ENERGY STAR® Portfolio Manager® Technical Reference

Greenhouse Gas Emissions

OVERVIEW

The energy used in commercial buildings results in significant emissions of greenhouse gases (GHGs) linked to global climate change, making buildings an important part of your GHG inventory. In order to help you assess the emissions footprint associated with your energy consumption, Portfolio Manager incorporates a number of metrics to quantify these emissions.

- **Total Emissions.** Total Emissions is the primary metric, quantifying the majority of GHGs associated with commercial buildings. It can be broken down into component metrics, also available in Portfolio Manager:
    - **Direct Emissions.** Emissions from fuel that is directly burned at your building, for example natural gas that may be combusted to heat your property.
    - **Indirect Emissions.** Emissions associated with energy purchased from a utility, for example emissions associated with the generation of electricity or district steam.
- **Biomass Emissions.** Biomass emissions are an additional element in your inventory. These are emissions from biogenic fuels that are burned onsite, such as wood. Though combustion occurs on site, the emissions from burning biomass are accounted for separately from direct fossil fuel emissions because they may or may not reduce carbon emissions, depending on the type and source of the biomass resources.

Emissions are calculated by multiplying the site energy for each fuel by the emissions factor for that specific fuel type. These factors incorporate the emissions of carbon dioxide, methane, and nitrous oxide, to provide a single carbon dioxide equivalent (CO_2e) number. Portfolio Manager uses different factors for the U.S. and Canada. Properties in other countries use U.S. factors.

Green power (electricity generated from environmentally preferable renewable resources, such as solar, wind, geothermal, low-impact biomass, and low-impact hydro resources) can have an important effect on your emissions inventory. Green power may be obtained from either onsite sources or offsite sources. We include a variety of metrics to help you understand the emissions benefit.

- **Offsite Green Power.** When you purchase offsite green power, you are making a purchase of electricity from the grid bundled with environmental benefits defined by Renewable Energy Certificates (RECs). We show the emissions associated with a conventional grid purchase, and the avoided emissions quantified in the REC.
- **Onsite Green Power.** When you have an onsite renewable system, the implications for emissions depend on whether you own the RECs. If you do, then onsite green power is counted as zero emissions in your GHG inventory, and you can also track the total avoided emissions associated with the system. If you do not own the RECs, you cannot claim an environmental benefit.

This technical reference is divided into the following sections:

THE VALUE OF A GHG INVENTORY 2
CALCULATING DIRECT EMISSIONS 3
CALCULATING INDIRECT EMISSIONS 4
CALCULATING BIOMASS EMISSIONS 5
UNDERSTANDING AVOIDED EMISSIONS FROM GREEN POWER 5
REFERENCE GHG EMISSIONS FACTORS 6

THE VALUE OF A GHG INVENTORY

Carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O) are the principal greenhouse gases emitted to the atmosphere from the burning of fossil and biomass fuels used in commercial buildings. The energy used by commercial buildings in the United States accounts for more than 16% of the nation's greenhouse gas (GHG) emissions.[1] In Canada, the energy used by commercial, institutional, and residential buildings accounts for 17% of Canada's greenhouse gas (GHG) emissions.[2] This makes commercial buildings an important target for organizations interested in pursuing energy and GHG management and reduction programs. Tracking and managing your GHG footprint can help improve your bottom line, while also helping to fight global climate change.

Portfolio Manager can help you inventory, track, and communicate the GHG emissions associated with the energy used by buildings in your portfolio. This includes a variety of metrics and graphs to demonstrate GHG emissions performance. An effective GHG reduction strategy may incorporate not only energy efficiency in your buildings, but also the purchase of green power to ensure that the energy you use comes from sources with a reduced GHG footprint. Therefore, Portfolio Manager includes several metrics to help you understand the environmental benefits of both onsite and offsite green power.

The methodology for calculating GHG emissions in Portfolio Manager is based on the *Greenhouse Gas Protocol Corporate Accounting and Reporting Standard* developed by the World Resources Institute (WRI) and World Business Council for Sustainable Development.[3] This protocol was developed as the accounting framework to provide a relevant, complete, consistent and transparent account of an organization's GHG emissions. As the global standard, it serves as the basis for the accounting, inventory and reporting guidance provided by the Environmental Protection Agency's (EPA) Center for Corporate Climate Leadership, as well as state and non-governmental organization registry, reporting, and recognition programs. The specific calculation details depend on the type of emissions, as detailed in the following sections.

Please note that Portfolio Manager does not account for energy consumed for onsite vehicle use, industrial or manufacturing processes, or fugitive refrigerant emissions resulting from a building's use of refrigeration or air conditioning equipment. These are important contributors to an organization's GHG footprint, but outside of the scope of Portfolio Manager.

WRI Protocol Updates and Scope 2 Emissions

In January 2015 the World Resources Institute amended their *Green House Gas Protocol Corporate Accounting and Reporting Standard* to update requirements and best practices for accounting and reporting of indirect (or scope 2) emissions.[4] Among these changes, the amendments now require indirect emissions to be calculated and reported in two ways: a *location-based* method relying on grid-average emissions factors, and a *market-based* method using energy supplier-specific emissions factors. Portfolio Manager currently has the capability to calculate *location-based* emissions. The capability to calculate market-based emissions will be added in 2024.

---

[1] U. S. Environmental Protection Agency, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2017*. Table 2-12: U.S. Greenhouse Gas Emissions by Economic Sector and Gas with Electricity Related Emissions Distributed (MMT CO2 Eq.) and Percent of Total in 2017. https://www.epa.gov/sites/production/files/2019-04/documents/us-ghg-inventory-2019-main-text.pdf

[2] *Specific Mitigation Opportunities Working Group: Final Report*. Section 6.4, "Built Environment." Published in 2016. https://www.canada.ca/content/dam/eccc/migration/cc/content/6/4/7/64778dd5-e2d9-4930-be59-d6db7db5cbc0/wg_report_specific_mitigation_opportunities_en_v04.pdf.

[3] World Resources Institute and the World Business Council for Sustainable Development, *The Greenhouse Gas Protocol; A Corporate Accounting and Reporting Standard*. Revised Edition. http://www.ghgprotocol.org/.

[4] World Resources Institute and the World Business Council for Sustainable Development, *The Greenhouse Gas Protocol; GHG Protocol Scope 2 Guidance, an amendment to the GHG Protocol Corporate Standard.* http://ghgprotocol.org/scope_2_guidance.

Historical Emissions Factors

On December 11, 2022, EPA changed the GHG emissions calculations to use historically accurate GHG emissions factors for all fuel types. Previously, Portfolio Manager used the current emissions factors for all GHG emissions calculations, regardless of the Period Ending Date. The decision to use historical emissions factors is consistent with guidance from World Resources Institute (WRI) and EPA's Center for Corporate Climate Leadership which requires that all emissions be calculated using the emissions factors for the time they occurred (2015 emissions are calculated using 2015 emissions factors). If your Period Ending Date spans two different emission years, the later emissions factor will be used for the entire period.

An Excel file with current and historical GHG factors from 2000 to the present is available at: https://www.energystar.gov/buildings/tools-and-resources/historical_greenhouse_gas_factors_2000_present

CALCULATING DIRECT EMISSIONS

To calculate direct GHG emissions, Portfolio Manager uses what is called a default fuel analysis approach. This approach requires that you know only the type and quantity of fuel. It eliminates the need for you to obtain fuel specific characteristics from your energy suppliers, as it assumes fuel-specific factors for heating value, carbon content, carbon to CO_2 ratio (12:44), and carbon oxidation factor (100%) for each fuel. Note that this methodology accounts for the emissions that occur at your building only – emissions that may have occurred during extracting, processing, or delivering these fuels is the responsibility of the fuel supplier and does not fall within your inventory.

While a default fuel analysis approach provides a straightforward estimation of direct CO_2 emissions, estimating direct emissions of CH_4, and N_2O is much more complicated. Unlike CO_2 emissions, CH_4, and N_2O emissions depend not only upon fuel characteristics, but also on combustion technology (size, vintage, maintenance, and operation), combustion characteristics, usage of pollution control equipment, and ambient environmental conditions. Fortunately, as these direct emissions comprise a small percentage of the total GHG footprint of a building (<1%), fuel-specific, commercial sector factors for combustion technology, characteristics and controls are considered adequate to estimate CH_4, and N_2O emissions associated with on-site fuel consumption.

To calculate direct GHG emissions:

1. All billed or metered site energy consumption for each fuel is converted from native units to million British thermal units (MBtu). Fuels that are delivered, billed, or measured in mass or volume units (i.e., cubic feet, tons, gallons) are converted to energy using standard heat content factors.
2. Total site energy for each fuel is multiplied by a single CO_2-equivalent factor that incorporates the reference global warming potential of each gas (CO_2=1, CH_4=28, and N_2O= 265).[5]
    a. In the US, these factors are computed at the national level (each fuel has one factor).
    b. In Canada, factors for fuel oil are applied at the national level, but factors for natural gas vary by province. Specific factors for each country are presented in the last section of this document.
3. Direct emissions are summed together across all fuels (e.g., oil, gas, etc.) and reported as a Direct Emissions Metric in Portfolio Manager.
4. Direct emissions are also added to the Total GHG Emissions.

[5] The 100-year global warming potential (GWP) of each greenhouse gas (CO_2=1, CH_4=28, and N_2O= 265) compares the radiative forcing ability of each gas relative to CO_2, which serves as the reference gas. 100-year GWPs from IPCC Fifth Assessment Report (AR5), 2014. https://www.ipcc.ch/reporter/ar5/syr/ . More information on the use of AR5 is available at https://www.epa.gov/climateleadership/center-corporate-climate-leadership-ghg-emission-factors-hub.

CALCULATING INDIRECT EMISSIONS

Indirect emissions result from the purchase of a utility-supplied energy product such as electricity or district heat. When these secondary forms of energy are purchased, emissions occur at the plant where the heat/electricity was originally produced. These factors are applied to your site energy consumption and take into account emissions associated with the heat (or power) generation. However, the emissions associated with energy losses from the delivery of that energy (e.g. along transmission and distribution lines) is attributed to the utility, not to your building. The main sources of indirect emissions are electricity, district steam, district hot water, and district chilled water.

District Heating and Cooling

Portfolio Manager applies default emission factor values to determine the indirect emissions from district heating and cooling energy purchased from an offsite supplier. This approach is selected for simplicity; it requires that you know only the type and quantity of district fuel used in your buildings. Use of default emissions factors does not require you to obtain boiler efficiency, fuel mix, or fuel emissions factor values from your steam or hot water district energy supplier. This approach does, however, require you to obtain the general production method of the district chilled water from your energy supplier.

To calculate indirect GHG emissions from district heating and cooling:

1. All billed or metered site energy consumption for each fuel is converted from native units to MBtu. Fuels that are delivered, billed, or measured in mass or volume units (i.e., pounds of steam) are converted to energy using standard heat content factors.[6]
2. Total site energy for each fuel is multiplied by a CO_2-equivalent factor that incorporates the contribution of CO_2, CH_4, and N_2O.
    a. In the U.S., a single national factor is applied for each type of district system.
    b. Canada uses a similar national approach, but the factors are different from the U.S. factors.
3. Indirect emissions from district energy consumption are added to electric indirect emissions to compute your Indirect Emissions metrics in Portfolio Manager.
4. Indirect emissions are also added to the Total GHG Emissions.

Electricity

Portfolio Manager applies regional GHG factors to compute the GHGs associated with electric consumption. Unlike the default fuel approach for direct emissions and indirect emissions from district systems, the approach for electricity is based on measured power plant data from utility owners and operators. For the U.S., these regional factors are determined using EPA's Emissions & Generation Resource Integrated Database (eGRID). For Canada, these factors are obtained from Canada's National Inventory Report – Greenhouse Gas Sources and Sinks in Canada.

To calculate indirect GHG emissions from electricity:

1. All billed or metered site energy consumption for each source is converted from native units to MBtu.
2. Total site energy for each source is multiplied by a single CO_2-equivalent (CO_{2eq}) factor that incorporates the contribution of CO_2, CH_4, and N_2O.
    a. In the U.S., these are regional factors according to the eGRID subregions.
    b. In Canada, factors are provided at the provincial level.

[6] District steam assumed delivered at 150 psig saturated steam with a Btu value of 1,194 Btu/pound. Letter communication from Robert P. Thornton, President, International District Energy Association to Felicia Ruiz, EPA Combined Heat and Power Partnership Program Manager, August 15, 2008.

3. Indirect emissions from electric energy consumption are added to indirect emissions from district energy to compute your Indirect Emissions Metrics in Portfolio Manager.
4. Indirect emissions are also added to the Total GHG Emissions.

CALCULATING BIOMASS EMISSIONS

Biomass emissions result from the combustion of biogenic fuels. Biomass emissions from buildings are similar to other direct emissions in that they reflect emissions from onsite fuel combustion. Although combustion occurs onsite, emissions from biomass are typically tracked and reported separately from the direct emissions from fossil fuels. At this time, there is only one biogenic fuel in Portfolio Manager, wood. There is one national factor for emissions from wood that is applied within the U.S. and a different national factor for emissions from wood that is applied in Canada.

To calculate indirect GHG emissions from wood:

1. All meters for wood (the only biomass fuel) are converted from native units to MBtu.
2. Total site energy for wood is multiplied by a single CO_{2eq} factor that incorporates the contribution of CO_2, CH_4, and N_2O.
    a. In the U.S., there is one national factor applied.
    b. In Canada, a single national factor (different from the U.S.) is applied.
3. Emissions resulting from wood are reported as biomass emissions

To allow for a separate evaluation and accounting, biomass emissions are ***not included*** in the Total GHG Emissions.

UNDERSTANDING AVOIDED EMISSIONS FROM GREEN POWER

Green power is a particular type of electricity that is produced from renewable sources (e.g., solar, wind, etc.) and is considered to have zero emissions. The methodology in Portfolio Manager to account for the contribution of green power in an emissions inventory depends on whether the green power is generated onsite or offsite. A complete discussion of green power is available in the Technical Reference for Green Power, at www.energystar.gov/GreenPower.

Offsite Green Power

When you purchase green power that is generated offsite, you are still making a purchase of electricity supplied from the grid. According to standard protocol, there are two associated metrics:

- **GHG Inventory (called "Total GHG Emissions" in Portfolio Manager).** To establish your starting GHG inventory, the standard procedures for electricity are applied. That is, your starting inventory includes the emissions from your electric purchase, irrespective of any adjustments for offsite green power. Choose this metric if you are following the WRI protocol's location-based inventory method.

- **Avoided Emissions.** The calculation of avoided emissions is based on the location where the green power was generated, which could be different than the location of your building. This location is specified in the Renewable Energy Certificate (REC), which quantifies the environmental benefits of your green power purchase. The emissions factors used to compute the avoided emissions are resolved at the same regional level as the factors associated with electric consumption. However, the actual factors are different. Whereas electric emissions associated with use of grid-supplied electricity are computed using what is called the "annual total output emissions rate factor," the avoided emissions from green power are computed using the annual "marginal" or "non-baseload" factors. Use of these factors provides a better estimate of the emissions reductions associated with reduced electricity use, reflecting the fact that when the load decreases, non-baseload or "peak load" power output is reduced first.

Onsite Green Power

When you have an onsite renewable system, the implications for your emissions inventory depend on whether you own the RECs. The RECs quantify the environmental benefit of your green power and they may be sold independently of the energy (kWh). If you do not own the RECs (either not purchased, sold, or arbitraged) then you can no longer claim that your onsite power is "green."

- **GHG Inventory (called "Total GHG Emissions" in Portfolio Manager).** If you own the RECs, then an onsite system is counted as zero emissions in your inventory. If you do not own the RECs, then the onsite system is counted using the system average electric emissions rate for your location.
- **Avoided Emissions.** If you own the RECs, then your avoided emissions are computed using the non-baseload (marginal) factors for your region. If you do not own the RECs, then you have no avoided emissions.

It is extremely important to clarify that emissions from onsite green power are based on the total amount of energy that you consume from your onsite system. Export of renewable energy back to the grid does not change the energy requirements of your building, and therefore does not offset the building's electricity consumption. It is not acceptable to enter a net meter reading that records the difference between the amount that is imported from the grid and the amount that is exported back to the grid (onsite generated electricity should not be net metered). For more information on green power, refer to our Technical Reference on Green Power, at www.energystar.gov/GreenPower.

REFERENCE GHG EMISSIONS FACTORS

Specific GHG emissions factors are presented in the following figures. All factors are applied to your ***site energy consumption*** in MBtu, to find the resulting GHG emissions. Please note that for buildings outside the U.S. and Canada, the U.S. factors are applied by default.

Direct Emissions

Figure 1 summarizes the GHG emissions factors for each fuel for buildings in the United States and Canada. For the U.S., this data is obtained from the published factors in the Federal Register associated with EPA's Final Rule for Mandatory Reporting of Greenhouse Gases.[7] For Canada, most onsite fuels follow the default fuel approach and have one factor per fuel type. To compute these factors, the heating content is obtained from Statistics Canada's Report on Energy Supply and Demand in Canada while the emissions factors are obtained from the National Inventory Report submitted by Canada to the United Nations Framework Convention on Climate Change.[8]

Natural gas factors in Canada are computed by province to account for difference in gas content and supply across the country. The gas factors for emissions in each province are presented in ***Figure 2***. These figures are determined based on the National Inventory Report submitted by Canada to the United Nations Framework Convention on Climate Change.[9]

Figure 1 – Direct GHG Emissions Factors for the U.S. and Canada

Fuel Type	CO_{2eq} Emissions			
	United States	Canada		
	(kg/MBtu)	(kg/MBtu)	(g/L)	(kg/tonne)
Natural Gas	53.11	*By Province*		
Propane	61.95	64.37	1,544	-
Fuel Oil (No. 1)	73.49	75.10	2,762	-
Fuel Oil (No. 2)	74.2	75.10	2,762	-
Fuel Oil (No. 4)	75.28	75.10	2,762	-
Fuel Oil (No. 5,6)	74.26	78.81	3,175	-
Diesel Oil	75.16	73.98	2,689	-
Kerosene	75.44	71.93	2,569	-
Coal (anthracite)	104.42	122.43	-	3,214
Coal (bituminous)	94.01	100.50	-	2,381
Coke	114.40	116.34	-	3,179

[7] Solid, gaseous, liquid and biomass fuels: Federal Register (2009) EPA; 40 CFR Parts 86, 87, 89 et al; Mandatory Reporting of Greenhouse Gases; Final Rule, 30Oct09, 261 pp. Tables C-1 and C-2 at FR pp. 56409-56410.
Revised emission factors for selected fuels: Federal Register (2010) EPA; 40 CFR Part 98; Mandatory Reporting of Greenhouse Gases; Final Rule, 17Dec10, 81 pp. With Amendments from Memo: Table of Final 2013 Revisions to the Greenhouse Gas Reporting Rule (PDF) to 40 CFR part 98, subpart C: Table C–1 to Subpart C—Default CO2 Emission Factors and High Heat Values for Various Types of Fuel and Table C–2 to Subpart C—Default CH4 and N2O Emission Factors for Various Types of Fuel.
[8] Heat Content: Statistics Canada - Report on Energy Supply and Demand in Canada, Catalogue 57-003 - Text Table 1
Emissions Factors (Other direct Fuels): National Inventory Report 1990-2022: Canada's Submission to the United Nations Framework Convention on Climate Change (April 2024) - Tables A6.1-4, A6.1-5, A6.1-9 to A6.1-11.
[9] Emission Factors (Natural Gas): National Inventory Report 1990-2022: Canada's Submission to the United Nations Framework Convention on Climate Change (April 2024) – Tables A6-1-1 and A6.1-3.

Figure 2 – Direct GHG Emissions Factors for Natural Gas by Canadian Province

Province	CO_{2eq} Emissions (kg/MBtu)	CO_{2eq} Emissions (g/m^3)
Alberta	54.15	1,972
British-Columbia	54.26	1,976
Manitoba	52.86	1,925
New Brunswick	52.97	1,929
Newfoundland and Labrador	52.97	1,929
Northwest Territories	54.26	1,976
Nova Scotia	52.97	1,929
Nunavut	54.26	1,976
Ontario	53.02	1,931
Prince Edward Island	52.97	1,929
Quebec	53.16	1,936
Saskatchewan	52.99	1,930
Yukon	54.26	1,976

Indirect Emissions

For district systems (steam, hot water, and chilled water), the U.S. and Canada each apply single national factors. A similar methodology is applied for each country, but specific factors differ because of the differences in the national grids. For both the United States and Canada, regional factors are applied to determine the emissions associated with electricity.

United States and Canada – District Heating and Cooling

Figure 3 summarizes the GHG emissions factors for district heating and cooling systems in Portfolio Manager for buildings in both the United States and Canada. This data is obtained from the US EPA Climate Leaders Greenhouse Gas Inventory Protocol Core Module Guidance and the US Energy Information Administration (EIA) guidance for the U.S. Department of Energy's Voluntary Reporting of Greenhouse Gases (1605(b)) Program.[10]

[10] For the United States: District Chilled Water: Energy Information Administration (2010); Voluntary Reporting of Greenhouse Gases, 1605(b) Program, Appendix N: Emissions Factors for Steam and Chilled/Hot Water. Steam and Hot Water: EPA (2008) Climate Leaders Greenhouse Gas Inventory Protocol Core Module Guidance - Indirect Emissions from Purchases/Sales of Electricity and Steam.
For Canada: Energy Information Administration (2010); Voluntary Reporting of Greenhouse Gases, 1605(b) Program, Appendix N: Emissions Factors for Steam and Chilled/Hot Water.

Figure 3 – Indirect GHG Emissions Factors for all District Fuels

Fuel Type	CO_{2eq} Emissions (kg/MBtu)	
	United States	Canada
District Steam	66.40	88.54
District Hot Water	66.40	88.54
District Chilled Water - Electric Driven Chiller	52.70	17.19
District Chilled Water - Absorption Chiller using Natural Gas	73.89	73.86
District Chilled Water - Engine-Driven Chiller Natural Gas	49.31	49.29

United States – Electricity

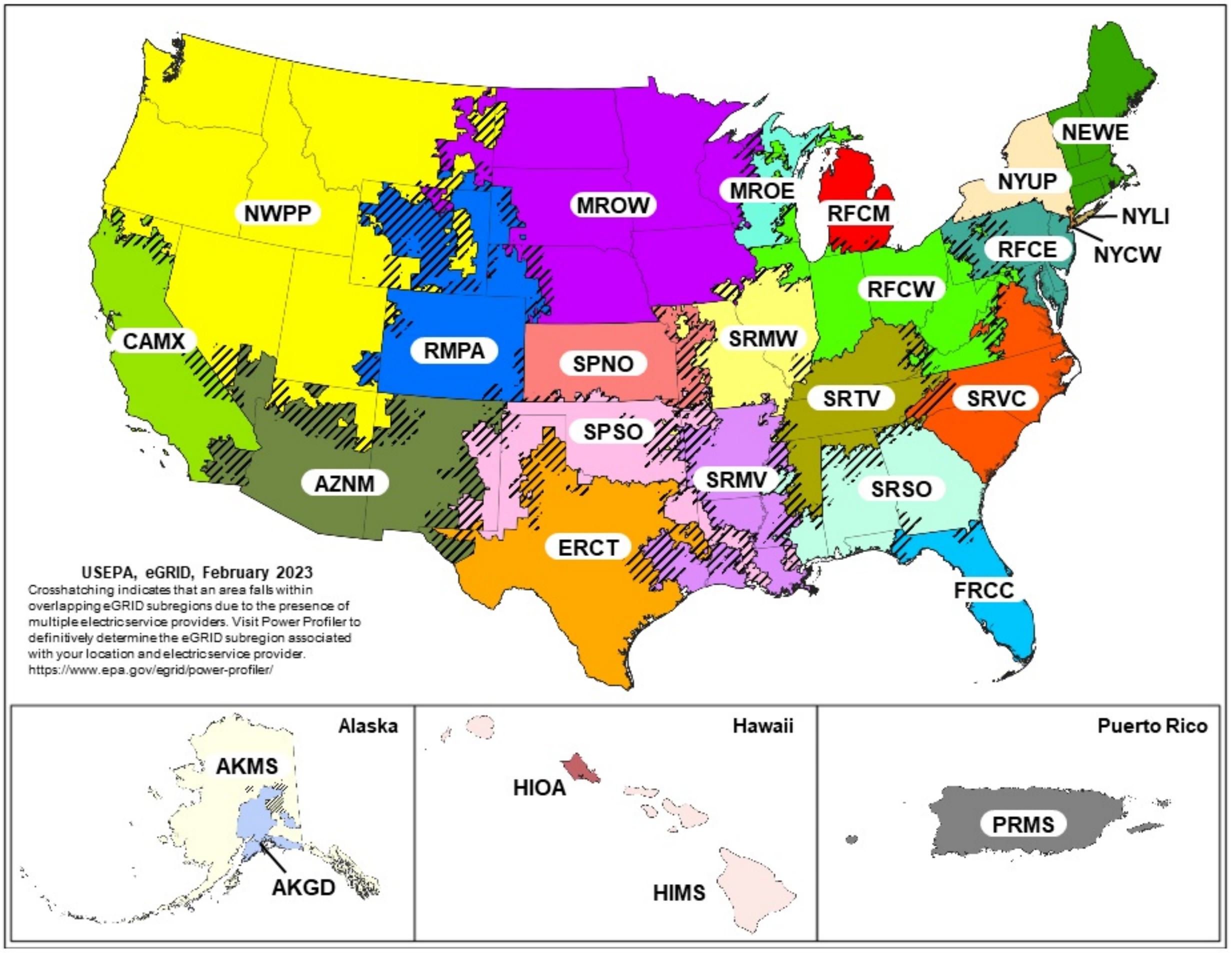
Emissions from electricity production are determined from direct measurement of power plants, who report continuous emissions monitoring system data to EPA. This information is compiled in the U.S. EPA's Emissions & Generation Resource Integrated Database (eGRID).[11] Data in eGRID are available at the power plant level and are also aggregated to state, electric generating company, parent company, power control area, eGRID subregion, NERC region, and the U.S. total levels.

Given the interconnected nature of the electric transmission and distribution system, it is not possible to identify the specific plant that provides electricity to a building. Portfolio Manager maps buildings to eGRID subregions as a practical resolution of electricity origin to determine the emissions factors to apply to a building's electricity consumption. An eGRID subregion represents a portion of the U.S. power grid that is contained within a single North America Electric Reliability Council (NERC) region. These regions have similar emissions and resource mix characteristics and may be partially isolated by transmission constraints. Portfolio Manager locates a building inside an eGRID subregion by mapping its Zip code to its eGRID subregion. In many cases, a Zip code is not confined within one eGRID subregion. In these instances, your electric distribution utility (EDU) will be used to locate your building within an eGRID subregion.[12] ***Figure 4*** presents a map of the eGRID subregions, and the system average emissions factors used to compute indirect emissions are presented ***Figure 5***. These factors represent the average emissions from the all grid-connected electricity generation units (baseload, intermediate, and peaking), and are appropriate for developing a carbon footprint or emissions inventory.

[11] United States Environmental Protection Agency (EPA). 2024. "Emissions & Generation Resource Integrated Database (eGRID), 2022" Washington, DC: Office of Atmospheric Programs, Clean Air Markets Division. Available from EPA's eGRID web site: https://www.epa.gov/egrid.

[12] Zip code mapping accomplished through data from EPA's Power Profiler. https://www.epa.gov/egrid/power-profiler#/

Figure 4 – Map of eGRID Regions



In very rare instances, it is possible that you may have a building that is ***directly connected*** to a specific power plant. In this case, you would have specific power purchasing agreement with an electric utility, so that you know exactly where your electricity is generated. This is more common in large industrial facilities but is occasionally found at commercial properties. In these cases, you can specify that power plant to apply its specific average output emission rate to the site energy consumed from that plant. For reference, plant specific emissions factors may be obtained directly from eGRID.

Figure 5 – Indirect Greenhouse Gas Emission Factors for Electricity in the U.S.

eGRID Regional Description	eGRID Acronym	$CO2_{eq}$ Emissions (kg/MBtu)
South/Central Alaska	AKGD	140.61
Most of Alaska	AKMS	66.14
Southwest US	AZNM	103.60
Southwest Coast	CAMX	66.36
Most of TX	ERCT	102.92
Most of Florida	FRCC	108.58
HI excluding Oahu	HIMS	154.58
Oahu Island	HIOA	210.91
Eastern WI	MROE	197.87
Upper Midwest	MROW	125.38
New England	NEWE	71.84
Northwest US	NWPP	80.53
New York City	NYCW	117.86
Long Island, NY	NYLI	160.73
Upstate NY	NYUP	36.61
Puerto Rico	PRMS	212.66
Mid Atlantic	RFCE	87.76
Most of Michigan	RFCM	162.71
Ohio Valley	RFCW	133.71
CO-Eastern WY	RMPA	150.43
KS-Western MO	SPNO	127.51
TX Panhandle-OK	SPSO	129.62
Lower Mississippi	SRMV	106.83
Middle Mississippi	SRMW	183.44
SE US, Gulf Coast	SRSO	119.31
Tennessee Valley	SRTV	124.76
Virginia/Carolina	SRVC	83.19
National Average		**109.99**

Canada – Electricity

Indirect emissions for electricity in Canada are computed based on the province, to account for differences in electric generation, transmission, and distribution methods. The electric factors for emissions in each region are presented in ***Figure 6***. These values are determined based on the National Inventory Report submitted by Canada to the United Nations Framework Convention on Climate Change.[13]

Figure 6 – Indirect GHG Emissions Factors for Electricity in Canada

Province	CO_{2eq} Emissions (kg/MBtu)	CO_{2eq} Emissions (g/kWh)
Alberta	152.40	520.0
British-Columbia	4.48	15.3
Manitoba	0.64	2.2
New Brunswick	87.92	300.0
Newfoundland and Labrador	4.98	17.0
Northwest Territories	52.75	180.0
Nova Scotia	205.16	700.0
Nunavut	243.26	830.0
Ontario	10.55	36.0
Prince Edward Island	87.92	300.0
Quebec	0.53	1.8
Saskatchewan	205.16	700.0
Yukon	23.45	80.0
National Average	**32.24**	**110.0**

[13] National Inventory Report 1990-2022: Canada's Submission to the United Nations Framework Convention on Climate Change (April 2024) - Tables A13-1 to A13-14.

Biomass Emissions

The only biomass fuel available in Portfolio Manager is wood. In the U.S., the factor for wood, similar to the factors for direct emissions, is obtained from the published factors in the Federal Register associated with EPA's Final Rule for Mandatory Reporting of Greenhouse Gases.[14] The factor for Canada is obtained from the National Inventory Report: 1990-2018.[15]

Figure 7 – Wood GHG Emissions Factors for the U.S. and Canada

Fuel Type	CO_{2eq} Emissions (kg/MBtu)	
	United States	Canada
Wood	94.96	101.75

Avoided Emissions from Green Power

Green power can result in an emissions benefit for your building. Both onsite and offsite green power purchases can be recorded in Portfolio Manager. The benefits of this green power depend upon you actually owning (via purchasing or retaining) the REC associated with the green power.

Your standard emissions inventory (called "Total GHG Emissions" in Portfolio Manager) for electricity applies what are called total output emission rate factors. This factor represents the overall system average for all power generation facilities in your region. To estimate the avoided emissions associated with green power use, we use a different factor, which is called the *non-baseload* or "marginal" factor. This factor represents the emissions from generation facilities that are the first to shut off when demand is reduced, and therefore better estimate the emissions benefits of green power use. In the U.S., these factors are part of the eGRID Database and are summarized in ***Figure 8***.[16]

The exact non-baseload eGRID Sub-region used to calculate Avoided Emissions is determined by the "Generation Location" chosen for each Offsite Green power meter entry:

1. **Specific Plant Selected**– If a specific plant is selected, use the non-baseload eGRID Sub-region emissions factor for that power plant's eGRID Sub-region.
2. **eGRID Sub-region Selected –** If an eGRID sub-region is selected, use the non-baseload eGRID Sub-region emissions factor for that eGRID sub-region.
3. **No Location (I don't know) Selected –** If "no region" is specified, use the smallest non-baseload eGRID Sub-regional factor in the US.

[14] Solid, gaseous, liquid and biomass fuels: Federal Register (2009) EPA; 40 CFR Parts 86, 87, 89 et al; Mandatory Reporting of Greenhouse Gases; Final Rule, 30Oct09, 261 pp. Tables C-1 and C-2 at FR pp. 56409-56410.
Revised emission factors for selected fuels: Federal Register (2010) EPA; 40 CFR Part 98; Mandatory Reporting of Greenhouse Gases; Final Rule, 17Dec10, 81 pp. With Amendments from Memo: Table of Final 2013 Revisions to the Greenhouse Gas Reporting Rule (PDF) to 40 CFR part 98, subpart C: Table C–1 to Subpart C—Default CO2 Emission Factors and High Heat Values for Various Types of Fuel and Table C–2 to Subpart C—Default CH4 and N2O Emission Factors for Various Types of Fuel.

[15] National Inventory Report 1990-2022: Canada's Submission to the United Nations Framework Convention on Climate Change (April 2024) - Table A6.6-1.

[16] U.S. EPA's Emissions & Generation Resource Integrated Database (eGRID). eGRID 2022 (released Jan 2024) contains the complete release of year 2022 data. https://www.epa.gov/energy/egrid.

Figure 8 – Non-Baseload Factors used for Avoided Emissions in the U.S.

eGRID Regional Description	eGRID Acronym	CO_{2eq} Emissions (kg/MBtu)
South/Central Alaska	AKGD	163.82
Most of Alaska	AKMS	211.78
Southwest US	AZNM	160.77
Southwest Coast	CAMX	140.65
Most of TX	ERCT	159.42
Most of Florida	FRCC	139.32
HI excluding Oahu	HIMS	216.71
Oahu Island	HIOA	242.27
Eastern WI	MROE	223.68
Upper Midwest	MROW	240.17
New England	NEWE	123.36
Northwest US	NWPP	202.66
New York City	NYCW	129.35
Long Island, NY	NYLI	175.34
Upstate NY	NYUP	122.66
Puerto Rico	PRMS	222.87
Mid Atlantic	RFCE	170.82
Most of Michigan	RFCM	213.64
Ohio Valley	RFCW	246.65
CO-Eastern WY	RMPA	223.97
KS-Western MO	SPNO	260.03
TX Panhandle-OK	SPSO	204.07
Lower Mississippi	SRMV	162.91
Middle Mississippi	SRMW	242.06
SE US, Gulf Coast	SRSO	180.91
Tennessee Valley	SRTV	223.48
Virginia/Carolina	SRVC	174.85
National Average		**187.90**

For Canada, the factors are summarized in ***Figure 9.*** The marginal fuels are determined for both summer and winter.[17] For both summer and winter, the marginal emissions are calculated by dividing the emission factors[18] for each province's marginal fuel by the energy content of the marginal fuel,[19] and by the expected operating efficiency of the marginal fuel plant.[20] Average marginal fuel emissions are calculated using summer and winter results.

[17] Natural Resources Canada's Analysis Modelling Division for the Energy Policy Branch, in consultation with the provinces and utilities.
[18] National Inventory Report 1990-2022: Canada's Submission to the United Nations Framework Convention on Climate Change (April 2024) – Annex 6.
[19] Statistics Canada's Report on Energy Supply and Demand in Canada, Catalogue 57-003.
[20] Statistics Canada's Annual Thermal plant survey and consultation with the provincial utilities.

Figure 9 – Non-Baseload Factors used for Avoided Emissions in Canada

Province	CO_{2eq} Emissions (kg/MBtu)
Alberta	148.89
British-Columbia	45.13
Manitoba	0.00
New Brunswick	183.76
Newfoundland and Labrador	202.23
Northwest Territories	247.07
Nova Scotia	278.43
Nunavut	247.07
Ontario	46.31
Prince Edward Island	184.94
Quebec	0.29
Saskatchewan	128.66
Yukon	247.07
National Average	**63.60**