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METHODS FOR ESTIMATING CARBON DIOXIDE EMISSIONS FROM COMBUSTION OF FOSSIL FUELS

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Volume VIII, Chapter 1, CO_2 from Combustion of Fossil Fuels

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INTRODUCTION

The EIIP guidelines are designed to describe emission estimation techniques for greenhouse gas sources in a clear and unambiguous manner and to facilitate preparation of inventories at the state level. This chapter presents the methodology for estimating carbon dioxide emissions from fossil fuel combustion. The methodology presented in this chapter has been revised to reflect new activity data, emission factors, and methods pertaining to this source category. Where possible, the methodology has been updated to be consistent with the *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2002*.

Section 2 of this chapter contains a general description of this source category. Section 3 provides a listing of the steps involved in estimating carbon dioxide emissions from fossil fuel consumption. Section 4 presents the preferred estimation method. Section 5 presents two alternative methodologies for estimating carbon dioxide emissions from this source category. A summary of uncertainty for this source category is provided in Section 6. References used in developing this chapter are identified in Section 7.

In addition to these guidelines, there are a series of user friendly spreadsheet tools available to assist in the development of emission inventories at the state level. Please consult the Carbon Dioxide Emissions from Fossil Fuel Combustion Module of the State Inventory Tool[1] to calculate emissions from this source category using the preferred emission estimation method.

[1] Note: The spreadsheet tool may have a different order of calculations, and may not show all calculations to the user.

2

SOURCE CATEGORY DESCRIPTION

2.1 EMISSION SOURCES

Energy-related activities are the most significant contributor to U.S. greenhouse gas emissions, accounting for nearly 85 percent of total emissions in 2002 (U.S. EPA 2004). Emissions from fossil fuel combustion comprise the vast majority of these energy-related emissions. In 2002, energy produced from the combustion of fossil fuels accounted for 86 percent of energy consumed (EIA 2003a). Fossil fuel is combusted to heat residential and commercial buildings, to generate electricity, to produce steam for industrial processes, and to power automobiles and other vehicles. As fossil fuels burn, they emit carbon dioxide (CO_2) as a result of oxidation of the carbon in the fuel. Other gases that are precursors of CO_2, such as carbon monoxide and non-methane volatile organic compounds, are emitted as by-products of incomplete combustion. These gases are then oxidized to CO_2 over periods ranging from a few days to 10 years or more. For purposes of most greenhouse gas inventories, emissions of these other gases are counted as CO_2 emissions. That is, all carbon emitted to the atmosphere (except for that emitted in the form of methane) is reported as CO_2 emissions, even though a very small portion of the carbon will be emitted as these other gases.[2] By reporting emissions in this fashion, state estimates of CO_2 will reflect total loadings of carbon to the atmosphere.

Carbon emissions occur from a number of activities associated with the production and transportation of energy, not all of which are accounted for in energy and non-energy uses of fossil fuels. These activities include venting and flaring, leakage of natural gas during the transmission and distribution of oil and natural gas, methane emissions from coal mines, and burning of coal in coal deposits. The first three of these activities—gas venting and flaring, gas leakage during the transmission and distribution of oil and natural gas, and methane emissions from coal mines—are addressed in chapters on these topics. Emissions from the burning of coal in coal deposits are highly variable from one state to another and are a very minor portion of total emissions. At this time, there is no recommended methodology to estimate emissions from this source.

2.2 FACTORS INFLUENCING EMISSIONS

The amount of CO_2 emitted from fossil fuel depends on the type and amount of fuel consumed, the carbon content of the fuel, and the fraction of the fuel that is oxidized. This relationship can be described in two parts:

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[2] Methane emitted from combustion of fossil fuels in stationary and mobile sources is addressed in Chapters 2 and 3 of this volume, respectively.

(1) The amount of carbon contained in the fuel per unit of energy produced varies for different fuel types. For example, coal contains the highest amount of carbon per unit of energy. For petroleum the amount of carbon per unit of energy is about 75 percent of that for coal; for natural gas, it is about 55 percent. Even within fuel types, carbon contents will vary, e.g., lower quality coal (such as lignite and sub-bituminous coal), has a higher carbon coefficient (i.e., more carbon emitted per unit of energy). There are similar carbon differences among the different types of liquid fuels and natural gas as well.

(2) Not all carbon in fuel products is oxidized to CO_2 for two reasons. First, inefficiencies in the combustion process cause a small fraction of the carbon to remain unburned as soot or ash. As noted earlier, some carbon is not immediately oxidized to CO_2, and is emitted in the form of other hydrocarbons. Second, fossil fuels are also used for non-energy purposes, primarily as a feedstock for such products as fertilizer, lubricants, and asphalt. In some cases, as in fertilizer production, the carbon from the fuels is oxidized quickly to CO_2. In other cases, as in asphalt production, the carbon is sequestered in the product for centuries.

The methods for estimating CO_2 emissions from combustion of fuels revolve around these two factors.

3

OVERVIEW OF AVAILABLE METHODS

Fossil fuels include coal, oil, and natural gas.[3] To estimate state emissions of carbon dioxide (CO_2) from fossil fuels, six steps should be performed: (1) obtain the required energy data; (2) estimate the total carbon content in fuels; (3) estimate the total carbon stored in products; (4) calculate net potential carbon emissions; (5) estimate the carbon oxidized from energy uses; and (6) convert net carbon emissions to units of metric tons of carbon equivalent (MTCE).

These steps are outlined in Section 4 below. An optional step—subtracting the carbon potentially emitted from bunker fuel consumption—can be conducted as part of Step 4 if state data are available. Additionally, it is recommended that states estimate net imports of electricity, which can be useful in considering strategies to reduce emissions. The estimation (and exclusion) of emissions from bunker fuel consumption and the estimation of emissions from electricity imported from other states are presented in Section 5. The method described in this chapter is more data-intensive and detailed than most of the other greenhouse gas estimation methods. There are three reasons for this:

(1) The U.S. Department of Energy's Energy Information Administration (EIA) collects detailed energy use statistics, which are available at the state level;
(2) CO_2 from energy use is the principal source of greenhouse gas emissions at the state and national level; and
(3) A detailed analysis of energy-related emissions provides insight on mitigation opportunities for this important sector.

The methods described here are taken from the report by the Intergovernmental Panel on Climate Change (IPCC) entitled *IPCC Guidelines for National Greenhouse Gas Inventories* (IPCC/UNEP/OECD/IEA 1997) and are in accordance with IPCC's *Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories* (IPCC 2000). The methods in this chapter are used at the national scale in the *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2002* (U.S. EPA 2004).

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[3] Carbon dioxide is also emitted during combustion of biomass fuels (e.g., wood, ethanol, charcoal, bagasse, agricultural wastes, and vegetal fuels such as soybean-based diesel fuel and "black liquor" from wood—a fuel used in paper mills). In the United States, biomass fuels are generally grown on a sustainable basis. Under the greenhouse gas emission estimation guidelines prepared by the Intergovernmental Panel on Climate Change (IPCC), carbon dioxide emissions from biomass fuels grown sustainably are not counted. Therefore, the method described in this chapter does not address biomass fuels as a source of greenhouse gases. For cases where biomass fuels are not grown sustainably, the greenhouse gas impact should be captured as a land use change; the *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories* (IPCC/UNEP/OECD/IEA 1997) provides information on how to do so.

4

PREFERRED METHOD FOR ESTIMATING EMISSIONS

To calculate carbon dioxide (CO_2) emissions from fossil fuel combustion,[4] the following data are needed:

- Fossil fuel energy consumption by fuel type and sector;
- Carbon (C) content coefficients;
- C sequestered in products; and
- Percentage of C oxidized during combustion.

Because the C content of fossil fuels varies by fuel type, it is necessary to compile consumption data for each type of fuel consumed. A recommended list of fuels is provided in Table 1.4-1. Default data on fuel consumption and fuel characteristics are provided in the CO_2 from Fossil Fuel Combustion Module of the State Inventory Tool (hereafter referred to as the State Inventory Tool) to assist in the calculations.[5] Note that while crude oil (a primary fuel) is primarily transformed into secondary fuels (such as distillate fuel) that are then consumed, it appears on this list to account for the occasional instances that crude oil is burned as a fuel. In these cases, emissions from crude oil should be estimated. However, the majority of crude oil is transformed into secondary fuels, and the C emissions occur only when the secondary fuels are combusted. Therefore, care should be taken not to calculate emissions from crude oil used to produce secondary fuels.

[4] As noted above, for this discussion, CO_2 emissions from fossil fuel combustion include all of the C in fuels that is either immediately oxidized or oxidized within a short time period (i.e., less than 20 years). It thus includes C in the form of gases, like carbon monoxide (CO). It also includes short-lived products that will be burned after use or decompose quickly. Methane (CH_4) emissions from oil and gas production and coal mining, as well as CH_4, CO, nitrous oxide, nitrogen oxides and non-methane volatile organic compounds emissions from stationary and mobile source combustion are not included in this section but are discussed later (see Chapters 2, 3, 4, and 5 of this volume).

[5] An electronic version of the tool in Excel format is available from EPA's State and Local Climate Change Program.

Table 1.4-1: Fuel Types Consumed by Sector

Residential	Commercial	Industrial	Transportation	Electric Utilities
Coal	Coal	Coking Coal Other Coal	Coal	Coal
Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
Petroleum: Distillate Fuel Kerosene LPG	Petroleum: Distillate Fuel Kerosene LPG Motor Gasoline Residual Fuel	Petroleum: Distillate Fuel Kerosene LPG Motor Gasoline Residual Fuel Lubricants Asphalt & Road Oil Crude Oil Feedstocks Misc. Petroleum Products Petroleum Coke Pentanes Plus Still Gas Special Naphthas Unfinished Oils Waxes Aviation Gasoline Blending Components Motor Gasoline Blending Components	Petroleum: Distillate Fuel LPG Motor Gasoline Residual Fuel Lubricants Aviation Gasoline Jet Fuel, Kerosene Jet Fuel, Naphtha	Petroleum: Distillate Fuel Residual Fuel Petroleum Coke

Source: U.S. EPA 2002b.

Box 1: Energy Units

A British thermal unit (Btu) is the quantity of heat required to raise the temperature of one pound of water one degree Fahrenheit at or near 39.2 Fahrenheit.

Btu	British thermal unit	1 Btu
MBtu	Thousand Btu	$1x10^3$ Btu
MMBtu	Million Btu	$1x10^6$ Btu
BBtu	Billion Btu	$1x10^9$ Btu
TBtu	Trillion Btu	$1x10^{12}$ Btu
QBtu	Quadrillion Btu	$1x10^{15}$ Btu

Fuel statistics should be provided on an energy basis—preferably in British thermal units (Btu)—rather than weight, because considerable variation exists in the energy content per weight of fossil fuels. To assist with conversions between Btu, refer to Box 1 on energy units. All energy data refer to gross caloric values (also called higher heating value) and not to net caloric value (lower heating value) to allow for accurate and transparent emissions estimates. Statistics using other units, such as barrels or tons, may be used, but require conversion to energy units. If conversion to energy units is necessary, the heat contents used for this conversion should be reported. Default heat contents for the various fuel types are presented in Tables 1.4-2 and 1.4-3. Annually variable heat contents are available for some of the fuel types and are presented in Table 1.4-3. The heat contents presented for natural gas are national averages, but state-specific values are provided in the State Inventory Tool and should be used for greater accuracy in the estimation process. The degree of variation geographically and temporally is less significant for natural gas and refined petroleum fuels than for coal, which may vary significantly from mine to mine and year to year.

Table 1.4-2 Heat Contents

Fuel Type	**Heat Equivalents**
Coal (MMBtu/ton)	
Residential Coal	[a]
Commercial Coal	[a]
Industrial Coking Coal	[a]
Industrial Other Coal	[a]
Utility Coal	[a]
Natural Gas (Btu/cubic foot)	[b]
Petroleum (MMBtu/barrel)	
Asphalt and Road Oil	6.636
Aviation Gasoline	5.048
Distillate Fuel Oil	5.825
Jet Fuel: Kerosene Type	5.670
Jet Fuel: Naphtha Type	5.355
Kerosene	5.670
Liquefied Petroleum Gases (LPG)	[a]
Lubricants	6.065
Miscellaneous Petroleum Products	5.796
Crude Oil	5.800
Motor Gasoline	[a]
Naphtha	5.248
Special Naphthas	5.248
Other Oil	5.825
Unfinished Oils	5.825
Pentanes Plus	4.620
Petroleum Coke	6.024
Residual Fuel Oil	6.287
Still Gas	6.000
Waxes	5.537

[a] Annually variable heat contents. Values are presented in Table 1.4-3.

[b] Varies annually by state. National averages are provided in Table 1.4-3 and state-specific values are provided in the State Inventory Tool.

Source: EIA 2003a.

Table 1.4-3: Annually Variable Heat Contents

Fuel	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Coal (MMBtu/ton)													
Residential Coal	23.137	23.114	23.105	22.994	23.112	23.118	23.011	22.494	21.620	23.880	25.020	24.905	24.836
Commercial Coal	23.137	23.114	23.105	22.994	23.112	23.118	23.011	22.494	21.620	23.880	25.020	24.905	24.836
Industrial Coking Coal	26.799	26.799	26.799	26.800	26.800	26.800	26.800	26.800	27.426	27.426	27.426	27.426	27.426
Industrial Other Coal	22.457	22.460	22.250	22.123	22.068	21.950	22.105	22.172	23.164	22.489	22.433	23.209	23.361
Utility Coal [a]	20.779	20.730	20.709	20.677	20.589	20.543	20.547	20.518	20.516	20.490	20.511	20.279	20.479
Petroleum (MMBtu/barrel)													
Motor Gasoline	5.253	5.253	5.253	5.253	5.230	5.215	5.216	5.213	5.212	5.211	5.210	5.210	5.208
LPG	3.625	3.614	3.624	3.606	3.635	3.623	3.613	3.616	3.614	3.616	3.607	3.614	3.612
Natural Gas [b] (Btu/cubic foot)	1,029	1,030	1,030	1,027	1,028	1,026	1,026	1,026	1,031	1,027	1,025	1,028	1,027

[a] Heat content for utility coal represents the average heat content for coal used for electric utilities and independent power producers based on the new EIA classification of electric power data.
[b] Heat contents varying by state are presented in the State Inventory Tool. Note this is dry natural gas.
Source: EIA 2003a.

In addition to the recommended approach outlined below, states may find it useful to distribute emissions from electric utilities across "end-use sectors," to assist in formulating emission reduction strategies. To distribute utility emissions accurately, it is necessary to obtain electricity consumption data by each of the four end-use sectors (residential, commercial, industrial, and transportation) in the state. Default values for the percentage of electricity used by each sector may be obtained from the *State Energy Data (SED) 2000* (EIA 2003d). Using these figures, states can calculate the fraction of total electricity consumption that is consumed by each of the four end-use sectors (i.e., each of these fractions is multiplied by total emissions from the utility sector, resulting in the portion of utility emissions attributable to each end-use sector). The end-use emissions from electricity consumption are then added to the other sectoral emissions.

The estimation methodology consists of seven steps: (1) obtain required energy data; (2) estimate total C content in fuels; (3) estimate C stored in products; (4) calculate net potential C emissions; (5) estimate C oxidized from energy uses; (6) convert units to million metric tons of C equivalent; and (7) calculate total emissions.

Step (1): Obtain Required Energy Data

- *Required Energy Data.* The information needed to perform these calculations is annual state energy consumption data based on *primary fuel type* (e.g., coal, natural gas, and petroleum) and *secondary fuel type* (e.g., gasoline, residual oil, natural gas, etc.) by *sector* (e.g., residential, commercial, industrial, transportation, and electric utilities). A list of potential fuel types consumed in each sector is provided in Table 1.4-1 and is included in the State Inventory Tool. Additionally, further disaggregation may be done (i.e., by individual industries within the industrial sector or by specific fuel types not listed) if the appropriate data are available.

  Data Sources. Any in-state sources, such as state energy commissions or public utility commissions, should be consulted first. Alternatively, state energy data by fuel type and sector for fossil fuels can be found in the *SED 2000* (EIA 2003d). These data are available on the Internet at http://www.eia.doe.gov/emeu/states/_use_multistate.html[6] and in the State Inventory Tool. Fossil fuel statistics should be provided on an energy basis (e.g., in units of Btu). If fuel data are reported in physical units and documented heat contents (which allow conversion to Btu) cannot be obtained within the state, the heat contents listed in Table 1.4-2 may be applied to convert to million Btu. Note that fuel consumption data provided in the State Inventory Tool (from the EIA 2003), are given in BBtu (billion Btu).

Example:	According to the *SED 2000* (EIA 2003d), Wisconsin energy consumption of LPG fuel for the industrial sector in 2000 was 12,019.1 billion Btu. To convert this value to million Btu (MMBtu) perform the following calculation:
	12,019.1 BBtu x 10^3 MMBtu/BBtu = **12,019,100 million Btu**

[6] Note that the *SED 2000* tables for state-by-state fuel consumption includes a category for “petroleum, other” under the industrial sector. This category includes petroleum coke. EIA can provide an extract from its database that lists, for a given state, the types and amounts of fuels that were combined in the “petroleum, other” category.

If using *SED 2000*, note that the reported values for gasoline consumption include ethanol fuel consumption. Because ethanol is a biofuel, C emissions from ethanol combustion should not be counted as greenhouse gas emissions. Thus, the gasoline values should be adjusted by subtracting out the energy consumption (Btu) of ethanol fuel combustion. State ethanol data can be obtained from FHWA's annual Highway Statistics report (U.S. DOT 1993 through 2002), and is also provided in the State Inventory Tool. This energy should be subtracted from motor gasoline energy consumption for users attempting to disaggregate the data further (e.g., by specific end user, such as chemical manufacturer).

EIA's data also includes industrial coal used to make synthetic natural gas, which is accounted for in both industrial coal and natural gas consumption data. Therefore, the energy content of synthetic natural gas should be subtracted from the energy content of industrial coal to prevent double-counting of emissions. State-specific natural gas data can be obtained from Table 12 of EIA's *Historical Natural Gas Annual* (EIA 2001) and Table 8 of EIA's *Natural Gas Annual* (EIA 2004). This information is also provided in the State Inventory Tool.

Currently emissions from non-utilities (e.g., independent power producers and industrial cogenerators) are accounted for in the industrial sector by the *SED 2000* and the State Inventory Tool. However, EIA has been working to combine fuel consumption by utilities with fuel consumption by non-utilities (currently captured in the industrial sector) to create an "electric power" sector. EPA's *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2002* accounts for this modification. However, because state-level non-utility data are not available prior to 1998, EPA recommends that states account for emissions from non-utilities in the industrial sector.

Step (2): Estimate Total Carbon Content in Fuels

C content represents the total amount of C that could be emitted if 100 percent was released to the atmosphere. To estimate the total C that could be released from the fuels, multiply energy consumption for each fuel type by the appropriate C content coefficient. This calculation should be done for all fuel types in each sector.

C content coefficients vary considerably both between and within the major fuel types, as noted below:

- For natural gas, the C content depends heavily on the composition of the gas, which includes methane, ethane, propane, other hydrocarbons, CO_2, and other gases. The relative proportions of these gases vary from one gas production site to another.

- For petroleum, Marland and Rotty (1984) suggest that the API gravity[7] indicates the carbon/hydrogen ratio. C content per unit of energy is usually less for light refined products such as gasoline than for heavier products such as residual fuel oil.

- For coal, C emissions per ton vary considerably depending on the coal's composition of C, hydrogen, sulfur, ash, oxygen, and nitrogen. While variability of C emissions on a mass basis can be considerable, C emissions per unit of energy (e.g., per Btu) vary less.

In general, C content coefficients are determined based on the composition and heat contents of fuel samples. Based on these studies and detailed fuel data, the EIA estimates C content coefficients for a wide range of fuel types. Nationally averaged C content coefficients for each fuel type are listed in Table 1.4-4. Annually variable C content coefficients by fuel type are provided in Table 1.4-5. These coefficients, which can also be found in EPA (2004), are similar to those recommended in the IPCC Guidelines (IPCC/ UNEP/OECD/IEA 1997) with modifications for U.S.-specific fuel characteristics. As with thermal conversion factors, these average C coefficients may not precisely reflect the C content of fuel used in a particular state, and the degree of variation geographically and temporally is generally quite small for natural gas and refined petroleum fuels, but coal coefficients vary from mine to mine and year to year. State factors for coal may be found in EIA's *Electric Power Annual* 2002 (2003b) and are also provided in the State Inventory Tool. States are encouraged to use more detailed data if it is available and well documented.

The specific elements of this step are as follows:

- To estimate the total C content of a particular fuel, multiply the Btus consumed by the appropriate C content coefficient, as presented in Tables 1.4-4 and 1.4-5. If state-specific C content data are available and well-documented, they may be used in place of the values in the below tables. The resulting potential emissions will be in pounds of C. The equations take the following form:

Total C Contained in Fuel i (lbs C) = Fuel Consumption for Fuel i (BBtu) x C Content Coefficient for Fuel i (lbs C/MMBtu)

- For each fuel type, divide the results by 2000 lbs per ton to obtain tons of C. For each sector, sum the results of the fuel types to obtain the total C content in tons.

[7] Variations in petroleum are most often expressed in terms of specific gravity at 15 degrees Celsius. The API gravity, where API gravity = 141.5/specific gravity - 131.5, is an indication of the molecular size, carbon/hydrogen ratio, and hence C content of a crude oil.

Table 1.4-4: Carbon Content Coefficients for Fuel Combustion[a]
(lbs C/MMBtu)

Fuel	Carbon Content Coefficient
Coal	
Residential Coal	[b]
Commercial Coal	[b]
Industrial Coking Coal	[b]
Industrial Other Coal	[b]
Utility Coal	[b]
Natural Gas	31.90
Petroleum	
Asphalt and Road Oil	45.46
Aviation Gas	41.60
Distillate Fuel Oil	43.98
Jet Fuel, Kerosene	[c]
Jet Fuel, Naphtha	[c]
Kerosene	43.48
LPG	[c]
Lubricants	44.62
Motor Gasoline	[c]
Residual Fuel Oil	47.38
Misc. Petroleum Products	[c]
Naphtha	39.99
Other Oils	43.98
Pentanes Plus	40.21
Petroleum Coke	61.40
Still Gas	38.60
Special Naphthas	43.78
Unfinished Oils	[c]
Waxes	43.67
Aviation Gasoline Blending Components	41.60
Motor Gasoline Blending Components	[c]
Crude Oil	[c]

All coefficients are given as pounds of C emitted per million Btu of fuel consumed (lbs C/MMBtu). When multiplied by consumption in MMBtu they result in emissions of C in pounds (lbs C).

[a] C content coefficients are sometimes called carbon coefficients.

[b] C content coefficients for coal vary annually and by state. Values are presented in the SIT.

[c] C content coefficients vary annually. Values are presented in Table 1.4-5.

Sources: U.S. EPA (2004b) and EIA (2003c).

Table 1.4-5: Annually Variable Carbon Content Coefficients (lbs C/MMBtu)

Fuel	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
LPG (energy use)	37.95	37.94	37.95	37.96	37.95	37.92	37.92	37.88	37.98	38.03	38.05	38.03	38.01
LPG (non-energy use)	37.09	37.12	37.12	37.04	37.22	37.20	37.16	37.20	37.20	37.12	37.02	37.07	37.05
Motor Gasoline	42.79	42.79	42.81	42.84	42.88	42.73	42.68	42.66	42.62	42.62	42.64	42.64	42.64
Jet Fuel	42.77	42.77	42.74	42.71	42.66	42.63	42.62	42.62	42.62	42.62	42.62	42.62	42.62
Motor Gasoline Blending Components	42.79	42.79	42.81	42.84	42.88	42.73	42.68	42.66	42.62	42.62	42.64	42.64	42.64
Misc. Petro Products	44.44	44.49	44.58	44.59	44.56	44.59	44.64	44.62	44.62	44.51	44.60	44.73	44.60
Unfinished Oils	44.44	44.49	44.58	44.59	44.56	44.59	44.64	44.62	44.62	44.51	44.60	44.73	44.60
Crude Oil	44.44	44.49	44.58	44.59	44.56	44.59	44.64	44.62	44.62	44.51	44.60	44.73	44.60

Source: U.S. EPA (2004b) and EIA (2003c).

Example:	To calculate the total C content for LPG in the industrial sector for Wisconsin in 2000, obtain the result from Step 1 (12,019,000 MMBtu) and perform the following calculations: 12,019,100 MMBtu x 38.05 lbs C/MMBtu = 457,326,755 lbs C 457,326,755 lbs C ÷ 2,000 lbs/ton = **228,663 tons C**

After estimating the total C contained in the fuels, the next step is to estimate the amount of C from these fuels that is sequestered in non-energy products for a significant period of time (e.g., more than 20 years). Most fossil fuels are used for non-energy purposes to some degree. For example, LPG is used for production of solvents and synthetic rubber; oil is used to produce asphalt, naphthas, and lubricants; and coal is used to produce coke, yielding crude light oil and crude tar as by-products that are used in the chemical industry.

However, not all non-energy uses of fossil fuels result in C sequestration. For example, the C from natural gas used in ammonia production is oxidized quickly; many products from the chemical and refining industries are burned or decompose within a few years; and the C in coke is oxidized when the coke is used.

The approach used to determine the portion of C sequestered in products is based on that used by EIA (2003c) and U.S. EPA (2004b), in which the following C storage assumptions can be made:

- *Petrochemical feedstocks, liquefied petroleum gases (LPG), pentanes plus, and natural gas used for chemical manufacturing plant feedstocks (i.e., not used as fuel)*: EPA has developed an annually variable empirically determined storage factor for the C consumed for non-energy end uses of petrochemical feedstocks, pentanes plus, LPG, and natural gas (henceforth referred to as feedstocks). The storage factor is equal to the ratio of C stored in the final products to total C content for the non-energy fossil fuel feedstocks used in industrial processes, after adjusting for net exports of feedstocks. Only one aggregate storage factor was calculated for the four fuel feedstock types; the four types are grouped because of the overlap of their derivative products. Due to the many reaction pathways involved in producing petrochemical products (or wastes), it becomes extraordinarily complex to link individual products (or wastes) to their parent fuel feedstocks. Overall storage factors for the feedstocks were determined by developing a mass balance on the C in feedstocks, and characterizing products, uses, and environmental releases as resulting in either storage or emissions. These factors are shown in Table 1.4-6.

- *Asphalt and Road Oil (i.e., Bitumen)*: Although there is some volatilization of organic compounds from hot mix asphalt (presumably followed by oxidation to CO_2 in the atmosphere), available data indicate that this comprises less than 1 percent of total C. Thus, a storage factor of 100 percent is used.

- *Lubricants:* Of the C contained in lubricants (e.g., automotive oil, grease, etc.), approximately 9 percent is assumed to remain unoxidized for long periods of time. This estimate is based on identifying various environmental fates of oils and greases, characterizing them as resulting in either emissions or indefinite storage, and calculating a weighted average factor for the entire category.

- *Waxes and Miscellaneous Products:* This category, as defined by EIA, includes waxes and various other petroleum products used for non-energy purposes. Until more exact information is available, 100 percent of the C contained in these products is assumed to be sequestered. For example, the C contained in waxes for food industry wrappers is assumed to be sequestered in landfills.

These assumptions, and storage factors for the remaining non-energy uses (which are based on the IPCC Guidelines), are reflected in the default values recommended in Table 1.4-7. As more detailed information on non-energy uses of fossil fuels becomes available, estimates of the fraction of C stored may change. States should use the most up-to-date information available, and document their assumptions.

The specific elements of this step are as follows:

For each fuel type that has non-energy uses (as listed in Tables 1.4-6 and 1.4-7), estimate the Btus consumed in non-energy uses, based on (1) the total Btus consumed and (2) the fraction consumed for non-energy uses. Data on the quantity of each fuel type consumed may be obtained as described in Step 1 above. For data on the fraction of each fuel type consumed for non-energy uses, in-state sources, such as state energy commissions or public utility commissions, should be consulted first. In the absence of state-specific data, estimates of the national-level fraction of each fuel type used for non-energy uses can be determined using the Annual Energy Review 2002 (EIA 2003a) and SED 2000 (EIA 2003d), and the national fractions may be used as a proxy for the state fractions although this method will be less accurate. Even though fuel used for non-energy purposes does not produce energy, it can still be measured in Btus because it has the potential to create this energy. Doing so keeps the units consistent with the other types of fuel consumption and allows for the subtraction of non-energy fuel consumption from the total fuel consumed.

Example: To calculate the amount of LPG used for non-energy purposes in Wisconsin in 2000 based on national-level non-energy usage, obtain (1) state-level data for LPG consumption in Wisconsin’s industrial sector, from the *SED 2000* (EIA 2003d), (2) national-level data for LPG used for non-energy purposes, from Table 1.15 of the *Annual Energy Review* (EIA 2000a), and (3) national-level data for total LPG consumption in the industrial sector, from Table 14 of the *SED 2000*. Then perform the following calculations. Note that these data can also be found in the State Inventory Tool.

Amount of LPG consumed in Wisconsin’s industrial sector in 2000: 12,019,100 MMBtu

Amount of LPG used for non-energy purposes nationwide in the industrial sector in 2000 (adjusted for exports): 1,707,341,000 MMBtu

Amount of LPG consumed nationwide in the industrial sector in 2000: 2,293,054,000 MMBtu

National-level fraction of LPG used for industrial non-energy uses: 1,707,341,000 ÷ 2,293,054,000 = 0.74

12,019,100 MMBtu × 0.74 = **8,894,134 MMBtu** LPG used for non-energy uses in Wisconsin in 2000

(4) To estimate C sequestered in products for each state, multiply the Btus consumed for non-energy purposes by (1) the fuel-specific C content coefficients in Tables 1.4-4 and 1.4-5 and (2) the fuel-specific storage factor. National default values for storage factors are given in Table 1.4-6. However, state-level fractions may differ depending on the type of non-energy uses. Thus, where state-specific estimates are available, their use is preferred; such estimates should be presented with adequate supporting documentation. The following equation outlines this step:

C Sequestered (tons C) = Non-energy use of fuel (MMBtu) x C Content Coefficient (lbs C/MMBtu) ÷ 2000 lbs/ton x Storage Factor (%)

Example: To estimate the C sequestered from industrial use of LPG, multiply the total LPG used for industrial non-energy uses by the carbon content coefficient of LPG. Then convert to tons C.

8,894,134 MMBtu x 37.02 lbs C/MMBtu = 329,260,841 lbs C

329,260,841 lbs C ÷ 2000 tons/lb = 164,630 tons C

164,630 tons C x 63% = **103,717 tons C**

(5) Sum the C sequestered for each fuel to yield the total C sequestered. This C should then be subtracted from the estimates of the total C in fuels. When estimating emissions sector-by-sector, it is suggested that sequestered C from products be assigned to the industrial sector, unless justification for allocating certain products to another sector can be clearly demonstrated.

Table 1.4-6: Annually Variable Percentage of Carbon Stored by Non-Energy Uses of Fuels as Petrochemical Feedstocks

Year	Percentage Stored
1990	59%
1991	60%
1992	62%
1993	64%
1994	64%
1995	65%
1996	66%
1997	65%
1998	64%
1999	65%
2000	66%
2001	66%
2002	67%

Notes: See discussion under Step 3 for assumptions on which these values are based. Petrochemical feedstocks include Natural, LPG, Pentanes Plus, Naphthas and Other Oil.

Source: U.S. EPA 2004b.

Table 1.4-7: Percentage of Carbon Stored by Non-Energy Uses[a]

Fuel Type	Percentage Stored
Coal Oils and Tars from Coke Production	75%
Asphalt and Road Oil	100%
Lubricants	9%
Distillate Fuel Oil	50%
Residual Fuel Oil	50%
Petroleum Coke	50%
Still Gas	80%
Waxes and Miscellaneous Products	100%

[a] See discussion under Step 3 for assumptions on which these values are based.

Source: U.S. EPA 2004b.

Step (4): Calculate Net Potential Carbon Emissions

- Subtract the C stored (as calculated in Step 3) from the total C estimated for each fuel type (from Step 2). The resulting estimates represent the net potential C emissions.[8]

> ***Example:*** To calculate total potential carbon for industrial LPG, subtract the C stored by the total carbon content of LPG.
>
> 228,663 tons C **-** 103,717 tons C = **124,946 tons C**

Step (5): Estimate Carbon Oxidized from Energy Uses

As described earlier, not all C is oxidized during the combustion of fossil fuels. The amount of C that does not oxidize during combustion is usually a small fraction of total C, and of this amount a large portion oxidizes in the atmosphere shortly after combustion. The remaining unoxidized C is sequestered in soot or ash. Based on EIA (2001c), the following factors are recommended:

- For natural gas and LPG, less than 0.5 percent of the C is unoxidized during combustion and remains as soot or ash in the burner, stack, or in the environment. This is equivalent to a fraction oxidized of 0.995.

- For petroleum fuels, approximately 1 percent is sequestered as soot or ash. This is equivalent to a fraction oxidized of 0.99.

- For coal, approximately 1 percent of C is sequestered, primarily as ash. This is equivalent to a fraction oxidized of 0.99.[9]

These values vary based on fuel quality and type of combustion technology (particularly for coal). If values are available for state level combustion, they should be used and documented.

- To complete this step, multiply net C content for each fuel and sector in tons (Step 4) by the fraction of C oxidized to obtain the total amount of C oxidized to the atmosphere.

> ***Example:*** To calculate the total amount of C oxidized from the combustion of LPG in the Wisconsin industrial sector, multiply net potential C by the fraction oxidized for LPG as shown.
>
> 124,946 tons C × 0.995 = **124,321 tons C**

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[8] If the C content of bunker fuels is estimated (this is an alternative method, described in Section 5 of this chapter), it should also be subtracted from the total C as part of this step.

[9] The IPCC recommends using a value of 0.98 for the fraction of coal oxidized. However, the U.S. Department of Energy recommends using a value of 0.99 because coal combustors in the United States achieve more complete combustion than the global average reflected in the IPCC value.

Step (6): Convert Units to Million Metric Tons of Carbon Equivalent (MMTCE)

- Multiply the total C oxidized in tons (Step 5) for each fuel type and sector by the ratio of metric tons per ton (0.9072) to obtain metric tons of C equivalent emissions.

- Sum across each fuel type and sector to find total state emissions of CO_2 from energy consumption (again, measured in metric tons of C). Divide by 10^6 to express emissions in million metric tons of C (MMTCE).

> ***Example:*** To convert the units for the amount of C emitted due to LPG consumption (124,321 tons C) to metric tons, perform the following calculation:
>
> 124,321 tons C x 0.9072 metric tons/ton ÷ 10^6 metric tons = **0.113 MMTCE**

Step (7): Calculate Total Emissions

- The steps above provide estimates of total C in fossil fuels consumed, C sequestered in non-energy products, and amount of C oxidized to CO_2. Given these estimates, total C emissions from fossil fuel combustion can be determined. Total C emissions are equal to the total C content in fuel, minus C sequestered in products (and emissions from international bunkers if estimated as explained in Section 5), adjusted for the C unoxidized during combustion, and summed over all fuel types and sectors.

5

ALTERNATIVE METHODS FOR ESTIMATING EMISSIONS

The preferred method outlined in Section 4 accounts for all carbon dioxide (CO_2) emissions from all statewide fossil fuel combusted, including fuel used to generate electricity. However, emissions from 2 special categories – (1) consumption of international bunker fuels and (2) electricity produced in one state for consumption in another – should also be estimated if feasible.

"International bunker fuels" are fuels used in international aviation and marine transport. These fuels are sold in-state, but supplied to ships and aircraft, which consume it during international transport activities. For example, distillate fuel, residual fuel, and jet fuel may be sold in a state and be consumed outside the United States. Because this fuel is not combusted solely in the United States, its emissions cannot be clearly attributed to the United States. In accordance with international inventory practices (IPCC/UNEP/OECD/IEA 1997), if state-level data are available, emissions from international bunkers may be calculated and reported by the state of origin, but not included in the state's total emission figures. In this way, emissions from these sources can be quantified without attributing undue emissions to the United States or any state therein. If state data are available and bunker fuel emissions are calculated, the total carbon (C) in bunker fuels should be subtracted from the C total in Step 4 of the previous section.

Fuel may be used in one state to generate electricity that is sent across power lines to be consumed in another state. The actual emissions from electricity consumption, however, occur in the generating state. For consistency, each state should count the CO_2 emissions from all electricity generation in the state, regardless of where the electricity is ultimately used. However, emission estimates for net imports may be useful in analyzing strategies to reduce emissions. For example, states may choose to implement energy efficiency measures; these measures relate to energy consumption, not generation. For this reason, states are encouraged to estimate the CO_2 emissions associated with electricity consumption in the state. To do so, a state will need to sum (a) the CO_2 emissions from electricity generation (estimated using the method in Section 4), and (b) the CO_2 emissions from net imports of electricity (estimated using the method described below). If a state exports more electricity than it imports, it will have negative net imports, and thus negative CO_2 emissions from net imports. In such a case, the state's CO_2 emissions from electricity consumption will be less than its emissions from electricity generation.

Section 5.1 below provides background for the estimation of C from bunker fuel consumption and presents the methodology based on the availability of state data. Section 5.2 below presents a method for estimating the CO_2 emissions from net imports of electricity.

5.1 Estimating Carbon from Bunker Fuel Consumption

Emissions from international bunker fuels are typically not addressed in state emission inventories, due to difficulties in obtaining the necessary data. EIA's State Energy Data (*SED) 2000* (EIA 2003d) does not provide data on bunker fuels; however the U.S. Department of Commerce, Bureau of the Census, does provide data on marine bunkers by port, which can be aggregated by state (U.S. DOC 1991-2003). Unfortunately these data may overestimate bunkers by including fuels that are not purchased within each state, but are already in ships leaving port. Therefore, using DOC's data in conjunction with the EIA's *SED 2000* may pose problematic and result in lower than actual emissions of distillate and residual fuels. However, if a state collects data on emissions from international bunker fuels, the state may estimate emissions from the combustion of these fuels. Estimated total C in bunker fuels should then be subtracted from total C in fuels, which is Step 4 of Section 4. The subtraction of bunker fuel consumed in international transportation is consistent with international greenhouse gas reporting guidelines developed by the Intergovernmental Panel on Climate Change (IPCC/UNEP/OECD/IEA 1997).

The discussion below outlines the procedure for estimating consumption of international bunker fuel (if data are available).

- International bunker fuel emissions are calculated in the same manner as other emissions from fossil fuel combustion. Once consumption of international bunker fuels is determined, multiply the consumption for each fuel by the appropriate C content coefficients (see Tables 1.4-4 and 1.4-5). This results in the amount of C potentially emitted by combustion of these fuels, or total C contained in the fuels, as shown in the equation below:

Total C in Bunker Fuel (lbs) = Consumption of Bunker Fuel (MMBtu) x C Content Coefficient for Bunker Fuel (lbs C/MMBtu)

- The total C contained in each bunker fuel should be subtracted from total C *only* if international bunkers have been captured in the total C figures. States using the *SED 2000 Consumption* data on fuel consumption will need to subtract out C in bunker fuels.

Example:	At the national level, data on distillate fuel oil used for civilian international marine bunkers is obtained from DOC's Bureau of the Census. The 2000 figure for the United States is 6,910,152 barrels. The following calculations are performed to compute the total C in this fuel: 6,910,152 barrels x 5.825 MMBtu/barrel = 40,251,635 MMBtu 40,251,635 MMBtu x 43.98 lbs C/MMBtu = **1,770,266,907 lbs C**

5.2 Estimating Carbon Dioxide Emissions from Net Imports of Electricity

This section presents two methods for estimating CO_2 emissions from net imports of electricity, based on whether the state is a net exporter or net importer. If a state is a net exporter (i.e., net imports are negative), then CO_2 emissions can be estimated using the state average CO_2 emission rate. However, if a state is a net importer, then a regional emission rate should be used, since it is difficult to determine the fuel mix used to generate the electricity imported. All of these rates can be obtained from EPA's Emissions & Generation Resource Integrated Database (eGRID), which can be found at http://www.epa.gov/cleanenergy/egrid.htm (U.S. EPA 2004a).

Note that neither approach attempts to determine which type (or mix) of fuel is the marginal fuel combusted to generate the electricity that is exported to another state. Using CO_2 emission rates for the marginal fuel would result in the most accurate estimate, but at this time no methodology (complete with data sources) has been developed for such an approach.

Method A: Estimate CO_2 Emissions from Net Imports of Electricity *as a Net Exporter*

If emissions were distributed to end-users, accounting for net exports of electricity (negative net imports) would result in a decrease in state emission totals, as these emissions occur from fuels combusted to produce energy consumed by out-of-state users.

The specific elements of this method are as follows:

Step (1) Download eGRID2002 V2.01

Download and install eGRID2002 V2.01, which can be done by following the directions at http://www.epa.gov/cleanenergy/egrid.htm.

Step (2) Obtain Data on Net Exports of Electricity

Obtain the state's net exports of electricity (i.e., the absolute value of negative net imports). The eGRID model provides "State Estimated Net Imports (GWh)" from 1996 to 2000 in GWh.[10] This data can be accessed by choosing the aggregation level as "State", clicking on your state, and then selecting the "State Import/Export Data" tab.

Step (3) Obtain the CO_2 Emission Rate for Exported Electricity

Obtain the average annual CO_2 emission rate for your state from eGRID. This value is the "Output Rate (lbs/MWh)" for Annual CO_2. Convert this rate from lbs CO_2/MWh to $MMTCO_2$/GWh by multiplying by 4.54×10^{-7}. [11]

Step (4) Calculate CO_2 Emissions from Exported Electricity

Multiply the state's net exports of electricity (from Step 2) by the CO_2 emission rate for exported electricity (from Step 3) to estimate CO_2 emissions from net exports.

Emissions from Net Exports ($MMTCO_2$) = Electricity Net Exports (GWh) x CO_2 Emission Rate ($MMTCO_2$/GWh)

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[10] Although eGRID actually provides import/export data back to 1994, no CO_2 emission rates for 1994 or 1995 are given.

[11] This conversion factor represents the following calculations needed to convert from lbs/MWh to MMT/GWh: 10^3 MWh/GWh x 1 ton/2000 lbs x 0.9072 metric tons/ton x 1 MMT/10^6 MT.

Step (5) Convert to Million Metric Tons of Carbon Equivalent (MMTCE)

Multiply $MMTCO_2$ by 12/44 to obtain CO_2 emissions in MMTCE.

Example:	To calculate the CO_2 emissions from net exports of electricity in West Virginia in 2000, obtain the following data: Net Generation for Exports of Electricity in WI in 2000 = 56,173 GWh CO_2 Emission Rate for Exported Electricity in WI in 2000 = 2,027.33 lbs CO_2/MWh Next, convert the CO_2 emission rate to $MMTCO_2$/MWh by multiplying by the conversion factor provided in Step 3. 2,027.33 lbs CO_2/MWh x 4.54 x 10^{-7} = 0.00092 $MMTCO_2$/GWh Then, multiply net generation for exports (in GWh) by the CO_2 emission rate (in $MMTCO_2$/GWh) to obtain CO_2 emissions (in $MMTCO_2$). Convert to MMTCE by multiplying by the C/CO_2 ratio. 56,173 GWh x 0.00092 $MMTCO_2$/GWh = 51.68 $MMTCO_2$ 51.68 $MMTCO_2$ x 12/44 = **14.09 MMTCE**

To obtain a more accurate picture of CO_2 emissions from in-state energy use, these emissions can be subtracted from total state CO_2 emissions. However, to remain consistent with other state inventories, this adjustment should be presented and discussed separately from state emission totals.

For states that are net importers of electricity, it is relatively difficult to estimate the fuel mix that was used to generate the electricity that was imported. Electricity may originate from one state, multiple states, or even multiple grids. Due to the complex and varied nature of the specific circumstances surrounding electricity imports to each state, the methodology for determining a CO_2 emission rate should be tailored to state-specific circumstances and data availability.

CO_2 emission rates from eGRID were measured using continuous emission modeling (CEM) under EPA's Acid Rain program. Emission monitors tend to result in slightly higher CO_2 values than CO_2 emissions estimated using fuel consumption and carbon contents, which is the recommended approach in Section 4. Therefore, CO_2 emissions estimated using this approach are considered conservative. For the purpose of voluntarily estimating state CO_2 emissions, the slight disparity between emissions monitoring and emissions estimation should not be a concern.

The specific elements of this method are as follows:

Step (1) Download eGRID2002 V2.01

Download and install eGRID2002 V2.01, which can be done by following the directions at http://www.epa.gov/cleanenergy/egrid.htm.

Step (2) Obtain Data on Net Imports of Electricity

Obtain the state's net imports of electricity. The eGRID model provides "State Estimated Net Imports (GWh)" from 1994 to 2000 in GWh.[12] This data can be accessed by choosing the aggregation level as "State", clicking on your state, and then selecting the "State Import/Export Data" tab.

Step (3) Determine the CO_2 Emission Rate for Imported Electricity

Select/calculate an emission rate that best represents the electricity imported. This step constitutes the primary difference from Method A, and should be discussed with a state energy official before choosing an option. There are a number of ways states can choose a CO_2 emissions rate to most accurately represent their electricity imports. Four of these options are described below:[13]

1. Use the CO_2 emission rate for the NERC region from which power is imported.[14] Figure 1.5-1 illustrates the boundaries of each NERC region, and may assist in determining the appropriate NERC region. Next, obtain the average annual CO_2 output emission rate (lbs CO_2/MWh) for this NERC region from eGRID, making sure that "Location (Operator)-based" is selected. Convert this rate to $MMTCO_2$/GWh by multiplying by 4.54×10^{-7}.

2. If your state is located in the NERC region from which power is imported, an improvement upon the previous option would be to use an adjusted CO_2 emission rate for your NERC region. This approach entails subtracting out the CO_2 emissions and electricity generation for your state, which are factored into the average annual CO_2 output emission rate for your NERC region. Data needed for this calculation include:

    - **CO_2 emissions for your NERC region (tons CO_2).** Obtain the CO_2 emissions for your NERC region from eGRID.

    - **CO_2 emissions from state electricity generation (tons CO_2).** Obtain these CO_2 emissions for your state from eGRID.

    - **Net generation of electricity for your NERC Region (MWh).** Obtain the net generation for your NERC region from eGRID.

    - **State net electricity generation (MWh).** Obtain the total net generation for your state from eGRID.

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[12] Although eGRID actually provides import/export data back to 1994, no CO_2 emission rates for 1994 or 1995 are given.

[13] When obtaining regional data from eGRID, make sure that "Location (Operator)-based" is selected, rather than "Owner-based." This is the default selection.

[14] NERC (North American Electricity Reliable Council) regions are areas of cooperation for electric system reliability and security. For more information, see www.nerc.com.

To make this adjustment, follow the formula below:

Adjusted NERC Emission Rate (tons CO_2/MWh) = (CO_2 Emissions for NERC Region (tons CO_2) – State CO_2 Emissions (tons CO_2)) ÷ (Net Generation for NERC Region (MWh) – State Net Generation (MWh)).

Convert this rate to $MMTCO_2$/GWh by multiplying by 9.072×10^{-4}.[15]

3. Use the average annual CO_2 output emission rate for the eGRID Subregion[16] from which your state primarily imports electricity (lbs/MWh). Convert this rate to $MMTCO_2$/GWh by multiplying by 4.54 x 10-7.

4. Determine your own CO_2 emission rate (in $MMTCO_2$/GWh) in consultation with state energy experts, and document how you arrived at this value.

Step (4) Calculate CO_2 Emissions from Imported Electricity

Multiply the state's net imports of electricity (from Step 2) by the selected CO_2 emission rate for imported electricity (from Step 3) to estimate CO_2 emissions from net imports.

Emissions from Net Imports ($MMTCO_2$) = Electricity Net Imports (GWh) x CO_2 Emission Rate ($MMTCO_2$/GWh)

Step (5) Convert to Million Metric Tons of Carbon Equivalent (MMTCE)

Multiply $MMTCO_2$ by 12/44 to obtain CO_2 emissions in million metric tons of C equivalent (MMTCE).

To obtain a more accurate picture of CO_2 emissions from in-state energy use, these emissions can be subtracted from total state CO_2 emissions. However, to remain consistent with other state inventories, this adjustment should be presented and discussed separately from state emission totals.

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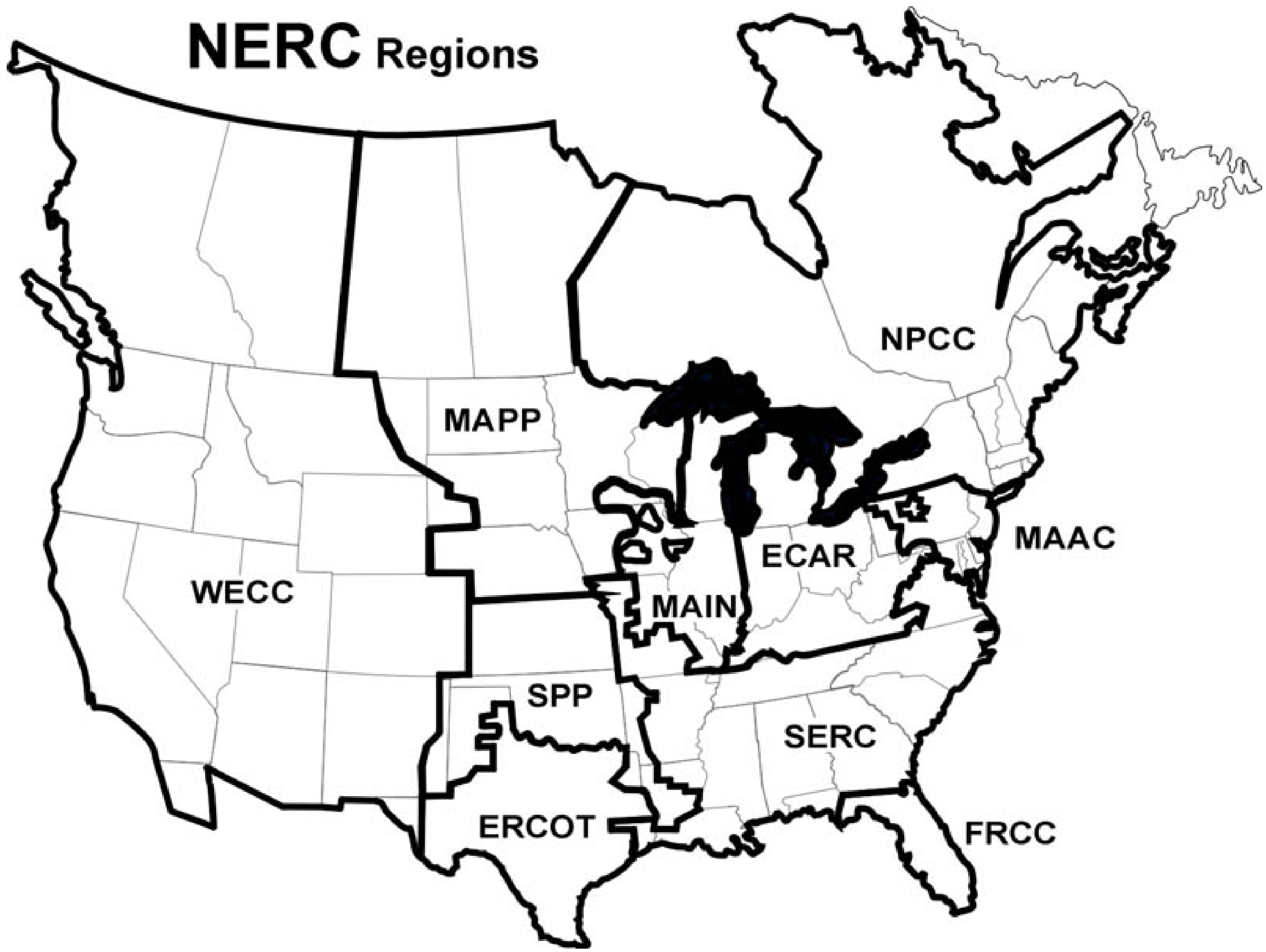
[15] This conversion factor represents the following calculations needed to convert from tons/MWh to MMT/GWh: 10^3 MWh/GWh x 0.9072 metric tons/ton x 1 MMT/10^6 MT.

[16] These subregions are defined by eGRID as the following: "eGRID subregions represent a portion of the U.S. power grid that is contained within a single NERC region. eGRID divides the U.S. power grid into 27 different eGRID subregions, plus an "Off-Grid" category for plants that are not grid-connected. Most of eGRID's subregions consist of one or more power control areas (PCAs), except for the New York ISO, which has been divided into three geographic eGRID subregions. eGRID subregions generally represent sections of the power grid that have similar emissions and resource mix characteristics and may be partially isolated by transmission constraints. eGRID's subregions correspond in most cases to subregions used by the North American Electric Reliability Council (i.e., subregions of NERC regions) and to IPM® regions developed by ICF Consulting." (EPA 2003)

Figure 1.5-1: North American Electric Reliability Council (NREC) Regional Councils



Note: As shown in the map above, NERC divides the US and southern Canada into the following ten regional councils: East Central Area Reliability Coordination Agreement (ECAR), Electric Reliability Council of Texas, Inc. (ERCOT), Florida Reliability Coordinating Council (FRCC), Mid-Atlantic Area Council (MAAC), Mid-America Interconnected Network, Inc. (MAIN), Mid-Continent Area Power Pool (MAPP), Northeast Power Coordinating Council (NPCC), Southeastern Electric Reliability Council (SERC), Southwest Power Pool, Inc. (SPP), and Western Electricity Coordinating Council (WECC). These councils are the regions used in the eGRID model.

6

UNCERTAINTY SUMMARY

The amount of CO_2 emitted from fossil fuel combustion depends on the type and amount of fuel consumed, the carbon content of the fuel, and the fraction of the fuel that is oxidized. Consequently, the more accurately these parameters are characterized, the more accurate the estimate of CO_2 emissions. Nevertheless, there are uncertainties associated with each of these parameters.

Although statistics of total fossil fuel and other energy consumption are relatively accurate at the national level, there is more uncertainty associated with the state-level data. In addition, the allocation of this consumption to individual end-use sectors (i.e., residential, commercial, industrial, and transportation) at the state level is more uncertain than at the national level.

Uses of fuels for non-energy purposes introduce additional uncertainty to estimating emissions, as the amount or rate at which carbon is emitted to the atmosphere can vary greatly depending on the fuel and use. This guidance and the State Inventory Tool provide default values for the amount of non-energy use and percentage of carbon stored by fuel type, based on data collected at the national level. State-specific data can reduce these uncertainties.

The accounting for emissions from international bunker fuels also introduces uncertainty. In accordance with international inventory practices (IPCC/UNEP/OECD/IEA 1997), if state-level data are available, emissions from international bunkers may be calculated and reported by the state of origin, but not included in the state's total emission figures. However, in practice, this can be difficult to do at the state level. Therefore, not subtracting out emissions from international bunker fuels overestimates emissions of these fuels.

In comparison with fuel consumption data, the uncertainties associated with carbon contents and oxidation efficiencies are relatively low. Carbon contents of each fuel type are determined by the EIA by sampling and the assessment of market requirements, and, with the exception of coal, do not vary significantly from state to state. EIA takes into account the variability of carbon contents of coal by state in EIA’s Electric Power Annual 2002 (2003b); these coefficients are also provided in the State Inventory Tool.

Many different factors introduce uncertainties into estimating emissions from imports and exports of electricity. The precise fuel mix used to generate the power crossing state lines is very difficult to determine, due to the highly complex nature of electricity flow through the U.S. power grid. Therefore, an average fuel mix for all electricity generation within a specific region of the grid must usually be used. Moreover, these emission factors are generated by emission monitors (rather than carbon contents of fuels), which may overestimate CO_2 emissions to a small extent.

7

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