2. Energy

Energy-related activities were the primary sources of U.S. anthropogenic greenhouse gas emissions, accounting for 85 percent of total emissions on a carbon equivalent basis in 2000. This included 97, 34, and 17 percent of the nation's carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O) emissions, respectively. Energy-related CO_2 emissions alone constituted 81 percent of national emissions from all sources on a carbon equivalent basis, while the non-CO_2 emissions from energy-related activities represented a much smaller portion of total national emissions (4 percent collectively).

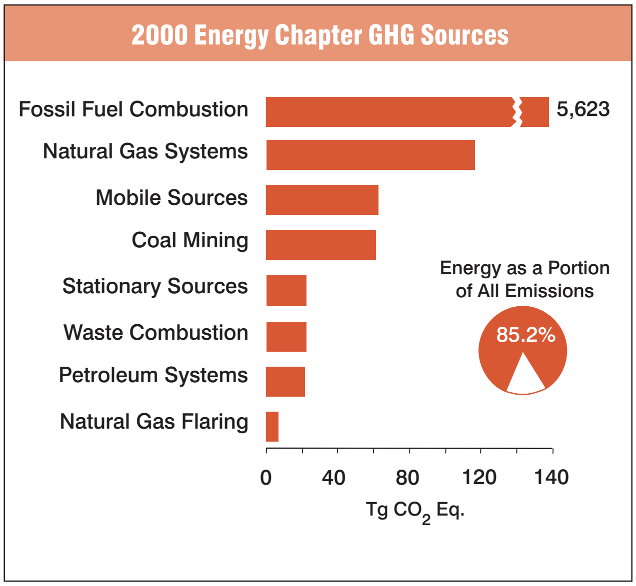
Emissions from fossil fuel combustion comprise the vast majority of energy-related emissions, with CO_2 being the primary gas emitted (see Figure 2-1). Globally, approximately 23,300 Tg of CO_2 were added to the atmosphere through the combustion of fossil fuels at the end of the 1990s, of which the United States accounted for about 24 percent (see Figure 2-2).[1] Due to the relative importance of fossil fuel combustion-related CO_2 emissions, they are considered separately from other emissions. Fossil fuel combustion also emits CH_4 and N_2O, as well as ambient air pollutants such as nitrogen oxides (NO_x), carbon monoxide (CO), and non-methane volatile organic compounds (NMVOCs). Mobile fossil fuel combustion was the second largest source of N_2O emissions in the United States, and overall energy-related activities were collectively the largest source of these ambient air pollutant emissions.

Energy-related activities other than fuel combustion, such as the production, transmission, storage, and distribution of fossil fuels, also emit greenhouse gases. These emissions consist primarily of CH_4 from natural gas systems, petroleum systems, and coal mining. Smaller quantities of CO_2, CO, NMVOCs, and NO_x are also emitted.

The combustion of biomass and biomass-based fuels also emits greenhouse gases. Carbon dioxide emissions from these activities, however, are not included in national emissions totals because biomass fuels are of biogenic origin. It is assumed that the carbon released when biomass is consumed is recycled as U.S. forests and crops regenerate, causing no net addition of CO_2 to the atmosphere. The net impacts of land-use and forestry activities on the carbon cycle are accounted for in the Land-Use Change and Forestry chapter. Emissions of other greenhouse gases from the combustion of biomass and biomass based fuels are included in national totals under stationary and mobile combustion.

Table 2-1 summarizes emissions for the Energy chapter in units of teragrams of carbon dioxide equivalents (Tg CO_2 Eq.), while unweighted gas emissions in gigagrams (Gg) are provided in Table 2-2. Overall, emissions due to energy-related activities were 5,962.6 Tg CO_2 Eq. in 2000, an increase of 16 percent since 1990.

Figure 2-1



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[1] Global CO_2 emissions from fossil fuel combustion were taken from Marland et al. (2001) <http://cdiac.esd.ornl.gov/trends/emis/meth_reg.htm>.

Table 2-1: Emissions from Energy (Tg CO_2 Eq.)

Gas/Source	1990	1995	1996	1997	1998	1999	2000
CO_2	**4,830.3**	**5,141.8**	**5,323.3**	**5,396.8**	**5,410.8**	**5,504.1**	**5,678.1**
Fossil Fuel Combustion	4,779.8	5,085.0	5,266.6	5,339.6	5,356.2	5,448.6	5,623.3
Indirect CO_2 from CH_4 Oxidation	30.9	29.5	28.9	28.4	28.2	27.0	26.3
Waste Combustion	14.1	18.6	19.6	21.3	20.3	21.8	22.5
Natural Gas Flaring	5.5	8.7	8.2	7.6	6.3	6.7	6.1
Biomass-Wood*	149.6	163.3	166.6	159.3	159.6	173.9	174.8
International Bunker Fuels*	113.9	101.0	102.3	109.9	112.9	105.3	100.2
Biomass-Ethanol*	4.4	8.1	5.8	7.4	8.1	8.5	9.7
Carbon Stored in Products*	221.0	251.1	258.2	269.8	276.7	291.6	283.2
CH_4	**247.6**	**236.4**	**232.1**	**226.9**	**225.0**	**216.3**	**211.1**
Natural Gas Systems	121.2	125.7	126.6	122.7	122.2	118.6	116.4
Coal Mining	87.1	73.5	68.4	68.1	67.9	63.7	61.0
Petroleum Systems	26.4	24.2	24.0	24.0	23.4	22.3	21.9
Stationary Sources	7.9	8.2	8.4	7.5	7.0	7.3	7.5
Mobile Sources	4.9	4.8	4.7	4.6	4.5	4.4	4.4
International Bunker Fuels*	0.2	0.1	0.1	0.1	0.1	0.1	0.1
N_2O	**64.0**	**74.2**	**74.5**	**74.2**	**73.7**	**73.5**	**73.4**
Mobile Sources	50.9	60.4	60.1	59.7	59.1	58.7	58.3
Stationary Sources	12.8	13.5	14.1	14.2	14.3	14.6	14.9
Waste Combustion	0.3	0.3	0.3	0.3	0.2	0.2	0.2
International Bunker Fuels*	1.0	0.9	0.9	1.0	1.0	0.9	0.9
Total	**5,141.9**	**5,452.4**	**5,629.9**	**5,697.9**	**5,709.5**	**5,793.9**	**5,962.6**

+ Does not exceed 0.05 Tg CO_2 Eq.
* These values are presented for informational purposes only and are not included or are already accounted for in totals.
Note: Totals may not sum due to independent rounding.

Table 2-2: Emissions from Energy (Gg)

Gas/Source	1990	1995	1996	1997	1998	1999	2000
CO_2	**4,830,350**	**5,141,838**	**5,323,312**	**5,396,825**	**5,410,844**	**5,504,115**	**5,678,099**
Fossil Fuel Combustion	4,779,847	5,085,044	5,266,619	5,339,562	5,356,161	5,448,589	5,623,268
Indirect CO_2 from CH_4 Oxidation	30,899	29,458	28,891	28,354	28,183	27,004	26,302
Waste Combustion	14,091	18,608	19,569	21,344	20,251	21,843	22,470
Natural Gas Flaring	5,514	8,729	8,233	7,565	6,250	6,679	6,059
Biomass-Wood*	149,609	163,286	166,617	159,286	159,610	173,940	174,770
International Bunker Fuels*	113,863	101,037	102,272	109,885	112,913	105,341	100,228
Biomass-Ethanol*	4,380	8,099	5,809	7,356	8,128	8,451	9,667
Carbon Stored in Products*	220,959	251,110	258,238	269,787	276,659	291,623	283,180
CH_4	**11,789**	**11,259**	**11,052**	**10,807**	**10,715**	**10,298**	**10,050**
Natural Gas Systems	5,772	5,984	6,030	5,845	5,820	5,646	5,541
Coal Mining	4,149	3,502	3,255	3,244	3,235	3,033	2,903
Petroleum Systems	1,258	1,154	1,145	1,144	1,114	1,061	1,041
Stationary Sources	376	392	400	356	334	350	357
Mobile Sources	233	228	222	217	212	209	208
International Bunker Fuels*	8	6	6	7	7	6	6
N_2O	**207**	**239**	**240**	**239**	**238**	**237**	**237**
Mobile Combustion	164	195	194	192	191	189	188
Stationary Combustion	41	43	45	46	46	47	48
Waste Combustion	1	1	1	1	1	1	1
International Bunker Fuels*	3	3	3	3	3	3	3

+ Does not exceed 0.05 Tg
* These values are presented for informational purposes only and are not included or are already accounted for in totals.
Note: Totals may not sum due to independent rounding.

Carbon Dioxide Emissions from Fossil Fuel Combustion

Carbon dioxide (CO_2) emissions from fossil fuel combustion grew by 3.2 percent from 1999 to 2000. This above average growth rate was in part due to the strong performance of the U.S. economy and continued population growth. In 2000, CO_2 emissions from fossil fuel combustion were 5,623.1 Tg CO_2 Eq., or 17.6 percent above emissions in 1990 (see Table 2-3).[2]

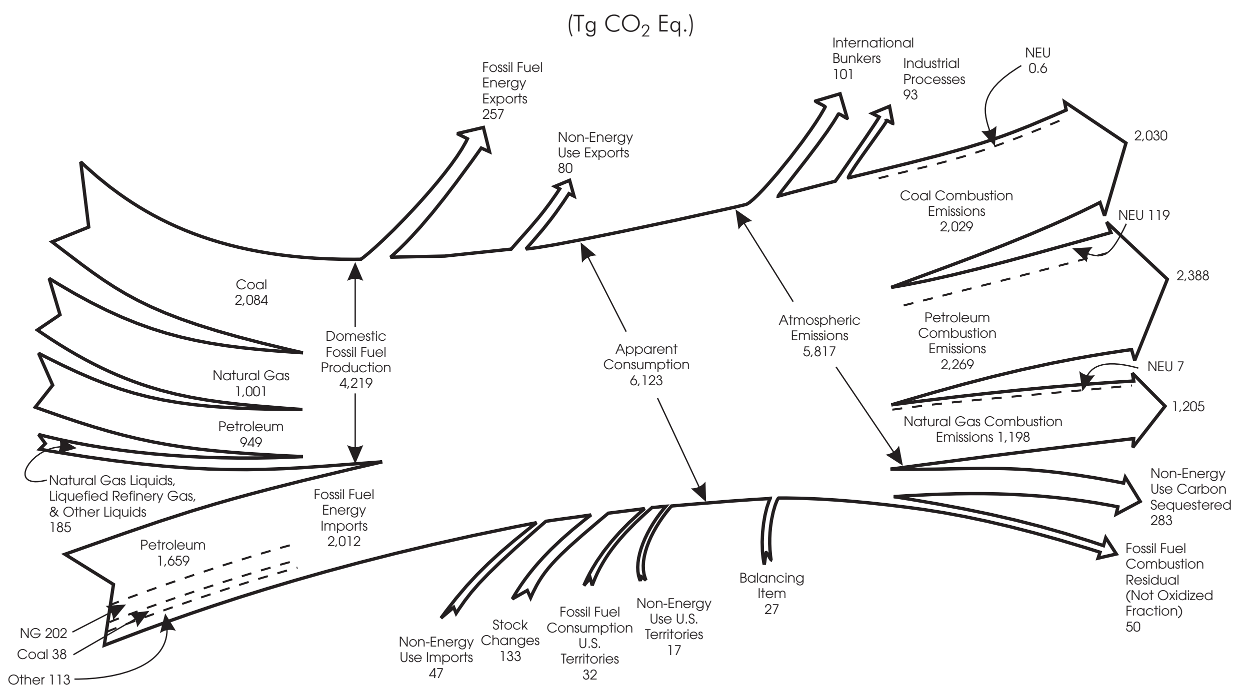
Trends in CO_2 emissions from fossil fuel combustion are influenced by many long-term and short-term factors. On a year-to-year basis, the overall demand for fossil fuels in the United States and other countries generally fluctuates in response to changes in general economic conditions, energy prices, weather, and the availability of non-fossil alternatives. For example, a year with increased consumption of goods and services, low fuel prices, severe summer and winter weather conditions, nuclear plant closures, and lower precipitation feeding hydroelectric dams would be expected to have proportionally greater fossil fuel consumption than a year with poor economic performance, high fuel prices, mild temperatures, and increased output from nuclear and hydroelectric plants.

Longer-term changes in energy consumption patterns, however, tend to be more a function of changes that affect the scale of consumption (e.g., population, number of cars, and size of houses), the efficiency with which energy is used in equipment (e.g., cars, power plants, steel mills, and light bulbs), and social planning and consumer behavior (e.g., walking, bicycling, or telecommuting to work instead of driving).

Carbon dioxide emissions are also a function of the source of energy and its carbon intensity. The amount of carbon in fuels varies significantly by fuel type. For example, coal contains

Figure 2-2

2000 U.S. Fossil Carbon Flows



Note: Totals may not sum due to independent rounding.

The "Balancing Item" above accounts for the statistical imbalances and unknowns in the reported data sets combined here.

NEU = Non-Energy Use
NG = Natural Gas

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[2] An additional discussion of fossil fuel emission trends is presented in the Recent Trends in U.S. Greenhouse Gas Emissions section of the Introduction chapter.

Table 2-3: CO_2 Emissions from Fossil Fuel Combustion by Fuel Type and Sector (Tg CO_2 Eq.)

Fuel/Sector	1990	1995	1996	1997	1998	1999	2000
Coal	**1,692.6**	**1,792.7**	**1,878.4**	**1,930.5**	**1,949.7**	**1,956.9**	**2,030.1**
Residential	5.8	5.0	5.1	5.5	4.2	4.4	4.4
Commercial	8.7	7.6	7.7	8.2	6.3	6.6	6.6
Industrial	135.9	131.2	125.5	126.9	121.4	117.0	102.8
Transportation	NE	NE	NE	NE	NE	NE	NE
Electricity Generation	1,541.5	1,647.9	1,739.1	1,789.0	1,817.0	1,828.0	1,915.4
U.S. Territories	0.6	0.9	0.9	0.9	0.9	0.9	0.9
Natural Gas	**988.8**	**1,141.3**	**1,162.4**	**1,166.7**	**1,125.8**	**1,145.2**	**1,204.8**
Residential	238.5	263.1	284.6	270.5	246.5	256.5	268.3
Commercial	142.4	164.5	171.6	174.7	163.6	165.2	180.8
Industrial	358.0	398.5	414.8	409.6	378.0	372.9	371.3
Transportation	36.0	38.3	38.9	41.5	34.9	40.2	41.9
Electricity Generation	213.8	276.8	252.5	270.4	302.9	310.4	341.9
U.S. Territories	NO	NO	NO	NO	NO	NO	0.6
Petroleum	**2,098.2**	**2,150.9**	**2,225.6**	**2,242.0**	**2,280.3**	**2,346.3**	**2,388.2**
Residential	87.7	94.2	100.7	98.9	91.1	99.6	102.2
Commercial	66.1	51.8	53.5	50.8	47.7	48.0	51.8
Industrial	377.8	365.1	396.2	398.7	381.7	368.2	355.1
Transportation	1,435.8	1,541.0	1,579.8	1,587.3	1,620.1	1,688.0	1,747.6
Electricity Generation	103.4	64.5	69.5	78.4	106.5	107.7	95.2
U.S. Territories	27.4	34.3	25.8	27.9	33.3	34.8	36.3
Geothermal*	**0.2**	**0.1**	**0.1**	**0.1**	**0.1**	**+**	**+**
Total	**4,779.8**	**5,084.9**	**5,266.4**	**5,339.4**	**5,356.0**	**5,448.4**	**5,623.1**

NE (Not estimated)
NO (Not occurring)
+ Does not exceed 0.05 Tg CO_2 Eq.
* Although not technically a fossil fuel, geothermal energy-related CO_2 emissions are included for reporting purposes.
Note: Totals may not sum due to independent rounding.

the highest amount of carbon per unit of useful energy. Petroleum has roughly 75 percent of the carbon per unit of energy as coal, and natural gas has only about 55 percent.[3] Therefore, producing heat or electricity using natural gas instead of coal, for example, can reduce the CO_2 emissions associated with energy consumption, and using nuclear or renewable energy sources (e.g., wind) can essentially eliminate emissions (see Box 2-1).

In the United States, 85 percent of the energy consumed in 2000 was produced through the combustion of fossil fuels such as coal, natural gas, and petroleum (see Figure 2-3 and Figure 2-4). The remaining portion was supplied by nuclear electric power (8 percent) and by a variety of renewable energy sources (7 percent), primarily hydroelectric power (EIA 2001). Specifically, petroleum supplied the largest share of domestic energy demands, accounting for an average of 38 percent of total energy consumption from 1990 through 2000. Natural gas and coal followed in order of importance, accounting for 28 and 26 percent of total consumption, respectively. Most petroleum was consumed in the transportation end-use sector, while the vast majority of coal was used in electricity generation, with natural gas broadly consumed in all end-use sectors except transportation (see Figure 2-5) (EIA 2001a).

Fossil fuels are generally combusted for the purpose of producing energy for useful heat and work. During the combustion process the carbon stored in the fuels is oxidized and emitted as CO_2 and smaller amounts of other gases, including methane (CH_4), carbon monoxide (CO), and non-methane volatile organic compounds (NMVOCs).[4] These other carbon containing non-CO_2 gases are emitted as a by-product of incomplete fuel combustion, but are, for the most part, eventually oxidized to CO_2 in the atmosphere. Therefore,

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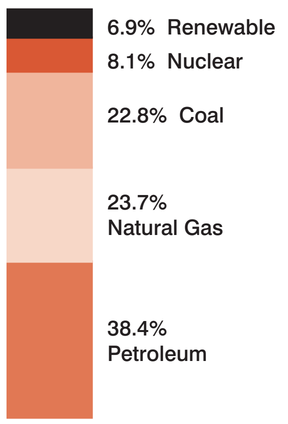
[3] Based on national aggregate carbon content of all coal, natural gas, and petroleum fuels combusted in the United States.

[4] See the sections entitled Stationary Combustion and Mobile Combustion in this chapter for information on non-CO_2 gas emissions from fossil fuel combustion.

Figure 2-3

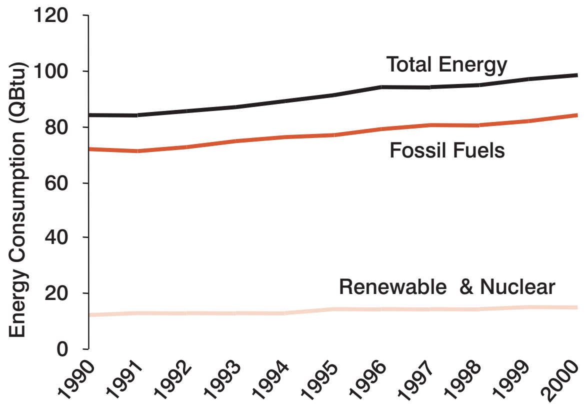
2000 U.S. Energy Consumption by Energy Source



Source: DOE/EIA-0384(2000), Annual Energy Review 2000, Table 1.3, August 2001

Figure 2-4

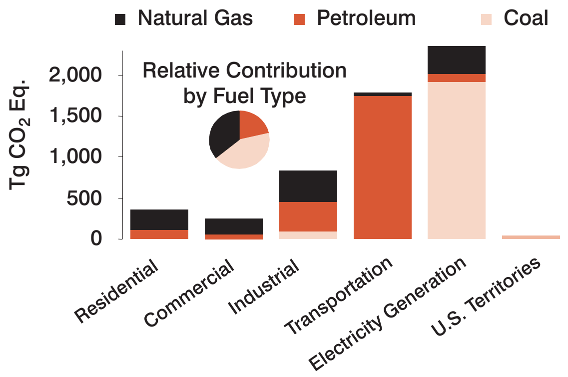
U.S. Energy Consumption (Quadrillion Btu)



Note: Expressed as gross calorific values.
Source: DOE/EIA-0384 (2000), Annual Energy Review 2000, Table 1.3, August 2001

Figure 2-5

2000 CO_2 Emissions from Fossil Fuel Combustion by Sector and Fuel Type



Note: Electricity Generation also includes emissions of less than 0.01 Tg CO_2 Eq. from geothermal plants.

except for the soot an ash left behind during the combustion process, all the carbon in fossil fuels used to produce energy is eventually converted to atmospheric CO_2.

For the purpose of international reporting, the IPCC (IPCC/UNEP/OECD/IEA 1997) requires that particular adjustments be made to national fuel consumption statistics. Certain fossil fuels can be manufactured into plastics, asphalt, lubricants, or other products. A portion of the carbon consumed for these non-energy products can be stored (i.e., sequestered) indefinitely. To account for the fact that the carbon in these fuels ends up in products instead of being combusted (i.e., oxidized and released into the atmosphere), the fraction of fossil fuel-based carbon in manufactured products is subtracted from emission estimates. (See the Carbon Stored in Products from Non-Energy Uses of Fossil Fuels section in this chapter.) The fraction of this carbon stored in products that is eventually combusted in waste incinerators or combustion plants is accounted for in the Waste Combustion section of this chapter.

The IPCC also requires that CO_2 emissions from the consumption of fossil fuels for aviation and marine international transport activities (i.e., international bunker fuels) be reported separately, and not included in national emission totals. Estimates of carbon in products and international bunker fuel emissions for the United States are provided in Table 2-4 and Table 2-5.

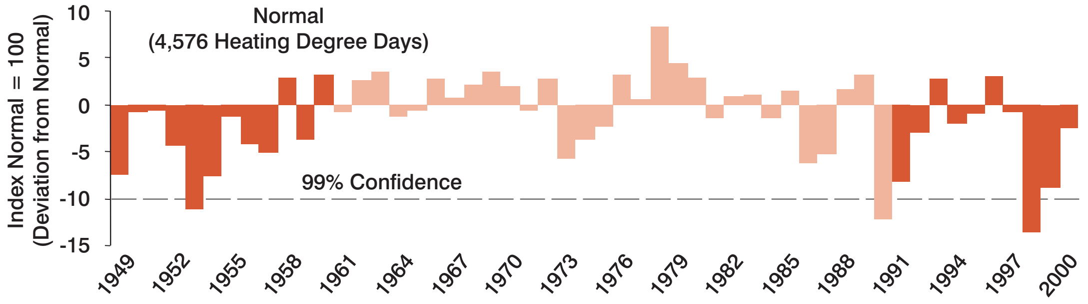
Box 2-1: Weather and Non-Fossil Energy Effects on CO_2 from Fossil Fuel Combustion Trends

After two unusually warm years in 1998 and 1999, weather conditions returned closer to normal in 2000. The colder winter conditions caused increased demand for heating fuels, while a cooler summer reduced electricity demand. Overall, however, conditions were still slightly warmer than usual. Heating degree days in the United States in 2000 were 3 percent below normal (see Figure 2-6) while cooling degree days in 2000 were 4 percent above normal (see Figure 2-7).[5]

Although no new U.S. nuclear power plants have been constructed in many years, the utilization (i.e., capacity factors[6]) of existing plants reached record levels in 2000, approaching 90 percent. This increase in utilization translated into an increase in electricity output by nuclear plants of slightly more than 3 percent in 2000. This output by nuclear plants, however, was offset by reduced electricity output by hydroelectric power plants, which declined by almost 12 percent. Electricity generated by nuclear plants provides approximately twice as much of the energy consumed in the United States as hydroelectric plants. Nuclear and hydroelectric power plant capacity factors since 1973 are shown in Figure 2-8.

Figure 2-6

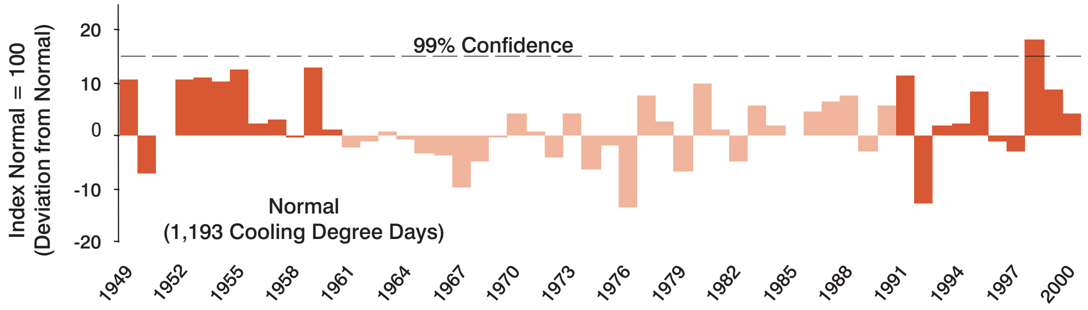
Annual Deviations from Normal Heating Degree Days for the United States (1949-2000)



Note: 1998 and climatological normal data is highlighted. Statistical confidence interval for "normal" climatology period of 1961 through 1990.
Source: NOAA (2001a)

Figure 2-7

Annual Deviations from Normal Cooling Degree Days for the United States (1949-2000)



Note: 1998 and climatological normal data is highlighted. Statistical confidence interval for "normal" climatology period of 1961 through 1990.
Source: NOAA (2001b)

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[5] Degree days are relative measurements of outdoor air temperature. Heating degree days are deviations of the mean daily temperature below 65° F, while cooling degree days are deviations of the mean daily temperature above 65° F. Excludes Alaska and Hawaii. Normals are based on data from 1961 through 1990. The variation in these normals during this time period was ±10 percent and ±14 percent for heating and cooling degree days, respectively (99 percent confidence interval).

[6] The capacity factor is defined as the ratio of the electrical energy produced by a generating unit for a given period of time to the electrical energy that could have been produced at continuous full-power operation during the same period (EIA 2001b).

Box 2-1: Weather and Non-Fossil Energy Effects on CO_2 from Fossil Fuel Combustion Trends (Continued)

Figure 2-8

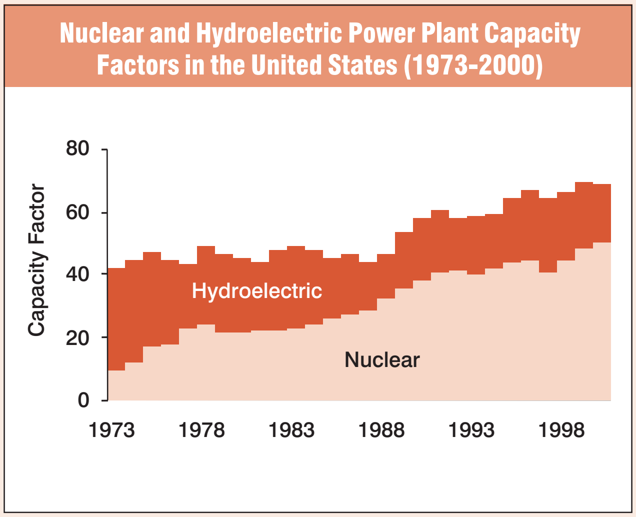

Table 2-4: Fossil Fuel Carbon in Products (Tg CO_2 Eq.)*

Sector	1990	1995	1996	1997	1998	1999	2000
Industrial	213.4	240.2	242.4	253.2	260.2	274.8	265.6
Transportation	1.2	1.2	1.1	1.2	1.2	1.2	1.2
Territories	6.3	9.8	14.7	15.4	15.2	15.6	16.3
Total	**221.0**	**251.1**	**258.2**	**269.8**	**276.7**	**291.6**	**283.2**

* See Carbon Stored in Products from Non-Energy Uses of Fossil Fuels section for additional detail.
Note: Totals may not sum due to independent rounding.

Table 2-5: CO_2 Emissions from International Bunker Fuels (Tg CO_2 Eq.)*

Vehicle Mode	1990	1995	1996	1997	1998	1999	2000
Aviation	46.6	51.1	52.1	55.9	55.0	58.9	57.3
Marine	67.3	49.9	50.1	54.0	57.9	46.4	43.0
Total	**113.9**	**101.0**	**102.3**	**109.9**	**112.9**	**105.3**	**100.2**

* See International Bunker Fuels section for additional detail.
Note: Totals may not sum due to independent rounding.

End-Use Sector Consumption

When analyzing CO_2 emissions from fossil fuel combustion, four end-use sectors were defined: industrial, transportation, residential, and commercial.[7] Electricity generation also emits CO_2; however, these emissions occur as power plants combust fossil fuels to provide electricity to one of the four end-use sectors. For the discussion below, electricity generation emissions have been distributed to each end-use sector based upon the sector's share of national electricity consumption. This method of distributing emissions assumes that each sector consumes electricity generated from an equally carbon-intensive mix of fuels and other energy sources. In reality, sources of electricity vary widely in carbon intensity (e.g., coal versus wind power). By giving equal carbon-intensity weight to each sector's electricity consumption, emissions attributed to one end-use sector may be somewhat overestimated, while emissions attributed to another end-use sector may be slightly underestimated. After the end-use sectors are discussed, emissions from electricity generation are addressed separately. Emissions from U.S. territories are also calculated separately due to a lack of end-use-specific consumption data. Table 2-6 and Figure 2-9 summarize CO_2 emissions from direct fossil fuel combustion and pro-rated electricity generation emissions from electricity consumption by end-use sector.

Transportation End-Use Sector

The transportation end-use sector accounted for the largest share (approximately 32 percent) of CO_2 emissions from fossil fuel combustion—excluding international bunker fuels.[8] Almost all of the energy consumed in this end-use sector was supplied by petroleum-based products, with nearly two-thirds being related to gasoline consumption in automobiles and other highway vehicles. Other fuel uses, especially diesel fuel for freight trucks and jet fuel for aircraft, accounted for the remainder.[9]

Carbon dioxide emissions from fossil fuel combustion for transportation increased by 22 percent from 1990 to 2000, to 1,792.3 Tg CO_2 Eq. The growth in transportation end-use sector emissions has been relatively steady, including a 3.5 percent single year increase in 2000. Like overall energy demand, transportation fuel demand is a function of many short and long-term factors. In the short term only minor adjustments can generally be made through consumer behavior (e.g., not driving as far for summer vacation).

Table 2-6: CO_2 Emissions from Fossil Fuel Combustion by End-Use Sector (Tg CO_2 Eq.)

End-Use Sector	1990	1995	1996	1997	1998	1999	2000
Industrial	**1,519.6**	**1,563.4**	**1,623.5**	**1,640.8**	**1,598.1**	**1,575.7**	**1,568.5**
Combustion	871.6	894.9	936.5	935.2	881.1	858.1	829.2
Electricity	648.0	668.5	687.0	705.6	717.0	717.7	739.3
Transportation	**1,474.5**	**1,582.0**	**1,621.3**	**1,631.6**	**1,657.7**	**1,731.0**	**1,792.3**
Combustion	1,471.8	1,579.4	1,618.7	1,628.8	1,655.0	1,728.2	1,789.5
Electricity	2.7	2.6	2.7	2.7	2.7	2.7	2.8
Residential	**965.3**	**1,050.6**	**1,109.9**	**1,106.1**	**1,112.6**	**1,136.9**	**1,199.8**
Combustion	332.1	362.3	390.4	374.9	341.8	360.5	374.8
Electricity	633.2	688.2	719.5	731.2	770.8	776.5	825.0
Commercial	**792.3**	**853.8**	**884.8**	**932.0**	**953.4**	**969.2**	**1,024.7**
Combustion	217.3	223.9	232.8	233.7	217.5	219.8	239.3
Electricity	575.0	629.9	652.0	698.4	735.9	749.4	785.4
U.S. Territories	**28.1**	**35.3**	**27**	**29.1**	**34.4**	**35.8**	**38**
Total	**4,779.8**	**5,085.0**	**5,266.4**	**5,339.6**	**5,356.2**	**5,448.6**	**5,623.3**
Electricity Generation	**1,858.9**	**1,989.3**	**2,061.2**	**2,137.9**	**2,226.4**	**2,246.2**	**2,352.5**

Note: Totals may not sum due to independent rounding. Emissions from fossil fuel combustion by electricity generation are allocated based on aggregate national electricity consumption by each end-use sector.

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[7] See Glossary (Annex Z) for more detailed definitions of the industrial, residential, commercial, and transportation end-use sector, as well as electricity generation.

[8] Note that electricity generation is actually the largest emitter of CO_2 when electricity is not distributed among end-use sectors.

[9] See Glossary (Annex Z) for a more detailed definition of the transportation end-use sector.

Figure 2-9

2000 End-Use Sector Emissions of CO_2 from Fossil Fuel Combustion

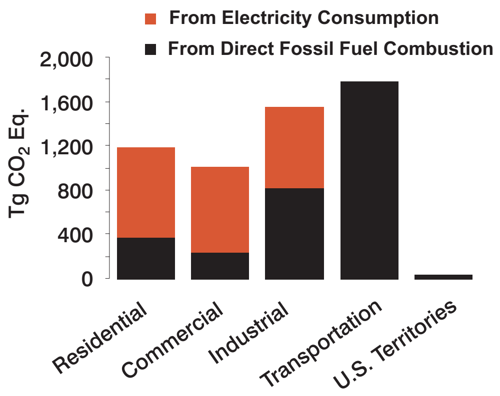
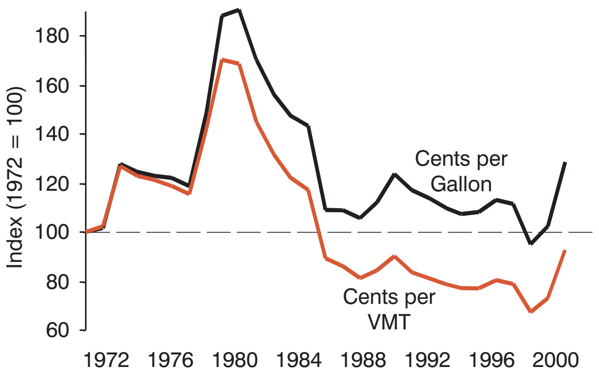


Figure 2-10

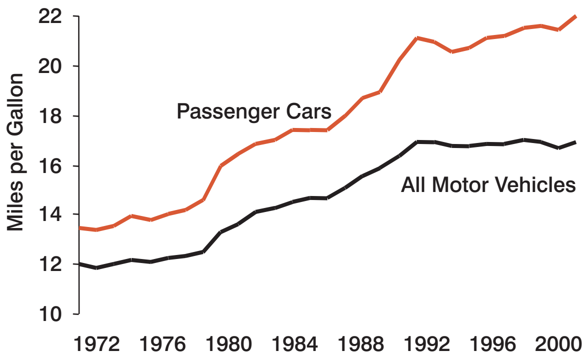
Motor Gasoline Retail Prices (Real)



Source for gasoline prices: DOE/EIA-0384(2000), Annual Energy Review 2000, August 2001, Table 5.22 Source for motor vehicle fuel efficiency: DOT/FHWA, Highway Statistics Summary to 1995, 1996, 1997, 1998, and 2000.

Figure 2-11

Motor Vehicle Fuel Efficiency



Source: DOT/FHWA, Highway Statistics Summary to 1995, 1996, 1997, 1998, 1999, and 2000.

However, long-term adjustments such as vehicle purchase choices, transport mode choice and access (i.e., trains versus planes), and urban planning can have a significant impact on fuel demand.

Motor gasoline and other petroleum product prices have generally declined since 1990 (see Figure 2-10). Although gasoline and other transport fuel prices did rise in 2000, an overall strong economy and short-term constraints on reductions in travel and increases in vehicle fuel efficiency were likely causes for demand for fuel from contracting. Since 1990, travel activity in the United States has grown more rapidly than population, with a 13 percent increase in vehicle miles traveled per capita. In the meantime, improvements in the average fuel efficiency of the U.S. vehicle fleet stagnated after increasing steadily since 1977 (EIA 2001a). The average miles per gallon achieved by the U.S. vehicle fleet has remained fairly constant since 1991. This trend is due, in part, to the increasing dominance of new motor vehicle sales by less fuel-efficient light-duty trucks and sport-utility vehicles (see Figure 2-11).

Table 2-7 provides a detailed breakdown of CO_2 emissions by fuel category and vehicle type for the transportation end-use sector. Fifty-five percent of the emissions from this end-use sector in 2000 were the result of the combustion of motor gasoline in passenger cars and light-duty trucks. Diesel highway vehicles and jet aircraft were also significant contributors, accounting for 15 and 13 percent of CO_2 emissions from the transportation end-use sector, respectively.[10]

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[10] These percentages include emissions from bunker fuels.

Table 2-7: CO_2 Emissions from Fossil Fuel Combustion in Transportation End-Use Sector (Tg CO_2 Eq.)

Fuel/Vehicle Type	1990	1995	1996	1997	1998	1999	2000
Motor Gasoline	**955.3**	**1,023.0**	**1,041.4**	**1,050.6**	**1,072.5**	**1,098.7**	**1,105.7**
Passenger Cars	612.8	634.3	646.6	652.3	665.9	682.2	686.5
Light-Duty Trucks	274.1	314.2	320.4	323.1	341.9	351.2	353.4
Other Trucks	41.4	40.0	40.7	40.5	32.1	34.7	34.9
Motorcycles	1.6	1.7	1.7	1.7	1.7	1.8	1.8
Buses	2.0	3.0	2.1	2.2	0.8	0.7	0.7
Construction Equipment	2.2	2.4	2.4	2.5	2.0	1.5	1.5
Agricultural Machinery	4.4	7.9	7.8	8.2	7.6	5.9	5.9
Boats (Recreational)	16.9	19.5	19.7	20.1	20.5	20.8	20.9
Distillate Fuel Oil (Diesel)	**277.4**	**312.2**	**329.0**	**342.8**	**353.5**	**373.7**	**391.0**
Passenger Cars	7.1	7.6	7.6	7.9	7.6	5.0	5.2
Light-Duty Trucks	9.0	11.2	13.1	14.2	14.4	15.3	16.0
Other Trucks	164.1	195.4	207.0	216.1	225.4	247.4	259.0
Buses	7.9	9.9	8.6	9.2	10.7	11.6	12.1
Construction Equipment	10.5	10.5	10.9	11.2	10.8	11.0	11.5
Agricultural Machinery	23.1	23.0	23.8	24.5	23.7	24.0	25.2
Boats (Freight)	18.0	16.1	18.4	18.3	17.8	18.1	18.9
Locomotives	26.3	29.5	31.5	32.4	31.6	33.2	34.8
Marine Bunkers	11.4	9.1	8.3	9.1	11.5	8.2	8.3
Jet Fuel	**220.4**	**219.9**	**229.8**	**232.1**	**235.6**	**242.9**	**251.2**
General Aviation	6.3	5.3	5.8	6.1	7.7	9.2	9.8
Commercial Air Carriers	118.2	121.4	124.9	129.4	131.4	137.3	141.0
Military Vehicles	34.8	24.1	23.1	21.1	21.7	21.0	21.4
Aviation Bunkers	46.6	51.1	52.2	55.9	55.0	58.9	57.3
Other[a]	14.6	17.9	23.9	19.6	19.7	16.6	21.8
Aviation Gasoline	**3.1**	**2.7**	**2.6**	**2.7**	**2.4**	**2.7**	**2.5**
General Aviation	3.1	2.7	2.6	2.7	2.4	2.7	2.5
Residual Fuel Oil	**80.4**	**72.1**	**67.5**	**56.7**	**55.9**	**62.3**	**84.7**
Boats (Freight)[b]	24.5	31.3	25.7	11.8	9.5	24.1	50.0
Marine Bunkers[b]	55.8	40.8	41.8	44.9	46.4	38.2	34.6
Natural Gas	**36.0**	**38.3**	**38.9**	**41.5**	**34.9**	**40.2**	**41.9**
Passenger Cars	+	0.1	+	+	+	+	+
Light-Duty Trucks	+	+	+	+	+	+	+
Buses	+	0.1	0.1	0.2	0.2	0.3	0.4
Pipeline	36.0	38.2	38.8	41.3	34.7	39.9	41.5
LPG	**1.3**	**1.0**	**0.9**	**0.8**	**1.0**	**0.8**	**0.8**
Light-Duty Trucks	+	+	+	+	+	+	+
Other Trucks	0.5	0.5	0.4	0.4	0.4	0.3	0.3
Buses	0.8	0.5	0.5	0.4	0.6	0.5	0.5
Electricity	**2.7**	**2.6**	**2.7**	**2.7**	**2.7**	**2.7**	**2.7**
Buses	+	+	+	+	+	+	+
Locomotives	2.2	2.1	2.1	2.1	2.2	2.1	2.1
Pipeline	0.5	0.5	0.5	0.6	0.6	0.6	0.6
Lubricants	**11.7**	**11.2**	**10.9**	**11.5**	**12.0**	**12.1**	**12.0**
Total (Including Bunkers)[c]	**1,588.4**	**1,683.0**	**1,723.6**	**1,741.4**	**1,770.6**	**1,836.3**	**1,892.5**
Total (Excluding Bunkers)[c]	**1,474.5**	**1,582.0**	**1,621.3**	**1,631.5**	**1,657.7**	**1,731.0**	**1,792.2**

Note: Totals may not sum due to independent rounding.

[a] Including but not limited to fuel blended with heating oils and fuel used for chartered aircraft flights.

[b] Fluctuations in emission estimates from the combustion of residual fuel oil are currently unexplained, but may be related to data collection problems.

[c] Official estimates exclude emissions from the combustion of both aviation and marine international bunker fuels; however, estimates including international bunker fuel-related emissions are presented for informational purposes.

+ Does not exceed 0.05 Tg of CO_2 Eq.

Industrial End-Use Sector

The industrial end-use sector accounted for 28 percent of CO_2 emissions from fossil fuel combustion. On average, 53 percent of these emissions resulted from the direct consumption of fossil fuels in order to meet industrial energy demands such as for steam and process heat. The remaining 47 percent was associated with their consumption of electricity for uses such as motors, electric furnaces, ovens, and lighting.

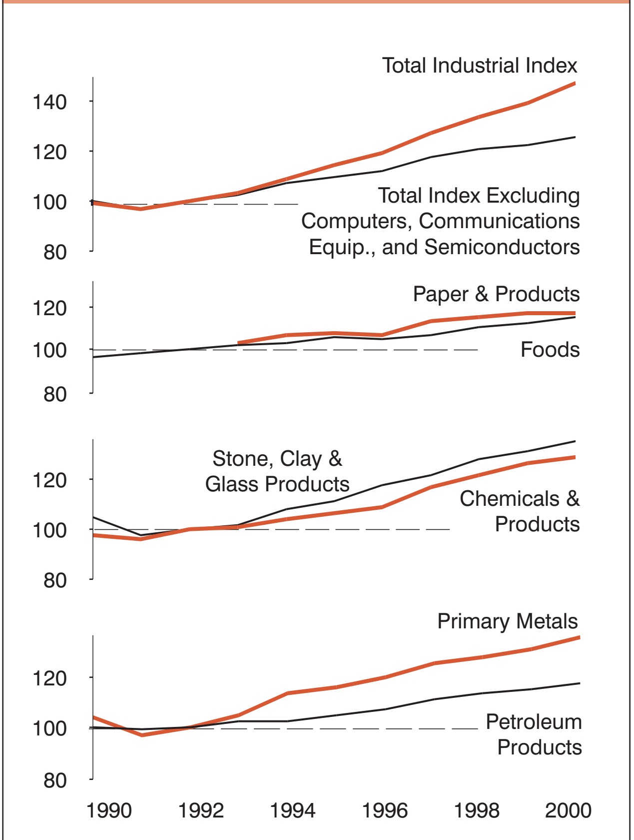
The industrial end-use sector includes activities such as manufacturing, construction, mining, and agriculture.[11] The largest of these activities in terms of energy consumption is manufacturing, which was estimated in 1998 to have accounted for about 84 percent of industrial energy consumption (EIA 1997). Manufacturing energy consumption was dominated by several industries, including petroleum, chemical, primary metal, paper, food, stone, clay, and glass products.

In theory, emissions from the industrial end-use sector should be highly correlated with economic growth and industrial output; however, certain activities within the sector, such as heating of industrial buildings and agricultural energy consumption, are also affected by weather conditions.[12] In addition, structural changes within the U.S. economy that lead to shifts in industrial output away from energy intensive manufacturing products to less energy intensive products (e.g., from steel to computer equipment) also have a significant affect on industrial emissions.

From 1999 to 2000, total industrial production and manufacturing output were reported to have increased by 4.5 and 4.8 percent, respectively (FRB 2001). However, excluding the fast growing computer, communication equipment, and semiconductor industries from these indexes reduces their growth considerably—to 1.2 and 1.1 percent, respectively—and illustrates some of the structural changes occurring in the U.S. economy (see Figure 2-12).

Figure 2-12

Industrial Production Indexes (Index 1992=100)



Despite the growth in industrial output (49 percent) and the overall U.S. economy (32 percent) from 1990 to 2000, emissions from the industrial end-use sector decreased slightly (by 0.5 percent). The reasons for the disparity between rapid growth in industrial output and stagnant growth in industrial emissions are not entirely clear. It is likely, though, that several factors have influenced industrial emission trends, including: 1) more rapid growth in output from less energy-intensive industries relative to traditional manufacturing industries, 2) improvements in energy efficiency; and 3) a lowering of the carbon intensity of fossil fuel consumption as industry shifts from its historical reliance on coal and coke to heavier usage of natural gas.

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[11] See Glossary (Annex Z) for a more detailed definition of the industrial end-use sector.

[12] Some commercial customers are large enough to obtain an industrial price for natural gas and/or electricity and are consequently grouped with the industrial end-use sector in U.S. energy statistics. These misclassifications of large commercial customers likely cause the industrial end-use sector to appear to be more sensitive to weather conditions.

Industry was the largest user of fossil fuels for non-energy applications. Fossil fuels can be used for producing products such as fertilizers, plastics, asphalt, or lubricants that can sequester or store carbon for long periods of time. Asphalt used in road construction, for example, stores carbon essentially indefinitely. Similarly, fossil fuels used in the manufacture of materials like plastics can also store carbon, if the material is not burned. The amount of carbon contained in industrial products made from fossil fuels rose 24 percent between 1990 and 2000, to 265.6 Tg CO_2 Eq.[13]

Residential and Commercial End-Use Sectors

The residential and commercial end-use sectors accounted for an average 21 and 18 percent, respectively, of CO_2 emissions from fossil fuel combustion. Both end-use sectors were heavily reliant on electricity for meeting energy needs, with electricity consumption for lighting, heating, air conditioning, and operating appliances contributing to about 69 and 77 percent of emissions from the residential and commercial end-use sectors, respectively. The remaining emissions were largely due to the direct consumption of natural gas and petroleum products, primarily for heating and cooking needs. Coal consumption was a minor component of energy use in both these end-use sectors.

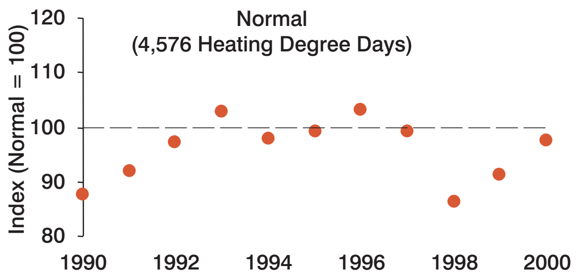
Emissions from residences and commercial buildings generally increased throughout the 1990s, and, unlike in other end-use sectors, emissions in these sectors did not decline during the economic downturn in 1991 (see Table 2-6). This difference exists because short-term fluctuations in energy consumption in these sectors are affected proportionately more by the weather than by prevailing economic conditions. In the long-term, both end-use sectors are also affected by population growth, regional migration trends, and changes in housing and building attributes (e.g., size and insulation).

In 2000, winter conditions in the United States were slightly warmer than normal (i.e., heating degree days were 3 percent below normal), although not as warm as in 1999 (see Figure 2-13). Due, in part, to this colder winter relative to the previous year, emissions from natural gas consumption in residences and commercial establishments increased by 5 percent and 9 percent, respectively.

In 2000, electricity sales to the residential and commercial end-use sectors increased by 4 and 3 percent, respectively. Even though cooler summer conditions in 2000 relative to 1999 likely led to decreased air-conditioning related electricity consumption (see Figure 2-14), growth in personal

Figure 2-13

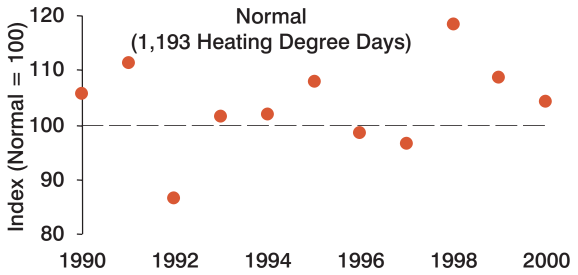
Heating Degree Days [14]



Note: Excludes Alaska and Hawaii
Source: DOE/EIA-0384(2000), Annual Energy Review 2000, August 2001, Table 1.7 and 1.8

Figure 2-14

Cooling Degree Days [15]



Note: Excludes Alaska and Hawaii
Source: DOE/EIA-0384(2000), Annual Energy Review 2000, August 2001, Table 1.7 and 1.8

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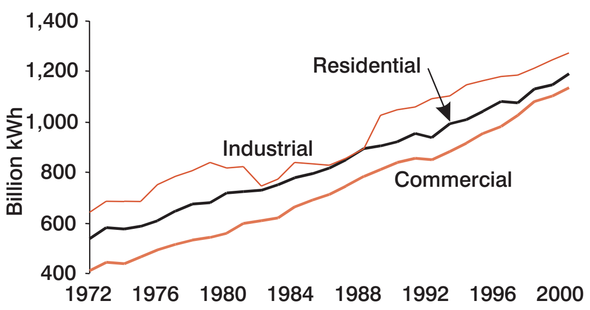
[13] See the Carbon Stored in Products in Non-Energy Uses of Fossil Fuels for a more detailed discussion. Also, see Waste Combustion in the Waste chapter for a discussion of emissions from the incineration or combustion of fossil fuel-based products.

[14] Degree days are relative measurements of outdoor air temperature. Heating degree days are deviations of the mean daily temperature below 65° F. Excludes Alaska and Hawaii. Normals are based on data from 1961 through 1990.

[15] Degree days are relative measurements of outdoor air temperature. Cooling degree days are deviations of the mean daily temperature above 65° F. Excludes Alaska and Hawaii. Normals are based on data from 1961 through 1990.

Figure 2-15

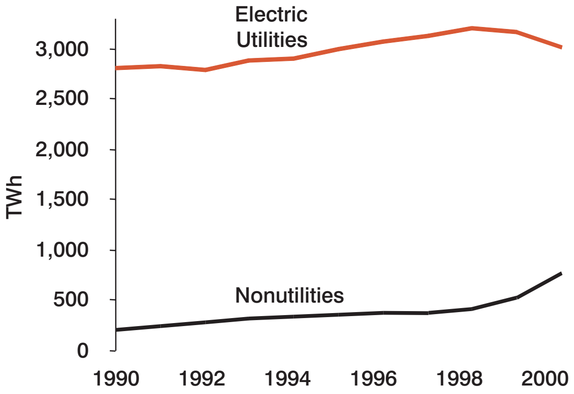
Electricity Generation Retail Sales by End-Use Sector



Note: The transportation end-use sector consumes minor quantities of electricity.

Figure 2-16

Net Generation by Electric Utilities and Nonutilities



Source: EIA (2000c)

income along with other trends such as population growth led to a 6 percent increase in both residential and commercial end-use sector emissions from 1999 to 2000.

Electricity Generation

The process of generating electricity is the single largest source of greenhouse gas emissions in the United States (34 percent), which relies on electricity to meet a significant portion of its energy requirements. Electricity was consumed primarily in the residential, commercial, and industrial end-use sectors for uses such as lighting, heating, electric motors, appliances, electronics, and air conditioning (see Figure 2-15). Electricity generation also accounted for the largest share of CO_2 emissions from fossil fuel combustion, approximately 42 percent in 2000.

The electric power industry includes all power producers, consisting of both regulated utilities and nonutilities (e.g. independent power producers, qualifying cogenerators, and other small power producers). While utilities primarily generate power for the U.S. electric grid for sale to retail customers, nonutilities produce electricity for their own use, to sell to large consumers, or to sell on the wholesale electricity market (e.g., to utilities for distribution and resale to customers). The net generation of electricity by utilities and nonutilities is shown in Figure 2-16.

The electric power industry in the United States is currently undergoing significant changes. Both Federal and State government agencies are modifying regulations to create a competitive market for electricity generation from what was a market dominated by vertically integrated and regulated monopolies (i.e., electric utilities). These changes have led to the growth of nonutility power producers, including the sale of generating capacity by electric utilities to nonutilities.[16] As a result, the proportion of electricity in the United States generated by nonutilities has grown from about 7 percent in 1990 to 21 percent in 2000 (EIA 2001b).

In 2000, CO_2 emissions from electricity generation increased by 4.7 percent relative to the previous year, coinciding with increased electricity consumption and robust growth in the U.S. economy. An additional factor leading to this above average increase in emissions was the decreased generation of electricity from renewable resources, including a 12 percent reduction in output from hydroelectric dams. This generation was primarily replaced by additional fossil fuel consumption for producing electricity, thus increasing the overall the carbon intensity from energy consumption for electricity generation (see Table 2-9).

Coal is consumed primarily by the electric power sector in the United States, which accounted for 94 percent of total coal consumption in 2000. Consequently, changes in

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[16] In 2000, 47,710 megawatts of electrical generating capacity was sold by electric utilities to nonutilities, or 5.9 percent of total electric power industry capacity (EIA 2001b).

Box 2-2: Sectoral Carbon Intensity Trends Related to Fossil Fuel and Overall Energy Consumption

Fossil fuels are the dominant source of energy in the United States, and carbon dioxide (CO_2) is emitted as a product from their combustion. Useful energy, however, can be generated from many other sources that do not emit CO_2 in the energy conversion process. In the United States, useful energy is also produced from renewable (i.e., hydropower, biofuels, geothermal, solar, and wind) and nuclear sources.[17]

Energy-related CO_2 emissions can be reduced by not only lowering total energy consumption (e.g., through conservation measures) but also by lowering the carbon intensity of the energy sources employed (e.g., fuel switching from coal to natural gas). The amount of carbon emitted—in the form of CO_2—from the combustion of fossil fuels is dependent upon the carbon content of the fuel and the fraction of that carbon that is oxidized.[18] Fossil fuels vary in their average carbon content, ranging from about 53 Tg CO_2 Eq./EJ for natural gas to upwards of 95 Tg CO_2 Eq./EJ for coal and petroleum coke.[19] In general, the carbon intensity per unit of energy of fossil fuels is the highest for coal products, followed by petroleum and then natural gas. Other sources of energy, however, may be directly or indirectly carbon neutral (i.e., 0 Tg CO_2 Eq./EJ). Energy generated from nuclear and many renewable sources do not result in direct emissions of CO_2. Biofuels such as wood and ethanol are also considered to be carbon neutral, as the CO_2 emitted during their combustion is assumed to be offset by the carbon sequestered in the growth of new biomass.[20] The overall carbon intensity of the U.S. economy is thus dependent upon the quantity and combination of fuels and other energy sources employed to meet demand.

Table 2-8 provides a time series of the carbon intensity for each sector of the U.S. economy. The time series incorporates only the energy consumed from the direct combustion of fossil fuels in each sector. For example, the carbon intensity for the residential sector does not include the energy from or emissions related to the consumption of electricity for lighting or wood for heat. Looking only at this direct consumption of fossil fuels, the residential sector exhibited the lowest carbon intensity, which is related to the large percentage of its energy derived from natural gas for heating. The carbon intensity of the commercial sector was greater than the residential sector for the period from 1990 to 1997, but then declined to a comparable level as commercial businesses shifted away from petroleum to natural gas. The industrial sector was more dependent on petroleum and coal than either the residential or commercial sectors, and thus had higher carbon intensities over this period. The carbon intensity of the transportation sector was closely related to the carbon content of petroleum products (e.g., motor gasoline and jet fuel, both around 67 Tg CO_2 Eq./EJ), which were the primary sources of energy. Lastly, the electricity generation sector had the highest carbon intensity due to its heavy reliance on coal for generating electricity.

In contrast to Table 2-8, Table 2-9 presents carbon intensity values that incorporate energy consumed from all sources (i.e., fossil fuels, renewables, and nuclear). In addition, the emissions related to the generation of electricity have been attributed to both electricity generation and the end-use sectors in which that electricity was eventually consumed.[21] This table, therefore, provides a more complete picture of the actual carbon intensity of each end-use sector per unit of energy consumed. The transportation end-use sector in Table 2-9 emerges as the most carbon intensive when all sources of energy are included, due to its almost complete reliance on petroleum products and relatively minor amount of biomass based fuels such as ethanol. The “other end-use sectors” (i.e., residential, commercial, and industrial) use significant quantities of biofuels such as wood, thereby lowering the overall carbon intensity. The carbon intensity of the electricity generation sector differs greatly from the scenario in Table 2-8, where only the energy consumed from the direct combustion of fossil fuels was included. This difference is due almost entirely to the inclusion of electricity generation from nuclear and hydropower sources, which do not emit carbon dioxide.

By comparing the values in Table 2-8 and Table 2-9, a couple of observations can be made. The usage of renewable and nuclear energy sources has resulted in a significantly lower carbon intensity of the U.S. economy. However, over the eleven year period of 1990 through 2000, the carbon intensity of U.S. energy consumption has been fairly constant, as the proportion of renewable and nuclear energy technologies has not changed significantly.

Although the carbon intensity of total energy consumption has remained fairly constant, per capita energy consumption has increased, leading to a greater energy-related CO_2 emissions per capita in the United States since 1990 (see Figure 2-17). Due to structural changes and the strong growth in the U.S. economy, though, energy consumption and energy-related CO_2 emissions per dollar of gross domestic product (GDP) declined in the 1990s.

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[17] Small quantities of CO_2, however, are released from some geologic formations tapped for geothermal energy. These emissions are included with fossil fuel combustion emissions from the electricity generation. Carbon dioxide emissions may also be generated from upstream activities (e.g., manufacture of the equipment) associated with fossil fuel and renewable energy activities, but are not accounted for here.

[18] Generally, more than 97 percent of the carbon in fossil fuel is oxidized to CO_2 with most carbon combustion technologies used in the United States.

[19] One exajoule (EJ) is equal to 10^{18} joules or 0.9478 QBtu.

[20] This statement assumes that there is no net loss of biomass-based carbon associated with the land use practices used to produce these biomass fuels.

[21] In other words, the emissions from the generation of electricity are intentionally double counted by attributing them both to electricity generation and the end-use sector in which electricity consumption occurred.

Table 2-8: Carbon Intensity from Direct Fossil Fuel Combustion by Sector (Tg CO_2 Eq./EJ)

Sector	1990	1995	1996	1997	1998	1999	2000
Residential[a]	53.8	53.7	53.6	53.7	53.7	53.7	53.7
Commercial[a]	55.7	54.2	54.2	54.0	53.8	53.8	53.8
Industrial[a]	60.5	59.6	59.5	59.6	59.7	59.2	58.9
Transportation[a]	66.9	66.8	66.7	66.6	66.7	66.7	66.8
Electricity Generation[b]	80.4	79.6	80.5	80.2	79.6	79.5	79.2
All Sectors[c]	**68.4**	**67.9**	**68.0**	**68.2**	**68.4**	**68.3**	**68.3**

[a] Does not include electricity or renewable energy consumption.

[b] Does not include electricity produced using nuclear or renewable energy.

[c] Does not include nuclear or renewable energy consumption.

Note: Excludes non-energy fuel use emissions and consumption. Exajoule (EJ) = 10^{18} joules = 0.9479 QBtu.

Table 2-9: Carbon Intensity from Energy Consumption by Sector (Tg CO_2 Eq./EJ)

Sector	1990	1995	1996	1997	1998	1999	2000
Transportation[a]	66.7	66.4	66.5	66.3	66.4	66.3	66.4
Other End-Use Sectors[a,b]	54.0	52.8	52.9	53.8	53.9	53.2	53.6
Electricity Generation[c]	55.0	53.4	53.8	55.1	55.3	54.5	55.3
All Sectors[d]	**57.6**	**56.6**	**56.7**	**57.3**	**57.5**	**57.0**	**57.3**

[a] Includes electricity (from fossil fuel, nuclear, and renewable sources) and direct renewable energy consumption.

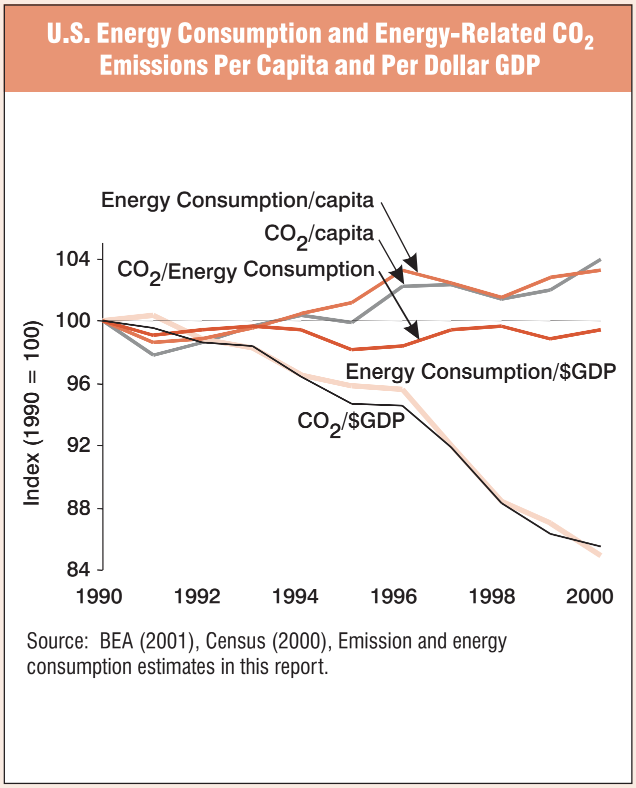
[b] Other End-Use Sectors include the residential, commercial, and industrial sectors.

[c] Includes electricity generation from nuclear and renewable sources.

[d] Includes nuclear and renewable energy consumption.

Note: Excludes non-energy fuel use emissions and consumption. Exajoule (EJ) = 10^{18} joules = 0.9479 QBtu.

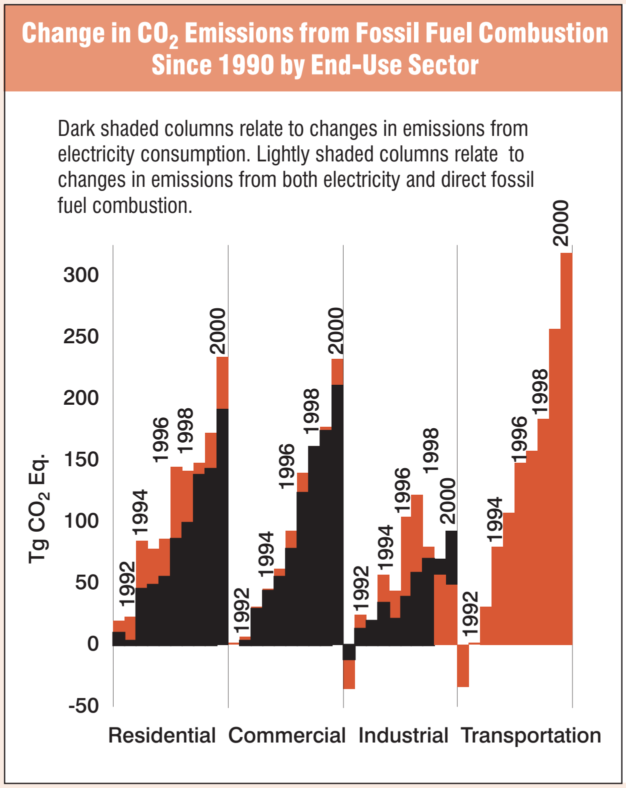
Figure 2-17



U.S. Energy Consumption and Energy-Related CO_2 Emissions Per Capita and Per Dollar GDP

Source: BEA (2001), Census (2000), Emission and energy consumption estimates in this report.

Figure 2-18



Change in CO_2 Emissions from Fossil Fuel Combustion Since 1990 by End-Use Sector

Dark shaded columns relate to changes in emissions from electricity consumption. Lightly shaded columns relate to changes in emissions from both electricity and direct fossil fuel combustion.

Figure 2-18 and Table 2-10 present the detailed CO_2 emission trends underlying the carbon intensity differences and changes described in Table 2-8. In Figure 2-18, changes over time in both overall end-use sector-related emissions and electricity-related emissions for each year since 1990 are highlighted. In Table 2-10 changes in emissions since 1990 are presented by sector and fuel type to provide a more detailed accounting.

Table 2-10: Change in CO_2 Emissions from Direct Fossil Fuel Combustion Since 1990 (Tg CO_2 Eq.)

Sector/Fuel Type	1991	1995	1996	1997	1998	1999	2000
Residential	**9.9**	**30.2**	**58.3**	**42.8**	**9.7**	**28.4**	**42.7**
Coal	(0.5)	(0.8)	(0.7)	(0.4)	(1.6)	(1.4)	(1.4)
Natural Gas	8.8	24.6	46.0	32.0	8.0	17.9	29.7
Petroleum	1.7	6.4	13.0	11.2	3.4	11.9	14.4
Commercial	**1.5**	**6.6**	**15.5**	**16.4**	**0.3**	**2.5**	**22.0**
Coal	(0.8)	(1.2)	(1.0)	(0.5)	(2.5)	(2.1)	(2.1)
Natural Gas	5.8	22.1	29.2	32.3	21.1	22.8	38.4
Petroleum	(3.5)	(14.3)	(12.6)	(15.3)	(18.4)	(18.1)	(14.3)
Industrial	**(24.3)**	**23.2**	**64.9**	**63.5**	**9.4**	**(13.6)**	**(42.4)**
Coal	(1.5)	(4.6)	(10.4)	(8.9)	(14.5)	(18.9)	(33.0)
Natural Gas	(1.4)	40.5	56.8	51.6	20.0	14.9	13.3
Petroleum	(21.4)	(12.7)	18.4	20.9	3.9	(9.6)	(22.7)
Transportation	**(34.1)**	**107.5**	**146.9**	**157.0**	**183.2**	**256.4**	**317.7**
Coal	NE	NE	NE	NE	NE	NE	NE
Natural Gas	(3.2)	2.3	2.9	5.5	(1.1)	4.2	5.9
Petroleum	(30.9)	105.3	144.0	151.6	184.3	252.3	311.9
Electricity Generation	**(3.7)**	**130.3**	**202.3**	**279.0**	**367.5**	**387.3**	**493.6**
Coal	(5.8)	106.4	197.6	247.5	275.4	286.5	373.8
Natural Gas	7.4	63.0	38.7	56.6	89.1	96.6	128.1
Petroleum	(5.2)	(38.9)	(33.9)	(25.0)	3.1	4.3	(8.2)
Geothermal	+	(0.1)	(0.1)	(0.1)	(0.1)	(0.2)	(0.2)
U.S. Territories	**3.7**	**7.2**	**(1.2)**	**0.9**	**6.1**	**7.6**	**9.8**
Coal	0.1	0.3	0.3	0.3	0.3	0.3	0.3
Natural Gas	NE	NE	NE	NE	NE	NE	0.6
Petroleum	3.7	6.9	(1.5)	0.6	5.9	7.4	8.9
All Sectors	**(46.8)**	**305.1**	**486.6**	**559.6**	**576.2**	**668.6**	**843.3**

+ Does not exceed 0.05 Tg CO_2 Eq.
NE (Not Estimated)
Note: Totals may not sum due to independent rounding.

electricity demand have a significant impact on coal consumption and associated U.S. CO_2 emissions. Coal consumption for electricity generation increased by 5 percent in 2000, due to 1) increased electricity demand, 2) decreased electricity output of from hydropower, and 3) the relatively stable price of coal. In 2000, the price of coal decreased 2 percent, while petroleum and natural gas prices increased 68 and 63 percent, respectively.

Methodology

The methodology used by the United States for estimating CO_2 emissions from fossil fuel combustion is conceptually similar to the approach recommended by the IPCC for countries that intend to develop detailed, sectoral-based emission estimates (IPCC/UNEP/OECD/IEA 1997). A detailed description of the U.S. methodology is presented in Annex A, and is characterized by the following steps:

1. *Determine fuel consumption by fuel type and sector*. By aggregating consumption data by end-use sector (e.g., commercial, industrial, etc.), primary fuel type (e.g., coal, petroleum, gas), and secondary fuel category (e.g., motor gasoline, distillate fuel oil, etc.), estimates of total U.S. fossil fuel consumption for a particular year were made. The United States does not include territories in its national energy statistics; therefore, fuel consumption data for territories was collected separately.[22] Portions of the fuel consumption data for three fuel categories – coking coal, petroleum coke, and natural gas – were reallocated to the

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[22] Fuel consumption by U.S. territories (i.e. American Samoa, Guam, Puerto Rico, U.S. Virgin Islands, Wake Island, and other U.S. Pacific Islands) is included in this report and contributed emissions of 53 Tg CO_2 Eq. in 2000.

industrial processes chapter, as these portions were actually consumed during a non-energy related industrial activity. [23]

2. *Determine the total carbon content of fuels consumed*. Total carbon was estimated by multiplying the amount of fuel consumed by the amount of carbon in each fuel. This total carbon estimate defines the maximum amount of carbon that could potentially be released to the atmosphere if all of the carbon in each fuel was converted to CO_2. The carbon content coefficients used by the United States are presented in Annex A.

3. *Subtract the amount of carbon stored in products*. Non-energy uses of fossil fuels can result in storage of some or all of the carbon contained in the fuel for some period of time, depending on the end-use. For example, asphalt made from petroleum can sequester up to 100 percent of the carbon for extended periods of time, while other fossil fuel products, such as lubricants or plastics, lose or emit some carbon when they are used and/or burned as waste. Aggregate U.S. energy statistics include consumption of fossil fuels for non-energy uses; therefore, the portion of carbon that remains in products after they are manufactured was subtracted from potential carbon emission estimates.[24] The amount of carbon remaining in products was based on the best available data on the end-uses and fossil fuel products. These non-energy uses occurred in the industrial and transportation end-use sectors and U.S. territories. Emissions of CO_2 associated with the disposal of these fossil fuel-based products are not accounted for here, but are instead accounted for under the Waste Combustion section in this chapter.

4. *Subtract the amount of carbon from international bunker fuels*. According to the IPCC guidelines (IPCC/UNEP/OECD/IEA 1997) emissions from international transport activities, or bunker fuels, should not be included in national totals. Because U.S. energy consumption statistics include these bunker fuels—distillate fuel oil, residual fuel oil, and jet fuel—as part of consumption by the transportation end-use sector, emissions from international transport activities were calculated separately and the carbon content of these fuels was subtracted from the transportation end-use sector. The calculations for emissions from bunker fuels follow the same procedures used for emissions from consumption of all fossil fuels (i.e., estimation of consumption, determination of carbon content, and adjustment for the fraction of carbon not oxidized).[25]

5. *Adjust for carbon that does not oxidize during combustion*. Because combustion processes are not 100 percent efficient, some of the carbon contained in fuels is not emitted to the atmosphere. Rather, it remains behind as soot and ash. The estimated amount of carbon not oxidized due to inefficiencies during the combustion process was assumed to be 1 percent for petroleum and coal and 0.5 percent for natural gas (see Annex A). Unoxidized or partially oxidized organic (i.e., carbon containing) combustion products were assumed to have eventually oxidized to CO_2 in the atmosphere.[26]

6. *Allocate transportation emissions by vehicle type*. Because the transportation end-use sector was such a large consumer of fossil fuels in the United States,[27] a more detailed accounting of carbon dioxide emissions is provided. For fuel types other than jet fuel, fuel consumption data by vehicle type and transportation mode were used to allocate emissions by fuel type calculated for the transportation end-use sector. Specific data by vehicle type were not available for 2000; therefore, the 1999 percentage allocations were applied to 2000 fuel consumption data in order to estimate emissions in 2000. Military vehicle jet fuel consumption was provided by the Defense Energy Support Center, under Department of Defense's (DoD) Defense Logistics Agency and the Office of the Undersecretary of Defense (Environmental Security). The difference between total U.S. jet fuel consumption (as reported by

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[23] See sections on Iron and Steel Production, Ammonia Manufacture, Titanium Dioxide Production, Ferroalloy Production, and Aluminum Production in the Industrial Proceses chapter.

[24] See Carbon Stored in Products from Non-Energy Uses of Fossil Fuels section in this chapter for a more detailed discussion.

[25] See International Bunker Fuels section in this chapter for a more detailed discussion.

[26] See Indirect CO_2 from CH_4 Oxidation section in this chapter for a more detailed discussion.

[27] Electricity generation is not considered a final end-use sector, because energy is consumed solely to provide electricity to the other sectors.

EIA) and civilian air carrier consumption for both domestic and international flights (as reported by DOT and BEA) plus military jet fuel consumption is reported as "other" under the jet fuel category in Table 2-7, and includes such fuel uses as blending with heating oils and fuel used for chartered aircraft flights.

Data Sources

Data on fuel consumption for the United States and its territories, and carbon content of fuels were obtained directly from the Energy Information Administration (EIA) of the U.S. Department of Energy (DOE). Fuel consumption data were obtained primarily from the *Annual Energy Review* and other EIA databases (EIA 2001a). Data on military jet fuel use was supplied by the Office of the Under Secretary of Defense (Environmental Security) and the Defense Energy Support Center (Defense Logistics Agency) of the U.S. Department of Defense (DoD) (DESC 2001). Estimates of international bunker fuel emissions are discussed in the section entitled International Bunker Fuels. Estimates of carbon stored in products are discussed in the section entitled Carbon Stored in Products from Non-fuel Uses of Fossil Fuels.

IPCC provided fraction oxidized values for petroleum and natural gas (IPCC/UNEP/OECD/IEA 1997). Bechtel (1993) provided the fraction oxidation value for coal. Vehicle type fuel consumption data for the allocation of transportation end-use sector emissions were primarily taken from the *Transportation Energy Data Book* prepared by the Center for Transportation Analysis at Oak Ridge National Laboratory (DOE 1993 through 2001). Specific data on military fuel consumption were taken from DESC (2001). Densities for each military jet fuel type were obtained from the Air Force (USAF 1998).

Carbon intensity estimates were developed using nuclear and renewable energy data from EIA (2001a) and fossil fuel consumption data as discussed above and presented in Annex A.

For consistency of reporting, the IPCC has recommended that national inventories report energy data—and emissions from energy—using the International Energy Agency (IEA) reporting convention and/or IEA data. Data in the IEA format are presented "top down"—that is, energy consumption for fuel types and categories are estimated from energy production data (accounting for imports, exports, stock changes, and losses). The resulting quantities are referred to as "apparent consumption." The data collected in the United States by EIA, and used in this inventory, are, instead, "bottom up" in nature. In other words, they are collected through surveys at the point of delivery or use and aggregated to determine national totals.[28]

It is also important to note that U.S. fossil fuel energy statistics are generally presented using gross calorific values (GCV) (i.e., higher heating values). Fuel consumption activity data presented here have not been adjusted to correspond to international standard, which are to report energy statistics in terms of net calorific values (NCV) (i.e., lower heating values).[29]

Uncertainty

For estimates of CO_2 from fossil fuel combustion, the amount of CO_2 emitted is – in principle – directly related to the amount of fuel consumed, the fraction of the fuel that is oxidized, and the carbon content of the fuel. Therefore, a careful accounting of fossil fuel consumption by fuel type, average carbon contents of fossil fuels consumed, and production of fossil fuel-based products with long-term carbon storage should yield an accurate estimate of CO_2 emissions.

There are uncertainties, however, in the consumption data, carbon content of fuels and products, and carbon oxidation efficiencies. For example, given the same primary fuel type (e.g., coal, petroleum, or natural gas), the amount of carbon contained in the fuel per unit of useful energy can vary.

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[28] See IPCC Reference Approach for estimating CO_2 emissions from fossil fuel combustion in Annex R for a comparison of U.S. estimates using top-down and bottom-up approaches.

[29] A crude convention to convert between gross and net calorific values is to multiply the heat content of solid and liquid fossil fuels by 0.95 and gaseous fuels by 0.9 to account for the water content of the fuels. Biomass-based fuels in U.S. energy statistics, however, are generally presented using net calorific values.

Although statistics of total fossil fuel and other energy consumption are considered to be relatively accurate, the allocation of this consumption to individual end-use sectors (i.e., residential, commercial, industrial, and transportation) is considerably more uncertain. For example, for some fuels the sectoral allocations are based on price rates (i.e., tariffs). However, commercial establishment may be able to negotiate an industrial rate or a small industrial establishment may end up paying an industrial rate, leading to a misallocation of emissions. Also, the deregulation of the natural gas industry and the more recent deregulation of the electric power industry have likely led to some minor problems in collecting accurate energy statistics as firms in these industries have undergone significant restructuring.

Non-energy uses of the fuel can also create situations where the carbon is not emitted to the atmosphere (e.g., plastics, asphalt, etc.) or is emitted at a delayed rate. The proportions of fuels used in these non-energy production processes that result in the sequestration of carbon have been assumed. Additionally, inefficiencies in the combustion process, which can result in ash or soot remaining unoxidized for long periods, were also assumed. These factors all contribute to the uncertainty in the CO_2 estimates. More detailed discussions on the uncertainties associated with Carbon Stored in Products from Non-Energy Uses of Fossil Fuels are provided this section in this chapter.

Various uncertainties surround the estimation of emissions from international bunker fuels, which are subtracted from U.S. totals. These uncertainties are primarily due to the difficulty in collecting accurate fuel consumption data for international transport activities. Small aircraft and many marine vessels often carry enough fuel to complete multiple voyages without refueling, which, if used for both domestic and international trips, may be classified as solely international. The data collected for aviation does not include some smaller planes making international voyages, and also designates some flights departing to Canada and Mexico as domestic. More detailed discussions on these uncertainties are provided in the International Bunker Fuels section of this chapter.

Another source of uncertainty is fuel consumption by U.S. territories. The United States does not collect energy statistics for its territories at the same level of detail as for the fifty States and the District of Columbia. Therefore estimating both emissions and bunker fuel consumption by these territories is difficult.

For Table 2-7, uncertainties also exist as to the data used to allocate CO_2 emissions from the transportation end-use sector to individual vehicle types and transport modes. In many cases, bottom up estimates of fuel consumption by vehicle type do not match aggregate fuel-type estimates from EIA. Further research is planned to better allocate detailed transportation end-use sector emissions. In particular, residual fuel consumption data for marine vessels are highly uncertain, as shown by the large fluctuations in emissions.

For the United States, however, the impact of these uncertainties on overall CO_2 emission estimates is believed to be relatively small. For the United States, CO_2 emission estimates from fossil fuel combustion are considered accurate within several percent. See, for example, Marland and Pippin (1990).

Carbon Stored in Products from Non-Energy Uses of Fossil Fuels

Besides being combusted for energy, fossil fuels are also consumed for non-energy purposes. The types of fuels used for non-energy uses are listed in Table 2-11. These fuels are used in the industrial and transportation end-use sectors and are quite diverse, including natural gas, asphalt (a viscous liquid mixture of heavy crude oil distillates), petroleum coke, (manufactured from heavy oil) and coal coke (manufactured from coking coal.) The non-energy fuel uses are equally diverse, and include application as solvents, lubricants, and waxes, or as raw materials in the manufacture of plastics, rubber, synthetic fibers, and fertilizers.

Carbon dioxide emissions arise from non-energy uses via several pathways. Emissions may occur during the manufacture of a product, as is the case in producing plastics or rubber from fuel-derived feedstocks. Additionally, in the case of solvents or lubricants, for example, emissions may occur during the product's lifetime. Overall, more than 65 percent of the total carbon consumed for non-energy purposes is stored in products, and not released to the atmosphere. However, some of the products release CO_2 at the end of their commercial life when they are disposed. These emissions are covered separately in this chapter in the Waste Combustion section.

In 2000, fossil fuel consumption for non-energy uses constituted 6 percent (5,915.6 TBtu) of overall fossil fuel consumption, approximately the same as 1990. In 2000, the carbon contained in fuels consumed for non-energy uses was approximately 410 Tg CO_2 Eq., an increase of 28 percent since 1990. About 283 Tg CO_2 Eq. of this carbon was stored, while the remaining 126 Tg CO_2 Eq. was emitted. The proportion of carbon emitted has remained about the same, at 31 percent of total non-energy consumption, since 1990. Table 2-12 shows the fate of the non-energy fossil fuel carbon for 1990 and 1995 through 2000.

Methodology

The first step in estimating carbon stored in products was to determine the aggregate quantity of fossil fuels consumed for non-energy uses. The carbon content of these feedstock fuels is equivalent to potential emissions, or the product of consumption and the fuel-specific carbon content values (see Annex A). Consumption of natural gas, LPG, pentanes plus, naphthas, and other oils were adjusted to account for net exports of these products. Approximately 8 percent of the U.S. production of these products is exported. Consumption values

Table 2-11: 2000 Non-Energy Fossil Fuel Consumption, Storage, and Emissions (Tg CO_2 Eq. unless otherwise noted)

	Consumption (TBtu)		Carbon	Storage	Carbon	
Sector/Fuel Type	**Total**	**Adjusted[a]**	**Content**	**Factor**	**Stored**	**Emissions**
Industry	**6,675.0**	**5,512.4**	**379.8**	**-**	**265.6**	**114.2**
Industrial Coking Coal	793.1	26.4	2.5	0.8	1.9	0.6
Natural Gas to Chemical Plants	372.3	342.4	18.2	0.6	11.5	6.7
Asphalt & Road Oil	1,275.7	1,275.7	96.4	1.0	96.4	-
LPG	1,856.7	1,707.3	105.6	0.6	66.8	38.8
Lubricants	189.9	189.9	14.1	0.1	1.3	12.8
Pentanes Plus	311.9	286.8	19.2	0.6	12.1	7.0
Petrochemical Feedstocks						
Naphtha (<401 deg. F)	613.5	564.2	37.5	0.6	23.7	13.8
Other Oil (>401 deg. F)	722.2	664.1	48.6	0.6	30.7	17.8
Still Gas	7.4	7.4	0.5	0.8	0.4	0.1
Petroleum Coke	225.5	141.4	14.4	0.5	7.2	7.2
Special Naphtha	97.4	97.4	7.1	-	-	7.1
Distillate Fuel Oil	7.0	7.0	0.5	0.5	0.3	0.3
Residual Fuel	50.3	50.3	4.0	0.5	2.0	2.0
Waxes	33.1	33.1	2.4	1.0	2.4	-
Miscellaneous Products	119.2	119.2	8.8	1.0	8.8	-
Transportation	**179.4**	**179.4**	**13.3**		**1.2**	**12.1**
Lubricants	179.4	179.4	13.3	0.1	1.2	12.1
U.S. Territories	**223.8**	**223.8**	**16.4**		**16.3**	**0.1**
Lubricants	1.4	1.4	0.1	0.1	+	0.1
Other Petroleum (Misc. Prod.)	222.5	222.5	16.3	1.0	16.3	-
Total	**7,078.3**	**5,915.6**	**409.6**	**-**	**283.2**	**126.4**

[a] Natural gas, LPG, Pentanes Plus, Naphthas, and Other Oils are adjusted to account for exports of chemical intermediates derived from these fuels. To avoid double-counting, coal coke, petroleum coke, and natural gas consumption are adjusted for industrial process consumption addressed in the Industrial Process chapter.

- Not applicable.

Note: Totals may not sum due to independent rounding.

Table 2-12: Storage and Emissions from Non-Energy Fossil Fuel Consumption (Tg CO_2 Eq.)

Variable	1990	1995	1996	1997	1998	1999	2000
Potential Emissions	319.9	362.9	371.9	388.0	402.7	428.1	409.6
Carbon Stored	221.0	251.1	258.2	269.8	276.7	291.6	283.2
Emissions	99.0	111.8	113.7	118.2	126.1	136.4	126.4

for industrial coking coal, petroleum coke, and natural gas in Table 2-11 are adjusted to subtract non-energy uses that are addressed in the Industrial Process chapter.[30]

For the remaining non-energy uses, the amount of carbon stored was estimated by multiplying the potential emissions by a storage factor. For several fuel types—asphalt and road oil, lubricants, petrochemical feedstocks, liquid petroleum gases (LPG), pentanes plus, and natural gas for non-fertilizer uses—U.S. data on carbon stocks and flows were used to develop carbon storage factors, calculated as the ratio of (a) the carbon stored by the fuel's non-energy products to (b) the total carbon content of the fuel consumed. A lifecycle approach was used in the development of these factors in order to account for losses in the production process—from raw material acquisition through manufacturing and processing—and during use. Details of these calculations are shown in Annex B. Because losses associated with municipal solid waste management are handled separately in this chapter under Waste Combustion, the storage factors do not account for losses at the disposal end of the life cycle. For the other fuel types, the storage factors were taken directly from Marland and Rotty (1984).

Lastly, emissions were estimated by subtracting the carbon stored from the potential emissions.

Data Sources

Non-energy fuel consumption and carbon content data were supplied by the EIA (2001a).

Where storage factors were calculated specifically for the United States, data was obtained on fuel products such as asphalt, plastics, synthetic rubber, synthetic fibers, pesticides, and solvents. Data was taken from a variety of industry sources, government reports, and expert communications. Sources include EPA compilations of air emission factors (EPA 1995, EPA 2001), the EIA Manufacturer's Energy Consumption Survey (MECS) (EIA 2001b), the National Petrochemical & Refiners Association (NPRA 2001), the National Asphalt Pavement Association (Connolly 2000), the Emissions Inventory Improvement Program (EIIP 1999), the U.S. Census Bureau (1999), the American Plastics Council (APC 2000), the International Institute of Synthetic Rubber Products (IISRP 2000), the Fiber Economics Bureau (FEB 2000), and the Chemical Manufacturer's Handbook (CMA 1999). For the other fuel types, storage factors were taken from Marland and Rotty (1984). Specific data sources are listed in full detail in Annex B.

Uncertainty

The fuel consumption data for non-energy uses and the carbon content values employed here were taken from the same references as the data used for estimating overall CO_2 emissions from fossil fuel combustion. In addition, data used to make adjustments to the fuel consumption estimates were taken from several sources. Given that the uncertainty in these data is expected to be small, the uncertainty of the estimate for the *potential* carbon emissions is also expected to be small. However, there is a large degree of uncertainty in the storage factors employed, depending upon the fuel type. For each of the calculated storage factors, the uncertainty is discussed in detail in Annex B. Generally, uncertainty arises from assumptions made to link fuel types with their derivative products and in determining the fuel products' carbon contents and emission or storage fates. The storage factors from Marland and Rotty (1984) are also highly uncertain.

Stationary Combustion (excluding CO_2)

Stationary combustion encompasses all fuel combustion activities except those related to transportation (i.e., mobile combustion). Other than carbon dioxide (CO_2), which was addressed in the previous section, gases from stationary combustion include the greenhouse gases methane (CH_4) and nitrous oxide (N_2O) and the ambient air pollutants nitrogen oxides (NO_x), carbon monoxide (CO), and non-methane volatile organic compounds (NMVOCs).[31] Emissions of these gases from stationary combustion sources depend upon fuel characteristics, size and vintage to the combustion technology, pollution control equipment, and ambient environmental conditions. Emissions also vary with operation and maintenance practices.

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[30] These source categories include Iron and Steel Production, Ammonia Manufacture, Titanium Dioxide Production, Ferroalloy Production, and Aluminum Production.

[31] Sulfur dioxide (SO_2) emissions from stationary combustion are addressed in Annex S.

Nitrous oxide and NO_x emissions from stationary combustion are closely related to air-fuel mixes and combustion temperatures, as well as the characteristics of any pollution control equipment that is employed. Carbon monoxide emissions from stationary combustion are generally a function of the efficiency of combustion; they are highest when less oxygen is present in the air-fuel mixture than is necessary for complete combustion. These conditions are most likely to occur during start-up, shutdown and during fuel switching (e.g., the switching of coal grades at a coal-burning electric utility plant). Methane and NMVOC emissions from stationary combustion are primarily a function of the CH_4 and NMVOC content of the fuel and combustion efficiency.

Emissions of CH_4 decreased 5 percent overall from 7.9 Tg CO_2 Eq. (376 Gg) in 1990 to 7.5 Tg CO_2 Eq. (357 Gg) in 2000. This decrease in CH_4 emissions was primarily due to lower wood consumption in the residential sector. Conversely, nitrous oxide emissions rose 16 percent since 1990 to 14.9 Tg CO_2 Eq. (48 Gg) in 2000. The largest source of N_2O emissions was coal combustion by electricity generators, which alone accounted for 60 percent of total N_2O emissions from stationary combustion in 2000. Overall, though, stationary combustion is a small source of CH_4 and N_2O in the United States.

In contrast, stationary combustion was a significant source of NO_x emissions, but a smaller source of CO and NMVOCs. In 2000, emissions of NO_x from stationary combustion represented 35 percent of national NO_x emissions, while CO and NMVOC emissions from stationary combustion contributed approximately 4 and 6 percent, respectively, to the national totals. From 1990 to 2000, emissions of NO_x and CO from stationary combustion decreased by 12 and 17 percent, respectively, and emissions of NMVOCs increased by 19 percent.

The decrease in NO_x emissions from 1990 to 2000 are mainly due to decreased emissions from electricity generation. The decrease in CO and increase in NMVOC emissions over this time period can largely be attributed to changes in residential wood consumption, which is the most significant source of these pollutants from stationary combustion. Table 2-13 through Table 2-16 provide CH_4 and N_2O emission estimates from stationary combustion by sector and fuel type. Estimates of NO_x, CO, and NMVOC emissions in 2000 are given in Table 2-17.[32]

Methodology

Methane and N_2O emissions were estimated by multiplying emission factors (by sector and fuel type) by fossil fuel and wood consumption data. National coal, natural gas, fuel oil, and wood consumption data were grouped into four sectors—industrial, commercial, residential, and electricity generation.

For NO_x, CO, and NMVOCs, the major categories included in this section are those used in EPA (2001): coal, fuel oil, natural gas, wood, other fuels (including LPG, coke, coke oven gas, and others), and stationary internal combustion. The EPA estimates emissions of NO_x, CO, and NMVOCs by sector and fuel source using a "bottom-up" estimating procedure. In other words, emissions were calculated either for individual sources (e.g., industrial boilers) or for multiple sources combined, using basic activity data as indicators of emissions. Depending on the source category, these basic activity data may include fuel consumption, fuel deliveries, tons of refuse burned, raw material processed, etc.

The EPA derived the overall emission control efficiency of a source category from published reports, the 1985 National Acid Precipitation and Assessment Program (NAPAP) emissions inventory, and other EPA databases. The U.S. approach for estimating emissions of NO_x, CO, and NMVOCs from stationary combustion, as described above, is consistent with the methodology recommended by the IPCC (IPCC/UNEP/OECD/IEA 1997).

More detailed information on the methodology for calculating emissions from stationary combustion, including emission factors and activity data, is provided in Annex C.

Data Sources

Emissions estimates for NO_x, CO, and NMVOCs in this section were taken directly from unpublished EPA data (2001). Fuel consumption data for CH_4 and N_2O estimates were provided by the U.S. Energy Information Administration's *Annual Energy Review* (EIA 2001). Estimates for wood biomass consumption for fuel combustion do not include wood wastes, liquors, municipal solid waste, tires, etc. that are reported as biomass by EIA. Emission factors were provided by the *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories* (IPCC/UNEP/OECD/IEA 1997).

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[32] See Annex C for a complete time series of ambient air pollutant emission estimates for 1990 through 2000.

Table 2-13: CH_4 Emissions from Stationary Combustion (Tg CO_2 Eq.)

Sector/Fuel Type	1990	1995	1996	1997	1998	1999	2000
Electricity Generation	**0.5**	**0.5**	**0.5**	**0.6**	**0.6**	**0.6**	**0.6**
Coal	0.3	0.4	0.4	0.4	0.4	0.4	0.4
Fuel Oil	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Natural gas	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Wood	+	+	+	+	+	+	+
Industrial	**2.1**	**2.3**	**2.3**	**2.4**	**2.3**	**2.4**	**2.3**
Coal	0.3	0.3	0.3	0.3	0.3	0.3	0.2
Fuel Oil	0.3	0.4	0.4	0.4	0.4	0.4	0.4
Natural gas	0.7	0.8	0.8	0.8	0.7	0.7	0.7
Wood	0.8	0.8	0.8	0.9	0.9	1.0	1.0
Commercial	**0.7**	**0.7**	**0.8**	**0.8**	**0.7**	**0.8**	**0.8**
Coal	+	+	+	+	+	+	+
Fuel Oil	0.2	0.2	0.2	0.1	0.1	0.1	0.2
Natural gas	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Wood	0.2	0.3	0.3	0.3	0.3	0.3	0.3
Residential	**4.6**	**4.7**	**4.7**	**3.8**	**3.3**	**3.6**	**3.7**
Coal	0.4	0.3	0.3	0.4	0.3	0.3	0.3
Fuel Oil	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Natural Gas	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Wood	3.5	3.6	3.6	2.6	2.3	2.5	2.6
Total	**7.9**	**8.2**	**8.4**	**7.5**	**7.0**	**7.3**	**7.5**

\+ Does not exceed 0.05 Tg CO_2 Eq.
Note: Totals may not sum due to independent rounding.

Table 2-14: N_2O Emissions from Stationary Combustion (Tg CO_2 Eq.)

Sector/Fuel Type	1990	1995	1996	1997	1998	1999	2000
Electricity Generation	**7.6**	**8.0**	**8.4**	**8.7**	**8.9**	**8.9**	**9.3**
Coal	7.2	7.7	8.1	8.3	8.5	8.5	8.9
Fuel Oil	0.2	0.2	0.2	0.2	0.3	0.3	0.2
Natural Gas	0.1	0.2	0.1	0.2	0.2	0.2	0.2
Wood	+	+	+	+	+	+	+
Industrial	**3.8**	**4.1**	**4.2**	**4.3**	**4.3**	**4.4**	**4.3**
Coal	0.6	0.6	0.6	0.6	0.6	0.6	0.5
Fuel Oil	1.5	1.6	1.7	1.7	1.7	1.7	1.6
Natural Gas	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Wood	1.5	1.7	1.7	1.8	1.8	2.0	2.0
Commercial	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**
Coal	+	+	+	+	+	+	+
Fuel Oil	0.2	0.1	0.1	0.1	0.1	0.1	0.1
Natural Gas	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Wood	+	0.1	0.1	0.1	0.1	0.1	0.1
Residential	**1.1**	**1.1**	**1.2**	**1.0**	**0.9**	**0.9**	**1.0**
Coal	+	+	+	+	+	+	+
Fuel Oil	0.2	0.3	0.3	0.3	0.2	0.3	0.3
Natural Gas	0.1	0.1	0.2	0.2	0.1	0.1	0.1
Wood	0.7	0.7	0.7	0.5	0.5	0.5	0.5
Total	**12.8**	**13.5**	**14.1**	**14.2**	**14.3**	**14.6**	**14.9**

\+ Does not exceed 0.05 Tg CO_2 Eq.
Note: Totals may not sum due to independent rounding.

Table 2-15: CH_4 Emissions from Stationary Combustion (Gg)

Sector/Fuel Type	1990	1995	1996	1997	1998	1999	2000
Electricity Generation	**24**	**25**	**26**	**27**	**29**	**29**	**30**
Coal	17	18	19	19	19	20	21
Fuel Oil	4	2	3	3	4	4	4
Natural Gas	4	5	5	5	5	6	6
Wood	+	+	+	+	+	+	+
Industrial	**100**	**108**	**111**	**113**	**110**	**114**	**111**
Coal	15	14	14	14	13	13	11
Fuel Oil	16	17	18	18	18	18	17
Natural Gas	33	37	38	38	35	35	34
Wood	36	40	41	43	45	49	48
Commercial	**33**	**36**	**38**	**37**	**35**	**37**	**39**
Coal	1	1	1	1	1	1	1
Fuel Oil	9	7	7	7	7	7	7
Natural Gas	13	15	15	16	15	15	16
Wood	11	13	14	13	13	15	15
Residential	**218**	**223**	**226**	**179**	**159**	**170**	**177**
Coal	19	16	16	17	13	14	14
Fuel Oil	13	14	15	14	13	15	15
Natural Gas	21	24	26	24	22	23	24
Wood	166	170	170	123	110	118	123
Total	**376**	**392**	**400**	**356**	**334**	**350**	**357**

+ Does not exceed 0.5 Gg

Note: Totals may not sum due to independent rounding.

Table 2-16: N_2O Emissions from Stationary Combustion (Gg)

Sector/Fuel Type	1990	1995	1996	1997	1998	1999	2000
Electricity Generation	**24**	**26**	**27**	**28**	**29**	**29**	**30**
Coal	23	25	26	27	27	27	29
Fuel Oil	1	+	+	1	1	1	1
Natural Gas	+	+	+	+	1	1	1
Wood	+	+	+	+	+	+	+
Industrial	**12**	**13**	**13**	**14**	**14**	**14**	**14**
Coal	2	2	2	2	2	2	2
Fuel Oil	5	5	5	5	5	5	5
Natural Gas	1	1	1	1	1	1	1
Wood	5	5	5	6	6	7	6
Commercial	**1**	**1**	**1**	**1**	**1**	**1**	**1**
Coal	+	+	+	+	+	+	+
Fuel Oil	1	+	+	+	+	+	+
Natural Gas	+	+	+	+	+	+	+
Wood	+	+	+	+	+	+	+
Residential	**3**	**4**	**4**	**3**	**3**	**3**	**3**
Coal	+	+	+	+	+	+	+
Fuel Oil	1	1	1	1	1	1	1
Natural Gas	+	+	1	+	+	+	+
Wood	2	2	2	2	1	2	2
Total	**41**	**43**	**45**	**46**	**46**	**47**	**48**

+ Does not exceed 0.5 Gg

Note: Totals may not sum due to independent rounding.

Table 2-17: NO_x, CO, and NMVOC Emissions from Stationary Combustion in 2000 (Gg)

Sector/Fuel Type	NO_x	CO	NMVOC
Electricity Generation	**4,763**	**380**	**51**
Coal	4,149	212	27
Fuel Oil	140	16	4
Natural Gas	320	95	10
Internal Combustion	154	56	10
Industrial	**2,924**	**1,108**	**169**
Coal	493	100	6
Fuel Oil	207	50	8
Natural Gas	1,137	327	57
Other Fuels[a]	112	322	34
Internal Combustion	976	308	64
Commercial	**376**	**137**	**26**
Coal	34	14	1
Fuel Oil	73	15	3
Natural Gas	244	63	14
Other Fuels[a]	26	46	9
Residential	**677**	**2,515**	**843**
Wood	30	2,292	812
Other Fuels[b]	647	223	31
Total	**8,740**	**4,140**	**1,089**

NA (Not Available)

[a] "Other Fuels" include LPG, waste oil, coke oven gas, coke, and non-residential wood (EPA 2001).

[b] "Other Fuels" include LPG, waste oil, coke oven gas, and coke (EPA 2001).

Note: Totals may not sum due to independent rounding. See Annex C for emissions in 1990 through 2000.

Uncertainty

Methane emission estimates from stationary sources are highly uncertain, primarily due to difficulties in calculating emissions from wood combustion (i.e., fireplaces and wood stoves). The estimates of CH_4 and N_2O emissions presented are based on broad indicators of emissions (i.e., fuel use multiplied by an aggregate emission factor for different sectors), rather than specific emission processes (i.e., by combustion technology and type of emission control). The uncertainties associated with the emission estimates of these gases are greater than with estimates of CO_2 from fossil fuel combustion, which mainly rely on the carbon content of the fuel combusted. Uncertainties in both CH_4 and N_2O estimates are due to the fact that emissions are estimated based on emission factors representing only a limited subset of combustion conditions. For the ambient air pollutants, uncertainties are partly due to assumptions concerning combustion technology types, age of equipment, emission factors used, and activity data projections.

Mobile Combustion (excluding CO_2)

Mobile combustion emits greenhouse gases other than CO_2, including methane (CH_4), nitrous oxide (N_2O), and the ambient air pollutants carbon monoxide (CO), nitrogen oxides (NO_x), and non-methane volatile organic compounds (NMVOCs). As with stationary combustion, N_2O and NO_x emissions are closely related to fuel characteristics, air-fuel mixes, combustion temperatures, as well as usage of pollution control equipment. Nitrous oxide, in particular, can be formed by the catalytic processes used to control NO_x, CO, and hydrocarbon emissions. Carbon monoxide emissions from mobile combustion are significantly affected by combustion efficiency and presence of post-combustion emission controls. Carbon monoxide emissions are highest when air-fuel mixtures have less oxygen than required for complete combustion. These emissions occur especially in idle, low speed and cold start conditions. Methane and NMVOC emissions from motor vehicles are a function of the CH_4 content of the motor fuel, the amount of hydrocarbons passing uncombusted through the engine, and any post-combustion control of hydrocarbon emissions, such as catalytic converters.

Emissions from mobile combustion were estimated by transport mode (e.g., highway, air, rail, and water) and fuel type—motor gasoline, diesel fuel, jet fuel, aviation gas, natural gas, liquefied petroleum gas (LPG), and residual fuel oil—and vehicle type. Road transport accounted for the majority of mobile source fuel consumption, and hence, the majority of mobile combustion emissions. Table 2-18 through Table 2-21 provide CH_4 and N_2O emission estimates from mobile combustion by vehicle type, fuel type, and transport mode. Estimates of NO_x, CO, and NMVOC emissions in 2000 are given in Table 2-22.[33]

Mobile combustion was responsible for a small portion of national CH_4 emissions but was the second largest source of N_2O in the United States. From 1990 to 2000, CH_4 emissions declined by 11 percent, to 4.4 Tg CO_2 Eq. (208 Gg). Nitrous oxide emissions, however, rose 14 percent to 58.3 Tg CO_2 Eq. (188 Gg) (see Figure 2-19). The reason for this conflicting trend was that the control technologies employed on highway vehicles in the United States lowered CO, NO_x, NMVOC, and CH_4 emissions, but resulted in higher average

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[33] See Annex D for a complete time series of emission estimates for 1990 through 2000.

Table 2-18: CH_4 Emissions from Mobile Combustion (Tg CO_2 Eq.)

Fuel Type/Vehicle Type	1990	1995	1996	1997	1998	1999	2000
Gasoline Highway	**4.2**	**4.1**	**3.9**	**3.8**	**3.8**	**3.7**	**3.6**
Passenger Cars	2.4	2.0	2.0	1.9	1.9	1.9	1.9
Light-Duty Trucks	1.6	1.8	1.7	1.7	1.6	1.6	1.5
Heavy-Duty Vehicles	0.2	0.1	0.1	0.1	0.1	0.1	0.1
Motorcycles	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Diesel Highway	**0.2**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**
Passenger Cars	+	+	+	+	+	+	+
Light-Duty Trucks	+	+	+	+	+	+	+
Heavy-Duty Vehicles	0.2	0.3	0.3	0.3	0.3	0.3	0.3
Non-Highway	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**0.5**
Ships and Boats	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Locomotives	0.1	0.1	0.1	0.1	+	+	0.1
Farm Equipment	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Construction Equipment	+	+	+	+	+	+	+
Aircraft	0.2	0.1	0.1	0.2	0.1	0.2	0.2
Other*	+	+	+	+	+	+	+
Total	**4.9**	**4.8**	**4.7**	**4.6**	**4.5**	**4.4**	**4.4**

\+ Does not exceed 0.05 Tg CO_2 Eq.

Note: Totals may not sum due to independent rounding.

* "Other" includes snowmobiles, small gasoline powered utility equipment, heavy-duty gasoline powered utility equipment, and heavy-duty diesel powered utility equipment.

Table 2-19: N_2O Emissions from Mobile Combustion (Tg CO_2 Eq.)

Fuel Type/Vehicle Type	1990	1995	1996	1997	1998	1999	2000
Gasoline Highway	**46.0**	**54.9**	**54.4**	**54.0**	**53.4**	**52.7**	**51.9**
Passenger Cars	31.0	33.1	32.7	32.2	32.0	31.2	30.6
Light-Duty Trucks	14.2	20.8	20.7	20.7	20.3	20.4	20.1
Heavy-Duty Vehicles	0.7	1.0	1.0	1.0	1.1	1.1	1.1
Motorcycles	+	+	+	+	+	+	+
Diesel Highway	**2.1**	**2.6**	**2.7**	**2.8**	**2.9**	**3.0**	**3.1**
Passenger Cars	0.1	0.1	0.1	0.1	0.1	+	+
Light-Duty Trucks	0.2	0.2	0.2	0.2	0.3	0.3	0.3
Heavy-Duty Vehicles	1.8	2.3	2.4	2.5	2.6	2.7	2.7
Non-Highway	**2.9**	**3.0**	**3.0**	**2.9**	**2.8**	**3.0**	**3.4**
Ships and Boats	0.4	0.5	0.4	0.3	0.3	0.4	0.6
Locomotives	0.3	0.3	0.3	0.2	0.2	0.2	0.2
Farm Equipment	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Construction Equipment	0.1	0.1	0.1	0.2	0.2	0.1	0.2
Aircraft	1.7	1.7	1.8	1.7	1.8	1.8	1.9
Other*	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	**50.9**	**60.4**	**60.1**	**59.7**	**59.1**	**58.7**	**58.3**

\+ Does not exceed 0.05 Tg CO_2 Eq.

Note: Totals may not sum due to independent rounding.

* "Other" includes snowmobiles, small gasoline powered utility equipment, heavy-duty gasoline powered utility equipment, and heavy-duty diesel powered utility equipment.

Table 2-20: CH_4 Emissions from Mobile Combustion (Gg)

Fuel Type/Vehicle Type	1990	1995	1996	1997	1998	1999	2000
Gasoline Highway	**202**	**193**	**188**	**183**	**179**	**175**	**171**
Passenger Cars	115	96	94	93	93	91	90
Light-Duty Trucks	74	86	83	81	77	75	72
Heavy-Duty Vehicles	9	7	6	6	6	6	6
Motorcycles	4	4	4	3	3	3	3
Diesel Highway	**11**	**13**	**13**	**14**	**14**	**14**	**14**
Passenger Cars	+	+	+	+	+	+	+
Light-Duty Trucks	+	+	+	+	+	+	+
Heavy-Duty Vehicles	10	13	13	13	13	13	13
Non-Highway	**21**	**21**	**21**	**20**	**19**	**20**	**23**
Ships and Boats	3	4	4	3	2	4	6
Locomotives	3	3	3	2	2	2	2
Farm Equipment	6	6	6	6	5	5	5
Construction Equipment	1	1	1	1	1	1	1
Aircraft	7	7	7	7	7	7	7
Other*	1	1	1	1	1	1	1
Total	**233**	**228**	**222**	**217**	**212**	**209**	**208**

+ Does not exceed 0.5 Gg

Note: Totals may not sum due to independent rounding.

* "Other" includes snowmobiles, small gasoline powered utility equipment, heavy-duty gasoline powered utility equipment, and heavy-duty diesel powered utility equipment.

Table 2-21: N_2O Emissions from Mobile Combustion (Gg)

Fuel Type/Vehicle Type	1990	1995	1996	1997	1998	1999	2000
Gasoline Highway	**148**	**177**	**176**	**174**	**172**	**170**	**167**
Passenger Cars	100	107	105	104	103	101	99
Light-Duty Trucks	46	67	67	67	66	66	65
Heavy-Duty Vehicles	2	3	3	3	3	4	3
Motorcycles	+	+	+	+	+	+	+
Diesel Highway	**7**	**8**	**9**	**9**	**9**	**10**	**10**
Passenger Cars	+	+	+	+	+	+	+
Light-Duty Trucks	1	1	1	1	1	1	1
Heavy-Duty Vehicles	6	7	8	8	8	9	9
Non-Highway	**9**	**10**	**10**	**9**	**9**	**10**	**11**
Ships and Boats	1	1	1	1	1	1	2
Locomotives	1	1	1	1	1	1	1
Farm Equipment	1	1	1	1	1	1	1
Construction Equipment	+	+	+	+	+	+	1
Aircraft	6	5	6	6	6	6	6
Other*	+	+	+	+	+	+	+
Total	**164**	**195**	**194**	**192**	**191**	**189**	**188**

+ Does not exceed 0.5 Gg

Note: Totals may not sum due to independent rounding.

* "Other" includes snowmobiles, small gasoline powered utility equipment, heavy-duty gasoline powered utility equipment, and heavy-duty diesel powered utility equipment.

Table 2-22: NO_x, CO, and NMVOC Emissions from Mobile Combustion in 2000 (Gg)

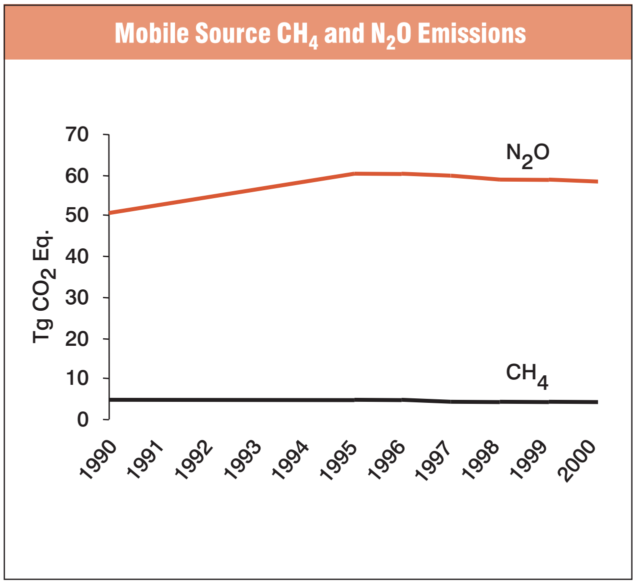
Fuel Type/Vehicle Type	NO_x	CO	NMVOCs
Gasoline Highway	**4,388**	**41,944**	**4,333**
Passenger Cars	2,519	24,058	2,500
Light-Duty Trucks	1,459	14,367	1,501
Heavy-Duty Vehicles	398	3,338	293
Motorcycles	12	181	38
Diesel Highway	**3,004**	**2,026**	**236**
Passenger Cars	6	5	2
Light-Duty Trucks	4	4	2
Heavy-Duty Vehicles	2,994	2,017	232
Non-Highway	**7,549**	**25,326**	**3,069**
Ships and Boats	1,041	2,070	833
Locomotives	704	70	27
Farm Equipment	815	465	93
Construction Equipment	1,114	1,290	199
Aircraft[a]	76	331	26
Other[b]	3,799	21,100	1,891
Total	**14,941**	**69,296**	**7,638**

[a] Aircraft estimates include only emissions related to landing and take-off (LTO) cycles, and therefore do not include cruise altitude emissions.

[b] "Other" includes gasoline powered recreational, industrial, lawn and garden, light commercial, logging, airport service, other equipment; and diesel powered recreational, industrial, lawn and garden, light construction, airport service.

Note: Totals may not sum due to independent rounding. See Annex D for emissions from 1990 through 2000.

Figure 2-19



Mobile Source CH_4 and N_2O Emissions

N_2O emission rates. Fortunately, since 1994 improvements in the emission control technologies installed on new vehicles have reduced emission rates of both NO_x and N_2O per vehicle mile traveled. Overall, CH_4 and N_2O emissions were predominantly from gasoline-fueled passenger cars and light-duty gasoline trucks.

Fossil-fueled motor vehicles comprise the single largest source of CO emissions in the United States and are a significant contributor to NO_x and NMVOC emissions. In 2000, mobile combustion contributed to 74 percent of national CO emissions and 60 and 43 percent of NO_x and NMVOC emissions, respectively. Since 1990, emissions of NMVOCs from mobile combustion decreased by 6 percent, while emissions of NO_x increased by 37 percent. Carbon monoxide emissions remained unchanged.

Methodology

Estimates for CH_4 and N_2O emissions from mobile combustion were calculated by multiplying emission factors by measures of activity for each category. Depending upon the category, activity data included such information as fuel consumption, fuel deliveries, and vehicle miles traveled (VMT). Emission estimates from highway vehicles were based on VMT and emission factors by vehicle type, fuel type, model year, and control technology. Fuel consumption data were employed as a measure of activity for non-highway vehicles and then fuel-specific emission factors were applied.[34] A complete discussion of the methodology used to estimate emissions from mobile combustion is provided in Annex D.

EPA (2001) provided emissions estimates of NO_x, CO, and NMVOCs for eight categories of highway vehicles,[35] aircraft, and seven categories of off-highway vehicles.[36]

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[34] The consumption of international bunker fuels is not included in these activity data, but are estimated separately under the International Bunker Fuels source category.

[35] These categories included: gasoline passenger cars, diesel passenger cars, light-duty gasoline trucks less than 6,000 pounds in weight, light-duty gasoline trucks between 6,000 and 8,500 pounds in weight, light-duty diesel trucks, heavy-duty gasoline trucks and buses, heavy-duty diesel trucks and buses, and motorcycles.

[36] These categories included: gasoline and diesel farm tractors, other gasoline and diesel farm machinery, gasoline and diesel construction equipment, snowmobiles, small gasoline utility engines, and heavy-duty gasoline and diesel general utility engines.

Data Sources

Emission factors used in the calculations of CH_4 and N_2O emissions are presented in Annex D. The *Revised 1996 IPCC Guidelines* (IPCC/UNEP/OECD/IEA 1997) provided emission factors for CH_4, and were developed using MOBILE5a, a model used by the Environmental Protection Agency (EPA) to estimate exhaust and running loss emissions from highway vehicles. The MOBILE5a model uses information on ambient temperature, vehicle speeds, national vehicle registration distributions, gasoline volatility, and other variables in order to produce these factors (EPA 1997).

Emission factors for N_2O from gasoline passenger cars are from EPA (1998). This report contains emission factors for older passenger cars—roughly pre-1992 in California and pre-1994 in the rest of the United States—from published references, and for newer cars from a recent testing program at EPA's National Vehicle and Fuel Emissions Laboratory (NVFEL). These emission factors for gasoline highway vehicles are lower than the U.S. default values in the *Revised 1996 IPCC Guidelines*, but are higher than the European default values, both of which were published before the more recent tests and literature review conducted by the NVFEL. The U.S. default values in the *Revised 1996 IPCC Guidelines* were based on three studies that tested a total of five cars using European rather than U.S. test protocols. More details may be found in EPA (1998).

Nitrous oxide emission factors for gasoline vehicles other than passenger cars (i.e., light-duty gasoline trucks, heavy-duty gasoline vehicles, and motorcycles) were scaled from N_2O factors from passenger cars with the same control technology, based on their relative fuel economy. Fuel economy for each vehicle category was derived from data in DOE (1993 through 2001), (FHWA 1996 through 2001), (EPA, DOE 2001), and (Census 1997). This scaling was supported by limited data showing that light-duty trucks emit more N_2O than passenger cars with equivalent control technology. The use of fuel consumption ratios to determine emission factors is considered a temporary measure only, and will be replaced as additional testing data become available.

Nitrous oxide emission factors for diesel highway vehicles were taken from the European default values found in the *Revised 1996 IPCC Guidelines* (IPCC/UNEP/OECD/IEA 1997). Little data exists addressing N_2O emissions from U.S. diesel-fueled vehicles, and in general, European countries have had more experience with diesel-fueled vehicles. U.S. default values in the *Revised 1996 IPCC Guidelines* were used for non-highway vehicles.

Activity data were gathered from several U.S. government sources including BEA (1991 through 2001), Census (1997), DESC (2001), DOC (1991 through 2001), DOT (1991 through 2001), EIA (2001a), EIA (1991-2001), EIA (2001c), EIA (2001e), EPA/DOE (2001), FAA (1995 through 2001), and FHWA (1996 through 20001). Control technology and standards data for highway vehicles were obtained from the EPA's Office of Transportation and Air Quality (EPA 1997 and 2000). These technologies and standards are defined in Annex D, and were compiled from EPA (1993), EPA (1994a), EPA (1994b), EPA (1998), EPA (1999), and IPCC/UNEP/OECD/IEA (1997). Annual VMT data for 1990 through 2000 were obtained from the Federal Highway Administration's (FHWA) Highway Performance Monitoring System database as reported in *Highway Statistics* (FHWA 1996 through 20001).

Emissions estimates for NO_x, CO, NMVOCs were taken directly from the EPA (2001).

Uncertainty

Mobile combustion emissions from each vehicle mile traveled can vary significantly due to assumptions concerning fuel type and composition, technology type, average speeds, type of emission control equipment, equipment age, and operating and maintenance practices. Fortunately, detailed activity data for mobile combustion were available, including VMT by vehicle type for highway vehicles. The allocation of this VMT to individual model years was done using temporally variable profiles of both vehicle usage by age and vehicle usage by model year in the United States. Data for these profiles were provided by EPA (2000).

Average emission factors were developed based on numerous assumptions concerning the age and model of vehicle; percent driving in cold start, warm start, and cruise conditions; average driving speed; ambient temperature; and maintenance practices. The factors for regulated emissions from mobile combustion (i.e., CO, NO_x, and hydrocarbons) have been extensively researched, and thus involve lower uncertainty than emissions of unregulated gases. Although CH_4 has not been singled out for regulation in the United States, overall hydrocarbon emissions from mobile combustion—a component of which is methane—are regulated.

In calculating CH_4 and N_2O emissions from highway vehicles, only data for Low Emission Vehicles (LEVs) in California has been obtained. Data on the number of LEVs in the rest of the United States will be researched and may be included in future inventories.

Compared to CH_4, CO, NO_x, and NMVOCs, there is relatively little data available to estimate emission factors for N_2O. Nitrous oxide is not a regulated air pollutant, and measurements of it in automobile exhaust have not been routinely collected. Research data has shown that N_2O emissions from vehicles with catalytic converters are greater than those without emission controls, and vehicles with aged catalysts emit more than new vehicles. The emission factors used were, therefore, derived from aged cars (EPA 1998). The emission factors used for Tier 0 and older cars were based on tests of 28 vehicles; those for newer vehicles were based on tests of 22 vehicles. This sample is small considering that it is being used to characterize the entire U.S. fleet, and the associated uncertainty is therefore large. Currently, N_2O gasoline highway emission factors for vehicles other than passenger cars are scaled based on those for passenger cars and their relative fuel economy. Actual measurements should be substituted for this procedure when they become available. Further testing is needed to reduce the uncertainty in emission factors for all classes of vehicles, using realistic driving regimes, environmental conditions, and fuels.

Overall, uncertainty for N_2O emissions estimates is considerably higher than for CH_4, CO, NO_x, or NMVOC; however, all these gases involve far more uncertainty than CO_2 emissions from fossil fuel combustion.

U.S. jet fuel and aviation gasoline consumption is currently all attributed to the transportation sector by EIA, and it is assumed that it is all used to fuel aircraft. However, some fuel purchased by airlines is not necessarily used in aircraft, but instead used to power auxiliary power units, in ground equipment, and to test engines. Some jet fuel may also be used for other purposes such as blending with diesel fuel or heating oil.

In calculating CH_4 emissions from aircraft, an average emission factor is applied to total jet fuel consumption. This average emission factor takes into account the fact that CH_4 emissions occur only during the landing and take-off (LTO) cycles, with no CH_4 being emitted during the cruise cycle. While some evidence exists that fuel emissions in cruise conditions may actually destroy CH_4, the average emission factor used does not take this into account.

Lastly, in EPA (2000b), U.S. aircraft emission estimates for CO, NOx, and NMVOCs are based upon landing and take-off (LTO) cycles and, consequently, only estimate near ground-level emissions, which are more relevant for air quality evaluations. These estimates also include both domestic and international flights. Therefore, estimates presented here overestimate IPCC-defined domestic CO, NO_x, and NMVOC emissions by including LTO cycles by aircraft on international flights but underestimate total emissions because they exclude emissions from aircraft on domestic flight segments at cruising altitudes.

Coal Mining

All underground and surface coal mining liberates methane as part of the normal mining operations. The amount of methane liberated depends upon the amount that remains in the coal ("*in situ*") and surrounding strata when mining occurs. The in-situ methane content depends upon the amount of methane created during the coal formation (i.e., coalification) process, and the geologic characteristics of the coal seams. During coalification, deeper deposits tend to generate more methane and retain more of the gas afterwards. Accordingly, deep underground coal seams generally have higher methane contents than shallow coal seams or surface deposits.

Three types of coal mining related activities release methane to the atmosphere: underground mining, surface mining, and post-mining (i.e. coal-handling) activities. Underground coal mines contribute the largest share of methane emissions. All underground coal mines employ ventilation systems to ensure that methane levels remain within safe concentrations. These systems can exhaust significant amounts of methane to the atmosphere in low concentrations. Additionally, seventeen U.S. coal mines supplement ventilation systems with degasification systems. Degasification systems are wells drilled from the surface or boreholes drilled inside the mine that remove large volumes of methane before, during or after mining. In 2000, ten coal mines collected methane from degasification systems and sold this gas to a pipeline, thus reducing emissions to the atmosphere. Surface coal mines also release methane as the overburden is removed and the coal is exposed; however, the level of emissions is much lower than from underground mines. Finally, some of the methane retained in the coal after mining is released during processing, storage, and transport of the coal.

Total methane emissions in 2000 were estimated to be 61.0 Tg CO_2 Eq. (2,903 Gg), declining 30 percent since 1990 (see Table 2-23 and Table 2-24). Of this amount, underground mines accounted for 65 percent, surface mines accounted for 14 percent, and post-mining emissions accounted for 21 percent. With the exception of 1994 and 1995, total methane emissions declined in each successive year during this period. In 1993, methane generated from underground mining dropped, primarily due to labor strikes at many large underground mines. In 1995, there was an increase in methane emissions from underground mining due to significantly increased emissions at the highest-emitting coal mine in the country. The decline in methane emissions from underground mines in 2000 is the result of a decrease in coal production, the mining of less gassy coal, and an increase in methane recovered and used. Surface mine emissions and post-mining emissions remained relatively constant from 1990 to 2000.

Methodology

The methodology for estimating methane emissions from coal mining consists of two parts. The first part involves estimating methane emissions from underground mines. Because of the availability of ventilation system measurements, underground mine emissions can be estimated on a mine-by-mine basis and then summed to

Table 2-23: CH_4 Emissions from Coal Mining (Tg CO_2 Eq.)

Activity	1990		1995	1996	1997	1998	1999	2000
Underground Mining	62.1		51.2	45.3	44.3	44.4	41.6	39.4
Liberated	67.6		63.3	59.8	55.7	58.6	54.4	54.1
Recovered & Used	(5.6)		(12.0)	(14.5)	(11.4)	(14.2)	(12.7)	(14.7)
Surface Mining	10.2		8.9	9.2	9.5	9.4	8.9	8.8
Post-Mining (Underground)	13.1		11.9	12.4	12.8	12.6	11.7	11.3
Post-Mining (Surface)	1.7		1.5	1.5	1.5	1.5	1.4	1.4
Total	**87.1**		**73.5**	**68.4**	**68.1**	**67.9**	**63.7**	**61.0**

Note: Totals may not sum due to independent rounding.

Table 2-24: CH_4 Emissions from Coal Mining (Gg)

Activity	1990		1995	1996	1997	1998	1999	2000
Underground Mining	2,956		2,439	2,158	2,111	2,117	1,982	1,877
Liberated	3,220		3,012	2,850	2,654	2,791	2,589	2,575
Recovered & Used	(265)		(574)	(692)	(543)	(674)	(607)	(698)
Surface Mining	488		425	436	451	446	424	420
Post-Mining (Underground)	626		569	590	609	600	557	538
Post-Mining (Surface)	79		69	71	73	72	69	68
Total	**4,149**		**3,502**	**3,255**	**3,244**	**3,235**	**3,033**	**2,903**

Note: Totals may not sum due to independent rounding.

determine total emissions. The second step involves estimating emissions from surface mines and post-mining activities by multiplying basin-specific coal production by basin-specific emissions factors.

Underground mines. Total methane emitted from underground mines was estimated as the sum of methane liberated from ventilation systems, plus methane liberated by means of degasification systems, minus methane recovered and used. The Mine Safety and Heath Administration (MSHA) samples methane emissions from ventilation systems for all mines with detectable[37] methane concentrations. These mine-by-mine measurements are used to estimate methane emissions from ventilation systems.

Some of the higher-emitting underground mines also use degasification systems (e.g., wells or boreholes) that remove methane before, during, or after mining. This methane can then be collected for use or vented to the atmosphere. Various approaches were employed to estimate the quantity of methane collected by each of the seventeen mines using these systems, depending on available data. For example, some mines report to EPA the amounts of methane liberated from their degasification systems. For mines that sell recovered methane to a pipeline, pipeline sales data were used to estimate degasification emissions. For those mines for which no other data are available, default recovery efficiency values were developed, depending on the type of degasification system employed.

Finally, the amount of methane recovered by degasification systems and then used (i.e., not vented) was estimated. This calculation was complicated by the fact that most methane is not recovered and used during the same year in which the particular coal seam is mined. In 2000, ten active coal mines sold recovered methane into the local gas pipeline networks. Emissions avoided for these projects were estimated using gas sales data reported by various State agencies. For most mines with recovery systems, companies and state agencies provided individual well production information, which was used to assign gas sales to a particular year. For the few remaining mines, coal mine operators supplied information regarding the number of years in advance of mining that gas recovery occurs.

Surface Mines and Post-Mining Emissions. Surface mining and post-mining methane emissions were estimated by multiplying basin-specific coal production by basin-specific emissions factors. Surface mining emissions factors were developed by assuming that surface mines emit two times as much methane as the average *in situ* methane content of the coal. This accounts for methane released from the strata surrounding the coal seam. For post-mining emissions, the emission factor was assumed to be 32.5 percent of the average *in situ* methane content of coals mined in the basin.

Data Sources

The Mine Safety and Health Administration provided mine-specific information on methane liberated from ventilation systems at underground mines. The primary sources of data for estimating emissions avoided at underground mines were gas sales data published by State petroleum and natural gas agencies, information supplied by mine operators regarding the number of years in advance of mining that gas recovery occurred, and reports of gas used on-site. Annual coal production data were taken from the Energy Information Administration's *Coal Industry Annual* (see Table 2-25) (EIA 2000). Data on *in situ* methane content and emissions factors are taken from EPA (1990).

Uncertainty

The emission estimates from underground ventilation systems were based upon actual measurement data, which are believed to have relatively low uncertainty. A degree of imprecision was introduced because the measurements were not continuous but rather an average of quarterly instantaneous readings. Additionally, the measurement equipment used possibly resulted in an average of ten percent overestimation of annual methane emissions (Mutmansky and Wang 2000). Estimates of methane liberated and recovered by degasification systems are also relatively certain because many coal mine operators provided information on individual well gas sales and mined through dates. Many of the recovery estimates use data on wells within 100 feet of a mined area. A level of uncertainty currently

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[37] MSHA records coal mine methane readings with concentrations of greater than 50 ppm (parts per million) methane. Readings below this threshold are considered non-detectable.

exists concerning the radius of influence of each well. The number of wells counted, and thus the avoided emissions, may increase if the drainage area is found to be larger than currently estimated. EPA is currently working to determine the proper drainage radius and may include additional mines in the recovery estimate in the future. Compared to underground mines, there is considerably more uncertainty associated with surface mining and post-mining emissions because of the difficulty in developing accurate emissions factors from field measurements. The EPA plans to update the basin-specific surface mining emission factors. Additionally, EPA plans to re-evaluate the post-mining emission factors for the impact of methane not released before combustion. Because underground emissions comprise the majority of total coal mining emissions, the overall uncertainty is preliminarily estimated to be roughly ±15 percent. Currently, the estimate does not include emissions from abandoned coal mines because of limited data. The EPA is conducting research on the feasibility of including an estimate in future years.

Natural Gas Systems

The U.S. natural gas system encompasses hundreds of thousands of wells, hundreds of processing facilities, and over a million miles of transmission and distribution pipelines. Overall, natural gas systems emitted 116.4 Tg CO_2 Eq. (5,541 Gg) of methane in 2000, a slight decrease over emissions in 1990 (see Table 2-26 and Table 2-27). Improvements in management practices and technology, along with the normal replacement of older equipment, have helped to stabilize emissions.

Table 2-25: Coal Production (Thousand Metric Tons)

Year	Underground	Surface	Total
1990	384,250	546,818	931,068
1991	368,635	532,656	901,291
1992	368,627	534,290	902,917
1993	318,478	539,214	857,692
1994	362,065	575,529	937,594
1995	359,477	577,638	937,115
1996	371,816	593,315	965,131
1997	381,620	607,163	988,783
1998	378,964	634,864	1,013,828
1999	355,433	642,877	998,310
2000[38]	338,173	635,592	973,765

Methane emissions from natural gas systems are generally process related, with normal operations, routine maintenance, and system upsets being the primary contributors. Emissions from normal operations include: natural gas combusting engine and turbine exhaust, bleed and discharge emissions from pneumatic devices, and fugitive emissions from system components. Routine maintenance emissions originate from pipelines, equipment, and wells during repair and maintenance activities. Pressure surge relief systems and accidents can lead to system upset emissions. Below is a characterization of the four major stages of the natural gas system. Each of the stages is described and the different factors affecting methane emissions are discussed.

Field Production. In this initial stage, wells are used to withdraw raw gas from underground formations. Emissions arise from the wells themselves, gathering pipelines, and well-site gas treatment facilities such as dehydrators and separators. Fugitive emissions and emissions from pneumatic devices account for the majority of emissions. Emissions from field production accounted for approximately 25 percent of methane emissions from natural gas systems between 1990 and 2000.

Processing. In this stage, natural gas liquids and various other constituents from the raw gas are removed, resulting in "pipeline quality" gas, which is injected into the transmission system. Fugitive emissions from compressors, including compressor seals, are the primary emission source from this stage. Processing plants account for about 12 percent of methane emissions from natural gas systems.

Transmission and Storage. Natural gas transmission involves high pressure, large diameter pipelines that transport gas long distances from field production and processing areas to distribution systems or large volume customers such as power plants or chemical plants. Compressor station facilities, which contain large reciprocating and turbine compressors, are used to move the gas throughout the United States transmission system. Fugitive emissions from these compressor stations and from metering and regulating stations account for

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[38] The EIA Coalndustry Annual 2000 was not yet available; however, EIA provided preliminary production statistics from MSHA (EIA 2001).

Table 2-26: CH_4 Emissions from Natural Gas Systems (Tg CO_2 Eq.)

Stage	1990		1995	1996	1997	1998	1999	2000
Field Production	29.6		31.0	30.9	29.5	31.7	28.3	26.2
Processing	14.7		15.0	14.9	14.9	14.6	14.5	14.8
Transmission and Storage	46.7		46.7	47.1	46.2	45.1	44.1	43.3
Distribution	30.2		33.0	33.6	32.1	30.8	31.5	32.0
Total	**121.2**		**125.7**	**126.6**	**122.7**	**122.2**	**118.6**	**116.4**

Note: Totals may not sum due to independent rounding.

Table 2-27: CH_4 Emissions from Natural Gas Systems (Gg)

Stage	1990		1995	1996	1997	1998	1999	2000
Field Production	1,407		1,477	1,474	1,407	1,511	1,350	1,248
Processing	702		712	711	710	693	693	707
Transmission and Storage	2,223		2,225	2,243	2,198	2,150	2,102	2,061
Distribution	1,440		1,570	1,602	1,530	1,467	1,501	1,526
Total	**5,772**		**5,984**	**6,030**	**5,845**	**5,820**	**5,646**	**5,541**

Note: Totals may not sum due to independent rounding.

the majority of the emissions from this stage. Pneumatic devices and engine exhaust are also sources of emissions from transmission facilities. Methane emissions from transmission account for approximately 37 percent of the emissions from natural gas systems.

Natural gas is also injected and stored in underground formations during periods of low demand (e.g., summer), and withdrawn, processed, and distributed during periods of high demand (e.g., winter). Compressors and dehydrators are the primary contributors to emissions from these storage facilities. Approximately one percent of total emissions from natural gas systems can be attributed to storage facilities.

Distribution. Distribution pipelines take the high-pressure gas from the transmission system at "city gate" stations, reduce the pressure and distribute the gas through mains and service lines to individual end users. There were over 1,043,000 miles of distribution mains in 2000, an increase from just over 837,000 miles in 1990 (AGA 1998). Distribution system emissions, which account for approximately 25 percent of emissions from natural gas systems, resulted mainly from fugitive emissions from gate stations and non-plastic piping (cast iron, steel).[39] An increased use of plastic piping, which has lower emissions than other pipe materials, has reduced the growth in emissions from this stage. Distribution system emissions in 1999 were only slightly higher than 1990 levels.

Methodology

The basis for estimates of methane emissions from the U.S. natural gas industry is a detailed study by the Gas Research Institute and EPA (EPA/GRI 1996). The EPA/GRI study developed over 100 emission and activity factors to characterize emissions from the various components within the operating stages of the U.S. natural gas system. The study was based on a combination of process engineering studies and measurements at representative gas facilities. From this analysis, the EPA developed a 1992 base year emissions estimate using the emission and activity factors. For other years, the EPA has developed a set of industry activity factor drivers that can be used to update activity factors. These drivers include statistics on gas production, number of wells, system throughput, miles of various kinds of pipe, and other statistics that characterize the changes in the U.S. natural gas system infrastructure and operations.

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[39] The percentages of total emissions from each stage may not add to 100 because of independent rounding.

The methodology also adjusts the emission factors to reflect underlying technological improvement through both innovation and normal replacement of equipment. For the period 1990 through 1995, the emission factors were held constant. Thereafter, emission factors are reduced at a rate of 0.2 percent per year such that by 2020, emission factors will have declined by 5 percent from 1995. Emission reductions, as reported by EPA's Natural Gas STAR partners, were also incorporated into the analysis. Emission reductions associated with each stage of the natural gas system (production, processing, transmission and distribution) were subtracted from the corresponding total emissions estimates for each operating stage. See Annex F for more detailed information on the methodology and data used to calculate methane emissions from natural gas systems.

Data Sources

Activity factor data were obtained from the following sources: American Gas Association (AGA 1991 through 1999); *Natural Gas Annual* (EIA 1999); *Natural Gas Monthly* (EIA 2001); *Oil and Gas Journal* (PennWell Corporation 1999, 2000, 2001); Independent Petroleum Association of America (IPAA 1998, 1999, 2000); and the Department of Transportation's Office of Pipeline Safety (OPS 2001a,b). The Minerals Management Service (DOI 1998 through 2001) supplied offshore platform data. All emission factors were taken from EPA/GRI (1996).

Uncertainty

The heterogeneous nature of the natural gas industry makes it difficult to sample facilities that are completely representative of the entire industry. Because of this, scaling up from model facilities introduces a degree of uncertainty. Additionally, highly variable emission rates were measured among many system components, making the calculated average emission rates uncertain. Despite the difficulties associated with estimating emissions from this source, the uncertainty in the total estimated emissions is preliminarily believed to be on the order of ±40 percent.

Petroleum Systems

Methane emissions from petroleum systems are primarily associated with crude oil production, transportation, and refining operations. During each of these activities, methane is released to the atmosphere as fugitive emissions, vented emissions, emissions from operational upsets, and emissions from fuel combustion. Methane emissions from petroleum systems in 2000 were 21.9 Tg CO_2 Eq. (1,041 Gg). Since 1990, emissions declined gradually, primarily due to a decline in domestic oil production. (See Table 2-28 and Table 2-29.) The activities associated with petroleum systems are detailed below.

Production Field Operations. Production field operations account for approximately 97 percent of total methane emissions from petroleum systems. Vented methane from oil wells, storage tanks, and related production field processing equipment account for the vast majority of the emissions from production, with field storage tanks and natural-gas-powered pneumatic devices being the dominant sources. The emissions from storage tanks occur when the methane entrained in crude oil under high pressure volatilizes once the crude oil is dumped into storage tanks at atmospheric pressure. The next most dominant sources of vented emissions are chemical injection pumps and vessel blowdown. The remaining emissions from production can be attributed to fugitives and combustion.

Crude Oil Transportation. Crude transportation activities account for approximately one-half percent of total methane emissions from the oil industry. Venting from tanks and marine vessel loading operations accounts for the majority of methane emissions from crude oil transportation. Fugitive emissions, almost entirely from floating roof tanks, account for the remainder.

Crude Oil Refining. Crude oil refining processes and systems account for only two percent of total methane emissions from the oil industry because most of the methane in crude oil is removed or escapes before the crude oil is delivered to the refineries. Within refineries, vented emissions account for about 87 percent of the emissions from refining, while fugitive and combustion emissions

Table 2-28: CH_4 Emissions from Petroleum Systems (Tg CO_2 Eq.)

Activity	1990	1995	1996	1997	1998	1999	2000
Production Field Operations	**25.8**	**23.6**	**23.4**	**23.3**	**22.7**	**21.6**	**21.2**
Tank venting	11.8	10.4	10.2	10.2	9.8	9.1	8.9
Pneumatic device venting	11.0	10.4	10.4	10.4	10.2	9.9	9.7
Wellhead fugitives	0.5	0.5	0.5	0.5	0.5	0.4	0.4
Combustion & process upsets	1.0	0.9	0.9	0.9	0.9	0.9	0.9
Misc. venting & fugitives	1.4	1.3	1.3	1.3	1.3	1.3	1.3
Crude Oil Transportation	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Refining	**0.5**	**0.5**	**0.5**	**0.6**	**0.6**	**0.6**	**0.6**
Total	**26.4**	**24.2**	**24.0**	**24.0**	**23.4**	**22.3**	**21.9**

Note: Totals may not sum due to independent rounding.

Table 2-29: CH_4 Emissions from Petroleum Systems (Gg)

Activity	1990	1995	1996	1997	1998	1999	2000
Production Field Operations	**1,227**	**1,122**	**1,114**	**1,112**	**1,081**	**1,028**	**1,008**
Tank venting	564	493	485	484	466	433	425
Pneumatic device venting	525	497	496	495	485	470	460
Wellhead fugitives	25	25	25	24	23	21	20
Combustion & process upsets	47	44	45	45	44	42	42
Misc. venting & fugitives	66	63	63	63	63	62	61
Crude Oil Transportation	**7**	**6**	**6**	**6**	**6**	**6**	**5**
Refining	**25**	**25**	**26**	**27**	**27**	**27**	**28**
Total	**1,258**	**1,154**	**1,145**	**1,144**	**1,114**	**1,061**	**1,041**

Note: Totals may not sum due to independent rounding.

account for approximately six percent each. Refinery system blowdowns for maintenance and the process of asphalt blowing—with air to harden it—are the primary venting contributors. Most of the fugitive emissions from refineries are from leaks in the fuel gas system. Refinery combustion emissions accumulate from small amounts of unburned methane in process heater stacks as well as from unburned methane in engine exhausts and flares. The very slight increase in emissions from refining, relative to the decline in emissions from field production operations, is due to increasing imports of crude oil.

Methodology

The methodology for estimating methane emissions from petroleum systems is based on a comprehensive studies of methane emissions from U.S. petroleum systems, *Estimates of Methane Emissions from the U.S. Oil Industry (Draft Report)* (EPA 1999) and *Methane Emissions from the U.S. Petroleum Industry* (Radian 1996). The studies estimated emissions from 70 activities occurring in petroleum systems from the oil wellhead through crude oil refining, including 39 activities for crude oil production field operations, 11 for crude oil transportation activities, and 20 for refining operations. Annex F explains the emission estimates for these 70 activities in greater detail. The estimates of methane emissions from petroleum systems do not include emissions downstream from oil refineries because these emissions are very small compared to methane emissions upstream from oil refineries.

The methodology for estimating methane emissions from the 70 oil industry activities employs emission and activity factors initially developed in EPA (1999) and Radian (1996). Emissions were estimated for each activity by multiplying emission factors (e.g., emission rate per equipment item or per activity) by their corresponding activity data (e.g., equipment count or frequency of activity). The report provides emission factors and activity factors for all activities except those related to offshore oil production. For offshore oil production, an emission factor was calculated by dividing an emission estimate from the Minerals Management Service (MMS) by the number of platforms. Emission factors were held constant for the period 1990 through 2000.

Activity data for 1990 through 2000 from a wide variety of statistical resources. For some years, complete activity factor data are not available. In these cases, the activity data was evaluated in the same manner as in Radian (1996), by arithmetic mean of component estimates based on annual oil production and producing wells. Alternatively, the activity data was held constant.

Annex F provides a more detailed discussion of the methodology for petroleum systems.

Data Sources

Nearly all emission factors were taken from Radian (1996e). Other emission factors were taken from an American Petroleum Institute publication (API 1996), EPA default values, MMS reports (MMS 1995 and 1999), the Exploration and Production (E&P) Tank model (API and GRI), reports by the Canadian Association of Petroleum Producers (CAPP 1992 and 1993), and consensus of industry peer review panels.

Among the more important references used to obtain activity data are Energy Information Administration annual and monthly reports (EIA 1998, 2001), the API *Basic Petroleum Data Book* (API 1997 and 1999), *Methane Emissions from the Natural Gas Industry* prepared for the Gas Research Institute (GRI) and EPA (Radian 1996a-d), consensus of industry peer review panels, MMS reports (MMS 1995 and 1999), and the *Oil & Gas Journal* (OGJ 2000a,b).

Uncertainty

There is uncertainty associated with the estimate of annual venting emissions in production field operations because a recent census of tanks and other tank battery equipment, such as separators and pneumatic devices, were not available. These uncertainties are significant because storage tanks and pneumatic devices accounted for 85 percent of methane emissions from petroleum systems. Emission rates can also vary widely from reservoir to reservoir and well to well. A single average emission factor cannot reflect this variation. Pneumatic devices were estimated by assuming that the devices were a function of number of heater/treaters and separators, and that 35 percent of the total pneumatic devices were high bleed and 65 percent were low bleed. These assumptions may overestimate the numbers of high bleed pneumatic devices, and thus overestimate emissions. Finally, because the majority of methane emissions occur during production field operations, where methane can first escape from crude oil, a better understanding of tanks, tank equipment and vapor recovery practices would reduce that uncertainty. Because of the dominance of crude storage tank venting and pneumatics, Table 2-30 provides preliminary emission estimate ranges for these sources. For tank venting, these ranges include numbers that are 25 percent higher than or lower than the given point estimates. For pneumatics, the range is between 33 percent lower or 25 percent higher than the point estimates.

Municipal Solid Waste Combustion

Combustion is used to manage about 7 to 17 percent of the municipal solid wastes (MSW) generated in the United States (EPA 2000c, Glenn 1999). Almost all combustion of MSW in the United States occurs at waste-to-energy facilities where energy is recovered, and thus emissions from waste combustion are accounted for in the Energy chapter. Combustion of MSW results in conversion of the organic inputs to CO_2. According to the IPCC Guidelines, when the CO_2 emitted is of fossil origin, it is counted as a net anthropogenic emission of CO_2 to the atmosphere. Thus, the emissions from waste combustion are calculated by estimating the quantity of waste combusted and the fraction of the waste that is carbon derived from fossil sources.

Most of the organic materials in MSW are of biogenic origin (e.g., paper, yard trimmings), and have their net carbon flows accounted for under the Land-Use Change and Forestry chapter (see Box 2-3). However, some components—plastics, synthetic rubber, and synthetic fibers—are of fossil origin. Plastics in the U.S. waste stream are primarily in the form of containers, packaging, and durable goods. Rubber is found in durable goods, such as carpets, and in non-durable goods, such as clothing and footwear. Fibers in MSW are predominantly from clothing and home furnishings. Tires are also considered a "non-hazardous" waste and are included in the MSW combustion estimate, though waste disposal practices for tires differ from the rest of MSW.

Table 2-30: Uncertainty in CH_4 Emissions from Production Field Operations (Gg)

Activity	1990	1995	1996	1997	1998	1999	2000
Tank venting (point estimate)	**564**	**493**	**485**	**484**	**466**	**433**	**425**
Low	423	370	364	363	349	325	319
High	705	617	606	605	582	541	531
Pneumatic devices (point estimate)	**525**	**497**	**496**	**495**	**485**	**470**	**460**
Low	352	333	332	332	325	315	308
High	656	621	620	619	606	588	575

It was estimated that approximately 24 million metric tons of MSW were combusted in the United States in 2000. Carbon dioxide emissions from combustion of MSW rose 63 percent since 1990, to an estimated 22.5 Tg CO_2 Eq. (22,470 Gg) in 2000, as the volume of plastics in MSW increased (see Table 2-31 and Table 2-32). Waste combustion is also a source of nitrous oxide (N_2O) emissions (De Soete 1993). Nitrous oxide emissions from MSW combustion were estimated to be 0.3 Tg CO_2 Eq. (1 Gg) in 2000, and have not changed significantly since 1990.

Methodology

Emissions of CO_2 from MSW combustion include CO_2 generated by the combustion of plastics, synthetic fibers, and synthetic rubber, as well as the combustion of synthetic rubber and carbon black in tires. These emissions were calculated by multiplying the amount of each material combusted by the carbon content of the material and the fraction oxidized (98 percent). Plastics combusted in MSW were categorized into seven plastic resin types, each material having a discrete carbon content. Similarly, synthetic rubber is categorized into three product types; synthetic fibers were categorized into four product types, each having a discrete carbon content. Scrap tires contain several types of synthetic rubber, as well as carbon black. Each type of synthetic rubber has a discrete carbon content, and carbon black is 100 percent carbon. Emissions of CO_2 were calculated based on the number of scrap tires used for fuel and the synthetic rubber and carbon black content of the tires.

Combustion of municipal solid waste also results in emissions of N_2O. These emissions were calculated as a function of the total estimated mass of MSW combusted and an emission factor.

More detail on the methodology for calculating emissions from each of these waste combustion sources is provided in Annex H.

Data Sources

For each of the methods used to calculate CO_2 emissions from MSW combustion, data on the quantity of product combusted and the carbon content of the product are needed. It was estimated that approximately 24 million metric tons of MSW were combusted in the United States in 2000, based on an extrapolation of data from 1998 and earlier years (EPA 2000c, Glenn 1999). Waste combustion for 2000 was assumed to be the same as for 1999. For plastics, synthetic rubber, and synthetic fibers, the amount of material in MSW and its portion combusted was taken from the *Characterization of Municipal Solid Waste in the United States* (EPA 2000c). For synthetic rubber and carbon black in scrap tires, this information was provided by the *Scrap Tire Use/Disposal Study 1998/1999 Update* (STMC 1999) and the *Scrap Tires, Facts and Figures* (STMC 2000).

Average carbon contents for the “Other” plastics category, synthetic rubber in scrap tires, synthetic rubber in MSW, and synthetic fibers were calculated from recent production statistics which divide their respective markets by chemical compound. The plastics production data set was taken from the website of the American Plastics Council (APC 2000); synthetic rubber production was taken from the website of the International Institute of Synthetic Rubber Producers (IISRP 2000); and synthetic fiber production was taken from the website of the Fiber Economics Bureau (FEB 2000). Personal communications with the APC (Eldredge-Roebuck 2000) and the FEB (DeZan 2000) validated the website information. All three sets of production data can also be found in Chemical and Engineering News, “Facts & Figures for the Chemical Industry.” Lastly, information about scrap tire composition was taken from the Scrap Tire Management Council’s Internet web site entitled “Scrap Tire Facts and Figures” (STMC 2000).

Box 2-3: Biogenic Emissions and Sinks of Carbon

For many countries, CO_2 emissions from the combustion or degradation of biogenic materials are important because of the significant amount of energy they derive from biomass (e.g., burning fuelwood). The fate of biogenic materials is also important when evaluating waste management emissions (e.g., the decomposition of paper). The carbon contained in paper was originally stored in trees during photosynthesis. Under natural conditions, this material would eventually degrade and cycle back to the atmosphere as CO_2. The quantity of carbon that these degradation processes cycle through the Earth's atmosphere, waters, soils, and biota is much greater than the quantity added by anthropogenic greenhouse gas sources. But the focus of the United Nations Framework Convention on Climate Change is on anthropogenic emissions—emissions resulting from human activities and subject to human control—because it is these emissions that have the potential to alter the climate by disrupting the natural balances in carbon's biogeochemical cycle, and enhancing the atmosphere's natural greenhouse effect.

Carbon dioxide emissions from biogenic materials (e.g., paper, wood products, and yard trimmings) grown on a sustainable basis are considered to mimic the closed loop of the natural carbon cycle—that is, they return to the atmosphere CO_2 that was originally removed by photosynthesis. However, CH_4 emissions from landfilled waste occur due to the man-made anaerobic conditions conducive to CH_4 formation that exist in landfills, and are consequently included in this Inventory.

The removal of carbon from the natural cycling of carbon between the atmosphere and biogenic materials—which occurs when wastes of biogenic origin are deposited in landfills—sequesters carbon. When wastes of sustainable, biogenic origin are landfilled, and do not completely decompose, the carbon that remains is effectively removed from the global carbon cycle. Landfilling of forest products and yard trimmings results in long-term storage of 154 Tg CO_2 Eq. and 13 Tg CO_2 Eq. on average per year, respectively. Carbon storage that results from forest products and yard trimmings disposed in landfills is accounted for in the Land-Use Change and Forestry chapter, as recommended in the *Revised 1996 IPCC Guidelines* (IPCC/UNEP/OECD/IEA 1997) regarding the tracking of carbon flows.

Table 2-31: CO_2 and N_2O Emissions from Municipal Solid Waste Combustion (Tg CO_2 Eq.)

Gas/Waste Product	1990		1995	1996	1997	1998	1999	2000
CO_2	**14.1**		**18.6**	**19.6**	**21.3**	**20.3**	**21.8**	**22.5**
Plastics	10.3		11.1	11.5	12.5	12.9	13.3	13.7
Synthetic Rubber in Tires	0.3		1.5	1.7	1.9	1.3	1.7	1.8
Carbon Black in Tires	0.4		2.4	2.7	3.0	2.0	2.7	2.8
Synthetic Rubber in MSW	1.6		1.7	1.7	1.8	1.8	1.9	1.9
Synthetic Fibers	1.5		1.9	2.0	2.1	2.2	2.3	2.3
N_2O	**0.3**		**0.3**	**0.3**	**0.3**	**0.2**	**0.2**	**0.2**
Total	**14.4**		**18.9**	**19.8**	**21.6**	**20.5**	**22.1**	**22.7**

Table 2-32: CO_2 and N_2O Emissions from Municipal Solid Waste Combustion (Gg)

Gas/Waste Product	1990		1995	1996	1997	1998	1999	2000
CO_2	**14,014**		**18,608**	**19,569**	**21,344**	**20,251**	**21,843**	**22,470**
Plastics	10,320		11,077	11,459	12,484	12,929	13,297	13,653
Synthetic Rubber in Tires	253		1,507	1,689	1,906	1,263	1,703	1,771
Carbon Black in Tires	399		2,377	2,666	3,006	1,993	2,687	2,795
Synthetic Rubber in MSW	1,584		1,708	1,737	1,807	1,833	1,870	1,905
Synthetic Fibers	1,535		1,938	2,018	2,141	2,233	2,285	2,346
N_2O	**1**		**1**	**1**	**1**	**1**	**1**	**1**

The use of the value 98 as the fraction of carbon oxidized, which applies to all municipal solid waste combustion categories for CO_2 emissions, was reported in the EPA's life cycle analysis of greenhouse gas emissions and sinks from management of solid waste (EPA 1998).

The N_2O emission estimates are based on different data sources. The N_2O emissions are a function of total waste combusted, as reported in the November 2000 issue of *BioCycle* (Goldstein N. and C. Matdes 2000). Table 2-33 provides MSW generation and percentage combustion data for the total waste stream. The emission factor of N_2O emissions per quantity of MSW combusted was taken from Olivier (1993).

Table 2-33: Municipal Solid Waste Generation (Metric Tons) and Percent Combusted

Year	Waste Generation	Combusted (%)
1990	266,541,881	11.5
1991	254,796,765	10.0
1992	264,843,388	11.0
1993	278,572,955	10.0
1994	293,109,556	10.0
1995	296,586,430	10.0
1996	297,268,188	10.0
1997	309,075,035	9.0
1998	340,090,022	7.5
1999	347,318,833	7.0
2000	347,318,833	7.0

Uncertainty

Uncertainties in the waste combustion emission estimates arise from both the assumptions applied to the data and from the quality of the data.

- *MSW Combustion Rate.* A source of uncertainty affecting both fossil CO_2 and N_2O emissions is the estimate of the MSW combustion rate. The EPA (2000c) estimates of materials generated, discarded, and combusted carry considerable uncertainty associated with the material flows methodology used to generate them. Similarly, *BioCycle* (Glenn 1999, Goldstein and Matdes 2000) estimate of total waste combustion — used for the N_2O emissions estimate—is based on a survey of State officials, who use differing definitions of solid waste and who draw from a variety of sources of varying reliability and accuracy. Despite the differences in methodology and data sources, the two references— the EPA's Office of Solid Waste (EPA 2000c) and *BioCycle* (Glenn 1999, Goldstein and Matdes 2000)—provide estimates of total solid waste combusted that are relatively consistent (see Table 2-34).
- *Fraction Oxidized.* Another source of uncertainty for the CO_2 emissions estimate is fraction oxidized. Municipal waste combustors vary considerably in their efficiency as a function of waste type, moisture content, combustion conditions, and other factors. The value of 98 percent assumed here may not be representative of typical conditions.
- *Use of 1998 Data on MSW Composition.* Emissions have been calculated from activity that has been extrapolated from reported 1998 values using average annual growth rates. In addition, the ratio of landfilling to combustion was assumed to be constant for the entire period (1990 to 2000) based on the 1998 ratio (EPA 2000c).
- *Average Carbon Contents.* Average carbon contents were applied to the mass of "Other" plastics combusted, synthetic rubber in tires and MSW, and synthetic fibers. These average values were estimated from the average carbon content of the known products recently produced. The true carbon content of the combusted waste may differ from this estimate depending on differences in the formula between the known and unspecified materials, and differences between the composition of the material disposed and that produced. For rubber, this uncertainty is probably small since the major elastomers' carbon contents range from 77 to 91 percent; for plastics, where carbon contents range from 29 to 92 percent, it may be more significant. Overall, this is a small source of uncertainty.
- *Synthetic/Biogenic Assumptions.* A portion of the fiber and rubber in MSW is biogenic in origin. Assumptions have been made concerning the allocation between synthetic and biogenic materials based primarily on expert judgment.
- *Combustion Conditions Affecting N_2O Emissions.* Because insufficient data exist to provide detailed estimates of N_2O emissions for individual combustion facilities, the estimates presented are highly uncertain. The emission factor for N_2O from MSW combustion facilities used in the analysis is a default value used to

Table 2-34: U.S. Municipal Solid Waste Combusted by Data Source (Metric Tons)

Year	EPA	BioCycle
1990	28,939,680	30,652,316
1991	30,236,976	25,479,677
1992	29,656,638	29,132,773
1993	29,865,024	27,857,295
1994	29,474,928	29,310,956
1995	32,241,888	29,658,643
1996	32,740,848	29,726,819
1997	32,294,240	27,816,753
1998	31,218,818	25,506,752
1999	30,945,455	NA
2000	NA	NA

NA (Not Available)

estimate N_2O emissions from facilities worldwide (Olivier 1993). As such, it has a range of uncertainty that spans an order of magnitude (between 25 and 293 g N_2O/metric ton MSW combusted) (Watanabe, et al. 1992). Due to a lack of information on the control of N_2O emissions from MSW combustion facilities in the United States, the estimate of zero percent for N_2O emissions control removal efficiency is also uncertain.

Natural Gas Flaring and Ambient Air Pollutant Emissions from Oil and Gas Activities

The flaring of natural gas from oil wells is a small source of carbon dioxide (CO_2). In addition, oil and gas activities also release small amounts of nitrogen oxides (NO_x), carbon monoxide (CO), and nonmethane volatile organic compounds (NMVOCs). This source accounts for only a small proportion of overall emissions of each of these gases. Emissions of NO_x, and CO from petroleum and natural gas production activities were both less than 1 percent of national totals, while NMVOC and SO_2 emissions were roughly 2 percent of national totals.

Carbon dioxide emissions from petroleum production result from natural gas that is flared (i.e., combusted) at the production site. Barns and Edmonds (1990) noted that of total reported U.S. venting and flaring, approximately 20 percent may be vented, with the remaining 80 percent flared; however, it is now believed that flaring accounts for an even greater proportion, although some venting still occurs. Methane emissions from venting are accounted for under Petroleum Systems. For 2000, CO_2 emissions from flaring were estimated to be approximately 6.1 Tg CO_2 Eq. (6,059 Gg), an increase of 10 percent since 1990 (see Table 2-35).

Ambient air pollutant emissions from oil and gas production, transportation, and storage, constituted a relatively small and stable portion of the total emissions of these gases from the 1990 to 2000 (see Table 2-36).

Methodology

Estimates of CO_2 emissions were prepared using an emission factor of 54.71 Tg CO_2 Eq./QBtu of flared gas, and an assumed flaring efficiency of 100 percent.

Ambient air pollutant emission estimates for NO_x, CO, and NMVOCs were determined using industry-published production data and applying average emission factors.

Data Sources

Total natural gas vented and flared was taken from EIA's *Natural Gas Annual* (EIA 2001). It was assumed that all reported vented and flared gas was flared. This assumption is consistent with that used by EIA in preparing their emission estimates, under the assumption that many states require flaring of natural gas (EIA 2000b).

There is a discrepancy in the time series for natural gas vented and flared as reported in EIA (2001). One facility in Wyoming had been incorrectly reporting CO_2 vented as CH_4. EIA has corrected these data in the *Natural Gas Annual* (EIA 2001a) for the years 1998 and 1999 only. Data for 1990 through 1997 were adjusted by assuming a proportionate share of CO_2 in the flare gas for those years as for 1998 and 1999. The adjusted values are provided in Table 2-37. The emission and thermal conversion factors were also provided by EIA (2001) and are included in Table 2-37.

Table 2-35: CO_2 Emissions from Natural Gas Flaring

Year	Tg CO_2 Eq.	Gg
1990	5.5	5,514
1995	8.7	8,729
1996	8.2	8,233
1997	7.6	7,565
1998	6.3	6,250
1999	6.7	6,679
2000	6.1	6,059

EPA (2001) provided emission estimates for NO_x, CO, and NMVOCs from petroleum refining, petroleum product storage and transfer, and petroleum marketing operations. Included are gasoline, crude oil and distillate fuel oil storage and transfer operations, gasoline bulk terminal and bulk plants operations, and retail gasoline service stations operations.

Uncertainty

Uncertainties in CO_2 emission estimates primarily arise from assumptions concerning the flaring efficiency and the correction factor applied to 1990-1997 venting and flaring data. Uncertainties in ambient air pollutant emission estimates are partly due to the accuracy of the emission factors used and projections of growth.

Indirect CO_2 from CH_4 Oxidation

Indirect CO_2 emissions are formed in the atmosphere from the oxidation of methane (CH_4). Although this indirect CO_2 is a greenhouse gas, its generation is not accounted for within the global warming potential (GWP) of CH_4. Thus for the sake of completion, it is necessary to account for these indirect emissions whenever anthropogenic sources of CH_4 are calculated.

Indirect CO_2 emissions from CH_4 oxidation originating from non-combustion fossil sources—coal mining, natural gas systems, petroleum systems, petrochemical production, and silicon carbide production—are included in this estimate. Methane is also emitted from stationary and mobile combustion sources (e.g., natural gas-fired boilers, gasoline fueled vehicles), and from several managed biological

Table 2-36: NO_x, NMVOCs, and CO Emissions from Oil and Gas Activities (Gg)

Year	NO_x	CO	NMVOCs
1990	139	302	555
1995	100	316	582
1996	126	321	433
1997	130	333	442
1998	130	332	440
1999	130	332	385
2000	132	335	393

Table 2-37: Total Natural Gas Reported Vented and Flared (Million Ft^3) and Thermal Conversion Factor (Btu/Ft^3)

Year	Vented and Flared (original)	Vented and Flared (revised)*	Thermal Conversion Factor
1990	150,415	91,130	1,106
1991	169,909	92,207	1,108
1992	167,519	83,363	1,110
1993	226,743	108,238	1,106
1994	228,336	109,493	1,105
1995	283,739	144,265	1,106
1996	272,117	135,709	1,109
1997	256,351	124,918	1,107
1998	103,019	103,019	1,109
1999	110,285	110,285	1,107
2000	100,048	100,048	1,107

* Wyoming venting and flaring estimates were revised. See text for further explanation.

systems (e.g., livestock, rice cultivation), but CO_2 produced through oxidation of CH_4 from these sources is excluded because:

- Indirect CO_2 emissions from CH_4 emitted by combustion sources are accounted for within the Carbon Dioxide from Fossil Fuel Combustion section in the assumption that all carbon containing gaseous combustion products are eventually oxidized to CO_2 in the atmosphere (see Annex A).
- Methane from biological systems is derived from rapidly cycling (non-fossil) sources. For example, the carbon content of methane from enteric fermentation is derived from plant matter, which has converted atmospheric CO_2 to organic compounds. Anthropogenic activity (e.g., management of a biological system) converts the atmospheric CO_2 to CH_4 and thus is counted in the Inventory. The subsequent atmospheric oxidation of CH_4 merely completes the natural cycle.

In addition to oxidation of CH_4, indirect CO_2 emissions can also result from emissions of carbon monoxide (CO) and non-methane volatile organic compounds (NMVOCs). However, CO_2 from non-combustion emissions of CO and NMVOCs are not included in this section because they are explicitly included in the mass balance used in calculating the storage and emissions from non-energy uses of fossil fuels, with the carbon components of CO and NMVOC counted as CO_2 emissions in the mass balance. Thus, it would be double-counting to include them in the indirect CO_2 emissions estimates presented in this section.[40] If reported separately, indirect CO_2 emissions from applicable CO and NMVOC sources—primarily from industrial processes and solvent use—would be 31.1 and 28.1 Tg of CO_2 in 2000.

Total CH_4 emissions from non-combustion fossil sources, gathered from the respective sections of this Inventory, are presented in Table 2-38. Indirect CO_2 emissions from those sources are summarized in Table 2-39 and Table 2-40.

Methodology

Indirect emissions of CO_2 are calculated by applying a factor of 44/16, which is the ratio of molecular weight of CO_2 to the molecular weight of CH_4, to the appropriate methane emissions. The methodology for calculating the methane emissions is presented within the respective sections of this Inventory. For the purposes of the calculation, it is assumed that CH_4 emitted to the atmosphere from non-combustion fossil processes is oxidized to CO_2 in the same year that it is emitted. This is a simplification, because the average atmospheric lifetime of methane is actually on the order of 12 years.

The IPCC Guidelines for Greenhouse Gas Inventories (IPCC/UNEP/OECD/IEA 1997) makes passing references to issues of "double counting carbon" in estimating CO_2 emissions from fossil fuel combustion. In one case, by double counting, the IPCC is referring to the fact that some carbon during the combustion is actually emitted as CH_4, CO, and NMVOCs. The IPCC also assumes that the carbon in these compounds is assumed to eventually oxidizes to CO_2 in the atmosphere. Therefore in the case of emissions from fossil fuel combustion, the carbon is intentionally double counted (e.g., once as an atom in a CH_4 molecule and once in a CO_2 molecule) in order to develop a more comprehensive estimate of the long-term CO_2 burden in the atmosphere and the radiative forcing effects of fossil fuel combustion emissions.

Table 2-38: CH_4 Emissions from Non-Combustion Fossil Sources (Gg)

Source	1990		1995	1996	1997	1998	1999	2000
Coal Mining	4,149		3,502	3,255	3,244	3,235	3,033	2,903
Natural Gas Systems	5,772		5,984	6,030	5,845	5,820	5,646	5,541
Petroleum Systems	1,258		1,154	1,145	1,144	1,114	1,061	1,041
Petrochemical Production	56		72	75	77	78	79	79
Silicon Carbide Production	1		1	1	1	1	1	1
Total	**11,236**		**10,712**	**10,506**	**10,311**	**10,248**	**9,820**	**9,564**

Note: These emissions are accounted for under their respective source categories. Totals may not sum due to independent rounding.

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[40] See Annex B for a more detailed discussion on accounting for indirect emissions from CO and NMVOCs.

Table 2-39: Indirect CO_2 Emissions from Non-Combustion Fossil Methane Sources (Gg)

Source	1990	1995	1996	1997	1998	1999	2000
Coal Mining	11,409	9,630	8,951	8,922	8,897	8,340	7,984
Natural Gas Systems	15,873	16,456	16,581	16,073	16,005	15,527	15,237
Petroleum Systems	3,460	3,173	3,149	3,146	3,063	2,917	2,862
Petrochemical Production	153	197	207	211	215	218	217
Silicon Carbide Production	3	2	2	2	2	2	1
Total	**30,899**	**29,458**	**28,891**	**28,354**	**28,183**	**27,004**	**26,302**

Note: Totals may not sum due to independent rounding.

Table 2-40: Indirect CO_2 Emissions from Non-Combustion Fossil Methane Sources (Tg CO_2 Eq.)

Source	1990	1995	1996	1997	1998	1999	2000
Coal Mining	11.4	9.6	9.0	8.9	8.9	8.3	8.0
Natural Gas Systems	15.9	16.5	16.6	16.1	16.0	15.5	15.2
Petroleum Systems	3.5	3.2	3.1	3.1	3.1	2.9	2.9
Petrochemical Production	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Silicon Carbide Production	+	+	+	+	+	+	+
Total	**30.9**	**29.5**	**28.9**	**28.4**	**28.2**	**27.0**	**26.3**

Note: Totals may not sum due to independent rounding.
+ Does not exceed 0.05 Tg CO_2 Eq.

The IPCC, though, points out that this approach misses the indirect CO_2 emitted from sources other than fossil fuel combustion, such as venting of CH_4 from natural gas and petroleum systems and coal mines. It also misses biogenic sources of CH_4, CO and NMVOCs, such as enteric fermentation in ruminant livestock and decomposition of organic wastes in landfills. The exclusion of biogenic emissions is appropriate, however, given the cyclical nature and probable net zero effect on the atmospheric CO_2 burden.

It should be noted that the climate forcing caused by CO_2 produced from the oxidation of CH_4 is not included in these GWP estimates. As discussed in IPCC (1996), it is often the case that this CO_2 is included in national carbon production inventories. Therefore, depending on how the inventories are combined, including CO_2 production from CH_4 could result in double counting this CO_2 (IPCC 2001).

Data Sources

Data sources for estimating methane emissions from non-combustion processes are summarized in other sections of this Inventory. Methane emissions from coal mining, natural gas systems, and petroleum systems are summarized in this chapter and described in detail in Annexes E, F, and G, respectively. Methane emissions from petrochemicals production and from silicon carbide production are discussed in the Industrial Processes chapter.

Uncertainty

The two principal sources of uncertainty in the estimate of indirect CO_2 emissions are the extent to which methane emissions are included in the overall carbon emissions calculated as CO_2 for combustion sources, and the time frame in which the methane is assumed to oxidize to CO_2 once emitted to the atmosphere. It is assumed that 100 percent of the methane emissions from combustion sources are accounted for in the overall carbon emissions calculated as CO_2 for sources using emission factors and carbon mass balances. However, it may be the case for some types of combustion sources that the oxidation factors used for calculating CO_2 emissions do not accurately account for the full mass of carbon emitted in gaseous form (i.e., partially oxidized or still in hydrocarbon form). Also, the indirect CO_2 emission calculation is based on the assumption that the methane is completely oxidized to CO_2 in the same year that it is emitted to the atmosphere, but its average atmospheric lifetime is approximately 12 years.

International Bunker Fuels

Emissions resulting from the combustion of fuels used for international transport activities, termed international bunker fuels under the United Nations Framework Convention on Climate Change (UNFCCC), are currently not included in national emission totals, but are reported separately based upon location of fuel sales. The decision to report emissions from international bunker fuels separately, instead of allocating them to a particular country, was made by the Intergovernmental Negotiating Committee in establishing the Framework Convention on Climate Change.[41] These decisions are reflected in the *Revised 1996 IPCC Guidelines*, in which countries are requested to report emissions from ships or aircraft that depart from their ports with fuel purchased within national boundaries and are engaged in international transport separately from national totals (IPCC/UNEP/OECD/IEA 1997).[42]

Greenhouse gases emitted from the combustion of international bunker fuels, like other fossil fuels, include carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), carbon monoxide (CO), oxides of nitrogen (NO_x), non-methane volatile organic compounds (NMVOCs), particulate matter, and sulfur dioxide (SO_2).[43] Two transport modes are addressed under the IPCC definition of international bunker fuels: aviation and marine. Emissions from ground transport activities—by road vehicles and trains—even when crossing international borders are allocated to the country where the fuel was loaded into the vehicle and, therefore, are not counted as bunker fuel emissions.

The IPCC Guidelines distinguish between different modes of air traffic. Civil aviation comprises aircraft used for the commercial transport of passengers and freight, military aviation comprises aircraft under the control of national armed forces, and general aviation applies to recreational and small corporate aircraft. The IPCC Guidelines further define international bunker fuel use from civil aviation as the fuel combusted for civil (e.g., commercial) aviation purposes by aircraft arriving or departing on international flight segments. However, as mentioned above, and in keeping with the IPCC Guidelines, only the fuel purchased in the United States and used by aircraft taking-off (i.e., departing) from the United States are reported here. The standard fuel used for civil aviation is kerosene-type jet fuel, while the typical fuel used for general aviation is aviation gasoline.[44]

Emissions of CO_2 from aircraft are essentially a function of fuel use. Methane, N_2O, CO, NO_x, and NMVOC emissions also depend upon engine characteristics, flight conditions, and flight phase (i.e., take-off, climb, cruise, decent, and landing). Methane, CO, and NMVOCs are the product of incomplete combustion and occur mainly during the landing and take-off phases. In jet engines, N_2O and NO_x are primarily produced by the oxidation of atmospheric nitrogen, and the majority of emissions occur during the cruise phase. The impact of NO_x on atmospheric chemistry depends on the altitude of the actual emission. The cruising altitude of supersonic aircraft, near or in the ozone layer, is higher than that of subsonic aircraft. At this higher altitude, NO_x emissions contribute to stratospheric ozone depletion.[45] At the cruising altitudes of subsonic aircraft, however, NO_x emissions contribute to the formation of tropospheric ozone. At these lower altitudes, the positive radiative forcing effect of ozone has enhanced the anthropogenic greenhouse gas forcing.[46] The vast majority of aircraft NO_x emissions occur at these lower cruising altitudes of commercial subsonic aircraft (NASA 1996).[47]

International marine bunkers comprise emissions from fuels burned by ocean-going ships of all flags that are engaged in international transport. Ocean-going ships are

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[41] See report of the Intergovernmental Negotiating Committee for a Framework Convention on Climate Change on the work of its ninth session, held at Geneva from 7 to 18 February 1994 (A/AC.237/55, annex I, para. 1c) (contact secretariat@unfccc.de).

[42] Note that the definition of international bunker fuels used by the UNFCCC differs from that used by the International Civil Aviation Organization.

[43] Sulfur dioxide emissions from jet aircraft and marine vessels, although not estimated here, are mainly determined by the sulfur content of the fuel. In the U.S., jet fuel, distillate diesel fuel, and residual fuel oil average sulfur contents of 0.05, 0.3, and 2.3 percent, respectively. These percentages are generally lower than global averages.

[44] Naphtha-type jet fuel was used in the past by the military in turbojet and turboprop aircraft engines.

[45] In 1996, there were only around a dozen civilian supersonic aircraft in service around the world which flew at these altitudes, however.

[46] However, at this lower altitude, ozone does little to shield the earth from ultraviolet radiation.

[47] Cruise altitudes for civilian subsonic aircraft generally range from 8.2 to 12.5 km (27,000 to 41,000 feet).

generally classified as cargo and passenger carrying, military (i.e., Navy), fishing, and miscellaneous support ships (e.g., tugboats). For the purpose of estimating greenhouse gas emissions, international bunker fuels are solely related to cargo and passenger carrying vessels, which is the largest of the four categories, and military vessels. Two main types of fuels are used on sea-going vessels: distillate diesel fuel and residual fuel oil. Carbon dioxide is the primary greenhouse gas emitted from marine shipping. In comparison to aviation, the atmospheric impacts of NO_x from shipping are relatively minor, as the emissions occur at ground level.

Overall, aggregate greenhouse gas emissions in 2000 from the combustion of international bunker fuels from both aviation and marine activities were 101.2 Tg CO_2 Eq., or 12 percent below emissions in 1990 (see Table 2-41). Although emissions from international flights departing from the United States have increased significantly (23 percent), emissions from international shipping voyages departing the United States have decreased by 36 percent since 1990. Increased military activity during the Persian Gulf War resulted in an increased level of military marine emissions in 1990 and 1991; civilian marine emissions during this period exhibited a similar trend.[48] The majority of these emissions were in the form of carbon dioxide; however, small amounts of CH_4 and N_2O were also emitted. Emissions of NO_x by aircraft during idle, take-off, landing and at cruising altitudes are of primary concern because of their effects on ground-level ozone formation (see Table 2-42).

Emissions from both aviation and marine international transport activities are expected to grow in the future, as both air traffic and trade increase, although emission rates should decrease over time due to technological changes.[49]

Methodology

Emissions of CO_2 were estimated through the application of carbon content and fraction oxidized factors to fuel consumption activity data. This approach is analogous to that described under CO_2 from Fossil Fuel Combustion. A complete description of the methodology and a listing of the various factors employed can be found in Annex A. See Annex I for a specific discussion on the methodology used for estimating emissions from international bunker fuel use by the U.S. military.

Emission estimates for CH_4, N_2O, CO, NO_x, and NMVOCs were calculated by multiplying emission factors by measures of fuel consumption by fuel type and mode. Activity data for aviation included solely jet fuel consumption statistics, while the marine mode included both distillate diesel and residual fuel oil.

Data Sources

Carbon content and fraction oxidized factors for jet fuel, distillate fuel oil, and residual fuel oil were taken directly from the Energy Information Administration (EIA) of the U.S. Department of Energy and are presented in Annex A. Heat content and density conversions were taken from EIA (2001) and USAF (1998). Emission factors used in the calculations of CH_4, N_2O, CO, NO_x, and NMVOC emissions were obtained from the *Revised 1996 IPCC Guidelines* (IPCC/UNEP/OECD/IEA 1997). For aircraft emissions, the following values, in units of grams of pollutant per kilogram of fuel consumed (g/kg), were employed: 0.09 for CH_4, 0.1 for N_2O, 5.2 for CO, 12.5 for NO_x, and 0.78 for NMVOCs. For marine vessels consuming either distillate diesel or residual fuel oil the following values, in the same units, except where noted, were employed: 0.32 for CH_4, 0.08 for N_2O, 1.9 for CO, 87 for NO_x, and 0.052 g/MJ for NMVOCs.

Activity data on aircraft fuel consumption were collected from three government agencies. Jet fuel consumed by U.S. flag air carriers for international flight segments was supplied by the Bureau of Transportation Statistics (DOT 1991 through 2001). It was assumed that 50 percent of the fuel used by U.S. flagged carriers for international flights—both departing and arriving in the United States—was purchased

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[48] See Uncertainty section for a discussion of data quality issues.

[49] Most emission related international aviation and marine regulations are under the rubric of the International Civil Aviation Organization (ICAO) or the International Maritime Organization (IMO), which develop international codes, recommendations, and conventions, such as the International Convention of the Prevention of Pollution from Ships (MARPOL).

Table 2-41: Emissions from International Bunker Fuels (Tg CO_2 Eq.)

Gas/Mode	1990	1995	1996	1997	1998	1999	2000
CO_2	**113.9**	**101.0**	**102.3**	**109.9**	**112.9**	**105.3**	**100.2**
Aviation	46.6	51.1	52.2	55.9	55.0	58.9	57.3
Marine	67.3	49.9	50.1	54.0	57.9	46.4	43.0
CH_4	**0.2**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Aviation	+	+	+	+	+	+	+
Marine	0.1	0.1	0.1	0.1	0.1	0.1	0.1
N_2O	**1.0**	**0.9**	**0.9**	**1.0**	**1.0**	**0.9**	**0.9**
Aviation	0.5	0.5	0.5	0.5	0.5	0.6	0.6
Marine	0.5	0.4	0.4	0.4	0.4	0.4	0.3
Total	**115.0**	**102.1**	**103.3**	**111.0**	**114.0**	**106.4**	**101.2**

+ Does not exceed 0.05 Tg CO_2 Eq.
Note: Totals may not sum due to independent rounding. Includes aircraft cruise altitude emissions.

Table 2-42: Emissions from International Bunker Fuels (Gg)

Gas/Mode	1990	1995	1996	1997	1998	1999	2000
CO_2	**113,863**	**101,037**	**102,272**	**109,885**	**112,913**	**105,341**	**100,228**
Aviation	46,591	51,117	52,164	55,925	55,012	58,913	57,274
Marine	67,272	49,921	50,109	53,960	57,900	46,429	42,954
CH_4	**8**	**6**	**6**	**7**	**7**	**6**	**6**
Aviation	1	1	1	2	2	2	2
Marine	7	5	5	5	6	5	4
N_2O	**3**	**3**	**3**	**3**	**3**	**3**	**3**
Aviation	1	2	2	2	2	2	2
Marine	2	1	1	1	1	1	1
CO	**116**	**113**	**115**	**124**	**125**	**124**	**120**
Aviation	77	84	86	92	91	97	94
Marine	39	29	29	32	34	27	25
NO_x	**1,987**	**1,541**	**1,549**	**1,667**	**1,771**	**1,478**	**1,379**
Aviation	184	202	207	222	218	233	227
Marine	1,803	1,339	1,343	1,446	1,553	1,244	1,152
NMVOC	**59**	**48**	**49**	**52**	**55**	**48**	**45**
Aviation	11	13	13	14	14	15	14
Marine	48	36	36	38	41	33	31

Note: Totals may not sum due to independent rounding. Includes aircraft cruise altitude emissions.

domestically for flights departing from the United States. In other words, only one-half of the total annual fuel consumption estimate was used in the calculations. Data on jet fuel expenditures by foreign flagged carriers departing U.S. airports was taken from unpublished data collected by the Bureau of Economic Analysis (BEA) under the U.S. Department of Commerce (BEA 1991 through 2001). Approximate average fuel prices paid by air carriers for aircraft on international flights was taken from DOT (1991 through 2001) and used to convert the BEA expenditure data to gallons of fuel consumed. Data on U.S. Department of Defense (DoD) aviation bunker fuels and total jet fuel consumed by the U.S. military was supplied by the Office of the Under Secretary of Defense (Installations and Environment), DoD. Estimates of the percentage of each services' total operations that were international operations were developed by DoD. Military aviation bunkers included international operations, operations conducted from naval vessels at sea, and operations conducted from U.S. installations principally over international water in direct support of military operations at sea. Military aviation bunker fuel emissions were estimated using military fuel and operations data synthesized from unpublished data by the Defense Energy Support Center, under DoD's Defense Logistics Agency (DESC 2001), and by the Naval Operations Navy Strategic Mobility/Combat Logistics Division (N42

2001). Together, the data allow the quantity of fuel used in military international operations to be estimated. Densities for each jet fuel type were obtained from a report from the U.S. Air Force (USAF 1998). Final jet fuel consumption estimates are presented in Table 2-43. See Annex I for additional discussion of military data.

Activity data on distillate diesel and residual fuel oil consumption by cargo or passenger carrying marine vessels departing from U.S. ports were taken from unpublished data collected by the Foreign Trade Division of the U.S. Department of Commerce's Bureau of the Census (DOC 1991 through 2001). Activity data on distillate diesel consumption by military vessels departing from U.S. ports were provided by DESC (2001) and N42 (2001). The total amount of fuel provided to naval vessels was reduced by 13 percent to account for fuel used while the vessels were not-underway (i.e., in port). Data on the percentage of steaming hours underway versus not-underway were provided by the U.S. Navy. These fuel consumption estimates are presented in Table 2-44.

Uncertainty

Emission estimates related to the consumption of international bunker fuels are subject to the same uncertainties as those from domestic aviation and marine mobile combustion emissions; however, additional uncertainties result from the difficulty in collecting accurate fuel consumption activity data for international transport activities separate from domestic transport activities.[50] For example, smaller aircraft on shorter routes often carry sufficient fuel to complete several flight segments without refueling in order to minimize time spent at the airport gate or take advantage of lower fuel prices at particular airports. This practice, called tankering, when done on international flights, complicates the use of fuel sales data for estimating bunker fuel emissions. Tankering is less common with the type of large, long-range aircraft that make many international flights from the United States, however. Similar practices occur in the marine shipping industry where fuel costs represent a significant portion of overall operating costs and fuel prices vary from port to port, leading to some tankering from ports with low fuel costs.

Particularly for aviation, the DOT (1991 through 2001) international flight segment fuel data used for U.S. flagged carriers does not include smaller air carriers and unfortunately defines flights departing to Canada and some flights to Mexico as domestic instead of international. As for the BEA (1991 through 2001) data on foreign flagged carriers, there is some uncertainty as to the average fuel price, and to the completeness of the data. It was also not possible to

Table 2-43: Aviation Jet Fuel Consumption for International Transport (Million Gallons)

Nationality	1990	1995	1996	1997	1998	1999	2000
U.S. Carriers	1,982	2,256	2,329	2,482	2,363	2,638	2,740
Foreign Carriers	2,062	2,549	2,629	2,918	2,935	3,085	2,818
U.S. Military	862	581	540	496	502	488	480
Total	**4,905**	**5,385**	**5,497**	**5,895**	**5,799**	**6,211**	**6,038**

Note: Totals may not sum due to independent rounding.

Table 2-44: Marine Fuel Consumption for International Transport (Million Gallons)

End-Use Sector	1990	1995	1996	1997	1998	1999	2000
Residual Fuel Oil	4,781	3,495	3,583	3,843	3,974	3,272	2,967
Distillate Diesel Fuel & Other	617	573	456	421	627	308	290
U.S. Military Naval Fuels	522	334	367	484	518	511	537
Total	**5,920**	**4,402**	**4,406**	**4,748**	**5,119**	**4,091**	**3,794**

Note: Totals may not sum due to independent rounding.

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[50] See uncertainty discussions under CO_2 from Fossil Fuel Combustion and Mobile Combustion.

determine what portion of fuel purchased by foreign carriers at U.S. airports was actually used on domestic flight segments; this error, however, is believed to be small.[51]

Uncertainties exist with regard to the total fuel used by military aircraft and ships, and in the activity data on military operations and training that were used to estimate percentages of total fuel use reported as bunker fuel emissions. There are also uncertainties in fuel end-uses by fuel-type, emissions factors, fuel densities, diesel fuel sulfur content, aircraft and vessel engine characteristics and fuel efficiencies, and the methodology used to back-calculate the data set to 1990. All assumptions used to develop the estimate were based on process knowledge, Department and military service data, and expert judgments. The magnitude of the potential errors related to the various uncertainties has not been calculated, but is believed to be small. The uncertainties associated with future military bunker fuel emissions estimates could be reduced through additional data collection.

Aircraft and ship fuel data were developed from DoD records, which document fuel sold to the Navy and Air Force by the Defense Logistics Agency. This data may slightly over or under estimate actual fuel use in aircraft and ships because each service may have procured fuel from, sold to, traded, or given fuel to other ships, aircraft, governments, or other entities. Small fuel quantities may have been used in vehicles or equipment other than that which was assumed for each fuel type. In particular, the marine fuel data provided by the Navy Fuels and Logistics office (N42 2001) were inconsistent with previous years' data.

There are also uncertainties in aircraft operations and training activity data. Estimates for the quantity of fuel used in Navy and Air Force flying activities reported as bunker fuel emissions was estimated based on a combination of available data and expert judgment.

Estimates of marine bunker fuel emissions were based on Navy vessel steaming hour data that reports fuel used while underway and fuel used while not underway. This approach does not capture some voyages that would be classified as domestic for a commercial vessel. Conversely, emissions from fuel used while not underway preceding an international voyage are reported as domestic rather than international, as would be done for a commercial vessel.

There is also uncertainty in the methodology used to estimate emissions for 1990 through 1994. These emissions were estimated based on the 1995 values of the original data set and extrapolated back in time based on a closely correlated data set of fuel usage.

Although aggregate fuel consumption data has been used to estimate emissions from aviation, the recommended method for estimating emissions of gases other than CO_2 in the *Revised 1996 IPCC Guidelines* is to use data by specific aircraft type (IPCC/UNEP/OECD/IEA 1997). The IPCC also recommends that cruise altitude emissions be estimated

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[51] Although foreign flagged air carriers are prevented from providing domestic flight services in the United States, passengers may be collected from multiple airports before an aircraft actually departs on its international flight segment. Emissions from these earlier domestic flight segments should be classified as domestic, not international, according to the IPCC.

[52] It should be noted that in the EPA's *National Air Pollutant Emissions Trends, 1900-2000* (EPA 2001), U.S. aviation emission estimates for CO, NOx, and NMVOCs are based solely upon LTO cycles and consequently only capture near ground-level emissions, which are more relevant for air quality evaluations. These estimates also include both domestic and international flights. Therefore, estimates given under Mobile Source Fossil Fuel Combustion overestimate IPCC-defined domestic CO, NO_x, and NMVOC emissions by including landing and take-off (LTO) cycles by aircraft on international flights but underestimate because they do not include emissions from aircraft on domestic flight segments at cruising altitudes. EPA (2001) is also likely to include emissions from ocean-going vessels departing from U.S. ports on international voyages.

separately using fuel consumption data, while landing and take-off (LTO) cycle data be used to estimate near-ground level emissions of gases other than CO_2.[52]

There is also concern as to the reliability of the existing DOC (1991 through 2001) data on marine vessel fuel consumption reported at U.S. customs stations due to the significant degree of inter-annual variation.

Wood Biomass and Ethanol Consumption

The combustion of biomass fuels—such as wood, charcoal, and wood waste—and biomass-based fuels—such as ethanol from corn and woody crops—generates carbon dioxide (CO_2). However, in the long run the carbon dioxide emitted from biomass consumption does not increase atmospheric carbon dioxide concentrations, assuming the biogenic carbon emitted is offset by the uptake of CO_2 resulting from the growth of new biomass. As a result, CO_2 emissions from biomass combustion have been estimated separately from fossil fuel-based emissions and are not included in the U.S. totals. Net carbon fluxes from changes in biogenic carbon reservoirs in wooded or crop lands are accounted for in the Land-Use Change and Forestry chapter.

In 2000, CO_2 emissions due to burning of woody biomass within the industrial and residential/commercial sectors and by electricity generation were about 174.8 Tg CO_2 Eq. (174,770 Gg) (see Table 2-45 and Table 2-46). As the largest consumer of woody biomass, the industrial sector in 2000 was responsible for 78 percent of the CO_2 emissions from this source. The residential sector was the second largest emitter, making up 20 percent of total emissions from woody biomass. The commercial end-use sector and electricity generation accounted for the remainder.

Biomass-derived fuel consumption in the United States consisted mainly of ethanol use in the transportation sector. Ethanol is primarily produced from corn grown in the Midwest, and was used mostly in the Midwest and South. Pure ethanol can be combusted, or it can be mixed with gasoline as a supplement or octane-enhancing agent. The most common mixture is a 90 percent gasoline, 10 percent ethanol blend known as gasohol. Ethanol and ethanol blends are often used to fuel public transport vehicles such as buses, or centrally fueled fleet vehicles. Ethanol and ethanol blends burn cleaner than gasoline (i.e., lower in NO_x and hydrocarbon emissions), and have been employed in urban areas with poor air quality. However, because ethanol is a hydrocarbon fuel, its combustion emits CO_2.

Table 2-45: CO_2 Emissions from Wood Consumption by End-Use Sector (Tg CO_2 Eq.)

End-Use Sector	1990	1995	1996	1997	1998	1999	2000
Industrial	100.2	112.0	115.1	120.9	124.9	136.7	136.0
Residential	46.4	47.6	47.5	34.6	30.9	33.1	34.6
Commercial	3.0	3.6	3.9	3.8	3.7	4.1	4.1
Electricity Generation	+	+	+	+	+	+	+
Total	**149.6**	**163.3**	**166.6**	**159.3**	**159.6**	**173.9**	**174.8**

Note: Totals may not sum due to independent rounding.

Table 2-46: CO_2 Emissions from Wood Consumption by End-Use Sector (Gg)

End-Use Sector	1990	1995	1996	1997	1998	1999	2000
Industrial	100,204	112,038	115,145	120,908	124,933	136,740	135,964
Residential	46,424	47,622	47,542	34,598	30,933	33,070	34,626
Commercial	2,956	3,596	3,899	3,752	3,717	4,099	4,148
Electricity Generation	25	30	30	28	26	31	33
Total	**149,609**	**163,286**	**166,617**	**159,286**	**159,610**	**173,940**	**174,770**

Note: Totals may not sum due to independent rounding.

Table 2-47: CO_2 Emissions from Ethanol Consumption

Year	Tg CO_2 Eq.	Gg
1990	4.4	4,380
1995	8.1	8,099
1996	5.8	5,809
1997	7.4	7,356
1998	8.1	8,128
1999	8.5	8,451
2000	9.7	9,667

In 2000, the United States consumed an estimated 139 trillion Btus of ethanol. Emissions of CO_2 in 2000 due to ethanol fuel burning were estimated to be approximately 9.7 Tg CO_2 Eq. (8,451 Gg) (see Table 2-47).

Ethanol production dropped sharply in the middle of 1996 because of short corn supplies and high prices. Plant output began to increase toward the end of the growing season, reaching close to normal levels at the end of the year. However, total 1996 ethanol production fell far short of the 1995 level (EIA 1997). Since the low in 1996, production has continued to grow.

Methodology

Woody biomass emissions were estimated by converting U.S. consumption data in energy units (17.2 million Btu per short ton) to megagrams (Mg) of dry matter using EIA assumptions. Once consumption data for each sector were converted to megagrams of dry matter, the carbon content of the dry fuel was estimated based on default values of 45 to 50 percent carbon in dry biomass. The amount of carbon released from combustion was estimated using 90 percent for the fraction oxidized (i.e., combustion efficiency). Ethanol consumption data in energy units were also multiplied by a carbon coefficient (18.96 mg C/Btu) to produce carbon emission estimates.

Data Sources

Woody biomass consumption data were provided by EIA (2001) (see Table 2-48). Estimates of wood biomass consumption for fuel combustion do not include wood wastes, liquors, municipal solid waste, tires, etc. that are reported as biomass by EIA. The factor for converting energy units to mass was supplied by EIA (1994). Carbon content and combustion efficiency values were taken from the *Revised 1996 IPCC Guidelines* (IPCC/UNEP/OECD/IEA 1997).

Table 2-49: Ethanol Consumption

Year	Trillion Btu
1990	63
1991	73
1992	83
1993	97
1994	109
1995	117
1996	84
1997	106
1998	117
1999	122
2000	139

Table 2-48: Woody Biomass Consumption by Sector (Trillion Btu)

Year	Industrial	Residential	Commercial	Electric Generation
1990	1,254	581	37	NO
1991	1,190	613	39	NO
1992	1,233	645	42	NO
1993	1,255	548	44	NO
1994	1,342	537	45	NO
1995	1,402	596	45	NO
1996	1,441	595	49	NO
1997	1,513	433	47	NO
1998	1,564	387	47	NO
1999	1,711	414	51	NO
2000	1,702	433	52	NO

NO (Not Occurring)
Emissions from ethanol were estimated using consumption data from EIA (2001) (see Table 2-49). The carbon coefficient used was provided by OTA (1991).

Uncertainty

The fraction oxidized (i.e., combustion efficiency) factor used is believed to under estimate the efficiency of wood combustion processes in the United States. The IPCC emission factor has been used because better data are not yet available. Increasing the combustion efficiency would increase emission estimates. In addition, according to EIA (1994) commercial wood energy use is typically not reported because there are no accurate data sources to provide reliable estimates. Emission estimates from ethanol production are more certain than estimates from woody biomass consumption due to better activity data collection methods and uniform combustion techniques.