Electricity Supply Sector

Part 1 of 6 Supporting Documents

Sector-Specific Issues and Reporting Methodologies Supporting the General Guidelines for the Voluntary Reporting of Greenhouse Gases under Section 1605(b) of the Energy Policy Act of 1992

Examples

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1.0 Electricity Supply Sector

This document supports and supplements the General Guidelines for reporting greenhouse gas information under Section 1605(b) of the Energy Policy Act (EPAct) of 1992. The General Guidelines provide the rationale for the voluntary reporting program and overall concepts and methods to be used in reporting. Before proceeding to the more specific discussion contained in this supporting document, you should read the General Guidelines. Then read this document, which relates the general guidance to the issues, methods, and data specific to the electricity supply sector. Other supporting documents address the residential and commercial buildings sector, the industrial sector, the transportation sector, the forestry sector, and the agricultural sector.

The General Guidelines and supporting documents describe the rationale and processes for estimating emissions and analyzing emissions-reducing and carbon sequestration projects. When you understand the approaches taken by the voluntary reporting program, you will have the background needed to complete the reporting forms.

The General Guidelines and supporting documents address four major greenhouse gases: carbon dioxide, methane, nitrous oxide, and halogenated substances. Although other radiatively enhancing gases are not generally discussed, you will be able to report nitrogen oxides (NO_x), nonmethane volatile organic compounds (NMVOCs), and carbon monoxide (CO) after the second reporting cycle (that is, after 1996).

The Department of Energy (DOE) has designed this voluntary reporting program to be flexible and easy to use. For example, you are encouraged to use the same fuel consumption or energy savings data that you may already have compiled for existing programs or for your own internal tracking. In addition, you may use the default emissions factors and stipulated factors that this document provides for some types of projects to convert your existing data directly into estimated emissions reductions. The intent of the default emissions and stipulated factors is to simplify the reporting process, not to discourage you from developing your own emissions estimates.

Whether you report for your whole organization, only for one project, or at some level in between, you will find guidance and overall approaches that will help you in analyzing your projects and developing your reports. If you need reporting forms, contact the Energy Information Administration (EIA) of DOE, 1000 Independence Avenue, SW, Washington, DC 20585.

1.1 Electricity Supply: Overview

The electricity supply sector consists of generation, transmission, and distribution subsystems.

- The generation system consists of units powered by coal, nuclear energy, water, oil, gas, or renewable sources, together with generation substations that connect the generators to transmission lines.

- The transmission system carries bulk power from generation substations to transmission substations located along lines in the system. The subtransmission system routes power to distribution substations, which are the points of power delivery to the distribution network.

- The distribution system delivers power supplied by the transmission and subtransmission network through a system of primary feeders, laterals, and secondary feeders to the utility's customers. The combined transmission and distribution (T&D) system connects the generation facilities with all end-use loads served by the utility.

Emissions-reducing projects in this sector can reduce primary inputs of fuels to the system, especially in the generation system; increase the efficiency of energy used or delivered; decrease energy losses in the T&D system; and decrease demand for electricity. Possible projects range from those that have direct, easily measurable emissions effects (such as fuel switching) to those that have indirect, difficult-to-estimate effects (such as efficiency improvements in T&D equipment).

1.1.1 Reporting Entities

Entities in this sector may fall into one of several categories: electric utilities or their subsidiaries, nonutility power producers, suppliers to the electric power industry, end users, or utility research/information organizations. An electric utility could be one of the following: investor-owned, rural electric cooperative, municipal utility or agency, government power authority, or power pool. Nonutility power producers include qualifying generators, qualifying small power producers, and other nonutility generators, including independent power producers (IPPs). Typical suppliers to the electric power industry include manufacturers of T&D equipment, other manufacturers or service suppliers, manufacturer's representatives, distributors, consultants, marketing entities, or contractors/ constructors. End users are in the industrial, institutional, commercial, or residential sectors. Research organizations may include such entities as the Electric Power Research Institute (EPRI).

If your company has multiple subsidiaries, you may choose to aggregate some or all of your projects in a single report or to have the subsidiaries report separately. Your decision to report on an entity-wide basis or separately must be based on the types of emissions reduction activities, keeping in mind that you must report the significant effects of a project. (See the General Guidelines, "What Effects Did the Project Have?")

1.1.2 Sector-Specific Issues

Generally speaking, issues in the electricity supply sector revolve around selecting, analyzing, and reporting information that is already available or easily derived. The interconnectedness of the parts of the grid vis a vis the move toward greater competition also raise issues of multiple reporting and confidentiality.

As a part of the electricity supply sector, you likely collect and report many types of data, including information on fuel use, system efficiency, and emissions to the air, water, and soil. For example, you may hold tradable permits under the Acid Rain Program. You may also already participate in programs that address climate change issues. You may be working with DOE on Climate Challenge, for which this voluntary reporting program is the principal reporting mechanism. You may be able to use the information or estimation methods developed for these other programs as a basis for your EPAct Section 1605(b) reports.

The integrated resource planning (IRP) process may provide a rich source of data you can use to develop reports under this voluntary reporting program. EPAct amends the Public Utility Regulatory Policies Act to require IRP, and public utility commissions (PUCs) in many jurisdictions are requiring utilities to incorporate IRP results into their reporting systems. The objective of IRP is to minimize the total cost of meeting demand for energy services. EPAct defines the IRP process as

> a planning and selection process for new energy resources that evaluates the full range of alternatives, including new generating capacity, power purchases, energy conservation and efficiency, cogeneration and district heating and cooling applications, and renewable energy resources, to provide adequate and reliable service to its electric customers at the lowest system cost (EPAct Section 111[d]).

The emphases on conservation, efficiency, alternative technologies, and renewable resources should both lead to adoption of emissions-reducing activities and provide data for reportable projects under the EPAct 1605(b) program. However, the focus of IRP is on least cost, not on emissions reductions, so you will likely need to perform some additional estimating in order to report under this program.

The electricity supply sector is also characterized by a wealth of methodologies that you can use to develop reports under this voluntary reporting program. You probably perform calculations with different estimation tools for a wide diversity of purposes. Some available methodologies, such as those set forth by the Intergovernmental Panel on Climate Change (IPCC 1991) and the Environmental Protection Agency (EPA 1990), were designed specifically to measure greenhouse gases or other emissions of environmental concern (for example, acid rain precursors). Other methods were designed for economic purposes and thus focus on fuel/energy use and efficiency. EIA, power marketing administrations, EPRI, and others collect data that, together with additional data such as default emissions factors, may be used to estimate greenhouse gas emissions.

To develop reports under this program, you may also use the stipulated factors by technology provided by this document for greenhouse gas emissions, primarily for non-carbon dioxide gases. (Carbon dioxide emissions rates depend almost entirely on the fuel use characteristics, not technology use.)

You may have developed estimating methods specific to your organization, perhaps adapted from standard methods but using measured/monitored data. On the other hand, you may use standard methods to be responsive to existing reporting requirements to your public utility commission and others. The examples in this supporting document and Case 3 in the General Guidelines will give you an idea of the range of options open to you. Under this voluntary reporting program, you may choose the methods that will help you build a credible report. In your report, you must identify or describe the methods you used to estimate your emissions and emissions reductions (see the General Guidelines, "What Are the Minimum Reporting Requirements?"). You may further wish to keep a complete set of data and calculations to back up your reports under this program.

When more than one party is involved in generating emissions or achieving emissions reductions, all or several may decide to report jointly, or each may report separately. (See the General Guidelines, "What If Two or More Organizations Wish to Report the Same Project?") For example, if you sell or purchase power, any or all sellers and purchasers may report under this voluntary program. A joint report would have the advantage of comprehensiveness, with full data provided for a complete picture of a utility's emissions and emissions reductions. If you do not report jointly, each seller and purchaser should identify the other as a possible reporter.

You may also wish to report jointly when you have been engaged with others on emissions-producing and emissions reduction activities. A special instance of this is the generation and transmission cooperatives, where estimation of emissions and projects can probably be most accurately and easily accomplished for the entire operation.

You may choose to report through a third party that could aggregate emissions reductions for a group of entities with similar backgrounds and methods for reporting. The third party could provide an additional layer of confidentiality, and your contributions would not have to be individually identified in the report. Examples of such third-party entities include government power authorities, regional transmission groups, regional reliability councils, trade associations, or engineering/energy service companies. A third party might also provide technical assistance in carrying out emissions reduction projects and reporting. For example, the Western Area, Southwestern, and Southeastern Power Administrations have jointly developed a set of integrated resource planning (IRP) tools called the *Resource Planning Guide* (WAPA et al. 1993), designed to help small- and mid-sized utilities analyze supply and demand-side management (DSM) alternatives.

When another party is involved in identifying, implementing, or paying for the emissions reduction project, you should identify that party to track possible multiple reporting. For example, when a utility replaces an existing fossil-fuel-fired plant with a gas turbine combined cycle system, the manufacturer of the turbine system should be identified. Similarly, if you submit data on emissions reductions to one or more trade associations, you should identify all those parties.

1.1.3 Key Concepts for Electricity Sector Analysis

For the electricity supply sector, your analysis should take into account two important distinctions: between direct and indirect emissions and between fuel-based and technology-based emissions. These will influence how you estimate emissions and perform project analyses (see Sections 1.2, 1.5, and 1.6).

- ***Direct vs. Indirect Emissions:*** Some activities in the electricity supply sector produce emissions directly, that is, from combusting fossil fuel in the electricity generation process. Other operations determine how electricity is transmitted, distributed, and used. These activities do not themselves produce emissions but indirectly affect emissions levels from the generating activities by affecting how much electricity must be produced. If you are *not* reporting total emissions for your whole organization, you will need to approach direct and indirect activities differently, especially when you estimate emissions (see Section 1.2).

  Three general approaches can be taken to estimate reductions in greenhouse gas emissions in the electricity supply sector:

- For *direct emissions* (from the generation subsystem), measure or calculate greenhouse gases with and without emission-reducing activities, and then calculate the net reduction in greenhouse gas emissions.

- For *direct emissions* from activities that involve *a combination of fuels*, calculate the change in greenhouse gas emissions for each fuel and then, for each gas, sum across the fuels to obtain the net reduction in emissions of each gas.

- For *indirect emissions*, calculate the energy savings from the energy activity and multiply the savings by a greenhouse gas emissions factor (see Section 1.7).

- ***Fuel-Based vs. Technology-Based Emissions:*** In the electricity supply sector, most carbon dioxide emissions levels are directly related to the type and quantity of fossil fuel combusted. Therefore, unless you directly monitor your emissions, you will likely begin with data on types and amounts of fuel consumed by your operations, then derive the amount of carbon contained in the fuels, and finally convert the carbon figure to an amount of carbon dioxide (see Appendix D).

  Emissions of greenhouse gases, however, can be estimated by data associated with the combustion technologies. Table 1.1 provides stipulated factors that you can use in generating reports under this voluntary reporting program if you do not directly monitor your emissions.

1.2 Estimating and Reporting Greenhouse Gas Emissions

The General Guidelines ("What is Involved in Reporting Emissions?") explain that reporting information on greenhouse gas emissions for the baseline period of 1987 through 1990 and for subsequent calendar years on an annual basis is considered an important element of this voluntary reporting program. If you are able to report emissions for your entire organization, you should consider providing a comprehensive accounting of such emissions so that your audience can gain a clear understanding of your overall activities.

1.2.1 Direct Emissions

Direct emissions (from fuels used at your generation sites) may be monitored or estimated. Monitoring emissions is discussed in Section 1.5.1, including continuous emissions monitoring (CEM) and stack approaches to monitoring. This section discusses a procedure for estimating greenhouse gas emissions from generation subsystem sources based on methodologies recommended by the IPCC (1991) and EPA (1990). You may use these methodologies to calculate emissions reductions in project analysis (see Section 1.7). Carbon dioxide is addressed separately from other energy-related greenhouse gases because the methods are fundamentally different. Carbon dioxide emissions depend primarily on fuel properties, while non-carbon dioxide greenhouse gases are primarily related to technology and combustion conditions.

Direct carbon dioxide emissions

Carbon dioxide emissions occur primarily from combustion of fossil fuels. Most carbon in fuel is emitted as carbon dioxide during the combustion process. Therefore, the method to estimate greenhouse gas emissions begins with determining amounts of fuels and amounts of carbon in those fuels. When you have estimated the total carbon, you can easily estimate the carbon dioxide that results from combusting the carbon. The following method is modified from the IPCC (1991) standard approach.

To estimate direct carbon dioxide emissions, follow the four steps below. Example 1.1 illustrates the method used in a hypothetical situation:

1. Identify the type of fuel consumed and energy consumption by fuel type. Energy consumption data by fuel type may be derived from data you supply to EIA (see the EIA report listing in Appendix 1.A and, for example, Form EIA-767) or to EPA under its Acid Rain Program. If you only know fuel quantity, you can calculate the energy supplied by using the heating value factors (HVFs) in IPCC (1991). (When these HVFs and other data are updated by the IPCC, you should use the most current numbers.)

2. Determine the carbon emissions coefficients of the fuels identified and total carbon potentially released from use of the fuels. Default values for greenhouse gas emissions per unit of energy for most common fossil fuels are provided in Appendix B, Emissions Factors. If you do not know the carbon content of a fossil fuel, but can identify the type, you should use an average emission/unit energy value for that fuel. For coal, carbon emissions per ton vary considerably, depending on the coal's composition. Although variability of carbon emissions on a mass basis can be considerable, carbon emissions per unit of energy (for example, per gigajoule) vary much less.

3. Using the values from Steps 1 and 2, estimate carbon oxidized from energy uses. (See Table C.2 in Appendix C for U.S. data.) For natural gas, less than 1 percent of the carbon in natural gas is unoxidized during combustion and remains as soot in the burner, in the stack or in the environment. For oil, 1.5 percent passes through the burners and is deposited in the environment without being oxidized. For coal, 1 percent of carbon supplied to furnaces is discharged unoxidized, primarily in the ash. In general, you may assume that 99 percent of carbon is oxidized during combustion.

4. Convert the net carbon oxidized during combustion to total carbon dioxide emissions. The conversion factor for translating carbon emissions into carbon dioxide emissions is 3.67, as explained in Appendix D.

This four-step method is shown by the following equation, using standard international units:

$$E_a = FC_a \bullet CECo_a \bullet 0.99 \bullet 3.67$$

where E_a = carbon dioxide emissions for fuel a (in gigagrams)
FC_a = energy consumption of fuel a (in petajoules)
$CECo_a$ = carbon emissions coefficient for fuel a (in kilograms of carbon/gigajoule)
0.99 = oxidation factor
3.67 = conversion factor (carbon to carbon dioxide) (See Appendix D).

The same equation may be written using English units:

$$E_a = FC_a \bullet CECo_a$$

where E_a = carbon dioxide emissions for fuel a (in pounds)
FC_a = energy consumption of fuel a (in million Btu)
$CECo_a$ = carbon dioxide emissions factor for fuel a (in pounds of carbon dioxide/million Btu) (See Appendix C and DOE/EIA 1992).

Note on using Standard International (SI) Units

Because greenhouse gas emissions raise global issues, international organizations such as the IPCC have developed estimating methods using standard international (SI) units such as petajoules and gigagrams. These metric units are presented in the guidelines as features of these internationally used methods. However, you may report in English units such as pounds and short tons. The EIA forms for this voluntary reporting program allow you to specify the units you use.

Metric SI units used in these supporting documents are listed in Appendix A to this volume, along with conversion factors to English units. Of particular interest for methods used in electricity supply are the following:

petajoules (PJ)	=	10^{15} joules	= 947.8×10^{9} Btu
gigajoules (GJ)	=	10^{9} joules	= 947.8×10^{3} Btu
gigagram (Gg)	=	10^{3} metric tons	= 1.1025358×10^{3} short tons

You may be more familiar with using British units. Therefore, the initial example, 1.1, in which SI units appear, is repeated using English units.

Example 1.1 - Calculation of Direct Carbon Dioxide Emissions (Standard International Units)

Note: This example illustrates only one approach to analyzing a project; your analysis, methods, and calculations will vary depending on your particular circumstances, the geographic location of the project, and other factors.

Northern Electric, at its Pine River power plant, consumed 1 million metric tons (MT) of sub-bituminous coal per year. To calculate total carbon dioxide emissions in that year, the utility used the modified IPCC methodology reflected in the equation discussed in Section 1.2.1 of this document:

$E_a = FC_a \bullet CECo_a \bullet 0.99 \bullet 3.67$

Step 1. Northern converted metric tons to energy consumption in petajoules. Using the IPCC (1991) value of 19.4 GJ/metric ton for sub-bituminous coal (see Appendix 1.C), Northern calculated its total annual coal energy consumption.

FC = Annual coal energy consumption = 10^6 MT coal • 19.4 GJ/metric ton • 10^{-6} PJ/GJ = 19.4 PJ

Step 2. The utility determined the carbon emissions coefficient from Table C.1:

CECo = Emissions coefficient for sub-bituminous coal = 26.1 kg C/GJ

Step 3. Northern was then ready to calculate total carbon oxidized, using the values from Steps 1 and 2:

Total Carbon oxidized = 19.4 PJ • 26.1 kg C/GJ • 10^6 Gg/kg • 10^{-6} PJ/GJ • 0.99 = 501.3 Gg carbon

Step 4. Finally, Northern converted the net carbon oxidized to carbon dioxide emissions, using the conversion factor described in Appendix D:

E = Total CO_2 = 3.67 Gg CO_2/Gg C • 501.3 Gg carbon = 1,839.7 Gg CO_2

The Pine River power plant consumed 1 million tons of coal and reports emissions of 1,839 Gg, or approximately 1.8 million metric tons of carbon dioxide annually (1 Gg = 10^3 metric tons).

Example 1.1 - Calculation of Direct Carbon Dioxide Emissions (English Units)

Note: This example illustrates only one approach to analyzing a project; your analysis, methods, and calculations will vary depending on your particular circumstances, the geographic location of the project, and other factors.

Northern Electric, at its Pine River power plant (located in Montana), consumed 1 million short tons (ST) of sub-bituminous coal per year. To calculate total carbon dioxide emissions in that year, the utility used the modified IPCC methodology reflected in the equation discussed in Section 1.2.1 of this document:

$E_a = FC_a \bullet CECo_a$

Step 1. First, Northern converted short tons to energy consumption in million Btu. Using its own value of 18 million Btu/short ton for sub-bituminous coal, Northern calculated its total annual coal energy consumption.

FC = Annual coal energy consumption = 10^6 ST coal x 18 million Btu/short ton = 18×10^6 million Btu

Step 2. The utility determined the carbon dioxide emissions factor from Table C.2 of DOE/EIA (1992):

CECo = Emissions factor for sub-bituminous Montana coal = 213.4 lb CO_2/million Btu

Step 3. Northern was then ready to calculate total carbon dioxide emissions, using the values from Steps 1 and 2:

Total CO_2 = 18×10^6 million Btu • 213.4 lb CO_2/million Btu = 3,841.2 million lb

The Pine River power plant consumed 1 million short tons of coal and reports emissions of 3,841 million pounds, or approximately 1.9 million short tons of carbon dioxide annually (1 short ton = 2,000 pounds).

In the example above, Northern Electric estimated the major component of its emissions at one plant. A more complete accounting would include Northern's other facilities and other emissions-producing activities. However, you may not have access to all the information you need to estimate your aggregate emissions. If you have partial information that includes most emissions, you should note in your report what activities are and are not included. For example, an IPP and a utility may report energy consumption emissions separately, noting other activities for which they are not directly responsible.

When you report historic emissions, you should note the activities that are excluded because you lack information. If you report emissions for several different years, you should report reasons for changes, including changes in the volume of business, internal efficiency, and types of services delivered; the amount of outsourcing; or other factors that could account for differences from year to year.

Direct non-carbon dioxide emissions

Carbon dioxide is not the only greenhouse gas emitted by fuel combustion. Other gases such as methane and nitrous oxide are also released. You may wish to report data on these other gases as well as carbon dioxide. This section presents a modified IPCC method for estimating emissions and illustrates that method in Example 1.2.

Emissions of non-carbon dioxide greenhouse gases depend on fuel, technology type, and the pollution control technologies. Emissions will also vary more specifically with the size and vintage of the combustion technology, its maintenance, and its operation. When you have data about your fuel consumption for each technology type and wish to estimate the contribution of each gas to that total, you may use the approach outlined in this section. Alternatively, data reported to EIA or EPA's Acid Rain Program can be used to estimate total emissions for each greenhouse gas type of interest.

Based on the modified IPCC methodology, the main steps in determining the non-carbon dioxide emissions can be summarized as follows:

1. Determine your energy input data for each fuel/technology type, using data reported to EIA as appropriate. Basic fuel categories include oil, coal, and other solids and gases.

2. Compile emissions factor data for each fuel/technology combination you use in electricity generation. You may use the representative emissions factors by main technology and fuel types from Table 1.1. These factors represent the average performance of a population of similar technologies. You may also use the Environmental Characterization Data prepared by the National Renewable Energy Laboratory (NREL 1993) to estimate emissions for your technologies. If control technologies are in place, you need to consider their performance.

3. Develop estimates of each greenhouse gas, based on the energy inputs to the various fuel/technology inputs, technology by technology.

4. For each gas, sum across the individual fuel/technology combinations to arrive at the entity-wide total for each greenhouse gas.

Table 1.1. Representative Emissions Factors for Non-Carbon Dioxide Greenhouse Gases

Fuel/Technology Type	Emissions Factors (expressed in grams per gigajoule g/GJ, of energy input[a] and lb/MWh)			
	CH_4 lb/MWh	CH_4 g/GJ	N_2O lb/MWh	N_2O g/GJ
Natural Gas - Boilers	N/A	0.1	N/A	N/A
Gas Turbine Combined Cycle	.015	6.1	.063	N/A
Gas Turbine Simple Cycle	N/A	5.9	.240	N/A
Residual Oil Boilers	N/A	0.7	N/A	N/A
Distillate Oil Boilers	N/A	0.03	.276	N/A
MSW - Mass Feed[b]	.02	N/A	.55	N/A
Coal - Spreader Stoker	N/A	0.7	N/A	0.8
Coal - Fluidized Bed Combined Cycle	N/A	0.6	N/A	N/A
Coal - Fluidized Bed	N/A	0.6	.325	N/A
Coal - Pulverized Coal	N/A	0.6	N/A	0.8
Coal -Tangentially Fired	N/A	0.6	N/A	0.8
Coal - Pulverized Coal Wall Fired	N/A	0.6	N/A	0.8
Wood - Fired Boilers[b]	N/A	18	.55	N/A

(a) Values were originally based on "gross" (or higher) heating value; they were converted to "net" (or lower) heating value by assuming that net heating values were 5 percent lower than gross heating values for coal and oil, and 10 percent lower for natural gas. These percentage adjustments are the assumption from the Organization for Economic Cooperation and Development and the International Energy Agency (cited in IPCC 1991) on how to convert from gross to net heating values as discussed in the IPCC 1991.

(b) Emissions factors were adjusted to lower heating value, assuming a 5 percent difference in energy content between lower heating value and higher heating value.

Source: IPCC 1991 (for g/GJ values); NREL 1993 (for lb/MWh values). N/A = not available

This four-step method may be expressed in the following equation:

$$E_j = \sum_{all\ k,l} \left(EF_{jkl} \bullet A_{kl} \right)$$

where E_j = emissions of gas j, in grams

EF_{jkl} = emissions factor (g/GJ), for gas j, fuel type k, technology l, given in Table 1.1

A_{kl} = energy input (GJ) of fuel type k to technology l.

Although carbon dioxide emissions are not technology dependent, they can also be estimated by technology using this "bottom-up" approach, from the data developed to estimate non-carbon dioxide emissions. Specifically, since the fuel type is known, the carbon emission coefficients, by fuel type, provided in Appendix B to this volume, Emissions Factors, can be applied to the total amount of input energy for each fuel/technology type to determine total carbon consumed for that category. To determine the total carbon dioxide emissions, you would sum across all technology/fuel type combinations and then follow steps 3 and 4, as discussed in the earlier section on "Direct carbon dioxide emissions" and illustrated in Example 1.1.

Example 1.2 illustrates the use of this method to calculate non-carbon dioxide emissions (methane) and carbon dioxide emissions for a hypothetical utility.

Example 1.2 - Calculation of Direct Methane Emissions

Notes: (1) This example illustrates only one approach to analyzing a project; your analysis, methods, and calculations will vary depending on your particular circumstances, the geographic location of the project, and other factors.

(2) The fuel type and technology type were selected for illustrative purposes only and may not reflect a realistic situation at a utility.

Rogers Utility (RU) decided to report methane emissions at its Century power plant, in addition to reporting carbon dioxide emissions. RU had one pulverized coal boiler, one fluidized-bed combustion coal boiler, one residual oil boiler, and one combined cycle gas turbine at the Century plant.

The table below illustrates how RU used the following equation to estimate its methane emissions using only data from its records or retrieved from Table 1.1 of this document.

$$E_j = \sum_{\text{all } k,l} \left(EF_{jkl} \bullet A_{kl} \right)$$

Fuel Type	**Technology Type**	**Monthly Fuel Consumption[(a)]**	**Conversion Factors[(b)]**	**A_{kl} Monthly Energy Input (GJ)**	**EF_{jkl}, Methane Emissions Conversion Factors (g/GJ)[(c)]**	**E_j, Methane Emission (g)**
Coal	Pulverized-coal boiler	100,000 MT	1 MT coal = 24×10^6 Btu = 25 GJ	2.5×10^6	0.6	1.52×10^6
Coal	Fluidized-bed boiler	100,000 MT	1 MT coal = 24×10^6 Btu = 25 GJ	2.5×10^6	0.6	1.52×10^6
Oil	Residual oil boiler	3,000 bbl	1 bbl oil = 5.8×10^6 Btu = 6.12 GJ	18.36×10^3	0.7	12.85×10^3
Natural gas	Combined-cycle gas turbine	2,048,000 Mcf	1 Mcf gas = 1.030×10^6 Btu = 1.09 GJ	2.23×10^6	6.1	13.62×10^6
Total methane emissions per month						**16.67×10^6**

MT = metric tons; cf = cubic feet; Mcf = one thousand cubic feet = 10^3 cf; bbl = barrels

(a) Amounts given for illustrative purpose.
(b) Source: DOE 1991.
(c) Source: Table 1.1 of this document.

The Century plant emitted 16.67 metric tons of methane per month, or 200.04 metric tons of methane annually.
RU wanted to also determine carbon dioxide emissions using this "bottom-up" approach. The utility used the same data developed to estimate non-carbon dioxide emissions, combined with the carbon emissions conversion factors for each fuel type, as given in Appendix 1.C.

Example 1.2 - (cont'd)

Fuel Type	Technology Type	Monthly Fuel Consumption[(a)]	Conversion Factors[(b)]	Monthly Energy Consumption (PJ)	Carbon Emissions Conversion Factors[(c)] (kg C/GJ)	Monthly Carbon Emissions (Gg)
Coal	Pulverized-coal boiler	100,000 MT	1 MT coal = 24×10^6 Btu = 25 GJ	2.5	25.8	64.5
Coal	Fluidized-bed boiler	100,000 MT	1 MT coal = 24×10^6 Btu = 25 GJ	2.5	25.8	64.5
Oil	Residual oil boiler	3,000 bbl	1 bbl oil = 5.8×10^6 Btu = 6.12 GJ	0.018	20	0.37
Natural gas	Combined-cycle gas turbine	2,048,000 Mcf	1 Mcf gas = 1.030×10^6 Btu = 1.09 GJ	2.23	15.3	34.12
Total carbon emissions per month						**163.49**

MT = metric tons; cf = cubic feet; Mcf = one thousand cubic feet = 10^3cf; bbl = barrels.

(a) Amounts given for illustrative purpose.
(b) Source: DOE 1991.
(c) Source: Table 1.1 of this document.

RU adjusted this factor to reflect an assumed 99 percent combustion efficiency and converted to annual carbon dioxide emissions.

$$\text{Total annual } CO_2 \text{ emissions} = 163.49 \text{ Gg C/month} \bullet 0.99 \bullet 3.67 \text{ Gg } CO_2/\text{Gg C} \bullet 12 \text{ months/yr} = 7.128 \times 10^3 \text{ Gg } CO_2/\text{yr}.$$

Note that both of these calculations for RU's Century plant reflect an assumption that the monthly fuel consumption figures represent an average of all months.

1.2.2 Indirect Emissions

Reporters may be responsible not only for emissions that occur at their own facilities, but also for emissions occurring at other sites. For example, an electricity consumer is indirectly responsible for some portion of the emissions that occur at the electricity generation site. Similarly, an electric utility that purchases power from outside sources contributes indirectly to the emissions of the generator.

If you are reporting emissions in this voluntary reporting program, you may also want to report emissions associated with purchased electricity. If so, you must distinguish between direct and indirect emissions, and you should identify the source of the indirect emissions and how you estimated the quantity of emissions. You may also want to discuss what you are reporting with the generator/seller of the power to identify or avoid multiple reporting of the same emissions.

1.3 Analyzing Emissions Reduction Projects

Section 1.2 discussed methods for estimating emissions; this section and the following sections provide guidance for analyzing projects you have undertaken to reduce those emissions so that you may report reductions. This section provides an overview and rationale for the process, relating the General Guidelines to the electricity supply sector. The following sections discuss specific emissions-reducing measures and methods for estimating the reductions achieved.

Figure 1.1 presents a simplified view of the project analysis process in the electricity supply sector. This process is discussed in the General Guidelines; this and the following sections augment the general guidance with considerations specific to electricity supply.

Define the project. In the project definition step, you determine whether to report emissions levels for your whole organization (entity-level reporting) or some part of it. This decision may be based, in part, on what data you have, what primary effects are associated with the project (for example, will effects show up at the overall organization level?), and who the audience for your report will be (for example, will interested environmental groups find a partial report credible?).

The analysis of emissions reductions projects in the electricity supply sector consists of the basic steps that are discussed in the General Guidelines under the heading "How Should I Analyze Projects I Wish to Report?":

Establish a reference case to use as a basis for comparison with the project. You need to determine your reference case in conjunction with defining your project, since you must establish a basis for comparison. If you wish to compare overall emissions from the project year with those of an earlier year, you may choose a basic reference case. If, however, your purpose is instead to highlight the effects of a specific emissions reductions project for which no historical comparison exists, you may choose a modified reference case.

Identify effects of the project. If you identify significant effects outside your current project definition, you may choose to redefine your project. In any case, you should identify all such effects you can and, if they are large, quantify them to the extent possible.

Estimate emissions for the reference case and the project. If you have monitored data on your total emissions and are reporting at the entity level, you are ready to report after identifying any external effects. Otherwise, your choice of an estimation method may depend on whether emissions are direct or indirect. Direct emissions may be estimated from fuel consumption data and from stipulated factors associated with technologies used to generate electricity. Indirect emissions are estimated from energy savings data (for example, reducing losses in the transmission system) that are then traced back to the generation system to determine the associated emissions reductions.

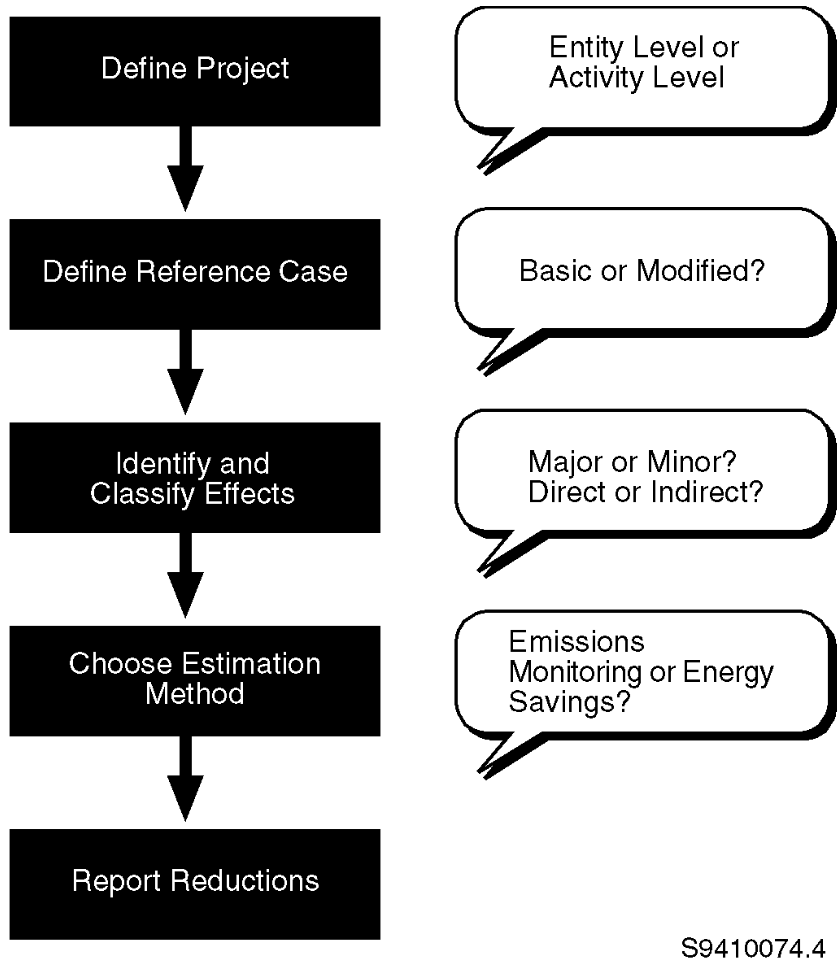

Figure 1.1. Project analysis in the electricity supply sector includes choosing estimation methods based on whether the project is at the entity or activity level and whether emissions effects are direct or indirect. (See Section 1.4.)

Project analysis can be simple or complex, depending upon a number of factors involved in each step. This section discusses the major methodologies used to calculate emissions reductions, but you have the flexibility to choose how to define your project and reference cases and how to estimate emissions reductions.

1.3.1 Establish a Reference Case

The first step after defining a project is identifying and describing a reference case. Emissions reductions are defined as the difference between actual emissions and what emissions would have been had the reported project not been undertaken. The reference case is the expression of what emissions would have been without the project.

You may define a reference case in two ways: a *basic* reference case and a *modified* reference case. A basic reference case is defined as the historic level of emissions; a modified reference case is adjusted to account for your expectation that, during the project year, emissions without the project would have been different from historic levels. Examples 1.3 and 1.4 illustrate situations in which a modified reference case would be appropriate.

Example 1.3 - A Modified Reference Case - Growth and Decline in Demand

Note: This example illustrates only one approach to analyzing a project; your analysis, methods, and calculations will vary depending on your particular circumstances, the geographic location of the project, and other factors.

A utility, Ptomkin Standard Electric (PSE), experienced an average growth in electricity demand of 1.3 percent per year. PSE could have met the growth in demand in two ways. One was to add generating plants (supply side resources); the other was to increase the efficiency of its T&D system and reduce demand (under a demand-side management program). Supply-side resources could have been built either by the utility itself or by a nonutility—an independent power producer.

To find the best mix of these resources, PSE engaged in the IRP process required by its public utility commission. IRP, an emerging planning standard for utilities, seeks full integration of forecasting, consideration of DSM, supply planning, T&D resources, rate and financial planning, and strategic management activities.

As a result of the IRP process, PSE was committed to a program to reduce a considerable amount (50 to 60 percent) of the growth in electricity demand in the next 10 years by promoting conservation of electricity. PSE could have met this commitment by a combination of DSM options (rebates to customers for more efficient lighting, motors, and air conditioning) and supply-side options (independent power production in the short term and repowering of some existing plants later).

Since PSE's demand *was and would be changing* from year to year, PSE used a modified reference case to report its projects. Furthermore, PSE's project analysis included the independent power production. To establish its modified reference case, PSE had data generated for the IRP report to its public utility commission which it verified against measurement data reported under the EPA's Acid Rain Program.

Once PSE established its modified reference case, the process for calculating and reporting emissions reductions for PSE followed the same steps as described in Sections 1.5, 1.6, and 1.7.

Example 1.4 - A Modified Reference Case - New Generating Capacity

Note: This example illustrates only one approach to analyzing a project; your analysis, methods, and calculations will vary depending on your particular circumstances, the geographic location of the project, and other factors.

A new IPP, Cogen, Inc., used combustion turbine technology to produce power as a cogenerator (that is, produce electricity while making use of the waste heat) for Ptomkin Standard Electric (PSE). Because Cogen had not existed the previous year, it could not use a basic reference case if it wished to report under this program. Cogen had to use a modified reference case, based on external data obtained from PSE, to determine what emissions would have been (but for the project) in the year in which the project's effects are being measured. Cogen needed to access PSE's data generated for the IRP report and measurement data reported to EPA's Acid Rain Program.

1.3.2 Identify Effects of the Project

Some projects have limited, well-defined effects. For example, improving the system efficiency of a boiler has beneficial effects but virtually no effects beyond the operation of the boiler itself. Other activities, such as fuel switching from coal to natural gas, may have the effect of reducing emissions related to serving baseload demand, but may also induce a change in the dispatching patterns. The switch to natural gas may also lead to higher methane emissions or lower transportation-related greenhouse gas emissions. In some instances, especially where two or more projects are undertaken simultaneously, you may not be able to distinguish the emissions effects of any given activity from the effects of other activities.

This raises two associated issues for project analysis. First, you must decide whether to concentrate your analysis narrowly on activity-level effects (see Example 1.5), broadly on entity-level effects, or even more broadly to include effects outside your organization (see Example 1.6). The underlying assumption in entity-level analysis is that any detected changes in entity-level emissions can be attributed to the project(s). The second issue is that, regardless of whether you focus your analysis narrowly or broadly, you should identify effects that are not accounted for within the scope of your analysis.

In theory, for a given project, an analysis narrowly focused at the activity level would produce the same estimate of emissions reductions as an analysis focused at the entity level if (1) the analysis fully accounted for and quantified all effects and (2) all changes to your organization's emissions can be attributed to the project. However, these two conditions are seldom met. For example, a utility might replace all distribution transformers on a feeder with energy efficient transformers, but find that economic growth in the region increased power demand and the resultant emissions did not decrease as much as planned. Therefore, you should carefully consider the focus of your analysis. If you are considering a narrowly focused analysis, but are finding that the project has significant effects elsewhere in your operations, you may more easily carry out the analysis through an entity-level estimation. At the same time you may find that estimating your project's effects is difficult to evaluate through entity-level measures because of other changes in your operations that obscure those effects.

Note that in one case the information needed for emissions reporting (see Section 1.3) is identical to the data needed for project evaluation. This occurs when (1) emissions reporting is at the entity level, (2) a basic reference case is used, (3) the project is estimated at the entity level, and (4) no effects exist beyond your operations. Under these circumstances the emissions reduction estimate can be simply derived as the difference in your emissions for the reference case year and the reporting year. Both of these emissions levels are reported under the emissions report.

Example 1.5 - Identifying Effects - Activity-Level Project Analysis

Note: This example illustrates only one approach to analyzing a project; your analysis, methods, and calculations will vary depending on your particular circumstances, the geographic location of the project, and other factors.

Sonomo Electric, a municipal utility, replaced all its distribution transformers on a feeder with energy efficient transformers. If Sonomo focused its project analysis on the whole utility, the results of the efficiency program would not have been fully reflected, because other changes in the system might have obscured them. Consequently, Sonomo evaluated its project by analyzing only the feeder distribution system serving the affected transformers.

Example 1.6 - Identifying Effects - Effects Outside the Utility

Note: This example illustrates only one approach to analyzing a project; your analysis, methods, and calculations will vary depending on your particular circumstances, the geographic location of the project, and other factors.

An electric utility, Salisbury Electric Power (SEP), undertook an industrial sector electrotechnology project that involved replacing its customer's coal-fueled aluminum smelting plant. It also undertook several unrelated projects to increase its own electricity generation efficiency. SEP used an entity-level analysis to capture the full effects of its own activities. It also identified the reduced emissions resulting from the aluminum smelter's switch from coal to electricity as an effect and quantified that effect. The methodology for quantifying emission reductions for electrotechnologies is discussed in the industrial sector document.

1.3.3 Estimate Emissions Reductions

The last step in analyzing greenhouse gas emissions-reducing projects is to estimate emissions for the reference case and the project case. This involves measuring or estimating energy use for each type of fuel that is consumed and for the energy conservation measures, relating them back to the net decrease in greenhouse gas emissions. In general, the level of emissions resulting from the production, delivery, and use of electricity depends on the four factors listed below. Note that the various emissions reductions activities in the electricity supply sector are each aimed at one of these four components:

- carbon content of the primary fuel (**emissions/unit of energy**). Fuel switching changes emissions per unit of energy.

- combination of technologies used to capture emissions before their release to the environment (**1 - the emissions removal efficiency**). Precombustion and postcombustion fuel technologies remove gases from the emission stream or prevent their creation in the first place.

- efficiency of the processes for producing and delivering energy to the point of use and conversion into the service demanded **(units of energy produced/unit service demand)**. Improvements in heat rate, controls, dispatch, and T&D reduce the amount of electricity that is lost between generation and use.

- total level of service demanded **(service demand level)**. Reductions in demands for electricity, through DSM programs and electricity energy conservation programs reduce the service level demand.

The following equation expresses the relation of energy-related emissions to these various components in the electricity supply sector. Example 1.7 illustrates the use of this equation in estimating emissions first for the reference case, then for the project case. The difference between the two estimates is the emissions reduction you may report.

$$\begin{aligned}\text{Emissions level} = {} & \text{(emission/unit of energy)} \\ & \bullet \text{ (1 - emissions removal efficiency)} \\ & \bullet \text{ (units of energy produced/unit service demand)} \\ & \bullet \text{ (service demand level)}\end{aligned}$$

1.4 Sector-Specific Types of Emissions Reduction Projects

The previous section presented general approaches for analyzing projects in the electricity supply sector, including estimation methods for direct emissions. This section and the next two sections focus on specific types of projects and analytical approaches appropriate to each.

- Section 1.5 discusses projects that reduce direct emissions: fuel substitution and direct carbon removal.

- Section 1.6 focuses on projects that reduce emissions indirectly: equipment upgrades, operational improvements, integration of energy supply, and reduction in demand or energy losses. These projects include electricity conservation projects, DSM activities, and T&D efficiency improvements.

Example 1.7 - Estimating Emissions Reductions

Note: This example illustrates only one approach to analyzing a project; your analysis, methods, and calculations will vary depending on your particular circumstances, the geographic location of the project, and other factors.

Wisconsin Integrated Power operated one pulverized coal-fired power plant that had no carbon dioxide removal technologies. Annual generation had been consistently at 2 million megawatt hours. In response to anticipated environmental regulations, the utility decided to install an amine carbon dioxide scrubbing unit with a 90 percent carbon dioxide removal efficiency. It also undertook a T&D project that reduced losses from the 15 percent level to a more efficient 10 percent, and a DSM project that reduced energy demand 3 percent. Using the equation discussed above, Wisconsin Integrated estimated, first, reference case emissions, then project case emissions. *[Note: The amine carbon dioxide scrubbing unit was selected for illustrative purposes only. No such units are known to be in commercial operation at this time in the United States, although some recent studies indicate limited applications in Japan (DOE 1991). As this and other CO_2 removal technologies become cost effective, they may see greater use.)*

Basic reference case emissions

From Table 1.3, the utility obtained the carbon dioxide emissions per unit of electrical energy produced, as follows:

$$1970 \text{ lbs } C0_2/\text{MWh} = 893 \text{ kg } CO_2/\text{MWh}$$

Wisconsin Integrated calculated its basic reference case, for the year 1990:

$$\begin{aligned} \text{Emissions}_{ref} &= (893 \text{ kg } CO_2/\text{MWh}) \bullet (1.0 - 0.0 \text{ emissions removal}) \\ &\quad \bullet (1.00 \text{ unit of energy produced}/0.850 \text{ unit of energy demand}) \bullet (2.00\text{x}10^6 \text{ MWh/yr}) \\ &= 2.10\text{x}10^9 \text{ kg } CO_2/\text{yr} \\ &= 2.10\text{x}10^6 \text{ metric tons } CO_2/\text{yr.} \end{aligned}$$

It confirmed this calculation to within 1.5 percent, using the approach described in Section 1.2 on emissions reporting. The calculation also agreed with the utility's past reports to EIA. This served to increase the utility's confidence in the accuracy of this approach.

Project case emissions

For the project case Wisconsin Integrated calculated

$$\begin{aligned} \text{Emission}_{proj} &= (893 \text{ kg } CO_2/\text{MWh} \bullet (1.00 - 0.90 \text{ emissions removal}) \\ &\quad \bullet (1.00 \text{ unit of energy produced}/0.900 \text{ unit of energy demand}) \\ &\quad \bullet (1.94\text{x}10^6 \text{ MWh/yr}) \\ &= 193.\text{x}10^6 \text{ kg } CO_2/\text{yr} \\ &= 193.\text{x}10^3 \text{ metric tons } CO_2/\text{yr.} \end{aligned}$$

Emissions reductions

Wisconsin Integrated calculated its emissions reduction:

$$\begin{aligned} \text{Emissions reduction} &= \text{Emission}_{ref} - \text{emission}_{proj} \\ &= 2.10\text{x}10^6 \text{ MT } CO_2/\text{yr} - 0.193\text{x}10^6 \text{ MT } CO_2/\text{yr} \\ &= 1.91\text{x}10^6 \text{ MT } CO_2/\text{yr.} \end{aligned}$$

Electricity supply components, technologies and systems may be *direct* emitters of greenhouse gases or may be *indirectly* responsible for emissions through factors associated with their use. Direct emitting components are principally the plants that produce electricity using heat supplied by fuel combustion. Components that indirectly contribute to greenhouse gas emissions include all end-use loads that receive power from such plants and all electricity generation, transmission, and distribution equipment that causes energy losses that must be made up by additional power generation.

Appendix 1.B lists efficiency improvement, or energy conservation measures that indirectly reduce emissions in the electricity supply sector. Types of these activities are listed in Table 1.3, along with references to subsequent subsections that discuss appropriate estimation methods.

1.4.1 Project Types

The project types listed in Table 1.2 are grouped according to the electricity supply subsystem (generation, and transmission and distribution), and are categorized according to the type of activity: fuel substitution, direct carbon removal, and generation and T&D efficiency improvements. The project types are discussed in more detail after the table.

Table 1.2. Electricity Sector Activities Discussed in this Supporting Document

Type of Project	Activity	Section	Estimation Method
Direct (generation subsystem)	fuel substitution	1.5	IPCC (1991)/EPA (1990) EPA Acid Rain Program (49 CFR 75) measurement
Indirect/efficiency improvements (generation subsystem)	equipment upgrades operational improvements integration of energy supply	1.6.1	measurement engineering estimation
Indirect/efficiency improvements (transmission and distribution subsystem)	reduction in demand reduction in energy losses	1.6.2	measurement engineering estimation Dirkes, et al. 1993 BPA SCALE EPRI DSAS

Fuel substitution. Substituting non-fossil or low-emission fossil fuels for high-emission fossil fuels reduces emissions per unit of energy. Generation-side activities that lead directly to emissions reductions include introduction of renewables and replacement of a coal-fired plant by natural gas-fired units.

Energy efficiency improvements. The amount of primary energy required to provide a unit end-use energy service can be reduced through use of more efficient energy conversion, transfer, and end-use technologies. Energy efficiency improvement projects may include reducing losses in electricity generation, conversion, and transfer, in addition to reducing the energy required by end-use equipment to satisfy a given level of service demand.

1.4.2 Choice of Estimation Methods

Methods for estimating energy conservation and emissions reductions in the electricity supply sector include a broad range of approaches and techniques. The procedures for reporting and verifying the energy savings discussed in this guidance are flexible enough to accommodate standard conservation technologies as well as new developments in efficiency, fuel switching, and renewable technologies. You may report the estimation methods you use, whether or not those methods are included in this guidance.

Your choice of estimation methods may be constrained by the availability of data. For example, you may estimate emissions reductions from an energy efficiency project using measured data as well as engineering estimation. Using several methods and comparing the results may increase the credibility of your estimations.

1.5 Estimating Emissions Reductions for Direct Fuel Substitution Projects

This section presents standard methodologies for estimating reductions from projects involving direct emissions. The methods are applicable to both carbon dioxide and non-carbon dioxide greenhouse gases and can be used to compute emissions from carbon content or from various technologies employed in the electricity supply sector. The approaches also apply to analyses that use either a basic or modified reference case.

Substituting non-fossil or low-emission fossil fuels (natural gas or renewables) for high-emission fossil fuels will reduce total carbon dioxide emissions because of the variability of emission rates among primary fuels.

As described in Section 1.3.2, the effects of a project or group of projects can be evaluated by examining changes in emissions for your entire organization (entity-wide estimation) or for a more limited subset of your operations (activity-level estimation). This section discusses two approaches for entity-wide estimation of carbon dioxide emissions—one approach for activity-level estimation of carbon dioxide emissions reductions (the same approach presented in Section 1.2) and one for reductions in emissions of other greenhouse gases (using EPA's Acid Rain Methodology). The third approach discussed addresses non-carbon dioxide emissions reductions.

For fuel substitution projects, you can estimate the amount of greenhouse gas reductions using direct measurement (before and after the project), engineering estimation methods, or compilation of data on fuel use and default values. Savings may be derived using default values for emissions based on fuel types, as currently collected by utilities and reported to EIA and EPA, and default values for representative types of fuels and utility boiler sources. Generally, you will compute the net reduction in emissions by subtracting the after-project fuel emissions from the reference case emissions.

You may wish to report other aspects of your combustion process. For example, some generators recycle coal ash for use in making cement. In this case, the use of recycled material should be analyzed as an industrial sector project.

1.5.1 Estimating Carbon Dioxide Emissions Reductions: Modified IPCC Methodology

To estimate, on an entity-wide basis, the difference between the project case and the reference case, you may use the same 4-step, modified IPCC approach that was discussed in Section 1.2 for estimating emissions. Here, however, you will be performing two sets of calculations: one for the reference case and one for the project case. The difference between the two will be your reportable emissions reductions. (This is the same procedure described in Examples 1.6 and 1.7). For a basic reference case, you will calculate entity-wide emissions for a historical year; for a modified reference case, you will perform calculations on the basis of what emissions would have been without the project.

As described in Section 1.2, the amount of carbon dioxide emitted by an entity is directly related to the amount of fuel consumed, the fraction of fuel that is oxidized, and the carbon content of the fuel. For example, coal contains close to twice the carbon of natural gas and roughly 25 percent more than crude oil per unit of useful energy. Therefore, the approach for estimating emissions of carbon dioxide from fossil fuels is somewhat different from the approach used for estimating other greenhouse gas emissions, since carbon dioxide emissions depend mostly on the basic fuel characteristics, rather than on technology or emissions controls (as with such gases as nitrous oxide or carbon monoxide).

Estimating carbon dioxide emissions for the whole entity requires a careful accounting of fossil fuel consumption by type and carbon content of fossil fuels consumed. The methodology for estimating carbon dioxide emissions represents a top-down approach, rather than the bottom-up approach recommended for other greenhouse gases.

The methodology is illustrated in Example 1.8 (data drawn from Appendix 1.C).

Example 1.8 - Generation-Side Fuel Substitution: Modified IPCC Methodology

Note: This example illustrates only one approach to analyzing a project; your analysis, methods, and calculations will vary depending on your particular circumstances, the geographic location of the project, and other factors.

Southwestern Utility decided to convert 30 percent of its coal generation mix to natural gas. First, the utility needed to calculate monthly utility-wide carbon dioxide emissions. Since the project was motivated not by increasing demand (which was flat) but by financial and dispatching considerations, Southwestern decided to use a basic reference case.

Step 1. For the basic reference case, staff used their monthly fuel consumption and heat content data reported on FERC Form 423 to derive the utility's carbon emissions, using the following relationship:

$$\sum_a E_a = FC_a \cdot CECo_a \cdot 0.99 \cdot 3.67$$

Fuel	Monthly Fuel Consumption	Energy Conversion Factors	Monthly Energy Consumption (PJ)	Emissions Conversion Factors (kg C/GJ)	Monthly Carbon Emissions (10^3 MT)
Liquid oil	646×10^3 bbl	1 bbl = 5.8×10^6 Btu	3.75×10^{12} Btu = 3.96 PJ	20.0	79.20
Solid coal	962×10^3 MT	1 MT coal = 22×10^6 Btu	21.16×10^{12} Btu = 22.32 PJ	25.8	575.86
Gases natural gas	2.404×10^3 MCF	1 MCF = 1.030×10^6 Btu	2.48×10^9 Btu = 0.0026 PJ	15.3	39.78×10^{-3}
Total monthly carbon emissions					**655.10**

bbl = barrels; MCF = thousand cubic feet; MT = metric tons; PJ = petajoule = 1×10^{15} J; GJ = gigajoule = 1×10^9 J

Note that Southwestern used the identity (derived from Table A.5 in Appendix A)

$$\text{PJ} = 0.9480 \times 10^{12} \text{ Btu}$$

to convert from Btu to PJ.

Because only 99 percent of the total carbon emissions is oxidized, and the ratio of carbon dioxide to carbon on a weight basis is 3.67 (see Appendix D), the monthly emissions of carbon dioxide for the reference case was

$$\begin{aligned} CO_2 \text{ emissions} &= (655.10 \times 10^3 \text{ MT C}) \bullet (0.99) \bullet (3.67 \text{ MT } CO_2/\text{MT C}) \\ &= 2.38 \times 10^6 \text{ MT } CO_2 \end{aligned}$$

Example 1.8 - (cont'd)

Step 2. Southwestern then computed its monthly utility-wide carbon dioxide emission for the fuel substitution (project) case:

Fuel	Monthly Fuel Consumption	Energy Conversion Factors	Monthly Energy Consumption (PJ)	Emissions Conversion Factors (kg C/GJ)	Monthly Carbon Emissions (10^3 MT)
Liquid oil	646×10^3 bbl	1 bbl = 5.8×10^6 Btu	3.75×10^{12} Btu = 3.96 PJ	20.0	79.20
Solid coal	695×10^3 MT	1 MT coal = 22×10^6 Btu	15.29×10^{12} Btu = 16.13 PJ	25.8	416.15
Gases natural gas	6657×10^3 Mcf	1 Mcf = 1.030×10^6 Btu	6.86×10^{12} Btu = 7.24 PJ	15.3	110.77
Total monthly carbon emissions					**606.12**

bbl = barrels; MCF = thousand cubic feet; MT = metric tons; PJ = petajoule = 1×10^{15} J; GJ = gigajoule = 1×10^9 J

Southwestern then converted its project case monthly total carbon emissions to carbon dioxide emissions using the same method as for the reference case.

$$CO_2 \text{ emissions} = (606.12 \times 10^3 \text{ MT C}) \bullet (99 \text{ percent}) \bullet (3.67 \text{ MT } CO_2/\text{MT C}) = 2.20 \times 10^6 \text{ MT } CO_2$$

Step 3. Southwestern then determined its monthly emissions reductions:

$$\text{Emissions reduction} = \text{Emissions}_{ref} - \text{Emissions}_{proj}$$

$$= 2.38 \times 10^6 \text{ MT } CO_2 - 2.20 \times 10^6 \text{ MT } CO_2$$

$$= 0.18 \times 10^6 \text{ MT } CO_2$$

Step 4. Since carbon dioxide emissions during each month will be different, Southwestern finally determined its annual emissions reduction, E_{CO2a}, by summing the reductions achieved monthly during the year being reported:

$$E_{CO_2a} = \sum_{m-1}^{12} E_{CO_2m}$$

where E_{CO2a} = annual total CO_2 mass emissions reductions
E_{CO2m} = total CO_2 mass emissions reductions in month m

In the above example, Southwestern used the modified IPCC methodology, based on the carbon consent of the various fuels. Example 1.9 illustrates a technology-based approach, using the stipulated factors given in Table 1.3.

Table 1.3. Stipulated Carbon Dioxide Emissions from Selected Fossil Technologies

Technology	Heat Rate Btu/kWh	Stipulated CO_2 Emissions Factors	
		lb/MMBtu	lb/MWh
Uncontrolled PCF	9,500	207	1,970
PCF/Wet FGD	9,850	213	2,100
PCF/NOXSO	9,850	207	2,040
IGCC	8,730	207	1,810
AFBC	9,750	221	2,150
PFBC	8,710	229	1,990
Oil Steam	9,460	181	1,710
Gas Steam	9,580	115	1,100
NGCC	7,570	115	870
STIG	8,100	115	930
ISTIG	7,260	115	830

KEY: PCF = pulverized - coal-fired; FGD = flue gas desulfurization; IGCC = integrated coal-gasification combined cycle option;
AFBC = atmospheric pressurized fluidized-bed combustion; NGCC = natural gas combined cycle;
STIG = steam injection turbine; ISTIG = intercooled STIG.
lbs/MMBtu = pounds per million Btu of heat input; lbs/MWh = pounds per million megawatt hours of electrical generation.

Source: DOE/PE-0101 1991 (Table 2.5, page 2.10).

Example 1.9 - Fuel Substitutes - Renewables: Technology-Based Approach

Note: This example illustrates only one approach to analyzing a project; your analysis, methods, and calculations will vary depending on your particular circumstances, the geographic location of the project, and other factors.

The Quality Electric Development Utility (QED) recently issued a Request for Proposals (RFP) to private developers for a renewable electric power facility. The new facility was required to increase the utility's generating capacity in order to meet a projected modest increase in demand. The winning proposal from All-American Wind Generators, Inc., specified a wind farm with generating characteristics closely matching the projected demand increase. The power generated by the wind farm deferred the construction of a small, intermediate load, pulverized-coal-fired facility by QED. The coal facility would have produced 1,400 GWh annually.

Step 1. Determine emissions for the modified reference case from Table 1.3. Carbon dioxide emissions per unit of energy are

$$1{,}970 \text{ lbs } CO_2/\text{MWh} = 893 \text{ kg } CO_2/\text{MWh}.$$

Step 2. Determine emissions for the project case. Emissions from a wind turbine are 0.

Step 3. The pulverized coal plant would have produced 1,400 GWh annually. The wind facility produces 350,000 MWh annually. Assuming these 350,000 MWh replaced a like quantity of energy from the pulverized coal facility, the emissions reduction would be

$$(893 \text{ kg } CO_2/\text{MWh}) \bullet (350{,}000 \text{ MWh/yr}) = 313\text{x}10^6 \text{ kg } CO_2/\text{yr} = 313{,}000 \text{ MT/yr}.$$

Hence, the use of wind turbines resulted in 313,000 MT/yr of avoided CO_2 emissions.

1.5.2 Entity-Wide Estimation of Carbon Dioxide Emissions Reductions: EPA's Acid Rain Methodology

EPA's Acid Rain Program requires utilities to establish CEM systems for measuring emissions of sulfur dioxide and nitrogen oxides. It also requires utilities to report their carbon dioxide emissions, based on continuous measurements or estimation. Starting in April 1995, almost all U.S. utilities will be required to report their emissions of carbon dioxide and nitrogen oxides to EPA.

An increasing number of utilities are choosing to implement a continuous carbon dioxide monitoring system. When implemented, the continuous monitoring systems will provide important data on the actual amounts of greenhouse gas emissions by utilities. The data can then be used to verify greenhouse gas reduction levels. However, information is collected daily or monthly, so the initial calculations must be made on that basis, then aggregated to annual totals.

EPA's Acid Rain Program rules (40 CFR Part 75, Appendix G) outline procedures for estimating carbon dioxide emissions from the combustion of fossil fuels for each combustion unit, based on two methods: carbon content of fuel burned and CEM systems. The total carbon dioxide emissions from the utility is the sum of the emissions for each combustion unit.

To calculate daily carbon dioxide mass emissions in tons/day, based on carbon content of fuel method, use the following equation (taken directly from EPA's Acid Rain Program rules):

$$W_{CO_2} = 11/6{,}000 \bullet W_C$$

where W_{CO2} = carbon dioxide mass emissions in short tons/day
W_C = carbon burned, lb/day.

Example 1.10 - Estimation of Annual Carbon Dioxide Mass Emissions Reductions for a Coal-Fired Unit From Daily Data

Note: This example illustrates only one approach to analyzing a project; your analysis, methods, and calculations will vary depending on your particular circumstances, the geographic location of the project, and other factors.

Assume that a coal-fired unit consumes 1,000 short tons of bituminous coal per day. Weekly coal analysis determined that the carbon content of this coal is $1.3\text{x}10^6$ lb/day. (See EPA's Acid Rain Program rules for the standard test method for carbon and hydrogen in the analytical sample of coal and coke, ASTM D3178-89.) *[Note: At this time, technologies for producing cleaner burning coal may not be cost-effective. Such a technology is referred to here for illustrative purposes only.]*

The coal-fired unit calculated daily carbon dioxide mass emissions, using the relationship and substituting its own physical data:

$$\begin{aligned} W_{CO_2} &= 11/6{,}000 \bullet W_C \\ &= 11/6{,}000 \bullet (1.3\text{x}10^6) \\ &= 2.4\text{x}10^3 \text{ short tons per day} \\ &= 2.4\text{x}10^3 \bullet 365 = 876\text{x}10^3 \text{ short tons per year} \end{aligned}$$

The coal-fired unit's estimated emissions were $876\text{x}10^3$ short tons per year. If the plant substituted cleaner burning coal and wished to report emissions reductions, the reporter would perform this calculation again for the cleaner coal, then determine the difference between the two.

Monthly carbon dioxide emissions may also be calculated, as in the following example.

Example 1.11 - Estimation of Annual Carbon Dioxide Emissions Reductions From Monthly Data

Note: This example illustrates only one approach to analyzing a project; your analysis, methods, and calculations will vary depending on your particular circumstances, the geographic location of the project, and other factors.

Tri-States Electric Utility consists of 20 separate power plants, including coal, gas, and petroleum generation units. To calculate the monthly carbon dioxide emissions, the utility followed three steps (using conversion factors and default data from the tables in Appendixes A and 1.C):

Step 1. Tri-States estimated total carbon content in all fuels for one month.

Fuel	Consumption	Monthly Energy Consumption	Emissions Coefficient (kg C/GJ)	Total Carbon (Gg)
Liquid petroleum	3,000 bbl	1 bbl = 5.8×10^6 Btu 17.4×10^9 Btu = 0.018 PJ	20.0	0.36
Solid coal	252,000 ST	1 ton = 24×10^6 Btu $6{,}048 \times 10^9$ Btu = 6.4 PJ	25.8	165.12
Gases natural gas	2.048×10^3 MCF	1 MCF = 1.030×10^6 Btu 2.1×10^9 Btu = 0.002 PJ	15.3	0.03
TOTAL				165.51 Gg C

bbl = barrels ST = short tons MCF = thousand cubic feet PJ = petajoules = 0.9480×10^{12} Btu

Step 2. Tri-States then converted its total carbon emissions to CO_2 emissions, assuming a 99 percent oxidization rate and using the conversion factor described in Appendix D.

$$\text{Total monthly } CO_2 \text{ emissions} = 165.51 \text{ Gg C} \bullet (44 \text{ Gg } CO_2/12 \text{ Gg C}) \bullet (0.99) = 600.80 \text{ Gg}$$

The total monthly carbon dioxide emissions were 600.80 Gg.

To report emissions reductions from changes in the fuel mix, Tri-States would perform the same calculations for the project case and determine the difference between the two emissions levels to derive monthly emissions reductions.

Example 1.11 - (cont'd)

Step 3. Tri-States finally determines its annual emissions reduction, E_{CO2a}, by summing the reductions achieved monthly during the year being reported:

$$E_{CO_2a} = \sum_{m=1}^{12} E_{CO_2m}$$

where E_{CO2a} = annual total CO_2 mass emissions reductions
E_{CO2m} = total CO_2 mass emissions reductions in months

To report emissions reductions from changes in the fuel mix, Tri-States would perform the same calculations for the project mix and determine the difference between the two emissions levels.

Depending on equipment used and/or data collected, the estimation approach illustrated in Example 1.11 might be varied in a number of ways. For example, when the combustion unit uses emissions controls, the total carbon dioxide emissions (in tons) is the sum of combustion-related emissions and sorbent-related emissions. (See Appendix G of the Acid Rain Program.) If the generator has installed a CEM system, Appendix F of the Acid Rain Program outlines procedures to convert CEM system measurements of carbon dioxide concentration and volumetric flow rate into carbon dioxide mass emissions (in tons/day).

Example 1.11 illustrated how a utility could report its emissions reductions using an entity-level analysis. This is a particularly convenient approach for utilities who are already reporting emissions, and who use a basic reference case in their project analysis, because it does not require any additional data. However, not all electricity generators will report their entity-wide emissions. In those cases, the reporter may use an activity-level analysis, as shown in Example 1.12.

Example 1.12 - Project-Level Emissions Reductions Analysis: Efficiency Improvement

Note: This example illustrates only one approach to analyzing a project; your analysis, methods, and calculations will vary depending on your particular circumstances, the geographic location of the project, and other factors.

CK/MGJ, Inc., an independent power producer recently renovated one of its natural gas-fired electricity generation plants.

CK/MGJ repowered the plant, and experienced an efficiency improvement from 25 percent to 30 percent, representing a nearly 17 percent drop in natural gas consumption and a 15 percent capacity improvement. The owners calculated their emissions reductions at the activity level, using a basic reference case. They do not anticipate any other significant effects.

Step 1. For the basic reference case, CK/MGJ determined the carbon content of the fuel combusted, using the utility's historic natural gas consumption figures (1.2 PJ/yr) and the emissions conversion factor for natural gas from Appendix B (15.3 kg C/GJ).

$$\text{Emissions}_{ref} = (1.2 \text{ PJ/yr}) \bullet (15.3 \text{ kg C/GJ}) \bullet (1\text{x}10^{6} \text{ GJ/PJ}) \bullet (1\text{x}10^{-6} \text{ Gg C/kg C})$$

$$= 18.36 \text{ Gg C/yr}$$

Step 2. CK/MGJ calculated that a 17 percent drop in fuel consumption combined with the 15 percent capacity increase, resulted in a project case natural gas consumption of (1.2 PJ/yr • 0.83 • 1.15), 1.1454 PJ/yr, a net drop of 4.55 percent. This implied that carbon emissions had also dropped to 17.52 Gg C/yr.

Step 3. CK/MGJ calculated that its emissions reduction for this project was:

$$\text{Emissions Reduction} = \text{Emission}_{ref} - \text{Emission}_{proj}$$

$$= 18.36 \text{ Gg C/yr} - 17.52 \text{ Gg C/yr}$$

$$= 0.835 \text{ Gg C/yr.}$$

The company converted this to metric tons of carbon dioxide per year using the conversion factor from Appendix D:

$$\text{Carbon dioxide emissions reduction} = 0.835 \text{ Gg C/yr} \bullet 10^{3} \text{ metric tons/Gg} \bullet 3.67 \text{ Gg } CO_2\text{/Gg C}$$

$$= 3.064 \text{ metric tons } CO_2\text{/yr.}$$

The next example, also an analysis at the activity level, illustrates the use of Table 1.3's stipulated data that express emissions of carbon dioxide per energy input to various types of technologies.

Example 1.13 - Project-Level Emissions Reduction Analysis: Boiler Replacement

Note: This example illustrates only one approach to analyzing a project; your analysis, methods, and calculations will vary depending on your particular circumstances, the geographic location of the project, and other factors.

Mid States Power and Light replaced one pulverized coal plant with a natural gas combined cycle (NGCC) technology, both of which produced 1,000 GWh annually. From Table 1.3, the utility determined the following stipulated factors:

Coal CO_2 emissions coefficient = 689 lbs/mmBtu
Heat Rate = 9,750 Btu/KWH
Production = 1,000 GWH/yr

Heat Rate • Production = Annual Heat Input
9,750 Btu/kWh • 1,000 GWH/yr = 9.75×10^6 mmBtu/yr

Annual Heat Input • CO_2 emissions coefficient = Annual CO_2 emissions
9.75×10^6 mmBtu/yr • 689 lbs/mmBtu = 6.72×10^9 lbs/yr

NGCC CO_2 emissions coefficient = 115 lbs/mmBtu
Heat Rate = 7,570 Btu/KWH
Production = 1,000 GWH/yr

Heat Rate • Production = Annual Heat Input
7,570 Btu/KWh • 1,000 GWH/yr = 7.57×10^6 mmBtu/yr

Annual Heat Input • CO_2 emissions coefficient = Annual CO_2 emissions
7.57×10^6 mmBtu/yr • 115 lbs/mmBtu = 871×10^6 lbs/yr

Using the general equation

$$\text{Emissions reduction} = \text{Emissions}_{ref} - \text{Emissions}_{proj}$$

the utility substituted the stipulated factors:

$$\text{Emissions reduction} = (6.72 \times 10^9) - (871 \times 10^6) = 5.85 \times 10^9 \text{ lbs/yr}$$

The reduction in carbon dioxide emissions is therefore 5.85×10^9 lbs/yr. Note that the same GWH are assumed before and after the change in technologies.

Sources: DOE (1983), Northwest Public Planning Council (1991).

1.5.3 Estimation of Non-Carbon Dioxide Emissions Reductions

Estimation of emissions other than carbon dioxide from combustion generation units can be time consuming and complex. The simplest method is the modified IPCC method, outlined in Section 1.3, "Direct emissions of a mix of greenhouse gases." Table 1.1 lists representative stipulated factors for non-carbon dioxide greenhouse gases, methane (CH_4), nitrous oxide (N_2O), by principal technology and fuel type. Note that, unlike carbon dioxide emissions estimates, estimates of non-carbon dioxide emissions are based on technologies used, not fuel carbon content alone. Use the methods described in Section 1.3 to estimate emissions for both the reference case and the project case. Emissions reductions are simply the difference between the two.

1.6 Energy Efficiency Improvements

This section provides guidance for engineering estimates and default-derived energy savings from energy efficiency projects related to generation, transmission, distribution, and end-use. Generation-side projects are described in subsection 1.6.1; however, estimation methods are not discussed, since the estimations may be made using methods detailed in Section 1.5 for direct emissions. T&D projects are described in subsection 1.6.2, along with some appropriate estimation methods. These projects reduce emissions indirectly, so an extra step will be required to determine emissions reductions at the point of generation (see Section 1.7).

1.6.1 Generation-Side Energy Efficiency Improvements

This subsection presents types of projects that result in emissions reductions from energy efficiency improvements from generation activities. To determine appropriate reference cases for these projects, you need to carefully consider where other effects may be occurring and how large they are relative to the project's obvious, intended effects (see the discussion in Section 1.3.2). To estimate emissions reductions from these projects, you could use the same approaches discussed for direct projects (Section 1.5).

On the generation side, projects can be categorized into improvements to plant operations and equipment, and integrated energy supply. Projects that involve equipment upgrades will help provide a larger percentage of "clean power" from a greenhouse gas perspective, thus reducing many of the pollutants under consideration. Improved operations of the energy control centers and dispatching practices, use of efficient controls and adjustments, and coordinated operation and planning systems are key elements to making effective and efficient energy choices that ultimately reduce greenhouse gases.

Entities can enhance the performance of some existing hydroelectric and nuclear plants by upgrading equipment, changing operation and maintenance practices, and improving training to increase the output. These improvements result in energy savings that reduce the emissions level of the system as a whole; therefore, an entity-level project analysis is appropriate.

An integrated or fuel-flexible energy supply involves combining separate energy supply technologies into integrated systems to provide multiple energy services at higher overall performance. Examples include cogeneration, fuel cells, and integrated energy storage networks. Key features of an integrated energy supply system include recovering or reusing waste heat and balancing peak and off-peak electrical or thermal loads.

Cogeneration is the joint production of electrical and thermal energy from an input fuel. This use of input energy for two separate output forms can result in higher overall energy conversion efficiencies. A system may supply electric power requirements as well as thermal energy for space heating, hot water, district heating, and industrial process heating. Project analysis for cogeneration is covered in the supporting document for the industrial sector.

Fuel cells convert the chemical energy of a fuel directly into electric power via an electrochemical reaction between hydrogen and oxygen. Depending on the cost and availability of input fuel, the electrical conversion efficiency from the input fuel to the electric power in fuel cells may be higher than conventional generation techniques.

Most energy storage systems do not emit greenhouse gases directly. Their use as components in the electricity supply sector can improve overall system efficiency and, therefore, can help lower emissions. Storage systems provide the ability to uncouple supply from end-use demand, which is important for flexibility in the choice of fuels. Some storage shaves peaks on a daily basis, others on a seasonal basis. In general, energy storage offers the potential to reduce emissions by reducing the need for additional energy conversion to meet a service demand. Principal applications of energy storage include utility load leveling in the following end-use sectors: electric vehicles, customer-side storage, and thermal energy management in buildings.

1.6.2 Transmission and Distribution Subsystem Energy Efficiency Improvements

Energy savings associated with reducing T&D losses can be realized by replacing the existing stock of equipment with more efficient units and components, by implementing more efficient system management practices, and by operational modifications.

Supply curves can be used to describe the conservation resource potentially available from T&D subsystem improvements and to estimate energy savings. Supply curves relate the levelized cost of upgrading existing equipment to the estimated amount of energy saved. Stated in this form, the resource represented by reducing T&D losses can be compared in the IRP process to other conservation options to determine the most cost-effective method of supplying power to the utility's customers. The IRP process is rapidly being accepted as the planning standard for utilities.

Approaches for improving T&D efficiency include reconductoring (replacing existing lines with larger-size conductors), replacing transformers, upgrading the voltage of distribution systems, and adding capacity.

Estimation of T&D energy savings based on a single activity

The existence and quality of data that characterize your T&D system will determine the quality of your estimates. If you have existing models of your T&D subsystems, then the effort involved in estimating the energy savings should be minimal. If you have a good database representing a portion of your T&D system, then you will need to estimate the overall system characteristics. Any T&D energy savings (in the absence of other measures) should be reflected in the reduced levels of carbon dioxide emissions, which you may be continuously reporting to the EPA under the Acid Rain Program.

The following two component categories contribute to the majority of total T&D system losses: *conductors* (feeders and transmission lines), and *transformers* (distribution systems and substations). Project activities may involve replacing a single unit, a number of units in a subsystem, or the entire system. Each of these component categories is discussed below.

Conductors. Conductor loss occurs primarily because of the resistance of the conducting materials (copper or aluminum) to the flow of electric current. In general, the smaller the diameter of the conductor, the greater the resistance to the flow of the current. Literature-derived values for conductor resistance [see, for example, the *Standard Handbook for Electrical Engineers* (Fowle 1993)] can be used to calculate feeder and transmission-line conductor losses.

For a project involving a single conductor segment,

$$\text{loss reduction} = \text{conductor loss}_{\text{reference}} - \text{conductor loss}_{\text{replacement, larger size}}$$

A standard conductor loss methodology (IEEE 1994; Tepel, Callaway, and DeSteese 1987) is used to calculate annual conductor losses. The following equation can be used to calculate the annual energy loss, on a per unit basis, for a single conductor (feeder or transmission line) segment:

$$L_L = 8.76\,(p)^2\,(r)\,(LSF)/(kV)^2$$

where
- L_L = line losses in Watt-hours per year per circuit mile
- p = peak apparent power in kVA
- r = conductor resistance in ohms per mile
- LSF = loss factor, which ranges between 0.2 and 0.6
- kV = voltage in kilovolts.

Typically, you will evaluate the economic feasibility of upgrading a segment of a conductor by computing annual conductor costs for two conductor sizes. You determine the economic range of operation by computing peak current as a function of loss factor, LSF, where LSF varies from 0.2 to 0.6, and with conductor size as a parameter (IEEE 1994). If you have undertaken a reconductoring project, you have determined all the parameters you need to compute energy savings.

Example 1.14: Replacement of Feeder Conductor: Reduction of Conductor Losses

Note: This example illustrates only one approach to analyzing a project; your analysis, methods, and calculations will vary depending on your particular circumstances, the geographic location of the project, and other factors.

Knowlton Electric, a utility, estimated that, within its distribution system, the 12.5 kV overhead feeder consists of a medium size, 2/0 AWG (American Wire Gauge), ACSR (aluminum). According to the *Standard Handbook for Electrical Engineers* (Fowle 1993), this feeder has a resistance of 0.89 ohm/mile.

To reduce losses, the feeder conductor was replaced with aluminum conductor that was three sizes larger (266.8 kcmil, where kcmil is thousand circular mils), which has a resistance of 0.385 ohm/mile when operating at 50 degrees C and 60 Hz [*Standard Handbook for Electrical Engineers* (Fowle 1993)].

To estimate annual energy savings from reconductoring, Knowlton used the conductor equation to estimate emissions from both the reference case and the project case:

Reference Case

$$L_L = 8.76\,(p)^2\,(r)(LSF)/(kV)_2$$
$$= 8.76\,(2531)^2\,(0.89)(0.2)/(12.5)^2$$
$$= 63.9 \text{ kWh/circuit mile/yr}$$

Project Case

$$L_L = 8.76\,(p)^2\,(r)(LSF)/(kV)_2$$
$$= 8.76\,(2531)^2\,(0.385)(0.2)/(12.5)^2$$
$$= 27.7 \text{ kWh/circuit mile/yr}$$

The annual energy savings = 63.9 - 27.7 = 36.2 kWh/circuit mile/yr.

To compute annual emissions reductions, Knowlton multiplied the annual energy savings by the appropriate emissions factor (see Section 1.7), and the number of circuit miles in its system.

The previous discussion and Example 1.14 used a methodology for a *single* feeder/transmission line segment. For a *collection* of feeder/transmission line segments, the resultant loss can be estimated using the following equation:

$$SUMLOSS_n = (KLOSS_n)\,(RR_n)\,(TLEN_n)$$

where $SUMLOSS_n$ = sum of the calculated losses for sample lines, in MWh per year for size group n

$KLOSS_n$ = constant size group n

RR_n = "real" resistance closest to size group n average resistance

$TLEN_n$ = total length of line in size group n, in circuit miles.

For the *entire entity*, use the following equation:

$$LOSS_n = (RR_n)\ (KLOSS_n)\ (DF)$$

where $LOSS_n$ = loss per circuit mile of line in MWh per year for size group n
DF = distribution factor (estimated at 0.765 for feeders, 1.0 for transmission lines).

Finally, the per-unit loss reduction (annual energy savings) from a high-efficiency replacement conductor project is equal to the difference between the per-unit losses for the reference components and per-unit losses for the replacement components. Details about methodology can be found in Tepel, Callaway, and DeSteese (1987).

Transformers. Transformers generate losses in two ways. Coil loss (also known as copper loss or load loss) is caused by the impedance to the flow of current in the transformer windings when supplying an electrical load. The second source of loss results from hysteresis and eddy currents in the steel core of the transformer, which are independent of the load. This loss is referred to as a core loss, or no-load loss.

Following are examples of projects that can be undertaken to reduce transformer load and no-load losses:

- Replace transformers with amorphous core transformers (load loss improvements).
- Replace transformers with improved silicon steel core transformers (load loss improvements).
- Replace transformers with amorphous core transformers and improved winding efficiency (load and no-load loss improvements).
- Replace transformers with improved silicon steel core transformers and improved winding efficiency (load and no-load loss improvements).

The total transformer losses may be expressed as

$$P_{loss} = P_L + P_{NL}$$

where P_{loss} = the total transformer loss
P_L = the load loss
P_{NL} = the no-load loss.

The load loss term can be expressed as

$$P_L = \sum_{\text{all } i} (I_i^2 R_i)$$

where I_i = the current in winding i
R_i = the resistance of winding i.

To estimate transformer losses, you may follow standard methodology (IEEE 1994; Fowle and Knowlton 1993; Dirks et al. 1993). Example 1.15 illustrates the use of this methodology. Several computer models have been developed to calculate annual transformer losses. One such model is XFMR (Dirks et al. 1993).

To compute total annual energy losses for the reference case transformer, first determine annual no-load and annual load losses. Since no-load losses continue throughout the year, they are estimated as

Annual no-load losses = 8760 hrs/yr • (no-load loss expressed in kW)

Load losses for transformers are estimated by an empirical relationship that accounts for the variability of transformer load throughout the year and the fact that load losses vary with the square of the transformer current. Annual load losses are estimated by

Annual load losses = 8760 hrs/yr • loss factor • (rated load losses expressed in kW)

The loss factor is typically assumed to be between 0.2 and 0.6. For additional guidance, see IEEE 1994.

Tables in Dirks et al. (1993) present the full-load performance data for a number of transformers representative of the designs typically encountered in the utility power system. You may use your own data or these tables to estimate savings for your transformer replacement project.

Included in each table (Dirks et al. 1993) are the full-load efficiency, all the losses modeled by the XFMR code, the percentage of the total thermal loss that each of the losses represents, and the percentage of the total electric loss represented by each loss. The tables list representative loss parameters for conventional core as well as amorphous core transformers. Transformers with amorphous cores offer the potential for greatly reduced core losses by increasing the resistivity of the core material. This increased resistivity reduces eddy currents in the core, and the amorphous structure greatly reduces hysteresis losses.

Example 1.15 - Project to Reduce Transformer Losses

Note: This example illustrates only one approach to analyzing a project; your analysis, methods, and calculations will vary depending on your particular circumstances, the geographic location of the project, and other factors.

Norton Power and Light (NPL) replaced a 30 MVA conventional core grid transformer with an array equivalent to 30 MVA amorphous core transformers on a feeder.

Step 1. NPL estimated the basic reference case annual energy losses.

Dirks et al. (1993) provides the following:

Annual no-load losses = 8760 hrs/yr • (core loss + eddy-current coil + leakage loss + dielectric loss)

Annual no-load losses = 8760 hrs/yr • (20,030W + 70.23W + 3,116W + 1.587W) = 203 MWh

Annual load losses = 8760 hrs/yr • 0.6 • (55.54 kW • 0.42) = 122.6 MWh

Total annual loss for the reference case transformer = 203 MWh + 122.6 MWh = 325.6 MWh

Step 2. NPL then estimated the project case's annual energy losses.

For the project amorphous core transformers, annual no-load losses are provided in Dirks et al. (1993)

Annual no-load losses = 8,760 hrs/yr • (4,998W) = 43.78 MWh
Annual load losses = 8,760 hrs/yr • 0.6 • (59,390 kW • 0.42) = 131 MWh

The total annual loss for the project transformers = 174.78 MWh

Step 3. NPL then calculated annual energy savings.

$$\text{Total annual energy savings} = \text{annual losses}_{ref} - \text{annual losses}_{proj}$$

The total annual energy savings = 325.6 - 174.78 = 150.82 MWh

Step 4. Finally, the utility estimated emissions reductions by multiplying the total annual energy savings by the emissions factor (see Section 1.7).

Annual losses per transformer based on the Westinghouse/EPRI methodology (Westinghouse 1981) can be estimated using the following equation:

$$LT = 8.76\ (NLL + LL(PLR^2)\ (LSF))$$

where LT = annual loss in kWh per year (distribution) and in MWh (substation), per transformer
NLL = no-load loss, watts (distribution), or kW (substation)
LL = load loss, watts, or kW
PLR = peak load ratio (ratio of peak kVA to rated kVA)
LSF = loss factor.

Estimates of T&D energy savings for utility-wide projects

The utility-wide T&D system losses are the difference between the average annual power requirements of a given utility and its annual sales. System-wide losses can be estimated using one of the following methods, which are described in Tepel, Callaway, and DeSteese (1987):

- The method described in the Bonneville Power Administration (BPA) *Distribution System Efficiency Improvement Handbook* (1981). This approach is presented in the form of a field estimating handbook. By using the tables and worksheets in this manual that account for major loss sources in a system, field personnel can compute losses with a hand calculator. This approach is useful for evaluating losses in a small portion of a system. However, it does not appear to be suitable for evaluating a complete distribution system or a regional subset of a system.

- A computer model, such as SCALE (Simplified Calculation of Loss Equations) (EPRI 1983). This method was developed for computer implementation. It incorporates equations and estimating techniques that are generally accepted in the industry.

- Detailed calculation of distribution losses (EPRI 1983). This method requires a very large database, including metered substation energy and end-use billing for a year, and 24-hour profiles for transformers serving each class of consumers. The difference between energy entering the system and that received by consumers is attributed to losses.

- The DSAS (Distribution System Analysis and Simulation program) method (Sun et al. 1980). This method was developed by the Energy Systems Research Center at the University of Texas at Arlington, Texas. It integrates daily load shapes with a load flow procedure to produce an energy model. Feeder performance is analyzed by a load flow program capable of modeling different load component characteristics, load imbalances, and system configuration. This is probably the most rigorous method.

Following is an approach for estimating energy savings from T&D activities for an entity-wide project, based on the SCALE model. Details of this methodology and calculations for the case of BPA can be found in *Customer System Efficiency Improvement Assessment* (Tepel, Callaway, and DeSteese 1987). (References to tables below are from this source.)

1. Estimate numbers and types of T&D components: distribution transformers, substation transformers, primary feeders, and transmission lines (Table 3.4).

2. Establish operating characteristics of the reference case stock of components and the project stock (Table 4.1, 4.2, 4.3, and 4.4).

3. Calculate losses for the reference case stock (Table 4.5).

4. Calculate losses for the project stock (Table 4.5).

5. Calculate energy savings = losses (reference case stock) - losses (project stock) (Table 4.5).

Load management. Distribution system management practices that can reduce energy consumption include voltage regulation techniques collectively called conservation voltage reduction (CVR). CVR is, in principle, the regulation of distribution feeder voltages so that the load furthest from the substation is maintained at the minimum acceptable voltage under all load conditions on the circuit. This practice slightly reduces the average feeder voltage without affecting the function of customer equipment connected to the circuit. A modest load management effect is achieved by this voltage reduction because of the corresponding reduction in average end-use energy consumption.

In general, load management options reduce loads and modify end-use load shapes to produce an aggregate reduction in system peak load. Therefore, load management options present an alternative to constructing peaking plants and additional T&D capacity.

Data needs for load management include customer class loads, end-use loads, end-use load shapes, number of components, and load components. Load data should be separable into end-use sectors (residential, commercial, and industrial). Time-of-day data are needed to construct load shapes. Shape information is needed to estimate the effects of conservation and load management options on system peaks. End-use metered data are preferable. If no metered data exist for the project area, either meters can be installed or data can be borrowed from another area and normalized for differences in weather and customer characteristics. Data normalization requirements introduce extensive additional information needs regarding customer characteristics and weather. Utilities generally can provide numbers of customers by customer class, loads, and load forecasts. In the BPA area, for example, utilities provide all these data, as well as load forecasts, to the BPA on BPA Form 980.

Because the effects of load management are dispersed throughout the system, estimation of their effects on emissions of greenhouse gases is best carried out through project analysis at the entity level.

1.7 Converting Energy Reductions to Emissions Reductions

Several activities reported in this and other supporting documents are evaluated in terms of energy savings. For example, the evaluation of improvements in line losses expresses results in megawatt hours per year. Similarly, DSM projects are generally evaluated for electricity savings. Electric vehicle projects described in the transportation sector support document express energy changes in terms of decreases in liquid fuels and increases in electricity consumption. Evaluation of cogeneration projects involves estimation of utility electricity generation displaced by the project. For purposes of this reporting program, however, you must carry the analysis one step further.

Estimating reductions in electricity consumption is only the first step in estimating reductions of greenhouse gas emissions. The electricity savings must be traced back through the transmission and generation system to gauge how emissions change in a "mapping" process. This mapping process produces electricity emissions factors that provide a ratio for changes in emissions of greenhouse gases to changes in electricity consumption.

The mapping process can be quite complicated. Different generating resources have different greenhouse gas production characteristics. Nuclear power and renewable-energy sources, such as hydroelectric, wind, and solar power, produce emissions approaching zero, whereas natural gas, oil, and coal-powered electric-generating stations produce significant greenhouse gas emissions (with natural gas typically producing the least and coal the most). Since electric utility loads vary with the time of day and season, utilities will typically have several plants that they phase in and out of service. These plants are used (or dispatched, in industry terms) based on economics and other factors. Depending upon availability, the plant that produces power at the lowest cost will usually be dispatched first, and the plant that produces power at the highest cost will be dispatched last.

The greenhouse gas reduction depends on which plant's production is reduced to accommodate the reduced load resulting from the conservation measure. This mapping problem is complicated by time-of-day and magnitude issues.

The greenhouse gas emissions depend on the generating plant mix and how that mix is affected by the measure. If the base load plant is nuclear and the peaking plant is natural gas-fired, then reducing the peak load while increasing the base load would reduce greenhouse gas emissions. On the other hand, if the base load plant is coal and the peaking plant is natural gas, then reducing the peak load while increasing the base load will increase greenhouse gas production.

Emissions factors are very useful tools for estimating emissions of air pollutants. However, because they are averages obtained (in some cases) from data of wide range and varying degrees of accuracy, emissions calculated this way for a given project are likely to differ from that project's actual emissions. Because emissions factors are averages, they will indicate higher emissions estimates than are actual for some sources, lower for others. Only direct measurement can determine the actual pollutant contribution from a source, under existing conditions. For the most accurate emissions estimate, you should obtain source-specific data whenever possible.

Two types of emissions factors can be readily used for the voluntary reporting program: default values provided by DOE and emissions factors calculated from the generating mix of the utility. In general, reporters in the electricity supply sector will likely have specific data from which to derive project-specific or site-specific factors. The default factors will be useful to reporters, generally in other sectors, who do not have ready access to generation data.

1.7.1 Default Factors

The default emissions factors contained in Appendix C are the simplest to use relative to the other methods of calculating emissions. However, you should realize that these default factors will either underestimate or overestimate the actual emissions characteristics of any given power-generating equipment, as they represent the average emissions characteristics over a state.

For the purposes of the voluntary reporting program, and to retain flexibility and ease-of-use, Appendix C provides default state-level electrical emissions factors for carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O). Three factors are given for each state: one for emissions from utility generation, one for emissions from nonutility generation, and one combined utility/nonutility. If you know the source for your electricity (that is, utility or nonutility), you may use the appropriate factor. If you do not know or if you use both utility and nonutility sources, you should use the combined factors for your state. See Appendix C to this volume for more information.

1.7.2 Calculated Factors

To increase the accuracy of your reports, you may choose to calculate emissions factors, based on generating data specific to your situation. For example, you may choose to develop an emissions factor linking an individual DSM program or an hourly and daily basis to the marginal unit it is affecting. Or you may choose to be less specific, for example, applying a fossil or baseload/intermediate/peak average to an individual program or set of programs.

Average emissions factors for a group of generators can be based on the measured characteristics of the individual generators for the time period affecting the energy-saving activities, as illustrated in Example 1.16.

Example 1.16 - Estimation of Emissions Using a Calculated Emissions Factor

Note: This example illustrates only one approach to analyzing a project; your analysis, methods, and calculations will vary depending on your particular circumstances, the geographic location of the project, and other factors.

For this example, assume that three plants operate on different cycles to provide power, as described in the first table below. The generating mix, operating schedules, and emissions factors are for illustrative purposes only and may not reflect the actual conditions for any utility.

Calculate average emissions factors by the hour. After the data in the first table below are aggregated, the average emissions are obtained, as shown in the second table.

Generating Characteristics

Generating Plant	Operation Schedule	CO_2 Emissions[a] (lb/MWh)	Generation (MWh)
Pulverized Coal	24 hours	1,970	4,000
Gas Fired Combined Cycle	2-7 p.m.	1,300	1,500
Flash Geothermal	24 hours	160	100

Average Hourly Emissions Factors

Schedule	Emissions Factors (lb CO_2/MWh)
Base load: 12 a.m. to 2 p.m. and 7 p.m. to 12 a.m.	1,926
Peak Load: 2 p.m. to 7 p.m.	1,758
Daily average	1,891

The average daily emissions factors are 1,891 lb carbon dioxide per MWh of generation, assuming that the peak period lasts 5 hours. The total carbon dioxide emissions are calculated as

$$\begin{aligned}\text{Total } CO_2 \text{ Emissions} &= (CO_2 \text{ Emissions Factor}) \bullet (\text{Generation}) \\ &= (1{,}891 \ \frac{\text{lb } CO_2}{\text{MWh}}) \bullet (5{,}600 \text{ MWh}) \\ &= 10.59 \text{ million lb or } 5{,}295 \text{ short tons of } CO_2\end{aligned}$$

(a) Source: WAPA 1994.

In comparison to the default factors, the advantage of using the calculated factors is that they can be specifically tailored to match the energy-conservation characteristics of the activities being implemented, such as the time of day and the season of the year. In fact, this method could provide a more accurate emissions factor for certain activities than using measured factors, especially if the measured factors were a representative mean of all hours and generating plants for a specific utility. This approach has the highest credibility when it is used to assimilate data from individually monitored generating facilities into an activity-specific emissions factor.

1.7.3 Degree of Aggregation

You may report energy-efficiency savings that result from projects at various levels of aggregation. For fossil fuel savings, the level of aggregation is not important. For electrical savings, where time-of-day factors influence emissions reductions, it is important. You could report aggregate savings data for all T&D activities. Conversely, you may report at a more specific, disaggregated level—for example, delineating the savings by category of project (transformers, conductors, etc.).

Savings delineated by category may result in more accurate estimates of greenhouse gas emissions through the mapping process than aggregate data, because with aggregate data, mapping will estimate diurnal impacts based on archetypical load profiles. However, reporting at the aggregate level may be easier for many entities.

1.8 Existing Reporting Programs

You may also use data that are currently reported to other programs or used for other purposes in preparing your submissions under this voluntary reporting program. Appropriate data on current and past energy consumption by utilities, including both fuel tonnage and the energy content, reported to EIA and the Federal Energy Regulatory Commission (FERC) by domestic utilities. Utilities are required to report both the coal rank, the energy content, and the amount of the coal they burn. These data are compiled as follows:

- The EIA collects detailed monthly and annual reports on energy consumption in the electricity sector. A list of reports is provided in Appendix 1.A. Form EIA-767, Steam Electric Plant Operation and Design Report, includes information on fuel consumption and fuel quality, as well as information on flue gas desulfurization. Form EIA-861, Annual Electric Utility Report, includes information on energy sources, peak demand, and non-utility power producers, as well as DSM energy and peak reduction effects.

- Pursuant to the Clean Air Act Amendments of 1990, the Acid Rain Program establishes requirements for the monitoring, recordkeeping, and reporting of sulfur dioxide, nitrogen oxides, and carbon dioxide emissions to the EPA. Carbon dioxide emissions may be reported based on EPA-provided estimation methodology or continuous monitoring. EPA's Acid Rain Program must certify all CEM systems as well as any alternative monitoring systems.

- IRPs contain data and analysis of the environmental considerations associated with resource alternatives considered, on both the supply and the demand sides.

Some utility industry associations also collect energy data from their members for internal purposes. For example,

- Edison Electric Institute collects energy data from its investor-owned utility members.

- The American Public Power Association collects energy data from its public sector utilities.

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Appendix 1.A

EIA Data Collected for the Electricity Supply Sector

EIA Data Collected for the Electricity Supply Sector

Consumption	EIA-457A/H	Residential Energy Consumption Survey
	EIA-759	Monthly Power Plant Report
	EIA-846A/D	Manufacturing Energy Consumption Survey
	EIA-871A/F	Commercial Buildings Energy Consumption Survey
Costs and/or Prices	EIA-871A/F	Commercial Buildings Energy Consumption Survey
Disposition	EIA-826	Monthly Electric Utility Sales and Revenue Report with State Distributions
	EIA-861	Annual Electric Utility Report
	FE-781R	Annual Report of International Electrical Export/Import Data
Financial and/or Management	EIA-254	Semiannual Report on Status of Reactor Construction
	EIA-412	Annual Report of Electric Utilities
	EIA-826	Monthly Electric Utility Sales and Revenue Report with State Distributions
	EIA-846A/D	Manufacturing Energy Consumption Survey
	EIA-860	Annual Electric Generator Report
	EIA-861	Annual Electric Utility Report
	FERC-1	Annual Report of Major Electric Utilities, Licensees and Others
	OE-411	Coordinated Regional Bulk Power Supply Program Report
	OE-417R	Power System Emergency Reporting Procedures
Production	EIA-759	Monthly Power Plant Report
	EIA-767	Steam-Electric Power Plant Operation and Design Report
	EIA-846A/D	Manufacturing Energy Consumption Survey
	EIA-860	Annual Electric Generator Report
	EIA-861	Annual Electric Utility Report
	EIA-867	Annual Nonutility Power Producer Report
	FERC-1	Annual Report of Major Electric Utilities, Licensees and Others
	OE-411	Coordinated Regional Bulk Power Supply Program Report
Research and Development	EIA-846A/D	Manufacturing Energy Consumption Survey
Supply	EIA-759	Monthly Power Plant Report
	FE-781R	Annual Report of International Electrical Export/Import Data
	OE-411	Coordinated Regional Bulk Power Supply Program Report

Source: EIA, Directory of Energy Data Collection Forms.

Appendix 1.B

Energy Conservation Measures in the Electricity Supply Sector

Energy Conservation Measures in the Electricity Supply Sector
(excerpted from EPA Acid Rain Program Rule)

2. Supply-side Measures Applicable for Reduced Utilization

Supply-side measures that may be approved for purposes of reduced utilization plans under § 72.43 include the following:

2.1 Generation efficiency

- Heat rate improvement programs
- Availability improvement programs
- Coal cleaning measures that improve boiler efficiency
- Turbine improvements
- Boiler improvements
- Control improvements, including artificial intelligence and expert systems
- Distributed control—local (real-time) versus central (delayed)
- Equipment monitoring
- Performance monitoring
- Preventive maintenance
- Additional or improved heat recovery
- Sliding/variable pressure operations
- Adjustable speed drives
- Improved personnel training to improve man/machine interface

2.2 Transmission and distribution efficiency

- High efficiency transformer switchouts using amorphous core and silicon steel technologies
- Low-loss windings
- Innovative cable insulation
- Reactive power dispatch optimization
- Power factor control
- Primary feeder reconfiguration
- Primary distribution voltage upgrades
- High efficiency substation transformers
- Controllable series capacitors
- Real-time distribution data acquisition analysis and control systems
- Conservation voltage regulation

3. Renewable Energy Generation Measures Applicable for the Conservation and Renewable Energy Reserve Program

The following listed measures are approved as "qualified renewable energy generation" for purposes of the Conservation and Renewable Energy Reserve Program. Measures not appearing on the list may also be qualified renewable energy generation measures if they meet the requirements specified in § 73.81.

3.1 Biomass resources

- Combustible energy-producing materials from biological sources which include: wood, plant residues, biological wastes, landfill gas, energy crops, and eligible components of municipal solid waste.

3.2 Solar resources

- Solar thermal systems and the non-fossil fuel portion of solar thermal hybrid systems
- Grid and non-grid connected photovoltaic systems, including systems added for voltage or capacity augmentation of a distribution grid.

3.4 Geothermal resources

- Hydrothermal or geopressurized resources used for dry steam, flash steam, or binary cycle generation of electricity.

3.5 Wind resources

- Grid-connected and non-grid-connected wind farms
- Individual wind-driven electrical generating turbines

(The information requirements in this subpart have been approved by the Office of Management and Budget under the control number 2080-0221.)

In addition

3.6 Hydropower resource

- Conventional plants operate on the flow of water from storage reservoirs or free-flowing waterways
- Pumped storage plants pump water resource usually through a revariable turbine, from a lower reservoir to an upper reservoir.
- District heating and cooling systems
- Dispatching

Appendix 1.C

Background Data for IPCC/EPA Methodology, U.S. Data

Background Data for IPCC/EPA Methodology, U.S. Data

Table C.1. Estimation of Total Carbon in Fuels

Fuel	Conversion Factor (GJ/tonne)	Carbon Emissions Conversion Factors (kg C/GJ)
Liquid Fuels (1000 metric tonnes)		
1. Crude Oil	42.71	20.0
2. Natl. Gas Liquids	45.22	20.0
3. Gasoline	44.80	18.9
4. Kerosene	43.75	19.5
5. Jet Fuel	44.59	20.0
6. Gas/Diesel Oil	43.33	20.2
7. Residual Oil	40.19	21.1
8. LPG	47.31	17.2
9. Naphtha	45.01	20.0
10. Petroleum Coke	40.19	20.0
11. Refinery F-stocks	42.50	20.0
12. Other Oil	40.19	20.0
Solid Fuels (1000 metric tonnes)		
13. Coking Coal	29.68	25.8
14. Steam Coal	26.45	25.8
15. Sub-bit, Coal	19.40	26.1
16. Lignite	14.15	27.6
17. Peat	20.10	28.9
18. Coke	27.47	25.8
19. Other Solid Fuels		25.8
Gaseous Fuels (Terajoules)		
20. Natural Gas (dry)	0.0009	15.3

LPG = Liquified Petroleum Gases; tonne = metric ton.

Source: IPCC (1991).