U.S. Community Protocol
for Accounting and Reporting of Greenhouse Gas Emissions
Appendix C: Built Environment Emission Activities and Sources

Version 1.1

July 2013

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ICLEI – Local Governments for Sustainability USA

For the latest version of this Protocol, and other tools and resources that can help you report on community GHG emissions, visit www.icleiusa.org.

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Introduction

The built environment includes the human-made surroundings that provide the living and working spaces for human activity, ranging in scale from personal shelter and buildings to neighborhoods and cities that include supporting infrastructure, such as energy networks.[1] Greenhouse gas (GHG) emissions attributed to the built environment include those from government, residential, commercial and industrial buildings; the operational processes and human activities associated with those buildings; and electric vehicle use. These emissions are limited to energy used within buildings, refrigerants, fire suppressants, and industrial processes.

Built environment emissions are attributed to the following sources and activities:

- stationary fuel combustion
- electricity use
- district heating and cooling energy use
- electric power transmission and distribution losses
- life-cycle (i.e. "upstream") emissions from energy use
- electric power production
- refrigerant and fire suppressant leakage
- industrial process emissions

Table 1 below summarizes the built environment sources and activities outlined in this chapter. For each source or activity, the appropriate GHG types, data requirements, and the calculation methodologies are referenced. Details for each calculation methodology are outlined later in this Appendix. For any source or activity, methodologies may be substituted with those obtained from approved regulatory agencies.

[1] U.S. Department of Energy (DOE). *2008 Buildings Energy Data Book*. Prepared for the U.S. Department of Energy Office of Energy Efficiency and Renewable Energy by D&R International, Ltd. Silver Spring, MD. September 2008.

Table BE.1 Summary of Built Environment GHG Emission Sources

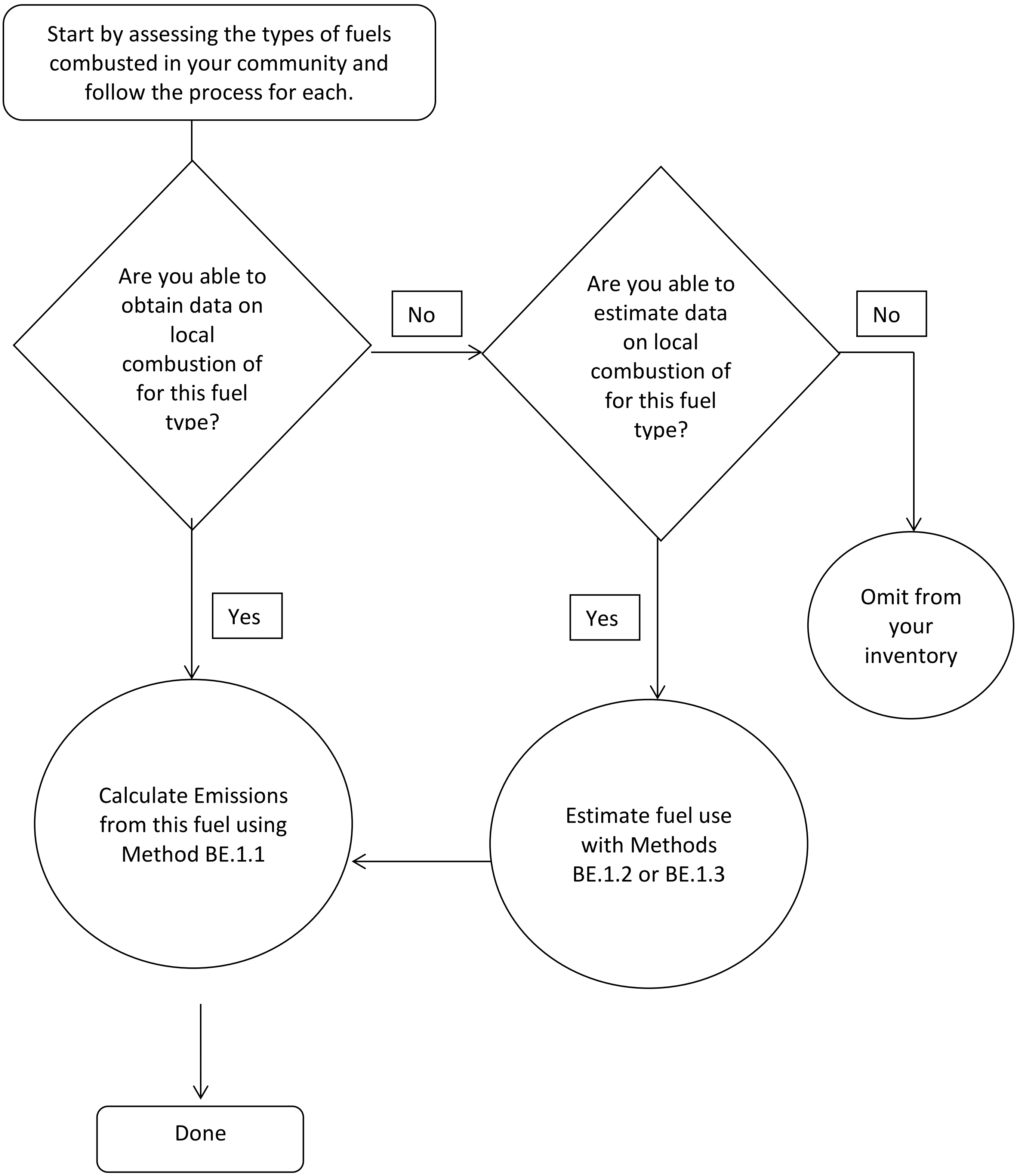
GHG Source	GHG Types	Data Required	Available Methodologies
Emissions from Stationary Fuel Combustion	CO_2, CH_4, N_2O	Annual totals of each fuel combusted by sector	BE.1.1, BE.1.2, BE.1.3
Emissions from Electricity Use	CO_2, CH_4, N_2O	Annual community-wide electricity use by sector	BE.2.1
Emissions from District Heating and Cooling Energy Use	CO_2, CH_4, N_2O	Reported emissions from district energy providers for energy used in the production of delivered heat and chilled water, or total fuels used in the production of delivered heat and chilled water	BE.3.1, BE.3.1.A
Electric Power Transmission and Distribution Losses	CO_2, CH_4, N_2O	Annual community-wide electricity use by sector	BE.4.1
Upstream Emissions from Energy Use	CO_2, CH_4, N_2O	Annual community-wide electricity use by sector and Annual totals of each fuel combusted by sector	BE.5.1 BE.5.2 BE.5.2.A
Emissions from Electric Power Production	CO_2, CH_4, N_2O, sulfur hexafluoride (SF_6)	Reported emissions by grid-connected electricity generation facilities	BE.6.1, BE.6.1.A.1, BE.6.1.A.2
Refrigerant Leakage and Fire Suppressant Emissions	Hydroflurocarbons (HFCs), Perflurocarbons (PFCs), Refrigerant Blends	Measurement, survey, or estimation of refrigerants and fire suppressant chemicals leaked annually.	BE.7.1, BE.7.1.A
Industrial Process Emissions	Any greenhouse gas	Reported point source emissions by individual facility.	BE.8.1

Uncertainties

It is important to consider the source of data you use in your inventory as it relates to quality and usability of the community emissions profile it will produce. The following methods for stationary combustion provide techniques for estimating energy use of several fuel types using the best available data sources. These may not accurately reflect the conditions in your community. Care should be taken in instances where you believe your local conditions may differ substantially from the average community at the scale of the data you are using, either within the state or region. Further, it is important to recognize that utilizing non-local and non-specific data for your inventory will not be sensitive to energy efficiency measures employed in your community when you perform periodic re-inventories.

BE.1 Emissions from Stationary Fuel Combustion

Chart BE.1.1 Decision tree for calculating emissions from stationary combustion



Introduction
Stationary fuel combustion is a broad category that covers activities which directly combust fuels for the production of heat used in a variety of end-use applications from heating building spaces, providing process heat, and cooking. Within this broad category, there are multiple types of fuels that are used in the various applications that could range from large industrial operations to a small residential wood stove. Because of this complexity, obtaining complete and accurate data across all fuel types will be a challenging exercise for most communities.

Natural gas is likely to be the most widely used stationary fuel in your community used in residential and commercial applications alike. Similar to electricity, natural gas will be distributed to customers in your community through a distribution system that is controlled by one, or perhaps a small number of natural gas utilities that serve your community. This should allow you to obtain aggregate natural gas use information for your entire community for both residential and commercial end-uses. It may also be possible to obtain industrial use as a separate classification from commercial use, depending on the classification system used by the natural gas utility. However, in some circumstances disclosure of industrial use may be limited by privacy restrictions where a few large industrial consumers dominate that share and by disclosing it at a fine resolution might risk revealing use of individual firms. Where possible, a division between commercial and industrial uses will give local policy makers better information into the types of end-uses that can be improved with efficiency initiatives separated from the energy use associated with unique industrial and manufacturing processes employed by the businesses in your community.

Data availability for most other fuel types will likely be limited in your community except in those circumstances where the vast majority of your community is serviced by a single supplier who is willing to provide data for the purpose of your inventory. Other fuel types are not tracked closely by local government agencies, and in these cases estimates must be used based on state-level or even regional data attributed to residential and commercial sectors in your community. Industrial energy use is not generally available at any scale that can be made useful for a local inventory, except in those cases where a facility is required to report its emissions either to the USEPA or a state agency where mandatory reporting may be required.

BE.1.1 Calculating Emissions from Stationary Fuel Combustion

This method will allow you to calculate emissions from stationary combustion activities. While the procedure is straightforward, obtaining complete data at the community scale will be challenging for most fuels. You should complete this method for each fuel type and sector for which you can obtain or reasonably estimate total fuel usage in your inventory year.

Please note that is you are generating power or heat at your wastewater treatment facility or landfill, and the electricity and/or heat are consumed entirely within the facility, you should report the combustion emissions from generating that power in either Appendix F: Wastewater

Emission Activities and Sources, or Appendix E: Solid Waste Emission Activities and Sources, not in Appendix C: the Built Environment Emissions Activities and Sources. If you generate power that is distributed outside your facility, report those emissions in Appendix C: the Built Environment Emissions Activities and Sources.

Recommended Approach:
Calculating emissions from stationary combustion using fuel use activity data and default emission factors by fuel type involves the following six Steps:

1. Determine annual use of each fuel combusted by each sector (residential, commercial, industrial) in your community;
2. Determine the appropriate CO_2 emission factors for each fuel;
3. Determine the appropriate CH_4 and N_2O emission factors for each fuel;
4. Calculate each fuel's CO_2 emissions;
5. Calculate each fuel's CH_4 and N_2O emissions; and
6. Convert CH_4 and N_2O emissions to CO_2 equivalent and determine total emissions.

Step 1: Determine annual use of each fuel combusted in your community.
First, identify all fuels combusted by each sector in your community for which you will be able to obtain data. Examples of fuel types include bituminous coal, residual fuel oil, distillate fuel (diesel), liquefied petroleum gas (LPG), and natural gas.

Then determine your annual fuel use by fuel type, measured in terms of physical units (mass or volume). This will most likely only be available for natural gas, however if other fuel types are delivered to your community by a small number of suppliers, it may be possible to obtain total sales of other fuels within the community for your inventory year. Data on fuels other than natural gas burned at certain industrial facilities may be available from state or regional air quality permitting agencies.

For fuels for which you are unable to obtain data, alternate methods for estimating fuel use for a limited number of fuels are provided in section BE.1.2 and BE.1.3. As with any estimation technique, these methods should be used with caution as they may not accurately reflect local circumstances well. Your knowledge of your community and best judgment considering the issues raised in the section on uncertainty should help you to determine whether to use the alternate methods provided here or omit the fuels for which you have been unable to locate actual data.

Step 2: Select the appropriate CO_2 emission factor for each fuel.
The Protocol provides default emission factors for a wide variety of fuels in Table B.1.

Emission factors are provided in units of CO_2 per unit energy and CO_2 per unit mass or volume.
Please note that if you are combusting non-fossil fuels or fuels partly derived from biomass, these CO_2 emissions are considered biogenic and should be reported separately as an

Information Item. See Table B.2 for default emission factors for non-fossil fuels. Note that CH_4 and N_2O emissions from biomass are not considered biogenic and those emissions should be reported.

Step 3: Select the appropriate CH_4 and N_2O emission factors for each fuel.
Estimating CH_4 and N_2O emissions depend not only on fuel characteristics, but also on technology type and combustion characteristics, usage of pollution control equipment, and maintenance and operational practices. Due to this complexity, estimates of CH_4 and N_2O emissions from stationary sources are less certain than estimates of CO_2 emissions. CH_4 and N_2O also account for much smaller quantities of emissions from stationary combustion than CO_2.

Use Table B.3 and Table B.4 to obtain default emission factors by fuel type and sector. The difference in factors for each sector accounts for the different characteristics in the combustion equipment for typical residential, commercial, and industrial applications.

Step 4: Calculate each fuel's CO_2 emissions and convert to metric tons.
To determine your CO_2 emissions from stationary combustion, multiply fuel use from Step 1 by the CO_2 emission factor from Step 2, and then convert kilograms to metric tons. Repeat the calculation for each sector and fuel type. See Equation BE.1.1.1.

Equation BE.1.1.1	**Calculating CO_2 Emissions From Stationary Combustion (gallons)**
Fuel A CO_2 Emissions (metric tons) = Fuel Used (gallons) × Emission Factor (kg CO_2/gallon) ÷ 1,000 (kg/metric ton)	
Fuel B CO_2 Emissions (metric tons) = Fuel Used (gallons) × Emission Factor (kg CO_2/gallon) ÷ 1,000 (kg/metric ton)	
Total CO_2 Emissions (metric tons) = CO_2 from Fuel A (metric tons) + CO_2 from Fuel B (metric tons)	
Note that Equation BE.1.1.1 expresses fuel use in gallons. If fuel use is expressed in different units (such as short tons, cubic feet, MMBtu, etc.), replace "gallons" in the equation with the appropriate unit of measure. Be sure that your units of measure for fuel use are the same as those in your emission factor.	

Step 5: Calculate each fuel's CH_4 and N_2O emissions and convert to metric tons.
To determine your CH_4 emissions from stationary combustion, multiply your fuel use from Step 1 by the CH_4 emission factor from Step 3, and then convert kilograms to metric tons. Repeat the calculation for each sector and fuel type. See Equations BE.1.2-BE.1.5

Equation BE.1.1.2	Calculating CH_4 Emissions From Stationary Combustion (MMBtu)
Fuel/Sector A CH_4 Emissions (metric tons) = Fuel Use (MMBtu) × Emission Factor (kg CH_4/MMBtu) ÷ 1,000 (kg/metric ton)	
Fuel/Sector B CH_4 Emissions (metric tons) = Fuel Use (MMBtu) × Emission Factor (kg CH_4/MMBtu) ÷ 1,000 (kg/metric ton)	
Total CH_4 Emissions (metric tons) = CH_4 from Type A (metric tons) + CH_4 from Type B (metric tons)	

Equation BE.1.1.3	Calculating CH_4 Emissions From Stationary Combustion (gallons)
Fuel/Sector A CH_4 Emissions metric tons) = Fuel Use (gallons) × Emission Factor (kg CH_4/gallon) ÷ 1,000 (kg/metric ton)	
Fuel/Sector B CH_4 Emissions (metric tons) = Fuel Use (gallons) × Emission Factor (kg CH_4/gallon) ÷ 1,000 (kg/metric ton)	
Total CH_4 Emissions (metric tons) = CH_4 from Type A (metric tons) + CH_4 from Type B (metric tons)	

Equation BE.1.1.4	Calculating N_2O Emissions From Stationary Combustion (MMBtu)
Fuel/Sector A N_2O Emissions (metric tons) = Fuel Use (MMBtu) × Emission Factor (kg N_2O/MMBtu) ÷ 1,000 (kg/metric ton)	
Fuel/Sector B N_2O Emissions (metric tons) = Fuel Use (MMBtu) × Emission Factor (kg N_2O/MMBtu) ÷ 1,000 (kg/metric ton)	
Total N_2O Emissions (metric tons) = N_2O from Type A (metric tons)+ N_2O from Type B (metric tons)	

Equation BE.1.1.5	**Calculating N_2O Emissions From Stationary Combustion (gallons)**
Fuel/Sector A N_2O Emissions (metric tons) = Fuel Use (gallons) × Emission Factor (kg N_2O/gallons) ÷ 1,000 (kg/metric ton)	
Fuel/Sector B N_2O Emissions (metric tons) = Fuel Use (gallons) × Emission Factor (kg N_2O/gallons) ÷ 1,000 (kg/metric ton)	
Total N_2O Emissions (metric tons) = N_2O from Type A (metric tons) + N_2O from Type B (metric tons)	
Note that Equation BE.1.1.2 and Equation BE.1.1.4 express fuel use in MMBtu, while Equation BE.1.1.3 and Equation BE.1.1.5 express fuel use in gallons. If your fuel use is expressed in MMBtu use Equation BE.1.1.2 and Equation BE.1.1.4. If your fuel use is expressed in gallons, use Equation BE.1.1.3 and Equation BE.1.1.5. If your fuel use is expressed different units (such as short tons, cubic feet, etc.), you must convert your fuel use data to units of MMBtu or gallons. Be sure that your units of measure for fuel use are the same as those in your emission factor.	

Follow the same procedure above, using Equation BE.1.1.4 or Equation BE.1.1.5, to calculate total emissions of N_2O in your community for each fuel type.

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

Use Equation BE.1.1.6 and United Nations International Panel on Climate Change (IPCC) global warming potential factors[2] to convert CH_4 and N_2O emissions to units of CO_2 equivalent. Sum the emissions of all three gases to determine your total GHG emissions from stationary combustion for each sector.

Equation BE.1.1.6	**Converting to CO_2e and Determining Total Emissions**
CO_2Emissions (metric tons CO_2e) = CO_2Emissions (metric tons) × GWP_{CO2}[3]	
CH4 Emissions (metric tons CO_2e) = CH4 Emissions (metric tons) × GWP_{CH4}[4]	
N_2O Emissions (metric tons CO_2e) = N_2O Emissions (metric tons) × GWP_{N2O}[5]	
Total Emissions (metric tons CO_2e) = CO_2 (metric tons CO_2e) + CH4 (metric tons CO_2e) + N_2O (metric tons CO_2e)	

[2] See Appendix GWP for value.
[3] See Appendix GWP for value.
[4] See Appendix GWP for value.
[5] See Appendix GWP for value.

BE.1.2 Estimating Fuel Use in the Residential Sector

For most communities, obtaining complete data on fuel oil, kerosene, wood, and other fuel use in the residential sector will not be possible due to the nature of the distribution process, which can involve many individual private suppliers. In order to account for these sources and recognize that they do contribute to the emissions profile of a community, this protocol provides methods for estimating these sources. Please note that these methods are of coarse resolution and they will not be sensitive to local level variation or changes that may be induced by local climate protection efforts between inventory years.

This method for estimating fuel use is based on census data from the American Community Survey to first define the proportion of households in your community that utilize these fuels. Next, state-level data from the US Energy Information Administration is used to estimate the annual per-household energy intensity for each fuel type. This is performed by dividing total statewide fuel use by the total number of households utilizing the fuel. This method has limitations with currently available data, in that you cannot differentiate between those homes that use a fuel source for primary heat, secondary heat, or simply cooking. These end-uses will have a wide range of actual use. Utilizing this method will apportion total statewide use among a smaller number of households than actually use the fuel, causing the per-household energy intensity for primary heating to be larger than it likely is in reality. However this method does not include those households which use a fuel source for back-up heating, cooking, or other end use, resulting in a smaller total use than may be actually present. While these two dynamics will balance each other to some degree, it is not possible to determine which error will dominate in the final result or the magnitude of the net error. This should be considered in the interpretation of your results.

Recommended Approach:
Estimating stationary energy use in the residential sector involves the following five Steps:

Step 1: Obtain the total number of households in your state that use the fuel type for any purpose from the Energy Information Administration's (EIA) Residential Energy Consumption Survey dataset, Tables HC1.8 – HC1.11.

Step 2: Obtain the total state-level fuel use from the Energy Information Administration (EIA) State Energy Data System (SEDS) for each fuel type.

Step 3: Calculate per-household energy use by dividing total fuel use obtained in Step 2 divided by the total households using the fuel type, obtained in Step 1.

Step 4: Obtain the number of households that use the fuel in your community using American Community Survey data from Census.gov.

Step 5: Calculate total residential fuel use by multiplying per-household energy use, calculated in Step 3 by the total number of households that use the fuel, obtained in Step 4.

The EIA provides this type of data in a number of different formats and combinations of tables. The method above uses a combination of tables and values that will be most widely applicable. Should you be able to obtain more specific data on conditions in your community, you are encouraged to utilize those sources. In all cases the methodologies used and sources of data should be disclosed wherever the results are published.

Step 1: Obtain the total number of households in your state which use each fuel type

The US Energy Information Administration conducts a periodic Residential Energy Consumption Survey (RECS) and publishes the results, most recently for the year 2009. Go to the EIA RECS website and click the "Data" tab and choose the sub-tab for "Household Characteristics." Expand the section for "Fuels Used and End Uses" and locate the table for Census Region, Division, and States appropriate for your area. (Tables HC1.8 – HC1.11). Obtain the total number of households that use the fuel type in your state.

Step 2: Obtain the total state-level fuel use

The Energy Information Administration (EIA) State Energy Data System (SEDS) collects annual fuel use for each sector in each state. Go to the EIA SEDS website and click the "Data" tab and choose "Consumption". Under the section for Consumption Estimates, expand the section for the Full Report and download the State Energy Consumption Estimates report PDF. Within this report there are sets of tables for each state as well as for the US as a whole. Locate Table CT.4 for your state in the State Consumption Tables section of the report. Obtain total use for the fuel type of interest.

Step 3: Calculate energy use per-household

Using the values obtained in Steps 1 and 2, calculate per-household energy use by dividing total fuel use by the total number of households using the fuel. Note that some unit conversions will likely be necessary to obtain this value in the same units as the emissions factors from this protocol.

Step 4: Obtain the number of households that use the fuel in your community

Next locate the number of households in your community that use the fuel. The American Community Survey contains much finer scale data on fuel usage and will provide an estimate for your community separate from the rest of the state.

Go to Census.gov and locate the American Fact Finder tool. As of the writing of this document, this can be located at: http://factfinder2.census.gov/. You will need to add criteria to your search topics to limit the results and find the data you are looking for. Under the Search Options sections, choose Topics. Expand the list to Housing/Physical Characteristics, and choose Home Heating Fuel. Next go to Geographies and choose "Place within a State". Next choose your State and community name from the list and click "Add to Your Selections".

Next click the record for House Heating Fuel. Note that there will be options for 1, 3, and 5-year estimates. The American Community Survey attempts to get a statistically valid sample for every location in at least a 5-year cycle. Smaller communities with smaller annual sample sizes may not have 1 or 3-year estimates available. You should select the lowest number for which data is available for your community. The frequency at which data is updated for your community may introduce significant time lags in data availability. This availability may not keep pace with the frequency that your community will want to monitor fuel consumption. Where this is the case, you may continue to use static values and cite them as the best available data. Doing so will limit decision making with regard to attempts to reduce fuel use. If the resolution of data available here does not meet your community's needs, it is recommended that you develop mechanisms to collect information on local residential fuel use.

Obtain the total households using the fuel. Note that for some less common fuels, the margin of error is significant. This should be taken into consideration when interpreting your final results.

Step 5: Calculate total residential fuel use
Finally calculate total fuel use by multiplying per-household energy use, calculated in Step 3 by the total number of households that use the fuel, obtained in Step 4.

Use this result in Method BE.1.1 for estimating emissions from this fuel type in the Residential Sector.

BE.1.3 Estimating Fuel Oil Use in the Commercial Sector

Estimating fuel oil use in commercial buildings is subject to many of the same limitations as the procedure described above for performing similar estimations of fuel use in the residential sector. Also note that while Method BE.1.2 allowed for many different fuel types in the residential sector, the data available for the commercial sector is more limited, and fuel oil is the only fuel that can be estimated using this method. You will need to rely on local data in order to include other fuel types in this category. Note that this method will only be needed in those cases where you believe commercial fuel oil use is wide-spread in your community. For many communities in the south and west of the country, commercial fuel oil use is likely insignificant, however variations of this method could be applied to estimate the use of other uncommon fuels.

Recommended Approach:
Estimating stationary energy use in the commercial sector involves the following five Steps:

Step 1: Obtain data on commercial buildings in your community.

Step 2: Calculate the total number of buildings that use the fuel in your community by applying the appropriate factor from Table B.6 for your region.

Step 3: Classify your community's buildings according to building age, size, or primary usage depending on the information that is available in you building records.

Step 4: Estimate the total square footage of building space in each class, by using either known building information or by applying a best available average building size.

Step 5: Calculate total fuel usage by applying the appropriate building energy intensity factor from Table B.7 which matches your building classifications.

Step 1: Obtain data on commercial buildings in your community
Your community's tax assessor or planning agency may keep records of the total number of commercial buildings and their characteristics. The principle characteristics that should be collected include the commercial building's square footage, principle building activity, and year constructed as fuel oil and fuel usage data are available (see Table B.6 and Table B.7). However, obtaining as much data as you are able will help you better classify your buildings to estimate fuel oil and fuel use from other data sources specific to the building's location.

Step 2: Calculate the total number of buildings that use the fuel oil in your community
Table B.6 contains an average proportion of the commercial buildings in your census region that utilize fuel oil. Multiply the total number of buildings by this value to calculate the total number of buildings that use fuel oil. Note that there may be more locally specific data available to you from your local tax assessor, planning, or energy agency.

Step 3: Classify your community's buildings
Using the best information available, classify your buildings according to the groups listed in Table B.7. Table B.7 provides multiple types of groupings that will allow you some flexibility in approaching the calculation using the most complete data that is available to you. Note that if you are unable to classify your buildings due to lack of reliable data, you may omit this Step and utilize the value for "All Buildings" in Step 5. With the resolution of the data available from EIA for this method, there are widely applicable rules that will help you determine whether any particular classification for the building space in your community will be more accurate than another. Any number of local variables from specific climate, history of building codes, and economic profile will have an influence on actual fuel use. Classification by building age is likely to have the most widely available data.

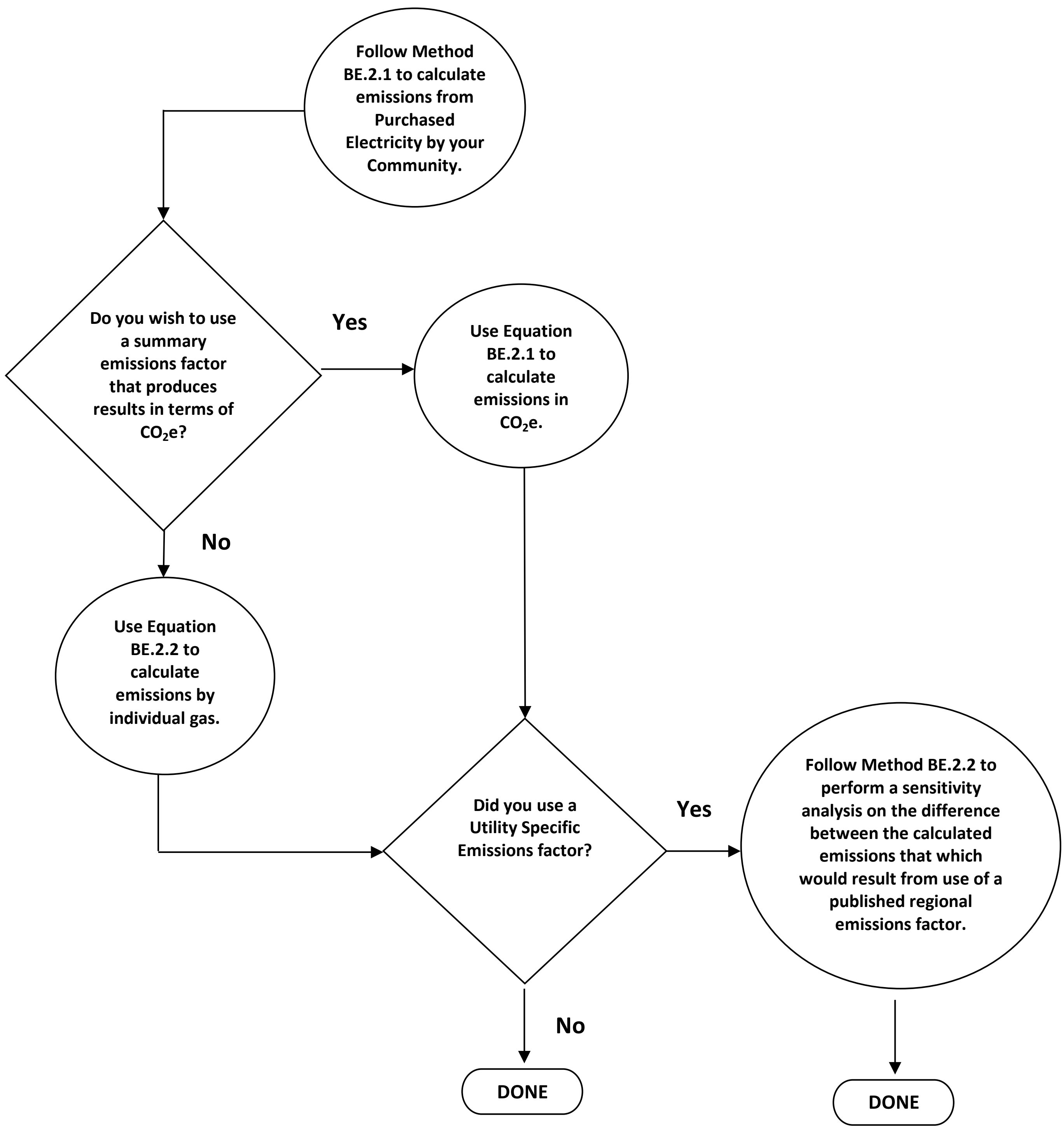
Step 4: Estimate the total square footage of building space in each class
Using the best information available, calculate the total amount of building space in each class. You may be able to do this with specific data. Otherwise you may use an appropriate average building size for your community.

Step 5: Calculate total fuel usage
Calculate total fuel usage by multiplying the square footage of each building class by the energy intensity figure available in Table B.7. Note that these values are from the most recently available Commercial Building Energy Consumption Survey, which was in 2003. If more recent data is available which is closer to your inventory year, please use that data.

With total commercial sector fuel oil use estimated in your community, you can now complete method BE.1.1 for this sector and fuel type.

BE.2 Emissions from Electricity Use

CHART BE.2.1: Decision Tree for Reporting Emissions from Purchased Electricity



Introduction

Estimating GHG emissions related to community electricity use is relatively straightforward. Most communities purchase all of their electricity from utilities that generate electricity in power plants located outside the community boundary. GHG emissions of this type are calculated by multiplying the community's annual electricity use in kWh or MWh (i.e., the "activity factor") by the appropriate average annual electricity GHG emission factor (typically in pounds of CO_2e per MWh). Annual electricity use data is generally available from the utility(s) serving the community and guidance on emission factor selection is provided below.

To keep the calculation of electricity use emissions manageable, meaningful, and actionable, this chapter of the Protocol does not attempt to separately account for direct and indirect (or in-boundary and out-of-boundary electricity emissions). Rather, it estimates net electricity-related emissions based on the total annual electricity used by a community multiplied by the average annual electricity emission factor for the utility providing the electricity. This method addresses only emissions at the point of power generation; emissions associated with producing and transporting the fuels used to generate electricity are addressed separately, in Method BE.5. The local utility emission factor is used, if available, (rather than a state or regional average emissions factor) because there is a wide diversity in power mixes and emissions factors by utility. In some cases, the city or county owns the utility and that community still has a choice from where it acquires its electricity. Even when the utility is not city-owned, communities may have indirect ability to influence (and pay for) the carbon intensity through political and regulatory processes (for example, passage of state-level renewable portfolio standards). Using utility-level emissions factors will allow local communities to more accurately reflect the actual carbon intensity of the electricity they are purchasing and reflect the impacts of any policies for clean power purchases, renewable portfolio standards, etc.

Renewable Energy Credits (RECs).

RECs allow electricity users to purchase the environmental benefits of renewable energy that is generated somewhere else. RECs can be a valuable policy tool to support development of low-carbon energy production. However, this Protocol does not count emissions reductions from RECs, because the inventory purpose is to account for overall emissions. In addition, eGRID does not separate out purchase or sale of RECs in calculation of regional emissions factors.

While it is common for utilities to provide data for the residential, commercial, and industrial business sectors, every effort should be made to obtain data for electricity use by electric vehicles operated in the community. These data are <u>not</u> accounted for in Appendix D: Transportation and Other Mobile Emission Activities and Sources.

Recommended Approach

The following steps should be used to calculate GHG emissions from electricity use in your community. Please note, multiple electricity utilities may service your community - including traditional electricity utility companies, Energy Service Providers (ESPs), Community Choice

Aggregators (CCA), and other similar organizations. As such, the following steps should be completed for each electricity utility serving your community;

Step 1: Obtain your community's annual electricity use in kWh or MWh for each electricity utility serving your community;

Step 2: Select or obtain the appropriate emission factor for the electric utility serving the community; and then

Step 3: Calculate the annual GHG emissions associated with the direct combustion of fuels to produce electricity used by the community.

Data Needs

There are two pieces of data required:

1. The community's annual electricity use in kWh or MWh for each electricity utility serving your community, and

2. The electricity emission factor(s) for the utility or utilities providing electricity to the community.

   Note: This emissions factor should account for both utility-owned power plant emissions, exported electricity sold from utility-owned power plants, and imported electricity purchased from generation plants not owned by the utility. Transmission and distribution losses are accounted for separately and should not be included.

   Electricity emission factors vary from year to year. Principally, the emission factor for the reporting year should be used. However, if the reporting year emission factor is not available, the most recently reported emission factor available should be used as a proxy until a reporting-year emission factor becomes available.

   The recommended sources for utility electricity emission factors, in order of preference and accuracy, are summarized below.

   A. Utility-specific electricity GHG emission factors[6] that have been third-party verified.[7] The Climate Registry's Power/Utility Protocol[8] is currently the most widely used standard for developing utility-specific emissions factors.

[6] Utility-specific electricity emission factors may be obtained through The Climate Registry, by request to the utility servicing your community, a state GHG regulatory agency, or by similar organizations.

[7] The Climate Registry maintains the process for third-party verification and a listing of registered third-party verifiers. More information can be found at http://www.theclimateregistry.org/resources/verification/.

B. Utility specific emission factors that have not been verified by third-parties but have been calculated according to The Climate Registry's Power/Utility Protocol.

C. Other utility reported electricity emission factors that have not been third-party verified, but are deemed to be accurate. The community should consult its electricity utility to see if GHG emission factors are available. Emission factors may be calculated for internal, regulatory, or other purposes, but may not have been registered with The Climate Registry or the California Climate Action Registry. These emission factors may be used if they are believed to be an accurate representation of the utility's total delivered electricity (including purchased/imported electricity).

D. If utility-specific emission factors are not available, regional emission factors should be used. Regional emissions factors include the U.S. EPA's eGRID electricity emission factors by eGRID Sub-region[9] and California Air Resources Board Emissions Inventory Data.[10]

If a community is able to utilize a third-party verified utility-specific emissions factor, it is recommended (though not required) that the community conduct an emissions factor sensitivity analysis. This sensitivity analysis includes measuring the difference between the reported third-party verified utility-specific emissions factor and the corresponding eGRID emissions factor. The corresponding difference will potentially highlight any disparity in a community's emissions that may result from low-emissions or high-emissions sources from local or inter-state electricity transmission. A sensitivity analysis will provide the community the ability to report emissions appropriately for their respective community's greenhouse gas characteristics. See BE.2.2 for additional details.

BE.2.1 Emissions from Electricity Use

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[8]http://www.theclimateregistry.org/resources/protocols/general-reporting-protocol/

[9] The Emissions & Generation Resource Integrated Database (eGRID) is a comprehensive source of data on the environmental characteristics of almost all electric power generated in the United States. These environmental characteristics include air emissions for nitrogen oxides, sulfur dioxide, carbon dioxide, methane, and nitrous oxide; emissions rates; net generation; resource mix; etc. At the time of writing, eGRID2012 Version 1.0 is the most recent release. This is the eighth edition of eGRID, which contains data for 2009, 2007, 2005, and 2004. eGRID is available online, http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html. Note that eGRID data lags by several years. Also note that eGRID does not account for electricity imports, which can be significant.

[10] The California Air Resources board publishes California-specific emission factors based on the total in-state and imported electricity emissions divided by the state's total electricity use. These current and historical California Emissions Inventory Data are available online, http://www.arb.ca.gov/ei/emissiondata.htm.

To calculate GHG emissions from your community's electricity use, use the following steps. If multiple utilities serve the community, this process will need to be repeated for each utility and the results added.

Step 1: Obtain your community's annual electricity use. Electricity use will be provided in either kilowatt-hours (kWh) or megawatt-hours (MWh). If the data is provided in kWh, divide by 1,000 to convert to MWh. The electricity utility serving the community should be able to provide aggregated annual community electricity use data. Some utilities may not have had this type of request before, so it may take some discussion and negotiation, but most communities have found that they can obtain this information readily.

At a minimum, total community electricity use is required. Ideally, electricity use would be broken out by residential, commercial, industrial, and municipal sectors, or similar subdivisions that provide additional insight into where the electricity is being used within the community. This will be useful for a city to help identify mitigation opportunities and track progress in different sectors. Depending on the utility billing structure, it may be difficult to break out all of these subdivisions (e.g., the utility may not distinguish between large residential accounts such as apartments, commercial, and industrial customers, but rather structure its billing rates by use levels such as small, medium, and large electricity consumers). Note: utilities cannot provide data that could potentially identify the electricity use of individual customers. For example, if there was a single or predominant large industrial customer in a community, the utility may not be able to break out industrial customers, but should be able to provide aggregate community electricity use.

Step 2: Select or obtain the appropriate emission factor(s) for the electric utility serving the community. An electricity emission factor represents the amount of GHG's emitted per unit of electricity delivered and typically has units of pounds of CO_2 equivalent per megawatt-hour (lbs-CO_2e/MWh). CO_2e includes all of the different GHG gas emissions associated with electricity generation converted to a common unit of CO_2e. Note that separate emission factors are sometimes reported for the three primary GHGs emitted during electricity production: CO_2, CH_4, and N_2O. If this is the case, separate emission coefficients for each gas must be obtained and then converted to CO_2e as described in Step 3.

Example Calculation: Convert 1,000 lb-CO_2/kWh into metric tons CO_2 /GJ

$$1{,}000\ \frac{\text{lb C}}{\text{kWh}} \times 277.8\ \frac{\text{kWh}}{\text{GJ}} \times 0.0004536\ \frac{\text{metric tons}}{\text{lb}} \times 44/12\ \frac{CO_2}{\text{C}} = 462.04\ \frac{\text{metric tons } CO_2}{\text{GJ}}$$

Step 3: Calculate the community's annual CO_2e emissions associated with electricity use. The following calculations should be performed for the community's total electricity use. If breakouts for electricity use by sector or other breakdowns are available, use the same formulas to calculate their emissions.

If a single CO_2e emission factor was obtained in Step 2, then calculate the total equivalent CO_2 emissions from electricity use from Equation BE.2.1

Equation BE.2.1 Calculating Electricity GHG Emissions Using a CO_2e Emission Factor
Annual CO_2e emissions (metric tons/year) = $\dfrac{electricity \times CO_2\ e\ emission\ factor}{2204.6}$ Where: • Electricity is the community's annual electricity use in MWh from Step 1, • the CO_2e emission factor is the combined carbon dioxide *equivalents* emission factor from Step 2, if available, and • 2204.6 is the conversion factor to convert from pounds to metric tons

If individual emission factors for CO_2, N_2O and CH_4 were obtained in Step 2, then calculate the total equivalent CO_2e emissions from electricity use from Equation BE.2.2

Equation BE.2.2 Calculating Electricity GHG Emissions Using Separate CO_2, N_2O, and CH_4 Emission Factors
Annual CO_2e emissions (metric tons/year) = $$\frac{electricity}{2204.6} \times \begin{pmatrix} CO_2\ emission\ factor \\ +21 \times CH_4\ emission\ factor \\ +310 \times N_2O\ emission\ factor \end{pmatrix}$$ Where: • electricity is the community's annual electricity use in MWh from Step 1,   • the CO_2 emission factor is the individual CO_2 emission factor from Step 2 (lb/MWh),   • the CH_4 emission factor is from Step 2 (lb/MWh),   • the N_2O emission factor is from Step 2 (lb/MWh),   • Use the CH_4 global warming potential[11] (GWP) to convert from pounds of CH_4 to CO_2e • Use the N_2O global warming potential[12] (GWP) to convert from pounds of N_2O to CO_2e, and   • 2204.6 is the conversion factor to convert from pounds to metric tons.

[11] See Appendix GWP for value.
[12] See Appendix GWP for value.

Box BE.2.1 Example Calculation for GHG Emissions from Electricity Use

Step 1: A community inquired its local utility company, Pacific Gas & Electricity, to obtain the community's total electricity use of 1,000,000 kWh for the 2010 calendar year. Dividing by 1,000 results in a use of 1,000 MWh.

Step 2: Referring to Table B.8, it is found that a 3rd party verified CO_2 emission factor has been reported for PG&E for 2010. CH_4 and N_2O emission factors have not been reported, so California grid average emission factors have been used from Table B.9. Note that the latest available data available is for 2007; per Protocol guidance, the latest values available (2007) are used pending availability of updated data. The following table is filled out to document the emission factors

Electricity Emission Factors Used for the Inventory				
Gas:	CO_2	CH_4	N_2O	CO_2e
Emission factor	444.64	0.029	0.010	n/a
Original units	lb/MWh	lb/MWh	lb/MWh	
Source(s) and notes	3rd party verified emission per *California Air Resources Board, Greenhouse Gas Inventory, 1990 – 2004*	California grid average factor for 2007, per Table B.9. Note, 2010 reporting year data is unavailable, so latest figure is used per protocol guidance	California grid average factor for 2007, per Table B.9. Note, 2010 reporting year data is unavailable, so latest figure is used per protocol guidance	
Emission factor in units of lb/MWh	444.64	0.029	0.010	

Step 3: Equation BE.2.2 is used to calculate the total CO_2e emissions associated with electricity use:

Annual CO_2e emissions =

$$\frac{1,000\ MWh}{2204.6} \times (444.64 + 21 \times\ 0.029 + 310 \times 0.010)$$

$$= 203.4\ metric\ tons$$

BE.2.2 Utility Specific Emissions Factor Sensitivity Analysis

If you have chosen to use a utility specific emissions factor for calculating emissions from purchased electricity, it is recommended that you perform a sensitivity analysis to compare the difference from using that factor to the result obtained using the appropriate regional eGRID emissions factor. Performing this optional analysis will allow you to interpret your inventory results and plan your emissions reduction activities with greater nuance and understanding of the impact of energy efficiency. As the US electrical grid is highly interconnected, the impacts of local action can have impacts on the larger system.

For example, if your local electricity generation mix is relatively clean as compared to the region, electricity conservation may appear to have minimal emissions impact. However, local conservation of relatively clean electricity would create more opportunity to export that electricity back to the wider grid, potentially displacing fossil generation in the region. Performing this comparison will also allow you to demonstrate the impact of local clean generation from your utility as compared to the region.

Step 1: Calculate emissions from purchased electricity according to Method BE.2.1 using the appropriate eGRID factor.

Step 2: Compare the resulting emissions calculated with each factor set and interpret the result for inclusion in your narrative report. You are highly encouraged to seek the input of representatives from your local utility on the differences observed. Variation in the results for an individual year could come from a number of sources, including fuel price fluctuations, availability of water for hydroelectric generation, and so on. Understanding the source of variation will help in your interpretation of the results.

BE.3 Emissions from District Heating and Cooling Energy Use

Your community may have facilities that provide steam or cooling for purchase by nearby customers. These facilities use fuels such as natural gas, electricity, and others and transform the energy in those fuels into useful heat (in the form of steam) or cooling (in the form of chilled water). Emissions in this sector are emitted from local combustion in a boiler, or indirectly from purchased electricity to produce chilled water. Accounting for these sources at the community scale is different from most other organizational or entity-specific protocols that cover this topic. For other types of entity-specific protocols, the purpose is to attribute a portion of the emissions from these sources to the entity using the output energy. At the community scale, the emissions from these sources can be treated like any other direct combustion source or indirect electricity use emissions. To the extent that district energy facilities in your community purchase their input fuels either from the electric grid or from utility provided natural gas, you may have already captured some or all of the emissions from these sources in your calculations for stationary combustion and electricity use. Care should be taken in reporting emissions from these sources to ensure they are not double counted with emissions associated with use of those other energy sources.

While emissions from these sources may have already been accounted for in other parts of your inventory, accounting and reporting of them individually can yield better information for local decision makers. Generally district energy sources can provide heating and cooling more efficiently to the buildings they serve than is achieved with many small heating and cooling systems for individual buildings. In many locations, district energy can be a significant contributor to lowering emissions at the community scale. For these reasons, you may want to account for these sources separately. Gathering other useful indicator data while accounting for these sources can help provide additional context to demonstrate the efficiency of these district energy sources in your community, such as the ratio of delivered energy-to-energy fuels used in the process and the amount of space that is conditioned using these sources.

Accounting for these emissions should be a straightforward exercise working with the operators of the facilities that provide district heating or cooling. Many of district energy suppliers, particularly those that have emissions reporting requirements due to their size, will have calculated their annual emissions already. For these facilities you may obtain total emissions in your inventory year from the facility operator and report them as line items. If the facility has not calculated its emissions already you will need to obtain a record of all the fuels used and follow method BE.1 to calculate emissions.

Recommended Approach:
Obtain direct emissions data from district energy utilities servicing your community attributed to generated from district energy utilities and report them as individual line items.

Alternate Approach:
Obtain data on the fuels used in the production of steam or chilled water and calculate emissions from these sources yourself according to Methods BE.1.1 as appropriate for each fuel source.

BE.3.1 Reporting Emissions from District Heating and Cooling Utilities

For this method you should consult with the district heating and cooling utilities servicing your community. Request data on the direct emissions attributed to the generation of steam or chilled water to service customers in your community. If this data is unavailable, utilize method BE.3.1.A.

BE.3.1.A Alternate Method to Report Emissions from District Heating and Cooling Utilities

Obtain data on the fuels used in the production of steam or chilled water and calculate emissions from these sources yourself according to Method BE.1.1 as appropriate for the fuel source. Note that you should obtain fuel use data that is specific to the production of steam or chilled water. For example, a chilled water plant will have electrical loads for the building itself and for the process of creating chilled water. Only the latter should be accounted separately in this alternate method.

BE.4 Electric Power Transmission and Distribution Losses

Introduction

A certain amount of electricity is lost to heat when electricity is transmitted through power lines. These losses are called transmission and distribution (T&D) losses, and they represent a significant portion of our total electricity generation, ranging from 5.8% to 8.2% depending on the location of your community

It is important to account for the indirect GHG emissions related to these T&D losses in your community's GHG inventory. Reducing your community's electricity use will also reduce the amount of T&D losses associated with delivering this electricity. Furthermore, implementing strategies that encourage local photovoltaic (PV) and other renewable and distributed energy generation will significantly reduce T&D losses associated with transmitting electricity across long distances.

Data Needs

There are three types of data required:

1. Community annual electricity use;
2. The electricity emission factor; and
3. Regional grid loss factor.

BE.4.1 Emissions from Electric Power Transmission and Distribution Losses

To calculate GHG emissions from your community's electricity T&D losses, use the following steps:

Step 1: Obtain your community's annual electricity use, as tabulated in the BE.2.

Step 2: Determine the appropriate CO_2-equivalent (CO_2e) electricity emission factor. Use the same factor (for either eGRID subregion or utility) that you used in calculating emissions from community electricity use in BE.2.

Step 3: Obtain your community's regional electricity T&D loss factor. These are tabulated on an annual or biennial basis in the U.S. EPA's eGRID database.

Step 4: Calculate your T&D CO_2 emissions from Equation BE.4.1.1.

Equation BE.4.1.1 Calculating Electricity GHG Emissions Using a CO_2e Emission Factor
Annual CO_2e emissions (metric tons/year) = $$\frac{Community\ electricity\ use \times grid\ loss\ factor \times CO_2\,e\ emission\ factor}{2204.6}$$ Where: • Electricity is the community's annual electricity use in MWh from Step 1, • the CO_2e emission factor is the combined carbon dioxide *equivalents* emission factor from Step 2 in lbs/MWh, • the grid loss factor is from Step 3, and • 2204.6 is the conversion factor to convert from pounds to metric tons.

Box BE.4.1	**Example Calculation for GHG Emissions from Electricity Use**

Step 1: A community located in the Los Angeles area has a total electricity use of 1,000 MWh, as determined from the electricity use methodology.

Step 2: Referring to Figure A.1, Los Angeles in the "CAMX" eGRID sub-region. Using Table B.11, the sub-regional GHG emission factor is 661.20 lb/MWH. Also note from Table B.11 that CAMX is in the "Western" region.

Step 3: Lookup the Western region's grid loss factor of 8.21% from Table B.12.

Step 4: Equation BE.4.1 is used to calculate the total CO_2e emissions associated with electricity use:

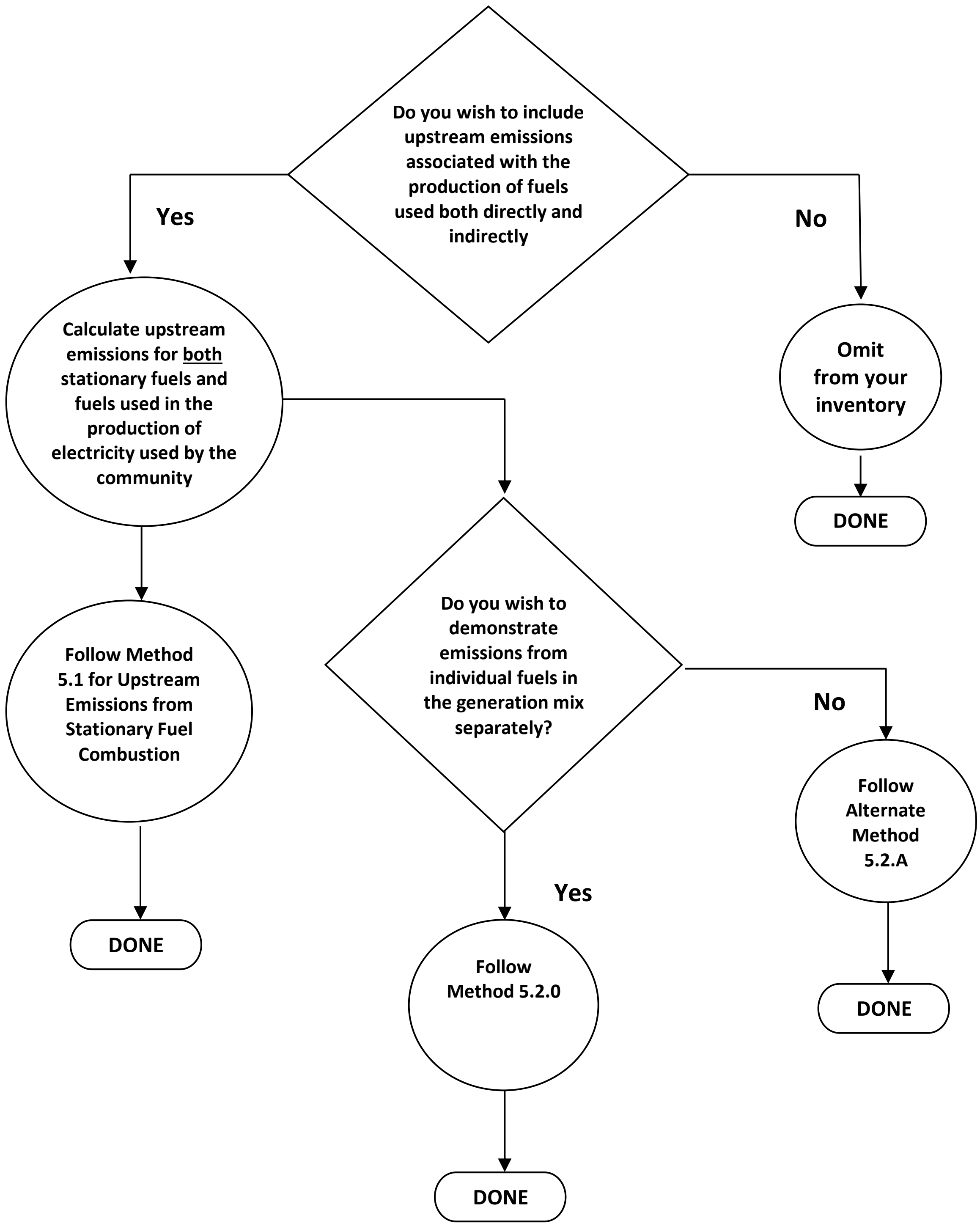
Annual CO_2e emissions =

$$\frac{\mathbf{1{,}000}\ \boldsymbol{MWh} \times \mathbf{8.21\%} \times \mathbf{661.20}\,\frac{\boldsymbol{lb}}{\boldsymbol{MWh}}}{2204.6\,\frac{lb}{metric\ tons}}$$

$$= \mathbf{24.6}\ \boldsymbol{metric\ tons}$$

BE.5 Upstream Emissions from Energy Use

CHART BE.5.1: Decision Tree for Reporting Upstream Emissions from Community Energy Use



Introduction

In addition to estimating GHG emissions that result from combusting fuel to produce electricity and heat, those who develop GHG inventories should also consider including GHG emissions that result from the use of energy required to extract, process, and deliver the fuel to either an electricity generation facility or other points of combustion. These GHG emissions are considered upstream emissions. Upstream emissions should be calculated for both fuels used directly inside the community, such as natural gas, propane, and heating oil, as well as for fuels used in the production of electricity purchased from outside the community.
Upstream GHG emissions considered in this method are limited to the following.

1. Upstream emissions associated with primary fuels. Primary fuels are those fuels that are used directly for the purposes of obtaining useful energy output, such as electricity or heat used by the community. Upstream refers to GHG emissions that occur as part of the extraction and refining of fuels (e.g., direct releases of methane from coal mines).

2. Direct combustion emissions associated with the use of secondary fuels. Secondary fuels are all fuels required to source, prepare, and transport primary fuels, as well as the fuels required to source, prepare and transport the fuels used to source, prepare, and transport primary fuels, and so on up the supply chain.

3. Upstream emissions associated with secondary fuels.

Note that "upstream emissions" refer strictly to the process of producing fuels. Upstream emissions do not include GHG emissions associated with construction, maintenance, and decommissioning of infrastructure (mines, pipelines, refineries, etc.), or the emissions associated with management of wastes, such as spent nuclear fuels.

The Department of Energy's National Renewable Energy Laboratory (NREL) provides national average emission factors derived from its Fuels and Energy Pre-combustion Life Cycle Inventory (LCI) database.[13] This method recommends using NREL LCI GHG emissions factors for determining upstream emissions from energy used within a community boundary.

Uncertainty associated with these methods does exist in the emissions factors from NREL as applied to any particular local. These factors, while widely applicable as national averages do not allow the user to account for differences that could exist if the exact source of a fuel, and technologies and processes used to extract and refine it, is known. The recent increase in unconventional extraction methods complicates the matter further. Hydraulic fracturing ("fracking") methods for natural gas extraction is known to increase methane leakage, causing higher upstream emissions as compared to other forms of natural gas extraction. Similarly, gasoline and other petroleum products derived from tar sands or other "heavy oil" deposits

[13] Deru, M. and Torcellini, P., "Source Energy and Emission Factors for Energy Use In Buildings," NREL Technical Report, NREL/TP-550-38617, Revised June 2007.

require significantly more energy inputs to extract and refine than is the case with traditional liquid deposits. This increases the amount of secondary fuels required to produce each unit of primary fuel that was refined from one of these unconventional deposits.

Due to a lack of available data, upstream emissions from some fuel types are not considered in this method, such as biomass. Also, data on secondary fuel use associated with the production of many fuel types beyond the most common (natural gas, coal, and fuel oil) are not widely available and not currently included in this protocol.

Where accurate additional data of these secondary fuel uses and upstream emission factors are known, they should be included. Moreover, where accuracy and precision of specific fuel types are greater than the data provided in this method, the community is encouraged to utilize these data. Whenever such factors are utilized, data sources should be disclosed by way of citation and description for their usage.

BE.5.1 Upstream Emissions from Stationary Fuel Combustion

Each of the fuels combusted directly within your community has upstream emissions associated with them. These include upstream emissions associated with the primary fuels (those combusted directly in your community) as well as emissions associated with secondary fuels (those used in the supply chain of the primary fuels). Upstream emissions from stationary fuel combustion are calculated for each fuel type individually and this calculation will need to be repeated for each fuel type used in your community. Note that this method covers fuels that are used directly in your community, but includes the emissions from associated secondary fuels. To calculate upstream emissions from purchased electricity, you must first estimate primary fuel use according to Method BE.5.2, then you can apply this method to the quantities of those fuels.

Data Needs

Aggregated use data of each stationary fuel used, gathered for the purposes of Method BE.1 (Stationary Combustion) or as estimated in Method BE.5.2 (Upstream Emissions from Purchased Electricity), including:

- Natural Gas
- Fuel Oil
- Coal
- Kerosene

This method is completed in four steps, though it will need to be repeated for each combination of sector and fuel type:

Step 1: Obtain fuel use for each fuel type and sector determined to complete Methods BE.1 and/or BE.3.1.

Step 2: Convert units of fuel to those used in the emissions factors table as necessary (for example, cubic feet for natural gas or gallons for distillate fuel oil).

Step 3: Calculate upstream emissions for each primary fuel used (from Steps 1 and 2) by multiplying the total amount of each primary fuel used by the appropriate CO_2e factor from Table B.13.

Step 4: Sum Upstream emissions

Equation BE.5.1.1 **Upstream emissions associated with stationary fuel use within a community. Note: this is for primary fuels only and also applies to primary fuels combusted outside of the community for generating electricity used by the community.**		
Annual CO_2e *emissions* $=\Sigma(\textit{Total Fuel Use}_{\textit{Fuel Type}} \times \textit{Conversion Factor} \times \textit{Upstream EF}) \times 10^{-3}$ Where:		
Description		Value
Annual CO_2e	= Total annual CO_2e emitted by upstream activities ($mtCO_2e$)	Result
Total Fuel $Use_{Fuel\ Type}$	= Total annual fuel of each type used in a community and sector	User Input
Conversion Factor	= Conversion factor to obtain the same units of fuel used in Table B.13	User Input
Upstream EF	= Fuel specific upstream emissions factor from Table B.13	User Input
10^{-3}	= Conversion from kg to metric ton (mt/kg)	10^{-3}

***Example BE.5.1.1* Upstream emissions associated with Natural Gas used within the residential sector of a community.**		
A community used 1,000,000 m^3 of natural gas in the residential sector, in the inventory year.		
Annual CO_2e	= Total annual CO_2e emitted by upstream activities (mt CO_2e)	Result
Total Natural Gas Use	= Total annual Natural Gas Use in m^3.	1,000,000
Conversion Factor	= Conversion factor to obtain the same units of fuel used in Table B.13(m^3 to 1,000 m^3).	10^{-3}
Natural Gas Upstream Emissions Factor	= kg CO_2e per 1,000m^3 of Natural Gas, obtained from Table B.13	4.45×10^{-1}
Natural Gas Primary Fuel Upstream Emissions (mtCO_2e)=	*= $(1{,}000{,}000 \times 10^{-3} \times 4.45\times10^{-1})\times10^{-3}$* = 0.445 mt CO_2e	

BE.5.2 Upstream Emissions from Electricity Use

This section describes the calculation of upstream emissions from electricity used within a community. Included in this calculation are upstream emissions from each primary fuel used in generating the electricity used in your community, as well as combustion and upstream emissions for each secondary fuel used in the production of each primary fuel. The calculation is made on the basis of total electricity used by the community, which includes transmission and distribution losses.

Two methods are presented here. The recommended method (BE.5.2) involves estimating the quantities of primary fuels used at the point of electricity generation to produce the electricity used in your community (including transmission and distribution losses). This method will allow for greater resolution on which primary fuels most contribute to upstream emissions and allow for the substitution of more locally tailored emissions factors where they are known. To complete this method, you will need to apply Method BE.5.1 to the quantities of fuels estimated here. The alternate method (BE.5.2.A) utilizes summary factors that combine average data for all the upstream sources, eliminating many calculation Steps.

Method BE.5.2.A will provide less information as a result, but it still can be useful for comparisons of the magnitude of emissions at the point of electricity generation as compared to upstream emissions.

Data

- Transmission and Distribution losses calculated in Method BE.4.
- Aggregated electricity data gathered for Method BE.2 (Purchased Electricity)
- Total primary fuel use for the generation of purchased electricity by your community (if utility specific emissions factor used in Method BE.2)

BE.5.2 Estimating Primary Fuel Use for Purchased Electricity

The overall process is to determine the quantities of primary fuels used to generate electricity. This data is then used to calculate upstream emissions using Method 5.1. This data is then used to calculate upstream emissions (for both primary fuels and their associated secondary fuels) using Method BE.5.1. Some of the factors used in this method are based on regional data sets, including EPA eGRID, North America Electric Reliability Corporation (NERC) Interconnection Regions, and EIA Petroleum Administration for Defense Districts (PADD). Maps of these regions are provided to help you locate the appropriate factor for your location in Appendix BE-B.

If you have chosen to use a utility specific emissions factor for calculating emissions from purchased electricity, you will need to obtain primary fuel used in the generation of the electricity purchased by your community from your utility directly, rather than following this method. Once primary fuels have been obtained, you can complete this section by using Method BE.5.1 for calculating upstream emissions from purchased electricity.

Step 1: Obtain total annual sector electricity use from Methods BE.2 and BE.4 in units of kWh (this should include electricity lost through transmission and distribution).

Step 2: Calculate the percent of electricity generated from each of four specific primary fuel types (i.e., coal, natural gas, oil, and nuclear) using the appropriate factors in Table B.14.A-D.

Step 3: Break total coal use into coal class with appropriate factors in Table B.15.

Step 4: Break total fuel oil use into fuel oil class with appropriate factors in Table B.16.

Step 5: Calculate the mass of each primary fuel using the Fuel Type Electricity Generation Potential factors in Table B.17.

Step 6: Go to Method BE.5.1 to estimate the upstream emissions associated primary fuels and their associated secondary fuels.

***Equation BE.5.2* Primary fuel use associated with grid electricity generation (illustrates Steps 1-5 of this method).**		
Total Primary Fuel Use$_{Fuel\ Type}$ = (Total Electricity Use x Fuel Type Generation Mix x Regional Fuel Type Class Mix x Fuel Type Generation Potential)* Where: Description		
Total Electricity Use	= Total annual electricity used in a community including transmission and distribution losses	User Input
Fuel Type Generation Mix	= Percent of total electricity that was generated from the fuel type Table B.14.A-D (%)	User Input
Regional Fuel Type Class Mix	= Percent of fuel type from each class (applicable to coal and fuel oil only) from Table B.15 and Table B.16(%)	User Input
Fuel Type Generation Potential	= Amount of fuel used in the generation of one kWh, from Table B.17 (unit/kWh)	User Input

Example BE.5.2 **Primary Fuel Use from Electricity Generation**		
A community in the Eastern Interconnection, NPCC New England sub-region (NEWE) used 1,000,000 kWh in the inventory year (2009).		
Total Electricity Use	= Total annual electricity used in a community including transmission and distribution losses.	1,000,000
Electricity Generation Mix, % Coal	= Percent of electricity produced from Coal, Obtained from Table B.14.A.	11.86
Electricity Generation Mix, % Fuel Oil	= Percent of electricity produced from Fuel Oil, Obtained from Table B.14.A.	1.50
Electricity Generation Mix, % Natural Gas	= Percent of electricity produced from Natural Gas, Obtained from Table B.14.A.	41.97
Electricity Generation Mix, % Nuclear	= Percent of electricity produced from Nuclear, Obtained from Table B.14.A.	29.76
Coal Type Mix, % Bituminous	= Bituminous fraction of total coal use, Obtained from Table B.15.	97
Coal Type Mix, % Lignite	= Lignite fraction of total coal use, Obtained from Table B.15.	3
Fuel Oil Type Mix, % Residual	= Residual fraction of total fuel oil use, Obtained from Table B.16.	77
Fuel Oil Type Mix, % Distillate	= Distillate fraction of total fuel oil use, Obtained from Table B.16.	23

Example BE.5.2 **Primary Fuel Use from Electricity Generation (continued)**		
Bituminous Coal Generation Potential	= kg bituminous coal used per kWh generated, Obtained from Table B.17.	0.44
Lignite Coal Generation Potential	= kg lignite coal used per kWh generated, Obtained from Table B.17.	0.78
Fuel Oil Generation Potential	= Liters of fuel oil used per kWh generated, Obtained from Table B.17.	0.26
Natural Gas Generation Potential	= m^3 of natural gas used per kWh generated, Obtained from Table B.17.	0.3
Uranium Generation Potential *Sample Calculations:*	= kg uranium used per kWh generated, Obtained from Table B.17.	3.04×10^{-6}
Bituminous Coal, Primary Fuel Use	*= 1,000,000 kWh x 11.86% x 97% x 0.44 kg/kWh* *= 50,618.48 kg*	
Lignite Coal, Primary Fuel Use	*= 1,000,000 kWh x 11.86% x 3% x 0.78 kg/kWh* *= 2775.240 kg*	
Distillate Fuel Oil, Primary Fuel Use	*= 1,000,000 kWh x 1.50% x 23% x 0.26 Liters/kWh* *= 897.0000 L*	

Example BE.5.2 Primary Fuel Use from Electricity Generation (continued)	
Residual Fuel Oil, Primary Fuel Use	*= 1,000,000 kWh x 1.50% x 77% x 0.26 Liters/kWh = 3,003.0 L*
Natural Gas, Primary Fuel Use	*= 1,000,000 kWh x 40.84% x 0.3 m^3/kWh = 122520 m^3*
Uranium, Primary Fuel Use	*= 1,000,000 kWh x 27.91% x $3.04x10^{-6}$kg/kWh = 0.848464 kg*

BE.5.2.A Alternate Method for Upstream Emissions from Electricity Use

This method is provided as a simplified alternative to Method BE.5.2. This method employs the use of summary factors that combine the regional primary fuel mix, upstream primary fuel emissions, secondary fuel combustion emissions and upstream secondary fuel emissions. This method provides a simplified approach to estimating upstream emissions from electricity generation that is useful for comparison with direct emissions in this category. This alternate method does not allow the user to view the fuel specific detail of the proportion of upstream emissions that come from individual processes, or how fuels compare against each other from a life cycle perspective. It also may limit the ability to apply more specific regional emissions factors than are provided here.

Data

- Transmission and Distribution losses calculated in Method BE.4.
- Aggregated electricity data gathered for Method BE.2

This calculation is completed in three steps, though it should be repeated for electricity use from each sector covered in your inventory.

Step 1: Obtain total annual sector electricity use from Methods BE.2 and BE.4 in units of kWh.

Step 2: Calculate the upstream emissions, using the factors provided in Table B.18.

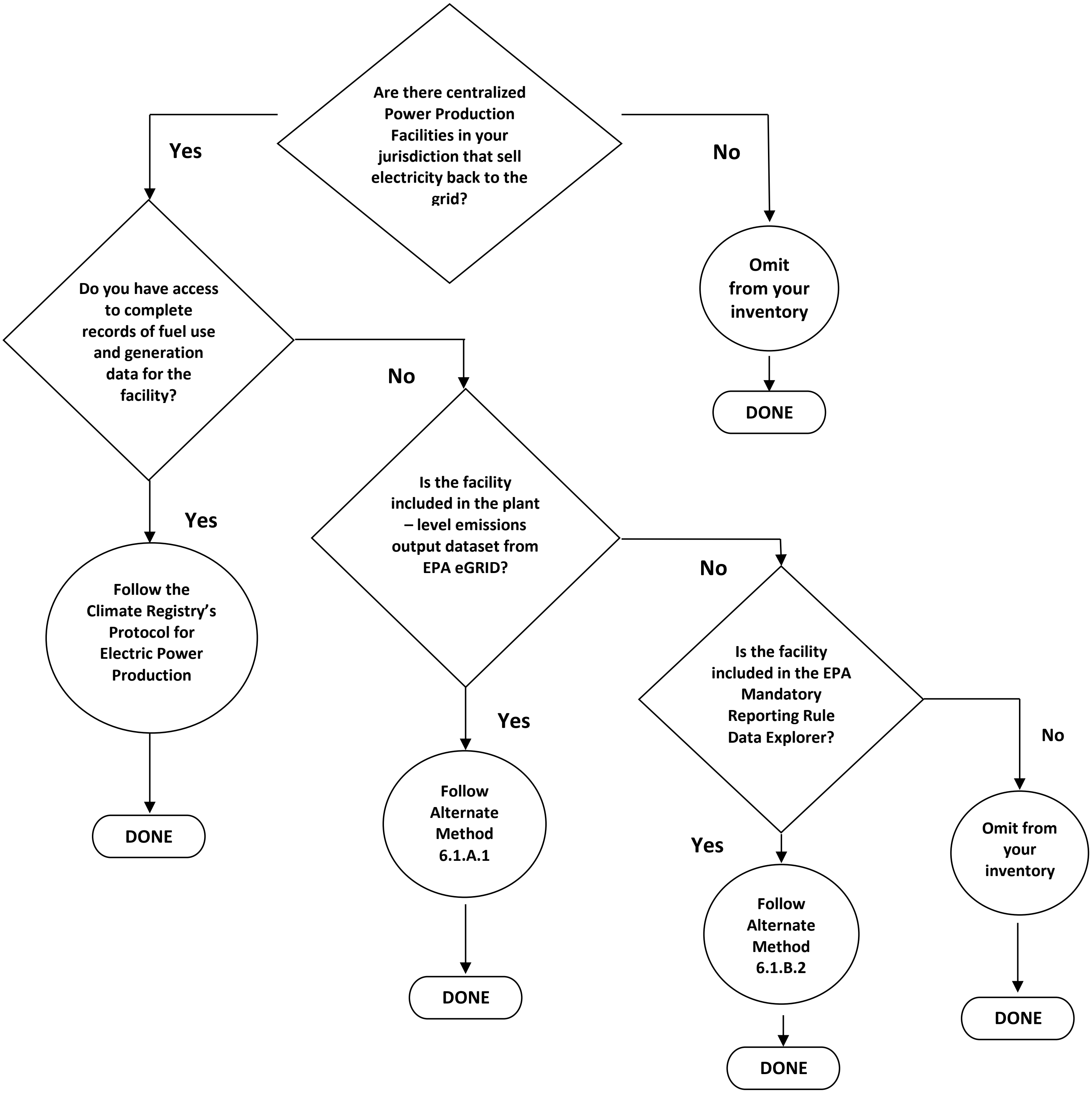
Step 3: Convert from kg to Metric Tons

***Equation BE.5.2.A* - Upstream emissions associated with electricity used within a community.**		
Total upstream emissions= (Total Electricity Use x Regional Upstream Emissions Factor Conversion Factor) Where: Description		
Annual CO_2e	= Total annual CO_2e emitted by upstream activities ($mtCO_2e$)	User Input
Total Electricity Use	= Total annual electricity used in a community including transmission and distribution losses	User Input
EF_{region}	= Regionally appropriate upstream emissions factor from Table B.18	User Input
Conversion Factor	= Conversion from kg to metric ton (mt/kg)	10^{-3}

Example BE.5.2.A **Upstream emissions associated with electricity used within a community in the Eastern Interconnection region.**		
A community in the Eastern Interconnection region used 1,000,000 kWh in the inventory year.		
Annual CO_2e	= Total annual CO_2e emitted by upstream activities ($mtCO_2e$)	Result
Total Electricity Use	= Total annual electricity used in a community including transmission and distribution losses	1,000,000
EF_{region}	= Regionally appropriate upstream emissions factor from Table B.18	6.88×10^{-2}
Conversion Factor	= Conversion from kg to metric ton (mt/kg)	10^{-3}
Sample Calculation:		
Annual CO_2e Emissions = $1{,}000{,}000 \times 6.88\times10^{-2} \times 10^{-3}$		
	= 68.8 $mtCO_2e$	

BE.6 Emissions from Electric Power Production

CHART BE.6.1: Decision Tree for Reporting Emissions from Electric Power Production



Introduction

If your community has an electric utility that operates grid-connected electricity generation facilities, it is important to account for and report the GHG emissions from this electricity generation. This applies to communities that have any of the following:

- 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.

BE.6.1 Emissions from Electric Power Production

Recommended Approach
To estimate your community's GHG emissions from the production of electricity, Protocol users are advised to use the Climate Registry's protocol for Electric Power Production.[14] That protocol was released in June 2009.

It is recognized, however, that completing The Climate Registry's protocol for Electric Power Production will be challenging, in part because a local government may not easily be able to get the appropriate data from their local utility nor necessarily have the technical capacity to complete the method as outlined. Consequently, two alternative methods are provided.

BE.6.1.A.1 Alternate Method to Estimate Emissions from Electric Power Production Emissions using EPA eGRID data

There are some secondary sources that may provide data on emissions from electricity generating facilities in your community. The EPA eGRID program provides facility level emissions reports for years when eGRID emissions factors were calculated.

Step 1. Go to the eGRID website and download the data file for your inventory year, if available.

Step 2. Open the excel file and locate the Plant level tab, and locate the facilities in your community from the data in that tab.

[14] http://www.theclimateregistry.org/resources/protocols/electric-power-sector-protocol/

Step 2. Go to the column labeled "Plant CO2 equivalent emissions (tons)" and record the value that corresponds with the facilities in your community, and report each facility as a line item in your inventory report.

BE.6.1.A.2 Alternate Method to Estimate Emissions from Electric Power Production using EPA MRR data

Another secondary data source may be available from the U.S. Environmental Protection Agency (EPA) Mandatory Reporting Rule (MRR). Obtaining necessary data to account for electricity generation facility emissions is limited due to privacy laws protecting many electricity generation facilities from disclosing and reporting process emissions data if operating under a minimum threshold of 25,000 $mtCO_2e$ per year. If operating above this threshold, electricity generation facilities are required to disclose and report emissions data to the EPA. The EPA Mandatory Reporting Rule and dissemination channels such as the GHG publication tool can be used to supplement your community inventory with additional electricity generation emissions sources that reside within a community's boundary. To find out more about the MRR, please visit: http://www.epa.gov/climatechange/emissions/ghgrulemaking.html

Accurately reporting electricity generation facility emissions using the MRR data may pose additional challenges that should be considered before deciding to include these sources in your inventory. Of first consideration is whether the reporting year covered by MRR is consistent with your inventory's evaluation year. The first reporting year mandated by the MRR for most electricity generation facilities is 2010. In some instances, processes were not required to report until 2011 or 2012. Assuming the reporting and publication of data maintains a regular interval, MRR data should be available for 2011 and future years beyond with an approximate two-year lag time from the current calendar year.

Another important consideration is to be sure you have a complete understanding of how specific electricity generation facilities emissions are treated in the MRR. For example, many of the largest sources include power generation facilities and other types of stationary combustion. The potential for double counting exists particularly for natural gas where aggregate commercial and industrial use collected for the calculation of emissions from stationary combustion may have been obtained from a centralized distributor that may have also included these sources.

A final consideration for the incorporation of these sources is that, in many cases, the MRR will not provide a complete accounting of all electricity generation emissions in your community. Any facility that is under the 25,000 $mtCO_2e$/year threshold will not be among the sources available from the US EPA Greenhouse Gas Emissions from Large Facilities data publication tool.[15] If the primary motivation for including these sources is for the sake of completeness, it should be recognized that relying solely on MRR data might not achieve that end.

[15] US EPA, Greenhouse Gas Emissions from Large Facilities Data Publication Tool, http://ghgdata.epa.gov/

The recommended approach for including GHG emissions for electricity generation facility emissions is to locate and report GHG inventories from the operation of facilities inside your community's boundary.

Data Needs

The procedure for obtaining these data begins with visiting the US EPA Greenhouse Gas Emissions from Large Facilities data publication tool website (ghgdata.epa.gov). The tool provides a map-based interface for finding facilities that have reported under MRR.

In addition to data from EPA's MRR, there may be other sources for this information, such as through voluntary reporting programs. As more and more businesses account for their own emissions, they may also be willing to disclose that information to a local government conducting a community scale inventory. Any data on electricity generation that is not coming from a published and verified source should always be presented in the context of the methods used to calculate emissions and the potential for double counting with other sections of the inventory.

To include GHG emissions from electricity generation, locate facility-specific inventories performed in the same year as your overall community inventory and report those emissions as appropriate and with as much detail as is available.

Step 1: Visit the US EPA, Greenhouse Gas Emissions from Large Facilities Data Publication Tool (http://ghgdata.epa.gov/) and use the GHG publication tool map interface to locate facilities within your jurisdiction and open their detailed record page.

Step 2: Obtain emissions reported under the Subpart D category electric power production and by individual GHGs.

Step 3: Report GHGs obtained as line items by facility and individual GHG and cite the EPA Mandatory Reporting Rule as the source of this information.

BE.7 Refrigerant Leakage and Fire Suppressant Emissions

Introduction

Many chemicals commonly used in refrigeration, fire suppression equipment, and other products can contribute to global warming. Through the installation, use, and disposal of these systems and products, leaks are likely to occur. While the volume of refrigerant and fire suppressant leakage may be small, the impact to a community's GHG emissions inventory may be significant due to the high global warming potential of these chemicals.

Unfortunately, obtaining accurate data for community refrigerant and fire suppression chemical leakage may be challenging. At the community scale, such information will be difficult to collect from all sources as there are potentially thousands of individual applications where these chemicals are used. Some common applications include the following.

Refrigeration and Air Conditioning

- Motor vehicle air conditioning
- Retail food refrigeration
- Refrigerated transport
- Household refrigeration
- Residential and commercial air conditioning and chillers
- Cold storage facilities
- Industrial process refrigeration

Industrial Processes

- Blowing agents used in the production of polyurethane
- Polystyrene
- Polyolefin and phenolic foams
- Solvents used in cleaning of precision metals and electronic manufacture.

Fire Protection

- Fire protection systems, including portable fire extinguishers and total flooding systems

Note that there are some chemicals used in these applications that do not contribute to global warming; only those chemicals that contain or consist of compounds of the GHGs in Table B.19 or Table B.20 should be reported. In addition to those compounds listed individually, some refrigerants are a blend of a number of compounds. Refrigerant blends that should be reported under this method and their associated global warming potential (GWP) are listed in Table B.19 or Table B.20.

If accurate data on refrigerant leakage at the community scale has been obtained, computing GHG emissions are calculated using the recommended approach below.

Recommended Approach
To estimate your community's refrigerant leakage and fire suppressants GHG emissions, Protocol users are advised to use the general methodology outlined by the US Environmental Protection Agency.[16] For further discussion of this general methodology and modification to estimate community-wide refrigerant leakage and fire suppressant emissions, users can reference the California Air Resources Board Rulemaking to Consider the Adoption of a Proposed Regulation for the Management of High Global Warming Potential Refrigerants for Stationary Sources.[17] An alternate method is provided if the recommended method proves unable to be used or if required data is not available.

BE.7.1 Estimating Refrigerant Leakage and Fire Suppressant Emissions

The general methodology outlined by the US Environmental Protection Agency and modified by the California Air Resource Board to accommodate for community-wide refrigerant leakage and fire suppressant emissions includes the following general steps. Users are encouraged to reference the California Air Resources Board to apply the steps to estimate community-wide refrigerant leakage and fire suppressant emissions.

Step 1: Divide equipment into three basic refrigerant (or fire suppressant) charge size categories (small, medium, large).

Step 2: Allocate specific equipment types to the three basic refrigerant (or fire suppressant) charge size categories.

Step 3: Establish emission factors for each basic refrigerant charge (or fire suppressant) size category and equipment.

Step 4: Estimate number of facilities with each basic refrigerant (or fire suppressant) charge size category and equipment.

Step 5: Calculate annual emissions from estimated number of facilities with each basic refrigerant (or fire suppressant) charge and equipment type and sum for overall refrigerant (or fire suppressant) leakage emissions.

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[16] U.S. Environmental Protection Agency, Climate Leaders. May 2008. Direct HFC and PFC Emissions from Use of Refrigeration and Air Conditioning Equipment. EPA430-K-03-004. http://www.epa.gov/stateply/documents/resources/mfgrfg.pdf.

[17] California Air Resources Board. Rulemaking to Consider the Adoption of a Proposed Regulation for the Management of High Global Warming Potential Refrigerants for Stationary Sources. Dec. 2009. Public Hearing Notice and Related Material. Appendix B: California Facilities and Greenhouse Gas Emissions Inventory – High-Global Warming Potential Stationary Source Refrigerant Management Program. http://www.arb.ca.gov/regact/2009/gwprmp09/refappb.pdf.

BE.7.1.A Alternate Method for Estimating Refrigerant Leakage and Fire Suppressant Emissions

For each refrigerant or fire suppressant chemical, repeat Steps 1 – 3 to determine the GHG emissions for each chemical. This calculation is completed in three Steps; though it may need to be repeated for each compound.

Step 1: Obtain total amount of refrigerant or fire suppressant chemical leakage in your community.

Approaches for collecting refrigerant and fire suppression chemical leakage include the following.

- Within a single organization, refrigerant and fire suppressant leakage can be calculated by mass balance methods using the amount of chemical that is purchased to recharge equipment as a proxy for the volume released.
- Estimate leakage at the community scale based on number of businesses or similar metrics.
- Collect leakage data through business surveys.

Step 2: Multiply each refrigerant or fire suppressant chemical leakage total by its global warming potential according to Table B.19 or Table B.20 to obtain GHG emissions for each chemical.

Step 3: Sum GHG emissions from all refrigerant and fire suppressant chemicals.

***Equation BE.7* Fugitive emissions from refrigerant or fire suppressant leakage**		
Annual CO_2e *emissions =Σ Total Chemicals Released x* $GWP_{chemical}$ *x* 10^{-3}		
Where:		
Description		Value
Total Chemical Released	= The total quantity of each refrigerant or fire suppressant chemical released annually in kg.	User Input
$GWP_{chemical}$[18]	= Chemical-specific global warming factor to convert an amount of refrigerant or fire suppressant into CO_2 equivalents, from Table B.19 or Table B.20	User Input
10^{-3}	= Conversion from kg to metric ton (mt/kg)	10^{-3}
Annual CO_2e		Result

[18] See Appendix GWP for value.

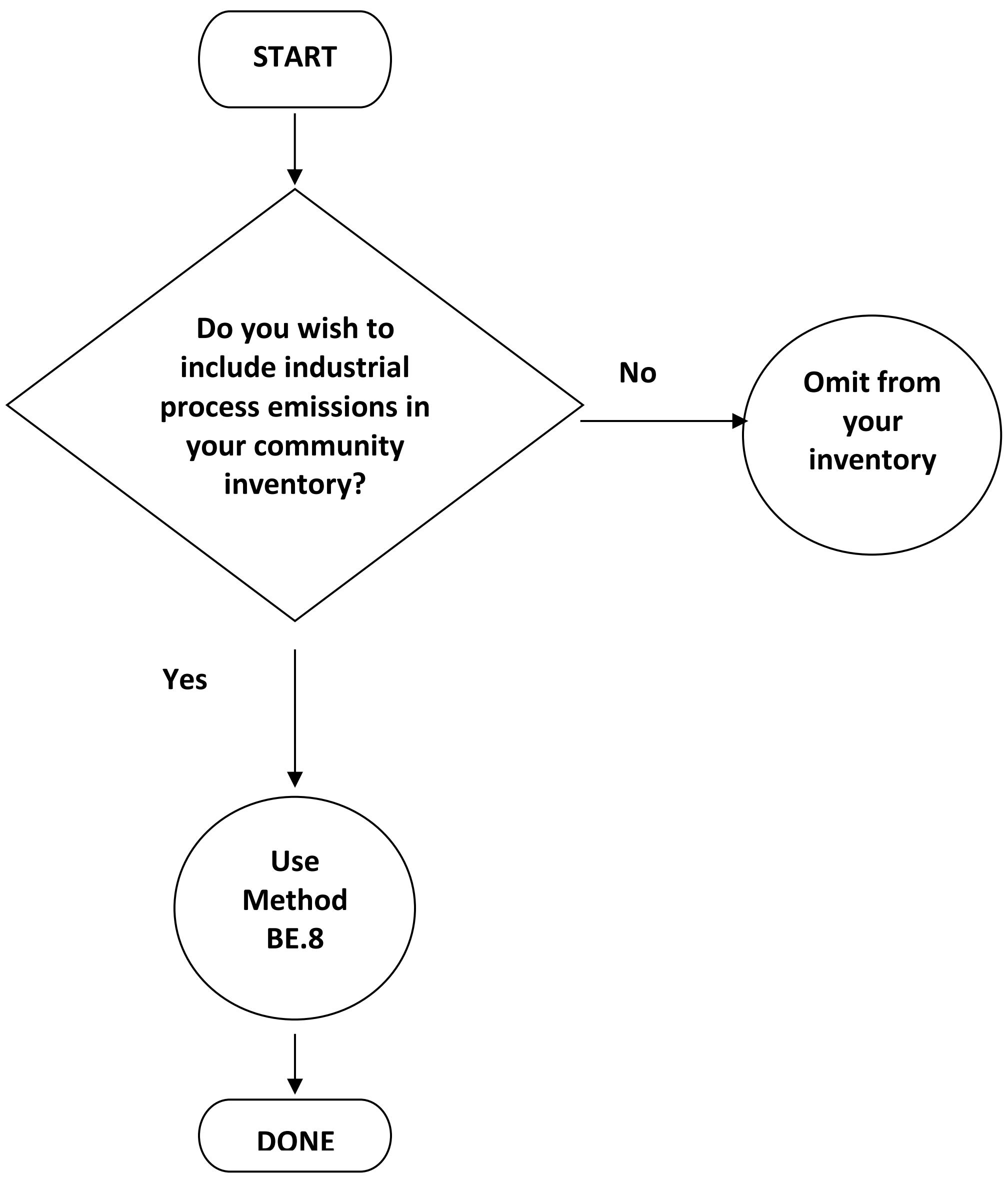
Example BE.7 **Fugitive emissions from refrigerant or fire suppressant leakage.**		

It was determined that 100 kg of R-403A and 200 kg of R-408B were released in the inventory year.

Description		Value
Annual CO_2e	= Total annual CO_2e emitted by upstream activities ($mtCO_2e$)	Result
Total R-403A Released	= The total quantity of each refrigerant or fire suppressant chemical released annually in kg.	100 kg
R-403A Global Warming Potential	= Factor to convert an amount of R-403A into CO_2 equivalents, from Table B.19or Table B.20	1,400
Total R-407B Released	= The total quantity of each refrigerant or fire suppressant chemical released annually in kg.	200 kg
R-407B Global Warming Potential	= Factor to convert an amount of R-403A into CO_2 equivalents, from Table B.19or Table B.20	2,285
10^{-3}	= Conversion from kg to metric ton (mt/kg)	10^{-3}
Sample Calculation:	*Annual CO2e Emissions =* *((100 x 1,400) +(200 x 2,285)) x* 10^{-3} *=* $597 mtCO_2e$	

BE.8 Industrial Process Emissions

CHART BE.8: Decision Tree for Reporting Industrial Process Emissions



Introduction

In addition to the typical sources of GHG emissions from fossil fuel energy use and other sources, a community may also contain industrial operations that contribute significant emissions as byproduct of production and other processes. These industrial process emissions may not be accounted using other methods in the GHG inventory. A community may choose to include these sources in their inventory for the sake of completeness, however, industrial process emissions are likely to be outside of the control of the local government or community at large. Unlike residential and typical commercial energy use, industrial process emissions do not necessarily indicate inefficiencies. Instead, individual industrial process emissions may be a unique byproduct of a specific industry. Therefore, management of these GHG emissions will be most effectively managed from within the industrial organization itself, where growing numbers of industrial organizations recognize industrial process emissions management as a key to maintaining competitiveness. Communities wishing to explore these types of relationships may find benefit in utilizing the optional Consumption-Based or Community-wide Supply Chain methods from this protocol.

Obtaining necessary data to account for industrial process emissions is limited due to privacy laws and a lack of disclosure requirements for organizations operating under a minimum threshold of 25,000 mtCO_2e per year. If operating above this threshold, industrial organizations are required to disclose and report emissions data to the US Environmental Protection Agency (EPA). The EPA Mandatory Reporting Rule (MRR) and dissemination channels such as the GHG publication tool can be used to supplement your community inventory with additional process emissions sources that reside within a community's boundary. To find out more about the MRR, please visit:
http://www.epa.gov/climatechange/emissions/ghgrulemaking.html

Accurately reporting industrial process emissions using the MRR data may pose additional challenges that should be considered before deciding to include these sources in your inventory. Of first consideration is whether the reporting year for industrial operations covered by MRR is consistent with your inventory's evaluation year. The first reporting year mandated by the MRR for most industrial processes is 2010. In some instances, processes were not required to report until 2011 or 2012. Assuming the reporting and publication of data maintains a regular interval, MRR data should be available for 2011 and future years beyond with an approximate two-year lag time from the current calendar year. Table B.21 contains a summary of the different MRR sub-part categories and the initial reporting year for each data category.

Another important consideration is to be sure you have a complete understanding of how specific industrial process emissions are treated in the respective subparts of the MRR. For example, many of the largest sources include power generation facilities and other types of stationary combustion. The potential for double counting exists particularly for natural gas where aggregate commercial and industrial use collected for the calculation of emissions from stationary combustion may have been obtained from a centralized distributor that may have also included these sources. Landfills located within a jurisdiction may also be a point of potential double counting.

A final consideration for the incorporation of these sources is that, in many cases, the MRR will not provide a complete accounting of all process emissions in your community. Any facility that is under the 25,000 $mtCO_2e$/year threshold will not be among the sources available from the EPA GHG publication tool. If the primary motivation for including these sources is for the sake of completeness, it should be recognized that relying solely on MRR data might not achieve that end.

It is also possible to identify industries in your community that may fall under the EPA reporting threshold and directly request GHG data from them. U.S. EPA publishes a data table of non-GHG pollutants by facility that can be useful in identifying major industries in your community. The *National Emissions Inventory Facility Emissions Summaries* (NEI) do not contain information about GHGs, but they do show sources of other emissions in your community by North American Industry Classification System (NAICS) code. The NAICS codes will show the type of industry, so if there are cement producers, steel manufacturers, or other likely GHG emitters in your community that fall below the EPA's mandatory reporting threshold for GHGs, you may be able to find them in this data source and contact them directly for information. Because other pollutants have lower reporting thresholds than GHGs this data source may contain industries in your community that are not required to publicly report GHGs.[19]

Recommended Method

The recommended approach for including GHG emissions for industrial process emissions is to locate and report GHG inventories from the operation of facilities inside your community boundary.

Data Needs

Should you decide to include process emissions as published by EPA in your inventory, the procedure for obtaining these data begins with visiting the EPA Greenhouse Gas Emissions from Large Facilities data publication tool.[20] From here the tool provides a map-based interface for finding facilities that have reported under MRR.

In addition to data from EPA's MRR, there may be other sources for this information, such as through voluntary reporting programs. As more and more businesses account for their own emissions, they may also be willing to disclose that information to a local government conducting a community scale inventory. Any data on process emissions that is not coming from a published and verified source should always be presented in the context of the methods used to calculate emissions, the processes that created the emissions, and the potential for double counting with other sections of the inventory.

[19] *National Emissions Inventory Facility Emissions Summaries* (NEI) can be found at ftp://ftp.epa.gov/EmisInventory/2008v2/2008neiv2_facility.zip

[20] US EPA, Greenhouse Gas Emissions from Large Facilities Data Publication Tool, http://ghgdata.epa.gov/

BE.8.1 Industrial process emissions

To include GHG emissions from industrial processes, locate facility-specific inventories performed in the same year as your overall community inventory and report those emissions as appropriate and with as much detail as is available.

Step 1: Visit the US EPA, Greenhouse Gas Emissions from Large Facilities Data Publication Tool (http://ghgdata.epa.gov/) and use the GHG publication tool map interface to locate facilities within your jurisdiction and open their detailed record page.

Step 2: Obtain emissions by MRR subpart category and by individual GHGs.

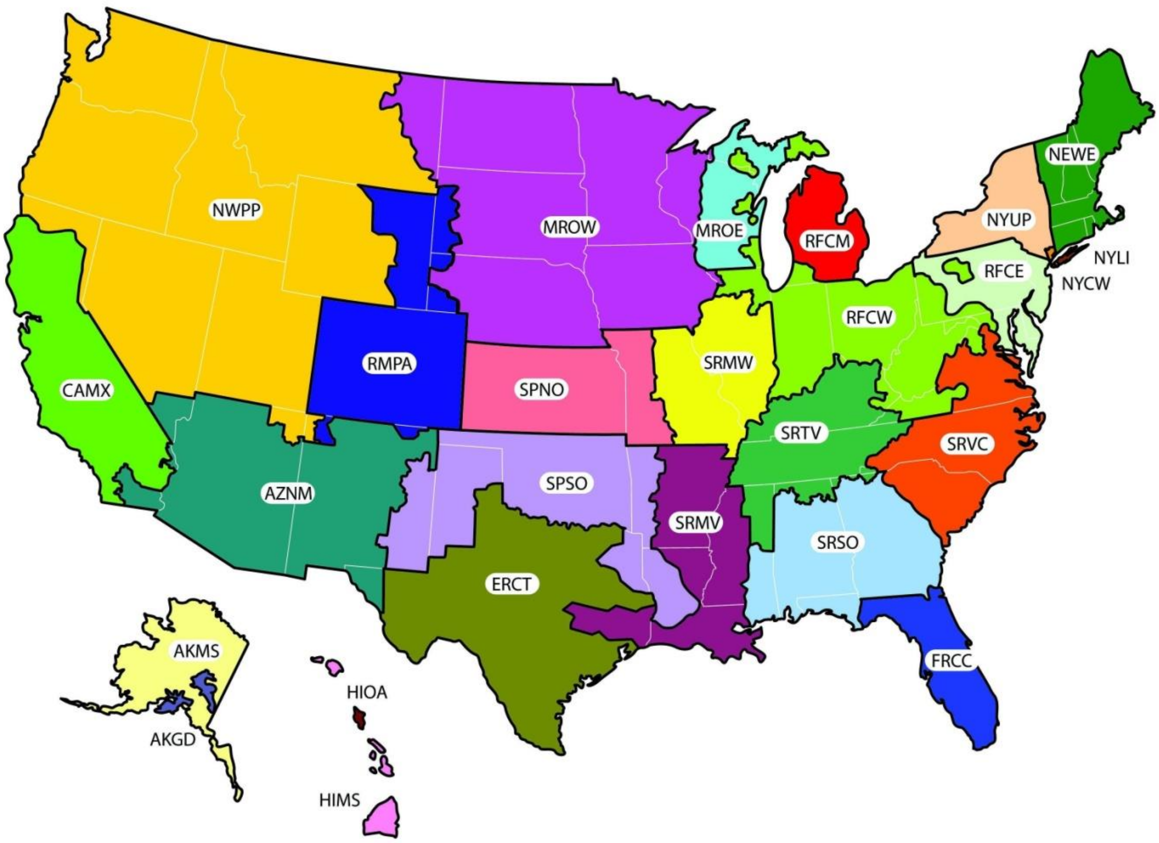
Step 3: Report GHGs obtained as line items by MRR Subpart and individual GHG. A list of the MRR Subpart categories is included here in Table B.21. Include the name of the facility and cite the EPA Mandatory Reporting Rule as the source of this information.

Appendix BE-A: Standard Conversion Factors

Mass			
1 pound (lb) =	453.6 grams (g)	0.4536 kilograms (kg)	0.0004536 metric tons (tons)
1 kilogram (kg) =	1,000 grams (g)	2.2046 pounds (lb)	0.001 metric tons (tons)
1 short ton (ton) =	2,000 pounds (lb)	907.18 kilograms (kg)	0.9072 metric tons (tons)
1 metric ton (ton) =	2,204.62 pounds (lb)	1,000 kilograms (kg)	1.1023 short tons (tons)
Volume			
1 cubic foot (ft^3) =	7.4805 US gallons (gal)	0.1781 barrels (bbl)	
1 cubic foot (ft^3) =	28.32 liters (L)	0.02832 cubic meters (m^3)	
1 US gallon (gal) =	0.0238 barrels (bbl)	3.785 liters (L)	0.003785 cubic meters (m^3)
1 barrel (bbl) =	42 US gallons (gal)	158.99 liters (L)	0.1589 cubic meters (m^3)
1 liter (L) =	0.001 cubic meters (m^3)	0.2642 US gallons (gal)	0.0063 barrels (bbl)
1 cubic meter (m^3) =	6.2897 barrels (bbl)	264.17 US gallons (gal)	1,000 liters (L)
Energy			
1 kilowatt hour (kWh) =	3,412 Btu (Btu)	3,600 kilojoules (KJ)	
1 megajoule (MJ) =	0.001 gigajoules (GJ)		
1 gigajoule (GJ) =	0.9478 million Btu (MMBtu)	277.8 kilowatt hours (kWh)	
1 British thermal unit (Btu) =	1,055 joules (J)	1.055 kilojoules (KJ)	
1 million Btu (MMBtu) =	1.055 gigajoules (GJ)	293 kilowatt hours (kWh)	
1 therm =	100,000 Btu	0.1055 gigajoules (GJ)	29.3 kilowatt hours (kWh)
Other			
kilo =	1,000		
mega =	1,000,000		
giga =	1,000,000,000		
tera =	1,000,000,000,000		
peta =	1,000,000,000,000,000		
1 mile =	1.609 kilometers		
1 metric ton carbon (C) =	$^{44}/_{12}$ metric tons CO_2		

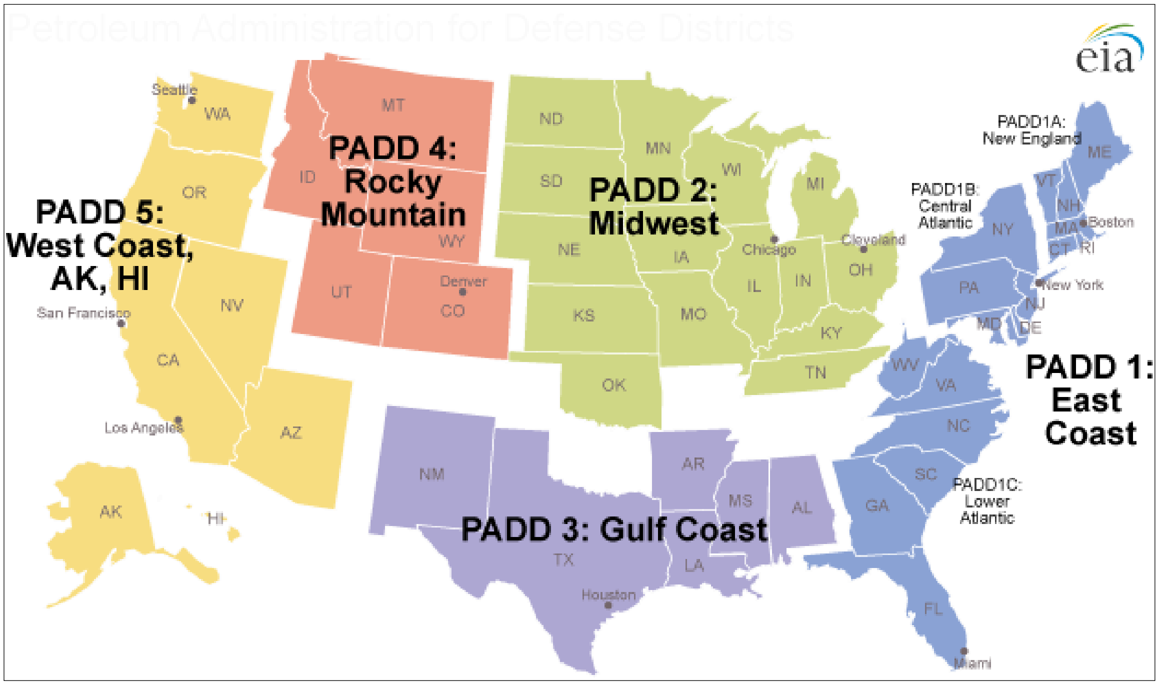
Appendix BE-B: Built Environment References and Data

Figure B.1 eGRID Sub-regional Grid Map



This Is a representational map; many of the boundaries shown on this map are approximate because they are based on companies, not on strictly geographical boundaries.
USEPA eGRID2010 Version 1.0 December 2010

Figure B.2 PADD Region Map



Source: Energy Information Administration

Figure B.3 NERC Interconnection Region Map

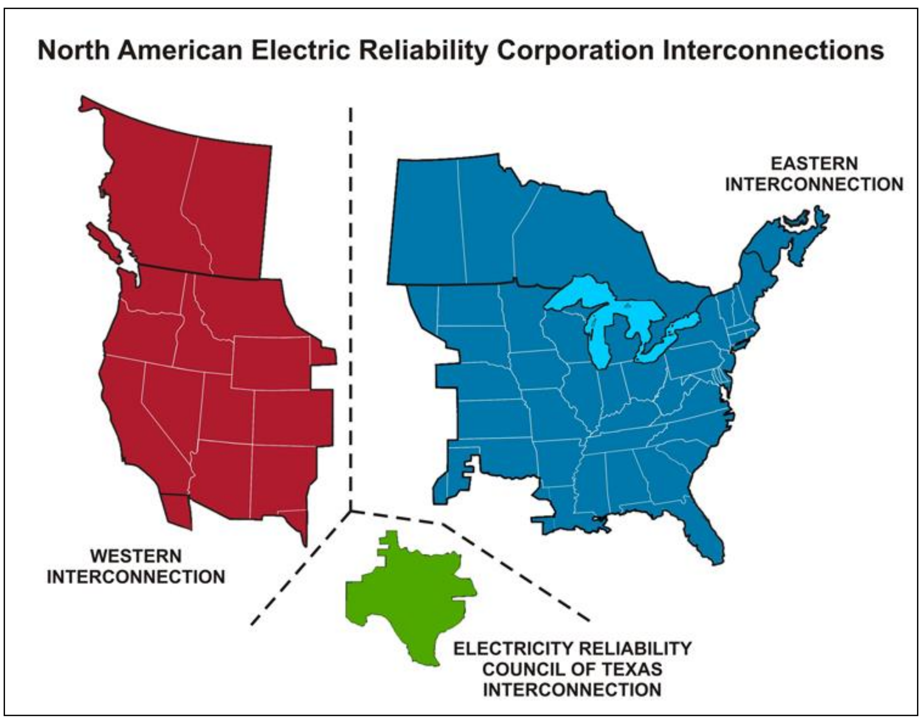


Table B.1 Default Factors for Calculating Carbon Dioxide Emissions from Fossil Fuel Combustion[21]

Fuel Type	Heat Content	Carbon Content (per unit energy)	Fraction Oxidized	CO_2 Emissions Factor (per unit energy)	CO_2 Emissions Factor (per unit mass or volume)
Coal and Coke	**MMBtu / Short ton**	**kg C / MMBtu**		**kg CO_2 / MMBtu**	**kg CO_2 / Short ton**
Anthracite	25.09	28.24	1	103.54	2597.82
Bituminous	24.93	25.47	1	93.40	2328.46
Subbituminous	17.25	26.46	1	97.02	1673.60
Lignite	14.21	26.28	1	96.36	1369.28
Coke	24.80	27.83	1	102.04	2530.59
Mixed Electric Utility/electric power	19.73	25.74	1	94.38	1862.12
Unspecified Residential/Com*	22.05	26.00	1	95.33	2102.03
Mixed commercial sector	21.39	25.98	1	95.26	2037.61
Mixed industrial coking	26.28	25.54	1	93.65	2461.12
Mixed industrial sector	22.35	25.61	1	93.91	2098.89
Natural Gas	**Btu/scf**	**kg C / MMBtu**		**kg CO_2 / MMBtu**	**kg CO_2/scf**
Pipeline (US weighted average)	1028	14.47	1	53.02	0.0545
Greater than 1000 btu	>1000	14.47	1	53.06	Varies
975 to 1000	975-1,000	14.73*	1	54.01*	Varies
1000 to 1025	1,000 – 1,025	14.43	1	52.91*	Varies
1025-1035	1025-1035	14.45	1	52.98*	Varies
1025 to 1050	1,025 – 1,050	14.47*	1	53.06*	Varies
1050 to 1075	1,050 – 1,075	14.58*	1	53.46*	Varies
1075 to 1100	1,075 – 1,100	14.65*	1	53.72*	Varies
Greater than 1100	> 1,110	14.92*	1	54.71*	Varies

[21] CCAR's General Reporting Protocol Version 3.1 (January 2009) and CARROT contain different default CO2 emission factors than presented here. CCAR members are allowed to use either the emission factors presented here or those found in the GRP/CARROT. If members use the default emission factors from the Local Government Operations Protocol, CCAR asks that this be documented in CARROT.

Fuel Type	Heat Content	Carbon Content (per unit energy)	Fraction Oxidized	CO_2 Emissions Factor (per unit energy)	CO_2 Emissions Factor (per unit mass or volume)
Natural Gas (cont.)	**Btu/scf**	**kg C / MMBtu**		**kg CO_2 / MMBtu**	**kg CO_2/scf**
Fossil Fuel-derived Fuels (gaseous)	**MMBtu/scf**	**kg C / MMBtu**		**g CO_2/MMBtu**	**g CO_2/short ton**
Acetylene***	0.00147	n/a	1	0.0716	n/a
Fossil Fuel-derived Fuels (solid)	**MMBtu/short ton**	**kg C / MMBtu**		**kg CO_2/mmBtu**	**kg CO_2/short ton**
Municipal Solid Waste	9.95	24.74	1	90.7	902.47
Tires	26.87	23.45	1	85.97	2310.01
Fossil Fuel-derived Fuels (gaseous)	**MMBtu/scf**	**kg C / MMBtu**		**kg CO_2/MMBtu**	**kg CO_2 / scf**
Blast Furnace Gas	0.000092	n/a	1	274.32	0.0252
Coke Oven Gas	0.000599	n/a	1	46.85	0.0281
Petroleum Products	**MMBtu / gallon**	**kg C / MMBtu**		**kg CO_2 / MMBtu**	**kg CO_2 / gallon**
Distillate Fuel Oil No. 1	0.139	19.98	1	73.25	10.18
Distillate Fuel Oil No. 2	0.138	20.17	1	73.96	10.21
Distillate Fuel Oil No. 4	0.146	20.47	1	75.04	10.96
Residual Fuel No. 5	0.140	19.89	1	72.93	10.21
Residual Fuel No. 6	0.150	20.48	1	75.10	11.27
Still Gas	0.143	18.20	1	66.72	9.54
Kerosene	0.135	20.51	1	75.20	10.15
LPG	0.092	17.18	1	62.98	5.79
Propane	0.091	16.76	1	61.46	5.59
Ethane	0.096	17.08	1	62.64	6.01
Propylene	0.091	17.99	1	65.95	6.00
Ethylene	0.100	18.39	1	67.43	6.74
Isobutane	0.097	17.70	1	64.91	6.30
Isobutylene	0.103	18.47	1	67.74	6.98
Butane	0.101	17.77	1	65.15	6.58
Butylene	0.103	18.47	1	67.73	6.98
Naphtha (<401d F)	0.125	18.55	1	68.02	8.50
Natural Gasoline	0.110	18.23	1	66.83	7.35
Other oil (>401 d F)	0.139	20.79	1	76.22	10.59
Pentanes Plus	0.110	19.10	1	70.02	7.70
Petrochemical Feedstocks	0.129	19.36	1	70.97	9.16

Fuel Type	Heat Content	Carbon Content (per unit energy)	Fraction Oxidized	CO_2 Emissions Factor (per unit energy)	CO_2 Emissions Factor (per unit mass or volume)
Petroleum Coke	0.143	27.93	1	102.41	14.64
Special Naphtha	0.125	19.73	1	72.34	9.04
Unfinished Oils	0.139	20.32	1	74.49	10.35
Heavy Gas Oils	0.148	20.43	1	74.92	11.09
Lubricants	0.144	20.26	1	74.27	10.69
Motor Gasoline	0.125	19.15	1	70.22	8.78
Aviation Gasoline	0.120	18.89	1	69.25	8.31
Kerosene Type Jet Fuel	0.135	19.70	1	72.22	9.75
Asphalt and Road Oil	0.158	20.55	1	75.36	11.91
Crude Oil	0.138	20.32	1	74.49	10.28
Waxes*	0.132	19.81	1	72.64	9.58

Table B.2 Default Factors for Calculating Carbon Dioxide Emissions from Non-Fossil Fuel Combustion[22]

Fuel Type	Heat Content	Carbon Content (per unit energy)	Fraction Oxidized	CO_2 Emissions Factor (per unit energy)	CO_2 Emissions Factor (per unit mass or volume)
Biomass Fuels – Solid	**MMB tu/short ton**	**Kg C/ MMBtu**		**Kg CO_2/MMBtu**	**Kg CO_2/short ton**
Wood and Wood residuals	15.38	25.58	1	93.80	1442.64
Agricultural Byproducts	8.25	32.23	1	118.17	974.90
Peat	8.00	30.50	1	111.84	894.72
Solid Byproducts	25.83	28.78	1	105.51	2725.32
Kraft Black Liquor (NA Hardwood)**	11.98	25.75	1	94.41	1131.03
Kraft Black Liquor (NA Softwood)**	12.24	25.94	1	95.13	1164.39
Biomass Fuels – Gaseous	**MMBtu/scf**	**kg C / MMBtu**		**kg CO_2 / MMBtu**	**Kg CO_2 / scf**
Biogas (captured methane)	0.000841	14.20	1	52.07	0.0438
Landfill Gas (50% CH4/50%CO2)**	0.0005025	14.20	1	52.07	0.0262
Wastewater Treatment Biogas**	Varies	14.20	1	52.07	Varies
Biomass Fuels – Liquid	**MMBtu/gallon**	**kg C / MMBtu**		**kg C / MMBtu**	**kg CO_2 / gallon**
Ethanol (100%)	0.084	18.67	1	68.44	5.75
Biodiesel (100%)	1.28	20.14	1	73.84	9.45
Rendered Animal Fat	0.125	19.38	1	71.06	8.88
Vegetable Oil	0.120	22.24	1	81.55	9.79
Geothermal	**MMBtu / gallon**	**kg C / MMBtu**		**kg CO2 / MMBtu**	**kg CO_2 / gallon**
Geothermal	n/a	2.05		n/a	n/a
Source: Heat Content and Default Emission factors are from EPA Final Mandatory Reporting of Greenhouse Gases Rule Table C-1. Carbon Content derived using the heat content and default emission factor . Except those marked with * are from US Inventory of Greenhouse Gas Emissions and Sinks 2004-2007 (2009) and **EPA Climate Leaders Technical Guidance (2008) Table B-2 and *** derived from the API Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry (2009) Table 3-8.					

[22] CCAR's General Reporting Protocol Version 3.1 (January 2009) and CARROT contain different default CO2 emission factors than presented here. CCAR members are allowed to use either the emission factors presented here or those found in the GRP/CARROT. If members use the default emission factors from the Local Government Operations Protocol, CCAR asks that this be documented in CARROT.

Table B.3 Default Methane and Nitrous Oxide Emissions Factors by Fuel Type and Sector[23]

Fuel Type / End-Use Sector	CH_4 (kg/MMBtu)	N_2O (kg/MMBtu)
Coal		
Industrial	0.011	0.0016
Energy Industry	0.01	0.0016
Residential	0.316	0.0016
Commercial	0.011	0.0016
Coke		
Industrial	0.011	0.0016
Energy Industry	0.011	0.0016
Petroleum Products		
Industrial	0.003	0.0006
Energy Industry	0.003	0.0006
Residential	0.011	0.0006
Commercial	0.011	0.0006
Natural Gas		
Industrial	0.001	0.0001
Energy Industry	0.001	0.0001
Residential	0.005	0.0001
Commercial	0.005	0.0001
Municipal Solid Waste		
Industrial	0.032	0.0042
Energy Industry	0.032	0.0042
Tires		
Industrial	0.032	0.0042
Energy Industry	0.032	0.0042
Blast Furnace Gas		
Industrial	0.000022	0.0001
Energy Industry	0.000022	0.0001
Coke Oven Gas		
Industrial	0.00048	0.0001
Energy Industry	0.00048	0.0001
Biomass Fuels Solid		
Industrial	0.032	0.0042
Energy Industry	0.032	0.0042
Residential	0.316	0.0042

[23] Source: EPA Climate Leaders, Stationary Combustion Guidance (2008), Table A-1, based on U.S. EPA, *Inventory of Greenhouse Gas Emissions and Sinks: 1990-2005* (2007), Annex 3.1.

Fuel Type / End-Use Sector	CH_4 (kg/MMBtu)	N_2O (kg/MMBtu)
Commercial	0.316	0.0042
Biogas		
Industrial	0.0032	0.00063
Fuel Type /	**CH_4**	**N_2O**
End-Use Sector	**(kg/MMBtu)**	**(kg/MMBtu)**
Energy Industry	0.0032	0.00063
Biomass Fuels Liquid		
Industrial	0.0011	0.00011
Energy Industry	0.0011	0.00011
Pulping Liquors		
Industrial	0.0025	0.002

Table B.4 Methane and Nitrous Oxide Emissions Factors for Stationary Combustion for Petroleum Products by Fuel Type and Sector

Fuel Type / End-Use Sector	CH_4 (kg/gallon)	N_2O (kg/gallon)
Residential		
Distillate Fuel No. 2	0.0015	0.0001
Kerosene	0.0015	0.0001
Liquefied Petroleum Gas (LPG)	0.0010	0.0001
Motor Gasoline	0.0014	0.0001
Residual Fuel No. 5	0.0015	0.0001
Residual Fuel No. 6	0.0017	0.0001
Propane	0.0010	0.0001
Butane	0.0011	0.0001
Commercial/Institutional		
Distillate Fuel No. 2	0.0015	0.0001
Kerosene	0.0015	0.0001
Liquefied Petroleum Gas (LPG)	0.0010	0.0001
Motor Gasoline	0.0014	0.0001
Residual Fuel No. 5	0.0015	0.0001
Residual Fuel No. 6	0.0017	0.0001
Propane	0.0010	0.0001
Butane	0.0011	0.0001
Industrial		
Distillate Fuel No. 2	0.0004	0.0001
Kerosene	0.0004	0.0001
Liquefied Petroleum Gas (LPG)	0.0003	0.0001
Motor Gasoline	0.0004	0.0001
Residual Fuel No. 5	0.0004	0.0001
Residual Fuel No. 6	0.0005	0.0001
Propane	0.0003	0.0001
Butane	0.0003	0.0001
Electric Power		
Distillate Fuel No. 2	0.0004	0.0001
Kerosene	0.0004	0.0001
Liquefied Petroleum Gas (LPG)	0.0003	0.0001
Motor Gasoline	0.0004	0.0001
Residual Fuel No. 5	0.0004	0.0001
Residual Fuel No. 6	0.0005	0.0001
Propane	0.0003	0.0001
Butane	0.0003	0.0001
Source: Derived from EPA Climate Leaders, Stationary Combustion Guidance (2007), Table A-1, based on U.S. EPA, Inventory of Greenhouse Gas Emissions and Sinks: 1990-2005 (2007), Annex 3.1.		
Note: All emission factors were converted to kg/gallon using the Petroleum Products emission factors from Table BE.1.3 and the heat content in MMBtu/barrel from Table BE.1.1 specific to each petroleum fuel. Heat Content of Fuel Type (MMBtu/gallon) x Petroleum Emission Factor (kg/MMBtu) = Petroleum Emission Factor (kg/gallon)		

Table B.5 Default Methane and Nitrous Oxide Emissions Factors by Technology Type for the Electricity Generation Sector

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

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

Table B.6 Proportion of Commercial Buildings Using Fuel Oil by Census Region

Census Region	% of Commercial Buildings Using Fuel Oil
Northeast	35%
Midwest	6%
South	5%
West	4%
Derived from Table B22 of the 2003 EIA Commercial Building Energy Survey	

Table B.7 Commercial Building Fuel Oil Energy Intensity

	Fuel Oil Energy Intensity (gallons/square foot) by Census Region			
Characterization Classes	**Northeast**	**Midwest**	**South**	**West**
All Buildings	0.2	0.06	0.02	n/a
Building Floor Space				
(Square Feet)				
1,001 to 10,000	0.5	n/a	0.1	n/a
10,001 to 100,000	0.22	0.1	n/a	n/a
Over 100,000	0.13	0.01	0.01	n/a
Principal Building Activity				
Education	0.3	n/a	n/a	n/a
Health Care	n/a	n/a	0.02	0.03
Office	0.08	0.01	0.01	n/a
All Others	0.23	n/a	0.02	n/a
Year Constructed				
1945 or Before	0.26	n/a	n/a	n/a
1946 to 1959	0.22	n/a	n/a	n/a
1960 to 1969	0.34	n/a	n/a	n/a
1970 to 1979	0.19	n/a	0.03	n/a
1980 to 1989	0.09	n/a	n/a	0.01
1990 to 2003	0.07	0.02	n/a	n/a
Source: 2003 EIA Commercial Building Energy Survey, Table C35a, http://www.eia.gov/consumption/commercial/				

Table B.8 Utility-Specific Verified Electricity CO_2 Emission Factors (lbs CO_2/MWh)

	Year										
	2000[a]	**2001**[a]	**2002**[a]	**2003**[a]	**2004**[a]	**2005**[a]	**2006**[a]	**2007**[a]	**2008**[a]	**2009**[a,b]	**2010**[b]
Anaheim Public Utilities						1,399.80	1,416.74	1,543.28			
Austin Energy						1,127.37	1,077.97	1,117.37			
City and County of San Francisco								76.28			
City of Palo Alto Public Utilities						320.94	39.02	426.82			
City of Vernon, Light and Power											775.83
Glendale Water & Power								1,065.00			
Los Angeles Department of Water & Power	1,407.44	1,403.39	1,348.48	1,360.07	1,360.60	1,303.58	1,238.52	1,227.89			
Modesto Irrigation District, Retail Power										1,036.17	942.99
Modesto Irrigation District, Wholesale Power										2,048.09	2,026.12
Newmont Nevada Energy Investment											2,055.79
Pacific Gas & Electric Company					566.20	489.16	455.81	635.67		575.38	444.64
PacifiCorp					1,811.00	1,812.22	1,747.30	1,775.28			
Pasadena Water & Power							1,409.65	1,664.14			
Platte River Power Authority						1,970.93	1,955.66	1,847.88			
Riverside Public Utilities						1,333.45	1,346.15	1,325.65			
Roseville Electric							565.52	793.80			
Sacramento Municipal Utility District					769.00	616.07	555.26	714.31			526.47
Salt River Project							1,546.28	1,469.90			
San Diego Gas & Electric					613.75	546.46	780.79	806.27	739.05	720.49	
Seattle City Light								17.77			
Sierra Pacific Resources								1,442.78			
Southern California Edison					678.88	665.72	641.26	630.89			

Data Source Notes:

[a]*Data from the California Climate Action Registry Power/Utility Protocol public reports, http://www.climateregistry.org/CARROT/public/reports.aspx*

[b]*Data from the Climate Registry Electric Power Sector Protocol public reports, http://www.climateregistry.org/carrot/public/reports.aspx*

Table B.9 California Grid Average Electricity Emission Factors (1990-2007) (lbs/MWh)

Year	CO_2	CH_4	N_2O	CO_2e
1990	1031.14	0.040	0.014	1036.19
1991	994.03	0.037	0.013	998.72
1992	984.42	0.040	0.012	988.87
1993	1007.26	0.037	0.013	1011.95
1994	1071.19	0.040	0.013	1075.94
1995	929.77	0.031	0.012	934.03
1996	827.65	0.029	0.011	831.57
1997	874.96	0.029	0.011	878.88
1998	941.54	0.029	0.011	945.46
1999	917.60	0.031	0.011	921.56
2000	829.50	0.029	0.009	832.82
2001	1009.75	0.033	0.011	1013.75
2002	865.28	0.031	0.010	868.94
2003	888.41	0.031	0.011	892.37
2004	958.49	0.029	0.011	962.41
2005	948.28	0.030	0.011	952.22
2006	889.75	0.031	0.009	893.11
2007	919.64	0.029	0.010	923.26

Sources: Calculated from total in-state and imported electricity emissions divided by total use in MWh. Emissions from California Air Resources Board, Greenhouse Gas Inventory, 1990 – 2004 (November 17, 2007 version), available on line. CO_2e calculated using current 100-yearGlobal Warming Potentials (GWPs)from US EPA.(GWP_{CO2} = 1, GW_{CH4} = 21, GWP_{N2O} = 310).

Table B.10 2009 eGRID Electricity Emission Factors by eGRID Sub-region

eGRID sub-region	**eGRID sub-region name**	**acronym**	**CO_2 lb/MWh**	**CH_4lb/GWh**	**N_2O lb/GWh**	**CO_2e lb/MWh**
AKGD	ASCC Alaska Grid	ASCC	1,280.86	27.74	7.69	1,283.82
AKMS	ASCC Miscellaneous	ASCC	521.26	21.78	4.28	523.05
ERCT	ERCOT All	TRE	1,181.73	16.70	13.10	1,186.14
FRCC	FRCC All	FRCC	1,176.61	39.24	13.53	1,181.63
HIMS	HICC Miscellaneous	HICC	1,351.66	72.40	13.80	1,357.46
HIOA	HICC Oahu	HICC	1,593.35	101.74	21.98	1,602.30
MROE	MRO East	MRO	1,591.65	23.98	27.04	1,600.54
MROW	MRO West	MRO	1,628.60	28.80	27.79	1,637.82
NYLI	NPCC Long Island	NPCC	1,347.99	96.86	12.37	1,353.86
NEWE	NPCC New England	NPCC	728.41	75.68	13.86	734.29
NYCW	NPCC NYC/Westchester	NPCC	610.67	23.75	2.81	612.04
NYUP	NPCC Upstate NY	NPCC	497.92	15.94	6.77	500.35
RFCE	RFC East	RFC	947.42	26.84	14.96	952.63
RFCM	RFC Michigan	RFC	1,659.46	31.41	27.89	1,668.76
RFCW	RFC West	RFC	1,520.59	18.12	25.13	1,528.76
SRMW	SERC Midwest	SERC	1,749.75	19.57	28.98	1,759.15
SRMV	SERC Mississippi Valley	SERC	1,002.41	19.45	10.65	1,006.12
SRSO	SERC South	SERC	1,325.68	22.27	20.78	1,332.59
SRTV	SERC Tennessee Valley	SERC	1,357.71	17.28	22.09	1,364.92
SRVC	SERC Virginia/Carolina	SERC	1,035.87	21.51	17.45	1,041.73
SPNO	SPP North	SPP	1,815.76	21.01	28.89	1,825.15
SPSO	SPP South	SPP	1,599.02	23.25	21.79	1,606.26
CAMX	WECC California	WECC	658.68	28.94	6.17	661.20
NWPP	WECC Northwest	WECC	819.21	15.29	12.50	823.40
RMPA	WECC Rockies	WECC	1,824.51	22.25	27.19	1,833.41
AZNM	WECC Southwest	WECC	1,191.35	19.13	15.58	1,196.58
Source: eGRID2010 Version 1.0 Sub-region data (Year 2009 Data), http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html						

Table B.11 eGRID Sub-region CO_2e Emission Rates

Region	eGRID Sub-region Acronym	eGRID Sub-region Name	Annual CO_2 Equivalent Electricity Emission Rate (lb/MWh)
Alaska	AKGD	ASCC Alaska Grid	1,283.82
Alaska	AKMS	ASCC Miscellaneous	523.05
Eastern	FRCC	FRCC All	1,181.63
Eastern	MROE	MRO East	1,600.54
Eastern	MROW	MRO West	1,637.82
Eastern	NYLI	NPCC Long Island	1,353.86
Eastern	NEWE	NPCC New England	734.29
Eastern	NYCW	NPCC NYC/Westchester	612.04
Eastern	NYUP	NPCC Upstate NY	500.35
Eastern	RFCE	RFC East	952.63
Eastern	RFCM	RFC Michigan	1,668.76
Eastern	RFCW	RFC West	1,528.76
Eastern	SRMW	SERC Midwest	1,759.15
Eastern	SRMV	SERC Mississippi Valley	1,006.12
Eastern	SRSO	SERC South	1,332.59
Eastern	SRTV	SERC Tennessee Valley	1,364.92
Eastern	SRVC	SERC Virginia/Carolina	1,041.73
Eastern	SPNO	SPP North	1,825.15
Eastern	SPSO	SPP South	1,606.26
ERCOT	ERCT	ERCOT All	1,186.14
Hawaii	HIMS	HICC Miscellaneous	1,357.46
Hawaii	HIOA	HICC Oahu	1,602.30
Western	CAMX	WECC California	661.20
Western	NWPP	WECC Northwest	823.40
Western	RMPA	WECC Rockies	1,833.41
Western	AZNM	WECC Southwest	1,196.58

Table B.12 eGRID Regional Transmission and Distribution Loss Factors

Region	Grid Loss
Eastern	5.82%
Western	8.21%
ERCOT	7.99%
Alaska	5.84%
Hawaii	7.81%
U.S.	6.50%

Table B.13 Upstream Emissions per Unit Fuel Used[24]

	Anthracite Coal	Bituminous Coal	Lignite Coal	Natural Gas	Residual Fuel Oil	Distillate Fuel Oil	Gasoline	LPG	Kerosene
Fuel Used	1000 kg	1000 kg	1000 kg	1000 m^3	1000 L	1000 L	1000 L	1000 L	1000 L
Emissions	97.6 kg	189 kg	137 kg	445 kg	535 kg	492 kg	419 kg	307 kg	459 kg

[24] NREL (2007) and Oregon DEQ (2012)

Table B.14.A Primary Fuel Mix for Electricity Generation by eGRID Region (2009)

		2009 Generation Resource Mix (%)										
eGRID Sub-region acronym	eGRID Sub-region Name	Coal	Oil	Gas	Other Fossil	Biomass	Hydro	Nuclear	Wind	Solar	Geothermal	Other Unknown Purchased Fuel
AKGD	ASCC Alaska Grid	11.81%	13.67%	66.03%	-	-	8.48%	-	-	-	-	-
AKMS	ASCC Miscellaneous	-	31.30%	3.85%	-	0.48%	63.86%	-	0.52%	-	-	-
AZNM	WECC Southwest	38.60%	0.06%	35.68%	0.00%	0.32%	6.09%	16.47%	0.50%	0.10%	2.18%	-
CAMX	WECC California	7.33%	1.36%	53.05%	0.21%	2.72%	12.72%	14.93%	2.76%	0.30%	4.37%	0.26%
ERCT	ERCOT All	32.98	1.05	47.83	0.13	0.12	0.15	12.31	5.33	-	-	0.09
FRCC	FRCC All	23.65	4.42	54.83	0.63	1.74	0.01	13.99	-	0.00	-	0.71
HIMS	HICC Miscellaneous	1.99	69.87	-	7.13	3.35	3.73	-	8.33	0.05	5.55	-
HIOA	HICC Oahu	18.02	77.61	-	2.21	2.16	-	-	-	-	-	-
MROE	MRO East	68.90	2.37	4.98	0.12	3.24	2.71	15.26	2.32	-	-	0.10
MROW	MRO West	69.09	0.15	2.40	0.16	1.18	4.36	13.90	8.66	-	-	0.09
NEWE	NPCC New England	11.86	1.50	41.97	1.62	5.92	7.04	29.76	0.31	-	-	0.01
NWPP	WECC Northwest	29.83	0.34	15.15	0.15	1.09	46.50	2.46	3.80	-	0.55	0.12
NYCW	NPCC NYC/Westchester	-	1.79	55.86	0.48	0.54	0.02	40.84	0.48	-	-	-
NYLI	NPCC Long Island	-	12.99	77.34	4.55	5.11	-	-	-	-	-	-
NYUP	NPCC Upstate NY	14.49	0.90	18.93	0.36	1.60	30.79	30.59	2.35	-	-	-
RFCE	RFC East	35.37	0.73	17.13	0.84	1.32	1.24	42.96	0.41	0.01	-	0.00
RFCM	RFC Michigan	71.99	0.41	9.51	0.60	1.88	-	15.28	0.34	-	-	-
RFCW	RFC West	69.88	0.40	3.51	0.35	0.51	0.79	23.56	0.94	-	-	0.06
RMPA	WECC Rockies	67.77	0.04	22.60	-	0.09	4.30	-	5.07	0.04	-	0.09
SPNO	SPP North	73.84	0.26	7.81	0.04	0.03	0.14	13.49	4.40	-	-	-
SPSO	SPP South	55.23	0.17	33.87	0.22	1.21	5.53	-	3.78	-	-	0.00
SRMV	SERC Mississippi Valley	22.73	1.45	45.09	0.86	1.93	1.73	25.97	-	-	-	0.23
SRMW	SERC Midwest	79.79	0.09	1.04	0.01	0.13	1.76	17.08	0.11	-	-	-

		2009 Generation Resource Mix (%) (Continued)										
eGRID Sub-region acronym	eGRID Sub-region Name	Coal	Oil	Gas	Other Fossil	Biomass	Hydro	Nuclear	Wind	Solar	Geothermal	Other Unknown Purchased Fuel
SRSO	SERC South	52.18	0.35	22.31	0.07	2.92	4.09	18.07	-	-	-	0.00
SRTV	SERC Tennessee Valley	58.80	0.94	8.61	0.01	0.78	8.58	22.13	0.15	-	-	-
SRVC	SERC Virginia/Carolina	45.10	0.64	8.95	0.19	2.05	1.65	41.35	-	0.00	-	0.07

Table B.14.B Primary Fuel Mix for Electricity Generation by eGRID Region (2007)

		2007 Generation Resource Mix (%)										
eGRID Sub-region acronym	eGRID Sub-region Name	Coal	Oil	Gas	Other Fossil	Biomass	Hydro	Nuclear	Wind	Solar	Geothermal	Other Unknown Purchased Fuel
AKGD	ASCC Alaska Grid	11.76	10.44	70.05	0.00	0.00	7.75	0.00	0.00	0.00	0.00	0.00
AKMS	ASCC Miscellaneous	0.00	32.24	3.36	0.00	0.75	63.57	0.00	0.07	0.00	0.00	0.00
AZNM	WECC Southwest	40.18	0.08	36.23	0.00	0.20	5.94	14.82	0.39	0.03	2.12	0.00
CAMX	WECC California	7.59	1.04	52.47	0.93	2.40	12.06	16.25	2.54	0.25	4.38	0.10
ERCT	ERCOT All	34.39	0.37	49.48	0.87	0.10	0.27	11.98	2.37	0.00	0.00	0.18
FRCC	FRCC All	26.86	9.23	47.29	0.62	1.70	0.00	13.41	0.00	0.00	0.00	0.89
HIMS	HICC Miscellaneous	1.93	76.94	0.00	0.00	3.62	2.89	0.00	7.44	0.00	7.18	0.00
HIOA	HICC Oahu	18.21	77.43	0.00	2.45	1.91	0.00	0.00	0.00	0.00	0.00	0.00
MROE	MRO East	66.58	3.19	7.88	0.12	3.35	2.98	15.64	0.15	0.00	0.00	0.12
MROW	MRO West	70.99	0.50	4.96	0.23	0.96	3.48	15.42	3.43	0.00	0.00	0.03
NEWE	NPCC New England	15.15	4.23	40.84	1.47	5.81	4.51	27.91	0.08	0.00	0.00	0.01
NWPP	WECC Northwest	31.96	0.22	12.78	0.29	1.10	48.37	3.00	1.89	0.00	0.34	0.05
NYCW	NPCC NYC/Westchester	0.00	4.97	56.33	0.42	0.47	0.00	37.80	0.00	0.00	0.00	0.02
NYLI	NPCC Long Island	0.00	31.41	61.31	3.40	3.88	0.00	0.00	0.00	0.00	0.00	0.00
NYUP	NPCC Upstate NY	23.09	2.18	17.92	0.39	1.26	26.41	27.85	0.90	0.00	0.00	0.00
RFCE	RFC East	42.20	1.10	13.08	1.09	1.16	0.93	40.28	0.17	0.00	0.00	0.00
RFCM	RFC Michigan	69.78	0.68	12.24	0.63	1.84	0.00	14.83	0.00	0.00	0.00	0.00
RFCW	RFC West	72.87	0.28	2.91	0.56	0.33	0.56	22.29	0.15	0.00	0.00	0.06
RMPA	WECC Rockies	71.30	0.06	23.62	0.00	0.05	2.88	0.00	2.03	0.00	0.00	0.06
SPNO	SPP North	74.91	0.34	8.11	0.05	0.00	0.12	14.82	1.65	0.00	0.00	0.00
SPSO	SPP South	56.35	0.17	34.55	0.31	1.59	4.39	0.00	2.43	0.00	0.00	0.20
SRMV	SERC Mississippi Valley	22.99	1.64	44.72	1.30	2.19	1.35	25.47	0.00	0.00	0.00	0.35
SRMW	SERC Midwest	80.80	0.06	4.39	0.02	0.08	1.29	13.37	0.01	0.00	0.00	0.00

		2007 Generation Resource Mix (%) (Continued)										
eGRID Sub-region acronym	eGRID Sub-region Name	Coal	Oil	Gas	Other Fossil	Biomass	Hydro	Nuclear	Wind	Solar	Geothermal	Other Unknown Purchased Fuel
SRSO	SERC South	63.51	0.35	15.12	0.12	2.89	1.38	16.62	0.00	0.00	0.00	0.00
SRTV	SERC Tennessee Valley	66.14	1.25	7.20	0.01	0.85	3.73	20.81	0.02	0.00	0.00	0.00
SRVC	SERC Virginia/Carolina	51.08	0.88	6.69	0.22	1.96	0.73	38.36	0.00	0.00	0.00	0.08

Table B.14.C Primary Fuel Mix for Electricity Generation by eGRID Region (2005)

		2005 Generation Resource Mix (%)										
eGRID Sub-region acronym	eGRID Sub-region Name	Coal	Oil	Gas	Other Fossil	Biomass	Hydro	Nuclear	Wind	Solar	Geothermal	Other Unknown Purchased Fuel
AKGD	ASCC Alaska Grid	11.76	7.13	69.38	0.00	0.01	11.72	0.00	0.00	0.00	0.00	0.00
AKMS	ASCC Miscellaneous	0.00	29.91	3.71	0.00	0.38	65.95	0.00	0.05	0.00	0.00	0.00
AZNM	WECC Southwest	45.75	0.06	31.61	0.07	0.04	3.54	16.38	0.33	0.01	2.21	0.00
CAMX	WECC California	11.90	1.17	42.27	1.03	2.61	17.65	16.46	1.94	0.24	4.62	0.09
ERCT	ERCOT All	37.06	0.48	47.52	1.24	0.07	0.31	11.91	1.24	0.00	0.00	0.17
FRCC	FRCC All	26.24	17.87	39.03	0.64	1.54	0.01	13.83	0.00	0.00	0.00	0.84
HIMS	HICC Miscellaneous	1.47	83.49	0.00	0.00	4.70	3.06	0.00	0.21	0.00	7.06	0.00
HIOA	HICC Oahu	18.91	77.00	0.00	2.26	1.83	0.00	0.00	0.00	0.00	0.00	0.00
MROE	MRO East	67.95	2.19	11.99	0.15	3.68	3.59	10.18	0.12	0.00	0.00	0.15
MROW	MRO West	73.52	0.60	4.04	0.22	0.76	4.15	14.62	2.07	0.00	0.00	0.03
NEWE	NPCC New England	15.15	9.80	36.65	1.46	5.28	6.01	25.64	0.01	0.00	0.00	0.01
NWPP	WECC Northwest	34.36	0.27	10.84	0.28	1.27	48.61	3.28	0.71	0.00	0.33	0.05
NYCW	NPCC NYC/Westchester	0.00	20.21	34.93	0.48	0.54	0.02	43.82	0.00	0.00	0.00	0.00
NYLI	NPCC Long Island	0.00	59.06	34.74	2.87	3.33	0.00	0.00	0.00	0.00	0.00	0.00
NYUP	NPCC Upstate NY	21.55	7.76	15.48	0.44	1.19	26.43	27.04	0.11	0.00	0.00	0.00
RFCE	RFC East	45.09	3.97	9.64	0.89	1.07	0.91	38.31	0.09	0.00	0.00	0.03
RFCM	RFC Michigan	66.89	0.85	13.75	1.02	1.89	0.00	15.60	0.00	0.00	0.00	0.00
RFCW	RFC West	72.83	0.35	2.73	0.61	0.34	0.67	22.34	0.07	0.00	0.00	0.07
RMPA	WECC Rockies	71.69	0.04	19.46	0.00	0.05	7.37	0.00	1.39	0.00	0.00	0.00
SPNO	SPP North	78.26	1.60	5.94	0.08	0.00	0.12	13.36	0.65	0.00	0.00	0.00
SPSO	SPP South	55.67	0.36	37.41	0.25	1.52	3.67	0.00	0.94	0.00	0.00	0.17
SRMV	SERC Mississippi Valley	21.20	3.34	45.16	2.28	2.07	1.27	24.47	0.00	0.00	0.00	0.22
SRMW	SERC Midwest	83.15	0.26	3.52	0.04	0.08	0.99	11.95	0.00	0.00	0.00	0.00

		2005 Generation Resource Mix (%) (Continued)										
eGRID Sub-region acronym	eGRID Sub-region Name	Coal	Oil	Gas	Other Fossil	Biomass	Hydro	Nuclear	Wind	Solar	Geothermal	Other Unknown Purchased Fuel
SRSO	SERC South	64.73	0.47	10.96	0.08	3.09	3.32	17.34	0.00	0.00	0.00	0.01
SRTV	SERC Tennessee Valley	66.74	1.69	3.58	0.01	0.81	7.70	19.48	0.00	0.00	0.00	0.00
SRVC	SERC Virginia/Carolina	50.46	1.69	4.95	0.22	1.93	1.93	38.73	0.00	0.00	0.00	0.07

Table B.14.D Primary Fuel Mix for Electricity Generation by eGRID Region (2004)

		2004 Generation Resource Mix (%)										
eGRID Sub-region acronym	eGRID Sub-region Name	Coal	Oil	Gas	Other Fossil	Biomass	Hydro	Nuclear	Wind	Solar	Geothermal	Other Unknown Purchased Fuel
AKGD	ASCC Alaska Grid	12.30	7.30	68.00	0.00	0.00	12.40	0.00	0.00	0.00	0.00	NA
AKMS	ASCC Miscellaneous	0.00	28.80	3.60	0.00	0.70	66.90	0.00	0.00	0.00	0.00	NA
AZNM	WECC Southwest	40.40	0.00	31.50	0.00	0.00	4.50	21.20	0.39	0.00	2.00	NA
CAMX	WECC California	12.60	1.10	46.40	0.90	2.80	15.10	14.20	2.01	0.27	4.70	NA
ERCT	ERCOT All	37.70	0.50	45.90	1.30	0.10	0.30	13.20	0.94	0.00	0.00	NA
FRCC	FRCC All	26.40	18.30	36.50	0.30	2.00	0.00	15.50	0.00	0.00	0.00	NA
HIMS	HICC Miscellaneous	3.60	77.20	4.10	0.00	4.90	3.00	0.00	0.24	0.00	6.90	NA
HIOA	HICC Oahu	18.00	77.40	0.00	1.90	2.70	0.00	0.00	0.00	0.00	0.00	NA
MROE	MRO East	71.30	2.40	5.20	0.10	3.70	3.90	13.20	0.14	0.00	0.00	NA
MROW	MRO West	74.60	0.60	1.80	0.10	0.80	4.70	16.00	1.26	0.00	0.00	NA
NEWE	NPCC New England	14.50	9.40	36.70	1.00	5.70	5.10	27.60	0.01	0.00	0.00	NA
NWPP	WECC Northwest	34.40	0.30	10.60	0.10	1.20	49.00	3.60	0.49	0.00	0.30	NA
NYCW	NPCC NYC/Westchester	0.00	20.40	29.80	0.30	0.80	0.00	48.60	0.00	0.00	0.00	NA
NYLI	NPCC Long Island	0.00	58.20	35.50	1.80	4.50	0.00	0.00	0.00	0.00	0.00	NA
NYUP	NPCC Upstate NY	25.40	6.60	13.20	0.30	1.30	26.00	27.10	0.11	0.00	0.00	NA
RFCE	RFC East	44.90	3.50	9.60	0.70	1.30	1.60	38.40	0.10	0.00	0.00	NA
RFCM	RFC Michigan	67.00	0.90	15.50	0.30	2.00	0.00	14.30	0.00	0.00	0.00	NA
RFCW	RFC West	72.80	0.50	1.50	0.70	0.30	0.70	23.20	0.06	0.00	0.00	NA
RMPA	WECC Rockies	80.60	0.00	13.50	0.00	0.00	5.30	0.00	0.46	0.00	0.00	NA
SPNO	SPP North	78.10	1.30	4.60	0.10	0.00	0.10	15.20	0.54	0.00	0.00	NA
SPSO	SPP South	58.80	0.20	34.10	0.30	1.70	4.20	0.00	0.61	0.00	0.00	NA
SRMV	SERC Mississippi Valley	23.40	5.00	39.30	1.10	2.40	1.60	26.60	0.00	0.00	0.00	NA
SRMW	SERC Midwest	84.70	0.30	2.00	0.10	0.10	1.20	11.70	0.00	0.00	0.00	NA

		2004 Generation Resource Mix (%) (Continued)										
eGRID Sub-region acronym	eGRID Sub-region Name	Coal	Oil	Gas	Other Fossil	Biomass	Hydro	Nuclear	Wind	Solar	Geothermal	Other Unknown Purchased Fuel
SRSO	SERC South	64.00	0.60	10.10	0.10	3.50	3.10	18.60	0.00	0.00	0.00	NA
SRTV	SERC Tennessee Valley	65.80	1.70	2.40	0.00	0.90	8.80	20.40	0.00	0.00	0.00	NA
SRVC	SERC Virginia/Carolina	51.00	1.70	3.80	0.20	2.00	1.70	39.50	0.00	0.00	0.00	NA

Table B.15 Percent Coal Class Mix by NERC Interconnection Region

Region	U.S. Average	Eastern Interconnection	Western Interconnection	Electric Reliability Council of Texas Interconnection	Alaska	Hawaii
% Bituminous and subbituminous	95	97	100	59	100	100
% Lignite	5	3	0	41	0	0

Table B.16 Percent Fuel Oil Class Mix by PADD Region

	Year	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
US Total	**% Distillate**	19%	19%	17%	18%	15%	14%	21%	20%	24%	33%	32%
	% Residual	81%	81%	83%	82%	85%	86%	79%	80%	76%	67%	68%
East Coast (PADD 1)	**% Distillate**	10%	10%	10%	11%	9%	8%	13%	12%	13%	23%	24%
	% Residual	90%	90%	90%	89%	91%	92%	87%	88%	87%	77%	76%
New England (PADD 1A)	**% Distillate**	3%	4%	3%	2%	3%	2%	5%	4%	6%	23%	15%
	% Residual	97%	96%	97%	98%	97%	98%	95%	96%	94%	77%	85%
Central Atlantic (PADD 1B)	**% Distillate**	89%	91%	84%	86%	87%	89%	81%	84%	68%	69%	50%
	% Residual	11%	9%	16%	14%	13%	11%	19%	16%	32%	31%	50%
Lower Atlantic (PADD 1C)	**% Distillate**	10%	12%	9%	14%	10%	8%	11%	11%	10%	17%	17%
	% Residual	90%	88%	91%	86%	90%	92%	89%	89%	90%	83%	83%
Midwest (PADD 2)	**% Distillate**	70%	48%	67%	55%	65%	67%	91%	91%	95%	97%	99%
	% Residual	30%	52%	33%	45%	35%	33%	9%	9%	5%	3%	1%
Gulf Coast (PADD 3)	**% Distillate**	51%	42%	63%	42%	7%	23%	38%	37%	27%	53%	68%
	% Residual	49%	58%	37%	58%	93%	77%	62%	63%	73%	47%	32%
Rocky Mountain (PADD4)	**% Distillate**	100%	100%	100%	98%	97%	100%	100%	100%	100%	100%	100%
	% Residual	0%	0%	0%	2%	3%	0%	0%	0%	0%	0%	0%
West Coast (PADD5)	**% Distillate**	30%	30%	28%	33%	51%	39%	28%	25%	25%	27%	24%
	% Residual	70%	70%	72%	67%	49%	61%	72%	75%	75%	73%	76%

Table B.17 Generation Potential of Primary Fuels

Primary Fuel Type	Fuel used to generate one kWh of electricity
Bituminous & Subbituminous Coal	0.44 kg/kWh
Lignite Coal	0.78 kg/kWh
Fuel Oil	0.26 Liters/kWh
Natural Gas	0.3 m^3/kWh
Uranium	3.04×10^{-6} kg/kWh

Table B.18 Alternate Upstream Emissions Factors by NERC Interconnection Region (kg/kWh)

Emissions Type	National	Eastern	Western	ERCOT	Alaska	Hawaii
CO_2e	**6.99E-2**	**6.88E-2**	**6.25E-2**	**9.47E-2**	**1.13E-1**	**1.26E-1**

Table B.19 Global Warming Potentials of Fire Suppressants and other industrial Chemicals

Common Name	Formula	Chemical Name	GWP
Carbon dioxide	CO_2		1
Methane	CH_4		21
Nitrous oxide	N_2O		310
Sulfur hexafluoride	SF_6		23,900
Hydrofluorocarbons (HFCs)			
HFC-23	CHF_3	trifluoromethane	11,700
HFC-32	CH_2F_2	difluoromethane	650
HFC-41	CH_3F	fluoromethane	150
HFC-43-10mee	$C_5H_2F_{10}$	1,1,1,2,3,4,4,5,5,5-decafluoropentane	1,300
HFC-125	C_2HF_5	pentafluoroethane	2,800
HFC-134	$C_2H_2F_4$	1,1,2,2-tetrafluoroethane	1,000
HFC-134a	$C_2H_2F_4$	1,1,1,2-tetrafluoroethane	1,300
HFC-143	$C_2H_3F_3$	1,1,2-trifluoroethane	300
HFC-143a	$C_2H_3F_3$	1,1,1-trifluoroethane	3,800
HFC-152	$C_2H_4F_2$	1,2-difluoroethane	43*
HFC-152a	$C_2H_4F_2$	1,1-difluoroethane	140
HFC-161	C_2H_5F	fluoroethane	12*
HFC-227ea	C_3HF_7	1,1,1,2,3,3,3-heptafluoropropane	2,900
HFC-236cb	$C_3H_2F_6$	1,1,1,2,2,3-hexafluoropropane	1,300*
HFC-236ea	$C_3H_2F_6$	1,1,1,2,3,3-hexafluoropropane	1,200*
HFC-236fa	$C_3H_2F_6$	1,1,1,3,3,3-hexafluoropropane	6,300
HFC-245ca	$C_3H_3F_5$	1,1,2,2,3-pentafluoropropane	560
HFC-245fa	$C_3H_3F_5$	1,1,1,3,3-pentafluoropropane	950*
HFC-365mfc	$C_4H_5F_5$	1,1,1,3,3-pentafluorobutane	890*
Perfluorocarbons (PFCs)			
Perfluoromethane	CF_4	tetrafluoromethane	6,500
Perfluoroethane	C_2F_6	hexafluoroethane	9,200
Perfluoropropane	C_3F_8	octafluoropropane	7,000
Perfluorobutane	C_4F_{10}	decafluorobutane	7,000
Perfluorocyclobutane	$c\text{-}C_4F_8$	octafluorocyclobutane	8,700
Perfluoropentane	C_5F_{12}	dodecafluoropentane	7,500
Perfluorohexane	C_6F_{14}	tetradecafluorohexane	7,400
Source: Intergovernmental Panel on Climate Change (IPCC) Second Assessment Report published in 1995, unless no value was assigned in the document. In that case, the GWP values are from the IPCC Third Assessment Report published in 2001 (those marked with *). GWP values are from the Second Assessment Report (unless otherwise noted) to be consistent with international practices. Values are 100-year GWP values.			

Table B.20 Global Warming Potentials of Refrigerant Blends

Refrigerant Blend	Global Warming Potential
R-401A	18
R-401B	15
R-401C	21
R-402A	1,680
R-402B	1,064
R-403A	1,400
R-403B	2,730
R-404A	3,260
R-406A	0
R-407A	1,770
R-407B	2,285
R-407C	1,526
R-407D	1,428
R-407E	1,363
R-408A	1,944
R-409A	0
R-409B	0
R-410A	1,725
R-410B	1,833
R-411A	15
R-411B	4
R-412A	350
R-413A	1,774
R-414A	0
R-414B	0
R-415A	25
R-415B	105
R-416A	767
R-417A	1,955
R-418A	4
R-419A	2,403
R-420A	1,144
R-500	37
R-501	0
R-502	0
R-503	4,692
R-504	313
R-505	0
R-506	0
R-507 or R-507A	3,300
R-508A	10,175
R-508B	10,350
R-509 or R-509A	3,920
Source: ASHRAE Standard 34	

Table B.21 MRR Reporting Subpart Categories

Rule Section	Subpart	Initial Reporting Year
98.10	Subpart A—General Provisions	2010
98.20	Subpart B—(Reserved)	
98.30	Subpart C—General Stationary Fuel Combustion Sources	2010
98.40	Subpart D—Electricity Generation	2010
98.50	Subpart E—Adipic Acid Production	2010
98.60	Subpart F—Aluminum Production	2010
98.70	Subpart G—Ammonia Manufacturing	2010
98.80	Subpart H—Cement Production	2010
98.90	Subpart I—Electronics Manufacturing	2011
98.100	Subpart J—Ethanol Production	N/A
98.110	Subpart K—Ferroalloy Production	2010
98.120	Subpart L—Fluorinated Gas Production	2011
98.130	Subpart M—Food Processing	N/A
98.140	Subpart N—Glass Production	2010
98.150	Subpart O—HCFC–22 Production and HFC–23 Destruction	2010
98.160	Subpart P—Hydrogen Production	2010
98.170	Subpart Q—Iron and Steel Production	2010
98.180	Subpart R—Lead Production	2010
98.190	Subpart S—Lime Manufacturing	2010
98.200	Subpart T—Magnesium Production	2011
98.210	Subpart U—Miscellaneous Uses of Carbonate	2010
98.220	Subpart V—Nitric Acid Production	2010
98.230	Subpart W—Petroleum and Natural Gas Systems	2011
98.240	Subpart X—Petrochemical Production	2010
98.250	Subpart Y—Petroleum Refineries	2010
98.260	Subpart Z—Phosphoric Acid Production	2010
98.270	Subpart AA—Pulp and Paper Manufacturing	2010
98.280	Subpart BB—Silicon Carbide Production	2010
98.290	Subpart CC—Soda Ash Manufacturing	2010

Rule Section	Subpart	Initial Reporting Year
98.300	Subpart DD—Use of Electric Transmission and Distribution Equipment	2011
98.310	Subpart EE—Titanium Dioxide Production	2010
98.320	Subpart FF—Underground Coal Mines	2011
98.330	Subpart GG—Zinc Production	2010
98.340	Subpart HH—Municipal Solid Waste Landfills	2010
98.350	Subpart II—Industrial Wastewater Treatment	2011
98.360	Subpart JJ—Manure Management	N/A
98.370	Subpart KK—Suppliers of Coal	N/A
98.380	Subpart LL—Suppliers of Coal-based Liquid Fuels	2010
98.390	Subpart MM—Suppliers of Petroleum Products	2010
98.400	Subpart NN—Suppliers of Natural Gas and Natural Gas Liquids	2010
98.410	Subpart OO—Suppliers of Industrial Greenhouse Gases	2010
98.420	Subpart PP—Suppliers of Carbon Dioxide	2010
98.430	Subpart QQ—Imports and Exports of Equipment Pre–charged with Fluorinated GHGs or Containing Fluorinated GHGs in Closed–cell Foams	2011
98.440	Subpart RR—Geologic Sequestration of Carbon Dioxide	2011
98.450	Subpart SS—Manufacture of Electric Transmission and Distribution Equipment	2011
98.460	Subpart TT—Industrial Waste Landfills	2011
98.470	Subpart UU—Injection of Carbon Dioxide	2011

From: http://www.epa.gov/climatechange/emissions/subpart.html