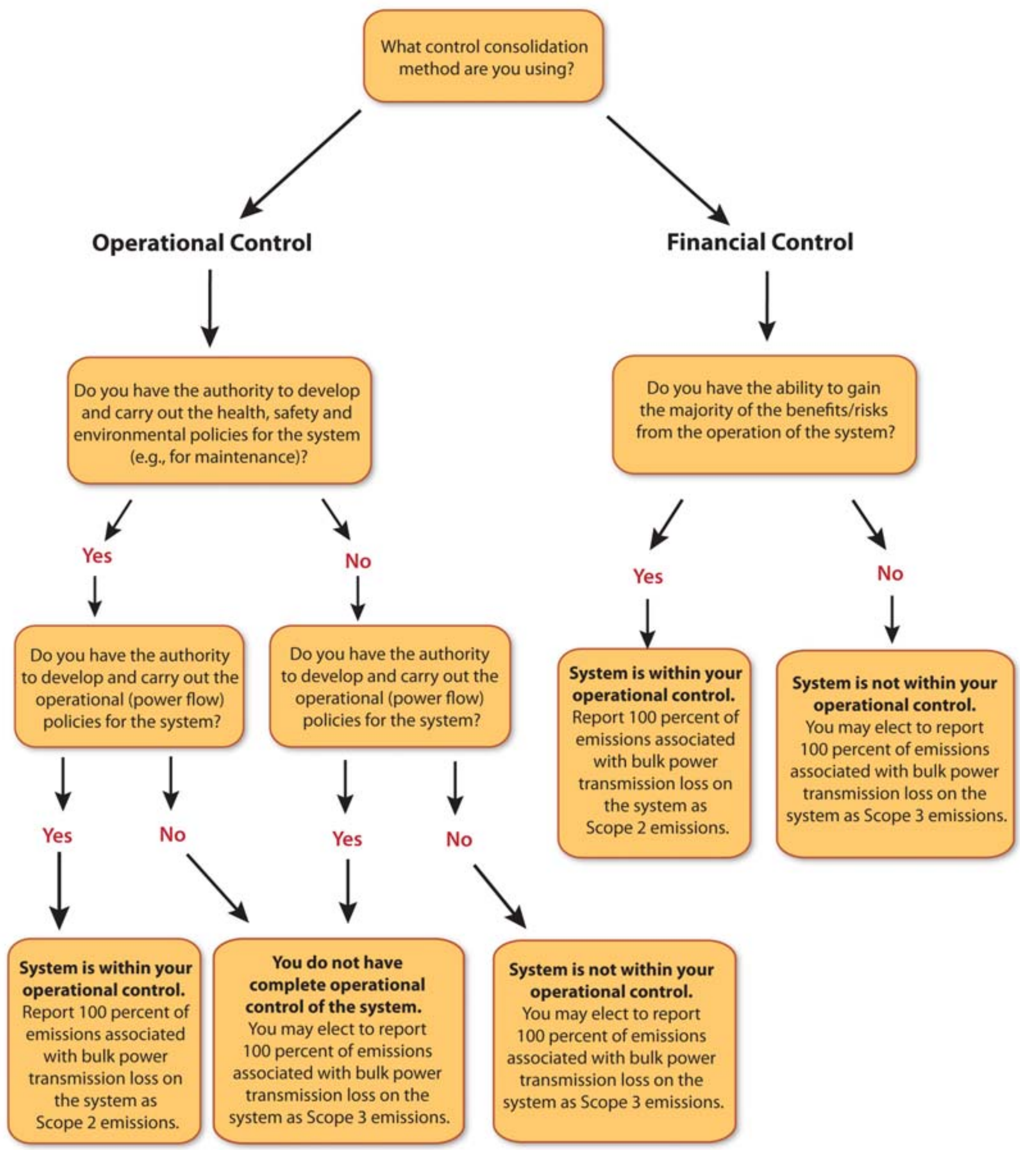
However, when a Member selects the operational control approach, bulk power transmission systems can raise unique challenges. The complex arrangements in place for managing the day-to-day operation of these transmission systems often make it difficult for Members to understand their control responsibilities. For example, transmission systems are often co-owned by a number of entities, and the lines can be operated by one entity and maintained by another.

In applying a standard sense of operational control, it is possible that more than one entity could be deemed responsible for reporting emissions associated with bulk power transmission losses. The entity that has the authority to implement the environmental, health and safety policies related to a system – typically the entity that manages the physical aspects (lines, substations, etc.) of the transmission system – could be deemed to have partial operational control and hence the responsibility to report the emissions associated with losses on that system. In other cases, a different entity may have partial operational control by virtue of managing the day-to-day power flows through the system; while they may not control the physical aspects of the system itself, they often control the amount of power transmitted across the system, affecting the associated emissions of the line losses.

A Registry Member reporting under the operational control approach that has control of both the implementation of environmental, health and safety standards as well as the day-to-day power flows traveling across the system is deemed to have complete operational control of the bulk power transmission system and is required to report 100 percent of the emissions associated with bulk power transmission losses as Scope 2 emissions. Entities that have only partial control however are not required to report bulk power transmission losses.

Figure 4.1 is a decision tree designed to provide guidance to Members when determining whether emissions associated with bulk power transmission losses are within their organizational boundary. Methodologies for calculating the indirect emissions associated with bulk power transmission system losses are included in Section 14.3 of the EPS Protocol.

Figure 4.1 Decision Tree for Determining Reporting Requirements for Emissions Associated with Bulk Power Transmission Loss



Chapter 5: Operational Boundaries

5.1 Required Emission Reporting

The GRP includes methodologies for reporting emissions for Scope 1 and Scope 2 emission sources that are not unique to the EPS, including stationary combustion sources, mobile sources, common fugitive sources, and indirect emissions from purchased electricity. As with the GRP, the EPS Protocol requires Members to report all Scope 1 and Scope 2 emissions.

The EPS Protocol includes methodologies for reporting Scope 1 emissions associated with electric power generation and Scope 2 emissions associated with losses that occur through electric power transmission and distribution and with consumption of purchased electricity by the reporting Member. Some Members will, as part of the process of reporting emissions associated with transmission and distribution losses, also report emissions associated with power purchases that ultimately are delivered to customers.[8] This protocol also includes direction for calculating these Scope 3 emissions.

Members with power generation operations are also required to report some non-emissions data (e.g. generation output) that are needed to calculate power generation metrics. The EPS Protocol also provides an option for Members to calculate and report power deliveries metrics. Members that choose to report power deliveries metrics must follow the methods provided in Chapter 19.

Subsequent sections of the EPS Protocol provide detailed guidance on reporting sources of emissions that are related directly to power generation and power delivery, including Scope 1, 2, and 3 emissions and metrics. Table 5.1 provides a matrix of likely emission source categories for a range of EPS entity types. Some Members will have more than one operational activity within their organizational boundaries, in which case their emissions inventory will include emissions from all categories applicable to those operations. For example, a vertically integrated utility will have emissions associated with power generation, power transmission and power distribution.[9] Table 5.1 should not be interpreted as an exhaustive list of emissions categories for your entity, as the operations undertaken by entities within each of these headings can be different; however it does provide an indication of the likely sources for each type of EPS entity.

[8] Only Members that are required to report emissions from transmission and distribution, and choose to use a particular energy balance methodology described in Chapter 14 will report these emissions.

[9] Most Members will also have other direct sources of emissions from non-generation stationary combustion, such as mobile combustion, fugitive and process emissions. Methods for calculating and reporting these emissions are provided in the GRP and are not indicated in Table 5.1.

5.1 TABLE 5.1
Expected Emissions Categories for Various EPS Organizations

EPS Report Entity Type

	Fossil Generator[1]	Other Generator[2]	Transmission Company, Balancing Authority, ISO[3]	Local Distribution Company[4]	Marketer/ Intermediary/ Retail Provider[5]
Direct Emissions (Scope 1)					
Stationary Combustion	√	√			
Process Emissions	√	√			
Fugitive Emissions	√	√			
Direct Emissions (Biogenic)					
Stationary Combustion		√			
Process		√			
Indirect Emissions (Scope 2)					
Bulk Power Transmission Losses			√		
Wheeled Power			√		
Local T&D Losses				√	√
Purchased and Consumed Electricity	√	√	√	√	√
Other Indirect Emmisions (Scope 3)[6]					
Specified Purchases			√	√	√
Other Purchases			√	√	√
Direct Access			√	√	
Power Exchanges			√	√	
Wheeled Power			√		

Notes:

1. Fossil Generator is an entity that owns, controls or shares ownership in a facility that uses fossil fuels for power generation, including coal, oil, waste oil fuel or waste tires. These entities will report emissions and power output for these facilities.

2. Other Generator is any entity that generates power at facilities using fuels and technologies that are not fossil fuels. Relevant facilities include nuclear, hydro, geothermal, biomass, biogas, and other renewable power generation. These entities will report anthropogenic and biogenic emissions, if applicable, and power output by facility.

3. Transmission companies, Balancing Authorities and Independent System Operators are required to report indirect emissions if they control the bulk power transmission systems they oversee.

4. Local Distribution Companies are required to report indirect emissions if they control a local transmission and distribution system.

5. Power Marketers, intermediaries and retail service providers that do not own or control physical assets (such as generation facilities or transmission or distribution systems) are not responsible for reporting Scope 1 emissions. The only Scope 2 emissions these entities are expected to have are those associated with purchased and consumed electricity. These entities may opt to report emissions associated with the power they purchase for resale (Scope 3). This is a necessary step for marketers, intermediaries or retail service providers that choose to report power deliveries metrics and do not already report their purchases as part of a T&D loss calculation.

5.2 Direct Emissions: Scope 1

The EPS Protocol provides specific methods to address the following types of Scope 1 emission sources involved in power generation and power delivery:

1. **Stationary combustion emissions.** These are emissions from the production of electricity at facilities owned or controlled by your organization.[10,11] (Chapter 12)
2. **Fugitive emissions.** These are the emissions of: (a) SF_6 from high voltage equipment used in electricity transmission and distribution systems, (b) HFCs from power generation air intake chillers, and (c) CH_4 emissions from coal piles (Chapter 16).
3. **Process emissions.** These are emissions from acid gas/SO_2 scrubbers, geothermal facilities, and other small sources associated with electric power generation (Chapter 17).

Scope 1 emissions not directly related to power generation or power delivery, such as emissions from vehicles and buildings, should be reported following the requirements of the GRP.

5.3 Indirect Emissions: Scope 2

The EPS Protocol provides specific methods to address the following types of Scope 2 emission sources:

1. **Indirect emissions associated with T&D system losses.** These are the emissions associated with the portion of purchased electricity that is consumed (i.e. lost) in the T&D system (Section 14.2).
2. **Indirect emissions associated with losses in the bulk power transmission system.** These are the emissions associated with (1) the portion of purchased electricity consumed in the transmission system prior to delivery to a T&D system, and (2) the portion of wheeled electricity that is consumed in the transmission system prior to delivery to another transmission system (Section 14.3).
3. **Purchased or acquired electricity, steam, or heat for own consumption.** These are the emissions associated with purchased electricity, steam/heating/cooling consumed in owned equipment or facilities (e.g., office buildings and maintenance facilities) (Section 14.4).

10 Combustion emissions from mobile generators that produce electricity (for example for demand response) must also be included as an EPS source of Scope 1 emissions if the electricity is delivered to the grid.

11 The EPS Protocol also has methodologies for calculating biogenic CO_2 emissions; however, these emissions are reported separately from the scopes.

5.4 Reporting Emissions from Biomass Combustion

The GRP includes direction for quantifying and reporting biogenic emissions from the combustion of biomass separately from any anthropogenic emissions. This approach is consistent with the Intergovernmental Panel on Climate Change (IPCC) Guidelines for National Greenhouse Gas Inventories. This approach also supports The Registry's goal to uphold policy-neutral reporting, which allows groups analyzing the data to make their own determinations about the carbon neutrality of emissions from biomass combustion.

The EPS Protocol requires that Members report certain biogenic process emissions in addition to the stationary and mobile biogenic emissions required to be reported in the GRP. These required biogenic process emissions are necessary to determine accurate power generation and power deliveries metrics (Chapter 18).

Chapter 12 of the EPS Protocol includes further guidance to allow power generators to estimate emissions from a wider range of biogenic sources used for power generation, and for fuels (such as Municipal Solid Waste) that consist of a mixture of fossil and biogenic source material.

5.5 Scope 3 Emissions

The Registry requires that Members use the following sources of Scope 3 emissions to calculate the indirect emissions described in section 5.3 when they own or control transmission and/or distribution systems (Chapter 14):

1. *Emissions associated with power purchased and delivered to wholesale customers or end users (in scenarios where the Member is an LSE).* These Scope 3 emissions are important for calculating the Scope 2 emissions associated with Transmission and Distribution losses (Chapter 14), and the power deliveries metrics (Chapter 19) if you choose to calculate and report these metrics.

2. *Emissions associated with power wheeled across your transmission lines.* These emissions are important for determining losses associated with the transmission or distribution of wheeled power (Chapter 14).

Members may report Scope 3 emissions as optional data. These include GHG emissions that occur upstream (and outside of your organizational boundaries) of the generation of electricity (e.g. mining of coal or nuclear fuels, refining of fuel oil, extraction of natural gas, emissions from fuel cell reformers, emissions from the manufacture of solar panels, and emissions from the production of biofuels). Members are encouraged but not required to report these emissions when they fall outside of a Member's organizational boundary.

Emission sources commonly found in the EPS are summarized in Table 5.2.

5.2 TABLE 5.2
Overview of EPS Emissions Sources and Gases

DIRECT EMISSIONS		
Technology/Segment	**Source Type**	**Greenhouse Gases**
Boilers	Natural Gas Boilers Residual or Distillate Oil Boilers Coal-fired Boilers (pulverized coal, fluidized bed, spreader stoker, tangentially fired, wall fired, etc.) Biomass-fired Boilers Dual-fuel Fired Boilers Auxiliary Boilers	CO_2, CH_4, N_2O
Turbines	Combined Cycle Gas Simple Cycle Gas Combined Heat and Power Microturbines Steam Turbines Integrated Gasification Combined Cycle, etc.	CO_2, CH_4, N_2O
Internal Combustion Engines	Emergency and Backup Generators Reciprocating Engines Compressors Firewater Pumps Black Start Engines, etc.	CO_2, CH_4, N_2O
Other Electricity Generation	Fuel Cells Geothermal Anaerobic Digesters Refuse-derived Fuels, etc.	CO_2, CH_4, N_2O
Electricity Transmission and Distribution	Circuit Breakers and Other Equipment with SF_6	SF_6
Reservoirs Used for Hydroelectric Power Generation	Fugitive emissions from decomposing organic matter	CO_2, CH_4
Electricity Generation, Fuel Storage	Coal Piles, Biomass Piles	CH_4
Electricity Generation	Air Intake Chiller – Power Generation	HFCs
Electricity Generation	Fire Extinguishers	CO_2, HFCs, PFCs
INDIRECT EMISSIONS		
Technology/Segment	**Source Type**	**Greenhouse Gases**
Electricity Transmission	Transmission Line Losses	CO_2, CH_4, N_2O
Electricity Distribution	Transmission & Distribution Losses	CO_2, CH_4, N_2O
Electricity Consumption	Buildings and Offices[12]	CO_2, CH_4, N_2O
Electricity Generation	Imported steam or heat for power generation	CO_2, CH_4, N_2O

12 This source is not unique to EPS, but the methodology for estimating emissions is unique for many Members where the electricity consumed includes self-generated power (Chapter 14).

Chapter 6: Facility-Level Reporting

6.1 Required Facility-Level Reporting

REFER TO GRP.

6.2 Defining Facility Boundaries

REFER TO GRP.

6.3 Optional Aggregation of Emissions from Certain Types of Facilities

In general, the GRP provisions in Section 6.3 that allow for aggregation of certain types of sources and facilities also apply to the EPS.

Additionally, Members in the EPS may choose to aggregate the emissions (if any) and net power generation by generation type for zero or low emitting electric generating facilities (e.g. hydro, wind, solar, etc) that may be geographically distributed.

Members may also select to aggregate all lines in a T&D system or for selected subsets of the T&D system. Substations and their equipment (breakers, transformers, etc.) may be considered part of the T&D system for estimating T&D losses and fugitive emissions of SF_6.

If a T&D system crosses state or national borders, the system should be reported at the most appropriate geographical level. For example, if a T&D system crosses state or provincial lines but does not cross national borders, it should be reported as a country-level facility. If a T&D system crosses national borders, it should be reported as a North American facility.

In many cases, the control and operation of bulk power transmission pathways (including interconnections from one control area to another) are managed in a different way than the T&D lines used to deliver power to retail consumers within a utility's service area. As such, it is acceptable to treat the T&D system within the service area as one reporting facility, and to treat the bulk power transmission lines as a distinct facility. Chapter 14 provides further guidance about how to establish reporting boundaries for this type of situation.

6.4 Categorizing Mobile Source Emissions

REFER TO GRP.

6.5 Unit Level Data

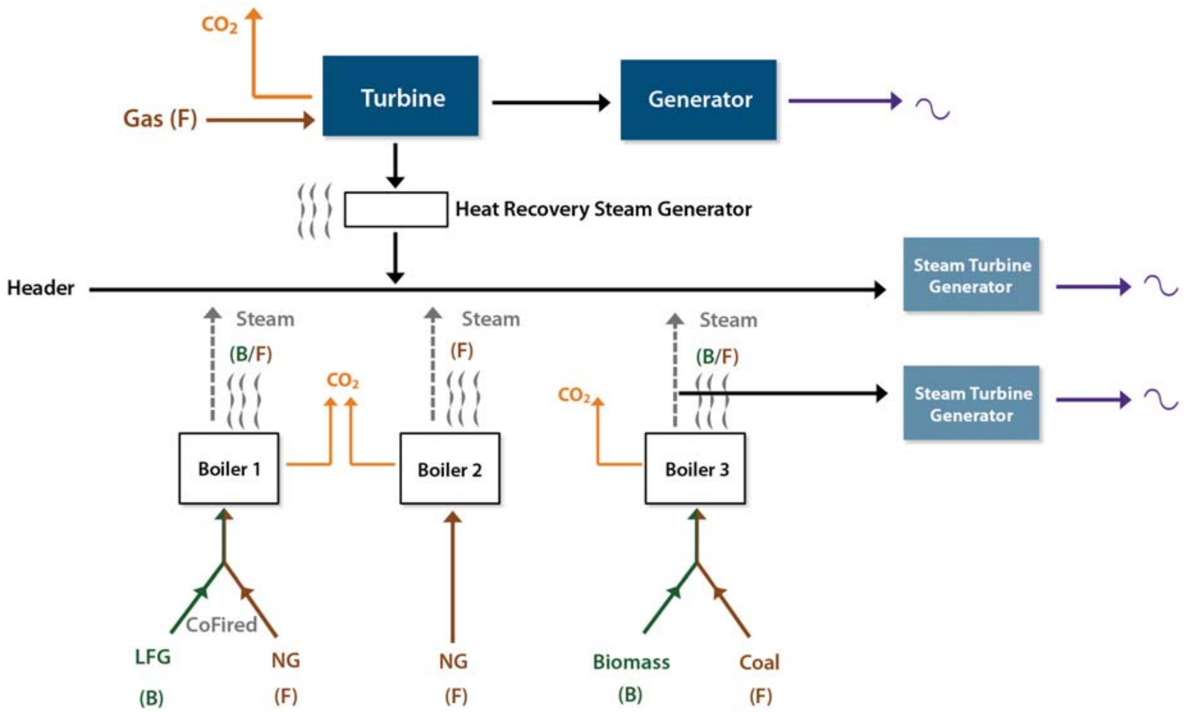
Members in the EPS must follow the basic GRP requirements for facility level reporting. However, many large electric generation facilities are comprised of multiple combustion and generation devices. In some instances, the ownership of these devices within a single facility may vary from one to the next (i.e. ownership of the overall facility does not mirror the ownership of the individual devices that comprise the facility). This creates challenges when trying to determine overall facility emissions on an equity share basis (either as part of Option 1 for organizational boundaries or for the supplemental requirement to report any equity share emissions from electric generation facilities that is part of Option 2).

When ownership of devices within a facility varies, output and GHG emissions must be reported at a sub-facility level. Depending on the particular configuration of combustion devices and generating units this might require separate reporting for each combustion device, generating device or effluent stack, together with the equity share the reporting Member has in each device or unit. When combustion devices are owned by more than one entity, the emissions must be pro-rated between owners based on the equity share. This additional requirement for reporting equity share emissions at the sub-facility level ensures that emissions can be consolidated in a way that reflects the Member's selected organizational boundary approach, and to ensure that power generation metrics are calculated properly (Chapter 18).

Unit level reporting is only required when there is shared ownership of the combustion devices or generating units at a single facility, and the ownership structure varies from device to device. If this does not occur, no unit level reporting is required. It should be noted that even when unit level reporting is required, the total facility emissions will still be reported by one entity under the control consolidation method.

Figure 6.1 depicts a hypothetical facility in which there are multiple combustion devices including boilers, a combustion turbine, and shared generating units. When the combustion devices and/or generators are owned by different entities, the emissions and output need to be accurately attributed to each owner. This must be done by pro-rating emissions based on heat input or steam production for each combustion device, and/or electricity generation. How this is done in practice will depend on what operational variables are being measured and the degree of accuracy associated with each. Example 6.1 provides a hypothetical ownership scenario based on Figure 6.1.

Figure 6.1 Generation Facility with Multiple Units



Notes:

B	– Biofuel with biogenic CO_2 emissions	LFG	– Landfill Gas
F	– Fossil fuel with anthropogenic emissions	NG	– Natural Gas

6.5.1 Example: Reporting Unit Level Data

6.1

EXAMPLE 6.1
Reporting Responsibilities for Facilities where there is a Shared Ownership of Generating Units and Non-Generating Equipment

Company A and Company B are both reporting to The Registry according to GRP Option 2. A power plant operated by Company A has four combustion devices. The first three are boilers owned by Company A, and the fourth unit is a turbine owned by Company B (see Figure 6.1). Each of these four combustion devices has 100,000 metric tons of emissions (CO_2e). The facility also has a fleet of three vehicles with an aggregate of 100 metric tons of CO_2e emissions, a facility-wide fire suppression system (10 metric tons, CO_2e), and a central control room with an HVAC unit (five metric tons CO_2e).

Company A has operational control of the facility, and as such, all emissions are assigned to this entity under the control option (400,115 metric tons CO_2e). The emissions associated with power generation (400,000 metric tons CO_2e) are tagged as such and reported separately in CRIS from the non-generation emissions (115 metric tons CO_2e). Company B reports zero emissions with this option.

The EPS Protocol also requires equity share consolidation for power generation. In this example, the equity share of power generation emissions for Company A would be 300,000 metric tons CO_2e and 100,000 metric tons CO_2e for Company B. The vehicle, fire suppressions system and HVAC unit emissions are not included in the equity reporting of emissions because they are not associated directly with power generation.

Chapter 7: Establishing and Updating the Base Year

7.1 Required Base Year

Section 7.1 of the GRP outlines The Registry's requirement for Members to set, and under certain circumstances, adjust base year emissions. Setting a base year serves the specific purpose of allowing Members to normalize their emissions in terms of their organizational structure within The Registry's database. Base year emissions are then adjusted when there are significant and relevant changes (changes can include mergers, acquisitions, or divestments of sources that existed in the base year—see Section 7.1 of the GRP for a description of relevant changes) in the Member's organizational structure. A Member's base year is defined as the earliest reporting year to The Registry in which a complete emission report is submitted (i.e. a non-transitional report—see GRP Chapter 8: Transitional Reporting). Significant changes are defined as those changes to organizational structure that result in a cumulative change of five percent or more in your entity's total base year emissions (Scope 1 plus Scope 2, and Scope 3 if reported).

7.2 Updating Your Base Year Emissions

A Member within the EPS can have large swings between Scope 1 (owned or controlled generation) and Scope 3 (power purchases) and concomitant variation in Scope 2 emissions (T&D losses), due to year-to-year operational decisions to purchase versus generate electricity.[13] Although these swings may be significant, they do not represent swings that are due to changes in the actual organizational structure of the entity. Consequently, Members should not adjust their base year in response to such changes. Please see the GRP's base year discussion of emitting activities that are "insourced" or "outsourced" for more information (GRP Chapter 7).

Members that anticipate dramatic swings between the different categories of their emissions (i.e. Scope 1, 2 or 3) from year to year are encouraged to upload additional public documents in The registry's reporting software (see GRP Chapter 19) to add explanatory notes for any such emissions swings.

7.3 Optional Reporting: Updating Intervening Years

REFER TO GRP.

[13] *This may be particularly true for utilities that own or control significant hydropower operations. For example, a dry year may necessitate the purchase of significant quantities of power from other generation sources.*

Chapter 8: Transitional Reporting (Optional)

8.1 Reporting Transitional Data

REFER TO GRP.

8.2 Minimum Reporting Requirements for Transitional Reporting

The GRP indicates that the minimum requirements for transitional reporting are as follows:

- A transitional reporter must report at a minimum all CO_2 emissions from stationary combustion for all of its operations in at least one state, province or territory

- All transitional emission reports must be third-party verified by a Registry-recognized Verification Body

These minimum requirements for transitional reporting remain unmodified for the EPS Protocol. However, while the GRP encourages Members reporting transitionally to exceed the minimum requirements in their report and to report as comprehensively as possible, the EPS Protocol recognizes that in many instances, these Members may not be able to report the supplemental information required by the EPS Protocol, until they report completely.

For instance, it is difficult and of limited meaning to report Scope 2 line loss emissions associated with a T&D system that spans multiple states, provinces, territories or Native Sovereign Nations, if a Member is not yet reporting on a complete geographic basis.

Consequently, the EPS Protocol strongly recommends that Members who are reporting transitionally not report the following emissions categories until they report completely:

- Scope 2 emissions associated with T&D line losses
- Scope 3 emissions from power purchases and wheeled power
- Power deliveries metrics (optional)

8.3 Public Disclosure of Transitional Data

REFER TO GRP.

Chapter 9: Historical Reporting (Optional)

9.1 Reporting Historical Data

REFER TO GRP.

9.2 Minimum Reporting Requirements for Historical Data

REFER TO GRP.

9.3 Importing Historical Data

REFER TO GRP.

9.4 Public Disclosure of Historical Data

REFER TO GRP.

PART III: QUANTIFYING YOUR EMISSIONS

Chapter 10: Introduction to Quantifying Your Emissions

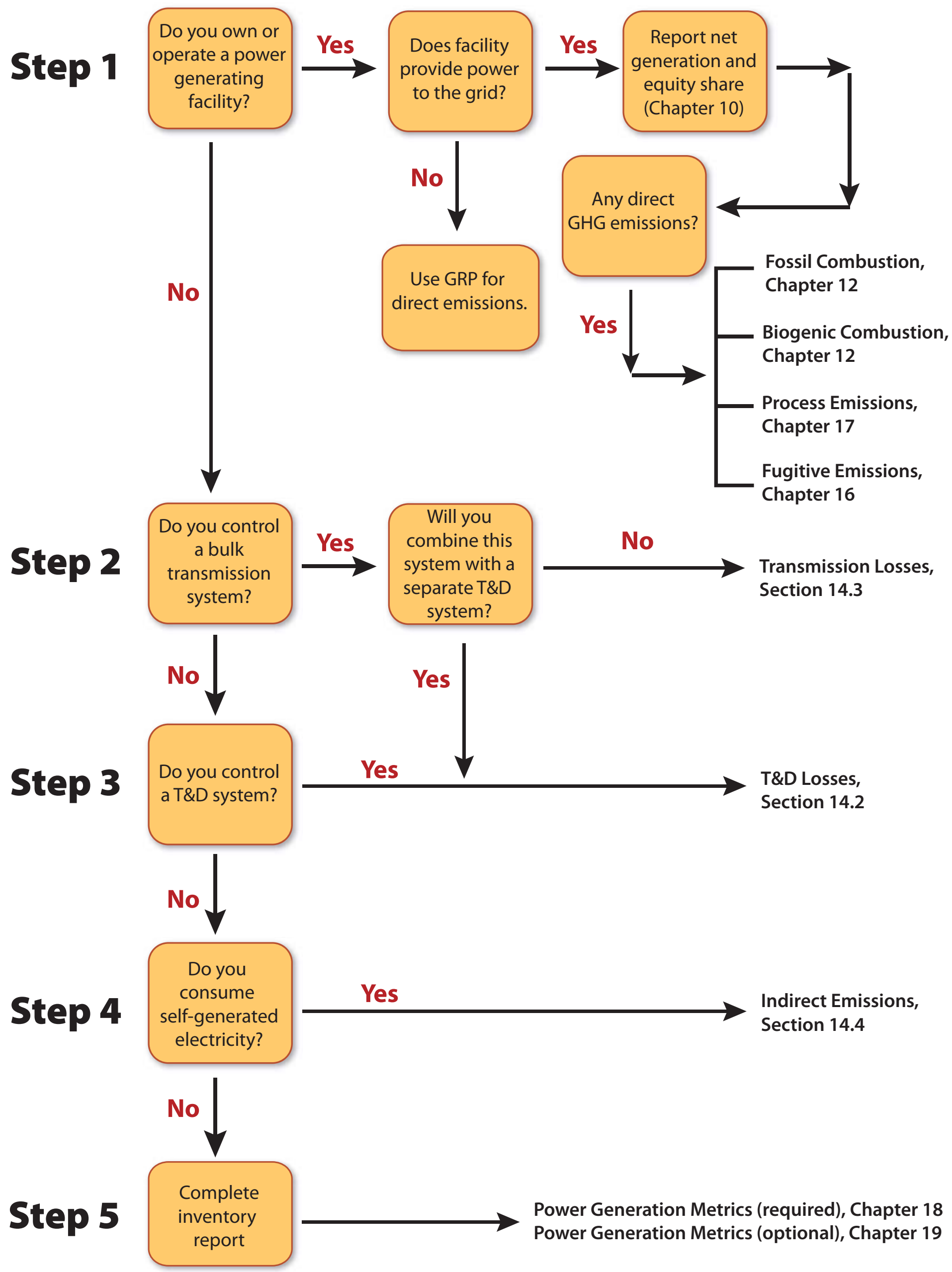
Part III of the EPS Protocol includes detailed methods for calculating emissions associated with electric power generation, transmission and distribution (Chapters 10 through 17).

The following summary indicates the chapters where Part III of the protocol provides additional direction for the EPS:

Chapter 10	Introduction to Quantifying Your Emissions
Chapter 11	Simplified Estimation Methods (no change from GRP)
Chapter 12	Direct Emissions from Stationary Combustion (includes specific methods unique to EPS)
Chapter 13	Direct Emissions from Mobile Combustion (no change from GRP)
Chapter 14	Indirect Emissions from Electricity Use (includes specific methods unique to EPS)
Chapter 15	Indirect Emissions from Imported Steam, District Heating, Cooling and Electricity from a CHP Plant (no change from GRP)
Chapter 16	Direct Fugitive Emissions (includes specific methods unique to EPS)
Chapter 17	Direct Process Emissions (includes specific methods unique to EPS)

Figure 10.1 is a flow chart that you should use to identify your reporting requirements. The specific chapters and methodologies that apply to your entity will depend on your organizational and operational boundaries.

Figure 10.1 Flow Chart Showing Reporting Requirements and Relevant Quantification Chapter for EPS Members



Chapter 11: Simplified Estimation Methods

REFER TO GRP.

Chapter 12: Direct Emissions from Stationary Combustion

This chapter applies to Members that own or control any combustion facilities or devices used for electricity generation and it supplements the guidance provided for general stationary combustion included in the GRP. Members must report power generation and non-power generation stationary combustion sources separately. This chapter applies only to the power generating sources.

The data elements you will need for reporting stationary combustion emissions associated with electricity generation are as follows:

- Facility (or combustion device) name
- Control of facility (or combustion device) (Y/N)
- Equity share (percent) of facility (or combustion device)
- Fuel types per facility (or combustion device)
- Fuel use (MMBtu or J) per facility (or combustion device)
- Emissions for each GHG (metric tons) per facility (or combustion device)

It should be noted that this information is required at the combustion device level only when needed to address shared ownership relationships or equity share reporting (Chapter 6.5).

Emissions from auxiliary boilers used to supplement the prime mover heat source upon startup and any engines used for startup assistance should be considered to be directly associated with power generation and must be reported according to the requirements in this chapter. However, auxiliary boilers used for building heat or used solely to provide steam to another customer are not part of the power generation system, and should be treated in the same way as any other GRP emission source. Similarly, the emissions from portable generators should only be included with other power generation emissions if they are specifically used for grid power generation.

Additionally, the following sources (even when associated with a power plant) are not part of power generation and should be reported using the GRP: mobile sources, fire suppression equipment, and air conditioning or refrigeration units for power plant office buildings and in vehicles.

Members may calculate stationary combustion emissions using a Continuous Emissions Monitoring System (CEMS) or based on fuel use and heat input or carbon content. The methods provided in the EPS Protocol to calculate stationary combustion emissions for power generation are summarized in Table 12.1.[14,15]

[14] *Methods EPS ST-01 through EPS ST-07 have been adapted from the State of California's mandatory reporting regulations (California Code of Regulations Title 17, Subchapter 10, Article 2, Sections 95110 to 95115).*

[15] *When using EPS ST-02, EPS ST-03 or EPS ST-04, refer to the GRP for guidance on using oxidation factors and the current emission factors.*

12.1 TABLE 12.1
Summary of Calculation Methods for Stationary Combustion Emissions

Direct CO_2 Emissions From Stationary Combustion		
Method	**Type of Method**	**Data Requirements**
EPS ST-01-CO_2	Direct Monitoring	Continuous emissions monitoring (CEMS)
EPS ST-02-CO_2	Calculation Based on Fuel Use	Measured fuel consumption, measured carbon content of fuel (per unit mass or volume)
EPS ST-03-CO_2	Calculation Based on Fuel Use	Measured fuel consumption, measured heat content of fuels and default emission factor
EPS ST-04-CO_2	Calculation Based on Fuel Use	Measured fuel consumption, default heat content, default emission factor

Biogenic CO_2 Emissions From Stationary Combustion		
Method	**Type of Method**	**Data Requirements**
EPS ST-05-CO_2	Calculation Based on Heat Input	Imputed heat input and default carbon content
EPS ST-06-Partioning anthropogenic and biogenic CO_2	Direct Measurement or default (MSW and WDF)	Sample analysis or waste characterization study (MSW and WDF)
EPS ST-07-CO_2 Biogas	Calculation Based on Fuel Use	Measured fuel consumption and measured carbon or, measured or default heat content

Direct CH_4 and N_2O Emissions From Stationary Combustion		
Method	**Type of Method**	**Data Requirements**
EPS ST-08-CH_4 and N_2O	Calculation Based on Fuel Use	Source test based emissions factors; Measured fuel consumption and measured or default heat content

Once a calculation methodology has been chosen, in most cases the same methodology should be used for reporting emissions in all subsequent years. This does not preclude a Member from changing to an alternative method if doing so will lead to more accurate or comprehensive reporting. However, changing calculation methodologies may trigger a base year adjustment review as described in Chapter 7 of the GRP.

12.1 Measurement of Carbon Dioxide Using Continuous Emissions Monitoring System Data

This section discusses the provisions for reporting your CO_2 emissions using CEMS data. This section applies to the use of CEMS data for anthropogenic emissions (fossil fuel combustion) and biogenic emissions (biomass or biogas combustion).

In the U.S., many of the power generators reporting under the EPS Protocol must use Continuous Emissions Monitoring Systems (CEMS) as required under the U.S. Environmental Protection Agency's (EPA) acid rain regulation (40 CFR Part 75). Others generating power from landfill gas, municipal solid waste, and other waste derived fuels are subject to similar monitoring requirements under 40 CFR Part 60.

In Canada, the following documents from Environment Canada outline specifications for the design, installation, certification, and operation of CEMS used for fossil fuel-fired steam and electric generating facilities in Canada. They include procedures used to determine the standards for CEMS measurements during initial certification testing as well as subsequent long-term operation of the monitoring system.

- From Environment Canada's Website: http://www.ec.gc.ca/cleanair-airpur/Pollution_Sources/Electricity_Generation/Guidelines_and_Codes_of_Practice-WS047445FC-0_En.htm
- Environment Canada's "Protocols and Performance Specifications for Continuous Monitoring of Gaseous Emissions from Thermal Power Generation, Report EPS 1/PG/7 (revised)," originally published in 1993 and updated in November 2005.

CO_2 emissions data compiled using systems that meet the specifications in these federal procedures (U.S. or Canada) will be acceptable for reporting to The Registry. If you are reporting CO_2 emissions to the U.S. EPA or Environment Canada under these CEMS programs, you are encouraged to report those same emissions values to The Registry. The specific method for compiling and reporting emissions is presented below (EPS ST-01).[16]

If you are not required to report under any of the aforementioned regulations, but operate a CEMS device comparable with EPA or Environment Canada provisions, you may also use this method to report to The Registry.

Members are strongly encouraged to consider reporting both CEMS data and emissions data calculated using fuel-based methodologies, if the data are available. Doing so will provide a more comprehensive picture of your emissions from power generation and it is unclear whether future mandatory reporting schemes will require CEMS data or fuel-based calculations. The Registry's reporting software can accommodate both data sets, though only one (as designated by the Member) will be used for the purposes of public reporting.

[16] *It is important to convert from short tons to metric tons when using the EPA CEMS data to report to The Registry. (Conversion factor: 1 metric ton = 1.1023 short tons)*

— EPS ST-01: CONTINUOUS EMISSIONS MONITORING SYSTEM (CEMS)

If your facility combusts fossil fuels or biomass and operates Continuous Emissions Monitoring Systems (CEMS) in response to federal, state, or local air agency regulations, you may use CO_2 or O_2 concentrations and flue gas flow measurements to determine hourly CO_2 mass emissions. You should report CO_2 emissions in metric tons based on the sum of hourly CO_2 mass emissions over the year. This procedure is consistent with the CEMS methodology required by 40 CFR Part 75 in the U.S.[17]

If your facility combusts biomass, and you use O_2 concentrations to calculate CO_2 concentrations, annual source testing must demonstrate that calculated CO_2 concentrations, when compared to measured CO_2 concentrations, meet the Relative Accuracy Test Audit (RATA) requirements in 40 CFR Part 60, Appendix B, Performance Specification 3.

If your facility combusts municipal solid waste or other waste-derived fuels and you operate a CEMS in response to federal, state, or local agency regulations, you may use CO_2 concentrations and flue gas flow measurements to determine hourly CO_2 mass emissions using methodologies provided in 40 CFR Part 75, Appendix F. Alternatively, if your CEMS measures CO_2 and steam flow, but not flue gas flow, then you may use the method provided in 40 CFR 60, Method 19 (see text box below). You should report CO_2 emissions for the reporting year in metric tons based on the sum of hourly CO_2 mass emissions over the year.

If your facility combusts municipal solid waste or other waste-derived fuels and you choose to calculate CO_2 emissions using CEMS measurements, determine the portion of emissions associated with the combustion of biomass-derived fuels using EPS ST-06, if applicable.

If you choose to use CEMS data to report CO_2 emissions from a facility that co-fires fossil fuels with biomass or waste-derived fuels that are partly biomass, determine the portion of total CO_2 emissions separately assigned to the fossil fuel and the biomass-derived fuel using EPS ST-06, if applicable. Alternatively, if your facility co-fires biomass with fossil fuels, you may calculate CO_2 emissions for the fossil fuels using EPS ST-02, EPS ST-03 or EPS ST-04, and then subtract the fossil fuel related emissions from the total CO_2 emissions measured by CEMS to derive the biogenic CO_2 emissions.

If you choose to report CO_2 emissions using CEMS data, this data will include process emissions associated with scrubbers. You are not required to separately report these process emissions. Similarly when reporting using CEMS, you do not need to report emissions separately for different fossil fuels when fossil fuels are co-fired.

[17] For power generation sources that report CO_2 emissions to a federal, state, or provincial agency based on the measurement of natural gas fuel flow and heat input, refer to the provisions included in EPS ST-03 for reporting those emissions into The Registry. While these emissions are not measured CEMS data, they are often reported for compliance purposes in the same way as CEMS data. For example, U.S. EPA allows this alternative for reporting as part of their Acid Rain regulations (40 CFR Part 75, Appendices F and G).

Report CO_2 emissions in metric tons based on the sum of hourly CO_2 mass emissions over the year.

For each monitoring system, report CO_2 emissions for the year, total fuel used, and any other parameter required to determine CO_2 mass emissions and heat input in accordance with 40 CFR 75. The quarterly reports submitted to the U.S. EPA showing CO_2 mass emissions data and heat input data for the CO_2 emissions unit (and U.S. EPA's confirmation correspondence) will be used as evidence that the emissions data have been accepted by the U.S. EPA.

CALCULATING BOILER FLUE GAS FLOW RATE USING STEAM GENERATION RATE

If you have a CEMS that provides the CO_2 or O_2 concentration in the flue gas and steam generation rate from a boiler, you can use this method to calculate flue gas flow using the measured steam rate, the design steam and waste heat content specifications for the boiler.

In this method[18] CO_2 or oxygen O_2 concentrations and appropriate F factors are used to calculate pollutant emission rates from pollutant concentrations. The F factor is the volume of combustion components per unit of heat content, scm/J or scf/ million Btu.

Using this method with measured CO_2 concentrations, the relevant equation for hourly flow rate is:

$$\text{Flow} = F_c * (H_d / \text{Steam}_d) * \text{Steam}_a / (CO_2\%/100)$$

where **Flow** = stack flow, dscfh
F_c = CO_2 based factor from 40 Cfr 60 Method 19 Table 19-2 (dscf/MMBtu)
H_d = design heat input rate (MMBtu/hr)
Steam_d = design steam rate (lbs steam/hr)
Steam_a = CEMS-measured steam rate (lbs steam/hr)
$CO_2\%$ = measured CO_2 concentration from CEMS, percent

Refer to 40 CFR 60, Method 19 for details of how to conduct this calculation using measured O_2 concentrations in the flue gas in place of CO_2.

Typically the CEMS data are provided on an hourly basis for each day. The CO_2 emissions are then calculated for each hour using:

$$E = MW_{CO2} * (CO_2\%/100) / V_m * \text{Flow}$$

where **E** = CO_2 emissions (lbs/hr)
MW_{CO2} = molecular weight CO_2 (44 lb/lbmol)
$CO_2\%$ = concentration of CO_2 in percent
V_m = standard molar volume of gas at 68°F (385.286 dscf/lbmol)
Flow = stack flow rate, dscfh

The hourly results are then summed to determine the annual total CO_2 emissions.

18 Methodology adapted from the U.S. 40 CFR 60, Method 19.

12.2 Calculating Anthropogenic Carbon Dioxide Emissions Using Fuel Use Data

This section includes several methods for calculating CO_2 emissions using fuel use data, including methods that involve the use of measured values and default emission factors. For fossil fuels, you must select one of the methods from those included below (EPS ST-02 through EPS ST-04). For biomass fuels (including biomass, municipal solid waste, or waste derived fuels with biomass), you should use the methods provided in Section 12.3.

In all cases where emissions are calculated using fuel use data, values for the applicable emission factors (and carbon content of fuels) can be found in the GRP, Tables 12.1 through 12.5. For EPS ST-02 through EPS ST-08, it is acceptable to substitute heat input units from Btu to joules using a conversion factor of 1055 J/Btu.

— EPS ST-02: Method for Calculating CO_2 Emissions from Fuel Combustion Using Measured Carbon Content of the Fuel

For each type of fuel combusted at your facility, calculate CO_2 emissions using the appropriate method below:

If combusting solid fuels, use the following equation to calculate CO_2 emissions:

Equation 12a	Solid Fuels

$$CO_2 = \sum_{1}^{12} Fuel_n * CC_n * 3.664$$

Where:

CO_2 = carbon dioxide emissions, metric tons per year

$Fuel_n$ = mass of fuel combusted in month "n," metric tons

CC_n = carbon content from fuel analysis for month "n," percent (e.g. 95 percent expressed as 0.95)

3.664 = CO_2 to carbon molar ratio

When reporting emissions from the combustion of solid fuels for power generation, measure and record the carbon content monthly. The monthly solid fuel sample should be a composite sample of weekly sub-samples. The solid fuel should be sampled weekly at a location after all fuel treatment operations, and the sub-samples should be representative of the fuel chemical characteristics combusted during the sub-sample week. Collect each weekly sub-sample at a time (day and hour) of the week when the fuel consumption rate is representative and unbiased. Combine weekly sub-samples of equal mass to form the monthly composite sample. The monthly composite sample should be homogenized and well mixed prior to withdrawal of a sample for analysis. Randomly select one in twelve composite samples for additional analysis of its discreet constituent samples. Use this information to monitor the homogeneity of the composite.

Determine carbon content coal and coke, solid biomass-derived fuels, and waste-derived fuels using ASTM 5373.[19]

If your facility combusts liquid fuels, use the following equation to calculate CO_2 emissions:

Equation 12b	Liquid Fuels

$$CO_2 = \sum_{1}^{12} Fuel_n * CC_n * 3.664 * 0.001$$

Where:

CO_2 = carbon dioxide emissions, metric tons per year

$Fuel_n$ = volume of fuel combusted in month "n", gallons

CC_n = carbon content from fuel analysis for month "n", kg carbon per gallon fuel

3.664 = mass conversion factor from carbon to carbon dioxide

0.001 = factor to convert kg to metric tons

[19] *ASTM 5373 - Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal and Coke.*

Measure and record carbon content monthly or for each new delivery of fuel. When measured by you or a fuel supplier, determine carbon content as follows:

- For petroleum-based liquid fuels and liquid waste-derived fuels, use ASTM D5291, ultimate analysis of oil or computations based on ASTM D3238-95 (reapproved 2005) and either ASTM D2502-04 or ASTM D2503-92 (reapproved 2002).[20]

- For gaseous fuels, use the following equation to calculate CO_2 emissions:

Equation 12c	Gaseous Fuels

$$CO_2 = \sum_{1}^{12} Fuel_n * CC_n * 1/MVC * 3.664 * 0.001$$

Where:

CO_2 = carbon dioxide emissions, metric tons per year

$Fuel_n$ = volume of gaseous fuel combusted in month "n," scf

CC_n = carbon content from fuel analysis for month "n," kg C per kg-mole fuel

MVC = molar volume conversion factor (849.5 scf/kg-mole for STP of 20°C and 1 atmosphere, or 836 scf/kg-mole for STP of 60°F and 1 atmosphere)

3.664 = mass conversion factor from carbon to carbon dioxide

0.001 = factor to convert kg to metric tons

[20] *ASTM D5291 - Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants. ASTM D3238 – Standard Test Method for Calculation of Carbon Distribution and Structural Group Analysis of Petroleum Oils. ASTM D2502 – Standard Test Method for Estimation of Mean Relative Molecular Mass of Petroleum Oils from Viscosity Measurements ASTM D2503 – Standard Test Method for Relative Molecular Mass (Molecular Weight) of Hydrocarbons by Thermoelectric Measurement of Vapor Pressure.*

When measured by you or a fuel supplier, determine carbon content using the method in ASTM D1945.[21] Measure and record the carbon content monthly.

If your facility combusts waste-derived fuels that are partly but not pure biomass and if you determine CO_2 emissions using EPS ST-04, determine the biomass-derived portion of CO_2 emissions using EPS ST-06, if applicable.

— EPS ST-03: Method for Calculating CO_2 Emissions from Fuel Combustion Using Measured Fuel Flow, Heating Value for the Fuel and Default Emission Factor

Use the following equation to calculate fuel combustion CO_2 emissions by fuel type using the measured heat content of the fuel combusted:

Equation 12d

$$CO_2 = \sum_{1}^{n} Fuel_P * HHV_P * EF * 0.001$$

Where:

CO_2 = combustion emissions from specific fuel type, metric tons CO_2 per year

n = period/frequency of heat content measurements over the year (e.g. monthly n = 12)

$Fuel_P$ = mass or volume of fuel combusted for the measurement period specified by fuel type, units of mass or volume per unit time

HHV_P = high heat value measured for the measurement period specified by fuel type, MMBtu per unit mass or volume

EF = default carbon dioxide emission factor provided in Chapter 12 of the GRP, kg CO_2 per MMBtu

0.001 = factor to convert kg to metric tons

[21] *ASTM D1945 – Standard Test Method for Analysis of Natural Gas by Gas Chromatography.*

Measure and record fuel consumption and the fuel's high heat value at frequencies specified by fuel type below. You may use the high heat values provided by the fuel supplier if they are calculated using an applicable method approved in the EPS Protocol. The required frequencies for measurements and recordings are as follows:

1. At receipt of each new fuel shipment or delivery or on a monthly basis for middle distillates (diesel, gasoline, fuel oil, kerosene), residual oil, liquid waste-derived fuels, and Liquefied Petroleum Gas (ethane, propane, isobutene, n-Butane, unspecified Liquefied Petroleum Gas).
2. Monthly for natural gas, associated gas, and mixtures of low Btu gas excluding refinery fuel gas. If combusting gases with high heat value (<975 or >1100 Btu per scf) including natural gas, associated gas, and mixtures of low Btu gas and natural gas, use EPS ST-04 to calculate CO_2 emissions.
3. Monthly for gases derived from biomass including landfill gas and biogas from wastewater treatment or agricultural processes.
4. Monthly for the heat content of all solid fuels. Monthly solid fuel sample should be a composite sample of weekly sub-samples. The solid fuel should be sampled at a location after all fuel treatment operations and the sub-samples should be representative of the fuel chemical and physical characteristics immediately prior to combustion. Collect each weekly sub-sample at a time (day and hour) of the week when the fuel consumption rate is representative and unbiased. Combine weekly sub-samples of equal mass to form the monthly composite sample. The monthly composite sample should be homogenized and well mixed prior to withdrawal of a sample for analysis.

The method described above is a detailed method that will provide accurate data. However, if other sampling and analysis methods are used that provide equal or better accuracy, they may be used for EPS reporting to The Registry.

High heat values must be determined using one of the following methods when measured by you or the fuel supplier for:

1. Gases, use ASTM D1826, ASTM D3588, ASTM D4891, GPA Standard 2261-00 "Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography." You may alternatively elect to use on-line instrumentation that determines heating value accurate to within ± 5.0 percent. Where existing on-line instrumentation provides only low heating value convert the value to high heating value as specified in EPS ST-03.
2. Middle distillates and oil, or liquid waste-derived fuels, use ASTM D240, ASTM D4809.
3. Solid biomass-derived fuels use ASTM D5865.
4. Waste-derived fuels use ASTM D5865 or ASTM D5468. If your facility combusts waste-derived fuels that are partly but not pure biomass, determine the biomass-derived portion of CO_2 emissions using EPS ST-06, if applicable.

If yours is a facility where currently installed on-line instrumentation provides a measure of lower heating value (LHV) but not higher heating value (HHV), convert LHVs (Btu/scf) to HHVs (Btu/scf) in the following manner.

Equation 12e

HHV = LHV * CF

Where:

HHV = fuel or fuel mixture higher heating value (Btu/scf)

LHV = fuel or fuel mixture lower heating value (Btu/scf)

CF = conversion factor

For natural gas, use a CF of 1.11.

For refinery fuel gas and mixtures of refinery fuel gas, derive a fuel system specific conversion factor. Determine a weekly average conversion factor from either concurrent LHV instrumentation measurements and HHV determined as part of the daily carbon content determination (by on-line instrumentation or laboratory analysis), or by the HHV/LHV ratio obtained from your laboratory analysis of the daily samples.

For power generation sources that report CO_2 emissions to a federal, state or provincial agency based on the measurement of natural gas fuel flow and heat input, those emissions may be used for reporting to The Registry in place of this method if they are based on fuel measurement, fuel heating value measurement and a default emission factor for CO_2 stipulated by the regulation. No changes to those data are required for reporting to The Registry.[22]

[22] *For example, this alternative applies to facilities in the United States reporting to U.S. EPA under the Acid Rain regulations (40 CFR Part 75, Appendices F and G).*

— EPS ST-04: Method for Calculating CO_2 Emissions from Fuel Combustion Using Default Emission Factors and Default Heat Content

This method should be used and repeated for each type of fuel combusted in power generating units you control.

Calculate each fuel's CO_2 emissions and report them in metric tons using the following equation:

Equation 12f

$$CO_2 = Fuel * HHV_D * EF_{CO2} * 0.001$$

Where:

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

Fuel = mass or volume of fuel combusted specified by fuel type, unit of mass or volume per year

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

EF_{CO2} = default CO_2 emission factor selected from Chapter 12 of the GRP (kg CO_2 per MMBtu), based on fuel type.[23]

0.001 = factor to convert kg to metric tons

12.3 Calculating Biogenic Carbon Dioxide Emissions

This section includes three methods for calculating biogenic emissions from stationary combustion of biomass, wood waste, Municipal Solid Waste (MSW), Waste-Derived Fuel (WDF), and/or biogas – the term used to collectively describe Landfill Gas (LFG) and Digester Gas (DG).

— EPS ST-05: Method for Calculating CO_2 Emissions from Biogenic Sources

Use the following method to calculate CO_2 emissions from combustion of biogenic sources including the combustion of biomass, municipal solid waste, waste or biomass derived fuels, and/or biodiesel. This method does not apply for biogas combustion where the heating value of the gas can be used to calculate emissions using EPS ST-03 or EPS ST-04.

[23] *The Registry updates the emission factors in Chapter 12 of the GRP on a regular basis, including those for Canada and Mexico.*

Calculate CO_2 emissions from combusting biomass or MSW using the following equation:

Equation 12g

CO_2 = Heat * CC_{EF} * 3.664 * 0.001

Where:

CO_2 = CO_2 emissions from fuel combustion, metric tons per year

Heat = heat Input as calculated below (MMBtu per year)

CC_{EF} = default carbon content emission factor provided in Chapter 12 of the GRP, kg carbon per MMBtu [2]

3.664 = CO_2 to carbon molar ratio

0.001 = conversion factor to convert kilograms to metric tons

Calculate heat content using the following equation:

Equation 12h

Heat = Steam * B

Where:

Heat = heat, MMBtu per year

Steam = actual steam generated, pounds per year

B = boiler design heat input/boiler design steam output, MMBtu per pound steam

24 *The applicable emission factors for MSW and Biomass Derived Fuel (BDF) are found in the GRP and regularly updated by The Registry.*

— EPS ST-06: Methods for Partitioning of Anthropogenic/Biogenic CO_2 Emissions

If your fuels or fuel mixtures are at least five percent biomass by weight and not pure biomass,[25] determine the biomass-derived portion of CO_2 emissions using ASTM D6866. You should conduct ASTM D6866 analysis at least every three months, and you should collect each gas sample for analysis during normal operating conditions over at least 24 consecutive hours. Then divide total CO_2 emissions between biomass-derived emissions and non-biomass-derived emissions using the average proportionalities of the samples analyzed. If there is a common fuel source to multiple combustion devices at the facility, you may elect to conduct ASTM D6866 testing for just one of the devices.

This method is consistent with that included in the GRP. Alternatively, for MSW and WDF, you may obtain information on the biomass portion of the fuel from a local waste characterization study, and partition the fossil/biogenic emissions accordingly. Studies conducted within the previous five years are acceptable, and must be for the specific source material and the applicable region, state or province.

— EPS ST-07: Methods for Calculating Biogenic CO_2 Emissions from Biogas Combustion

Biogas (Landfill Gas (LFG) or Digester Gas (DG)) usually includes a mixture of CO_2 and CH_4 in approximately equal proportions.[26] The Registry considers releases of the CO_2 in the raw gas to be a process emission, and when this gas is released to atmosphere it must be categorized separately from the combustion CO_2 that results when the CH_4 is used as a fuel (or flared). However, both sources of CO_2 are considered to be biogenic. Use methods EPS ST-02, EPS ST-03 or EPS ST-04 to calculate the biogenic CO_2 emissions. If natural gas (NG) is also used as a fuel to supplement power generation with LFG or DG, then the process and combustion CO_2 from that fuel should be categorized as anthropogenic.

12.4 Calculating Methane and Nitrous Oxide Emissions

Emissions of CH_4 and N_2O from stationary combustion may be estimated using default emission factors, source test data and/or CEMS using Fourier Transform Infrared spectroscopy, if available. Use EPS ST-08 below to calculate these emissions.

25 *Except for waste-derived fuels that are less than 30 percent by weight of total fuels combusted.*

26 *GRP Chapter 12*

— EPS ST-08: Method for Calculating CH_4 and N_2O Emissions from Fuel Combustion Using Default Emission Factors or Source Test Data

You should use the methods in this section to calculate CH_4 and N_2O emissions from fuel combustion. The methods presented below are for fuel-based calculations using fuel-specific emission factors.

You may elect to calculate CH_4 and N_2O emissions using source-specific emission factors derived from source tests. Source test data must be less than three years old and must be specific to the site, fuel and engine type for which emissions are being calculated. If a source test result is below the non-detect limit, an emission factor of one-half the non-detect limit may be used. Source test data up to five years old may be used if the last two consecutive source tests (conducted at least one year apart) were below the non-detect limit.

In the absence of source-specific emission factors, you may use the default emission factors provided in Chapter 12 of the GRP for each type of fuel.

If the heat content of the fuel is measured, calculate each fuel's CH_4 and N_2O emissions and report them in metric tons using the following equation:

Equation 12i

$$CH_4 \text{ or } N_2O = \sum_{1}^{n} Fuel_P * HHV_P * EF * 0.001$$

Where:

CH_4 or N_2O = combustion emissions from specific fuel type, metric tons CH_4 or N_2O per year

n = period/frequency of heat content measurements over the year (e.g. monthly n = 12)

$Fuel_P$ = mass or volume of fuel combusted for the measurement period specified by fuel type, units of mass or volume per unit time

HHV_P = high heat value measured for the measurement period specified by fuel type, MMBtu per unit mass or volume

EF = default CH_4 or N_2O emission factor provided in Chapter 12 of the GRP, kg CH_4 or N_2O per MMBtu

0.001 = factor to convert kg to metric tons

If the heat content of the fuel is not measured or if it is calculated, calculate each fuel's CH_4 and N_2O emissions and report them in metric tons using the following equation:

Equation 12j

CH_4 or N_2O= Fuel * HHV_D * EF* 0.001

Where:

CH_4 or N_2O = CH_4 or N_2O emissions from a specific fuel type, metric tons CH_4 or N_2O per year

Fuel = mass or volume of fuel combusted specified by fuel type, unit of mass or volume per year

HHV_D = default high heat value specified by fuel type provided in Chapter 12 of the GRP or calculated heat value from EPS Method ST-05, MMBtu per unit of mass or volume

EF = default emission factor provided in Chapter 12 of the GRP, kg CH_4 or N_2O per MMBtu

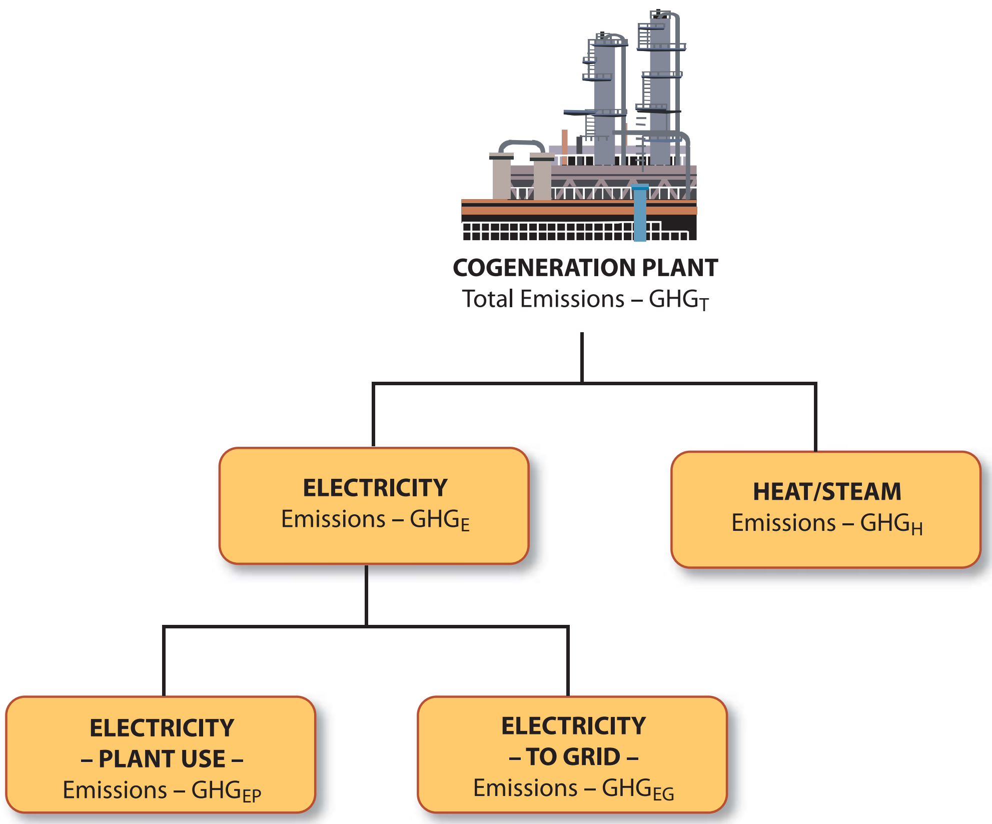
0.001 = factor to convert kg to metric tons

12.5 Allocating Emissions from Combined Heat and Power

If your facility operates a cogeneration unit or group of units and at least a portion of the electricity is exported to the grid, then you must calculate and report distributed emissions for each of your cogeneration systems. The method to achieve this is included in Chapter 12 of the GRP. The requirement to allocate emissions based on the heat and power outputs is used to generate the appropriate power generation metrics for this power. This is illustrated in Figure 12.1 below.

Note that all emissions from your cogeneration facility will be included in your Scope 1 emissions, regardless of the dispensation of heat or power.

Figure 12.1 Allocation of Emissions from a Cogeneration Plant



$GHG_T = GHG_E + GHG_H$ (Allocation Method from GRP, Chapter 12)

$MWh_T = MWh_P + MWh_G$

$GHG_{EP} = GHG_E * MWh_P / (MWh_T)$

$GHG_{EG} = GHG_E * MWh_G / (MWh_T)$

where:

GHG_T – greenhouse gas emissions – total stationary combustion
GHG_E – greenhouse gas emissions – electricity
GHG_H – greenhouse gas emissions – heat/steam
GHG_{EP} – greenhouse gas emissions – electricity to plant
GHG_{EG} – greenhouse gas emissions – electricity to grid

MWh_T – electricity net generation - total
MWh_P – electricity net generation - plant
MWh_G – electricity net generation - grid

12.6 Examples: Calculating Direct Emissions from Stationary Combustion

12.1 EXAMPLE 12.1
Coal-fired Power Plant Reporting With CEMS Data

Opal Power owns and operates Unit #2 of a coal-fired power plant. A CEMS unit is operated for Unit #2 in accordance with 40 CFR Part 75 (U.S. EPA). Opal Power has decided to report CO_2 emissions to The Registry using CEMS data, and is additionally providing fuel use data for purposes of calculating CH_4 and N_2O emissions using default emissions factors from the GRP.

Opal Power collects the following data to report emissions and electricity generation from this unit:

Annual Emissions of CO_2	= 2,952,000 tons (CEMS data reported to EPA)
Annual fuel usage	= 28,770,000 MMBtu (calculated from coal usage, GRP defaults)
Annual net generation	= 3,104,300 MWh
Fuel Type:	= sub bituminous coal
Boiler technology:	= dry bottom, wall-fired

Organizational Consolidation

Opal Power has a 100 percent equity share in Unit #2, and also has operational control. Therefore, the reported emissions will be the same for the operational boundaries and equity share consolidation methods.

CO_2 Emissions Reported Using CEMS: Direct Monitoring

2,952,000 tons CO_2 x (2000 lb/ton) ÷ (2204.62 lb/metric ton) = 2,678,013 metric tons CO_2.

CO_2 Emissions Calculated using Measured Heat Content and Default Carbon Content

Carbon Content for Sub bituminous Coal:	= 26.48 kg C/MMBtu (default, GRP Chapter 12)
Molecular Weight Ratio of CO_2/Carbon	= 44/12

(28,770,000 MMBtu) x (26.48 kg C/MMBtu) x (44 kg CO2/12 kg C) ÷ (1000 kg/metric ton) = 2,793,375 metric tons CO_2

CH_4 and N_2O Emissions Calculated Using Default Emission Factors by Sector and Technology Type

Emission Factors for Dry Bottom, Wall-Fired Boilers (Default, GRP Chapter 12):

0.7 g CH_4/MMBtu
0.5 g N_2O/MMBtu

(28,770,000 MMBtu) x (0.7 g CH_4/MMBtu) ÷ (1,000,000 g/metric ton) = 20.14 metric tons CH_4

(28,770,000 MMBtu) x (0.5 g N_2O/MMBtu) ÷ (1,000,000 g/metric ton) = 14.39 metric tons N_2O

12.2 EXAMPLE 12.2
Co-firing Of Natural Gas and Digester Gas - Direct Monitoring (CEMS)

Opal Power owns and operates a power generation facility that co-fires natural gas with digester gas from a wastewater treatment plant. Opal operates a CEMS unit in accordance with 40 CFR Part 75 which measures O_2 concentrations. CO_2 emissions are calculated from the O_2 CEMS, and annual source testing demonstrates that the calculated CO_2 concentrations meet the Relative Accuracy Test Audit (RATA) requirements in 40 CFR Part 60, Appendix B, Performance Specification 3.

Opal has decided to report CO_2 emissions to The Registry using the CEMS data, and to apportion the anthropogenic and biogenic CO_2 emissions using the methodology described in ASTM D6866-06a, "Standard Test methods for Determining the Biobased Content of Natural Range Materials Using Radiocarbon and Isotope Ratio Mass Spectrometry Analysis." Fuel use data (for natural gas and digester gas) are metered and used for calculating CH_4 and N_2O emissions using default emissions factors from the GRP.

Opal Power collects the following data to report total emissions from this facility:

Annual CO_2 Emissions	= 1,050,000 tons (calculated from CEMS)
Annual natural gas usage	= 14,825,000 kscf (metered)
Natural gas HHV	= 1,034 Btu/scf (measured and averaged using monthly data)
Annual digester gas usage	= 2,650,000 kscf (metered)
Digester gas HHV	= 629 Btu/scf (measured)
Biogenic Carbon/Total Carbon	= 17% (ASTM D6866-06a)

Total CO_2 Emissions
1,050,000 tons CO_2 x (2000 lb/ton) ÷ (2204.62 lb/metric ton) = 952,545 metric tons CO_2

Biogenic CO_2 Emissions
952,545 metric tons total CO_2 x 17% biogenic content = 161,933 metric tons

Anthropogenic CO_2 Emissions
952,545 metric tons total CO_2 - 161,933 metric tons biogenic CO_2 = 790,612 metric tons

Note: per GRP guidance (GRP Chapter 12), digester gas is considered to be 50 percent CH_4 and 50 percent CO_2 by volume. Site specific gas composition analysis data may be used for more accurate percentages. The CH_4 component is combusted to form CO_2 combustion emissions, while the CO_2 component passes through the generation facility and is considered CO_2 pass-through (process) emissions. Both components are included in the CEMS biogenic CO_2 emissions total.

12.3 EXAMPLE 12.3
Co-firing Of Natural Gas and Digester Gas - Heat Input Method

For the same facility as described in Example 12.2, this example shows how to calculate CO_2 emissions using measured heat input and default carbon content for natural gas and digester gas fuels.

Natural Gas
Carbon content for natural gas (with HHV of 1,034 Btu/scf): 14.47 kg C/MMBtu (default, GRP Chapter 12)
Molecular Weight Ratio of CO_2/Carbon = 44/12
(14,825,000 kcf) x (1,000 cf/kcf) x (1,034 Btu/cf) x (MMBtu/1,000,000 Btu) x (14.47 kg C/MMBtu) x (44 kg CO_2/12 kg C) ÷ (1000 kg/metric ton) = 813,308 metric tons CO_2 (anthropogenic)

Digester Gas
Carbon content for digester gas (CH_4 component only): 14.20 kg C/MMBtu
Molecular Weight Ratio of CO_2/Carbon = 44/12
(2,650,000 kscf) x (1,000 cf/kscf) x (629 Btu/scf) x (MMBtu/1,000,000 Btu) x (14.20 kg C/MMBtu) x (44 kg CO_2/12 kg C) ÷ (1000 kg/metric ton) = 86,787 metric tons combustion CO_2 (biogenic)

Volume of biogenic "pass-through" CO_2 = (2,650,000 kscf ÷ 2) = 1,325,000 kscf CO_2
(1,325,000 kscf) x 0.056 MT/kscf = 74,289 metric tons of biogenic pass-through CO_2

With this method, the total anthropogenic emissions are 813,308 metric tons, and the biogenic emissions are 161,076 metric tons.

Note: because Opal Power has selected to report CO_2 emissions using direct monitoring (CEMS), the CO_2 emissions calculated using EPS-ST-03 do not appear in the public report, but they are included in the private detailed inventory report.

12.4 EXAMPLE 12.4
Co-firing Of Natural Gas And Digester Gas - Ch_4 And N_2o Emissions

For the same facility as described in Examples 12.2 and 12.3, this example shows how to calculate CH_4 and N_2O emissions using measured heat input and default emission factors.

Emission factors for natural gas boilers: 0.9 g CH_4/MMBtu (default, GRP Chapter 12)
0.9 g N_2O/MMBtu (default, GRP Chapter 12)

Note. These emission factors are used for natural gas and digester gas as follows:

Natural Gas
(14,825,000 kcf natural gas) x (1,000 cf/kcf) x (1,034 Btu/cf) x (MMBtu/1,000,000 Btu) x (0.9 g CH_4/MMBtu) ÷ (1,000,000 g/metric ton) = 13.80 metric tons CH_4
(14,825,000 kcf natural gas) x (1,000 cf/kcf) x (1,034 Btu/cf) x (MMBtu/1,000,000 Btu) x (0.9 g N_2O/MMBtu) ÷ (1,000,000 g/metric ton) = = 13.80 metric tons N_2O

Digester Gas
(2,650,000 kcf digester gas) x (1,000 cf/kcf) x (629 Btu/cf) x (MMBtu/1,000,000 Btu) x (0.9 g CH_4/MMBtu) ÷ (1,000,000 g/metric ton) = 1.5 metric tons CH_4
(2,650,000 kcf digester gas) x (1,000 cf/kcf) x (629Btu/cf) x (MMBtu/1,000,000 Btu) x (0.9 g N_2O/MMBtu) ÷ (1,000,000 g/metric ton) = 1.5 metric tons N_2O

Chapter 13: Direct Emissions from Mobile Combustion

13.1 Calculating Carbon Dioxide Emissions from Mobile Combustion

REFER TO GRP.

13.2 Calculating Methane and Nitrous Oxide Emissions from Mobile Combustion

REFER TO GRP.

13.3 Example: Calculating Direct Emissions from Mobile Combustion

REFER TO GRP.

Chapter 14: Indirect Emissions from Electricity Use

Chapter 14 addresses the reporting of indirect emissions associated with the consumption of purchased or acquired electricity. The sections that follow provide a general description of indirect electricity emissions applicable to the EPS (Section 14.1), and methods for calculating emissions associated with transmission and distribution (T&D) losses (Section 14.2), emissions associated with bulk transmission system losses (Section 14.3), and emissions associated with electricity use in buildings and facilities (Section 14.4). The chapter ends with a brief discussion of other types of indirect emissions common to the EPS that may be optionally reported (Section 14.5).

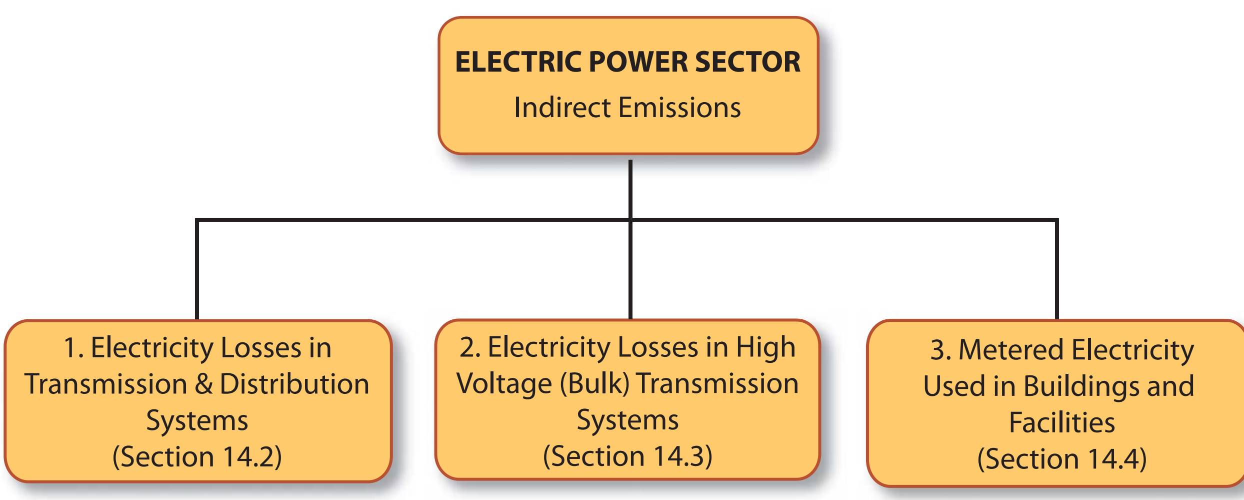
14.1 Quantifying Indirect Emissions from Electricity Use

In general, electricity is consumed in the EPS in three distinct categories as follows:

1. T&D systems used to deliver electricity to retail and wholesale customers.
2. High-voltage bulk power transmission systems.
3. Facilities and buildings.

These three categories of emissions are represented in Figure 14.1.

Figure 14.1 Categories of Indirect Emissions Applicable to the Electric Power Sector



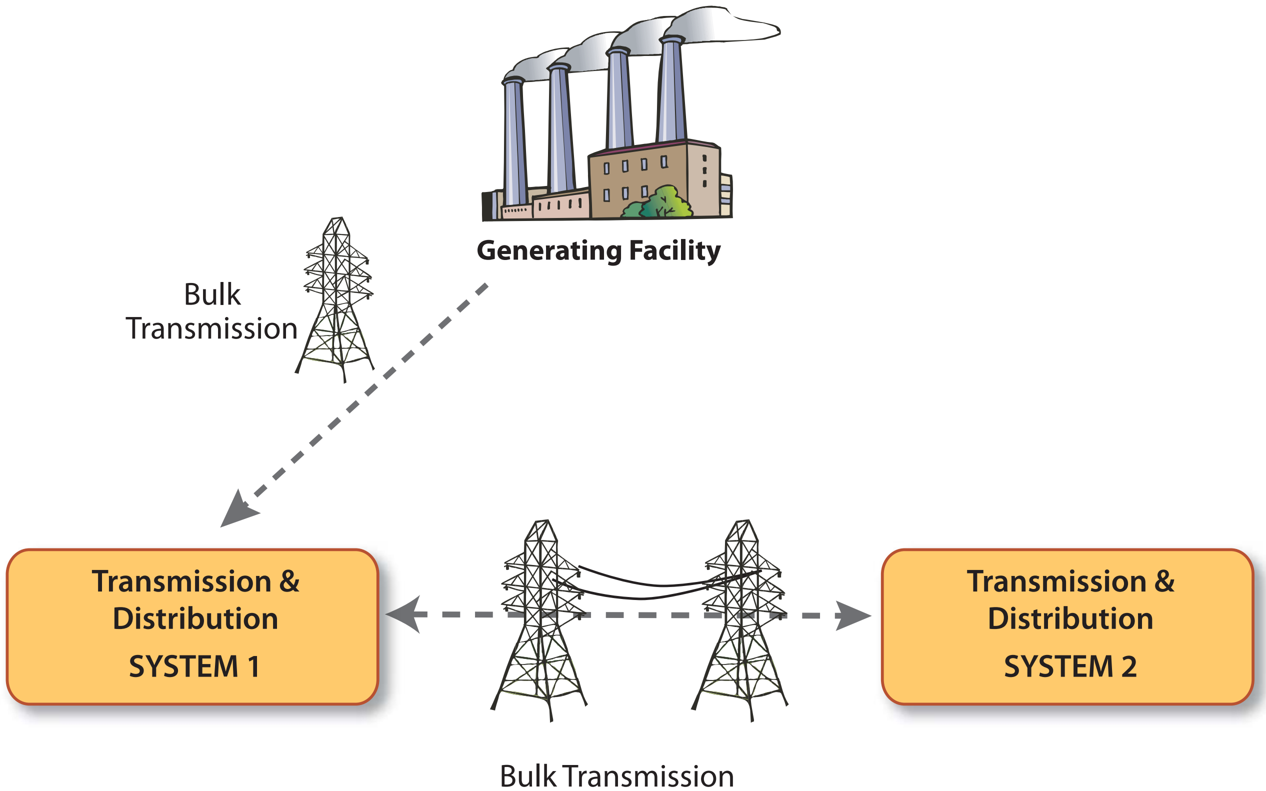
Members reporting indirect emissions from T&D systems at the local level may include utilities and other Local Distribution Companies (LDCs) and Cooperatives. Members that report emissions from high-voltage bulk transmission systems may include transmission companies, Balancing Authorities, Independent System Operators (ISOs), Wholesale Cooperatives and integrated utilities that also engage in local distribution. Members may also have some indirect emissions from the use of electricity in facilities and buildings.

If you control a local T&D system (e.g. serving a discrete service territory) you may aggregate the transmission and distribution components of the system together into a single “facility”. If you own or control T&D systems that are essentially separate from each other and operated as separate systems (these systems may be geographically separate, have different supply resources, and/or have different customer bases), you must report data separately for each distinct system to ensure that losses and emissions are accurately determined for each system.

If you own or control a local T&D system and also own or control bulk power transmission lines that interconnect your T&D system with remote generation and/or other T&D systems (Figure 14.2), then you may choose to include the bulk power system with the T&D system it serves as a single “facility.” If you aggregate emissions from these systems together, you should use the guidance in Section 14.2 to calculate emissions associated with losses for your combined system. You may alternately choose to report the bulk transmission line(s) as a separate facility. In this case, you should use the guidance provided in Section 14.3. In many instances bulk power transmission systems are controlled by entities that are not involved in power distribution and do not own or control local T&D systems. In these cases, the bulk transmission system must be reported as a distinct “facility.” Additional guidance on how to report bulk transmission systems can be found in Section 14.3.

Your chosen organizational boundary approach and the nature of your control will determine whether or not you have the responsibility to report emissions from these bulk transmission systems (Section 4.6).

Figure 14.2 T&D Systems With Transmission Interconnections



If you operate a T&D system or bulk transmission system and you also generate power, you will need to report indirect emissions associated with the losses that occur on T&D and bulk transmission systems for all power that flows on the systems that are not self generated. You should not report the indirect emissions associated with the self-generated power flowing through your lines as this would result in the double counting of emissions.[27] However, you do need to understand how much self-generated power is flowing through your T&D system in order to calculate a system "loss factor" (as described in the next section).

14.2 Indirect Emissions from Electricity Use: Transmission and Distribution Losses

T&D system losses are a result of electricity consumption as it moves from one point to another in the T&D system. These losses occur in wires, transformers and other electricity system components due to resistance, unmetered paths to ground, and related electrical inefficiencies. The losses that occur on these power delivery systems are dependent on the

[27] *World Resource Institute/World Business Council for Sustainable Development (WRI/WBCSD) GHG Protocol Corporate Accounting and Reporting Standard (Revised Edition).*

physical characteristics of the lines, and the power that flows through them. In order to calculate the indirect emissions associated with these losses, Members with power delivery systems need to know how much power is conveyed through the lines, what the "loss factor" is for the system as a whole, and the emission factor (or carbon intensity) of the power, which in turn depends on the generation characteristics of the power.

This section includes methods for compiling the information needed to calculate the indirect emissions associated with T&D losses. Two alternatives are offered as follows:

> **EPS IE-01: Energy Balance Method:** This method is a detailed approach based on an energy balance analysis to determine a system-specific loss factor, and a detailed review of purchases to determine a more accurate estimate of the total emissions flowing through the system and, therefore, the Scope 2 emissions associated with the T&D losses. You must use this option if you intend to report the optional power deliveries metrics (Chapter 19).
>
> **EPS IE-02: Aggregated Power Flow Method:** The aggregated power flow method is a simplified approach based on default loss factors and default emission factors. Note, however, that you cannot use this option if you plan to report optional power deliveries metrics (Chapter 19).

Table 14.1 provides a summary of the differences between methods EPS IE-01 and EPS IE-02.

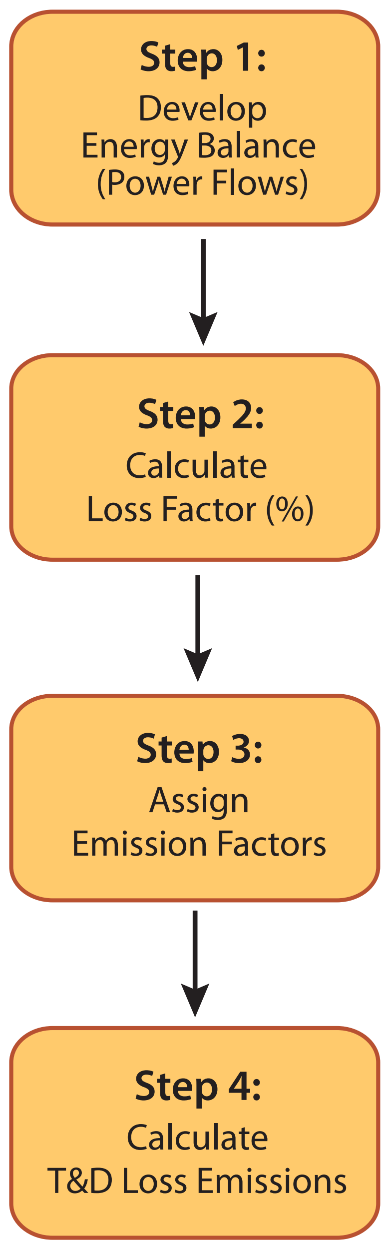
14.1 TABLE 14.1 Overview of Methods for Reporting T&D System Emissions

	Table 14.1 Indirect Emissions From Electricity Use			
	Method	**Power Flows**	**T&D Loss Factor**	**Emission Factors**
Emissions from T&D Systems	EPS IE-01	Energy Balance Method	Engineering Estimate, Modeled Loss Rate or Energy Balance Approach	Emission factors assigned to each purchase by counterparty or by fuel type
	EPS IE-02	Aggregated Power Flow Method	Default Factor	Average emission rates for eGRID sub-region, state, province or territory

Note:
Members are encouraged to use as much site-specific information as they have available. If you have sources for some but not all of the information required for EPS IE-01 you are encouraged to use a hybrid of methods EPS IE-01 and EPS IE-02.

Figure 14.3 summarizes the four steps you will need to follow to calculate the emissions associated with your T&D losses. These four steps are applied differently depending on the method you use to calculate your indirect emissions. These steps and their application for EPS IE-01 and EPS IE-02 are discussed in Sections 14.2.1 through 14.2.4.

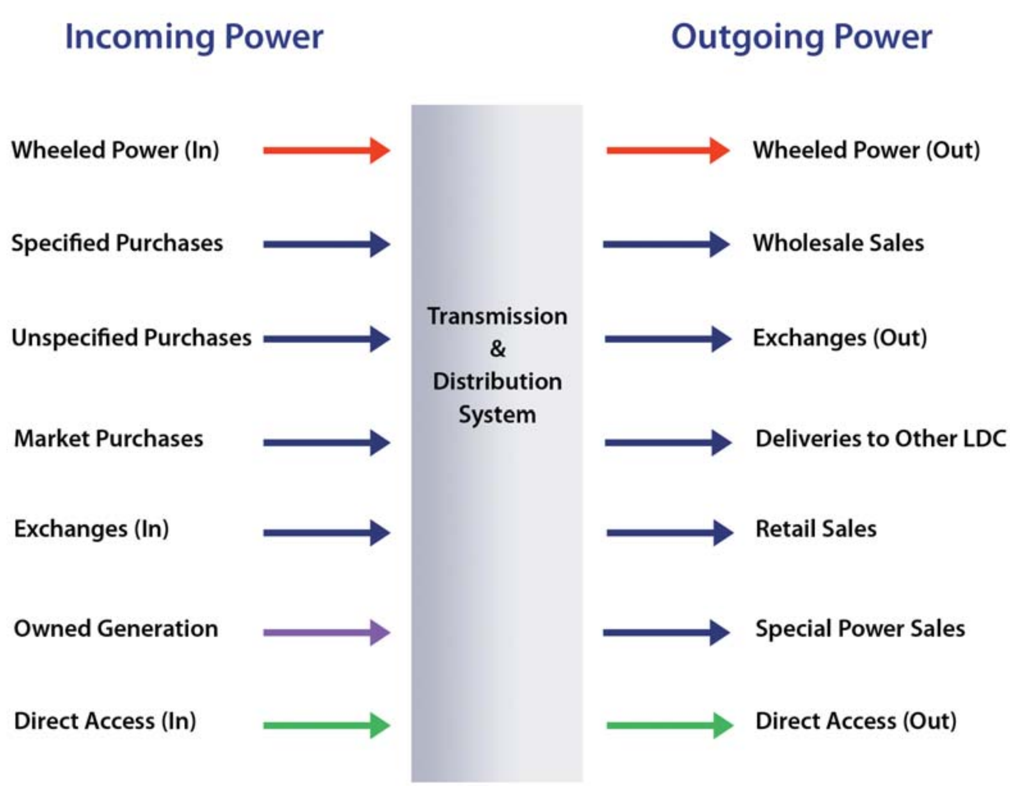
Figure 14.3 Four-Step Process for Calculating Emissions from T&D Losses and Associated Emissions



14.2.1 Step 1: Identify Power Flows Conveyed on the T&D System

Figure 14.4 provides a generalized illustration of how power flows onto a typical T&D system and where it goes when it leaves the system.

Figure 14.4 Energy Balance of a Typical T&D System Showing Power Flows



The two options to account for the power flows are described below.

— EPS IE-01: Accounting for Power Flows on a T&D System Using the Energy Balance Method

With the energy balance method, you will need to develop a detailed account of the energy that flows onto and out of your system. You must account for power flows onto your system as follows:

- Net generation delivered from each generating facility you own or operate
- Power received from each Specified Purchase
- Total power received from Spot Market Purchases
- Power purchased and received from all Other Sources ("Other Purchases")

- Power received from power exchanges
- Power received from transactions of power with a Balancing Authority (e.g., power exchanges made to relieve transmission congestion)
- Power conveyed through the system for others, including but not limited to power received from power generators, retail providers, and power marketers. This category includes Direct Access power and any other power wheeled across the system for others.

You must also account for power that flows out of the system as follows:

- Power delivered for retail sales
- Power delivered for wholesale sales
- Power exchanges (delivered)
- Power conveyed through the system for others (as discussed above)
- Power consumed in buildings and facilities you own and/or operate

If your T&D system is in the U.S. and you are required to submit a FERC Form 1, these power flows are available from the various sheets that make up the Form 1.[28] If you do not compile a FERC Form 1, you should refer to that form, and use it as a guide for gathering the data you need for your own system.

To properly account for power flows, you will need to define your system's boundaries including the Point of Receipt (POR) where each purchase of electricity is received by the system, and the Point of Delivery (POD) where electricity is delivered wholesale from the system. The POR is the first point of interconnection to your system where a purchase is received, and the POD is the interconnection where electricity is sold wholesale to another party. The PORs and PODs are usually well-defined substations. The PORs and PODs are likely to be at or near the boundary of the LDC service area for purchases made outside the service area, and at a local substation for power generated or purchased from facilities within the service area. Retail sales to customers usually occur within the system boundaries, and wholesale sales usually occur at a well-defined substation at the perimeter of the service area.

Each main category of power needed for the energy balance is discussed briefly below.

Owned/Controlled Power Generation – The requirements for reporting power flows from owned/controlled generation are discussed in Chapter 12 of the EPS Protocol. It should be noted that because both owned/controlled and purchased generation flow onto the T&D system, inclusion of both are important factors for determining the T&D losses (expressed in MWh) and the line loss factor.

Specified Purchase – This is a purchase from a particular generating unit or facility for which electricity generation can be confidently tracked due to its identification in a power contract or invoice. This category also includes contracts which tie the energy to specific resources and/or to specific group of facilities. It is important to differentiate these purchases, because they can be assigned facility or unit-specific emission factors.

28 *Available at:* *http://www.ferc.gov/docs-filing/eforms/form-1/viewer-instruct.asp*

Spot Market and Other Purchases – For spot market or other purchases, you must identify a region of origin for each purchase. The regions to be used are the eGRID sub-regions for the U.S. (GRP, Figure 14.2),[29] the Canadian Provinces/Territories (GRP, Table 14.2), and the Mexican States (GRP, Table 14.3). When the region of origin is uncertain, you will need to make a determination of the most likely place of origin. You may aggregate the power purchased by counterparty (supplying the power) if the purchases are known to originate in the same region.

Direct Access Deliveries – You should identify all power deliveries to end-use customers for other retail providers in a separate category.

Power Exchanges – These represent real energy flows out of and onto the T&D system, so they are included in the required energy balance of power flows. When reporting power transactions associated with exchange agreements, you should report electricity received as a power purchase together with the region of origin. This approach reflects the intent to track actual power flows (and emissions) wherever possible rather than the financial transaction.

“Off System Purchases” – Some purchases and sales made by a Load Serving Entity are specified for “off system” locations. You should remove all of these transactions from the T&D System Energy Balance because they have no influence on your T&D system losses.[30]

Power Deliveries – You must report all sales of power from the system (including retail and wholesale), power exchanges (delivered), and all power delivered through the system for others who request use of the transmission system (as discussed above). All wholesale sales and all other power conveyances are measured at the POD.

Self-Consumed Power – You should include all self-consumed power in the energy balance, including both self-generated and purchased power. This is the total amount of metered electricity taken from the grid and consumed in your facilities and buildings, whether billed or not.

“Book-outs” – Purchased power data records often include “virtual energy” reflective of hedge or speculative trades of energy that were not delivered to the system. Similarly, scheduled power records may include transactions that were initially scheduled, but subsequently canceled. These “book-outs” should not be included in the energy balance.

29 Emissions & Generation Resource Integrated Database, U.S. EPA.

30 Note that these “off system” transactions are included in the U.S. FERC Form 1 report, so they need to be removed from the system energy balance required in the EPS Protocol.

— EPS IE-02: Accounting for Power Flows on a T&D System Using the Aggregated Flow Method

With the aggregated flow method, you will need to obtain an aggregate of your power flows from a form such as the FERC Form 1 page 401 "Energy Account" and the EIA 861 Page 2 "Energy Balance Account." These forms do not provide the degree of detail that the energy balance method does, but they are an acceptable alternative for those Members that do not plan to report power deliveries metrics.

14.2.2 Step 2: Develop T&D System Loss Factor

After identifying and reporting all power flows over the system, a loss factor needs to be calculated (EPS IE-01) or selected (EPS IE-02). The two options are discussed below.

— EPS IE-01: Calculating a Loss Factor Using the Energy Balance Method

You can calculate the T&D losses (MWh) by subtracting the total power you deliver and consume from the total power received into your system. The system average loss factor is the ratio of these losses to the total power received over an annual reporting period (expressed as a percentage). This energy balance approach needs to account for all energy flows into and out of the system as described in the previous section. To calculate a system loss factor using this approach, use Equation 14a, as follows:

Equation 14a
T&D System Loss Factor [%] = (Total Power Flows onto System [MWh] - Total Power Flows out of System [MWh]) / Total Power Flows onto System [MWh]

Another approach, consistent with the energy balance method, is to use an estimate of the losses derived from measured flow data through the system or modeling calculations available from a Balancing Authority. These estimates are based on current loading, ambient conditions, and measured losses on representative samples of T&D segments and components in the T&D system. The loss factor is the ratio of the modeled losses to the total energy flow into the system. If a modeled system loss factor is used, then you must have documentation from the entity that provides the calculated number or reference to a source where the loss factor is publicly available.

— EPS IE-02: Selecting a Default Loss Factor

You may use a default T&D loss factor based on the best avaliable eGRID data.[31] Table 14.2 shows the loss factors from the eGRID database for five grid regions in the United States. For Canada and Mexico, you may use the average loss factor for the entire United States (also included in Table 14.2) as a default.

14.2 TABLE 14.2
eGRID Average Loss Factors

Grid Region	2004	2005
East	6.54 %	6.41 %
West	2.48 %	5.33 %
Texas	7.69 %	6.18 %
Hawaii	-0.13 %	3.69 %
Alaska	3.69 %	2.79 %
United States		**5.60 %**

Source – eGRID 2007 (includes data for both years as shown above)

14.2.3 Step 3: Assign Emission Factors and Determine Scope 3 Emissions

The third step is to assign GHG emission factors (for CO_2, CH_4, N_2O) to the power that flows through the T&D system and calculate the Scope 3 emissions. Note that this step does not apply to power that you generate and report as Scope 1 emissions. These emissions are already reported according to the requirements in Chapter 12. The two options for selecting and assigning emission factors are presented below.

31 http://www.epa.gov/cleanenergy/documents/egridzips/eGRID2007V1_1_year0504_STIE_USGC.xls.

— EPS IE-01: Assigning Specific Emission Factors to Power Flows

This section provides guidance for assigning emission factors for four general power purchase categories as follows:

Specified Purchases. Where unit, facility, or utility-specific purchases can be identified through contract and/or financial accounting records (such as invoices and payments), you can assign an emission factor applicable for that source. These emission factors may be obtained from one of the following sources: (a) metrics reported in The Registry's database; (b) facility-specific emission factors from eGRID or reports to EIA-906/920 (United States); (c) U.S. EPA Part 75 Electronic Database Reports (EDR); or (d) another equivalent third-party verified or governmental source (See text box pn page 67 for further discussion: Emissions Factors for Power Purchases). Applicable emission factors may be available from other state/ provincial reporting programs, other public third-party verified registries, and/or proprietary databases.

If there is no unit or facility-specific emission factor available, you may use a fuel specific emission factor (Table 14.3). Table 14.3 includes CO_2 emission factors from the combustion of biogenic fuels, but other renewable energy sources with zero emissions are not included (i.e., wind, solar wave energy). At this time, hydro power purchases (large and small should be considered non-emitting). For specified purchases from known geothermal power production facilities that are known to use binary technology, the emission factors are zero. Emissions may be attributed to known non-binary geothermal purchases using the net power generation together with a default emission factor. Default emission factors for this method are 90.7 kg/ MWh (200 lb/MWh) for CO_2 and 0.75 kg/MWh (1.66 lb/MWh) for CH_4.[32]

32 *These emission factors are based on the weighted average of data obtained from a range of geothermal energy production technologies. See Bloomfield, K. (INEEL), Joseph N. Moore (EGI), and Robert M. Neilson, Jr. (INEEL). 2003. "Geothermal Energy reduces Greenhouse Gases. CO_2 Emissions from Geothermal Energy Facilities are Insignificant Compared to Power Plants Burning Fossil Fuels." Geothermal Resources Council Bulletin, March/April 2003.*

14.3 TABLE 14.3
Default CO_2 Emission Factors For Purchases From Specific Resources

Resource Type	CO_2 lbs/MWh	Resource Type		CO_2 lbs/MWh
Coal		**Natural Gas**		
Lignite Coal	2,402	CA (combined cycle two turbines)		909
Petroleum Coke	2,390	CS (combined cycle - single shaft)		860
Sub-Bituminous Coal	2,212	GT (combustion [gas] turbine)		1,329
Bituminous Coal	2,047	ST (steam turbine)		1,532
		IC (internal combustion)		1,226
Liquid/Gas Fossil Fuels				
Kerosene	2,130	**Biogenic Fuels**		
Waste Oil	1,306		**Anthropogenic**	**Biogenic**
Distillate Fuel Oil	1,604	Wood-Derived Solids	44	2,492
Residual Fuel Oil	1,499	Black Liquor	136	1,670
Jet Fuel	1,410	Landfill Gas	38	2,677
Other Fossil Gas	1,755	Municipal Solid Waste	1,353	2,513
Blast Furnace Gas	1,019			

Notes:

The data presented in this table were derived from the US EPA's eGRID-2007 based on data for 2005. The emission factors were derived by totaling the emissions and net power generation for each of the generating resource categories, and using these totals to derive an average of emissions per MWh.

For the eGRID facilities that use biogenic fuels (biomass, wood waste, biogas and MSW), there are some facilities that co-fire fossil fuels along with the biogenic fuel. For resource-specific emission factors, the anthropogenic emissions at these facilities have been averaged to give an overall average for the entire subset of each resource type. Thus, for resource-specific purchases, there will be a small amount of anthropogenic emissions for each of the biogenic fuels.

The eGRID database includes anthropogenic CO_2 emissions, but not biogenic CO_2. Biogenic emission factors for wood-derived solids and black liquor were derived using the heat input and net generation data from eGRID-2007 together with the default emission factors from the GRP. For landfill gas, the emissions were calculated using an emission factor from the California Air Resources Board's "Regulation for the Mandatory Reporting of Greenhouse Gas Emissions". This was done to include the process emissions (from "pass-through" CO_2) as well as the combustion emissions.

MSW emission factors were derived using the eGRID-2007 data, and the biogenic/anthropogenic emissions were partitioned using a 65/35 percent split based on data reported by Covanta Energy.[33]

33 *"Updated Analysis of Greenhouse Gas Emissions and Mitigation from Municipal Solid Waste Management Options Using A Carbon Balance," Brian Bahor, Keith Weitz and Andrew Szurgot. Global Waste Management Symposium, June 30, 2008.*

Spot Market Purchases. For these purchases, you should use the annual average output emission rate for the applicable sub-region (or province/territory) where the power is obtained. These can be obtained from Chapter 14 of the GRP. [34]

Other Purchases (including Power Exchanges, Received). In some cases there may be sufficient data available and sufficient confidence in the source of the power to assign a facility or utility specific emission factor to the purchase. However, you should keep in mind that the power may not be delivered from a particular facility under certain circumstances even when the facility location is referred to in a power contract. For example, with firm power contracts, power may be received from one facility for most of the year, but alternative power must be provided when the facility is not available. For such cases, this protocol gives discretion to the Member, subject to Verification Body approval, to determine the most accurate emission factors to assign. However, if there is no reasonable justification for assigning a specific emission factor, then average output emission rates should be used, consistent with the treatment of Spot Market Purchases.

Direct Access Deliveries and Wheeled Power. If you do not have data on the source of power delivered for others – as with Direct Access – then these power deliveries should be treated the same as Spot Market or Other Purchases. Use measured and reported MWh data together with the eGRID or provincial annual average output rate emission factors (provided in GRP Tables 14.1, 14.2 and 14.3) for the sub-region or province of origin. If the Member does not know the sub-region or province of origin, then the local sub-region or province should be used. This also applies to wheeled power.

When emission factors have been assigned for each source, the emissions associated with each purchase can be estimated using Equation 14b, as follows:

Equation 14b

Emissions from Purchased Power[MT GHG] = Power Delivered onto System [MWh] x Emission Factor [MT GHG/MWh]

This calculation is repeated for each GHG (CO_2, CH_4, N_2O) using the appropriate emission factors identified above.

The text box that follows provides a discussion of specific sources of emissions factors for power purchases that Members may use for calculating T&D losses and emissions consistent with the provisions discussed above.

34 For the United States, the eGRID subregion annual output emissions rates are the system wide emissions divided by the system wide generation within each eGRID subregion. The Registry will regularly update the eGRID sub-region emission factors in the GRP as eGRID updates are issued by the U.S. EPA.

EMISSION FACTORS FOR POWER PURCHASES

The emission factor and the best data source to use for power purchases will depend on the type of power purchase.

Registry (Online) Databases
When the facility (or generating unit) is known, it may be possible to use a facility-specific or unit-specific emission factor. If the facility has reported data to The Registry or to other registries where data is publicly reported and third-party verified, it may be possible to obtain a facility specific CO_2 emission factor directly from The Registry's database or other databases.

U.S. EPA's eGRID Database
The eGRID database includes output emission rates (lb/MWh) for power generating facilities – for CO_2, CH_4 and N_2O emissions. In this case, it is possible to obtain facility emission factors for past years, though current-year or immediate past-year data are not likely to be available. The database includes average output emissions rates for sub-regions of the U.S that provide default emission factors on a regional basis. The database can also be used to derive utility or generator-specific average emission rates. You can use the utility or generator-specific average, if known, fuel-specific emission factors if the generation source is known (Table 14.3), or the regional average emission rate if there is no specific facility or utility/generator to which the purchase can be assigned.

U.S. DOE's EIA Power Generator Databases (EIA-906-920)
Each year, power generators in the U.S. report power generation data to the EIA. The reported data are available online, and provide another opportunity to develop facility emission factors. These data are not available at the combustion or stack level, and they do not include GHG emissions data. However, the emissions can be calculated using a default emission factor for the fuel type, using the heat input that is also reported in these datasets.

U.S. EPA's Electronic Data Reports for Power Generating Facilities
This data source is U.S. EPA's Electronic Data Reporting (EDR) system used for Acid Rain compliance reporting by large power generation facilities. The data elements reported include CO_2 emissions (short tons) and Gross Generation (MWh), and they are included at the stack level which is often consistent with the generating unit. This dataset may not be the best for unit-specific emission factors because the output gives Gross Generation (MWh) rather than Net Generation, and the power generation from non-emitting units (such as combined-cycle steam generators) is not included with the combustion unit-specific data.

Biogenic CO_2 Emission Factors
When selecting emission factors from agency databases for purchased electricity generated using fuels that have biogenic emissions (including Landfill Gas, Digester Gas, Biomass, Municipal Solid Waste, etc.), it is important to consider what assumptions are made by the agency in compiling the emissions dataset regarding biogenic CO_2 emissions. In some cases, if the power is generated with a combination of fossil and biomass fuels, the reported CO_2 emissions may be a combination of fossil and biogenic emissions, or they may just be fossil CO_2 emissions. You should refer to the Users' Guide of the database before selecting the emission factors for these types of purchases.

The Registry requires that biogenic CO_2 emissions be reported separately from anthropogenic emissions. This extends also to purchases. If biogenic CO_2 emissions cannot be separately determined, then Members should use regional average output emissions factors, as with Spot Market and Other Power purchases.

— EPS IE-02: Assigning Default Emission Factors to Aggregate Power Flows

If you are using the aggregate flow method, you may assign regional average output emissions factors to your aggregate purchases. Power purchases should be disaggregated to the extent possible by region of origin. Regional average output emissions factors may then be applied using equation 14b.

14.2.4 Step 4: Quantify Emissions from T&D Losses for Purchased Power

— EPS IE-01 and EPS IE-02: Quantifying Emissions for T&D Losses

To calculate your Scope 2 emissions from T&D losses associated with purchased power, use Equation 14c as follows:

Equation 14c

Emissions from T&D Losses [MT GHG] = Purchased Power Emissions [MT GHG] x T&D System Loss Factor [%]

This calculation is repeated for each GHG (CO_2, CH_4, N_2O) using the emissions totals derived in the previous section.

14.2.5 Example: Estimating Purchased Power Emissions

Example 14.1 shows how EPS IE-01 is applied in practice (for CO_2 emissions only) for an entity that purchases power from a range of sources and delivers that power through a T&D system.

14.1

EXAMPLE 14.1
Estimating Purchased Power Emissions

A vertically integrated utility located in Idaho generates power with one natural gas turbine generator (100 percent ownership) and purchases electricity from specified facilities, utilities and the spot market. The utility also has one exchange in place with another utility in the northwest to receive hydro power in the spring, and to deliver natural gas power in the summer. Over the course of the year, the power received onto their system was as followes:

Category/Facility	Comment	Power Received (MWh)
A. Owned Generation	Natural gas turbine generator	400,000
B. Specified Purchase	Known facility – coal power plant	1,000,000
C. Specified Purchase	Known facility – natural gas power plant	140,000
D. Specified Purchase	Known facility – hydro power plant	200,000
E. Resource-Specific Purchase	From utility that generates hydro power only	100,000
F. Resource-Specific Purchase	From utility that generates hydro power only	100,000
G. Spot Market Purchases	Purchased in Idaho (WECC Northwest)	40,000
H. Exchange Power (In)	Received from NW utility	20,000
	Total	**2,000,000**

Most of the power received into the system is sold to retail customers (1,800,000 MWh), with a small quantity of excess power resold wholesale (40,000 MWh). For the exchange, 20,000 MWh of power is delivered back to the NW utility.

For this example, the loss factor is determined by subtracting total power sold/delivered (1,860,000 MWh) from the total power received (2,000,000 MWh). The difference (140,000 MWh) is divided by the total power received to calculate the loss factor (seven percent).

Emission factors are assigned to each category of purchased power and the purchased power emissions are calculated as follows:

Category/Facility	Emission Factor (lb/ MWh)	Power Received (MWh)	Purchased Power CO_2 Emissions (Scope3) (MT)
A. Natural gas turbine generator	N/A	N/A	N/A
B. Known facility – coal power plant	2,150	1,000,000	975,225
C. Known facility – natural gas power plant	1,050	140,000	66,678
D. Known facility – hydro power plant	0	200,000	0
E. From utility that generates hydro power only	0	100,000	0
F. From utility that generates hydro power only	0	100,000	0
G. Purchased in Idaho (WECC Northwest)	921	40,000	16,712
H. Received from NW utility	0	20,000	0
Total		**2,000,000**	**1,058,615**

Note that losses and emissions are not counted for owned generation, so there is no emission factor and no purchased power emissions (i.e. Scope 3) shown for Facility A.

The T&D losses are calculated by multiplying the Scope 3 emissions by the loss factor as follows:

T&D Losses (Scope 2 emissions) = 1,058,615 MT x 7% = 74,103 MT

14.3 Bulk Power Transmission Systems

This section provides a method for quantifying losses on high voltage bulk transmission systems operated principally for the conveyance of wholesale power or wheeled power. This method is applicable to entities that own or control bulk transmission systems for regional wholesale conveyance (e.g. Balancing Authorities, ISOs, etc.).

The method presented below is similar to that provided in Section 14.2 for local T&D systems, but recognizes that these transactions are conducted almost entirely at transmission level voltages with lower losses, and are separate from an LDC system (See Figure 14.2). Similar to the calculation for T&D losses, the calculation of emissions associated with bulk transmission system losses requires data for the total power conveyed on the line or the system (MWh), the average loss factor (percent), and the emission factor for the electricity delivered to the system.

For every bulk transmission system, all transmission lines, substations and other associated equipment may be grouped for convenience into one system "facility." You should at a minimum report your bulk transmissions system at the appropriate level reflecting the geographical expanse (state, national or North American) of its lines. You may however choose to break down your system into more discrete state or national segments or segments that are consistent with subsidiaries that you may be required to report distinctly. However, in deciding the appropriate level for reporting, it is also important to be sure that loss factors can be determined for each segment that is reported separately.

Transmission system operators usually have information about the amount of power that flows through the system, and losses are usually assigned to each transaction based on theoretical or modeled loss factors. However, these same operators may not know the specific origin of the power or its generation type, especially with open access systems.

— EPS IE-03: Quantifying Losses on High Voltage Bulk Transmissions Systems

This method estimates the losses and emissions associated with power flows on bulk power transmission systems. The five steps in this methodology are:

(1) Decide how you will report bulk power transmission losses;
(2) Determine power flows on the transmission system;
(3) Determine a loss factor for each power flow;
(4) Assign emission factors (CO_2, CH_4 and N_2O) for each type of power delivered to the system; and
(5) Calculate and aggregate the emissions.

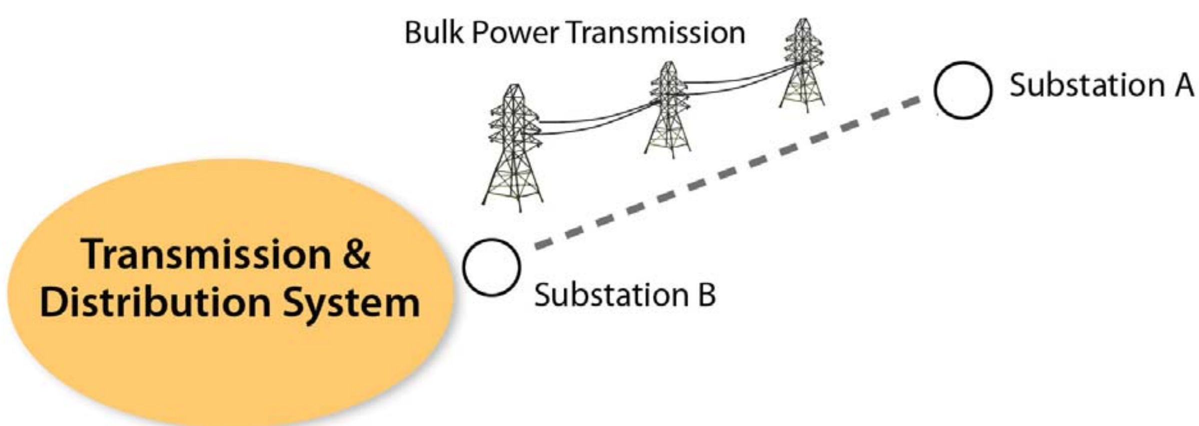
14.3.1 Step 1: Define how Bulk Transmission Losses will be Reported

If you do not own or control a bulk transmission system that is distinct from any local T&D system you reported according to the requirements in Section 14.2, you do not need to report under this section. Similarly, if you own or control both a T&D system and a bulk transmission system that delivers power you're your T&D system, you may choose to treat the two as a single "facility." In this case you should use Section 14.2 to determine emissions associated with losses (see Table 14 below, which provides additional guidance on integrating or separating bulk transmission with or from T&D systems).

However, if your transmission system(s) are considered to be a separate, stand-alone system(s), then the bulk power transmission losses should be evaluated separately from the rest of T&D system, and you should use the methodology presented here. The bulk power transmission losses may be reported as one "facility" for your entire bulk power transmission system, or as separate "facilities" for discrete bulk power transmission pathways within the system.

Figure 14.5 shows a simplified T&D system with a connected transmission system that may or may not be controlled by the same entity. Options for defining the reporting boundaries in this case are presented below for a range of control scenarios.

Figure 14.5 – Illustration of a T&D System Connected to a Bulk Power Transmission System



14.4 TABLE 14.4 Options For Reporting Bulk Transmission Losses

Options	How to Report Bulk Transmission Losses
Option 1 – Entity controls local T&D System, but no bulk power transmission outside the T&D service area. (Use EPS IE-01 or EPS IE-02 and report per 14.2)	No bulk transmission system. Include all power generated within the local T&D service area if it is received into the T&D system (whether owned or purchased). Report net generation at the generating facility step-up substation. Include wholesale purchases and power from remote generation at the place where it is received into the local T&D system (e.g., Substation B).
Option 2 – Entity controls bulk power transmission system, but no local T&D. (Continue using EPS IE-03)	Bulk transmission system considered distinct from any T&D systems it feeds. Report incoming power flows (e.g. at substation A) and outgoing power flows (e.g. at Substation B). These will include wholesale purchases, wheeled power and any direct access power delivered for others.
Option 3 – Same entity controls local T&D System and bulk power transmission outside the T&D service area. Entity elects to combine bulk power transmission with local T&D system for reporting power flows, losses and indirect GHG emissions. (Use EPS IE-01 or EPS IE-02 per section 14.2)	Report transmission power flows at the location where the power comes onto the combined system (e.g., at Substation A). Include wholesale purchases/ exchanges, wheeled power and direct access power. For all power generated within the local T&D service area and delivered to the T&D system (whether owned or purchased) report Net Generation at the generating facility step-up substation. Report bulk power flows leaving the system at the substation where power leaves the combined system.
Option 4 – Same entity controls local T&D System and bulk power transmission outside the T&D service area. Entity elects to create separate reporting "facilities" for the bulk power transmission system and the local T&D system. (Continue to use EPS IE-03 for the bulk transmission system but use EPS IE-01 or EPS IE-02 for the T&D system)	For the local T&D system, include all power generated within the local T&D service area if it is received into the T&D system (whether owned or purchased). Report Net Generation at the generating facility step-up substation. Include wholesale purchases and power from remote generation at the place where it is received into the local T&D system (e.g., Substation B). For the bulk power transmission system, report incoming power flows (e.g. at substation A) and outgoing power flows (e.g. at Substation B). These will include wholesale purchases, wheeled power and any direct access power delivered for others.

It should be noted that if you decide to report discrete bulk power transmission pathways as separate facilities, you will need to have power flow data specific to each of those pathways.

Methodologically, the following steps of EPS IE-03 parallel the steps of EPS IE-01 and EPS IE-02, but focus primarily on the treatment of bulk transmission systems. You may choose to consult EP IE-01 or EPS IE-02 for additional methodological detail.

14.3.2 Step 2: Determine Power Flows through the Bulk Transmission System

Once the bulk power transmission system has been defined, you must obtain information about its power flows. You must account for all power coming in (generated power, wholesale power purchases, exchanges (in) and wheeled power), and all power delivered out of the system (wholesale power sales, wheeled power deliveries). These power flows should be aggregated over your one-year reporting period (calendar year).

You may report the incoming power flows as a system total, or by place of origin, or by contract counterparty, or by generation resource (fuel type), if known. Having a greater level of detail about the incoming power flows provides the opportunity to select and assign more accurate emission rates to the power flows (Step 4, below), but this is not necessary to determine the energy balance and the bulk power transmission system loss factor (Step 3). Incoming wheeled power should be measured at the first point of receipt into the system, and aggregated for the year by supplier or by region of origin.

You may already track bulk power transmission system power flows for regulatory purposes,[35] and if so, these data may be used to develop the power flow energy balance you must report to The Registry. If these datasets are not readily available, you may be able to gather the data from the logs of real-time bulk power transactions compiled by operations.

14.3.3 Step 3: Select or Derive a Bulk Power Transmission Loss Factor

You may select or derive a bulk power transmission loss factor using one of the following options:

- **Engineering Estimate –** Use engineering estimates based on measured losses of known power and ambient conditions on each transmission segment, projected for the entire system for appropriately weighted average demand and ambient conditions over a reporting year. Alternatively you may use a modeled or calculated loss factor provided by the Balancing Authority or ISO. For Open Access systems, system average loss factors may be available from regulatory bodies such as FERC (e.g. Tariff Loss Factors).

[35] Two examples of regulatory reports that have this information (for reporters in the United States) are the FERC Form 1 and the EIA Form 861. For EPS Members that do not compile these reports, these reports do nevertheless provide an additional view of the power flow accounting principles being applied.

- **Default Loss Factor** – Use a default transmission loss factor of 2.0 percent.[36] It must be noted that if relying on the default factor, it must be applied to aggregate power flows into your transmission system, not power flows out of the system (14.3.2).

14.3.4 Step 4: Assign Emission Factor(s)

You may select or derive an emission factor using one of the following options:

- **Engineering Estimate** – If you have specific information about the source of the power (wholesale or wheeled), you may use an emission factor applicable to those sources. Refer to Section 14.2.3 for acceptable options.

- **Default Loss Factor** – If you know the eGRID subregion where the power originates (United States), you may use the eGRID regional average emission rate applicable to that region (Table 14.2). If you know the province where the power originates (Canada), you may use the average emission rate for that province (GRP Table 14.3). For Mexico, use the eGRID average for the United States as a default. If you do not know the source of the power, you may use the eGRID or Provincial average emission rate applicable to the location at which the power first enters your transmission system.

14.3.5 Step 5: Quantify Emissions Associated with Bulk Power Transmission Losses

Quantify the GHG emissions from bulk transmission losses using Equation 14d:

Equation 14d
Bulk transmission System Line Loss emissions [MT GHG] = Power transmitted onto the system [MWh] x emission factor [MT GHG/MWh] x Loss Factor [%]

Or more specifically:

$$\text{Bulk transmission System Line Loss emissions [MT GHG]} = \text{SUM}[(MWh_1 \times kg/MWh_1) + (MWh_2 \times kg/MWh_2) + \ldots (MWh_n \times kg/MWh_n)] \times MT/1000\ kg \times \text{Loss Factor } [\%]$$

36 *A transmission loss factor of 2.0 percent is considered to be a representative average of the transmission tariff loss factors reported to FERC for open access transmission. Loss factors range from about 0.5 percent to 3.5 percent. A system specific average should be used when available through FERC or other recognized regulating agency, subject to a Verification Body's approval.*

You should repeat this calculation for all three GHGs (CO_2, CH_4, N_2O). This method will quantify the total emissions resulting from bulk power transmission system losses (or for each transmission pathway).

14.3.6 Example: Estimating Transmission & Distribution Losses for Bulk Power Transmission

14.2

EXAMPLE 14.1
Estimating T&D Losses for Bulk Power Transmission

A Transco (i.e. transmission company) generates 200,000 MWh and purchases 100,000 MWh to provide power for its utility customers. It also wheels 100,000 MWh of power across the system during the course of the year. It is assumed that all power is generated with natural gas as the primary fuel and the emission factor is assumed to be 0.5 MT/MWh. The following table shows how bulk power transmission losses are calculated for this example.

	MWh	MT CO_2
A. Own Generation	200,000	100,000
B. Power Received – Wholesale	100,000	50,000
C. Power Received – Wheeled	100,000	50,000
D. Power Received – Total (A + B + C)	400,000	
E. Power Delivered – Retail	46,000	
F. Power Delivered – Wholesale	248,000	
G. Power Delivered – Wheeled	98,000	
H. Power Delivered – Total (E + F + H)	392,000	
I. Emissions from non-generated received power (Scope 3) (B + C)		100,000
J. System Average Loss Factor (D-H)/D	2.0%	
K. Emissions from T&D Losses (Scope 2)		
L. Losses – Wholesale Purchases (B x J)	2,000	1,000
M. Losses – Wheeled Power (C x J)	2,000	1,000
N. Emissions from T&D Losses – Total (L + M)	4,000	2,000

14.4 Estimating Indirect Emissions from Power which is Purchased/Acquired and Consumed

This section provides a methodology for reporting indirect Scope 2 emissions from electricity purchased and consumed in buildings and facilities. In order to quantify these emissions, you will need to determine the amount of electricity consumed, estimate the fraction of consumed electricity that was purchased (not self-generated), and assign appropriate emission factors to these purchases. Most of the data required for this process have been collected or calculated to meet other reporting requirements in the EPS Protocol.

14.4.1 EPS IE-04

The power you may take from the grid and consume is typically comprised of a mix of owned generation and purchased electricity sources. Emissions from the portion of the consumed electricity that is from purchased or acquired sources must be reported as Scope 2 emissions. Emissions from consumed electricity that you generate are already reported as Scope 1 emissions, so they are not again reported in Scope 2.

To partition total consumption into these two categories, the following ratio is used:

Equation 14e
Power Purchased, as a fraction of Total Power Flows on System = (Power received from Specified Purchases, Spot Market Purchases, and Power Exchanges [MWh]) / (Total power flows onto the T&D system from Generation, Purchases and Power Exchanges [MWh])

This ratio should be applied to the metered power consumed at each facility where electricity is consumed.[37] Doing so will yield the portion of power consumed at each facility that, on average comes from purchases power rather than self generated power. Once your purchased power consumption has been calculated for each facility, you must multiply it by an appropriate emissions factor, as indicated in Equation 14f. This will give you the Scope 2 CO_2 emissions associated with the power you consumed in your buildings and facilities.

37 Note that, if the electricity consumed in buildings and facilities is not metered, then the consumption may be estimated based on the area and utility average electricity consumption rate for all metered facilities.

Equation 14f
CO_2 emissions = MWh Purchased and Consumed x Emission Factor The applicable emissions factors for CO_2 emissions are, in order of required use, as available: • EPS Metric D-3 (System-wide Electric Deliveries Metric—optionally calculated in Chapter 19), • EPS Metric D-1 (Electricity Deliveries Metric for Wholesale Power Sales—optionally calculated in Chapter 19), or • eGRID or provincial average factors for the applicable region if you do not elect to report either of the aforementioned optional metrics.

This calculation will also need to be repeated for CH_4 and N_2O emissions. Use the appropriate average emission factors from GRP Tables 14.1, 14.2 and 14.3.

Chapter 15 Indirect Emissions from Imported Steam, District Heating, Cooling and Electricity from a CHP Plant

In the GRP, Chapter 15 refers to indirect emissions from imported steam, district heating, cooling and electricity from a Combined Heat and Power (CHP) Plant. Members are required to report emissions from these sources according to the methodologies in the GRP.

Typically, Members in the EPS will not have indirect emissions from imported steam, district heating or cooling in the majority of their facilities. However, Members may have indirect emissions from heating and cooling in spaces they lease. Calculation methodologies for indirect emissions from heating and cooling leased spaces are included in chapters 15.2 and 15.3 of the GRP.

Chapter 16 Direct Fugitive Emissions

This chapter outlines methodologies for calculating a broad range of direct fugitive emissions from common EPS sources including emissions of SF_6 from circuit breakers and other equipment, HFCs from generating unit intake air cooling units, and CH_4 from coal storage. Members must apply the methodologies included below in EPS FG-01 through EPS FG-05 when quantifying emissions from the following sources:

- SF_6 Emissions
- HFC Emissions
- Coal Pile CH_4 Emissions
- CH_4 Emissions from Natural Gas Pipelines
- Fugitive Emissions from Hydro-Power Reservoirs (Optional)

Fugitive emissions are typically quantified using a mass-balance method that takes into account the quantity of gas used to “top up” a unit when there have been small fugitive leaks over a period of time. If there is an interval of several years between top-up events, the emissions should only be reported in the year when the gas is topped up. You must not report fugitive emissions that are averaged across the number of years between top up events when several years have passed between top up events.

16.1 TABLE 16.1
Overview of Methodologies for Reporting Fugitive Emissions in the EPS

Method	Emissions Source	Basis
EPS FG-01	SF_6 emissions from T&D and/or bulk transmission systems	U.S. EPA methodology
EPS FG-02	SF_6 emissions from T&D and/or bulk transmission systems	Environment Canada/ Canadian Electric Associations methodology
EPS FG-03 (simplified methodology)	SF_6 emissions from T&D and/or bulk transmission systems	Energy Information Administration methodology
EPS FG-04	HFCs from cooling units that support power generation	Mass balance
EPS FG-05	CH_4 from coal storage	Default emissions factors
EPS FG-06	CH_4 from natural gas pipelines	Default emissions factors
EPS FG-07 (optional)	CH_4 and CO_2 from reservoirs	IPCC methodology

16.1 Calculating Fugitive Sulfur Hexafluoride Emissions

SF_6 is used for electrical insulation and can escape into the atmosphere during normal operations of electrical transmission and distribution systems or when added to or extracted from breaker equipment. If you control power generating facilities you must report fugitive SF_6 emitted from equipment at your facilities. If you control transmissions and distribution systems you must report fugitive SF_6 emissions from all aspects of your transmission and distribution systems, including substations and circuit breakers.

Often SF_6 emissions from transmission and distribution sources consist of a larger number of small facilities that are dispersed across a region. The Registry explicitly allows for the aggregation of these facilities at the state level in order to streamline emission reporting.

Two mass-balance methods are presented in the EPS Protocol to estimate fugitive SF_6 emissions. The first is provided by the U.S. EPA SF_6 Emission Reduction Partnership for Electric Power Systems (EPS FG-01), and the second is provided by Environment Canada and the Canadian Electricity Association (EPS FG-02).

If sufficient data are not available to quantify SF_6 emissions from your transmission and distribution systems using a mass-balance method, you should use the simplified EIA calculation method based on the miles of transmission lines you control (EPS FG-03).

— EPS FG-01:EPA SF_6 Fugitive Emissions Quantification Method

This quantification method is the U.S. EPA mass-balance methodology for estimating SF_6 emissions from electricity delivery systems. When using this quantification method, you must annually report your SF_6 emissions from each delivery system (i.e. facility) reported in The Registry's reporting software. This reporting is required to follow the structure you used to set up the facilities for your T&D system(s) and/or bulk transmission system(s) in Chapter 14.

The mass-balance method works by tracking and systematically accounting for uses of SF_6 for each electricity delivery system during the reporting year. The quantity of SF_6 that cannot be accounted for is then assumed to have been emitted to the atmosphere. Table 16.1 is a worksheet based on the mass-balance method. You should use the mass balance worksheet for each system that you report separately (see 14.1 for discussion of requirements related to reporting systems in aggregate or separately). The method has four sub calculations (A-D), a final total (E), and an optional emission rate calculation (F) as follows:

A. **Change in Inventory.** This is the difference between the quantity of SF_6 in storage at the beginning of the year and the quantity in storage at the end of the year. The "quantity in storage" includes SF_6 gas contained in cylinders (such as 115-pound storage cylinders), gas carts, and other storage containers. It does not refer to SF_6 gas held in operating equipment. The change in inventory will be negative if the quantity of SF_6 in storage increases over the course of the year.

B. **Purchases/Acquisitions of SF_6.** This is the sum of all the SF_6 acquired during the year either in storage containers or in equipment.

C. **Sales/Disbursements of SF_6.** This is the sum of all the SF_6 sold or otherwise disbursed during the year either in storage containers or in equipment.

D. **Change in Total Nameplate Capacity of Equipment.** This is the net increase in the total volume of SF_6 using equipment in a facility during the year. Note that "total nameplate capacity" refers to the full and proper charge of the equipment rather than to the actual charge, which may reflect leakage. This term accounts for the fact that if new equipment is purchased, the SF_6 that is used to charge that new equipment should not be counted as an emission. It also accounts for the fact that if the amount of SF_6 recovered from retiring equipment is less than the nameplate capacity, then the difference between the nameplate capacity and the recovered amount has been emitted. This quantity will be negative if the retiring equipment has a total nameplate capacity larger than the total nameplate capacity of the new equipment.

E. **Total Annual Emissions**. This is the total amount of SF_6 emitted over the course of the year from a facility, based on the information provided above.

F. **Emission Rate (optional).** By providing the total nameplate capacity of all the electrical equipment in the facility at the end of the year, you can obtain an estimate of the emission rate of the facility's equipment (in percent per year). The emission rate is equal to the total annual emissions at the facility divided by the total equipment nameplate capacity.

16.2

TABLE 16.2
U.S. EPA Methodology for Estimating SF_6 Emissions Worksheet
(To be applied to each Electric Power Delivery System)

SF_6 Emissions Reduction Partnership for Electric Power Systems

Annual Reporting Form

Name:		Company Name:	
Title:		Report Year:	
Phone:		Date Completed:	

Decrease in Inventory (SF_6 contained in cylinders, not electrical equipment)

Inventory (in cylinders, **not** equipment)	AMOUNT (lbs.)	Comments
1. Beginning of Year		
2. End of Year		
A. Decrease in Inventory (1 - 2)	-	

Purchases/Acquisitions of SF_6

	AMOUNT (lbs.)	Comments
3. SF_6 purchased from producers or distributors in cylinders		
4. SF_6 provided by equipment manufacturers with/inside equipment		
5. SF_6 returned to the site after off-site recycling		
B. Total Purchases/Acquisitions (3+4+5)	-	

Sales/Disbursements of SF_6

	AMOUNT (lbs.)	Comments
6. Sales of SF_6 to other entities, including gas left in equipment that is sold		
7. Returns of SF_6 to supplier		
8. SF_6 sent to destruction facilities		
9. SF_6 sent off-site for recycling		
C. Total Sales/Disbursements (6+7+8+9)	-	

Increase in Nameplate Capacity

	AMOUNT (lbs.)	Comments
10. Total nameplate capacity (proper full charge) of new equipment		
11. Total nameplate capacity (proper full charge) of retired or sold equipment		
D. Increase in Capacity (10 - 11)	-	

Total Annual Emissions

	lbs. SF_6	kgs. SF6	Tonnes CO_2 equiv.
E. Total Emissions (A+B-C-D) (lbs.)	-	-	-

Emission Rate (optional)

	AMOUNT (lbs.)	Comments
Total Nameplate Capacity at End of Year		
	PERCENT (%)	
F. Emission Rate (Emissions/Capacity)	-	

16.1 EXAMPLE 16.1.1
Calculating Sulfur Hexafluoride Emissions

A retail provider, reporting using operational controls a portion of a transmission and distribution system located inside their geographical boundary. The retail provider has reported its portion of the transmission and distribution system as a single facility. In order to report the fugitive SF_6 emissions from this facility the retail provider makes the following calculations based on maintenance logs.

5,000 pounds = SF_6 inventory in cylinders at beginning of report year
9,000 pounds = SF_6 inventory in cylinders at the end of the year
-4,000 pounds = Decrease in inventory (5,000 – 9,000)

3,000 pounds = Purchases of SF_6 in cylinders
7,000 pounds = Provided by manufacturers inside new equipment purchased
5,000 pounds = Recovered from retired equipment
15,000 pounds = Total purchases (3,000 + 7,000 + 5,000)

0 = Sales/disbursements of SF_6

7,000 pounds = Capacity of new equipment (full charge)
6,000 pounds = Capacity of retired equipment (full charge)
1,000 pounds = Increase in capacity (7,000 – 6,000)

10,000 pounds = SF_6 emissions for the report year (-4,000 + 15,000 – 0 – 1,000)

Conversion: 10,000 pounds * 0.45359 kg/pound = 4,536 kg SF_6

— EPS FG-02: Environment Canada/Canadian Electric Association SF_6 Fugitive Emission Calculation Method

The Registry also allows its Members to quantify and report SF_6 emissions associated with electric power delivery systems using the Environment Canada/Canadian Electric Association SF_6 Fugitive Emission Calculation Method.

Please see the Registry's Electric Power Sector webpage for a full reproduction this methodology: http://www.theclimateregistry.org/resources/protocols/electric-power-sector-protocol/

— EPS FG-03: EIA SF_6 Fugitive Emissions Calculation Method (Simplified Methodology)

This section describes the EIA methodology for estimating SF_6 emissions from electric transmission and distribution equipment based on miles of transmission lines.[38] The applicable portion of Section 4.2.4 of this document is reproduced below. This methodology should be applied separately to each delivery system the Member is reporting.

38 *Documentation for Emissions of Greenhouse Gases in the United States 2006, October 2008.*

Emissions from Electric Power Systems from 1999 to present

Emissions from electric power systems from 1999 onward were estimated based on (1) reporting from utilities participating in U.S. EPA's SF_6 Emissions Reduction Partnership for Electric Power Systems, which began in 1999, and (2) utilities' transmission miles as reported in the 2001 and 2004 Utility Data Institute (UDI) Directories of Electric Power Producers and Distributors. (Transmission miles are defined as the miles of lines carrying voltages above 34.5 kV). Between 1999 and 2003, participating utilities represented between 31 percent and 35 percent of total U.S. transmission miles. The emissions reported by participating utilities each year were added to the emissions estimated for non-reporting utilities in that year. Emissions from non-reporting utilities were estimated using the results of a regression analysis that showed that the emissions of reporting utilities were most strongly correlated with their transmission miles. As described further below, the transmission miles of the various types of non-reporting utilities were multiplied by the appropriate regression coefficients, yielding an estimate of emissions. Transmission miles are clearly physically related to emissions, since in the United States, SF_6 is contained primarily in transmission equipment rated at or above 34.5 kV.

The regression equations reflect two distinctions among non-reporting utilities: (1) between small and large utilities (i.e., with less or more than 10,000 transmission miles, respectively), and (2) between utilities that do not participate in the SF_6 Emission Reduction Partnership (non-partners) and those that participate but that have not reported in a given year (non-reporting partners). (Historically, these non-reporting partners have accounted for 5 percent or less of total estimated partner emissions.) The distinction between small and large utilities was made because the regression analysis showed that the relationship between emissions and transmission miles differed for small and large facilities. The distinction between non-partners and non-reporting partners was made because the emission trends of these two groups were believed to be different. Reporting partners have reduced their emission rates significantly since 1999. The emission trend of non-reporting partners was believed to be similar to that of the reporting partners, because all partners commit to reducing SF_6 emissions through technically and economically feasible means. However, non-partners were assumed not to have implemented any changes that would have reduced emissions over time.

To estimate emissions from non-partners in every year since 1999, the following regression equations were used. These equations were developed based on the 1999 SF_6 emissions reported by 49 partner utilities (representing approximately 31 percent of U.S. transmission miles), and 2000 transmission mileage data obtained from the 2001 UDI Directory of Electric
Power Producers and Distributors:

Non-partner small utilities (less than 10,000 transmission miles, in kilograms):
Emissions = 0.874 × Transmission Miles

Non-partner large utilities (more than 10,000 transmission miles, in kilograms):
Emissions = 0.558 × Transmission Miles
To estimate emissions from non-reporting partners in each year, the regression equations based on the emissions reported by partners in that year were used. To estimate non-reporting partner emissions, the regression equations are based on the SF_6 emissions reported by 51 partner utilities, and updated transmission mileage data obtained from the latest UDI Directory of Electric Power Producers and

Distributors. The resulting equations:

Non-reporting partner small utilities (less than 10,000 transmission miles, in kilograms):
Emissions = 0.398 × Transmission Miles

Non-reporting partner large utilities (more than 10,000 transmission miles, in kilograms):
Emissions = 0.387 × Transmission Miles

UDI Directories of Electric Power Producers and Distributors are used to obtain U.S. transmission system growth.

For each year, total emissions were then determined by summing the partner-reported emissions, the non-reporting partner emissions (determined with that year's regression equation for the partners), and the non-partner emissions (determined using the 1999 regression equation).

16.2 Fugitive HFC Emissions

If you have generating facilities that have cooling units directly related to power production, you must report fugitive HFC emissions at the facility level by compound. The reportable emissions will be for the same HFCs as indicated in the GRP. You may use the same type of mass balance methodology used to quantify SF_6 emissions or select the single unit methodology discussed in EPS Method FG-04.

— EPS FG-04: HFC Compounds Fugitive Emissions Quantification Methodology

Members with electric generating facilities are required to quantify fugitive HFC emissions separately for each HFC compound used in cooling units that support power generation or are used in heat transfers to cool stack gases. You must use the same mass balance methodology provided in Chapter 16 of the GRP for reporting HFC emissions unless reporting for an individual cooling unit. You are required to report fugitive emissions for each HFC compound separately, as applicable, and to convert pounds of HFCs into kilograms, if necessary. This requirement does not apply to air or water cooling systems or condensers that do not contain HFCs.

If you are reporting for an individual cooling unit, you may calculate fugitive HFC emissions using service logs to document HFC usage and emissions. HFC emissions must be reported separately for each HFC compound as applicable. The service logs should document all maintenance and service performed on the unit during the report year, including the quantity of HFCs added to or removed from the unit, and include a record at the beginning and end of each report year.

Alternatively, the following material balance equations are provided to quantify fugitive HFCs from unit installation, servicing, and retirement, as applicable. Total fugitive HFC emissions are the sum of HFC emissions from each of the three applicable equations.

Equation 16a

$$HFC_{Install} = R_{new} - C_{new}$$

$$HFC_{Service} = R_{recharge} - R_{recover}$$

$$HFC_{Retire} = C_{retire} - R_{retire}$$

Where:

$\mathbf{HFC_{Install}}$ = HFC emitted during initial charging/installation of the unit, kilograms;

$\mathbf{HFC_{Service}}$ = HFC emitted during use and servicing of the unit for the report year, kilograms;

$\mathbf{HFC_{Retire}}$ = HFC emitted during the removal from service/retirement of the unit, kilograms;

$\mathbf{R_{new}}$ = HFC used to fill new unit (omit if unit was pre-charged by the manufacturer), kilograms;

$\mathbf{C_{new}}$ = Nameplate capacity of new unit (omit if unit was pre-charged by the manufacturer), kilograms;

$\mathbf{R_{recharge}}$ = HFC used to recharge the unit during maintenance and service, kilograms;

$\mathbf{R_{recover}}$ = HFC recovered from the unit during maintenance and service, kilograms;

$\mathbf{C_{retire}}$ = Nameplate capacity of the retired unit, kilograms;

$\mathbf{R_{retire}}$ = HFC recovered from the retired unit, kilograms.

16.2

EXAMPLE 16.2.1
Calculating Hydrofluorocarbon Emissions from A Cooling Unit

An electric generating facility uses a chiller to cool input air for one of the electric generating turbines. The chiller uses HFC-134a refrigerant and was installed five years ago. The Member that controls the electric generating facility must determine its fugitive HFC-134a emissions. The information below was compiled from service logs:

$HFC_{Install}$ = 0 kg (the chiller was not installed during the report year)
HFC_{Retire} = 0 kg (the chiller was not retired during the report year)
$HFC_{Service} = R_{recharge} - R_{recover}$ = 23 kg – 0 kg = 23 kg

Where:

$R_{recharge}$ = (50 pounds HFC-134a) x (0.45359 kg/pound) = 23 kg (the amount of HFC-134a added to the chiller)

$R_{recover}$ = (0 pounds HFC-134a) x (0.45359 kg/pound) = 0 kg (the amount of HFC-134a recovered from the chiller)

Total fugitive HFC-134a = $HFC_{Install} + HFC_{Service} + HFC_{Retire}$
= 0 kg + 23 kg + 0 kg = 23 kg

16.3 Quantifying Fugitive Methane Emissions from Coal Storage

If you store coal at power plants or control coal mines, you must report fugitive CH_4 emitted from coal storage, as addressed in EPS FG-05.

— EPS FG-05: Method for Calculating Fugitive CH_4 Emissions from Coal Storage

Quantify fugitive CH_4 emissions from coal storage using the following equation:

Equation 16b

$$CH_4 = PC * EF * CF_1 / CF_2$$

Where:

CH_4 = CH_4 emissions in the report year, metric tons per year;
PC = Purchased coal in the report year, tons per year;
EF = Default emission factor for CH_4 based on coal origin and mine type provided in Table 15.2 below, scf CH_4/shortton;
CF_1 = Conversion factor equals 0.04228, lbs CH_4/scf;
CF_2 = Conversion factor equals 2,204.6, lbs/metric ton.

16.3 TABLE 16.3
Default Fugitive Methane Emission Factors from Post-Mining Coal Storage and Handling (CH_4 ft^3 per Short Ton)

Coal Origin		Coal Mine Type	
Coal Basin	States	Surface Post-Mining Factors	Underground Post-Mining Factors
Northern Appalachia	Maryland, Ohio, Pennsylvania, West Virginia North	19.3	45.0
Central Appalachia (WV)	Tennessee, West Virginia South	8.1	44.5
Central Appalachia (VA)	Virginia	8.1	129.7
Central Appalachia (E KY)	East Kentucky	8.1	20.0
Warrior	Alabama, Mississippi	10.0	86.7
Illinois	Illinois, Indiana, Kentucky West	11.1	20.9
Rockies (Piceance Basin)	Arizona, California, Colorado, New Mexico, Utah	10.8	63.8
Rockies (Uinta Basin)		5.2	32.3
Rockies (San Juan Basin)		2.4	34.1
Rockies (Green River Basin)		10.8	80.3
Rockies (Raton Basin)		10.8	41.6
N. Great Plains	Montana, North Dakota, Wyoming	1.8	5.1
West Interior (Forest City, Cherokee Basins)	Arkansas, Iowa, Kansas, Louisiana, Missouri, Oklahoma, Texas	11.1	20.9
West Interior (Arkoma Basin)		24.2	107.6
West Interior (Gulf Coast Basin)		10.8	41.6
Northwest (AK)	Alaska	1.8	52.0
Northwest (WA)	Washington	1.8	18.9

Source: Inventory of U.S. Greenhouse Gas Emissions and Sinks:1990 – 2005 April 15, 2007, U.S. Environmental Protection Agency. Annex 3, Methodological Descriptions for Additional Source or Sink Categories, Section 3.3, Table A-115, Coal Surface and Post-Mining CH_4 Emission Factors (ft^3 per Short Ton). (Only Post-Mining EFs used from Table). State assignments shown from Table 113 of Annex 3.

16.4 Quantifying Fugitive CH_4 Emissions from Natural Gas Pipelines

Guidance is provided below for a simplified methodology for quantifying fugitive emissions associated with natural gas pipelines (onsite) that deliver fuel from the utility tie-in to the power generating unit. This methodology may be used consistent with the GRP's provisions on applications of simplified methodologies (Chapter 11).

If your pipeline and processing equipment are extensive, fugitive CH_4 emissions should be calculated using the methods included in documents that describe industry-standard methodologies such as the API's Compendium of GHG Emission Factors, the Intrastate Natural Gas Association GHG Guidance, or the American Gas Association GHG Guidance.

— EPS FG-06: Methods for Quantifying Fugitive Emissions from Natural Gas Pipelines

Fugitive emissions of CH_4 can occur in the pipelines and fuel processing equipment used to deliver gaseous fuel to power generating facilities and equipment. In most cases, the length of pipeline from the fuel provider to the point of combustion is very short and there is a limited degree of fuel conditioning needed. These factors typically result in small amounts of fugitive emissions from natural gas pipelines at electric generating facilities. Where these factors exist, fugitive CH_4 emissions can be quantified using the following estimation method:

Equation 16c

$$CH_4 = L * EF / 1000$$

Where:

CH_4 = Methane emissions from the natural gas pipeline, metric tons;
L = Length of pipe in miles;
EF = Default emission factor (1611 kg/mile-year);
1000 = Conversion factor from kg to metric tons.

16.5 Fugitive Emissions from Hydro-Power Reservoirs (Optional)

Prior to the 1990s, there was little or no data available on CO_2 and CH_4 emissions from reservoirs used to store water for power generation. There is now a growing body of literature on this subject, some of which suggests that the organic carbon stored in plants and soils in flooded areas decomposes to CO_2 and CH_4, and these gases are subsequently released to the atmosphere.

However, different regions and soils contain different amounts of stored organic carbon. Furthermore, the rate of decomposition of this carbon depends on local climatic conditions, reservoir area, and potentially a whole host of other site specific parameters. Consequently, the potential for GHG production is thought to vary tremendously from one reservoir site to another.

While the body of literature is growing and the scientific community is gaining a better understanding of the complex issues associated with these reservoir emissions, there is still no consensus on how to quantify these emissions in a standardized way that accommodates the broad range of variables involved. Direct measurement methodologies are still in their infancy and not widely available. For this reason, The Registry is not requiring Members to quantify emissions from reservoirs within their organizational boundaries at this time. However, if you determine that EPS FG-07 is adequate for your reservoir(s), then you may use that method to optionally report those emissions.

The Registry intends to adopt a requirement to report any GHGs emitted from reservoirs once a feasible and defensible methodology becomes available, consistent with its requirement for complete reporting.

— EPS FG-07 (OPTIONAL): Methods for Quantifying Fugitive Emissions from Hydro-Power Reservoirs

Duchemin, E.J. T. Huttunen, A. Tremblay, R. Delmas and C.F. Silveira Menezes, 2006a (Lead authors). "*Appendix 2 – Possible approach for estimating CO_2 emissions from lands converted to permanently flooded lands*". Basis for future methodological development. In Eggletion, H.S., L. Buendia, K. Iwa, T. Ngara and K. Tanabe (eds.), 2006. Intergovernmental Panel on Climate Change (IPCC), National Greenhouse Gas Inventories Guidelines, Vol. 4 – Agriculture, Forestry and Other Land Use, IGES, Kanagawa, Japan, pp. AP2.1-AP2.9

Duchemin, E.J. T. Huttunen, A. Tremblay, R. Delmas and C.F. Silveira Menezes, 2006a (Lead authors). "*Appendix 3 – CH_4 Emissions from Flooded lands: Basis for future methodological development*". In Eggletion, H.S., L. Buendia, K. Iwa, T. Ngara and K. Tanabe (eds.), 2006. Intergovernmental Panel on Climate Change (IPCC), National Greenhouse Gas Inventories Guidelines, Vol. 4 – Agriculture, Forestry and Other Land Use, IGES, Kanagawa, Japan, pp. AP3.1-AP3.8

Chapter 17 Direct Process Emissions

This chapter includes methodologies to quantify emissions for typical sources of process emissions in the Electric Power Sector, including acid gas scrubbers (Section 15.2.1), geothermal power generation (Section 15.2.2), and other common sources (Section 15.2.3).

The need for reporting of process emissions from other small sources is addressed in EPS PR-05.

17.1 TABLE 17.1
Overview of Methodologies for Reporting Process Emissions in the EPS

Method	Emissions Source	Basis
EPS PR-01	Acid gas scrubbers	Mass balance
EPS PR-02	Geothermal emissions	Default emissions factor
EPS PR-03	Geothermal emissions	Site specific emissions factor

17.1 Quantifying Process Emissions from Acid Gas Scrubbers

— EPS PR-01: CO_2 Process Emissions Calculation Methodology for Acid Gas Scrubbers

If you use acid gas scrubbers or add an acid gas reagent to a combustion source, there may be CO_2 emissions that occur during the SO_2 scrubbing process, depending on the type of reagent used. The CO_2 emissions from acid gas scrubbers are categorized as process emissions.

If you calculate CO_2 emissions from stationary combustion using a CEMS method, the process emissions from acid gas scrubbers are most likely included in the CO_2 concentrations used in the CEMS methodology. In this case, you are not required to report process emissions separately from total CO_2 emissions for the facility, and you will simply indicate in The Registry's reporting software that these emissions are accounted for in the total CO_2 emissions reported from fuel combustion.

If you calculate CO_2 emissions using a fuel-based method, then a separate calculation is needed to calculate and report CO_2 emissions from acid gas scrubbers, as discussed below. The following equation[39] must be used to quantify CO_2 emissions from the acid gas process:

Equation 17a

$$CO_2 = S * R * (CO_{2\ MW} / Sorbent_{MW})$$

Where:

CO_2 = CO_2 emitted from sorbent for the report year, metric tons;
S = Limestone or other sorbent used in the report year, metric tons;
R = Ratio of moles of CO_2 released upon capture of one mole of acid gas;
$CO_{2\ MW}$ = molecular weight of carbon dioxide (44);
$Sorbent_{MW}$ = molecular weight of sorbent (if calcium carbonate, 100).

In order to quantify emissions from the acid gas process you must first determine the amount of limestone ($CaCO_3$) or sorbent used during the reporting year. This can be done by identifying total sorbent inventory at the beginning of the year, adding the total sorbent purchases during the year, and then subtracting the total sorbent inventory at year end. You will need to make the necessary conversions in order to express total sorbent used as metric tons for the year.

The variable "R" in the above equation is the ratio of the number of moles of CO_2 released upon capture of one of mole of SO_2. Variable "R" is dependent on the type of sorbent used in the scrubbing process. If limestone is the sorbent, R is equal to 1.0.

Note that there are no CO_2 process emissions from the scrubber if calcium oxide (Quick Lime) is used as the sorbent.

You may use alternative methodologies to quantify the CO_2 emissions from the acid gas process provided they are explicitly accepted or approved by a federal, state or provincial agency. If using an alternative quantification methodology you must indicate the methodology and the agency that accepts it in The Registry's reporting software.

39 California Air Resources Board Regulation for the Mandatory Reporting of Greenhouse Gas Emissions, California Code of Regulations, Title 17, Subchapter 10.

17.1

EXAMPLE 17.1.1
Calculating Carbon Dioxide Emissions from Acid Gas Scrubber

A coal-fired generating facility uses limestone as the sorbent for its SO_2 scrubber. CO_2 emissions from coal combustion are calculated using the fuel-based methodology in EPS ST-04. Since this methodology does not account for the CO_2 emitted from the SO_2 scrubber, the CO_2 emissions from the acid gas scrubber must be calculated in addition to the CO_2 emissions reported from fuel combustion. To do so, the following information is gathered:

2,000 tons = Inventory of limestone at beginning of report year

11,000 tons = Limestone purchased during the report year

3,000 tons = Inventory of limestone at the end of the report year

1 = R for limestone

44 = molecular weight of CO_2

100 = molecular weight of limestone ($CaCO_3$)

Thus, the amount of limestone used in the scrubber during the year was 10,000 tons (2,000 + 11,000 – 3,000). The 10,000 short tons of limestone is converted to 9,072 metric tons (10,000 * 0.9072). Values are then substituted into the formula in Equation 17a to determine CO_2 emissions as follows:

$$CO_2 = S * R * (CO_{2\ MW} / Sorbent_{\ MW})$$

$$CO_2 = 9{,}072 * 1 * (44/100) = 3{,}992 \text{ metric tons}$$

17.2 Quantifying Process Emissions from Geothermal Power Generation

If you operate a geothermal electricity generating facility, you are required to calculate and report process emissions if the technology releases geothermal steam to atmosphere as part of the power generation process. In this case, there will be emissions of CO_2 and CH_4 from the geothermal steam vented to atmosphere.

There are three main technologies used to convert hydrothermal fluids to electric power. The conversion technologies are dry steam, flash, and binary cycle. The type of conversion used depends on the state of the fluid (whether steam or water) and its temperature. Dry steam power plant systems were the first type of geothermal power generation plants built. They use the steam from the geothermal reservoir as it comes from wells, and route it directly through turbine/generator units to produce electricity. Flash steam plants are the most common type of geothermal power generation plants in operation today. They use water at temperatures greater than 360°F (182°C) that is pumped under high pressure to the generation equipment

at the surface. Binary cycle geothermal power generation plants differ from dry steam and flash steam systems in that the water or steam from the geothermal reservoir never comes in contact with the turbine/generator units.

Process emissions from the geothermal process are dependent on the concentration of CO_2 and CH_4 in the geothermal steam, and the amount of steam vented to atmosphere. For binary plants, there are typically no emissions to atmosphere.

Two possible methods for estimating CO_2 and CH_4 emissions from geothermal processes are included below. The first method provides a basis for calculating direct emissions using the geothermal heat input and the second method uses the measured concentration and flow of CO_2/CH_4 in the vented steam.

— EPS PR-02

Using the first method you may quantify CO_2 emissions using the following equation:

Equation 17b

$$CO_2 = EF * Heat * (0.001)$$

Where

CO_2 = CO_2 emissions, metric tons per year;

EF = Default process CO_2 emission factor for geothermal facilities (7.53 kg/MMBtu)[40]; and

Heat = Heat taken from geothermal steam and/or fluid, MMBtu per year.

You can use CO_2 emissions to estimate the CH_4 emissions if the relative concentration of CH_4 to CO_2 in the process steam is known.

— EPS PR-03

In the second method for quantifying CO_2 and/or CH_4 emissions, you are given the option to develop your own site-specific emission factors derived from site-specific source test data or gas sample analyses. The degree of certainty in the results will depend on the frequency of sampling. It is preferable with this method to derive source test data at least annually, and from the complete set of wells providing steam to the power generation unit.

40 *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry, Appendix C. American Petroleum Institute (API), February 2004.*

17.2

EXAMPLE 17.2.1
Calculating Carbon Dioxide Emissions from Geothermal Facility

Calculate the process CO_2 emissions associated with a geothermal facility where the heat taken from steam was 1,300,000 MMBtu.

Use EPS PR-02 and Equation 17(c) as follows:

Process CO_2 emissions = EF * Heat * (0.001)

Process CO_2 emissions = 7.53 kg CO_2/MMBtu * 1,300,000 MMBtu * (0.001)

= 9,789 metric tons CO_2

17.3 Calculating Process Emissions from Other Common Sources within the EPS

There are several small sources of process emissions that are associated with power generation as listed below. No specific methods are provided for estimating these emissions as they are very dependent on the technologies used, facility-specific operational and maintenance procedures, etc. Members should report emissions from these sources consistent with the GRP's provisions on the application of simplified estimation methodologies (Chapter 11). These sources may include:

1. Emissions of nitrous oxide from Selective Catalytic Reduction and Selective Non-Catalytic Reduction systems used for post-combustion control of oxides of nitrogen (NO_x). Based on data provided in the American Petroleum Institute "Compendium of GHG Emissions Methodologies for the Oil and Gas Industry", the addition of NO_x controls increase N_2O emissions by an order of magnitude for Selective Catalytic Reduction systems on gas turbines and increases N_2O emissions by a factor of 3.5 for natural gas-fired heaters/boilers.[41] (However, in general, concentrations of N_2O in the combustion exhaust gases are typically three to four orders of magnitude less than CO_2.)
2. Venting of natural gas (CH_4) during the start-up and/or shut-down for some gas-fired turbines used as compressors or prime movers in power generation.
3. Venting of CO_2 which is used to purge hydrogen from electricity generators. This procedure may be used prior to generator maintenance, and is likely to be a very low frequency event with very low emissions.
4. Venting of CO_2, HFCs and/or PFCs during the testing of fire suppression systems that use these gases as a fire suppressant on power generating units.

41 *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry, Appendix C. American Petroleum Institute (API), February 2004.*

PART IV: REPORTING YOUR EMISSIONS

Chapter 18: Additional Reporting Requirements

This chapter defines the indicator data that Members using the EPS Protocol must report and the calculation methodologies for power generation metrics, which are required to be reported to The Registry.

Emissions calculations from previous chapters are used in combination with the indicator data described here to develop sector-specific power generation metrics.

The EPS Protocol provides guidance for reporting two different classes of emissions metrics, power generation metrics and power deliveries metrics. Reporting the latter is optional and described in Chapter 19. Both express emissions per unit of power, either from the Member's owned or controlled generation sources or associated with the power that they deliver, which may be a combination of owned generation and purchased power.

Some of the benefits of developing and reporting standardized metrics for the electric power sector are as follows:

1. To provide a basis for consistent comparison between industry members, regardless of entity size.
2. To track an entity's carbon intensity performance over time as a complement to absolute emissions reporting.
3. To provide meaningful carbon intensity information to customers who purchase electricity wholesale from a power generator. Power generation metrics will be useful to utilities and intermediaries that purchase their power.

All of the emissions data needed to calculate the required power generation metrics are entered into The Registry's reporting software as part of your inventory. Therefore, most of the metrics will be calculated automatically in The Registry's reporting software, down to the facility level. As such, there should be little or no additional burden associated with the development of these metrics.

All metrics discussed below are based on CO_2 emissions per unit of output, rather than CO_2e. For power generation involving the combustion of fossil fuels, CO_2 accounts for the majority of emissions from the EPS, and it provides a consistent and reliable basis for tracking emissions over time, and for comparing the emissions from different facilities and entities. Additionally, CO_2e metrics would be less useful to customers who have to report CO_2, CH_4, and N_2O separately rather than one CO_2e value.

The metrics rely on only those CO_2 emissions which are directly related to power generation (with anthropogenic and biogenic emissions treated separately). Thus, the only sources of emissions to be included are direct stationary combustion and process geothermal and acid gas scrubber emissions, or in the case of biogenic metrics, biogenic process emissions. Specifically not included are the CO_2 emissions from sources such as coal piles, fugitive leaks from pipelines, venting of fuel gas from turbines at start-up and shut-down, from fire suppression for power generation, and from CO_2 used to purge hydrogen from generators. Emissions of gases other than CO_2 are not used in the metric calculations.

18.1 Compiling Data for Power Generation Metrics

For each generating facility in which you have an ownership interest, you must report the indicator data listed below: [42]

- Facility name
- Total facility net generation (MWhr)
- Your equity share in the facility (percent)
- Net generation - equity share (MWhr)
- Power exported to own T&D system (MWhr)
- Power exported to grid (MWhr)

If you only have an ownership interest in one or more specific units at a generating facility (rather than the entire facility), you must provide the data listed above at the unit level.

You must report power generation metrics for all generating facilities you own and for all shared units, including those with no emissions.The Registry's reporting software will then compile an entity average generation metric that includes all generation facilities and units.

18.2 Power Generation Metrics

For power generators and any entity that delivers power to the grid on a net annual basis, power generation metrics must be reported under this EPS Protocol. Members that own or control non-combustion generation facilities must also report these metrics, even for power generation with low or no GHG emissions.

All power generation metrics are based on the emissions directly related to the power generation and proportional to the power output. The emissions do not include any upstream emissions or any emissions from ancillary equipment and operations at the power generating facility.

One source of process emissions that is related to power generation directly is the CO_2 from acid gas scrubbers. If a CEMS unit is used, the CO_2 emissions will be automatically included as part of the stationary combustion emissions total. For consistency, if fuel based calculations are used, the scrubber emissions will need to be added to the CO_2 emissions in the metric calculation. Process emissions of CO_2 from geothermal power generation should also be included in the anthropogenic emissions metric calculations.

With the biogenic emissions metrics, the process emissions of biogenic CO_2 must be included as well as the combustion CO_2. This is an important consideration when biogas is used as a fuel (Section 12.3). In this case, the process emissions are considered to be directly related to power generation.

[42] *All power generation metrics are based on the equity share of emissions and corresponding power generation (MWh). The power generation metrics do not use the emissions associated with the control consolidation methodology.*

In terms of organizational boundaries, the generation metrics are based on the equity share of power generated (net generation) and the equivalent emissions associated with that share of the generation. If you have a large equity share in a facility (e.g. 80 percent) and you take a small portion of the power to serve end use customers (e.g. 20 percent), the generation metric should be based on 80 percent of the emissions and 80 percent of the power output.[43]

Table 18.1 presents a summary of the generation metrics that must be reported by all power generators. However, only those metrics applicable to the Member's scope of operations need to be calculated. For example, a Member that operates three natural gas power plants will report EPS Metric G-1 for each facility and G-4 for all facilities combined. EPS Metrics G-2 and EPS Metric G-3 would not apply.

18.1 TABLE 18.1
Summary of Required Power Generation Metrics

Ref	Metric	Comment	Units
EPS Metric G-1	Fossil Generation	Anthropogenic CO_2 (MT) / Net Generation (MWh)	CO_2 / MWh (Net)
EPS Metric G-2	Biofuels Generation	Biogenic CO_2 (MT) / Net Biogenic Power Generation (MWh)	MT Biogenic CO_2 / Biogenic MWh
EPS Metric G-3	Geothermal Generation	Geothermal Process CO_2 / Geothermal MWh	MT Process CO_2 / Geothermal MWh
EPS Metric G-4	Company Average	MT CO_2 / MWh (All Generation)	MT CO_2 / MWh (All Generation)

EPS Metric G-1. Metric for Fossil Generated Electricity: Metric tons of direct CO_2 emissions from stationary fossil fuel combustion for electricity generation per net megawatt-hour of fossil-generated electricity. This metric is calculated for each entity-owned or controlled fossil fuel fired electric generating facility and for all owned or controlled fossil facilities combined. This metric does not include any biogenic CO_2 emissions from biogenic sources.[44]

EPS Metric G-2. Metric Electricity Generated from Combustion of Biofuels: Metric tons of direct biogenic CO_2 emissions per net megawatt-hour of electricity generated.[45] The metric must include biogenic process emissions (i.e. biogenic CO_2 that is mixed with CH_4 in LFG and DG) as well as combustion emissions. Only the generation that is directly attributable to the biofuel combustion is included in this metric. The metric is calculated for each entity-owned or controlled generating unit that uses biofuels. Biofuel here includes biogas (LFG and DG), biomass, Waste Derived Fuels (WDFs), and the biogenic component of MSW.

43 *Note that this differs from the approach used for the electricity deliveries metric. (See Section 17.2).*

44 *This metric includes MWh from generated and purchased biomass sources, but not the biogenic CO_2 emissions.*

45 *Direct biogenic emissions may come from stationary combustion, process emissions (like CO_2 "pass-through" for Landfill Gas) or from fugitive emissions directly related to the power generation.*

EPS Metric G-3. Metric for Geothermal Electricity Generation: Metric tons of direct CO_2 emissions from process/fugitive emissions per net megawatt-hour of electricity generated for each entity-owned or controlled electric generating facility.

EPS Metric G-4. Metric for System-wide Electricity Generation: Metric tons of direct anthropogenic CO_2 emissions for electricity generation per net megawatt-hour of electricity generated for all owned or controlled facilities combined. The numerator for this metric includes the equity share of anthropogenic CO_2 emissions from fossil fuel combustion, process emissions from SO_2 scrubbers, geothermal fugitive emissions, and all other CO_2 emissions directly related to the power generation, but no biogenic CO_2 emissions from the combustion of biofuels nor emissions from other activities onsite that are not directly related to power generation. The denominator includes the equity portion of all power generated by the EPS Member from all sources including coal, natural gas, distillate fuel, hydro, nuclear, renewables, etc. (Note that there is no equivalent system-wide metric for biogenic emissions.)

For all these metrics, the emissions are taken directly from the direct emissions calculations in Chapters 12 and 16.

The following details are addressed in the accounting methodology used for compiling these metrics:

- For a cogeneration facility, the generation metrics include only the CO_2 emissions allocated to electricity rather than the total CO_2 emissions.
- For geothermal facilities, the process emissions of CO_2 are considered to be anthropogenic.
- For any generation source which has biogenic and anthropogenic emissions, (e.g., a wood plant with fuel oil as a starting fuel), a separate metric will be developed for each fuel type. For the anthropogenic emissions, the Net Generation (MWh) from power produced using biogenic sources is included, but the biogenic emissions are not. The biogenic CO_2 emissions are accounted for separately in the inventory and in the biogenic emission metric (EPS Metric G-2).
- The system-wide average generation metric includes the MWh from biofuel power generation, but not the biogenic emissions.

Fossil fuels used at startup do not need to be included in EPS Metric G-2 or EPS Metric G-4.

Chapter 19: Optional Reporting

The EPS Protocol provides the option for reporting efficiency metrics related to wholesale and retail power deliveries, if applicable.

Reporting efficiency metrics (or carbon intensities) allows Members to monitor trends in the carbon intensity of the electricity it acquires and sells to its customers. Over time, an LSE may increase its total GHG emissions to meet growing demand, but if it becomes more efficient, the metrics (representing emissions per unit of output) would provide an important measure to reflect these system improvements regardless of whether the emissions increased or decreased. Therefore, efficiency metrics can provide a valuable source of information to determine the LSE's full impact on GHG emissions over time. Industry observers may also be interested in comparing the environmental performance of power producers of different sizes, which is not easy to evaluate on the basis of absolute emissions. Standardized metrics provide the means to do this on a consistent basis.

The Registry anticipates that the power deliveries metrics reported by Members under the EPS Protocol will become a valuable source of emission factors for other Registry Members to use when calculating their own indirect emissions. Members that choose to report power deliveries metrics will provide a valuable service to their wholesale and/or retail customers.

The following sections discuss the reporting methods that must be followed when a Member chooses to report power deliveries metrics.

19.1 Compiling Power Deliveries Data

Customers that purchase electric power are becoming increasingly interested in the carbon intensity of the power they purchase. Reporting these power deliveries metrics is a way to provide information to your customers and have credible data that adheres to The Registry's well-defined standards and third-party verification requirements. Metrics are calculated in units of CO_2 in order to allow each Member to compile their GHG emissions by gas.[46]

For Members that deliver power to wholesale or retail customers, the reporting of power deliveries metrics is optional under the EPS Protocol. However, if you choose to report these metrics, you must follow the methodologies outlined in this section, and the reported power deliveries metrics must be third-party verified.

If you choose to calculate one or more power deliveries metrics you need to establish the customer categories you will have for your power deliveries, and then assign the power generation and power purchases to specific customer categories. For a Load Serving Entity (LSE), the simplest form of the power deliveries metric will be to have all sources of power (generated and purchased or exchanged) flowing into

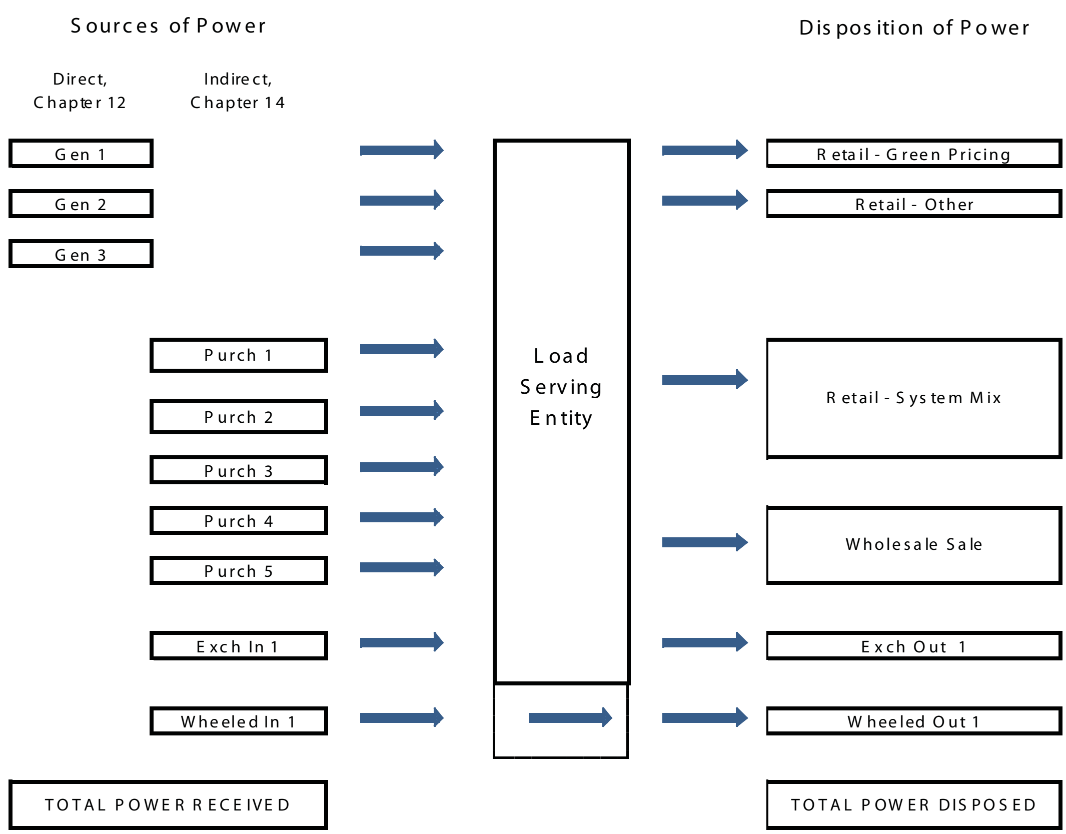
46 *It should be noted that, even though the metrics include CO_2 emissions only, the end-users of electricity will still have to quantify their Scope 2 emissions associated with electricity use for CH_4 and N_2O, and this would be done using the default factors for these gases provided in the GRP.*

one system mix, where the metric for the system mix would be the metric used for power delivered to all customer categories.

Another option would be to assign one group of purchased (or generated) power directly to a specific customer category. For example, you may assign specified power purchased from a wind farm to your green pricing program, and then have all other purchases flow to the mix. In some cases, there may be a need to have multiple categories of delivered power to meet the needs of multiple customers, and this may include wholesale sales as well as a range of retail products.

Once these categories are defined, you will need to compile a table showing the power delivered to the system from each source or each group of sources. You may group the sources of purchased power by supplier or counterparty, or by fuel type, especially for purchases. Exchanges (received) must also be included in this table. Refer to Figure 19.1 for an example of this table.

Figure 19.1 Schematic Showing Power Flow Accounting for a Load Serving Entity



For all power received into the system, aggregate each power resource separately – fossil, biogenic, geothermal, other zero emissions generation (nuclear and hydro). An example of this data compilation process was included in Chapter 14 (Example 14.1).

19.2 Developing Power Deliveries Metrics

If you elect to report power delivery metrics you can choose to report a single system-average metric applicable to all customers (Option A), or to report separate metrics for your wholesale sales, retail sales, and/or special power products (Option B). You might choose to develop multiple metrics for the electricity delivered to distinct customer groups if you are extensively involved in wholesale power transactions or providing a special power product like a "Green Pricing Program." If you have a distinctly separate generation type in one portion of your service area (such as fuel-oil generation in a rural area not connected to the grid) it may also be beneficial to develop multiple power deliveries metrics.

When calculating power deliveries metrics, you should aggregate the power and associated emissions for the power that flows to the customer group you have defined.

A special case to consider is when you have a large equity share in a facility (e.g. 80 percent) and you take a small portion of the power to serve end use customers (e.g., 20 percent). In this example, the electric deliveries metric (for which this power is assigned) should be based on 20 percent of the emissions and 20 percent of the power output. (Note that this differs from the approach used for the required generation metrics.)

In the EPS Protocol, there are no separate power deliveries metrics related to biogenic emissions. The power from these sources (MWh) is included in the deliveries metrics, with zero anthropogenic emissions.

Table 19.1 provides a summary of the electric deliveries metrics that you may choose to report.

19.1 TABLE 19.1
Summary of Power Deliveries Metrics

Ref	Metric	Units
EPS Metric D-1	Wholesale Electric Deliveries	MT CO_2 / MWh
EPS Metric D-2	Special Power Electric Deliveries	MT CO_2 / MWh
EPS Metric D-3	Retail Electric Deliveries	MT CO_2 / MWh

The metrics calculations are summarized below, and Figure 19.2 presents a flow chart showing how Members may define and report multiple electric deliveries metrics for wholesale power, special power products (such as a green pricing program), and for retail power. As the methods are applied, it is important to account for all the power and emissions flowing into the system – through owned generation and purchased power – to ensure that no carbon is "lost" in this accounting process.

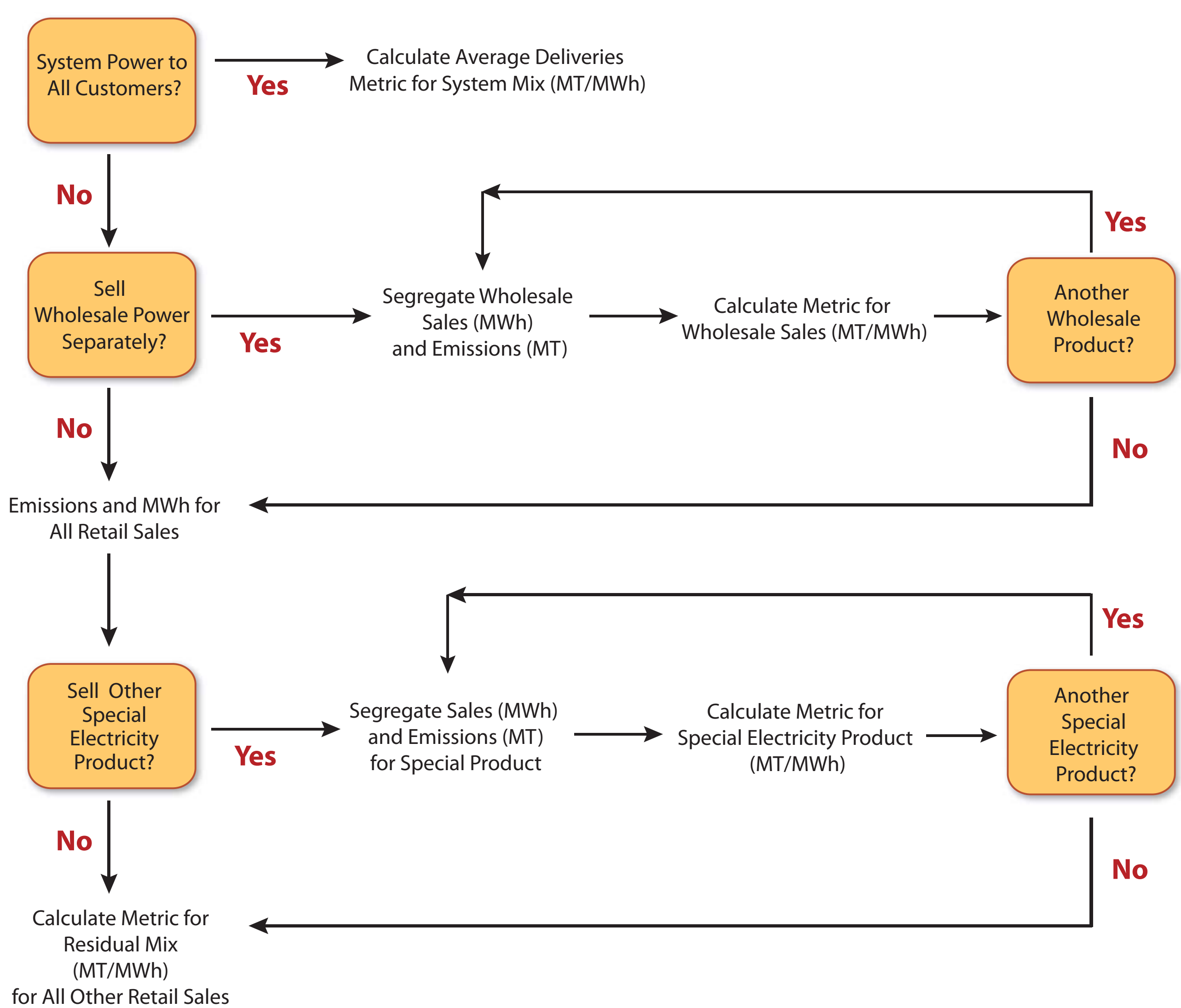
EPS Metric D-1. Electric Deliveries Metric for Retail Sales: Metric tons of anthropogenic CO_2 emissions from electricity generation and purchases per net megawatt-hour of electricity delivered to retail customers. The numerator for this metric includes the portion of CO_2 from all anthropogenic CO_2 emissions sources directly related to the owned power generation delivered to the system, plus the CO_2 emissions associated with all purchased power.[47] The denominator includes the equity portion of all power delivered by the Member from all sources. If you choose to report any of the other deliveries metrics (below), then must remove the emissions and power associated with those other products before calculating the retail deliveries metric. With Option A, this metric becomes the system-average metric used to designate the carbon intensity applicable to all sales.

EPS Metric D-2. Electric Deliveries Metric for Wholesale Power Sales: Metric tons of anthropogenic CO_2 emissions from electricity generation and purchases for the portion of electricity resold at the wholesale level. There is no requirement to derive a separate metric for wholesale power sales, but if used, the power and emissions assigned to this category are set aside and deducted from the remaining power mix delivered to retail customers. The power assigned to wholesale sales has to be clearly tied to specific sources of generation and/or specific power purchases. When this metric is used, the retail sales metric (EPS Metric D-1) must be adjusted, such that the generation and emissions assigned to wholesale sales are deducted from the remaining power mix delivered to retail customers.

EPS Metric D-3. Electric Deliveries Metrics for Special Power Product: Metric tons of anthropogenic CO_2 emissions from electricity generation and purchases for the portion of electricity sold as a special power product. There is no requirement to derive separate metrics for special power products, but if used, the power and emissions assigned to this special product are set aside and deducted from the remaining power mix delivered to retail customers. The power assigned to each special product has to be clearly tied to specific sources of generation and/or specific power purchases. When this metric is used, the retail sales metric (EPS Metric D-1) needs to be adjusted, such that the generation and emissions assigned to special power sales are deducted from the remaining power mix delivered to retail customers.

47 *If wholesale power is resold and accounted for separately under the wholesale metric below, then the emissions and power associated with wholesale sales can be subtracted from the numerator and denominator, respectively*

Figure 19.2 Flow Chart of Options for Reporting Electric Deliveries Metrics



19.1

EXAMPLE 19.2.1
Developing Power Deliveries Metrics

Company X has an equity share in two power plants (one fired with coal and one with natural gas), and purchases power from a wind farm. It delivers power to retail customers, offers a green power "special power" product, and sells a portion of its power wholesale. Relevant data for this scenario are presented in the following tables:

Source	Power Generated/ Purchased	CO_2 Emissions
Coal Plant	1,000,000 MWh	1,000,000 MT
Natural Gas Plant	1,000,000 MWh	500,000 MT
Wind Farm	500,000 MWh	0 MT
Total	2,500,000 MWh	1,500,000 MT

Customer	Power Delivered
Retail End-Users	2,000,000 MWh
Green Power	100,000 MWh
Wholesale	400,000 MWh
Total	2,500,000 MWh

There are several options for reporting metrics for this example:

1. With Option A, Company X chooses to report one system-average power deliveries metric (EPS Metric D-1), which would be 0.6 MT/MWh (1,500,000 MT / 2,500,000 MWh).

2. With Option B, Company X might report two metrics – one for its green power product and one for all remaining power sales. It designates a portion of the wind power to fulfill the green power obligation (100,000 MWh), and the rest of the wind power goes into the system mix. In this case the Special Power Deliveries Metric (EPS Metric D-2) for its green power product would be 0.0 MT/MWh, and the remaining metric (EPS Metric D-1) would be 0.625 MT/MWh (1,500,000 MT / 2,400,000 MWh).

3. Alternatively with Option B, Company X could report separate metrics for all three categories, developed as follows. First it would assign power and emissions to wholesale sales (e.g., designate excess coal generation for wholesale sales (400,000 MWh with 400,000 MT of emissions giving a metric of 1.0 MT/MWh). Next it could assign the wind power to the green pricing product (100,000 MWh with no emissions for a special power product metric of 0 MT/MWh). Finally, it would apply all remaining power and emissions to retail sales (2,000,000 MWh and 1,100,000 MT giving a retail deliveries metric of 0.55 MT/MWh).

19.3 Adjusting Power Deliveries Metrics to Account for the Purchase of Certificates

The purchase and sale of Renewable Energy Certificates (RECs), Tradable Renewables Credits (TRCs), Tradable Renewable Energy Certificates (TRECs), “Green Tags”, and other special electricity certificates are common practice in the EPS. These certificates are used by market participants in order to meet certain mandatory or voluntary commitments regarding the power mix delivered to its customers. For example, RECs may be purchased to comply with a state or provincial Renewable Portfolio Standard, or to support the claims made regarding a Green Pricing Program or Product offered to retail or wholesale customer.

This section of the EPS Protocol discusses how such certificates may be used by Members to adjust power deliveries metrics and to report these adjusted metrics publicly. The section includes:

- A brief overview of special power certificates and the practice of trading these certificates (Section 19.3.1)
- An accounting methodology that allows Members to adjust their deliveries metrics to account for certificate purchases; (Section 19.3.2)
- A discussion of how these transactions might affect The Registry’s overall framework of reporting based on the eGRID regional average emission factors; (Section 19.3.4)
- A brief discussion of other special power programs and their relationship to The Registry’s entity-level inventory reporting system. (Section 19.4)

19.3.1 Overview of Special Power Programs and Power Certificates

Many Members in the EPS purchase or sell “green power” certificates such as Renewable Energy Certificates (RECs), Tradable Renewable Credits (TRCs), Tradable Renewable Energy Certificates (TRECs), and other certificates linked to special types of power generation (collectively referred to in this protocol as power certificates).[48] Power certificates provide proof that a given unit of electricity has been generated from a qualified resource connected to the grid (e.g. in the case of RECs a qualified renewable resource).[49] These certificates are often “unbundled” and sold separately from the underlying physical electricity associated with the generation source, and in this way they provide a mechanism for certificate buyers to incentivize the generation of specific types of power.

48 These certificates are sometimes also referred to as green tags, green energy certificates, or tradable renewable certificates.

49 As originally proposed by the following: Jansen Jaap, “A Green Jewel Box?”, Environmental Finance, March 2003 pp 27. and Natsource. Williamson, Matthew, “Estimating Benefits from Renewable Energy”, CEC Technical Meeting, July 17, 2003 and Environmental Resources Trust. Renewable Energy Certificates and Air Emission Benefits: Developing an Appropriate Definition for RECs. April 2004.

Specifically this chapter focuses on how Members can account for purchases and sales of these special power certificates in their emissions metrics. It does not address methods for end users of electricity to account for direct purchases of power certificates, as those methods are addressed in the GRP. The methods in this chapter discuss how you adjust your own power delivery metrics if you buy or sell a special power certificate, and how this affects the regional average metrics.

The Registry recognizes that the bulk of the current transactions in special power certificates in North America involve RECs or other "green power" products that are associated with zero or low emitting sources. Because of the size of the market for RECs and the value The Registry sees in promoting low emitting sources of power, this protocol provides a method for appropriately recognizing purchases of RECs and special power certificates by Members in their power deliveries metrics. The approach taken in this section applies equally to all power certificates that can be verifiably linked to a specific source of generation and meet certain basic requirements.

The adjustment methodology in this section should not be used when the certificates are bundled with the renewable power or low emissions generation. In this case, the power flows into the LSE's system (whether generated or purchased), and the benefits of the low emissions power (generated or purchased) are inherently reflected in the inventory.

All specified purchases of power must include certificates with the electricity, whether or not the purchase is intended to apply toward the LSE's RPS target or toward a special power product. This is required in order to prevent reporters from counting both the specified power emissions in their power purchases and separately via a certificate linked to that power in their adjusted metrics.

19.3.2 Accounting for Unbundled RECs and Special Certificates

When an LSE purchases an unbundled special power certificate, the EPS Protocol allows it to account for the effect the transactions have on the GHG intensity of the electricity mix that the LSE delivers to its customers. This is done by calculating an adjusted emission metric for the power product to which the certificates are being applied. Making this adjustment to the metric is optional. If you intend to calculate an adjusted metric, you will need to report information about all eligible RECs or special power certificates purchased or retired for the emissions year.

Also, power generators that create and sell special power certificates (linked to any portion of their generation) are required to provide a full accounting of those certificate sales. The requirements for disclosing certificate purchases and sales are presented in a four-step process outlined below.

Step 1: Eligibility of Green and Special Power Certificates

You must report any purchase of a REC or special power certificate in CRIS if you wish to calculate an adjusted emissions metric. The eligibility requirements are as follows:

- Certificates must be purchased from an entity that is different and distinct from your own organization (i.e., not included within your organizational boundaries).
- Certificates must be third-party certified or registered in a publicly accessible registry or tracking system.
- Certificates must be unambiguously tied to a specific power generation facility or unit with a known emissions rate.
- Certificates must be of the same vintage as the emissions reporting year against which they are to be applied or retired no more than six months prior to the start of the year or three months after the end of the year.
- Certificates must be retired prior to the date on which you wish to apply them, and this must be reported to The Registry.
- Facilities from which certificates are derived must be located in North America (Canada, United States, or Mexico).

There are no limits on the number of certificates that may be used in this capacity. Certificates used to meet your Renewable Portfolio Standard (if applicable) must be applied to the retail power metric (or system-average), and may not be applied to a separate power product (e.g., green pricing program).

Step 2: GHG Emissions from Green or Special Power Technologies

The Registry expects that most certificates reported by Members will be associated with low or zero emission power sources. However, to adjust your emissions metric, you must determine the CO_2 emissions (anthropogenic only) attributable to the underlying power source, if any. Though the CO_2 emissions from renewable energy power generation are usually small, it is important to account for the emissions that do occur. This reporting should include all direct emissions operationally related to the generation of the underlying electricity. An example would be the process CO_2 emissions from some forms of geothermal energy production.

You will need to attribute these CO_2 emissions to the RECs or special power certificates that you intend to apply to your reporting year inventory in the same way as you would if the renewable energy were bundled power (generated or purchased). Chapter 14 of the GRP and Table 14.1 in this EPS Protocol provide default emission factors that can be used to calculate emissions for the RECs or other certificates when the generation does have associated CO_2 emissions.

Step 3: Reporting Green and Special Power Certificates

When reporting green power certificates purchased in The Registry's reporting software, you will need to input the following information:

- Number of certificates and MWh represented
- Relevant serial numbers or identification numbers associated with certificates
- Renewable energy facility or facilities that created the certificate
- Type of technology used to create the certificate
- Name of the eGRID region, Canadian province/territory or Mexican state served by the renewable energy facility
- Anthropogenic GHG emissions associated with the underlying power
- "Vintage" or dates for certificate power generation
- Registry or tracking system used for certificate registration and date of retirement
- Intended use of certificate – for green power product or for system average adjustment/RPS requirement

If you sell any unbundled certificates, you must report the following information about the certificates that are sold:

- Number of certificates created and sold (MWh) during emissions year
- Name of registry or tracking system used for certificate registration
- Relevant serial numbers or identification numbers associated with certificates

Step 4: Adjusting Emissions Metrics to Account for Certificate Purchases

Accounting for the purchase of RECs and other certificates from zero or low emissions generation provides a way to lower the carbon intensity of one or more electricity products delivered to your customers. This section outlines the method used within The Registry's reporting software to make the adjustment to the efficiency metrics.

In this approach, certificates are treated as if they represent the underlying power generation to which they were associated. They are used to displace an equivalent amount of power from your actual power mix with the emissions profile associated with the certificate. The Registry's reporting software will first calculate the emissions metric without the application of certificates, and then calculate a "Certificate-Adjusted" metric that incorporates the low emissions generation.

First, you will need to select which power product the certificate(s) will be applied to and make that selection in The Registry's reporting software. (Note that the same certificates cannot be applied to more than one power product.) The Registry's reporting software will sum the power and all the emissions associated with this power product, subtract a portion of that power and emissions equivalent to the amount of power represented by the certificate(s), and then add back the same amount of power with the emissions (if any) associated with the certificate(s). How this calculation works in practice is illustrated in the example given below.

19.3.3 Example: Adjusting the Deliveries Metrics to Account for Special Power Certificate Purchases

19.2

EXAMPLE 19.2
Adjusting the Deliveries Metrics to Account For Special Power Certificate Purchases

A Member chose to report its power deliveries metrics to The Registry and has used the method in Chapter 19 of the EPS Protocol to develop three metrics. The metric calculations are summarized below:

Electricity Product	MWh	Scope 1 + Scope 3 CO_2 Emissions (MT)	Efficiency Metric (kg/MWh)
Green Pricing Program	1,500,000	150,000	100
Retail Sales		24,000,000	300
Wholesale Electricity	1,200,000	600,000	400

This same Member purchased 1,000,000 MWh of unbundled Renewable Energy Credits from a wind power generator during the reporting year, and applied those credits to the Green Pricing Program to develop an adjusted metric for this product. This adjustment for the Green Pricing Program is shown below:

Electricity Product	MWh	Scope 1 + Scope 3 CO_2 Emissions (MT)	Efficiency Metric (kg/MWh)
Renewable Energy Certificates	1,000,000	0	0
Power from Member's own power mix	500,000	50,000	100
Green Pricing Program - Adjusted	1,500,000	50,000	33

The resulting adjusted metric (33 kg/MWh) is made available as an alternate power deliveries metric for the Green Pricing Program electricity, and this is included in The Registry's reporting software public report. (The shaded cells in this table show the calculations that are made in The Registry's reporting software, but these will not be included in the public report.)

19.3.4 Implications for the Regional Average Emission Factors

Allowing Members to adjust their efficiency metrics to account for certificate purchases may cause a need to rebalance the regional average emission factor as purchased RECs are accounted for. If the number of certificates reported by Registry Members and the claimed power transfers created by the certificate accounting approach described above become substantial, it could render regional default factors inaccurate and lead to a type of double counting. The Registry will monitor and undertake these adjustments in a phased approach.

During the first year of EPS reporting, no adjustments will be made for certificate transactions because the number certificates reported is likely to represent a very small percentage in emissions terms of the regional average power mixes. In subsequent years of EPS reporting, the eGRID or provincial emission factors for each region will be adjusted if the claimed certificates would result in a change of more than five percent to any regional emission factor. This approach should provide reasonable protection against the double counting of emission reductions in any material way, and is considered to be an adequate response for a voluntary reporting program in which not all GHG emitters are expected to participate.

19.4 Other Special Power Programs

It is important to emphasize that The Registry provides an entity-wide inventory emissions reporting framework, and it is not a project accounting system. As such, the reporting of offset projects and sequestration projects are not currently supported by this program. The Registry recognizes that some utilities support Special Power Products through the purchase of GHG offsets. These programs differ from products based on the delivery of low carbon emissions power or the use of certificates linked to such power. Members that offer these types of offset based programs are encouraged to report on them in the supplementary portion of their emissions inventory report in The Registry's reporting software.

19.5 Other Optional Emissions

As noted in Section 5.5, emissions associated with the upstream extraction and production of fuels consumed in the generation of electricity may be reported as optional data. Examples include emissions from mining of coal, nuclear fuels, refining of gasoline, extraction of natural gas, and production of hydrogen (if used as a fuel), transport of natural gas, upstream emissions from the manufacture of power generating equipment, and the lifecycle emissions from biofuels, etc.

Chapter 20: Reporting Your Data Using The Registry's Reporting Software

REFER TO GRP.

20.1 The Registry's Reporting Software Overview

REFER TO GRP.

20.2 Help with The Registry's Reporting Software

REFER TO GRP.

Chapter 21: Third-Party Verification

An overview of verification is provided in the GRP. Members should also consult the GVP and its EPS addendum in order to learn about specific requirements for verification bodies conducting verification activities in the EPS. Of particular import are application of materiality to metrics and to required subsidiary reporting (Chapter 4)

21.1 Background: The Purpose of The Registry's Verification Process

REFER TO GRP.

21.2 Activities To Be Completed by the Member in Preparation for Verification

REFER TO GRP.

21.3 Batch Verification Option

REFER TO GRP.

21.4 Verification Concepts

REFER TO GRP.

21.5 Verification Cycle

REFER TO GRP.

21.6 Conducting Verification Activities

REFER TO GRP.

21.7 Activities To Be Completed After the Verification Body Reports Its Findings

REFER TO GRP.

21.8 Unverified Emission Reports

REFER TO GRP.

Chapter 22: Public Emission Reports

22.1 Required Public Disclosure

REFER TO GRP.

In addition to the public reporting requirements laid out in the GRP, EPS emission reports will also include the required Scope 3 emissions and required & optional metrics described in earlier chapters of this protocol.

22.2 Confidential Business Information

REFER TO GRP.

GLOSSARY OF TERMS

The terms included in this glossary are sector-specific terms used in the EPS Protocol. Other terms more generally applicable to GHG reporting are included in the GRP.

Term	Definition
Ancillary Services	Services that ensure reliability and support the transmission of electricity from generation sites to customer loads. Such services may include: load regulation, spinning reserve, non-spinning reserve, replacement reserve, and voltage support.
Balancing Authority	A Balancing Authority is the entity responsible for operating a control area. It matches generation with loads and maintains frequency within limits.
Boiler	A device for generating steam for power, processing, or heating purposes, or for producing hot water for heating purposes or hot water supply. Heat from an external combustion source is transmitted to a fluid contained in the boiler. The heat added to this fluid in the boiler is delivered to an end use.
Bottom Cycle Plant	Electricity Generator using heat from combustion that has already been useful in another process or thermal cycle.
Bulk Power System/ Bulk Transmission System	A term commonly applied to the portion of an electric utility system that encompasses the high voltage power resources used for bulk power transmission.
Bulk Power Transmission	A functional or voltage classification relating to the high voltage, high power carrying portion of the transmission system. (Also refer toTransmission)
Busbar	The power conduit of an electricity generating facility that serves as the starting point for the electricity transmission system.
Capacity	The rated continuous load-carrying ability, expressed in megawatts (MW) or megavolt-amperes (MVA) of generation, transmission, or other electrical equipment.
Capacity Factor	The ratio of the total energy generated by a generating unit for a specified period to the maximum possible energy it could have generated if operated at the maximum capacity rating for the same specified period, expressed as a percentage.
Co-firing	Combustion of more than one fuel in a single generating unit. The co-firing may occur when fuels are used in combination or on their own at different times during the reporting period. Co-firing may involve the fossil fuels and/or biomass fuels.
Cogeneration Facility	An industrial structure, installation, plant, building, or self-generation facility, which may include one or more cogeneration systems.

Term	Definition
Combined Cycle	Any electric generating technology in which electricity is produced from two or more different thermal cycles using shared heat from a common combustion process. Commonly, a gas turbine electricity generator in which exhaust gas heat is used to produce steam in a boiler which in turn drives a steam turbine electricity generator. The steam produced in this example might also be used for additional purposes, thus becoming a cogenerator.
Continuous Emission Monitoring System (CEMS)	CEMS is the continuous direct measurement of pollutants or other exhaust gas constituents caused to be emitted into the atmosphere due to combustion or industrial processes. Depending on fossil fuel type and operating permit requirements, CEMS systems may include monitors for exhaust gas concentration, volumetric exhaust gas flow rate, and other constituents of interest. For liquid and gaseous fuels of known, consistent carbon content, CEMS may measure mass flow of fuel in lieu of CO_2 measurement in the exhaust gas stack. The term “CEMS” may include those systems where there is fuel flow measurement but no other relevant stack measurements (e.g., with natural gas power generation). A computer-based data acquisition and handling system (DAHS) is usually considered a part of the CEMS. The DAHS records raw emissions data, performs calculations with the data, and often combines the data with other plant process information.
Control Area	Electric power system in which operators match loads to resources within the system, maintain scheduled interchange between control areas, maintain frequency within reasonable limits, and provide sufficient generation capacity to maintain operating reserves. (Also refer to Balancing Authority.)
Cooperatively Owned Utility	A cooperatively owned utility (or “electric cooperative”) is a utility that is owned by its members who are often rural farmers and/or communities. Cooperatives may be Generation and Transmission Cooperatives or Distribution Cooperatives, and they provide electric service to their members.
Demand	The rate at which electric energy (power) is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time.
Demand-Side Management	The term for all activities or programs undertaken by an electric system or its customers to influence the amount or timing of electricity use.

Term	Definition
Direct Access	The ability of a retail customer to purchase electricity directly from an Electric Service Provider other than their incumbent Local Distribution Company.
Direct Monitoring	Direct monitoring of exhaust stream contents in the form of continuous emissions monitoring (CEM) or periodic exhaust gas (grab) sampling.
Distributed Emissions	CO_2 emissions from fuel combustion at cogeneration facilities distributed between energy stream outputs including thermal energy, electricity generation and potentially other product outputs.
Distribution System	The lower voltage system of power lines, poles, substations and transformers, directly connected to homes and businesses.
Duct Burner (Duct Firing)	A combustion heat source used to supplement heat exiting an upstream process and prior to being used in another process. (Also refer to Heat Recovery Steam Generator and Supplemental Firing).
Electric Plant (Physical)	A facility for generating electricity by converting a primary source of energy into electrical energy.
Electric System Losses	The loss of electric energy between the point of generation and its point of intended use. Electric energy is lost primarily due to resistance heating of transmission and distribution system wires and transformers.
Electric Utility	A corporation, person, agency, authority, or other legal entity or instrumentality that owns or operates facilities for the generation, transmission, distribution, or sale of electric energy primarily for use by the public, and is defined as a utility under the statutes and rules by which it is regulated. Electric utilities include privately owned companies (investor-owned utilities and cooperative utilities), and publicly owned agencies (including federal utilities, crown corporations, state and provincials authorities, municipals, public power districts and irrigation districts).
Electrical Energy	The generation or use of electric power by a device over a period of time, typically expressed in kilowatt-hours (kWh), megawatt-hours (MWh), or gigawatt-hours (GWh).
Electricity Generating Facility	See Generating Facility
Electricity Power Generator	See Independent Power Producer.
Electricity Transaction	The purchase, sale, import, export or exchange of electric power.
End User	A firm or individual that purchases products for its own consumption and not for resale (i.e., an ultimate consumer).

Term	Definition
Exchange Agreement	See Power Exchange Agreement.
Exempt Wholesale Generator	A corporate entity that owns an “eligible generating facility” under the Act. This category of power producer was created by the Energy Policy Act of 1992 (EPACT). EWGs are wholesale producers that do not sell electricity in the retail market and do not own transmission facilities. EWGs are not regulated and utilities are not required to buy their power.
Firm Power	Power for which the purchaser asks the seller to provide assurance that the purchased capacity will be available at a specified time. Firm power can be tied to a specified facility, but the seller typically can provide other power when the specified facility generation is not available.
Fuel Totalizer	A meter that sums the volume or mass of fuel used (rather than the flow rate of fuel).
Generating Facility	A facility that generates electricity and includes one or more generating units at the same location.
Generating Unit	A combination of physically connected generator(s), reactor(s), boiler(s), combustion turbine(s), or other prime mover(s) operated together to produce electric power.
Generation (Electricity)	The process of producing electrical energy from other forms of energy; also, the amount of electric energy produced, usually expressed in kilowatt-hours (kWh) or megawatt-hours (MWh).
Generator	See Independent Power Generator
Geothermal Plant	A plant with turbines powered by heat extracted from the earth using steam, hot water, or compatible working fluid recirculated through hot subterranean rock.
Gross Generation	The electrical output at the terminals (busbar) of the generator, typically expressed in Power (MW), or Energy (MWh).
Heat Rate	A measurement used in the energy industry to calculate how efficiently a generator uses heat energy. It is expressed as the number of BTUs of heat required to produce a kilowatt-hour of energy. Operators of generating facilities can make reasonably accurate estimates of the amount of heat energy a given quantity of any type of fuel, so when this is compared to the actual energy produced by the generator, the resulting figure tells how efficiently the generator converts that fuel into electrical energy. Heat rates are typically expressed as net heat rates.

Term	Definition
Heat Recovery Steam Generator	A boiler using heat all or mostly from a combustion source that has already been useful in another thermal process. (Also refer to Cogeneration, Combined Cycle, Bottoming Cycle, and Duct Burner).
Heating Value	The amount of energy released when a fuel is burned completely. Care must be taken not to confuse higher heating value (HHV) and lower heating value (LHV) of a fuel. This is particularly true for computing fuel use or CO_2 production using heat rates or efficiencies of conversion.
Holding Company	An investor-owned utility which is a parent company established to own one or more operating electric utility companies that are integrated with one another.
Independent Power Producers	As used in NERC reference documents and reports, any entity that owns or operates an electricity generating facility that is not included in an electric utility's rate base. This term may include, but is not limited to, cogenerators and small power producers and other non-utility electricity producers, such as exempt wholesale generators who sell electricity. In the protocol, the term Electric Power Generator is used interchangeably with Independent Power Producer.
Independent System Operator (ISO)	An impartial third-party that maintains secure and economic operation of an open access transmission system on a regional basis. An ISO provides availability and transmission pricing services to all users on the transmission grid.
kilowatt	A unit of electrical power that is 1000 watts. A watt is a unit of electrical power equal to one ampere under pressure of one volt, or 1/746 horsepower.
kilowatt-hour (kWh)	The electrical energy unit of measure equal to one thousand watts of power supplied to, or taken from, an electric circuit steadily for one hour.
Liquefied Natural Gas	Natural gas (primarily methane) that has been liquefied by reducing its temperature to minus 260 degrees Fahrenheit at atmospheric pressure.
Load	An end-use device or customer that receives power from the electric system. Load should not be confused with Demand, which is the measure of power that a load receives or requires. (Also refer to Demand).
Local Distribution Company	A Local Distribution Company Provider is an electric utility that physically delivers electricity to retail electricity consumers over its own wires.

Term	Definition
Load Serving Entity	A Load Serving Entities (LSE) is an entity that provides electric service to end-use retail consumers and to wholesale customers.
Marketer	See Power Marketer.
Megawatt	A unit of power equal to one million watts, or 1000 kilowatts
Megawatt-Hour	A unit of energy equal to one thousand kilowatt-hours or 1 million watt-hours. i.e., the energy equivalent to 1 MW of power lasting 1 hour.
MMBtu	A unit of energy; Million Btus (Btu x10^6); 1 MMBtu = 1 DecaTherm = 10 Therms = 1055 Mega Joules (MJ)
Municipal Utility	A municipal utility is a non-profit utility that is owned and operated by the community it serves; it is a civil government entity.
Nameplate Generating Capacity	The rated output of a generator under specific conditions designated by the manufacturer, expressed in megawatts (MW) or kilowatts (kW).
Net Capacity	The maximum capacity (or effective rating), modified for ambient limitations, that a generating unit, power plant, or electric system can sustain over a specified period, less the capacity used to supply the demand of station service or auxiliary needs.
Net Energy for Load	The electrical energy requirements of an electric system, defined as system net generation, plus energy received from others, less energy delivered to others through interchange. It includes system losses but excludes energy placed in storage at energy storage facilities.
Net Generation	Gross generation minus station service or unit service power requirements, usually expressed in megawatt-hours (MWh).
Net Power Generated	The gross generation minus station service or unit service power requirements, expressed in Megawatts (MW) or megawatt-hours (MWh) over a specified time period. In the case of cogeneration, this value is intended to include internal consumption of electricity for the purposes of a production process, as well as power put on the grid.
NERC E-Tag	North American Electric Reliability Corporation (NERC) energy tag representing transactions on the North American bulk electricity market scheduled to flow between or across control areas (Balancing Authorities).
North American Electric Reliability Council (NERC)	North American Electric Reliability Corporation. NERC is an international, independent, self-regulatory, not-for-profit organization, whose mission is to ensure the reliability of the bulk power system in North America. The NERC Regions are listed at: http://www.nerc.com/page.php?cid=1|9|119
Non-Utility Generator (NUG)	A privately owned company that generates power for its own use or for sale to the utilities and others. An electricity generator may or may not be interconnected to the electric grid.

Term	Definition
Point of Delivery	A location on an electric system where a power supplier delivers electricity to the receiver of that energy. This point can be an interconnection with another system or a substation where the transmission provider's transmission and distribution systems are connected to another system, or the busbar of a generator.
Point of Receipt	A location on an electric system where an entity receives electricity from a supplier. This point can be an interconnection with another system or a generator busbar.
Power	Power as used without elaboration in this protocol commonly means electricity, except where context or modifier makes clear that another meaning is intended (e.g. horsepower or n^{th} Power). Power has the specific technical definition of the rate at which energy is transferred or energy flux.
Power Contract	An arrangement for the purchase of electricity. Power contracts may be, but are not limited to, power purchase agreements and tariff provisions.
Power Generator	See Independent Power Producer.
Power Exchange Agreement	A commitment between electricity suppliers to swap energy for energy (i.e. later repayment-in-kind for an initial power delivery).
Power Marketer	A purchasing/selling entity that buys and sells electricity wholesale, and does not sell power to retail electricity consumers. Power marketers do not own or operate power generation, transmission or distribution facilities.
Power Pool	An association of two or more interconnected electric systems having an agreement to coordinate operations and planning for improved reliability and efficiencies.
Prime Mover	The type of equipment such as an engine or water wheel that converts prime energy (e.g., fossil fuel, solar, hydro, wind, biomass) into kinetic energy that drives a rotating electric generator. For purposes of this protocol "Prime Movers" include direct and solid state electrical generation devices such as fuel cells and Photovoltaics.
Qualifying Facility (QF)	A cogeneration or small power production facility that meets certain ownership, operating, and efficiency criteria established by FERC (Federal Energy Regulatory Commission) pursuant to PURPA (Public Utility Regulatory Policy Act). Refer to CFR, Title 18, Part 292.
Renewable Energy	Energy from sources that constantly renew themselves or that are regarded as practically inexhaustible. Renewable energy includes, but is not limited to, energy derived from solar, wind, geothermal, hydroelectric, biomass, MSW, tidal power, sea currents, and ocean thermal gradients.
Retail Consumer	A consumer of energy and an end-use customer. Includes residential, commercial and industrial customers, regardless of size.

Term	Definition
Retail Electricity Provider	An entity that provides electricity to be delivered at retail rates to end users. A Retail Electricity Provider is a Load Serving Entity that may or may not be the Local Distribution Company.
Retail Service Provider	See Retail Electricity Provider.
Self-Generation Facility	A facility dedicated to serving a particular end user, usually located on the user's premises. The facility may either be owned directly by the end user or owned by an entity with a contractual arrangement to provide electricity to meet some or all of the user's load.
Source	Source means direct greenhouse gas emission source.
Specified Source of Power	Specified source of power or specified source means a particular generating unit or facility for which electrical generation and imputed GHG emissions can be confidently tracked due to full or partial ownership or due to its identification in a power contract.
Stocks	A supply of fuel accumulated for future use. This includes, but is not limited to, coal and fuel oil stocks at the plant site, in coal cars, tanks, or barges at the plant site, or at separate storage sites.
Storage	Energy transferred from one entity to another entity that has the ability to conserve the energy (i.e., stored as water in a reservoir, coal in a pile, etc.) with the intent that the energy will be returned at a time when such energy is more usable to the original supplying entity.
Substation	A facility for switching electrical elements, transforming voltage, regulating power, or metering.
Supplemental Firing	A combustion energy input to a cogeneration or Combined Cycle facility used to increase quantity and/or quality of heat in an exhaust stream for use in a downstream process (Also refer to Duct Burner).
System	See Transmission and Distribution System.
Thermal Host (Heat Host)	The user of the steam or heat output of a cogeneration facility.
Tolling Agreement	This is an agreement whereby one entity (e.g., utility) provides fuel to another entity (e.g. a generator) to combust and generate electricity using the fuel. The generator receives compensation from the fuel provider in return for the electricity generated.
Topping Cycle Plant	An electrical generation plant using combustion heat in the first or highest temperature portion of a cogeneration facility and/or Combined Cycle Generation Plant.
Transformer	An electrical device for changing the voltage of alternating current.

Term	Definition
Transmission (Electric)	An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.
Transmission and Distribution System	Transmission and Distribution equipment that is owned or operated by a single entity and operated as a balance of supply and demand.
Unit	See Generating Unit.
Underground Gas Storage	The use of sub-surface facilities for storing gas that has been transferred from its original location. The facilities are usually hollowed-out salt domes, natural geological reservoirs (depleted oil or gas fields) or water-bearing sands topped by an impermeable cap rock (aquifer).
Unspecified Source (of Power)	Unspecified source of power or unspecified source means electricity generation that cannot be matched to a particular generating facility.
Useful Power Output	The electric or mechanical energy made available for use, exclusive of any such energy used in the power production process.
Useful Thermal Output	Useful thermal output means the thermal energy made available in a cogeneration system for use in any industrial or commercial process, heating or cooling application, or delivered to other end users (i.e. total thermal energy made available and consumed in processes and applications other than electrical generation).
Utility	See Electric Utility.
Waste-Derived Fuel	A fuel typically derived from waste(s) and generally used as a substitute for conventional fossil fuels. Waste-derived fuels can include fossil fuels such as waste oil, plastics or solvents, biomass such as dried sewage or impregnated saw dust, or fractions of both fossil fuels and biomass such as municipal solid waste or tires.
Wheeled Power	Electricity that passes from one system to another over transmission facilities of an intervening system without being purchased or sold (i.e. owned) by the transmission entity.
Wholesale Sales	Energy supplied to other electric utilities, cooperatives, municipals, and Federal and State electric agencies for resale to ultimate consumers.

1 This source is not unique to EPS, but the methodology for estimating emissions is unique for many Members where the electricity consumed includes self-generated power (Chapter 14).

2 The Registry updates the emission factors in Chapter 12 of the GRP on a regular basis, including those for Canada and Mexico.

3 The applicable emission factors for MSW and Biomass Derived Fuel (BDF) are found in the GRP and regularly updated by The Registry.

4 Source: U.S. Energy Information Administration, Electric Power Annual with data for 2005, carbon dioxide uncontrolled emission factors website see http://www.eia.doe.gov/cneaf/electricity/epa/epata3.html (Accessed 10/9/07).

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