3. Energy

Energy-related activities were the primary sources of U.S. anthropogenic greenhouse gas emissions, accounting for 86.7 percent of total greenhouse gas emissions on a carbon dioxide (CO_2) equivalent basis[52] in 2009. This included 98, 49, and 13 percent of the nation's 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 CO_2 equivalent basis, while the non-CO_2 emissions from energy-related activities represented a much smaller portion of total national emissions (5.6 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 3-1). Globally, approximately 30,398 Tg of CO_2 were added to the atmosphere through the combustion of fossil fuels in 2009, of which the United States accounted for about 18 percent.[53] Due to their relative importance, fossil fuel combustion-related CO_2 emissions are considered separately, and in more detail than other energy-related emissions (see Figure 3-2). Fossil fuel combustion also emits CH_4 and N_2O, and mobile fossil fuel combustion was the second largest source of N_2O emissions in the United States.

Figure 3-1: 2009 Energy Chapter Greenhouse Gas Sources

Figure 3-2: 2009 U.S. Fossil Carbon Flows (Tg CO_2 Eq.)

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 fugitive CH_4 from natural gas systems, petroleum systems, and coal mining.

Table 3-1 summarizes emissions from the Energy sector in units of teragrams (or million metric tons) of CO_2 equivalents (Tg CO_2 Eq.), while unweighted gas emissions in gigagrams (Gg) are provided in Table 3-2. Overall, emissions due to energy-related activities were 5,751.1 Tg CO_2 Eq. in 2009, an increase of 9 percent since 1990.

Table 3-1: CO_2, CH_4, and N_2O Emissions from Energy (Tg CO_2 Eq.)

Gas/Source	1990	2000	2005	2006	2007	2008	2009
CO_2	**4,903.2**	**5,781.3**	**5,939.4**	**5,842.5**	**5,938.2**	**5,752.3**	**5,377.3**
Fossil Fuel Combustion	4,738.4	5,594.8	5,753.2	5,653.1	5,756.7	5,565.9	5,209.0
Electricity Generation	1,820.8	2,296.9	2,402.1	2,346.4	2,412.8	2,360.9	2,154.0
Transportation	1,485.9	1,809.5	1,896.6	1,878.1	1,894.0	1,789.9	1,719.7
Industrial	846.5	851.1	823.1	848.2	842.0	802.9	730.4
Residential	338.3	370.7	357.9	321.5	342.4	348.2	339.2
Commercial	219.0	230.8	223.5	208.6	219.4	224.2	224.0
U.S. Territories	27.9	35.9	50.0	50.3	46.1	39.8	41.7
Non-Energy Use of Fuels	118.6	144.9	143.4	145.6	137.2	141.0	123.4
Natural Gas Systems	37.6	29.9	29.9	30.8	31.1	32.8	32.2
Incineration of Waste	8.0	11.1	12.5	12.5	12.7	12.2	12.3
Petroleum Systems	0.6	0.5	0.5	0.5	0.5	0.5	0.5
Biomass - Wood[*]	*215.2*	*218.1*	*206.9*	*203.8*	*203.3*	*198.4*	*183.8*
International Bunker Fuels[*]	*111.8*	*98.5*	*109.7*	*128.4*	*127.6*	*133.7*	*123.1*
Biomass – Ethanol[*]	*4.2*	*9.4*	*23.0*	*31.0*	*38.9*	*54.8*	*61.2*
CH_4	**327.4**	**318.6**	**291.3**	**319.2**	**307.3**	**323.6**	**336.8**
Natural Gas Systems	189.8	209.3	190.4	217.7	205.2	211.8	221.2

[52] Estimates are presented in units of teragrams of carbon dioxide equivalent (Tg CO_2 Eq.), which weight each gas by its global warming potential, or GWP, value. See section on global warming potentials in the Executive Summary.

[53] Global CO_2 emissions from fossil fuel combustion were taken from Energy Information Administration *International Energy Statistics 2010* < http://tonto.eia.doe.gov/cfapps/ipdbproject/IEDIndex3.cfm> EIA (2010).

Coal Mining	84.1	60.4	56.9	58.2	57.9	67.1	71.0
Petroleum Systems	35.4	31.5	29.4	29.4	30.0	30.2	30.9
Stationary Combustion	7.4	6.6	6.6	6.2	6.5	6.5	6.2
Abandoned Underground Coal Mines	6.0	7.4	5.5	5.5	5.6	5.9	5.5
Mobile Combustion	4.7	3.4	2.5	2.3	2.2	2.0	2.0
Incineration of Waste	+	+	+	+	+	+	+
*International Bunker Fuels**	*0.2*	*0.1*	*0.1*	*0.2*	*0.2*	*0.2*	*0.1*
N_2O	**57.2**	**68.1**	**52.1**	**48.5**	**45.2**	**40.7**	**37.0**
Mobile Combustion	43.9	53.2	36.9	33.6	30.3	26.1	23.9
Stationary Combustion	12.8	14.6	14.7	14.4	14.6	14.2	12.8
Incineration of Waste	0.5	0.4	0.4	0.4	0.4	0.4	0.4
*International Bunker Fuels**	*1.1*	*0.9*	*1.0*	*1.2*	*1.2*	*1.2*	*1.1*
Total	**5,287.8**	**6,168.0**	**6,282.8**	**6,210.2**	**6,290.7**	**6,116.6**	**5,751.1**

+ Does not exceed 0.05 Tg CO_2 Eq.

***** These values are presented for informational purposes only, in line with IPCC methodological guidance and UNFCCC reporting obligations, and are not included in the specific energy sector contribution to the totals, and are already accounted for elsewhere.

Note: Totals may not sum due to independent rounding.

Table 3-2: CO_2, CH_4, and N_2O Emissions from Energy (Gg)

Gas/Source	1990	2000	2005	2006	2007	2008	2009
CO_2	**4,903,171**	**5,781,303**	**5,939,434**	**5,842,464**	**5,938,203**	**5,752,327**	**5,377,271**
Fossil Fuel Combustion	4,738,422	5,594,848	5,753,200	5,653,116	5,756,746	5,565,925	5,208,981
Non-Energy Use of Fuels	118,630	144,933	143,392	145,574	137,233	140,952	123,356
Natural Gas Systems	37,574	29,877	29,902	30,755	31,050	32,828	32,171
Incineration of Waste	7,989	11,112	12,450	12,531	12,700	12,169	12,300
Petroleum Systems	555	534	490	488	474	453	463
*Biomass -Wood**	*215,186*	*218,088*	*206,865*	*203,846*	*203,316*	*198,361*	*183,777*
*International Bunker Fuels**	*111,828*	*98,482*	*109,750*	*128,384*	*127,618*	*133,704*	*123,127*
*Biomass - Ethanol**	*4,229*	*9,352*	*22,956*	*31,002*	*38,946*	*54,770*	*61,231*
CH_4	**15,590**	**15,171**	**13,872**	**15,202**	**14,634**	**15,408**	**16,037**
Natural Gas Systems	9,038	9,968	9,069	10,364	9,771	10,087	10,535
Coal Mining	4,003	2,877	2,710	2,774	2,756	3,196	3,382
Petroleum Systems	1,685	1,501	1,398	1,398	1,427	1,439	1,473
Stationary Combustion	354	315	312	293	308	310	293
Abandoned Underground Coal Mines	288	350	264	261	267	279	262
Mobile Combustion	223	160	119	112	105	97	93
Incineration of Waste	+	+	+	+	+	+	+
*International Bunker Fuels**	*8*	*6*	*7*	*8*	*8*	*8*	*7*
N_2O	**185**	**220**	**168**	**156**	**146**	**131**	**120**
Mobile Combustion	142	172	119	108	98	84	77
Stationary Combustion	41	47	47	47	47	46	41
Incineration of Waste	2	1	1	1	1	1	1
*International Bunker Fuels**	*3*	*3*	*3*	*4*	*4*	*4*	*4*

+ Does not exceed 0.05 Tg CO_2 Eq.

***** These values are presented for informational purposes only, in line with IPCC methodological guidance and UNFCCC reporting obligations, and are not included in the specific energy sector contribution to the totals, and are already accounted for elsewhere.

Note: Totals may not sum due to independent rounding.

3.1. Fossil Fuel Combustion (IPCC Source Category 1A)

Emissions from the combustion of fossil fuels for energy include the gases CO_2, CH_4, and N_2O. Given that CO_2 is the primary gas emitted from fossil fuel combustion and represents the largest share of U.S. total emissions, CO_2 emissions from fossil fuel combustion are discussed at the beginning of this section. Following that is a discussion of emissions of all three gases from fossil fuel combustion presented by sectoral breakdowns. Methodologies for estimating CO_2 from fossil fuel combustion also differ from the estimation of CH_4 and N_2O emissions from stationary combustion and mobile combustion. Thus, three separate descriptions of methodologies, uncertainties, recalculations, and planned improvements are provided at the end of this section. Total CO_2, CH_4, and N_2O emissions from fossil fuel combustion are presented in Table 3-3 and Table 3-4.

Table 3-3: CO_2, CH_4, and N_2O Emissions from Fossil Fuel Combustion (Tg CO_2 Eq.)

Gas	1990	2000	2005	2006	2007	2008	2009
CO_2	4,738.4	5,594.8	5,753.2	5,653.1	5,756.7	5,565.9	5,209.0
CH_4	12.1	10.0	9.1	8.5	8.7	8.5	8.1
N_2O	56.8	67.7	51.7	48.1	44.9	40.4	36.7
Total	**4,807.3**	**5,627.6**	**5,813.9**	**5,709.7**	**5,810.3**	**5,614.8**	**5,253.8**

Note: Totals may not sum due to independent rounding.

Table 3-4: CO_2, CH_4, and N_2O Emissions from Fossil Fuel Combustion (Gg)

Gas	1990	2000	2005	2006	2007	2008	2009
CO_2	4,738,422	5,594,848	5,753,200	5,653,116	5,756,746	5,565,925	5,208,981
CH_4	577	476	431	405	413	407	386
N_2O	183	219	167	155	145	130	118

Note: Totals may not sum due to independent rounding.

CO_2 from Fossil Fuel Combustion

CO_2 is the primary gas emitted from fossil fuel combustion and represents the largest share of U.S. total greenhouse gas emissions. CO_2 emissions from fossil fuel combustion are presented in Table 3-5. In 2009, CO_2 emissions from fossil fuel combustion decreased by 6.4 percent relative to the previous year. This decrease represents the largest annual decrease in CO_2 emissions from fossil fuel combustion for the twenty-year period.[54] The decrease in CO_2 emissions from fossil fuel combustion was a result of multiple factors including: (1) a decrease in economic output resulting in a decrease in energy consumption across all sectors; (2) a decrease in the carbon intensity of fuels used to generate electricity due to fuel switching as the price of coal increased, and the price natural gas decreased significantly; and (3) an increase in non-fossil fuel consumption by approximately 2 percent. In 2009, CO_2 emissions from fossil fuel combustion were 5,209.0 Tg CO_2 Eq., or almost 10 percent above emissions in 1990 (see Table 3-5).[55]

Table 3-5: CO_2 Emissions from Fossil Fuel Combustion by Fuel Type and Sector (Tg CO_2 Eq.)

Fuel/Sector	1990	2000	2005	2006	2007	2008	2009
Coal	**1,718.4**	**2,065.5**	**2,112.3**	**2,076.5**	**2,106.0**	**2,072.5**	**1,841.0**
Residential	3.0	1.1	0.8	0.6	0.7	0.7	0.6
Commercial	12.0	8.8	9.3	6.2	6.7	6.5	5.8
Industrial	155.3	127.3	115.3	112.6	107.0	102.6	83.4
Transportation	NE	NE	NE	NE	NE	NE	NE
Electricity Generation	1,547.6	1,927.4	1,983.8	1,953.7	1,987.3	1,959.4	1,747.6
U.S. Territories	0.6	0.9	3.0	3.4	4.3	3.3	3.5
Natural Gas	**1,000.6**	**1,217.4**	**1,159.0**	**1,141.3**	**1,218.0**	**1,226.0**	**1,200.9**

[54] This decrease also represents the largest absolute and percentage decrease since the beginning of EIA's record of annual energy consumption data, beginning in 1949 (EIA 2010a).

[55] An additional discussion of fossil fuel emission trends is presented in the Trends in U.S. Greenhouse Gas Emissions Chapter.

Residential	238.0	270.7	262.2	237.3	257.0	264.4	257.2
Commercial	142.1	172.5	162.9	153.8	164.0	170.2	167.9
Industrial	409.1	457.2	380.8	377.7	389.0	391.0	365.0
Transportation	36.0	35.6	33.1	33.1	35.3	36.8	36.3
Electricity Generation	175.3	280.8	318.8	338.0	371.3	361.9	373.1
U.S. Territories	NO	0.7	1.3	1.4	1.4	1.6	1.5
Petroleum	**2,019.0**	**2,311.6**	**2,481.5**	**2,434.9**	**2,432.4**	**2,267.1**	**2,166.7**
Residential	97.4	98.8	94.9	83.6	84.6	83.1	81.4
Commercial	64.9	49.6	51.3	48.5	48.7	47.4	50.3
Industrial	282.1	266.6	326.9	357.9	346.0	309.3	282.0
Transportation	1,449.9	1,773.9	1,863.5	1,845.0	1,858.7	1,753.1	1,683.4
Electricity Generation	97.5	88.4	99.2	54.4	53.9	39.2	32.9
U.S. Territories	27.2	34.2	45.7	45.5	40.4	35.0	36.7
Geothermal*	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**
Total	**4,738.4**	**5,594.8**	**5,753.2**	**5,653.1**	**5,756.7**	**5,565.9**	**5,209.0**

NE (Not estimated)
NO (Not occurring)
* 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.

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, in 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, there would likely be 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 aggregate societal trends that affect the scale of consumption (e.g., population, number of cars, size of houses, and number 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).

CO_2 emissions also depend on the source of energy and its carbon (C) intensity. The amount of C in fuels varies significantly by fuel type. For example, coal contains the highest amount of C per unit of useful energy. Petroleum has roughly 75 percent of the C per unit of energy as coal, and natural gas has only about 55 percent.[56] Table 3-6 shows annual changes in emissions during the last five years for coal, petroleum, and natural gas in selected sectors.

Table 3-6: Annual Change in CO_2 Emissions and Total 2009 Emissions from Fossil Fuel Combustion for Selected Fuels and Sectors (Tg CO_2 Eq. and Percent)

Sector	Fuel Type	2005 to 2006		2006 to 2007		2007 to 2008		2008 to 2009		Total 2009
Electricity Generation	Coal	-30.1	-1.5%	33.6	1.7%	-27.9	-1.4%	-211.7	-10.8%	1,747.6
Electricity Generation	Natural Gas	19.2	6.0%	33.3	9.9%	-9.3	-2.5%	11.1	3.1%	373.1
Electricity Generation	Petroleum	-44.8	-45.2%	-0.5	-0.9%	-14.7	-27.2%	-6.3	-16.0%	32.9
Transportation [a]	Petroleum	-18.5	-1.0%	13.7	0.7%	-105.6	-5.7%	-69.7	-4.0%	1,683.4
Residential	Natural Gas	-24.9	-9.5%	19.7	8.3%	7.4	2.9%	-7.3	-2.8%	257.2
Commercial	Natural Gas	-9.1	-5.6%	10.2	6.6%	6.2	3.8%	-2.3	-1.3%	167.9
Industrial	Coal	-2.8	-2.4%	-5.6	-5.0%	-4.4	-4.1%	-19.2	-18.7%	83.4
Industrial	Natural Gas	-3.1	-0.8%	11.3	3.0%	2.0	0.5%	-26.0	-6.6%	365.0
All Sectors [b]	**All Fuels [b]**	**-100.1**	**-1.7%**	**103.6**	**1.8%**	**-190.8**	**-3.3%**	**-356.9**	**-6.4%**	**5,209.0**

[a] Excludes emissions from International Bunker Fuels.
[b] Includes fuels and sectors not shown in table.

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

In the United States, 83 percent of the energy consumed in 2009 was produced through the combustion of fossil fuels such as coal, natural gas, and petroleum (see Figure 3-3 and Figure 3-4). The remaining portion was supplied by nuclear electric power (9 percent) and by a variety of renewable energy sources[57] (8 percent), primarily hydroelectric power and biofuels (EIA 2010). Specifically, petroleum supplied the largest share of domestic energy demands, accounting for an average of 42 percent of total fossil fuel based energy consumption in 2009. Natural gas and coal followed in order of importance, accounting for approximately 32 and 27 percent of total consumption, respectively. Petroleum was consumed primarily in the transportation end-use sector and the vast majority of coal was used in electricity generation. Natural gas was broadly consumed in all end-use sectors except transportation (see Figure 3-5) (EIA 2010).

Figure 3-3: 2009 U.S. Energy Consumption by Energy Source

Figure 3-4: U.S. Energy Consumption (Quadrillion Btu)

Figure 3-5: 2009 CO_2 Emissions from Fossil Fuel Combustion by Sector and Fuel Type

Fossil fuels are generally combusted for the purpose of producing energy for useful heat and work. During the combustion process, the C stored in the fuels is oxidized and emitted as CO_2 and smaller amounts of other gases, including CH_4, CO, and NMVOCs.[58] These other C 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, it is assumed that all of the C in fossil fuels used to produce energy is eventually converted to atmospheric CO_2.

[BEGIN BOX]

Box 3-1: Weather and Non-Fossil Energy Effects on CO_2 from Fossil Fuel Combustion Trends

In 2009, weather conditions remained constant in the winter and slightly cooler in the summer compared to 2008, as heating degree days decreased slightly and cooling degree days decreased by 3.8 percent. Winter conditions were relatively constant in 2009 compared to 2008, and the winter was slightly warmer than normal, with heating degree days in the United States 0.7 percent below normal (see Figure 3-6). Summer conditions were slightly cooler in 2009 compared to 2008, and summer temperatures were slightly cooler than normal, with cooling degree days 1 percent below normal (see Figure 3-7) (EIA 2010).[59]

Figure 3-6: Annual Deviations from Normal Heating Degree Days for the United States (1950–2009)

Figure 3-7: Annual Deviations from Normal Cooling Degree Days for the United States (1950–2009)

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[57] Renewable energy, as defined in EIA's energy statistics, includes the following energy sources: hydroelectric power, geothermal energy, biofuels, solar energy, and wind energy

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

[59] 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. Heating degree days have a considerably greater affect on energy demand and related emissions than do cooling degree days. Excludes Alaska and Hawaii. Normals are based on data from 1971 through 2000. 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).

Although no new U.S. nuclear power plants have been constructed in recent years, the utilization (i.e., capacity factors[60]) of existing plants in 2009 remained high at just over 90 percent. Electricity output by hydroelectric power plants increased in 2009 by approximately 6.8 percent. Electricity generated by nuclear plants in 2009 provided nearly 3 times as much of the energy consumed in the United States as hydroelectric plants (EIA 2010). Nuclear, hydroelectric, and wind power capacity factors since 1990 are shown in Figure 3-8.

Figure 3-8: Nuclear, Hydroelectric, and Wind Power Plant Capacity Factors in the United States (1990–2009)

[END BOX]

Fossil Fuel Combustion Emissions by Sector

In addition to the CO_2 emitted from fossil fuel combustion, CH_4 and N_2O are emitted from stationary and mobile combustion as well. Table 3-7 provides an overview of the CO_2, CH_4, and N_2O emissions from fossil fuel combustion by sector.

Table 3-7: CO_2, CH_4, and N_2O Emissions from Fossil Fuel Combustion by Sector (Tg CO_2 Eq.)

End-Use Sector	1990	2000	2005	2006	2007	2008	2009
Electricity Generation	**1,829.5**	**2,307.5**	**2,413.2**	**2,357.2**	**2,423.8**	**2,371.7**	**2,163.7**
CO_2	1,820.8	2,296.9	2,402.1	2,346.4	2,412.8	2,360.9	2,154.0
CH_4	0.6	0.7	0.7	0.7	0.7	0.7	0.7
N_2O	8.1	10.0	10.3	10.1	10.3	10.1	9.0
Transportation	**1,534.6**	**1,866.0**	**1,936.0**	**1,914.1**	**1,926.5**	**1,818.1**	**1,745.5**
CO_2	1,485.9	1,809.5	1,896.6	1,878.1	1,894.0	1,789.9	1,719.7
CH_4	4.7	3.4	2.5	2.3	2.2	2.0	2.0
N_2O	43.9	53.2	36.9	33.6	30.3	26.1	23.9
Industrial	**851.2**	**855.9**	**827.5**	**852.8**	**846.5**	**807.0**	**734.1**
CO_2	846.5	851.1	823.1	848.2	842.0	802.9	730.4
CH_4	1.5	1.6	1.4	1.5	1.4	1.3	1.2
N_2O	3.2	3.2	3.0	3.1	3.0	2.8	2.5
Residential	**343.8**	**375.0**	**362.2**	**325.4**	**346.6**	**352.6**	**343.4**
CO_2	338.3	370.7	357.9	321.5	342.4	348.2	339.2
CH_4	4.4	3.4	3.4	3.1	3.4	3.5	3.4
N_2O	1.1	0.9	0.9	0.8	0.9	0.9	0.9
Commercial	**220.2**	**232.1**	**224.8**	**209.7**	**220.6**	**225.4**	**225.2**
CO_2	219.0	230.8	223.5	208.6	219.4	224.2	224.0
CH_4	0.9	0.9	0.9	0.8	0.9	0.9	0.9
N_2O	0.4	0.4	0.4	0.3	0.3	0.3	0.3
U.S. Territories*	**28.0**	**36.0**	**50.2**	**50.5**	**46.3**	**40.0**	**41.8**
Total	**4,807.3**	**5,672.6**	**5,813.9**	**5,709.7**	**5,810.3**	**5,614.8**	**5,253.8**

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.
* U.S. Territories are not apportioned by sector, and emissions are total greenhouse gas emissions from all fuel combustion sources.

Other than CO_2, gases emitted from stationary combustion include the greenhouse gases CH_4 and N_2O and the

[60]The capacity factor equals generation divided by net summer capacity. Summer capacity is defined as "The maximum output that generating equipment can supply to system load, as demonstrated by a multi-hour test, at the time of summer peak demand (period of June 1 through September 30)." Data for both the generation and net summer capacity are from EIA (2010b).

indirect greenhouse gases NO_x, CO, and NMVOCs.[61] CH_4 and N_2O emissions from stationary combustion sources depend upon fuel characteristics, size and vintage, along with combustion technology, pollution control equipment, ambient environmental conditions, and operation and maintenance practices. N_2O 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. CH_4 emissions from stationary combustion are primarily a function of the CH_4 content of the fuel and combustion efficiency.

Mobile combustion produces greenhouse gases other than CO_2, including CH_4, N_2O, and indirect greenhouse gases including NO_x, CO, and NMVOCs. As with stationary combustion, N_2O and NO_x emissions from mobile combustion are closely related to fuel characteristics, air-fuel mixes, combustion temperatures, and the use of pollution control equipment. N_2O from mobile sources, 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 the presence of post-combustion emission controls. CO 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. CH_4 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).

An alternative method of presenting combustion emissions is to allocate emissions associated with electricity generation to the sectors in which it is used. Four end-use sectors were defined: industrial, transportation, residential, and commercial. In the table below, electricity generation emissions have been distributed to each end-use sector based upon the sector's share of national electricity consumption, with the exception of CH_4 and N_2O from transportation.[62] Emissions from U.S. territories are also calculated separately due to a lack of end-use-specific consumption data. This method of distributing emissions assumes that 564 combustion sources focus on the alternative method as presented in Table 3-8.

Table 3-8: CO_2, CH_4, and N_2O Emissions from Fossil Fuel Combustion by End-Use Sector (Tg CO_2 Eq.)

End-Use Sector	1990	2000	2005	2006	2007	2008	2009
Transportation	**1,537.6**	**1,869.5**	**1,940.8**	**1,918.6**	**1,931.5**	**1,822.8**	**1,750.0**
CO_2	1,489.0	1,813.0	1,901.3	1,882.6	1,899.0	1,794.6	1,724.1
CH_4	4.7	3.4	2.5	2.4	2.2	2.0	2.0
N_2O	44.0	53.2	37.0	33.6	30.3	26.2	23.9
Industrial	**1,541.2**	**1,649.3**	**1,567.9**	**1,568.1**	**1,579.7**	**1,525.1**	**1,340.1**
CO_2	1,533.2	1,640.8	1,560.0	1,560.2	1,572.0	1,517.7	1,333.7
CH_4	1.8	1.8	1.7	1.7	1.6	1.6	1.4
N_2O	6.3	6.7	6.2	6.2	6.1	5.8	5.0
Residential	**939.7**	**1,140.9**	**1,222.9**	**1,160.1**	**1,206.7**	**1,190.4**	**1,131.6**
CO_2	931.4	1,133.1	1,214.7	1,152.4	1,198.5	1,182.2	1,123.8
CH_4	4.6	3.6	3.7	3.3	3.6	3.7	3.6
N_2O	3.7	4.2	4.6	4.4	4.5	4.5	4.2
Commercial	**760.8**	**976.8**	**1,032.2**	**1,012.4**	**1,046.0**	**1,036.5**	**990.3**
CO_2	757.0	972.1	1,027.2	1,007.6	1,041.1	1,031.6	985.7
CH_4	1.0	1.1	1.1	1.1	1.1	1.2	1.1
N_2O	2.8	3.6	3.8	3.8	3.8	3.8	3.5
U.S. Territories*	**28.0**	**36.0**	**50.2**	**50.5**	**46.3**	**40.0**	**41.8**
Total	**4,807.3**	**5,672.6**	**5,813.9**	**5,709.7**	**5,810.3**	**5,614.8**	**5,253.8**

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.
* U.S. Territories are not apportioned by sector, and emissions are total greenhouse gas emissions from all fuel combustion sources.

[61] Sulfur dioxide (SO_2) emissions from stationary combustion are addressed in Annex 6.3.

[62] Separate calculations were performed for transportation-related CH_4 and N_2O. The methodology used to calculate these emissions are discussed in the mobile combustion section.

Stationary Combustion

The direct combustion of fuels by stationary sources in the electricity generation, industrial, commercial, and residential sectors represent the greatest share of U.S. greenhouse gas emissions. Table 3-9 presents CO_2 emissions from fossil fuel combustion by stationary sources. The CO_2 emitted is closely linked to the type of fuel being combusted in each sector (see Methodology section for CO_2 from fossil fuel combustion). Other than CO_2, gases emitted from stationary combustion include the greenhouse gases CH_4 and N_2O. Table 3-10 and Table 3-11 present CH_4 and N_2O emissions from the combustion of fuels in stationary sources. CH_4 and N_2O emissions from stationary combustion sources depend upon fuel characteristics, size and vintage, along with combustion technology, pollution control equipment, ambient environmental conditions, and operation and maintenance practices. N_2O 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. CH_4 emissions from stationary combustion are primarily a function of the CH_4 content of the fuel and combustion efficiency. Please refer to Table 3-7 for the corresponding presentation of all direct emission sources of fuel combustion.

Table 3-9: CO_2 Emissions from Stationary Fossil Fuel Combustion (Tg CO_2 Eq.)

Sector/Fuel Type	1990	2000	2005	2006	2007	2008	2009
Electricity Generation	**1,820.8**	**2,296.9**	**2,402.1**	**2,346.4**	**2,412.8**	**2,360.9**	**2,154.0**
Coal	1,547.6	1,927.4	1,983.8	1,953.7	1,987.3	1,959.4	1,747.6
Natural Gas	175.3	280.8	318.8	338.0	371.3	361.9	373.1
Fuel Oil	97.5	88.4	99.2	54.4	53.9	39.2	32.9
Geothermal	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Industrial	**846.5**	**851.1**	**823.1**	**848.2**	**842.0**	**802.9**	**730.4**
Coal	155.3	127.3	115.3	112.6	107.0	102.6	83.4
Natural Gas	409.1	457.2	380.8	377.7	389.0	391.0	365.0
Fuel Oil	282.1	266.6	326.9	357.9	346.0	309.3	282.0
Commercial	**219.0**	**230.8**	**223.5**	**208.6**	**219.4**	**224.2**	**224.0**
Coal	12.0	8.8	9.3	6.2	6.7	6.5	5.8
Natural Gas	142.1	172.5	162.9	153.8	164.0	170.2	167.9
Fuel Oil	64.9	49.6	51.3	48.5	48.7	47.4	50.3
Residential	**338.3**	**370.7**	**357.9**	**321.5**	**342.4**	**348.2**	**339.2**
Coal	3.0	1.1	0.8	0.6	0.7	0.7	0.6
Natural Gas	238.0	270.7	262.2	237.3	257.0	264.4	257.2
Fuel Oil	97.4	98.8	94.9	83.6	84.6	83.1	81.4
U.S. Territories	**27.9**	**35.9**	**50.0**	**50.3**	**46.1**	**39.8**	**41.7**
Coal	0.6	0.9	3.0	3.4	4.3	3.3	3.5
Natural Gas	NO	0.7	1.3	1.4	1.4	1.6	1.5
Fuel Oil	27.2	34.2	45.7	45.5	40.4	35.0	36.7
Total	**3,252.5**	**3,785.3**	**3,856.6**	**3,775.0**	**3,862.8**	**3,776.0**	**3,489.3**

* U.S. Territories are not apportioned by sector, and emissions are from all fuel combustion sources (stationary and mobile) are presented in this table.

Table 3-10: CH_4 Emissions from Stationary Combustion (Tg CO_2 Eq.)

Sector/Fuel Type	1990	2000	2005	2006	2007	2008	2009
Electricity Generation	**0.6**	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**
Coal	0.3	0.4	0.4	0.4	0.4	0.4	0.4
Fuel Oil	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	0.1
Industrial	**1.5**	**1.6**	**1.4**	**1.5**	**1.4**	**1.3**	**1.2**
Coal	0.3	0.3	0.3	0.3	0.2	0.2	0.2
Fuel Oil	0.2	0.1	0.2	0.2	0.2	0.2	0.1
Natural Gas	0.2	0.2	0.1	0.1	0.1	0.1	0.1
Wood	0.9	1.0	0.9	0.9	0.8	0.8	0.7
Commercial	**0.9**	**0.9**	**0.9**	**0.8**	**0.9**	**0.9**	**0.9**
Coal	+	+	+	+	+	+	+
Fuel Oil	0.2	0.1	0.2	0.1	0.1	0.1	0.1
Natural Gas	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Wood	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Residential	**4.4**	**3.4**	**3.4**	**3.1**	**3.4**	**3.5**	**3.4**
Coal	0.2	0.1	0.1	+	+	+	+
Fuel Oil	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Natural Gas	0.4	0.5	0.5	0.4	0.5	0.5	0.5
Wood	3.5	2.5	2.6	2.3	2.6	2.7	2.6
U.S. Territories	**+**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Coal	+	+	+	+	+	+	+
Fuel Oil	+	+	0.1	0.1	0.1	0.1	0.1
Natural Gas	+	+	+	+	+	+	+
Wood	+	+	+	+	+	+	+
Total	**7.4**	**6.6**	**6.6**	**6.2**	**6.5**	**6.5**	**6.2**

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

Table 3-11: N_2O Emissions from Stationary Combustion (Tg CO_2 Eq.)

Sector/Fuel Type	1990	2000	2005	2006	2007	2008	2009
Electricity Generation	**8.1**	**10.0**	**10.3**	**10.1**	**10.2**	**10.1**	**9.0**
Coal	7.6	9.4	9.7	9.5	9.7	9.6	8.5
Fuel Oil	0.2	0.2	0.2	0.1	0.1	0.1	0.1
Natural Gas	0.1	0.2	0.2	0.2	0.2	0.2	0.2
Wood	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Industrial	**3.2**	**3.2**	**3.0**	**3.1**	**3.0**	**2.8**	**2.5**
Coal	0.8	0.6	0.6	0.6	0.5	0.5	0.4
Fuel Oil	0.5	0.4	0.5	0.6	0.6	0.5	0.4
Natural Gas	0.2	0.3	0.2	0.2	0.2	0.2	0.2
Wood	1.7	1.9	1.7	1.7	1.7	1.6	1.4
Commercial	**0.4**	**0.4**	**0.4**	**0.3**	**0.3**	**0.3**	**0.3**
Coal	0.1	+	+	+	+	+	+
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	0.1
Residential	**1.1**	**0.9**	**0.9**	**0.8**	**0.9**	**0.9**	**0.9**
Coal	+	+	+	+	+	+	+
Fuel Oil	0.3	0.3	0.3	0.2	0.2	0.2	0.2
Natural Gas	0.1	0.2	0.1	0.1	0.1	0.1	0.1
Wood	0.7	0.5	0.5	0.5	0.5	0.5	0.5
U.S. Territories	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Coal	+	+	+	+	+	+	+

Fuel Oil	0.1		0.1		0.1	0.1	0.1	0.1	0.1
Natural Gas	+		+		+	+	+	+	+
Wood	+		+		+	+	+	+	+
Total	**12.8**		**14.6**		**14.7**	**14.4**	**14.6**	**14.2**	**12.8**

+ Does not exceed 0.05 Tg CO_2 Eq.

Note: Totals may not sum due to independent rounding.

Electricity Generation

The process of generating electricity is the single largest source of CO_2 emissions in the United States, representing 39 percent of total CO_2 emissions from all CO_2 emissions sources across the United States. CH_4 and N_2O accounted for a small portion of emissions from electricity generation, representing less than 0.1 percent and 0.4 percent, respectively.[63] Electricity generation also accounted for the largest share of CO_2 emissions from fossil fuel combustion, approximately 41 percent in 2009. CH_4 and N_2O from electricity generation represented 8 and 25 percent of emissions from CH_4 and N_2O emissions from fossil fuel combustion in 2009, respectively. Electricity was consumed primarily in the residential, commercial, and industrial end-use sectors for lighting, heating, electric motors, appliances, electronics, and air conditioning (see Figure 3-9).

Figure 3-9: Electricity Generation Retail Sales by End-Use Sector

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). For the underlying energy data used in this chapter, the Energy Information Administration (EIA) places electric power generation into three functional categories: the electric power sector, the commercial sector, and the industrial sector. The electric power sector consists of electric utilities and independent power producers whose primary business is the production of electricity,[64] while the other sectors consist of those producers that indicate their primary business is something other than the production of electricity.

The industrial, residential, and commercial end-use sectors, as presented in Table 3-8, were reliant on electricity for meeting energy needs. The residential and commercial end-use sectors were especially reliant on electricity consumption for lighting, heating, air conditioning, and operating appliances. Electricity sales to the residential and commercial end-use sectors in 2009 decreased approximately 1.2 percent and 1.0 percent, respectively. The trend in the commercial and residential sectors can largely be attributed to the decreased carbon intensity in the fuels used to generate electricity for these sectors. In addition, electricity consumption in both sectors decreased as a result of the less energy-intensive weather conditions compared to 2008. In 2009, the amount of electricity generated (in kWh) decreased by 4 percent from the previous year. This decline was due to the economic downturn, a decrease in the carbon intensity of fuels used to generate electricity due to fuel switching as the price of coal increased, and the price of natural gas decreased significantly, and an increase in non-fossil fuel sources used to generate electricity. As a result, CO_2 emissions from the electric power sector decreased by 8.8 percent as the consumption of coal and petroleum for electricity generation decreased by 10.8 percent and 16.6 percent, respectively, in 2009 and the consumption of natural gas for electricity generation, increased by 3.1 percent. The decrease in C intensity of the electricity supply (see Table 3-15) was the result of a decrease in the carbon intensity of fossil fuels consumed to generate electricity and an increase in renewable generation of 5 percent spurred by a 28 percent increase in wind-generated electricity.

[63] Since emissions estimates for U.S. territories cannot be disaggregated by gas in Table 3-7and Table 3-8, the percentages for CH_4 and N_2O exclude U.S. territory estimates.

[64] 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).

Industrial Sector

The industrial sector accounted for 14 percent of CO_2 emissions from fossil fuel combustion, 15 percent of CH_4 emissions from fossil fuel combustion, and 7 percent of N_2O emissions from fossil fuel combustion. CO_2, CH_4, and N_2O emissions resulted from the direct consumption of fossil fuels for steam and process heat production.

The industrial sector, per the underlying energy consumption data from EIA, includes activities such as manufacturing, construction, mining, and agriculture. The largest of these activities in terms of energy consumption is manufacturing, of which six industries—Petroleum Refineries, Chemicals, Paper, Primary Metals, Food, and Nonmetallic Mineral Products—represent the vast majority of the energy use (EIA 2010 and EIA 2009c).

In theory, emissions from the industrial sector should be highly correlated with economic growth and industrial output, but heating of industrial buildings and agricultural energy consumption are also affected by weather conditions.[65] 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 effect on industrial emissions.

From 2008 to 2009, total industrial production and manufacturing output decreased by 9.3 and 10.9 percent, respectively (FRB 2010). Over this period, output decreased across all production indices for Food, Petroleum Refineries, Chemicals, Paper, Primary Metals, and Nonmetallic Mineral Products (see Figure 3-10).

Figure 3-10: Industrial Production Indices (Index 2002=100)

Despite the growth in industrial output (41 percent) and the overall U.S. economy (60 percent) from 1990 to 2009, CO_2 emissions from fossil fuel combustion in the industrial sector decreased by 13.7 percent over that time. A number of factors are believed to have caused this disparity between growth in industrial output and decrease in industrial emissions, including: (1) more rapid growth in output from less energy-intensive industries relative to traditional manufacturing industries, and (2) energy-intensive industries such as steel are employing new methods, such as electric arc furnaces, that are less carbon intensive than the older methods. In 2009, CO_2, CH_4, and N_2O emissions from fossil fuel combustion and electricity use within the industrial end-use sector totaled 1,340.1 Tg CO_2 Eq., or approximately 12.1 percent below 2008 emissions.

Residential and Commercial Sectors

The residential and commercial sectors accounted for 7 and 4 percent of CO_2 emissions from fossil fuel combustion, 42 and 11 percent of CH_4 emissions from fossil fuel combustion, and 2 and 1 percent of N_2O emissions from fossil fuel combustion, respectively. Emissions from these sectors 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 of these end-use sectors. In 2009, CO_2, CH_4, and N_2O emissions from fossil fuel combustion and electricity use within the residential and commercial end-use sectors were 1,131.6 Tg CO_2 Eq. and 990.3Tg CO_2 Eq., respectively. Total CO_2, CH_4, and N_2O emissions from the residential and commercial sectors decreased by 4.9 and 4.5 percent from 2008 to 2009, respectively.

Emissions from the residential and commercial sectors have generally been increasing since 1990, and are often correlated with short-term fluctuations in energy consumption caused by weather conditions, rather than prevailing economic conditions. In the long-term, both sectors are also affected by population growth, regional migration trends, and changes in housing and building attributes (e.g., size and insulation).

Emissions from natural gas consumption represent about 76 and 75 percent of the direct fossil fuel CO_2 emissions from the residential and commercial sectors, respectively. In 2009, natural gas CO_2 emissions from the residential and commercial sectors decreased by 2.8 percent and 1.3 percent, respectively. The decrease in natural gas emissions in both sectors is a result of less energy-intensive weather conditions in the United States compared to

[65] 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.

2008.

U.S. Territories

Emissions from U.S. territories are based on the fuel consumption in American Samoa, Guam, Puerto Rico, U.S. Virgin Islands, Wake Island, and other U.S. Pacific Islands. As described the Methodology section for CO_2 from fossil fuel combustion, this data is collected separately from the sectoral-level data available for the general calculations. As sectoral information is not available for U.S. Territories, CO_2, CH_4, and N_2O emissions are not presented for U.S. Territories in the tables above, though the emissions will include some transportation and mobile combustion sources.

Transportation Sector

This discussion of transportation emissions follows the alternative method of presenting combustion emissions by allocating emissions associated with electricity generation to the transportation end-use sector, as presented in Table 3-8. For direct emissions from transportation (i.e., not including emissions associated with the sector's electricity consumption), please see Table 3-7.

The transportation end-use sector accounted for 1,745.5 Tg CO_2 Eq. in 2009, which represented 33 percent of CO_2 emissions, 24 percent of CH_4 emissions, and 65 percent of N_2O emissions from fossil fuel combustion, respectively. Fuel purchased in the U.S. for international aircraft and marine travel accounted for an additional 123.1 Tg CO_2 in 2009; these emissions are recorded as international bunkers and are not included in U.S. totals according to UNFCCC reporting protocols. Among domestic transportation sources, light duty vehicles (including passenger cars and light-duty trucks) represented 64 percent of CO_2 emissions, medium- and heavy-duty trucks 20 percent, commercial aircraft 6 percent, and other sources 9 percent. Light-duty truck CO_2 emissions increased by 60 percent (193.4 Tg) from 1990 to 2009, representing the largest percentage increase of any transportation mode. General aviation aircraft CO_2 emissions also increased by nearly 60 percent (5.7 Tg) from 1990 to 2009. CO_2 from the domestic operation of commercial aircraft decreased by 18 percent (24.0 Tg) from 1990 to 2009. Across all categories of aviation, CO_2 emissions decreased by 21.6 percent (38.7 Tg) between 1990 and 2009. This includes a 59 percent (20.3 Tg) decrease in emissions from domestic military operations. For further information on all greenhouse gas emissions from transportation sources, please refer to Annex 3.2. See Table 3-12 for a detailed breakdown of CO_2 emissions by mode and fuel type.

From 1990 to 2009, transportation emissions rose by 17 percent due, in large part, to increased demand for travel and the stagnation of fuel efficiency across the U.S. vehicle fleet. The number of vehicle miles traveled by light-duty motor vehicles (passenger cars and light-duty trucks) increased 39 percent from 1990 to 2009, as a result of a confluence of factors including population growth, economic growth, urban sprawl, and low fuel prices over much of this period.

From 2008 to 2009, CO_2 emissions from the transportation end-use sector declined 4 percent. The decrease in emissions can largely be attributed to decreased economic activity in 2009 and an associated decline in the demand for transportation. Modes such as medium- and heavy-duty trucks were significantly impacted by the decline in freight transport. Similarly, increased jet fuel prices were a factor in the 19 percent decrease in commercial aircraft emissions since 2007.

Almost all of the energy consumed for transportation was supplied by petroleum-based products, with more than half 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. The primary driver of transportation-related emissions was CO_2 from fossil fuel combustion, which increased by 16 percent from 1990 to 2009. This rise in CO_2 emissions, combined with an increase in HFCs from close to zero emissions in 1990 to 60.2 Tg CO_2 Eq. in 2009, led to an increase in overall emissions from transportation activities of 17 percent.

Transportation Fossil Fuel Combustion CO_2 Emissions

Domestic transportation CO_2 emissions increased by 16 percent (235.1 Tg) between 1990 and 2009, an annualized increase of 0.8 percent. The 4 percent decline in emissions between 2008 and 2009 followed the previous year's trend of decreasing emissions. Almost all of the energy consumed by the transportation sector is petroleum-based,

including motor gasoline, diesel fuel, jet fuel, and residual oil.[66] Transportation sources also produce CH_4 and N_2O; these emissions are included in Table 3-13 and Table 3-14 in the "Mobile Combustion" Section. Annex 3.2 presents total emissions from all transportation and mobile sources, including CO_2, N_2O, CH_4, and HFCs.

Carbon dioxide emissions from passenger cars and light-duty trucks totaled 1,111.7 Tg in 2009, an increase of 17 percent (161.3 Tg) from 1990. CO_2 emissions from passenger cars and light-duty trucks peaked at 1,184.3 Tg in 2004, and since then have declined about 6 percent. Over the 1990s through early this decade, growth in vehicle travel substantially outweighed improvements in vehicle fuel economy; however, the rate of Vehicle Miles Traveled (VMT) growth slowed considerably starting in 2005 (and declined rapidly in 2008) while average vehicle fuel economy increased. Among new vehicles sold annually, average fuel economy gradually declined from 1990 to 2004 (Figure 3-11), reflecting substantial growth in sales of light-duty trucks—in particular, growth in the market share of sport utility vehicles—relative to passenger cars (Figure 3-12). New vehicle fuel economy improved beginning in 2005, largely due to higher light-duty truck fuel economy standards, which have risen each year since 2005. The overall increase in fuel economy is also due to a slightly lower light-duty truck market share, which peaked in 2004 at 52 percent and declined to 40 percent in 2009.

Figure 3-11: Sales-Weighted Fuel Economy of New Passenger Cars and Light-Duty Trucks, 1990–2008

Figure 3-12: Sales of New Passenger Cars and Light-Duty Trucks, 1990–2008

Light-duty truck[67] CO_2 emissions increased by 60 percent (193.4 Tg) from 1990 to 2009, representing the largest percentage increase of any transportation mode. General aviation aircraft CO_2 emissions also increased by nearly 60 percent (5.7 Tg) from 1990 to 2009. CO_2 from the domestic operation of commercial aircraft decreased by 18 percent (24.0 Tg) from 1990 to 2009. Across all categories of aviation[68], CO_2 emissions decreased by 21.6 percent (38.7 Tg) between 1990 and 2009. This includes a 59 percent (20.3 Tg) decrease in emissions from domestic military operations. For further information on all greenhouse gas emissions from transportation sources, please refer to Annex 3.2.

Table 3-12: CO_2 Emissions from Fossil Fuel Combustion in Transportation End-Use Sector (Tg CO_2 Eq.) [a]

Fuel/Vehicle Type	1990	2000	2005	2006	2007	2008	2009
Gasoline	**983.7**	**1,135.0**	**1,187.8**	**1,178.2**	**1,181.2**	**1,130.3**	**1,125.7**
Passenger Cars	621.4	640.6	658.0	635.0	628.7	594.0	593.3
Light-Duty Trucks	309.1	446.4	478.7	491.5	500.1	486.5	485.9
Medium- and Heavy-Duty Trucks[b]	38.7	36.0	34.9	35.5	36.1	33.7	30.6
Buses	0.3	0.4	0.4	0.4	0.4	0.4	0.3
Motorcycles	1.7	1.8	1.6	1.9	2.1	2.1	2.1
Recreational Boats	12.4	9.8	14.1	14.0	13.9	13.5	13.4
Distillate Fuel Oil (Diesel)	**262.9**	**402.5**	**451.8**	**470.3**	**476.3**	**443.5**	**402.5**
Passenger Cars	7.9	3.7	4.2	4.1	4.1	3.9	3.9
Light-Duty Trucks	11.5	20.1	25.8	26.8	27.3	26.9	26.7
Medium- and Heavy-Duty	190.5	309.6	360.6	370.1	376.1	356.0	321.8

[66] Biofuel estimates are presented for informational purposes only in the Energy chapter, in line with IPCC methodological guidance and UNFCCC reporting obligations. Net carbon fluxes from changes in biogenic carbon reservoirs in croplands are accounted for in the estimates for Land Use, Land-Use Change, and Forestry (see Chapter 7). More information and additional analyses on biofuels are available at EPA's "Renewable Fuels: Regulations & Standards" web page: http://www.epa.gov/otaq/fuels/renewablefuels/regulations.htm

[67] Includes "light-duty trucks" fueled by gasoline, diesel and LPG.

[68] Includes consumption of jet fuel and aviation gasoline. Does not include aircraft bunkers, which are not included in national emission totals, in line with IPCC methodological guidance and UNFCCC reporting obligations.

Trucks[b]							
Buses	8.0	10.2	10.6	10.8	10.8	10.3	9.3
Rail	35.5	42.1	45.6	47.8	46.6	43.2	36.2
Recreational Boats	2.0	2.7	3.1	3.2	3.3	0.9	3.5
Ships and Other Boats	7.5	14.1	8.1	7.5	8.2	2.2	1.2
International Bunker Fuels [c]	*11.7*	*6.3*	*9.4*	*8.8*	*8.2*	*9.0*	*8.3*
Jet Fuel	**176.2**	**199.8**	**194.2**	**169.5**	**168.7**	**155.1**	**138.8**
Commercial Aircraft	135.4	169.2	161.2	137.1	138.1	122.2	111.4
Military Aircraft	34.4	21.1	18.1	16.4	16.1	16.3	14.1
General Aviation Aircraft	6.4	9.5	14.9	16.0	14.5	16.6	13.3
International Bunker Fuels [c]	*46.4*	*58.8*	*56.7*	*74.6*	*73.8*	*75.5*	*69.4*
Aviation Gasoline	**3.1**	**2.5**	**2.4**	**2.3**	**2.2**	**2.0**	**1.8**
General Aviation Aircraft	3.1	2.5	2.4	2.3	2.2	2.0	1.8
Residual Fuel Oil	**22.6**	**33.3**	**19.3**	**23.0**	**29.0**	**19.9**	**12.0**
Ships and Other Boats[d]	22.6	33.3	19.3	23.0	29.0	19.9	12.0
International Bunker Fuels [c]	*53.7*	*33.3*	*43.6*	*45.0*	*45.6*	*49.2*	*45.4*
Natural Gas	**36.0**	**35.6**	**33.1**	**33.1**	**35.3**	**36.8**	**36.3**
Passenger Cars	+	+	+	+	+	+	+
Light-Duty Trucks	+	+	+	+	+	+	+
Buses	+	0.4	0.8	0.8	1.0	1.1	1.1
Pipeline	36.0	35.2	32.2	32.3	34.3	35.7	35.2
LPG	**1.4**	**0.7**	**1.7**	**1.7**	**1.4**	**2.4**	**2.5**
Light-Duty Trucks	0.6	0.5	1.3	1.2	1.0	1.8	1.8
Medium- and Heavy-Duty Trucks[b]	0.8	0.3	0.4	0.5	0.4	0.7	0.7
Buses	+	+	+	+	+	+	+
Electricity	**3.0**	**3.4**	**4.7**	**4.5**	**5.0**	**4.7**	**4.4**
Rail	3.0	3.4	4.7	4.5	5.0	4.7	4.4
Total	**1,489.0**	**1,813.0**	**1,901.3**	**1,882.6**	**1,899.0**	**1,794.6**	**1,724.1**
Total (Including Bunkers) [c]	**1,600.8**	**1,911.4**	**2,011.1**	**2,011.0**	**2,026.6**	**1,928.3**	**1,847.2**

[a] This table does not include emissions from non-transportation mobile sources, such as agricultural equipment and construction/mining equipment; it also does not include emissions associated with electricity consumption by pipelines or lubricants used in transportation.
[b] Includes medium- and heavy-duty trucks over 8,500 lbs.
[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.
Note: Totals may not sum due to independent rounding.
Note: See section 3.10 of this chapter, in line with IPCC methodological guidance and UNFCCC reporting obligations, for more information on ethanol.
+ Less than 0.05 Tg CO_2 Eq.
- Unreported or zero

Mobile Fossil Fuel Combustion CH_4 and N_2O Emissions

Mobile combustion includes emissions of CH_4 and N_2O from all transportation sources identified in the U.S. inventory with the exception of pipelines, which are stationary; mobile sources also include non-transportation sources such as construction/mining equipment, agricultural equipment, vehicles used off-road, and other sources (e.g., snowmobiles, lawnmowers, etc.). Annex 3.2 includes a summary of all emissions from both transportation and mobile sources. Table 3-13 and Table 3-14 provide CH_4 and N_2O emission estimates in Tg CO_2 Eq.[69]

[69] See Annex 3.2 for a complete time series of emission estimates for 1990 through 2009.

Mobile combustion was responsible for a small portion of national CH_4 emissions (0.3 percent) but was the second largest source of U.S. N_2O emissions (9 percent). From 1990 to 2009, mobile source CH_4 emissions declined by 58 percent, to 2.0 Tg CO_2 Eq. (93 Gg), due largely to control technologies employed in on-road vehicles since the mid-1990s to reduce CO, NO_x, NMVOC, and CH_4 emissions. Mobile source emissions of N_2O decreased by 46 percent, to 23.9 Tg CO_2 Eq. (77 Gg). Earlier generation control technologies initially resulted in higher N_2O emissions, causing a 26 percent increase in N_2O emissions from mobile sources between 1990 and 1998. Improvements in later-generation emission control technologies have reduced N_2O output, resulting in a 50 percent decrease in mobile source N_2O emissions from 1998 to 2009 (Figure 3-13). Overall, CH_4 and N_2O emissions were predominantly from gasoline-fueled passenger cars and light-duty trucks.

Figure 3-13: Mobile Source CH_4 and N_2O Emissions

Table 3-13: CH_4 Emissions from Mobile Combustion (Tg CO_2 Eq.)

Fuel Type/Vehicle Type[a]	1990	2000	2005	2006	2007	2008	2009
Gasoline On-Road	**4.2**	**2.8**	**1.9**	**1.7**	**1.6**	**1.4**	**1.3**
Passenger Cars	2.6	1.6	1.1	1.0	0.9	0.8	0.7
Light-Duty Trucks	1.4	1.1	0.7	0.6	0.6	0.6	0.6
Medium- and Heavy-Duty Trucks and Buses	0.2	0.1	0.1	0.1	0.1	0.1	0.1
Motorcycles	+	+	+	+	+	+	+
Diesel On-Road	**+**	**+**	**+**	**+**	**+**	**+**	**+**
Passenger Cars	+	+	+	+	+	+	+
Light-Duty Trucks	+	+	+	+	+	+	+
Medium- and Heavy-Duty Trucks and Buses	+	+	+	+	+	+	+
Alternative Fuel On-Road	**+**	**+**	**+**	**0.1**	**0.1**	**0.1**	**0.1**
Non-Road	**0.4**	**0.5**	**0.6**	**0.6**	**0.5**	**0.5**	**0.5**
Ships and Boats	+	+	+	+	+	+	+
Rail	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Aircraft	0.2	0.2	0.2	0.1	0.1	0.1	0.1
Agricultural Equipment[b]	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Construction/Mining Equipment[c]	+	0.1	0.1	0.1	0.1	0.1	0.1
Other[d]	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	**4.7**	**3.4**	**2.5**	**2.3**	**2.2**	**2.0**	**2.0**

[a] See Annex 3.2 for definitions of on-road vehicle types.
[b] Includes equipment, such as tractors and combines, as well as fuel consumption from trucks that are used off-road in agriculture.
[c] Includes equipment, such as cranes, dumpers, and excavators, as well as fuel consumption from trucks that are used off-road in construction.
[d] "Other" includes snowmobiles and other recreational equipment, logging equipment, lawn and garden equipment, railroad equipment, airport equipment, commercial equipment, and industrial equipment, as well as fuel consumption from trucks that are used off-road for commercial/industrial purposes.
Note: Totals may not sum due to independent rounding.
+ Less than 0.05 Tg CO_2 Eq.

Table 3-14: N_2O Emissions from Mobile Combustion (Tg CO_2 Eq.)

Fuel Type/Vehicle Type[a]	1990	2000	2005	2006	2007	2008	2009
Gasoline On-Road	**40.1**	**48.4**	**32.1**	**29.0**	**25.5**	**21.8**	**19.9**
Passenger Cars	25.4	25.2	17.7	15.7	13.7	11.7	10.0
Light-Duty Trucks	14.1	22.4	13.6	12.5	11.1	9.5	9.3
Medium- and Heavy-Duty Trucks and Buses	0.6	0.9	0.8	0.7	0.7	0.6	0.5
Motorcycles	+	+	+	+	+	+	+

Diesel On-Road	**0.2**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**
Passenger Cars	+	+	+	+	+	+	+
Light-Duty Trucks	+	+	+	+	+	+	+
Medium- and Heavy-Duty Trucks and Buses	0.2	0.3	0.3	0.3	0.3	0.3	0.3
Alternative Fuel On-Road	**0.1**	**0.1**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**
Non-Road	**3.6**	**4.3**	**4.3**	**4.2**	**4.3**	**3.8**	**3.6**
Ships and Boats	0.6	0.9	0.6	0.7	0.8	0.5	0.4
Rail	0.3	0.3	0.4	0.4	0.4	0.3	0.3
Aircraft	1.7	1.9	1.9	1.6	1.6	1.5	1.3
Agricultural Equipment[b]	0.2	0.3	0.4	0.4	0.4	0.4	0.4
Construction/Mining Equipment[c]	0.3	0.4	0.5	0.5	0.5	0.5	0.5
Other[d]	0.4	0.5	0.6	0.6	0.6	0.6	0.6
Total	**43.9**	**53.2**	**36.9**	**33.6**	**30.3**	**26.1**	**23.9**

[a] See Annex 3.2 for definitions of on-road vehicle types.
[b] Includes equipment, such as tractors and combines, as well as fuel consumption from trucks that are used off-road in agriculture.
[c] Includes equipment, such as cranes, dumpers, and excavators, as well as fuel consumption from trucks that are used off-road in construction.
[d] "Other" includes snowmobiles and other recreational equipment, logging equipment, lawn and garden equipment, railroad equipment, airport equipment, commercial equipment, and industrial equipment, as well as fuel consumption from trucks that are used off-road for commercial/industrial purposes.
Note: Totals may not sum due to independent rounding.
+ Less than 0.05 Tg CO_2 Eq.

CO_2 from Fossil Fuel Combustion

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 in line with a Tier 2 method in the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006). A detailed description of the U.S. methodology is presented in Annex 2.1, and is characterized by the following steps:

1. *Determine total fuel consumption by fuel type and sector.* Total fossil fuel consumption for each year is estimated 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.). Fuel consumption data for the United States were obtained directly from the Energy Information Administration (EIA) of the U.S. Department of Energy (DOE), primarily from the Monthly Energy Review and published supplemental tables on petroleum product detail (EIA 2011). The EIA does not include territories in its national energy statistics, so fuel consumption data for territories were collected separately from Jacobs (2010).[70]

   For consistency of reporting, the IPCC has recommended that countries report energy data 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 on an annual basis and used in this inventory are predominantly from mid-stream or conversion energy consumers such as refiners and electric power generators. These annual surveys are supplemented with end-use energy consumption surveys, such as the Manufacturing Energy Consumption Survey, that are conducted on a periodic basis (every 4 years). These consumption data sets help inform the annual surveys to arrive at the

[70] 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 42 Tg CO_2 Eq. in 2009.

national total and sectoral breakdowns for that total. [71]

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 standards, which are to report energy statistics in terms of net calorific values (NCV) (i.e., lower heating values).[72]

2. *Subtract uses accounted for in the Industrial Processes chapter.* Portions of the fuel consumption data for seven fuel categories—coking coal, distillate fuel, industrial other coal, petroleum coke, natural gas, residual fuel oil, and other oil—were reallocated to the industrial processes chapter, as they were consumed during non-energy related industrial activity. To make these adjustments, additional data were collected from AISI (2004 through 2010), Coffeyville (2010), U.S. Census Bureau (2010), EIA (2010c), USGS (1991 through 2010), USGS (1994 through 2010), USGS (1995, 1998, 2000 through 2002, 2007, and 2009), USGS (1991 through 2009a), and USGS (1991 through 2009b).[73]

3. *Adjust for conversion of fuels and exports of CO_2.* Fossil fuel consumption estimates are adjusted downward to exclude fuels created from other fossil fuels and exports of CO_2.[74] Synthetic natural gas is created from industrial coal, and is currently included in EIA statistics for both coal and natural gas. Therefore, synthetic natural gas is subtracted from energy consumption statistics.[75] Since October 2000, the Dakota Gasification Plant has been exporting CO_2 to Canada by pipeline. Since this CO_2 is not emitted to the atmosphere in the United States, energy used to produce this CO_2 is subtracted from energy consumption statistics. To make these adjustments, additional data for ethanol were collected from EIA (2011) and data for synthetic natural gas were collected from EIA (2009b), and data for CO_2 exports were collected from the Dakota Gasification Company (2006), Fitzpatrick (2002), Erickson (2003), and EIA (2007b).

4. *Adjust Sectoral Allocation of Distillate Fuel Oil and Motor Gasoline.* EPA had conducted a separate bottom-up analysis of transportation fuel consumption based on the Federal Highway Administration's (FHWA) VMT that indicated that the amount of distillate and motor gasoline consumption allocated to the transportation sector in the EIA statistics should be adjusted. Therefore, for these estimates, the transportation sector's distillate fuel and motor gasoline consumption was adjusted upward to match the value obtained from the bottom-up analysis based on VMT. As the total distillate and motor gasoline consumption estimate from EIA are considered to be accurate at the national level, the distillate consumption totals for the residential, commercial, and industrial sectors were adjusted downward proportionately. The data sources used in the bottom-up analysis of transportation fuel consumption include AAR (2009 through 2010), Benson (2002 through 2004), DOE (1993 through 2010), EIA (2009a), EIA (1991 through 2010), EPA (2009), and FHWA (1996 through 2010).[76]

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[71] See IPCC Reference Approach for estimating CO_2 emissions from fossil fuel combustion in Annex 4 for a comparison of U.S. estimates using top-down and bottom-up approaches.

[72] 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.

[73] See sections on Iron and Steel Production and Metallurgical Coke Production, Ammonia Production and Urea Consumption, Petrochemical Production, Titanium Dioxide Production, Ferroalloy Production, Aluminum Production, and Silicon Carbide Production and Consumption in the Industrial Processes chapter.

[74] Energy statistics from EIA(2010c) are already adjusted downward to account for ethanol added to motor gasoline, and biogas in natural gas.

[75] These adjustments are explained in greater detail in Annex 2.1.

[76] FHWA data on vehicle miles traveled from the VM-1 table were not available for 2009 due to a delay caused by changes in data collection procedures. Based on data from FHWA's Traffic Volume Trends Program, the overall increase in VMT between 2008 and 2009 was estimated to be 0.2%. Total VMT was distributed among vehicle classes based on trends in fuel consumption by fuel type between 2008 and 2009, as described below.
Fuel use by vehicle class (also in the VM-1 table) was not available from FHWA for 2009, but changes in overall diesel and gasoline consumption were released in Table MF21. Fuel use in vehicle classes that were predominantly gasoline was estimated to grow by the rate of growth for gasoline between 2008 and 2009. Fuel use in vehicle classes that were predominantly diesel

5. *Adjust for fuels consumed for non-energy uses.* U.S. aggregate energy statistics include consumption of fossil fuels for non-energy purposes. These are fossil fuels that are manufactured into plastics, asphalt, lubricants, or other products. Depending on the end-use, this can result in storage of some or all of the C contained in the fuel for a period of time. As the emission pathways of C used for non-energy purposes are vastly different than fuel combustion (since the C in these fuels ends up in products instead of being combusted), these emissions are estimated separately in the Carbon Emitted and Stored in Products from Non-Energy Uses of Fossil Fuels section in this chapter. Therefore, the amount of fuels used for non-energy purposes was subtracted from total fuel consumption. Data on non-fuel consumption was provided by EIA (2011).

6. *Subtract consumption of international bunker fuels.* According to the UNFCCC reporting guidelines emissions from international transport activities, or bunker fuels, should not be included in national totals. U.S. energy consumption statistics include these bunker fuels (e.g., distillate fuel oil, residual fuel oil, and jet fuel) as part of consumption by the transportation end-use sector, however, so emissions from international transport activities were calculated separately following the same procedures used for emissions from consumption of all fossil fuels (i.e., estimation of consumption, and determination of C content).[77] The Office of the Under Secretary of Defense (Installations and Environment) and the Defense Energy Support Center (Defense Logistics Agency) of the U.S. Department of Defense (DoD) (DESC 2011) supplied data on military jet fuel and marine fuel use. Commercial jet fuel use was obtained from FAA (2006 and 2009); residual and distillate fuel use for civilian marine bunkers was obtained from DOC (1991 through 2010) for 1990 through 2001, 2007 and 2008, and DHS (2008) for 2003 through 2006. Consumption of these fuels was subtracted from the corresponding fuels in the transportation end-use sector. Estimates of international bunker fuel emissions for the United States are discussed in detail later in the International Bunker Fuels section of this chapter.

7. *Determine the total C content of fuels consumed.* Total C was estimated by multiplying the amount of fuel consumed by the amount of C in each fuel. This total C estimate defines the maximum amount of C that could potentially be released to the atmosphere if all of the C in each fuel was converted to CO_2. The C content coefficients used by the United States were obtained from EIA's Emissions of Greenhouse Gases in the United States 2008 (EIA 2009a), and an EPA analysis of C content coefficients used in the mandatory reporting rule (EPA 2010a). A discussion of the methodology used to develop the C content coefficients are presented in Annexes 2.1 and 2.2.

8. *Estimate CO_2 Emissions.* Total CO_2 emissions are the product of the adjusted energy consumption (from the previous methodology steps 1 through 6), the C content of the fuels consumed, and the fraction of C that is oxidized. The fraction oxidized was assumed to be 100 percent for petroleum, coal, and natural gas based on guidance in IPCC (2006) (see Annex 2.1).

9. *Allocate transportation emissions by vehicle type.* This report provides a more detailed accounting of emissions from transportation because it is such a large consumer of fossil fuels in the United States. 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.

    - For on-road vehicles, annual estimates of combined motor gasoline and diesel fuel consumption by vehicle category were obtained from FHWA (1996 through 2010); for each vehicle category, the percent gasoline, diesel, and other (e.g., CNG, LPG) fuel consumption are estimated using data from DOE (1993 through 2010). Fuel use by vehicle class (found in the VM-1 table) was not available from FHWA for 2009, but changes in overall diesel and gasoline consumption were released in Table MF21. Fuel use in vehicle classes that were predominantly gasoline was estimated to grow by the rate of growth for gasoline between 2008 and 2009. Fuel use in vehicle classes that were predominantly diesel were estimated to fall by the same rate that diesel fuel consumption fell overall in 2009.

    - For non-road vehicles, activity data were obtained from AAR (2009 through 2010), APTA (2007 through 2010), BEA (1991 through 2009), Benson (2002 through 2004), DOE (1993 through 2010),

was estimated to fall by the same rate that diesel fuel consumption fell overall in 2009. VMT was then distributed to vehicle classes based on these fuel consumption estimates, assuming no relative change in MPG between vehicle classes.

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

DESC (2011), DOC (1991 through 2010), DOT (1991 through 2010), EIA (2009a), EIA (2009d), EIA (2007a), EIA (2002), EIA (1991 through 2011), EPA (2010b), FAA (2008), and Gaffney (2007).

- For jet fuel used by aircraft, CO_2 emissions were calculated directly based on reported consumption of fuel as reported by EIA, and allocated to commercial aircraft using flight-specific fuel consumption data from the Federal Aviation Administration's (FAA) Aviation Environmental Design Tool (AEDT) (FAA 2011). [78] Allocation to domestic general aviation was made using FAA Aerospace Forecast data, and allocation to domestic military uses was made using DoD data (see Annex 3.7).

Heat contents and densities were obtained from EIA (2010) and USAF (1998). [79]

[BEGIN BOX]

Box 3-2: Carbon Intensity of U.S. Energy Consumption

Fossil fuels are the dominant source of energy in the United States, and CO_2 is the dominant greenhouse gas emitted as a product from their combustion. Energy-related CO_2 emissions are impacted by not only lower levels of energy consumption but also by lowering the C intensity of the energy sources employed (e.g., fuel switching from coal to natural gas). The amount of C emitted from the combustion of fossil fuels is dependent upon the C content of the fuel and the fraction of that C that is oxidized. Fossil fuels vary in their average C content, ranging from about 53 Tg CO_2 Eq./QBtu for natural gas to upwards of 95 Tg CO_2 Eq./QBtu for coal and petroleum coke.[80] In general, the C content per unit of energy of fossil fuels is the highest for coal products, followed by petroleum, and then natural gas. The overall C 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 3-15 provides a time series of the C 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 C intensity for the residential sector does not include the energy from or emissions related to the consumption of electricity for lighting. Looking only at this direct consumption of fossil fuels, the residential sector exhibited the lowest C intensity, which is related to the large percentage of its energy derived from natural gas for heating. The C intensity of the commercial sector has predominantly declined since 1990 as commercial businesses shift 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 C intensities over this period. The C intensity of the transportation sector was closely related to the C content of petroleum products (e.g., motor gasoline and jet fuel, both around 70 Tg CO_2 Eq./EJ), which were the primary sources of energy. Lastly, the electricity generation sector had the highest C intensity due to its heavy reliance on coal for generating electricity.

Table 3-15: Carbon Intensity from Direct Fossil Fuel Combustion by Sector (Tg CO_2 Eq./QBtu)

Sector	1990	2000	2005	2006	2007	2008	2009
Residential [a]	57.4	56.6	56.6	56.5	56.3	56.1	56.0
Commercial [a]	59.2	57.2	57.5	57.2	57.1	56.8	56.9
Industrial [a]	64.3	62.8	64.3	64.5	64.0	63.6	63.2
Transportation [a]	71.1	71.3	71.4	71.6	71.9	71.6	71.5

[78] Data for inventory years 2000 through 2005 were developed using the FAA's System for assessing Aviation's Global Emissions (SAGE) model. That tool has been incorporated into the Aviation Environmental Design Tool (AEDT), which calculates noise in addition to aircraft fuel burn and emissions for all commercial flights globally in a given year. Data for inventory years 2006-2009 were developed using AEDT. The AEDT model dynamically models aircraft performance in space and time to produce fuel burn, emissions and noise. Full flight gate-to-gate analyses are possible for study sizes ranging from a single flight at an airport to scenarios at the regional, national, and global levels. AEDT is currently used by the U.S. government to consider the interdependencies between aircraft-related fuel burn, noise and emissions.

[79] For a more detailed description of the data sources used for the analysis of the transportation end use sector see the Mobile Combustion (excluding CO_2) and International Bunker Fuels sections of the Energy chapter, Annex 3.2, and Annex 3.7.

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

Electricity Generation [b]	87.3		86.2		85.8	85.4	84.7	84.9	83.7
U.S. Territories [c]	73.0		72.5		73.4	73.5	73.8	73.3	73.1
All Sectors [c]	**73.0**		**73.0**		**73.5**	**73.5**	**73.3**	**73.1**	**72.4**

[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.

Over the twenty-year period of 1990 through 2009, however, the C intensity of U.S. energy consumption has been fairly constant, as the proportion of fossil fuels used by the individual sectors has not changed significantly. Per capita energy consumption fluctuated little from 1990 to 2007, but in 2009 was approximately 9 percent below levels in 1990 (see Figure 3-14). Due to a general shift from a manufacturing-based economy to a service-based economy, as well as overall increases in efficiency, energy consumption and energy-related CO_2 emissions per dollar of gross domestic product (GDP) have both declined since 1990 (BEA 2010).

Figure 3-14: U.S. Energy Consumption and Energy-Related CO_2 Emissions Per Capita and Per Dollar GDP

C intensity estimates were developed using nuclear and renewable energy data from EIA (2010), EPA (2010a), and fossil fuel consumption data as discussed above and presented in Annex 2.1.

[END BOX]

Uncertainty and Time Series Consistency

For estimates of CO_2 from fossil fuel combustion, the amount of CO_2 emitted is 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.

Nevertheless, there are uncertainties 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. For the United States, however, the impact of these uncertainties on overall CO_2 emission estimates is believed to be relatively small. See, for example, Marland and Pippin (1990).

Although statistics of total fossil fuel and other energy consumption are relatively accurate, the allocation of this consumption to individual end-use sectors (i.e., residential, commercial, industrial, and transportation) is less certain. For example, for some fuels the sectoral allocations are based on price rates (i.e., tariffs), but a 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.

To calculate the total CO_2 emission estimate from energy-related fossil fuel combustion, the amount of fuel used in these non-energy production processes were subtracted from the total fossil fuel consumption for 2009. The amount of CO_2 emissions resulting from non-energy related fossil fuel use has been calculated separately and reported in the Carbon Emitted from Non-Energy Uses of Fossil Fuels section of this report. These factors all contribute to the uncertainty in the CO_2 estimates. Detailed discussions on the uncertainties associated with C emitted from Non-Energy Uses of Fossil Fuels can be found within that section of this chapter.

Various sources of uncertainty surround the estimation of emissions from international bunker fuels, which are subtracted from the U.S. totals (see the detailed discussions on these uncertainties 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.

Uncertainties in the emission estimates presented above also result from 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 improve the allocation into detailed transportation end-use sector emissions.

The uncertainty analysis was performed by primary fuel type for each end-use sector, using the IPCC-recommended Tier 2 uncertainty estimation methodology, Monte Carlo Simulation technique, with @RISK software. For this uncertainty estimation, the inventory estimation model for CO_2 from fossil fuel combustion was integrated with the relevant variables from the inventory estimation model for International Bunker Fuels, to realistically characterize the interaction (or endogenous correlation) between the variables of these two models. About 120 input variables were modeled for CO_2 from energy-related Fossil Fuel Combustion (including about 10 for non-energy fuel consumption and about 20 for International Bunker Fuels).

In developing the uncertainty estimation model, uniform distributions were assumed for all activity-related input variables and emission factors, based on the SAIC/EIA (2001) report.[81] Triangular distributions were assigned for the oxidization factors (or combustion efficiencies). The uncertainty ranges were assigned to the input variables based on the data reported in SAIC/EIA (2001) and on conversations with various agency personnel.[82]

The uncertainty ranges for the activity-related input variables were typically asymmetric around their inventory estimates; the uncertainty ranges for the emissions factors were symmetric. Bias (or systematic uncertainties) associated with these variables accounted for much of the uncertainties associated with these variables (SAIC/EIA 2001).[83] For purposes of this uncertainty analysis, each input variable was simulated 10,000 times through Monte Carlo Sampling.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 3-16. Fossil fuel combustion CO_2 emissions in 2009 were estimated to be between 5,149.0 and 5,522.4 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 1 percent below to 6 percent above the 2009 emission estimate of 5,209.0.0 Tg CO_2 Eq.

Table 3-16: Tier 2 Quantitative Uncertainty Estimates for CO_2 Emissions from Energy-related Fossil Fuel Combustion by Fuel Type and Sector (Tg CO_2 Eq. and Percent)

Fuel/Sector	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)		(%)	
		Lower Bound	Upper Bound	Lower Bound	Upper Bound
Coal [b]	**1,841.0**	**1,779.3**	**2,015.6**	**-3%**	**+9%**
Residential	0.6	0.6	0.7	-6%	+15%
Commercial	5.8	5.5	6.7	-5%	+15%
Industrial	83.4	80.5	97.5	-3%	+17%
Transportation	NE	NE	NE	NA	NA
Electricity Generation	1,747.6	1,680.4	1,915.8	-4%	+10%
U.S. Territories	3.5	3.1	4.2	-12%	+19%

[81] SAIC/EIA (2001) characterizes the underlying probability density function for the input variables as a combination of uniform and normal distributions (the former to represent the bias component and the latter to represent the random component). However, for purposes of the current uncertainty analysis, it was determined that uniform distribution was more appropriate to characterize the probability density function underlying each of these variables.

[82] In the SAIC/EIA (2001) report, the quantitative uncertainty estimates were developed for each of the three major fossil fuels used within each end-use sector; the variations within the sub-fuel types within each end-use sector were not modeled. However, for purposes of assigning uncertainty estimates to the sub-fuel type categories within each end-use sector in the current uncertainty analysis, SAIC/EIA (2001)-reported uncertainty estimates were extrapolated.

[83] Although, in general, random uncertainties are the main focus of statistical uncertainty analysis, when the uncertainty estimates are elicited from experts, their estimates include both random and systematic uncertainties. Hence, both these types of uncertainties are represented in this uncertainty analysis.

Natural Gas [b]	**1,200.9**	**1,209.4**	**1,276.6**	**+1%**	**+6%**
Residential	257.2	250.0	275.2	-3%	+7%
Commercial	167.9	163.2	179.7	-3%	+7%
Industrial	365.0	374.9	412.7	+3%	+13%
Transportation	36.3	35.2	38.8	-3%	+7%
Electricity Generation	373.1	362.3	392.0	-3%	+5%
U.S. Territories	1.5	1.3	1.7	-12%	+17%
Petroleum [b]	**2,166.7**	**2,067.2**	**2,323.5**	**-5%**	**+7%**
Residential	81.4	76.9	85.7	-6%	+5%
Commercial	50.3	47.9	52.4	-5%	+4%
Industrial	282.0	231.2	330.4	-18%	+17%
Transportation	1,683.4	1,598.6	1,826.8	-5%	+9%
Electric Utilities	32.9	31.5	35.4	-4%	+7%
U.S. Territories	36.7	33.8	40.9	-8%	+11%
Total (excluding Geothermal) [b]	**5,208.6**	**5,148.76**	**5,522.0**	**-1%**	**+6%**
Geothermal	0.4	NE	NE	NE	NE
Total (including Geothermal) [b,c]	**5,209.0**	**5,149.0**	**5,522.4**	**-1%**	**+6%**

NA (Not Applicable)
NE (Not Estimated)
[a] Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval.
[b] The low and high estimates for total emissions were calculated separately through simulations and, hence, the low and high emission estimates for the sub-source categories do not sum to total emissions.
[c] Geothermal emissions added for reporting purposes, but an uncertainty analysis was not performed for CO_2 emissions from geothermal production.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

A source-specific QA/QC plan for CO_2 from fossil fuel combustion was developed and implemented. This effort included a Tier 1 analysis, as well as portions of a Tier 2 analysis. The Tier 2 procedures that were implemented involved checks specifically focusing on the activity data and methodology used for estimating CO_2 emissions from fossil fuel combustion in the United States. Emission totals for the different sectors and fuels were compared and trends were investigated to determine whether any corrective actions were needed. Minor corrective actions were taken.

Recalculations Discussion

The Energy Information Administration (EIA 2011) updated energy consumption statistics across the time series. These revisions primarily impacted the emission estimates for 2007 and 2008. In addition, the coal emissions for U.S. Territories decreased from 2001 to 2008 due to the closure of a coal power plant in the U.S. Virgin Islands. Overall, these changes resulted in an average annual increase of 0.5 Tg CO_2 Eq. (less than 0.1 percent) in CO_2 emissions from fossil fuel combustion for the period 1990 through 2008.

Planned Improvements

To reduce uncertainty of CO_2 from fossil fuel combustion estimates, efforts will be taken to work with EIA and other agencies to improve the quality of the U.S. territories data. This improvement is not all-inclusive, and is part of an ongoing analysis and efforts to continually improve the CO_2 from fossil fuel combustion estimates. In addition, further expert elicitation may be conducted to better quantify the total uncertainty associated with emissions from this source.

Beginning in 2010, those facilities that emit over 25,000 tons of greenhouse gases (CO_2 Eq.) from stationary combustion across all sectors of the economy are required to calculate and report their greenhouse gas emissions to

EPA through its Greenhouse Gas Reporting Program. These data will be used in future inventories to improve the emission calculations through the use of these collected higher tier methodological data.

CH_4 and N_2O from Stationary Combustion

Methodology

CH_4 and N_2O emissions from stationary combustion were estimated by multiplying fossil fuel and wood consumption data by emission factors (by sector and fuel type). National coal, natural gas, fuel oil, and wood consumption data were grouped by sector: industrial, commercial, residential, electricity generation, and U.S. territories. For the CH_4 and N_2O estimates, wood consumption data for the United States was obtained from EIA's Annual Energy Review (EIA 2010). Fuel consumption data for coal, natural gas, and fuel oil for the United States were obtained from EIA's Monthly Energy Review and unpublished supplemental tables on petroleum product detail (EIA 2011). Because the United States does not include territories in its national energy statistics, fuel consumption data for territories were provided separately by Jacobs (2010).[84] Fuel consumption for the industrial sector was adjusted to subtract out construction and agricultural use, which is reported under mobile sources.[85] Construction and agricultural fuel use was obtained from EPA (2010a). 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 for the four end-use sectors were provided by the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006). U.S. territories' emission factors were estimated using the U.S. emission factors for the primary sector in which each fuel was combusted.

More detailed information on the methodology for calculating emissions from stationary combustion, including emission factors and activity data, is provided in Annex 3.1.

Uncertainty and Time-Series Consistency

CH_4 emission estimates from stationary sources exhibit high uncertainty, 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).

An uncertainty analysis was performed by primary fuel type for each end-use sector, using the IPCC-recommended Tier 2 uncertainty estimation methodology, Monte Carlo Simulation technique, with @RISK software.

The uncertainty estimation model for this source category was developed by integrating the CH_4 and N_2O stationary source inventory estimation models with the model for CO_2 from fossil fuel combustion to realistically characterize the interaction (or endogenous correlation) between the variables of these three models. About 55 input variables were simulated for the uncertainty analysis of this source category (about 20 from the CO_2 emissions from fossil fuel combustion inventory estimation model and about 35 from the stationary source inventory models).

In developing the uncertainty estimation model, uniform distribution was assumed for all activity-related input variables and N_2O emission factors, based on the SAIC/EIA (2001) report.[86] For these variables, the uncertainty

[84] U.S. territories data also include combustion from mobile activities because data to allocate territories' energy use were unavailable. For this reason, CH_4 and N_2O emissions from combustion by U.S. territories are only included in the stationary combustion totals.

[85] Though emissions from construction and farm use occur due to both stationary and mobile sources, detailed data was not available to determine the magnitude from each. Currently, these emissions are assumed to be predominantly from mobile sources.

[86] SAIC/EIA (2001) characterizes the underlying probability density function for the input variables as a combination of uniform and normal distributions (the former distribution to represent the bias component and the latter to represent the random component). However, for purposes of the current uncertainty analysis, it was determined that uniform distribution was more appropriate to characterize the probability density function underlying each of these variables.

ranges were assigned to the input variables based on the data reported in SAIC/EIA (2001).[87] However, the CH_4 emission factors differ from those used by EIA. Since these factors were obtained from IPCC/UNEP/OECD/IEA (1997), uncertainty ranges were assigned based on IPCC default uncertainty estimates (IPCC 2000).

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 3-17. Stationary combustion CH_4 emissions in 2009 (including biomass) were estimated to be between 4.1 and 14.0 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 34 percent below to 127 percent above the 2009 emission estimate of 6.2 Tg CO_2 Eq.[88] Stationary combustion N_2O emissions in 2009 (*including* biomass) were estimated to be between 9.8 and 36.7 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 23 percent below to 187 percent above the 2009 emissions estimate of 12.8 Tg CO_2 Eq.

Table 3-17: Tier 2 Quantitative Uncertainty Estimates for CH_4 and N_2O Emissions from Energy-Related Stationary Combustion, Including Biomass (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a]			
			(Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Stationary Combustion	CH_4	6.2	4.1	14.0	-34%	+127%
Stationary Combustion	N_2O	12.8	9.8	36.7	-23%	+187%

[a] Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval.

The uncertainties associated with the emission estimates of CH_4 and N_2O are greater than those associated 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 indirect greenhouse gases, uncertainties are partly due to assumptions concerning combustion technology types, age of equipment, emission factors used, and activity data projections.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

A source-specific QA/QC plan for stationary combustion was developed and implemented. This effort included a Tier 1 analysis, as well as portions of a Tier 2 analysis. The Tier 2 procedures that were implemented involved checks specifically focusing on the activity data and emission factor sources and methodology used for estimating CH_4, N_2O, and the indirect greenhouse gases from stationary combustion in the United States. Emission totals for the different sectors and fuels were compared and trends were investigated.

Recalculations Discussion

Historical CH_4 and N_2O emissions from stationary sources (excluding CO_2) were revised due to a couple of changes, mainly impacting 2007 and 2008 estimates. Slight changes to emission estimates for sectors are due to revised data from EIA (2010). Wood consumption data in EIA (2011) were revised for the residential, commercial, and industrial sectors for 2007 and 2008 as well as for the electric power sector for 2006 through 2008. The combination of the methodological and historical data changes resulted in an average annual increase of 0.01 Tg CO_2 Eq. (0.2 percent) in CH_4 emissions from stationary combustion and an average annual decrease of 0.08 Tg CO_2 Eq. (0.5 percent) in N_2O emissions from stationary combustion for the period 1990 through 2008.

[87] In the SAIC/EIA (2001) report, the quantitative uncertainty estimates were developed for each of the three major fossil fuels used within each end-use sector; the variations within the sub-fuel types within each end-use sector were not modeled. However, for purposes of assigning uncertainty estimates to the sub-fuel type categories within each end-use sector in the current uncertainty analysis, SAIC/EIA (2001)-reported uncertainty estimates were extrapolated.

[88] The low emission estimates reported in this section have been rounded down to the nearest integer values and the high emission estimates have been rounded up to the nearest integer values.

Planned Improvements

Several items are being evaluated to improve the CH_4 and N_2O emission estimates from stationary combustion and to reduce uncertainty. Efforts will be taken to work with EIA and other agencies to improve the quality of the U.S. territories data. Because these data are not broken out by stationary and mobile uses, further research will be aimed at trying to allocate consumption appropriately. In addition, the uncertainty of biomass emissions will be further investigated since it was expected that the exclusion of biomass from the uncertainty estimates would reduce the uncertainty; and in actuality the exclusion of biomass increases the uncertainty. These improvements are not all-inclusive, but are part of an ongoing analysis and efforts to continually improve these stationary estimates.

Beginning in 2010, those facilities that emit over 25,000 tons of greenhouse gases (CO_2 Eq.) from stationary combustion across all sectors of the economy are required to calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. These data will be used in future inventories to improve the emission calculations through the use of these collected higher tier methodological data.

CH_4 and N_2O from Mobile Combustion

Methodology

Estimates of CH_4 and N_2O emissions from mobile combustion were calculated by multiplying emission factors by measures of activity for each fuel and vehicle type (e.g., light-duty gasoline trucks). Activity data included vehicle miles traveled (VMT) for on-road vehicles and fuel consumption for non-road mobile sources. The activity data and emission factors used are described in the subsections that follow. A complete discussion of the methodology used to estimate CH_4 and N_2O emissions from mobile combustion and the emission factors used in the calculations is provided in Annex 3.2.

On-Road Vehicles

Estimates of CH_4 and N_2O emissions from gasoline and diesel on-road vehicles are based on VMT and emission factors by vehicle type, fuel type, model year, and emission control technology. Emission estimates for alternative fuel vehicles (AFVs)[89] are based on VMT and emission factors by vehicle and fuel type.

Emission factors for gasoline and diesel on-road vehicles utilizing Tier 2 and Low Emission Vehicle (LEV) technologies were developed by ICF (2006b); all other gasoline and diesel on-road vehicle emissions factors were developed by ICF (2004). These factors were derived from EPA, California Air Resources Board (CARB) and Environment Canada laboratory test results of different vehicle and control technology types. The EPA, CARB and Environment Canada tests were designed following the Federal Test Procedure (FTP), which covers three separate driving segments, since vehicles emit varying amounts of greenhouse gases depending on the driving segment. These driving segments are: (1) a transient driving cycle that includes cold start and running emissions, (2) a cycle that represents running emissions only, and (3) a transient driving cycle that includes hot start and running emissions. For each test run, a bag was affixed to the tailpipe of the vehicle and the exhaust was collected; the content of this bag was then analyzed to determine quantities of gases present. The emissions characteristics of segment 2 were used to define running emissions, and subtracted from the total FTP emissions to determine start emissions. These were then recombined based upon the ratio of start to running emissions for each vehicle class from MOBILE6.2, an EPA emission factor model that predicts gram per mile emissions of CO_2, CO, HC, NO_x, and PM from vehicles under various conditions, to approximate average driving characteristics.[90]

Emission factors for AFVs were developed by ICF (2006a) after examining Argonne National Laboratory's GREET 1.7–Transportation Fuel Cycle Model (ANL 2006) and Lipman and Delucchi (2002). These sources describe AFV emission factors in terms of ratios to conventional vehicle emission factors. Ratios of AFV to conventional vehicle emissions factors were then applied to estimated Tier 1 emissions factors from light-duty gasoline vehicles to estimate light-duty AFVs. Emissions factors for heavy-duty AFVs were developed in relation to gasoline heavy-duty vehicles. A complete discussion of the data source and methodology used to determine emission factors from

[89] Alternative fuel and advanced technology vehicles are those that can operate using a motor fuel other than gasoline or diesel. This includes electric or other bi-fuel or dual-fuel vehicles that may be partially powered by gasoline or diesel.

[90] Additional information regarding the model can be found online at http://www.epa.gov/OMS/m6.htm.

AFVs is provided in Annex 3.2.

Annual VMT data for 1990 through 2010 were obtained from the Federal Highway Administration's (FHWA) Highway Performance Monitoring System database as reported in Highway Statistics (FHWA 1996 through 2010).[91] VMT estimates were then allocated from FHWA's vehicle categories to fuel-specific vehicle categories using the calculated shares of vehicle fuel use for each vehicle category by fuel type reported in DOE (1993 through 2010) and information on total motor vehicle fuel consumption by fuel type from FHWA (1996 through 2010). VMT for AFVs were taken from Browning (2003). The age distributions of the U.S. vehicle fleet were obtained from EPA (2010a, 2000), and the average annual age-specific vehicle mileage accumulation of U.S. vehicles were obtained from EPA (2000).

Control technology and standards data for on-road vehicles were obtained from EPA's Office of Transportation and Air Quality (EPA 2007a, 2007b, 2000, 1998, and 1997) and Browning (2005). These technologies and standards are defined in Annex 3.2, and were compiled from EPA (1993, 1994a, 1994b, 1998, 1999a) and IPCC/UNEP/OECD/IEA (1997).

Non-Road Vehicles

To estimate emissions from non-road vehicles, fuel consumption data were employed as a measure of activity, and multiplied by fuel-specific emission factors (in grams of N_2O and CH_4 per kilogram of fuel consumed).[92] Activity data were obtained from AAR (2009 through 2010), APTA (2007 through 2010), APTA (2006), BEA (1991 through 2005), Benson (2002 through 2004), DHS (2008), DOC (1991 through 2008), DOE (1993 through 2010), DESC (2011), DOT (1991 through 2010), EIA (2008a, 2007a, 2007b, 2002), EIA (2007 through 2010), EIA (1991 through 2011), EPA (2009), Esser (2003 through 2004), FAA (2011, 2010, and 2006), Gaffney (2007), and (2006 through 2010). Emission factors for non-road modes were taken from IPCC/UNEP/OECD/IEA (1997) and Browning (2009).

Uncertainty and Time-Series Consistency

A quantitative uncertainty analysis was conducted for the mobile source sector using the IPCC-recommended Tier 2 uncertainty estimation methodology, Monte Carlo simulation technique, using @RISK software. The uncertainty analysis was performed on 2009 estimates of CH_4 and N_2O emissions, incorporating probability distribution functions associated with the major input variables. For the purposes of this analysis, the uncertainty was modeled for the following four major sets of input variables: (1) vehicle miles traveled (VMT) data, by on-road vehicle and fuel type and (2) emission factor data, by on-road vehicle, fuel, and control technology type, (3) fuel consumption, data, by non-road vehicle and equipment type, and (4) emission factor data, by non-road vehicle and equipment type.

Uncertainty analyses were not conducted for NO_x, CO, or NMVOC emissions. Emission factors for these gases have been extensively researched since emissions of these gases from motor vehicles are regulated in the United States, and the uncertainty in these emission estimates is believed to be relatively low. However, a much higher level of uncertainty is associated with CH_4 and N_2O emission factors, because emissions of these gases are not regulated in the United States (and, therefore, there are not adequate emission test data), and because, unlike CO_2 emissions, the emission pathways of CH_4 and N_2O are highly complex.

Mobile combustion CH_4 emissions from all mobile sources in 2009 were estimated to be between 1.8 and 2.2 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 9 percent below to 15 percent above the corresponding 2009 emission estimate of 2.0 Tg CO_2 Eq. Also at a 95 percent confidence level, mobile combustion N_2O emissions from mobile sources in 2009 were estimated to be between 20.5 and 27.9 Tg CO_2 Eq., indicating a range of 14 percent below to 17 percent above the corresponding 2009 emission estimate of 23.9 Tg CO_2 Eq.

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[91] Fuel use by vehicle class (VM-1 table) was not available from FHWA for 2009, but changes in overall diesel and gasoline consumption were released in Table MF21. Fuel use in vehicle classes that were predominantly gasoline were estimated to grow by the rate of growth for gasoline between 2008 and 2009. Fuel use in vehicle classes that were predominantly diesel were estimated to fall by the same rate that diesel fuel consumption fell overall in 2009. VMT was then distributed to vehicle classes based on these fuel consumption estimates, assuming no relative change in MPG between vehicle classes.

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

Table 3-18: Tier 2 Quantitative Uncertainty Estimates for CH_4 and N_2O Emissions from Mobile Sources (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate[a] (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a]			
			(Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Mobile Sources	CH_4	2.0	1.8	2.2	-9%	+15%
Mobile Sources	N_2O	23.9	20.5	27.9	-14%	+17%

[a] Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval.

This uncertainty analysis is a continuation of a multi-year process for developing quantitative uncertainty estimates for this source category using the IPCC Tier 2 approach to uncertainty analysis. As a result, as new information becomes available, uncertainty characterization of input variables may be improved and revised. For additional information regarding uncertainty in emission estimates for CH_4 and N_2O please refer to the Uncertainty Annex.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2008. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

A source-specific QA/QC plan for mobile combustion was developed and implemented. This plan is based on the IPCC-recommended QA/QC Plan. The specific plan used for mobile combustion was updated prior to collection and analysis of this current year of data. This effort included a Tier 1 analysis, as well as portions of a Tier 2 analysis. The Tier 2 procedures focused on the emission factor and activity data sources, as well as the methodology used for estimating emissions. These procedures included a qualitative assessment of the emissions estimates to determine whether they appear consistent with the most recent activity data and emission factors available. A comparison of historical emissions between the current Inventory and the previous Inventory was also conducted to ensure that the changes in estimates were consistent with the changes in activity data and emission factors.

Recalculations Discussion

In order to ensure that these estimates are continuously improved, the calculation methodology is revised annually based on comments from internal and external reviewers. Each year, a number of adjustments are made to the methodologies used in calculating emissions in the current Inventory relative to previous Inventory reports. One of the revisions that were made this year was incorporating motor vehicle age distribution from EPA's MOtor Vehicle Emission Simulator (MOVES) model. MOVES is EPA's tool for estimating emissions from highway vehicles, based on analysis of millions of emission test results and considerable advances in EPA's understanding of vehicle emissions. Population data from the MOVES model was used to estimate the age distribution of motor vehicles in the United States.

Planned Improvements

While the data used for this report represent the most accurate information available, four areas have been identified that could potentially be improved in the short-term given available resources.

1. Develop updated emissions factors for diesel vehicles, motorcycle, and biodiesel vehicles. Previous emission factors were based upon extrapolations from other vehicle classes and new test data from Environment Canada and other sources may allow for better estimation of emission factors for these vehicles.
2. Develop new emission factors for non-road equipment. The current inventory estimates for non-CO_2 emissions from non-road sources are based on emission factors from IPCC guidelines published in 1996. Recent data on non-road sources from Environment Canada and the California Air Resources Board will be investigated in order to assess the feasibility of developing new N_2O and CH_4 emissions factors for non-road equipment.
3. Examine the feasibility of estimating aircraft N_2O and CH_4 emissions by the number of takeoffs and landings, instead of total fuel consumption. Various studies have indicated that aircraft N_2O and CH_4

emissions are more dependent on aircraft takeoffs and landings than on total aircraft fuel consumption; however, aircraft emissions are currently estimated from fuel consumption data. FAA's SAGE and AEDT databases contain detailed data on takeoffs and landings for each calendar year starting in 2000, and could potentially be used to conduct a Tier II analysis of aircraft emissions. This methodology will require a detailed analysis of the number of takeoffs and landings by aircraft type on domestic trips, the development of procedures to develop comparable estimates for years prior to 2000, and the dynamic interaction of ambient air with aircraft exhausts is developed. The feasibility of this approach will be explored.

Develop improved estimates of domestic waterborne fuel consumption. The inventory estimates for residual and distillate fuel used by ships and boats is based in part on data on bunker fuel use from the U.S. Department of Commerce. Domestic fuel consumption is estimated by subtracting fuel sold for international use from the total sold in the United States. It may be possible to more accurately estimate domestic fuel use and emissions by using detailed data on marine ship activity. The feasibility of using domestic marine activity data to improve the estimates will be investigated. Continue to examine the use of EPA's MOVES model in the development of the inventory estimates, including use for uncertainty analysis. Although the inventory uses some of the underlying data from MOVES, such as vehicle age distributions by model year, MOVES is not used directly in calculating mobile source emissions. As MOVES goes through additional testing and refinement, the use of MOVES will be further explored.

3.2. Carbon Emitted from Non-Energy Uses of Fossil Fuels (IPCC Source Category 1A)

In addition to being combusted for energy, fossil fuels are also consumed for non-energy uses (NEU) in the United States. The fuels used for these purposes are diverse, including natural gas, liquefied petroleum gases (LPG), asphalt (a viscous liquid mixture of heavy crude oil distillates), petroleum coke (manufactured from heavy oil), and coal (metallurgical) coke (manufactured from coking coal). The non-energy applications of these fuels are equally diverse, including feedstocks for the manufacture of plastics, rubber, synthetic fibers and other materials; reducing agents for the production of various metals and inorganic products; and non-energy products such as lubricants, waxes, and asphalt (IPCC 2006).

CO_2 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, emissions may occur during the product's lifetime, such as during solvent use. Overall, throughout the time series and across all uses, about 61 percent of the total C consumed for non-energy purposes was stored in products, and not released to the atmosphere; the remaining 39 percent was emitted.

There are several areas in which non-energy uses of fossil fuels are closely related to other parts of the inventory. For example, some of the NEU products release CO_2 at the end of their commercial life when they are combusted after disposal; these emissions are reported separately within the Energy chapter in the Incineration of Waste source category. In addition, there is some overlap between fossil fuels consumed for non-energy uses and the fossil-derived CO_2 emissions accounted for in the Industrial Processes chapter, especially for fuels used as reducing agents. To avoid double-counting, the "raw" non-energy fuel consumption data reported by EIA are modified to account for these overlaps. There are also net exports of petrochemicals that are not completely accounted for in the EIA data, and the inventory calculations make adjustments to address the effect of net exports on the mass of C in non-energy applications.

As shown in Table 3-19, fossil fuel emissions in 2009 from the non-energy uses of fossil fuels were 123.4 Tg CO_2 Eq., which constituted approximately 2 percent of overall fossil fuel emissions. In 2009, the consumption of fuels for non-energy uses (after the adjustments described above) was 4,451.0 TBtu, an increase of 0.2 percent since 1990 (see Table 3-20). About 49.9 Tg of the C (182.8 Tg CO_2 Eq.) in these fuels was stored, while the remaining 33.6 Tg C (123.4 Tg CO_2 Eq.) was emitted.

Table 3-19: CO_2 Emissions from Non-Energy Use Fossil Fuel Consumption (Tg CO_2 Eq.)

Year	1990	2000	2005	2006	2007	2008	2009
Potential Emissions	310.8	383.6	381.6	381.7	370.1	344.9	306.1
C Stored	192.2	238.6	238.3	236.1	232.8	204.0	182.8
Emissions as a % of Potential	38%	38%	38%	38%	37%	41%	40%
Emissions	**118.6**	**144.9**	**143.4**	**145.6**	**137.2**	**141.0**	**123.4**

Methodology

The first step in estimating C stored in products was to determine the aggregate quantity of fossil fuels consumed for non-energy uses. The C content of these feedstock fuels is equivalent to potential emissions, or the product of consumption and the fuel-specific C content values. Both the non-energy fuel consumption and C content data were supplied by the EIA (2011) (see Annex 2.1). Consumption of natural gas, LPG, pentanes plus, naphthas, other oils, and special naphtha were adjusted to account for net exports of these products that are not reflected in the raw data from EIA. Consumption values for industrial coking coal, petroleum coke, other oils, and natural gas in Table 3-20 and Table 3-21 have been adjusted to subtract non-energy uses that are included in the source categories of the Industrial Processes chapter.[93] Consumption values were also adjusted to subtract net exports of intermediary chemicals.

For the remaining non-energy uses, the quantity of C stored was estimated by multiplying the potential emissions by a storage factor.

- For several fuel types—petrochemical feedstocks (including natural gas for non-fertilizer uses, LPG, pentanes plus, naphthas, other oils, still gas, special naphtha, and industrial other coal), asphalt and road oil, lubricants, and waxes—U.S. data on C stocks and flows were used to develop C storage factors, calculated as the ratio of (a) the C stored by the fuel's non-energy products to (b) the total C 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 and during use. Because losses associated with municipal solid waste management are handled separately in this sector under the Incineration of Waste source category, the storage factors do not account for losses at the disposal end of the life cycle.
- For industrial coking coal and distillate fuel oil, storage factors were taken from IPCC/UNEP/OECD/IEA (1997), which in turn draws from Marland and Rotty (1984).
- For the remaining fuel types (petroleum coke, miscellaneous products, and other petroleum), IPCC does not provide guidance on storage factors, and assumptions were made based on the potential fate of C in the respective NEU products.

Table 3-20: Adjusted Consumption of Fossil Fuels for Non-Energy Uses (TBtu)

Year	1990	2000	2005	2006	2007	2008	2009
Industry	**4,181.1**	**5,214.4**	**5,174.4**	**5,163.2**	**5,060.7**	**4,671.9**	**4,267.7**
Industrial Coking Coal	+	53.0	79.8	62.3	1.7	28.4	6.1
Industrial Other Coal	8.2	12.4	11.9	12.4	12.4	12.4	12.4
Natural Gas to Chemical Plants	277.3	420.3	397.0	407.7	412.5	395.2	366.0
Asphalt & Road Oil	1,170.2	1,275.7	1,323.2	1,261.2	1,197.0	1,012.0	873.1
LPG	1,119.2	1,607.0	1,444.0	1,488.6	1,483.0	1,409.6	1,446.2
Lubricants	186.3	189.9	160.2	156.1	161.2	149.6	134.5
Pentanes Plus	77.5	229.3	146.3	105.5	132.7	114.9	93.4
Naphtha (<401 ° F)	325.9	593.7	679.6	618.1	542.6	467.3	450.7
Other Oil (>401 ° F)	661.4	527.0	514.8	573.4	669.2	599.2	392.5
Still Gas	21.3	12.6	67.7	57.2	44.2	47.3	133.9
Petroleum Coke	54.8	35.3	128.8	172.2	155.9	174.4	133.0
Special Naphtha	100.8	94.4	60.9	68.9	75.5	83.2	44.2
Distillate Fuel Oil	7.0	11.7	16.0	17.5	17.5	17.5	17.5
Waxes	33.3	33.1	31.4	26.1	21.9	19.1	12.2
Miscellaneous Products	137.8	119.2	112.8	136.0	133.5	142.0	151.8
Transportation	**176.0**	**179.4**	**151.3**	**147.4**	**152.2**	**141.3**	**127.1**
Lubricants	176.0	179.4	151.3	147.4	152.2	141.3	127.1
U.S. Territories	**86.7**	**152.2**	**121.9**	**133.4**	**108.4**	**126.7**	**56.3**
Lubricants	0.7	3.1	4.6	6.2	5.9	2.7	1.0

[93] These source categories include Iron and Steel Production, Lead Production, Zinc Production, Ammonia Manufacture, Carbon Black Manufacture (included in Petrochemical Production), Titanium Dioxide Production, Ferroalloy Production, Silicon Carbide Production, and Aluminum Production.

Other Petroleum (Misc. Prod.)	86.0	149.1	117.3	127.2	102.5	124.1	55.2
Total	**4,443.8**	**5,546.0**	**5,447.6**	**5,444.0**	**5,321.3**	**4,940.0**	**4,451.0**

+ Does not exceed 0.05 TBtu

Note: To avoid double-counting, coal coke, petroleum coke, natural gas consumption, and other oils are adjusted for industrial process consumption reported in the Industrial Processes sector. Natural gas, LPG, Pentanes Plus, Naphthas, Special Naphtha, and Other Oils are adjusted to account for exports of chemical intermediates derived from these fuels. For residual oil (not shown in the table), all non-energy use is assumed to be consumed in C black production, which is also reported in the Industrial Processes chapter.

Note: Totals may not sum due to independent rounding.

Table 3-21: 2009 Adjusted Non-Energy Use Fossil Fuel Consumption, Storage, and Emissions

Sector/Fuel Type	Adjusted Non-Energy Use[a] (TBtu)	Carbon Content Coefficient (Tg C/QBtu)	Potential Carbon (Tg C)	Storage Factor	Carbon Stored (Tg C)	Carbon Emissions (Tg C)	Carbon Emissions (Tg CO_2 Eq.)
Industry	**4,267.7**	**-**	**79.8**	**-**	**49.5**	**30.3**	**111.1**
Industrial Coking Coal	6.1	31.00	0.2	0.10	0.0	0.2	0.6
Industrial Other Coal	12.4	25.82	0.3	0.58	0.2	0.1	0.5
Natural Gas to Chemical Plants	366.0	14.47	5.3	0.58	3.1	2.2	8.1
Asphalt & Road Oil	873.1	20.55	17.9	1.00	17.9	0.1	0.3
LPG	1,446.2	17.06	24.7	0.58	14.3	10.3	37.9
Lubricants	134.5	20.20	2.7	0.09	0.2	2.5	9.0
Pentanes Plus	93.4	19.10	1.8	0.58	1.0	0.7	2.7
Naphtha (<401° F)	450.7	18.55	8.4	0.58	4.9	3.5	12.9
Other Oil (>401° F)	392.5	20.17	7.9	0.58	4.6	3.3	12.2
Still Gas	133.9	17.51	2.3	0.58	1.4	1.0	3.6
Petroleum Coke	133.0	27.85	3.7	0.30	1.1	2.6	9.5
Special Naphtha	44.2	19.74	0.9	0.58	0.5	0.4	1.3
Distillate Fuel Oil	17.5	20.17	0.4	0.50	0.2	0.2	0.6
Waxes	12.2	19.80	0.2	0.58	0.1	0.1	0.4
Miscellaneous Products	151.8	20.31	3.1	0.00	0.0	3.1	11.3
Transportation	**127.1**	**-**	**2.6**	**-**	**0.2**	**2.3**	**8.5**
Lubricants	127.1	20.20	2.6	0.09	0.2	2.3	8.5
U.S. Territories	**56.3**	**-**	**1.1**	**-**	**0.1**	**1.0**	**3.7**
Lubricants	1.0	20.20	+	0.09	+	+	0.1
Other Petroleum (Misc. Prod.)	55.2	20.00	1.1	0.10	0.1	1.0	3.6
Total	**4,451.0**	**-**	**83.5**	**-**	**49.9**	**33.6**	**123.4**

+ Does not exceed 0.05 Tg

- Not applicable.

[a] To avoid double counting, net exports have been deducted.

Note: Totals may not sum due to independent rounding.

Lastly, emissions were estimated by subtracting the C stored from the potential emissions (see Table 3-19). More detail on the methodology for calculating storage and emissions from each of these sources is provided in Annex 2.3.

Where storage factors were calculated specifically for the United States, data were obtained on (1) products such as asphalt, plastics, synthetic rubber, synthetic fibers, cleansers (soaps and detergents), pesticides, food additives, antifreeze and deicers (glycols), and silicones; and (2) industrial releases including energy recovery, Toxics Release Inventory (TRI) releases, hazardous waste incineration, and volatile organic compound, solvent, and non-combustion CO emissions. Data were taken from a variety of industry sources, government reports, and expert communications. Sources include EPA reports and databases such as compilations of air emission factors (EPA 2001), *National Emissions Inventory (NEI) Air Pollutant Emissions Trends Data* (EPA 2010), *Toxics Release Inventory, 1998* (2000b), *Biennial Reporting System* (EPA 2004, 2007a), and pesticide sales and use estimates

(EPA 1998, 1999, 2002, 2004); the EIA Manufacturer's Energy Consumption Survey (MECS) (EIA 1994, 1997, 2001, 2005, 2010); the National Petrochemical & Refiners Association (NPRA 2002); the U.S. Bureau of the Census (1999, 2004, 2009); Bank of Canada (2009); Financial Planning Association (2006); INEGI (2006); the United States International Trade Commission (2011); Gosselin, Smith, and Hodge (1984); the Rubber Manufacturers' Association (RMA 2009a,b); the International Institute of Synthetic Rubber Products (IISRP 2000, 2003); the Fiber Economics Bureau (FEB 2010); and the American Chemistry Council (ACC 2003-2010). Specific data sources are listed in full detail in Annex 2.3.

Uncertainty and Time-Series Consistency

An uncertainty analysis was conducted to quantify the uncertainty surrounding the estimates of emissions and storage factors from non-energy uses. This analysis, performed using @RISK software and the IPCC-recommended Tier 2 methodology (Monte Carlo Simulation technique), provides for the specification of probability density functions for key variables within a computational structure that mirrors the calculation of the inventory estimate. The results presented below provide the 95 percent confidence interval, the range of values within which emissions are likely to fall, for this source category.

As noted above, the non-energy use analysis is based on U.S.-specific storage factors for (1) feedstock materials (natural gas, LPG, pentanes plus, naphthas, other oils, still gas, special naphthas, and other industrial coal), (2) asphalt, (3) lubricants, and (4) waxes. For the remaining fuel types (the "other" category in Table 3-22 and Table 3-23), the storage factors were taken directly from the IPCC *Guidelines for National Greenhouse Gas Inventories*, where available, and otherwise assumptions were made based on the potential fate of carbon in the respective NEU products. To characterize uncertainty, five separate analyses were conducted, corresponding to each of the five categories. In all cases, statistical analyses or expert judgments of uncertainty were not available directly from the information sources for all the activity variables; thus, uncertainty estimates were determined using assumptions based on source category knowledge.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 3-22 (emissions) and Table 3-23 (storage factors). Carbon emitted from non-energy uses of fossil fuels in 2009 was estimated to be between 97.6 and 135.3 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 21 percent below to 10 percent above the 2009 emission estimate of 123.4 Tg CO_2 Eq. The uncertainty in the emission estimates is a function of uncertainty in both the quantity of fuel used for non-energy purposes and the storage factor.

Table 3-22: Tier 2 Quantitative Uncertainty Estimates for CO_2 Emissions from Non-Energy Uses of Fossil Fuels (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)		Uncertainty Range Relative to Emission Estimate[a] (%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Feedstocks	CO_2	79.3	63.4	96.1	-20%	21%
Asphalt	CO_2	0.3	0.1	0.6	-58%	119%
Lubricants	CO_2	17.7	14.6	20.5	-17%	16%
Waxes	CO_2	0.4	0.3	0.7	-29%	74%
Other	CO_2	25.7	10.3	27.0	-60%	5%
Total	**CO_2**	123.4	97.6	135.3	-21%	10%

[a] Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval.
NA (Not Applicable)

Table 3-23: Tier 2 Quantitative Uncertainty Estimates for Storage Factors of Non-Energy Uses of Fossil Fuels (Percent)

Source	Gas	2009 Storage Factor (%)	Uncertainty Range Relative to Emission Estimate[a] (%)		(%, Relative)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Feedstocks	CO_2	58%	56%	60%	-3%	4%
Asphalt	CO_2	99.6%	99.1%	99.8%	-0.5%	0.3%
Lubricants	CO_2	9%	4%	17%	-57%	91%
Waxes	CO_2	58%	49%	71%	-15%	22%
Other	CO_2	17%	16%	66%	-3%	292%

[a] Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval, as a percentage of the inventory value (also expressed in percent terms).

In Table 3-23, feedstocks and asphalt contribute least to overall storage factor uncertainty on a percentage basis. Although the feedstocks category—the largest use category in terms of total carbon flows—appears to have tight confidence limits, this is to some extent an artifact of the way the uncertainty analysis was structured. As discussed in Annex 2.3, the storage factor for feedstocks is based on an analysis of six fates that result in long-term storage (e.g., plastics production), and eleven that result in emissions (e.g., volatile organic compound emissions). Rather than modeling the total uncertainty around all of these fate processes, the current analysis addresses only the storage fates, and assumes that all C that is not stored is emitted. As the production statistics that drive the storage values are relatively well-characterized, this approach yields a result that is probably biased toward understating uncertainty.

As is the case with the other uncertainty analyses discussed throughout this document, the uncertainty results above address only those factors that can be readily quantified. More details on the uncertainty analysis are provided in Annex 2.3.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

A source-specific QA/QC plan for non-energy uses of fossil fuels was developed and implemented. This effort included a Tier 1 analysis, as well as portions of a Tier 2 analysis for non-energy uses involving petrochemical feedstocks and for imports and exports. The Tier 2 procedures that were implemented involved checks specifically focusing on the activity data and methodology for estimating the fate of C (in terms of storage and emissions) across the various end-uses of fossil C. Emission and storage totals for the different subcategories were compared, and trends across the time series were analyzed to determine whether any corrective actions were needed. Corrective actions were taken to rectify minor errors and to improve the transparency of the calculations, facilitating future QA/QC.

For petrochemical import and export data, special attention was paid to NAICS numbers and titles to verify that none had changed or been removed. Import and export totals were compared for 2009 as well as their trends across the time series.

Recalculations Discussion

In previous Inventories, the storage factor for asphalt was incorrectly assumed to be 100 percent. For the current Inventory, it has been updated to 99.6 percent to reflect some loss of VOCs (see Annex 2.3 for more detailed discussion).

Updates to the EIA Manufacturer's Energy Consumption Survey (MECS) for 2006 were released in the past year. MECS data are only released once every four years and contribute to approximately 28 percent (as a time-weighted average) of the C accounted for in feedstocks. MECS data are used to estimate the amount of C emitted from energy recovery. Updating the energy recovery emission estimates with this new data affected emissions from 2003

through 2009, resulting in annual average increases of 7 percent from 2003 through 2009. In addition, the entire energy recovery time series was recalculated to adjust for energy recovered from combustion of scrap tires. Carbon emissions from scrap tires were inadvertently included in the energy recovery estimates; however, they are already accounted for in the Incineration of Waste category.[94] MECS data were adjusted to remove C from scrap tires used as fuel in cement kilns, lime kilns, and electric arc furnaces. This adjustment resulted in decreases in emissions across the entire time series. Emissions decreased by 0.3, 2.1, 1.3, and 1.5 percent for MECS-reporting years 1991, 1994, 1998, and 2002, respectively. Updating the energy recovery emission estimates with the 2006 MECS data combined with adjusting for combustion of scrap tires increased the 2006 emission estimate by 9.5 percent. Overall, emissions from energy recovery averaged over the entire time series increased by 1.2 percent when compared to last year's inventory estimate because the increase resulting from updating the MECS data more than offsets the decrease from adjusting for scrap tire combustion across the time series.

Planned Improvements

There are several improvements planned for the future:

- Improving the uncertainty analysis. Most of the input parameter distributions are based on professional judgment rather than rigorous statistical characterizations of uncertainty.
- Better characterizing flows of fossil C. Additional fates may be researched, including the fossil C load in organic chemical wastewaters, plasticizers, adhesives, films, paints, and coatings. There is also a need to further clarify the treatment of fuel additives and backflows (especially methyl tert-butyl ether, MTBE).
- Reviewing the trends in fossil fuel consumption for non-energy uses. Annual consumption for several fuel types is highly variable across the time series, including industrial coking coal and other petroleum (miscellaneous products). EPA plans to better understand these trends to identify any mischaracterized or misreported fuel consumption for non-energy uses.
- More accurate accounting of C in petrochemical feedstocks. Since 2001, the C accounted for in the feedstocks C balance outputs (i.e., storage plus emissions) exceeds C inputs. Prior to 2001, the C balance inputs exceed outputs. EPA plans to research this discrepancy by assessing the trends on both sides of the C balance. An initial review of EIA (2011) data indicates that trends in LPG consumption for non-energy uses may largely contribute to this discrepancy.
- More accurate accounting of C in imports and exports. As part of its effort to address the C balance discrepancy, EPA will examine its import/export adjustment methodology to ensure that net exports of intermediaries such as ethylene and propylene are fully accounted for.
- EPA recently researched updating the average carbon content of solvents, since the entire time series depends on one year's worth of solvent composition data. Unfortunately, the data on C emissions from solvents that were readily available do not provide composition data for all categories of solvent emissions and also have conflicting definitions for volatile organic compounds, the source of emissive carbon in solvents. EPA plans to identify additional sources of solvents data in order to update the C content assumptions.

Finally, although U.S.-specific storage factors have been developed for feedstocks, asphalt, lubricants, and waxes, default values from IPCC are still used for two of the non-energy fuel types (industrial coking coal and distillate oil), and broad assumptions are being used for miscellaneous products and other petroleum. Over the long term, there are plans to improve these storage factors by conducting analyses of C fate similar to those described in Annex 2.3 or deferring to more updated default storage factors from IPCC where available.

3.3. Incineration of Waste (IPCC Source Category 1A1a)

Incineration is used to manage about 7 to 19 percent of the solid wastes generated in the United States, depending on the source of the estimate and the scope of materials included in the definition of solid waste (EPA 2000, Goldstein

[94] From a regulatory-definition perspective combustion of scrap tires in cement kilns, lime kilns, and electric arc furnaces is not considered "incineration;" however the use of the term "incineration" in this document also applies to the combustion of scrap tires and other materials for energy recovery.

and Matdes 2001, Kaufman et al. 2004, Simmons et al. 2006, van Haaren et al. 2010). In the context of this section, waste includes all municipal solid waste (MSW) as well as tires. In the United States, almost all incineration of MSW occurs at waste-to-energy facilities or industrial facilities where useful energy is recovered, and thus emissions from waste incineration are accounted for in the Energy chapter. Similarly, tires are combusted for energy recovery in industrial and utility boilers. Incineration of waste results in conversion of the organic inputs to CO_2. According to 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 incineration are calculated by estimating the quantity of waste combusted and the fraction of the waste that is C derived from fossil sources.

Most of the organic materials in municipal solid wastes are of biogenic origin (e.g., paper, yard trimmings), and have their net C flows accounted for under the Land Use, Land-Use Change, and Forestry chapter. However, some components—plastics, synthetic rubber, synthetic fibers, and carbon black—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 municipal solid wastes are predominantly from clothing and home furnishings. As noted above, tires (which contain rubber and carbon black) are also considered a "non-hazardous" waste and are included in the waste incineration estimate, though waste disposal practices for tires differ from municipal solid waste. Estimates on emissions from hazardous waste incineration can be found in Annex 2.3 and are accounted for as part of the carbon mass balance for non-energy uses of fossil fuels.

Approximately 26 million metric tons of MSW was incinerated in the United States in 2009 (EPA 2011). CO_2 emissions from incineration of waste rose 54 percent since 1990, to an estimated 12.3 Tg CO_2 Eq. (12,300 Gg) in 2009, as the volume of tires and other fossil C-containing materials in waste increased (see Table 3-24 and Table 3-25). Waste incineration is also a source of N_2O and CH_4 emissions (De Soete 1993; IPCC 2006). N_2O emissions from the incineration of waste were estimated to be 0.4 Tg CO_2 Eq. (1 Gg N_2O) in 2009, and have not changed significantly since 1990. CH_4 emissions from the incineration of waste were estimated to be less than 0.05 Tg CO_2 Eq. (less than 0.5 Gg CH_4) in 2009, and have not changed significantly since 1990.

Table 3-24: CO_2 and N_2O Emissions from the Incineration of Waste (Tg CO_2 Eq.)

Gas/Waste Product	1990	2000	2005	2006	2007	2008	2009
CO_2	**8.0**	**11.1**	**12.5**	**12.5**	**12.7**	**12.2**	**12.3**
Plastics	5.6	6.1	6.9	6.7	6.7	6.1	6.2
Synthetic Rubber in Tires	0.3	1.5	1.6	1.7	1.8	1.8	1.8
Carbon Black in Tires	0.4	1.8	2.0	2.1	2.3	2.3	2.3
Synthetic Rubber in MSW	0.9	0.7	0.8	0.8	0.8	0.8	0.8
Synthetic Fibers	0.8	1.0	1.2	1.2	1.2	1.2	1.2
N_2O	**0.5**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**
CH_4	+	+	+	+	+	+	+
Total	**8.5**	**11.5**	**12.9**	**12.9**	**13.1**	**12.5**	**12.7**

+ Does not exceed 0.05 Tg CO_2 Eq.

Table 3-25: CO_2 and N_2O Emissions from the Incineration of Waste (Gg)

Gas/Waste Product	1990	2000	2005	2006	2007	2008	2009
CO_2	**7,989**	**11,112**	**12,450**	**12,531**	**12,700**	**12,169**	**12,300**
Plastics	5,588	6,104	6,919	6,722	6,660	6,148	6,233
Synthetic Rubber in Tires	308	1,454	1,599	1,712	1,823	1,823	1,823
Carbon Black in Tires	385	1,818	1,958	2,113	2,268	2,268	2,268
Synthetic Rubber in MSW	872	689	781	775	791	770	782
Synthetic Fibers	838	1,046	1,194	1,208	1,159	1,161	1,195
N_2O	**2**	**1**	**1**	**1**	**1**	**1**	**1**
CH_4	+	+	+	+	+	+	+

+ Does not exceed 0.5 Gg.

Methodology

Emissions of CO_2 from the incineration of waste include CO_2 generated by the incineration of plastics, synthetic fibers, and synthetic rubber, as well as the incineration of synthetic rubber and carbon black in tires. These emissions

were estimated by multiplying the amount of each material incinerated by the C content of the material and the fraction oxidized (98 percent). Plastics incinerated in municipal solid wastes were categorized into seven plastic resin types, each material having a discrete C content. Similarly, synthetic rubber is categorized into three product types, and synthetic fibers were categorized into four product types, each having a discrete C content. Scrap tires contain several types of synthetic rubber, as well as carbon black. Each type of synthetic rubber has a discrete C content, and carbon black is 100 percent C. Emissions of CO_2 were calculated based on the amount of scrap tires used for fuel and the synthetic rubber and carbon black content of tires.

More detail on the methodology for calculating emissions from each of these waste incineration sources is provided in Annex 3.6.

For each of the methods used to calculate CO_2 emissions from the incineration of waste, data on the quantity of product combusted and the C content of the product are needed. For plastics, synthetic rubber, and synthetic fibers, the amount of specific materials discarded as municipal solid waste (i.e., the quantity generated minus the quantity recycled) was taken from *Municipal Solid Waste Generation, Recycling, and Disposal in the United States: Facts and Figures* (EPA 1999 through 2003, 2005 through 2011) and detailed unpublished backup data for some years not shown in the reports (Schneider 2007). The proportion of total waste discarded that is incinerated was derived from data in BioCycle's "State of Garbage in America" (van Haaren et al. 2010). The most recent data provides the proportion of waste incinerated for 2008, so the corresponding proportion in 2009 is assumed to be equal to the proportion in 2008. For synthetic rubber and carbon black in scrap tires, information was obtained from U.S. Scrap Tire Markets in the United States, 2007 Edition (RMA 2009a). For 2008 and 2009, synthetic rubber mass in tires is assumed to be equal to that in 2007 due to a lack of more recently available data.

Average C contents for the "Other" plastics category and synthetic rubber in municipal solid wastes were calculated from 1998 and 2002 production statistics: carbon content for 1990 through 1998 is based on the 1998 value; content for 1999 through 2001 is the average of 1998 and 2002 values; and content for 2002 to date is based on the 2002 value. Carbon content for synthetic fibers was calculated from 1999 production statistics. Information about scrap tire composition was taken from the Rubber Manufacturers' Association internet site (RMA 2009b).

The assumption that 98 percent of organic C is oxidized (which applies to all waste incineration categories for CO_2 emissions) was reported in EPA's life cycle analysis of greenhouse gas emissions and sinks from management of solid waste (EPA 2006).

Incineration of waste, including MSW, also results in emissions of N_2O and CH_4. These emissions were calculated as a function of the total estimated mass of waste incinerated and an emission factor. As noted above, N_2O and CH_4 emissions are a function of total waste incinerated in each year; for 1990 through 2008, these data were derived from the information published in BioCycle (van Haaren et al. 2010). Data on total waste incinerated was not available for 2009, so this value was assumed to equal the most recent value available (2008). Table 3-26 provides data on municipal solid waste discarded and percentage combusted for the total waste stream. According to Covanta Energy (Bahor 2009) and confirmed by additional research based on ISWA (ERC 2009), all municipal solid waste combustors in the United States are continuously fed stoker units. The emission factors of N_2O and CH_4 emissions per quantity of municipal solid waste combusted are default emission factors for this technology type and were taken from the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006).

Table 3-26: Municipal Solid Waste Generation (Metric Tons) and Percent Combusted.

Year	Waste Discarded	Waste Incinerated	Incinerated (% of Discards)
1990	235,733,657	30,632,057	13.0
2000	252,328,354	25,974,978	10.3
2005	259,559,787	25,973,520	10.0
2006	267,526,493	25,853,401	9.7
2007	268,279,240	24,788,539	9.2
2008	268,541,088	23,674,017	8.8
2009	268,541,088[a]	23,674,017 [a]	8.8[a]

[a] Assumed equal to 2008 value.
Source: van Haaren et al. (2010).

Uncertainty and Time-Series Consistency

A Tier 2 Monte Carlo analysis was performed to determine the level of uncertainty surrounding the estimates of CO_2 emissions and N_2O emissions from the incineration of waste (given the very low emissions for CH_4, no uncertainty estimate was derived). IPCC Tier 2 analysis allows the specification of probability density functions for key variables within a computational structure that mirrors the calculation of the inventory estimate. Uncertainty estimates and distributions for waste generation variables (i.e., plastics, synthetic rubber, and textiles generation) were obtained through a conversation with one of the authors of the Municipal Solid Waste in the United States reports. Statistical analyses or expert judgments of uncertainty were not available directly from the information sources for the other variables; thus, uncertainty estimates for these variables were determined using assumptions based on source category knowledge and the known uncertainty estimates for the waste generation variables.

The uncertainties in the waste incineration emission estimates arise from both the assumptions applied to the data and from the quality of the data. Key factors include MSW incineration rate; fraction oxidized; missing data on waste composition; average C content of waste components; assumptions on the synthetic/biogenic C ratio; and combustion conditions affecting N_2O emissions. The highest levels of uncertainty surround the variables that are based on assumptions (e.g., percent of clothing and footwear composed of synthetic rubber); the lowest levels of uncertainty surround variables that were determined by quantitative measurements (e.g., combustion efficiency, C content of C black).

The results of the Tier 2 quantitative uncertainty analysis are summarized inTable 3-27. Waste incineration CO_2 emissions in 2009 were estimated to be between 9.8 and 15.2 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 21 percent below to 24 percent above the 2009 emission estimate of 12.3 Tg CO_2 Eq. Also at a 95 percent confidence level, waste incineration N_2O emissions in 2009 were estimated to be between 0.2 and 1.5 Tg CO_2 Eq. This indicates a range of 51 percent below to 320 percent above the 2009 emission estimate of 0.4 Tg CO_2 Eq.

Table 3-27: Tier 2 Quantitative Uncertainty Estimates for CO_2 and N_2O from the Incineration of Waste (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Incineration of Waste	CO_2	12.3	9.8	15.2	-21%	+24%
Incineration of Waste	N_2O	0.4	0.2	1.5	-51%	+320%

[a] Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990

through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

A source-specific QA/QC plan was implemented for incineration of waste. This effort included a Tier 1 analysis, as well as portions of a Tier 2 analysis. The Tier 2 procedures that were implemented involved checks specifically focusing on the activity data and specifically focused on the emission factor and activity data sources and methodology used for estimating emissions from incineration of waste. Trends across the time series were analyzed to determine whether any corrective actions were needed. Actions were taken to streamline the activity data throughout the calculations on incineration of waste.

Recalculations Discussion

Several changes were made to input variables compared to the previous Inventory, resulting in an overall decrease in the total emissions from the incineration of waste. Formerly, the percentage of overall rubber waste that is synthetic (i.e., fossil-derived rather than biogenic) varied across the product categories, ranging from 25 percent for clothing and footwear to 100 percent synthetic rubber for durable goods and containers and packaging. For the current Inventory, this variable was updated to be 70 percent synthetic rubber for all four waste categories based on an industry average (RMA, 2011). This change resulted in an average 1 percent decrease in CO_2 emissions throughout the time series. In addition, the percentage of waste incinerated was updated for 2008 based on data obtained from The State of Garbage in America report (van Haaren et al., 2010). Because the report is released every other year, the percentage incinerated in 2007 was also updated using linear interpolation from the 2006 and 2008 values. The change in the percentage incinerated, along with the change in the percentage synthetic rubber noted above, decreased the 2007 and 2008 estimates by 4 percent and 7 percent, respectively, relative to the previous report.

Planned Improvements

Beginning in 2010, those facilities that emit over 25,000 tons of greenhouse gases (CO_2 Eq.) from stationary combustion across all sectors of the economy are required to calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. These data will be used in future inventories to improve the emission calculations through the use of these collected higher tier methodological data.

Additional data sources for calculating the N_2O and CH_4 emission factors for U.S. incineration of waste may be investigated.

3.4. Coal Mining (IPCC Source Category 1B1a)

Three types of coal mining related activities release CH_4 to the atmosphere: underground mining, surface mining, and post-mining (i.e., coal-handling) activities. Underground coal mines contribute the largest share of CH_4 emissions. In 2009, 135 gassy underground coal mines in the United States employ ventilation systems to ensure that CH_4 levels remain within safe concentrations. These systems can exhaust significant amounts of CH_4 to the atmosphere in low concentrations. Additionally, 23 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 CH_4 before, during, or after mining. In 2009, 14 coal mines collected CH_4 from degasification systems and utilized this gas, thus reducing emissions to the atmosphere. Of these mines, 13 coal mines sold CH_4 to the natural gas pipeline and one coal mine used CH_4 from its degasification system to heat mine ventilation air on site. In addition, one of the coal mines that sold gas to pipelines also used CH_4 to fuel a thermal coal dryer. Surface coal mines also release CH_4 as the overburden is removed and the coal is exposed, but the level of emissions is much lower than from underground mines. Finally, some of the CH_4 retained in the coal after mining is released during processing, storage, and transport of the coal.

Total CH_4 emissions in 2009 were estimated to be 71.0 Tg CO_2 Eq. (3,382 Gg), a decline of 16 percent since 1990 (see Table 3-28 and Table 3-29). Of this amount, underground mines accounted for 71 percent, surface mines accounted for 18 percent, and post-mining emissions accounted for 11 percent. The decline in CH_4 emissions from underground mines from 1996 to 2002 was the result of the reduction of overall coal production, the mining of less gassy coal, and an increase in CH_4 recovered and used. Since that time, underground coal production and the associated methane emissions have remained fairly level, while surface coal production and its associated emissions

have generally increased.

Table 3-28: CH_4 Emissions from Coal Mining (Tg CO_2 Eq.)

Activity	1990	2000	2005	2006	2007	2008	2009
UG Mining	62.3	39.4	35.0	35.7	35.7	44.4	50.4
Liberated	67.9	54.4	50.2	54.3	51.0	60.5	67.0
Recovered & Used	(5.6)	(14.9)	(15.1)	(18.7)	(15.3)	(16.1)	(16.5)
Surface Mining	12.0	12.3	13.3	14.0	13.8	14.3	12.9
Post-Mining (UG)	7.7	6.7	6.4	6.3	6.1	6.1	5.6
Post-Mining (Surface)	2.0	2.0	2.2	2.3	2.2	2.3	2.1
Total	**84.1**	**60.4**	**56.9**	**58.2**	**57.9**	**67.1**	**71.0**

Note: Totals may not sum due to independent rounding. Parentheses indicate negative values.

Table 3-29: CH_4 Emissions from Coal Mining (Gg)

Activity	1990	2000	2005	2006	2007	2008	2009
UG Mining	2,968	1,878	1,668	1,699	1,700	2,113	2,401
Liberated	3,234	2,588	2,389	2,588	2,427	2,881	3,189
Recovered & Used	(265.9)	(710.4)	(720.8)	(889.4)	(727.2)	(768.0)	(787.1)
Surface Mining	573.6	585.7	633.1	668.0	658.9	680.5	614.2
Post-Mining (UG)	368.3	318.1	305.9	298.5	289.6	292.0	266.7
Post-Mining (Surface)	93.2	95.2	102.9	108.5	107.1	110.6	99.8
Total	**4,003**	**2,877**	**2,710**	**2,774**	**2,756**	**3,196**	**3,382**

Note: Totals may not sum due to independent rounding. Parentheses indicate negative values.

Methodology

The methodology for estimating CH_4 emissions from coal mining consists of two parts. The first part involves estimating CH_4 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 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 emission factors.

Underground mines. Total CH_4 emitted from underground mines was estimated as the sum of CH_4 liberated from ventilation systems and CH_4 liberated by means of degasification systems, minus CH_4 recovered and used. The Mine Safety and Heath Administration (MSHA) samples CH_4 emissions from ventilation systems for all mines with detectable[95] CH_4 concentrations. These mine-by-mine measurements are used to estimate CH_4 emissions from ventilation systems.

Some of the higher-emitting underground mines also use degasification systems (e.g., wells or boreholes) that remove CH_4 before, during, or after mining. This CH_4 can then be collected for use or vented to the atmosphere. Various approaches were employed to estimate the quantity of CH_4 collected by each of the twenty mines using these systems, depending on available data. For example, some mines report to EPA the amount of CH_4 liberated from their degasification systems. For mines that sell recovered CH_4 to a pipeline, pipeline sales data published by state petroleum and natural gas agencies 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 CH_4 recovered by degasification systems and then used (i.e., not vented) was estimated. In 2009, 13 active coal mines sold recovered CH_4 into the local gas pipeline networks and one coal mine used recovered CH_4 on site for heating. 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

[95] MSHA records coal mine CH_4 readings with concentrations of greater than 50 ppm (parts per million) CH_4. Readings below this threshold are considered non-detectable.

occurs.

Surface Mines and Post-Mining Emissions. Surface mining and post-mining CH_4 emissions were estimated by multiplying basin-specific coal production, obtained from the Energy Information Administration's Annual Coal Report (see Table 3-30) (EIA 2010), by basin-specific emission factors. Surface mining emission factors were developed by assuming that surface mines emit two times as much CH_4 as the average in situ CH_4 content of the coal. Revised data on in situ CH_4 content and emissions factors are taken from EPA (2005), EPA (1996), and AAPG (1984). This calculation accounts for CH_4 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 CH_4 content of coals mined in the basin.

Table 3-30: Coal Production (Thousand Metric Tons)

Year	Underground	Surface	Total
1990	384,244	546,808	931,052
2000	338,168	635,581	973,749
2005	334,398	691,448	1,025,846
2006	325,697	728,447	1,054,144
2007	319,139	720,023	1,039,162
2008	323,932	737,832	1,061,764
2009	301,241	671,475	972,716

Uncertainty and Time-Series Consistency

A quantitative uncertainty analysis was conducted for the coal mining source category using the IPCC-recommended Tier 2 uncertainty estimation methodology. Because emission estimates from underground ventilation systems were based on actual measurement data, uncertainty is relatively low. A degree of imprecision was introduced because the measurements used were not continuous but rather an average of quarterly instantaneous readings. Additionally, the measurement equipment used can be expected to have resulted in an average of 10 percent overestimation of annual CH_4 emissions (Mutmansky and Wang 2000). Estimates of CH_4 recovered by degasification systems are 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. Uncertainty also exists concerning the radius of influence of each well. The number of wells counted, and thus the avoided emissions, may vary if the drainage area is found to be larger or smaller than currently estimated.

Compared to underground mines, there is considerably more uncertainty associated with surface mining and post-mining emissions because of the difficulty in developing accurate emission factors from field measurements. However, since underground emissions comprise the majority of total coal mining emissions, the uncertainty associated with underground emissions is the primary factor that determines overall uncertainty. The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 3-31. Coal mining CH_4 emissions in 2009 were estimated to be between 62.0 and 82.4 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 12.7 percent below to 16.1 percent above the 2009 emission estimate of 71.0 Tg CO_2 Eq.

Table 3-31: Tier 2 Quantitative Uncertainty Estimates for CH_4 Emissions from Coal Mining (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Coal Mining	CH_4	71.0	62.0	82.4	-12.7%	+16.1%

[a] Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

Recalculations Discussion

For the current Inventory, there were some changes to pre-2009 emission estimates relative to the previous Inventory. For the current Inventory, the conversion factor for converting short tons to metric tons was updated to 0.90718474 to be consistent with the number of significant digits used in other source categories. In the past, 0.9072 had been used. The factor was updated for all years, thus coal production estimates in Table 3-31 have changed slightly.

Other changes include the recalculation of emissions avoided for two Jim Walter Resources (JWR) mines: Blue Creek #4 Mine and Blue Creek #7 Mine. This resulted in changes to emissions avoided numbers for 2007 and 2008.

In 1998, 2000, 2001, 2002, 2003, and 2004, the emissions avoided for the Blacksville No. 2 mine in West Virginia were assigned to Pennsylvania rather than West Virginia. These emissions avoided were correctly assigned to West Virginia in the current Inventory; however, total emissions were not affected.

The emissions avoided for the Emerald and Cumberland mines were adjusted going back to 2006 based on information provided by the project developer.

3.5. Abandoned Underground Coal Mines (IPCC Source Category 1B1a)

Underground coal mines contribute the largest share of CH_4 emissions, with active underground mines the leading source of underground emissions. However, mines also continue to release CH_4 after closure. As mines mature and coal seams are mined through, mines are closed and abandoned. Many are sealed and some flood through intrusion of groundwater or surface water into the void. Shafts or portals are generally filled with gravel and capped with a concrete seal, while vent pipes and boreholes are plugged in a manner similar to oil and gas wells. Some abandoned mines are vented to the atmosphere to prevent the buildup of CH_4 that may find its way to surface structures through overburden fractures. As work stops within the mines, the CH_4 liberation decreases but it does not stop completely. Following an initial decline, abandoned mines can liberate CH_4 at a near-steady rate over an extended period of time, or, if flooded, produce gas for only a few years. The gas can migrate to the surface through the conduits described above, particularly if they have not been sealed adequately. In addition, diffuse emissions can occur when CH_4 migrates to the surface through cracks and fissures in the strata overlying the coal mine. The following factors influence abandoned mine emissions:

- Time since abandonment;
- Gas content and adsorption characteristics of coal;
- CH4 flow capacity of the mine;
- Mine flooding;
- Presence of vent holes; and
- Mine seals.

Gross abandoned mine CH_4 emissions ranged from 6.0 to 9.1 Tg CO_2 Eq. from 1990 through 2009, varying, in general, by less than 1 to approximately 19 percent from year to year. Fluctuations were due mainly to the number of mines closed during a given year as well as the magnitude of the emissions from those mines when active. Gross abandoned mine emissions peaked in 1996 (9.1 Tg CO_2 Eq.) due to the large number of mine closures from 1994 to 1996 (70 gassy mines closed during the three-year period). In spite of this rapid rise, abandoned mine emissions have been generally on the decline since 1996. There were fewer than fifteen gassy mine closures during each of the years from 1998 through 2009, with only ten closures in 2009. By 2009, gross abandoned mine emissions decreased slightly to 8.5 Tg CO_2 Eq. (see Table 3-32 and Table 3-33). Gross emissions are reduced by CH_4 recovered and used at 38 mines, resulting in net emissions in 2009 of 5.5 Tg CO_2 Eq.

Table 3-32: CH_4 Emissions from Abandoned Coal Mines (Tg CO_2 Eq.)

Activity	1990	2000	2005	2006	2007	2008	2009
Abandoned Underground Mines	6.0	8.9	7.0	7.6	8.9	9.0	8.5
Recovered & Used	0.0	1.5	1.5	2.2	3.3	3.2	3.0
Total	**6.0**	**7.4**	**5.5**	**5.5**	**5.6**	**5.9**	**5.5**

Note: Totals may not sum due to independent rounding.

Table 3-33: CH_4 Emissions from Abandoned Coal Mines (Gg)

Activity	1990	2000	2005	2006	2007	2008	2009
Abandoned Underground Mines	288	422	334	364	425	430	406
Recovered & Used	0	72	70	103	158	150	144
Total	**288**	**350**	**264**	**261**	**267**	**279**	**262**

Note: Totals may not sum due to independent rounding.

Methodology

Estimating CH_4 emissions from an abandoned coal mine requires predicting the emissions of a mine from the time of abandonment through the inventory year of interest. The flow of CH_4 from the coal to the mine void is primarily dependent on the mine's emissions when active and the extent to which the mine is flooded or sealed. The CH_4 emission rate before abandonment reflects the gas content of the coal, rate of coal mining, and the flow capacity of the mine in much the same way as the initial rate of a water-free conventional gas well reflects the gas content of the producing formation and the flow capacity of the well. A well or a mine which produces gas from a coal seam and the surrounding strata will produce less gas through time as the reservoir of gas is depleted. Depletion of a reservoir will follow a predictable pattern depending on the interplay of a variety of natural physical conditions imposed on the reservoir. The depletion of a reservoir is commonly modeled by mathematical equations and mapped as a type curve. Type curves which are referred to as decline curves have been developed for abandoned coal mines. Existing data on abandoned mine emissions through time, although sparse, appear to fit the hyperbolic type of decline curve used in forecasting production from natural gas wells.

In order to estimate CH_4 emissions over time for a given mine, it is necessary to apply a decline function, initiated upon abandonment, to that mine. In the analysis, mines were grouped by coal basin with the assumption that they will generally have the same initial pressures, permeability and isotherm. As CH_4 leaves the system, the reservoir pressure, Pr, declines as described by the isotherm. The emission rate declines because the mine pressure (Pw) is essentially constant at atmospheric pressure, for a vented mine, and the PI term is essentially constant at the pressures of interest (atmospheric to 30 psia). A rate-time equation can be generated that can be used to predict future emissions. This decline through time is hyperbolic in nature and can be empirically expressed as:

$$q = q_i (1+bD_it)^{(-1/b)}$$

where,

- q = Gas rate at time t in mmcf/d
- q_i = Initial gas rate at time zero (t_o) in million cubic feet per day mmcfd)
- b = The hyperbolic exponent, dimensionless
- D_i = Initial decline rate, 1/yr
- t = Elapsed time from t_o (years)

This equation is applied to mines of various initial emission rates that have similar initial pressures, permeability and adsorption isotherms (EPA 2003).

The decline curves created to model the gas emission rate of coal mines must account for factors that decrease the rate of emission after mining activities cease, such as sealing and flooding. Based on field measurement data, it was assumed that most U.S. mines prone to flooding will become completely flooded within eight years and therefore no longer have any measurable CH_4 emissions. Based on this assumption, an average decline rate for flooding mines was established by fitting a decline curve to emissions from field measurements. An exponential equation was developed from emissions data measured at eight abandoned mines known to be filling with water located in two of the five basins. Using a least squares, curve-fitting algorithm, emissions data were matched to the exponential equation shown below. There was not enough data to establish basin-specific equations as was done with the vented, non-flooding mines (EPA 2003).

$$q = q_{ie}^{(-Dt)}$$

where,

- q = Gas flow rate at time t in mcf/d
- q_i = Initial gas flow rate at time zero (t_o) in mcfd

D = Decline rate, 1/yr
t = Elapsed time from t_o (years)

Seals have an inhibiting effect on the rate of flow of CH_4 into the atmosphere compared to the rate that would be emitted if the mine had an open vent. The total volume emitted will be the same, but will occur over a longer period. The methodology, therefore, treats the emissions prediction from a sealed mine similar to emissions from a vented mine, but uses a lower initial rate depending on the degree of sealing. The computational fluid dynamics simulator was again used with the conceptual abandoned mine model to predict the decline curve for inhibited flow. The percent sealed is defined as 100 × (1 − (initial emissions from sealed mine / emission rate at abandonment prior to sealing)). Significant differences are seen between 50 percent, 80 percent and 95 percent closure. These decline curves were therefore used as the high, middle, and low values for emissions from sealed mines (EPA 2003).

For active coal mines, those mines producing over 100 mcfd account for 98 percent of all CH_4 emissions. This same relationship is assumed for abandoned mines. It was determined that 469 abandoned mines closing after 1972 produced emissions greater than 100 mcfd when active. Further, the status of 273 of the 469 mines (or 58 percent) is known to be either: (1) vented to the atmosphere; (2) sealed to some degree (either earthen or concrete seals); or, (3) flooded (enough to inhibit CH_4 flow to the atmosphere). The remaining 42 percent of the mines were placed in one of the three categories by applying a probability distribution analysis based on the known status of other mines located in the same coal basin (EPA 2003).

Table 3-34: Number of gassy abandoned mines occurring in U.S. basins grouped by class according to post-abandonment state

Basin	Sealed	Vented	Flooded	Total Known	Unknown	Total Mines
Central Appl.	25	25	48	98	127	224
Illinois	30	3	14	47	25	72
Northern Appl.	42	22	16	80	35	115
Warrior Basin	0	0	16	16	0	16
Western Basins	27	3	2	32	9	41
Total	**124**	**53**	**96**	**273**	**196**	**469**

Inputs to the decline equation require the average emission rate and the date of abandonment. Generally this data is available for mines abandoned after 1972; however, such data are largely unknown for mines closed before 1972. Information that is readily available such as coal production by state and county are helpful, but do not provide enough data to directly employ the methodology used to calculate emissions from mines abandoned after 1971. It is assumed that pre-1972 mines are governed by the same physical, geologic, and hydrologic constraints that apply to post-1972 mines; thus, their emissions may be characterized by the same decline curves.

During the 1970s, 78 percent of CH_4 emissions from coal mining came from seventeen counties in seven states. In addition, mine closure dates were obtained for two states, Colorado and Illinois, for the hundred year period extending from 1900 through 1999. The data were used to establish a frequency of mine closure histogram (by decade) and applied to the other five states with gassy mine closures. As a result, basin-specific decline curve equations were applied to 145 gassy coal mines estimated to have closed between 1920 and 1971 in the United States, representing 78 percent of the emissions. State-specific, initial emission rates were used based on average coal mine CH_4 emission rates during the 1970s (EPA 2003).

Abandoned mines emission estimates are based on all closed mines known to have active mine CH_4 ventilation emission rates greater than 100 mcfd at the time of abandonment. For example, for 1990 the analysis included 145 mines closed before 1972 and 258 mines closed between 1972 and 1990. Initial emission rates based on MSHA reports, time of abandonment, and basin-specific decline curves influenced by a number of factors were used to calculate annual emissions for each mine in the database. Coal mine degasification data are not available for years prior to 1990, thus the initial emission rates used reflect ventilation emissions only for pre-1990 closures. CH_4 degasification amounts were added to the quantity of CH_4 ventilated for the total CH_4 liberation rate for 21 mines that closed between 1992 and 2009. Since the sample of gassy mines (with active mine emissions greater than 100 mcfd) is assumed to account for 78 percent of the pre-1971 and 98 percent of the post-1971 abandoned mine emissions, the modeled results were multiplied by 1.22 and 1.02 to account for all U.S. abandoned mine emissions.

From 1993 through 2009, emission totals were downwardly adjusted to reflect abandoned mine CH_4 emissions

avoided from those mines. The inventory totals were not adjusted for abandoned mine reductions in 1990 through 1992, because no data was reported for abandoned coal mining CH_4 recovery projects during that time.

Uncertainty and Time-Series Consistency

A quantitative uncertainty analysis was conducted to estimate the uncertainty surrounding the estimates of emissions from abandoned underground coal mines. The uncertainty analysis described below provides for the specification of probability density functions for key variables within a computational structure that mirrors the calculation of the inventory estimate. The results provide the range within which, with 95 percent certainty, emissions from this source category are likely to fall.

As discussed above, the parameters for which values must be estimated for each mine in order to predict its decline curve are: (1) the coal's adsorption isotherm; (2) CH_4 flow capacity as expressed by permeability; and (3) pressure at abandonment. Because these parameters are not available for each mine, a methodological approach to estimating emissions was used that generates a probability distribution of potential outcomes based on the most likely value and the probable range of values for each parameter. The range of values is not meant to capture the extreme values, but values that represent the highest and lowest quartile of the cumulative probability density function of each parameter. Once the low, mid, and high values are selected, they are applied to a probability density function.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 3-35. Abandoned coal mines CH_4 emissions in 2009 were estimated to be between 4.0 and 7.3 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 27 percent below to 32 percent above the 2009 emission estimate of 5.5 Tg CO_2 Eq. One of the reasons for the relatively narrow range is that mine-specific data is used in the methodology. The largest degree of uncertainty is associated with the unknown status mines (which account for 42 percent of the mines), with a ±57 percent uncertainty.

Table 3-35: Tier 2 Quantitative Uncertainty Estimates for CH_4 Emissions from Abandoned Underground Coal Mines (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Abandoned Underground Coal Mines	CH_4	5.5	4.0	7.3	-27%	+32%

[a] Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval.

Recalculations Discussion

Changes in pre-2009 emissions avoided relative to the previous Inventory are due to the additions of pre-1972 Grayson Hills Energy and DTE Corinth projects, which were added to the current inventory. There were also two abandoned mines added to the current Inventory, one abandoned in 2007 and one in 2008, which resulted in changes in the liberated emissions relative to the previous report.

3.6. Natural Gas Systems (IPCC Source Category 1B2b)

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 221.2 Tg CO_2 Eq. (10,535 Gg) of CH_4 in 2009, a 17 percent increase over 1990 emissions (see Table 3-36 and Table 3-37), and 32.2 Tg CO_2 Eq. (32,171 Gg) of non-combustion CO_2 in 2009, a 14 percent decrease over 1990 emissions (see Table 3-38 and Table 3-39). Improvements in management practices and technology, along with the replacement of older equipment, have helped to stabilize emissions. Methane emissions increased since 2008 due to an increase in production and production wells.

CH_4 and non-combustion CO_2 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 engines and turbine uncombusted 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 CH_4 and non-combustion CO_2 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. Emissions from pneumatic devices, well clean-ups, and gas well completions and re-completions with hydraulic fracturing account for the majority of CH_4 emissions. Flaring emissions account for the majority of the non-combustion CO_2 emissions. Emissions from field production accounted for approximately 59 percent of CH_4 emissions and about 34 percent of non-combustion CO_2 emissions from natural gas systems in 2009.

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 CH_4 emissions from compressors, including compressor seals, are the primary emission source from this stage. The majority of non-combustion CO_2 emissions come from acid gas removal units, which are designed to remove CO_2 from natural gas. Processing plants account for about 8 percent of CH_4 emissions and approximately 66 percent of non-combustion CO_2 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 CH_4 emissions from these compressor stations and from metering and regulating stations account for the majority of the emissions from this stage. Pneumatic devices and engine uncombusted exhaust are also sources of CH_4 emissions from transmission facilities.

Natural gas is also injected and stored in underground formations, or liquefied and stored in above ground tanks, 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. CH_4 emissions from the transmission and storage sector account for approximately 20 percent of emissions from natural gas systems, while CO_2 emissions from transmission and storage account for less than 1 percent of the non-combustion CO_2 emissions from natural gas systems.

Distribution. Distribution pipelines take the high-pressure gas from the transmission system at "city gate" stations, reduce the pressure and distribute the gas through primarily underground mains and service lines to individual end users. There were over 1,208,000 miles of distribution mains in 2009, an increase from just over 944,000 miles in 1990 (OPS 2010b). Distribution system emissions, which account for approximately 13 percent of CH_4 emissions from natural gas systems and less than 1 percent of non-combustion CO_2 emissions, result mainly from fugitive emissions from gate stations and pipelines. An increased use of plastic piping, which has lower emissions than other pipe materials, has reduced emissions from this stage. Distribution system CH_4 emissions in 2009 were 13 percent lower than 1990 levels.

Table 3-36: CH_4 Emissions from Natural Gas Systems (Tg CO_2 Eq.)*

Stage	1990	2000	2005	2006	2007	2008	2009
Field Production	89.2	113.5	105.4	134.0	118.2	122.9	130.3
Processing	18.0	17.7	14.3	14.5	15.1	15.7	17.5
Transmission and Storage	49.2	46.7	41.4	41.0	42.5	43.3	44.4
Distribution	33.4	31.4	29.3	28.3	29.4	29.9	29.0
Total	**189.8**	**209.3**	**190.4**	**217.7**	**205.2**	**211.8**	**221.2**

*Including CH_4 emission reductions achieved by the Natural Gas STAR program and NESHAP regulations.
Note: Totals may not sum due to independent rounding.

Table 3-37: CH_4 Emissions from Natural Gas Systems (Gg)*

Stage	1990	2000	2005	2006	2007	2008	2009
Field Production	4,248	5,406	5,021	6,380	5,628	5,854	6,205
Processing	855	841	681	689	717	748	834
Transmission and Storage	2,344	2,224	1,973	1,950	2,025	2,062	2,115

Distribution	1,591	1,497	1,395	1,346	1,402	1,423	1,381
Total	**9,038**	**9,968**	**9,069**	**10,364**	**9,771**	**10,087**	**10,535**

*Including CH_4 emission reductions achieved by the Natural Gas STAR program and NESHAP regulations.
Note: Totals may not sum due to independent rounding.

Table 3-38: Non-combustion CO_2 Emissions from Natural Gas Systems (Tg CO_2 Eq.)

Stage	1990	2000	2005	2006	2007	2008	2009
Field Production	9.7	6.4	8.0	9.4	9.7	11.3	10.9
Processing	27.8	23.3	21.7	21.2	21.2	21.4	21.2
Transmission and Storage	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Distribution	+	+	+	+	+	+	+
Total	**37.6**	**29.9**	**29.9**	**30.8**	**31.1**	**32.8**	**32.2**

Note: Totals may not sum due to independent rounding.
+ Emissions are less than 0.1 Tg CO_2 Eq.

Table 3-39: Non-combustion CO_2 Emissions from Natural Gas Systems (Gg)

Stage	1990	2000	2005	2006	2007	2008	2009
Field Production	9,704	6,425	8,050	9,438	9,746	11,336	10,877
Processing	27,763	23,343	21,746	21,214	21,199	21,385	21,189
Transmission and Storage	62	64	64	63	64	65	65
Distribution	46	44	41	40	41	42	41
Total	**37,574**	**29,877**	**29,902**	**30,755**	**31,050**	**32,828**	**32,171**

Note: Totals may not sum due to independent rounding.

Methodology

The primary basis for estimates of CH_4 and non-combustion-related CO_2 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 80 CH_4 emission and activity factors to characterize emissions from the various components within the operating stages of the U.S. natural gas system. The same activity factors were used to estimate both CH_4 and non-combustion CO_2 emissions. However, the CH_4 emission factors were adjusted for CO_2 content when estimating fugitive and vented non-combustion CO_2 emissions. The EPA/GRI study was based on a combination of process engineering studies and measurements at representative gas facilities. From this analysis, a 1992 emission estimate was developed using the emission and activity factors, except where direct activity data was available (e.g., offshore platform counts, processing plant counts, transmission pipeline miles, and distribution pipelines). For other years, a set of industry activity factor drivers was developed 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.

Although the inventory primarily uses EPA/GRI emission factors, significant improvements were made to the emissions estimates for three sources this year: gas well cleanups, condensate storage tanks and centrifugal compressors. In addition, data for two sources not included in the EPA/GRI study – gas well completions and gas well workovers (re-completions) with hydraulic fracturing- was added this year. In the case of gas well cleanups, the methodology was revised to use a large sample of well and reservoir characteristics from the HPDI database (HPDI 2009) along with an engineering statics equation (EPA 2006a) to estimate the volume of natural gas necessary to expel a liquid column choking the well production. The same sample E&P Tank sample runs for condensate tank flashing emissions was used; however, the factor was improved by using a large sample distribution of condensate production by gravity from the HPDI database (HPDI 2009) to weigh the sample simulation flashing emissions rather than assuming a uniform distribution of condensate gravities. Additionally, TERC (TERC 2009) data representing two regions was used in the emission factors for those two regions to estimate the effects of separator dump valves malfunctioning and allowing natural gas to vent through the downstream storage tanks. The EPA/GRI emission factor for centrifugal compressors sampled emissions at the seal face of wet seal compressors. A World Gas Conference publication (WGC 2009) on the seal oil degassing vents was used to update this factor and to also account for the emergence of dry seal centrifugal compressors (EPA 2006b), which eliminates seal oil degassing vents and reduces overall emissions. Gas well completions and workovers with hydraulic fracturing were

not common at the time the EPA/GRI survey was conducted. Since then, emissions data has become available through Natural Gas STAR experiences and presentations (EPA 2004, 2007) as these activities became more prevalent. The EPA/GRI study and previous Inventories did, however, include an estimate for well completions without hydraulic fracturing under the source category Completion Flaring. The changes for gas well cleanups, condensate storage tanks, centrifugal compressors, and gas well completions and gas well workovers (re-completions) with hydraulic fracturing are described below in the Recalculations section. See Annex 3.4 for more detailed information on the methodology and data used to calculate CH_4 and non-combustion CO_2 emissions from natural gas systems.

Activity factor data were taken from the following sources: American Gas Association (AGA 1991–1998); Bureau of Ocean Energy Management, Regulation and Enforcement (previous Minerals and Management Service) (BOEMRE 2010a-d); Monthly Energy Review (EIA 2010f); Natural Gas Liquids Reserves Report (EIA 2005); Natural Gas Monthly (EIA 2010b,c,e); the Natural Gas STAR Program annual emissions savings (EPA 2010); Oil and Gas Journal (OGJ 1997–2010); Office of Pipeline Safety (OPS 2010a-b); Federal Energy Regulatory Commission (FERC 2010) and other Energy Information Administration publications (EIA 2001, 2004, 2010a,d); World Oil Magazine (2010a-b). Data for estimating emissions from hydrocarbon production tanks were incorporated (EPA 1999). Coalbed CH_4 well activity factors were taken from the Wyoming Oil and Gas Conservation Commission (Wyoming 2009) and the Alabama State Oil and Gas Board (Alabama 2010). Other state well data was taken from: American Association of Petroleum Geologists (AAPG 2004); Brookhaven College (Brookhaven 2004); Kansas Geological Survey (Kansas 2010); Montana Board of Oil and Gas Conservation (Montana 2010); Oklahoma Geological Survey (Oklahoma 2010); Morgan Stanley (Morgan Stanley 2005); Rocky Mountain Production Report (Lippman 2003); New Mexico Oil Conservation Division (New Mexico 2010, 2005); Texas Railroad Commission (Texas 2010a-d); Utah Division of Oil, Gas and Mining (Utah 2010). Emission factors were taken from EPA/GRI (1996). GTI's Unconventional Natural Gas and Gas Composition Databases (GTI 2001) were used to adapt the CH_4 emission factors into non-combustion related CO_2 emission factors and adjust CH_4 emission factors from the EPA/GRI survey. Methane compositions from GTI 2001 are adjusted year to year using gross production by NEMS for oil and gas supply regions from the EIA. Therefore, emission factors may vary from year to year due to slight changes in the methane composition for each NEMS oil and gas supply module region. Additional information about CO_2 content in transmission quality natural gas was obtained via the internet from numerous U.S. transmission companies to help further develop the non-combustion CO_2 emission factors.

Uncertainty and Time-Series Consistency

A quantitative uncertainty analysis was conducted to determine the level of uncertainty surrounding estimates of emissions from natural gas systems. Performed using @RISK software and the IPCC-recommended Tier 2 methodology (Monte Carlo Simulation technique), this analysis provides for the specification of probability density functions for key variables within a computational structure that mirrors the calculation of the inventory estimate. The @RISK model utilizes 1992 (base year) emissions to quantify the uncertainty associated with the emissions estimates using the top twelve emission sources for the year 2009.

The results presented below provide with 95 percent certainty the range within which emissions from this source category are likely to fall for the year 2009. 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. The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 3-40. Natural gas systems CH_4 emissions in 2009 were estimated to be between 179.1 and 287.6 Tg CO_2 Eq. at a 95 percent confidence level. Natural gas systems non-energy CO_2 emissions in 2009 were estimated to be between 26.1 and 41.9 Tg CO_2 Eq. at 95 percent confidence level.

Table 3-40: Tier 2 Quantitative Uncertainty Estimates for CH_4 and Non-energy CO_2 Emissions from Natural Gas Systems (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)[c]	Uncertainty Range Relative to Emission Estimate[a]			
			(Tg CO_2 Eq.)		(%)	
			Lower Bound[c]	Upper Bound[c]	Lower Bound[c]	Upper Bound[c]

Natural Gas Systems	CH_4	221.2	179.1	287.6	-19%	+30%
Natural Gas Systems[b]	CO_2	32.2	26.1	41.9	-19%	+30%

[a] Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval.
[b] An uncertainty analysis for the non-energy CO_2 emissions was not performed. The relative uncertainty estimated (expressed as a percent) from the CH_4 uncertainty analysis was applied to the point estimate of non-energy CO_2 emissions.
[c] All reported values are rounded after calculation. As a result, lower and upper bounds may not be duplicable from other rounded values as shown in table.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification Discussion

A number of potential data sources were investigated to improve selected emission factors in the natural gas industry. First, the HPDI database for well production and well properties was investigated for potential engineering parameters to be used in engineering equations to develop a new emission factor for well cleanups (HPDI 2009). The database was queried to obtain average well depth, shut-in pressure, well counts, and well production from each basin. These parameters were used along with industry experiences to develop an engineering estimate of emissions from each well in each basin of the sample data. The analysis led to a new emission factor for the gas well cleanup source.

Additionally, industry experiences with hydraulic fracturing of tight formations for the completion or workover of natural gas wells were reviewed to account for this source of emissions. Several Partners of the Natural Gas STAR Program have reported recovering substantial volumes of natural gas that would have otherwise been vented following completions or re-completions (workovers) involving hydraulic fracturing. This completion method, which is a large emission source, was not characterized by the base EPA/GRI 1996 study and has not been accounted for in the national Inventory until this year.

A World Gas Conference paper (WGC 2009) gathered 48 sample measurements of centrifugal compressor wet seal oil degassing emissions and published the results. The base year EPA/GRI 1996 study did not measure emissions from the seal oil degassing vent. Instead seal face emissions were quantified and as such this emission source has gone uncharacterized in the national Inventory until this year.

In some production areas the separator liquid level may drop too low such that the produced associated gas blows through the dump valve and vents through the storage tank. These data were included where available for the Inventory. More data will be necessary to potentially separate this source from storage tank flashing emissions and also to represent the true scope of activity across the United States.

A number of other data sources for fugitive emission factors from the processing and transmission and storage segments were reviewed. Several studies have been published since the EPA/GRI 1996 base year study that sample emissions from the same common equipment components. The raw emissions data from these surveys can potentially be combined with the raw data from the base year study to develop stronger emission factors. In addition to common component leaks, several of these studies propose emission factors for pneumatic devices or other sources. These studies require further review and thus the data are not included in the Inventory at this time.

Recalculations Discussion

Methodologies for gas well cleanups and condensate storage tanks were revised for the current Inventory, and new sources of data for centrifugal compressors with wet seals, gas well completions with hydraulic fracturing, and gas well workovers with hydraulic fracturing were used.

The largest increase in emissions relative to the previous Inventory was due to the revised emission factor for gas well cleanups (also referred to in industry as gas well liquids unloading). HPDI well production and well property sample data on well depth, shut-in pressure, and production rates were used in an engineering equation to re-estimate the average unloading emissions by NEMS oil and gas module region for this source (HPDI 2009). This methodological change increased emissions by more than 22 times while decreasing the substantial uncertainty that was associated with the previous emission factor from the EPA/GRI 1996 study. The activity data remained the same as the previous methodology. Emissions from non-Gas STAR Partners were not considered, nor was an independent estimate of the scope of those emissions accounted for. Reductions beyond those reported from Natural

Gas STAR Partners will be considered for inclusion in the next Inventory of sufficient data are available.

The next largest increase in emissions was due to the inclusion of gas well completions and workovers involving hydraulic fracture (i.e. unconventional completions and workovers). The EPA/GRI 1996 study did not account for this emerging technology and the source was previously unaccounted for in the Inventory. The Inventory did account for completion flaring, however, this only includes emissions from completions without hydraulic fracturing (i.e. conventional completions), which the EPA/GRI 1996 study assumes are mostly flared. Unlike completions and workovers without hydraulic fracturing (i.e. conventional workovers), the high pressure venting of gas in order to expel the large volumes of liquid used to fracture the well formation, results in a large emission of natural gas. The Inventory tracks activity data for wells completed with hydraulic fracturing in each region. The gas well completions with hydraulic fracturing was approximated using total number of producing gas wells completed with hydraulic fracturing and the total number of shut-in gas wells completed with hydraulic fracturing from each year. This approximation is made by taking the difference between the number of unconventional wells reported by EIA for the current year and the previous year. Since drilling and hydraulic fracturing in unconventional (e.g. shale, tight, and coal bed methane) formations is a relatively new technology, it is assumed that zero gas wells completed with hydraulic fracturing are shut-in each year. This activity data was used along with a newly developed emission factor to estimate emissions from these sources. It was assumed that approximately 50 percent of emissions from gas well completions and workovers with hydraulic fracturing would be flared due to states such as Wyoming that do not permit the venting of natural gas during well completions.

The same E&P Tank simulation data for hydrocarbon liquids above 45˚API flashing emission in tanks was used as in previous Inventories to estimate emissions from condensate tanks; however, these flashing emissions simulations were coupled with a large sample of condensate production gravities from the HPDI database to improve the factor to account for the average national distribution of condensate gravities. Previously, a simple average of simulation results for each liquid gravity was used. Additionally, the TERC (2009) study provided a small sample of data representing two regions in Texas where separator dump valve malfunctions were detected and measured. This data was applied only to the regions represented by the study to account for this emission source.

Finally, WGC (2009) sample data on centrifugal compressor seal oil degassing vent rates was used to divide the centrifugal compressors source in the processing and transmission and storage segments into two sources—centrifugal compressors equipped with wet seals and centrifugal compressors equipped with dry seals. The seal oil degassing vent (found with compressors using wet seals) was previously unaccounted for in the Inventory. This improved methodology accounted for an increase in emissions from these sources between 50 and 100 percent.

Finally, the previous Inventory activity data are updated with revised values each year. However, the impact of these changes was small compared to the changes described above.

The net effect of these changes was to increase total CH_4 emissions from natural gas systems between 47 and 120 percent each year between 1990 and 2008 relative to the previous report. The natural gas production segment accounted for the largest increases, largely due to the methodological changes to gas well cleanups and the addition of gas well completions and workovers with hydraulic fracturing.

Planned Improvements

Emission reductions reported to Natural Gas STAR are deducted from the total sector emissions each year in the natural gas systems inventory model to estimate emissions. These reported reductions often rely on Inventory emission factors to quantify the extent of reductions. These reductions are also a source of uncertainty that is not currently analyzed in the Inventory. Emissions reductions—in particular from gas well cleanups—may be underestimated, and we intend to investigate whether additional data are available, and if appropriate, revisions to more accurately account for emissions from natural gas systems will be incorporated into future inventories. Additionally, accounting for the uncertainty of these reductions to more accurately provide upper and lower bounds within the 95 percent confidence interval, will be investigated.

Separately, a larger study is currently underway to update selected compressor emission factors used in the national inventory. Most of the activity factors and emission factors in the natural gas inventory are from the EPA/GRI (1996) study. The current measurement-based study to develop updated emission factors for compressors is intended to better reflect current national circumstances. Results from these studies are expected in 2011, and will be incorporated into the Inventory, pending a peer review.

Malfunctioning separator dump valves is not an occurrence isolated to the Texas counties in which the sample data was obtained. New data will be reviewed as it becomes available on this emissions source and emissions will be updated, as appropriate.

Data collected through EPA's Greenhouse Gas Reporting Program (40 CFR Part 98, Mandatory Reporting of Greenhouse Gases; Final Rule, Subpart W) will be reviewed for potential improvements to the natural gas systems emissions estimates. The rule will collect actual activity data using improved quantification methods from those used in several of the studies which form the basis of this Inventory. Data collection for Subpart W began January 1, 2011 with emissions reporting beginning in 2012. These base year 2011 data will be reviewed for inclusion into a future Inventory to improve the accuracy and reduce the uncertainty of the emission estimates.

3.7. Petroleum Systems (IPCC Source Category 1B2a)

CH_4 emissions from petroleum systems are primarily associated with crude oil production, transportation, and refining operations. During each of these activities, CH_4 emissions are released to the atmosphere as fugitive emissions, vented emissions, emissions from operational upsets, and emissions from fuel combustion. Fugitive and vented CO_2 emissions from petroleum systems are primarily associated with crude oil production and refining operations but are negligible in transportation operations. Combusted CO_2 emissions from fuels are already accounted for in the Fossil Fuels Combustion source category, and hence have not been taken into account in the Petroleum Systems source category. Total CH_4 and CO_2 emissions from petroleum systems in 2009 were 30.9 Tg CO_2 Eq. (1,473 Gg CH_4) and 0.5 Tg CO_2 (463 Gg), respectively. Since 1990, CH_4 emissions have declined by 13 percent, due to industry efforts to reduce emissions and a decline in domestic oil production (see Table 3-41and Table 3-42). CO_2 emissions have also declined by 17 percent since 1990 due to similar reasons (see Table 3-43 and Table 3-44).

Production Field Operations. Production field operations account for about 98 percent of total CH_4 emissions from petroleum systems. Vented CH_4 from field operations account for over 90 percent of the emissions from the production sector, unburned CH_4 combustion emissions account for 6.4 percent, fugitive emissions are 3.4 percent, and process upset emissions are slightly under two-tenths of a percent. The most dominant sources of emissions, in order of magnitude, are shallow water offshore oil platforms, natural-gas-powered high bleed pneumatic devices, oil tanks, natural-gas powered low bleed pneumatic devices, gas engines, deep water offshore platforms, and chemical injection pumps. These seven sources alone emit about 94 percent of the production field operations emissions. Offshore platform emissions are a combination of fugitive, vented, and unburned fuel combustion emissions from all equipment housed on oil platforms producing oil and associated gas. Emissions from high and low-bleed pneumatics occur when pressurized gas that is used for control devices is bled to the atmosphere as they cycle open and closed to modulate the system. Emissions from oil tanks occur when the CH_4 entrained in crude oil under pressure volatilizes once the crude oil is put into storage tanks at atmospheric pressure. Emissions from gas engines are due to unburned CH_4 that vents with the exhaust. Emissions from chemical injection pumps are due to the 25 percent that use associated gas to drive pneumatic pumps. The remaining six percent of the emissions are distributed among 26 additional activities within the four categories: vented, fugitive, combustion and process upset emissions. For more detailed, source-level data on CH_4 emissions in production field operations, refer to Annex 3.5.

Vented CO_2 associated with natural gas emissions from field operations account for 99 percent of the total CO_2 emissions from this source category, while fugitive and process upsets together account for less than 1 percent of the emissions. The most dominant sources of vented emissions are oil tanks, high bleed pneumatic devices, shallow water offshore oil platforms, low bleed pneumatic devices, and chemical injection pumps. These five sources together account for 98.5 percent of the non-combustion CO_2 emissions from this source category, while the remaining 1.5 percent of the emissions is distributed among 24 additional activities within the three categories: vented, fugitive and process upsets.

Crude Oil Transportation. Crude oil transportation activities account for less than one half of one percent of total CH_4 emissions from the oil industry. Venting from tanks and marine vessel loading operations accounts for 61 percent of CH_4 emissions from crude oil transportation. Fugitive emissions, almost entirely from floating roof tanks, account for 19 percent. The remaining 20 percent is distributed among six additional sources within these two categories. Emissions from pump engine drivers and heaters were not estimated due to lack of data.

Crude Oil Refining. Crude oil refining processes and systems account for slightly less than two percent of total CH_4 emissions from the oil industry because most of the CH_4 in crude oil is removed or escapes before the crude oil is delivered to the refineries. There is an insignificant amount of CH_4 in all refined products. Within refineries, vented

emissions account for about 86 percent of the emissions, while both fugitive and combustion emissions account for approximately seven percent each. Refinery system blowdowns for maintenance and the process of asphalt blowing—with air, to harden the asphalt—are the primary venting contributors. Most of the fugitive CH_4 emissions from refineries are from leaks in the fuel gas system. Refinery combustion emissions include small amounts of unburned CH_4 in process heater stack emissions and unburned CH_4 in engine exhausts and flares.

Asphalt blowing from crude oil refining accounts for 36 percent of the total non-combustion CO_2 emissions in petroleum systems.

Table 3-41: CH_4 Emissions from Petroleum Systems (Tg CO_2 Eq.)

Activity	1990	2000	2005	2006	2007	2008	2009
Production Field Operations	**34.7**	**30.8**	**28.7**	**28.7**	**29.3**	**29.6**	**30.3**
Pneumatic device venting	10.3	9.0	8.4	8.3	8.4	8.7	8.8
Tank venting	5.3	4.5	3.9	3.9	4.0	4.0	4.5
Combustion & process upsets	1.9	1.6	1.5	1.5	1.5	1.6	2.0
Misc. venting & fugitives	16.8	15.3	14.5	14.6	15.0	14.8	14.6
Wellhead fugitives	0.6	0.5	0.4	0.4	0.4	0.5	0.5
Crude Oil Transportation	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Refining	**0.5**	**0.6**	**0.6**	**0.6**	**0.6**	**0.5**	**0.5**
Total	**35.4**	**31.5**	**29.4**	**29.4**	**30.0**	**30.2**	**30.9**

Note: Totals may not sum due to independent rounding.

Table 3-42: CH_4 Emissions from Petroleum Systems (Gg)

Activity	1990	2000	2005	2006	2007	2008	2009
Production Field Operations	**1,653**	**1,468**	**1,366**	**1,365**	**1,396**	**1,409**	**1,444**
Pneumatic device venting	489	428	397	396	398	416	419
Tank venting	250	214	187	188	192	189	212
Combustion & process upsets	88	76	71	71	72	75	94
Misc. venting & fugitives	799	727	691	693	714	707	696
Wellhead fugitives	26	22	19	17	20	23	23
Crude Oil Transportation	**7**	**5**	**5**	**5**	**5**	**5**	**5**
Refining	**25**	**28**	**28**	**28**	**27**	**25**	**24**
Total	**1,685**	**1,501**	**1,398**	**1,398**	**1,427**	**1,439**	**1,473**

Note: Totals may not sum due to independent rounding.

Table 3-43: CO_2 Emissions from Petroleum Systems (Tg CO_2 Eq.)

Activity	1990	2000	2005	2006	2007	2008	2009
Production Field Operations	**0.4**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**
Pneumatic device venting	+	+	+	+	+	+	+
Tank venting	0.3	0.3	0.2	0.2	0.3	0.2	0.3
Misc. venting & fugitives	+	+	+	+	+	+	+
Wellhead fugitives	+	+	+	+	+	+	+
Crude Refining	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.1**
Total	**0.6**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**

+ Does not exceed 0.05 Tg CO_2 Eq.

Note: Totals may not sum due to independent rounding.

Table 3-44: CO_2 Emissions from Petroleum Systems (Gg)

Activity	1990	2000	2005	2006	2007	2008	2009
Production Field Operations	**376**	**323**	**285**	**285**	**292**	**288**	**319**
Pneumatic device venting	27	24	22	22	22	23	23
Tank venting	328	281	246	246	252	247	278
Misc. venting & fugitives	18	17	16	16	16	16	16
Wellhead fugitives	1	1	1	1	1	1	1
Crude Refining	**180**	**211**	**205**	**203**	**182**	**165**	**144**
Total	**555**	**534**	**490**	**488**	**474**	**453**	**463**

Note: Totals may not sum due to independent rounding.

Methodology

The methodology for estimating CH_4 emissions from petroleum systems is a bottom-up approach, based on comprehensive studies of CH_4 emissions from U.S. petroleum systems (EPA 1996, EPA 1999). These studies combined emission estimates from 64 activities occurring in petroleum systems from the oil wellhead through crude oil refining, including 33 activities for crude oil production field operations, 11 for crude oil transportation activities, and 20 for refining operations. Annex 3.5 provides greater detail on the emission estimates for these 64 activities. The estimates of CH_4 emissions from petroleum systems do not include emissions downstream of oil refineries because these emissions are negligible.

The methodology for estimating CH_4 emissions from the 64 oil industry activities employs emission factors initially developed by EPA (1999). Activity factors for the years 1990 through 2009 were collected from a wide variety of statistical resources. Emissions are estimated for each activity by multiplying emission factors (e.g., emission rate per equipment item or per activity) by their corresponding activity factor (e.g., equipment count or frequency of activity). EPA (1999) provides emission factors for all activities except those related to offshore oil production and field storage tanks. For offshore oil production, two emission factors were calculated using data collected over a one-year period for all federal offshore platforms (EPA 2005, BOEMRE 2004). One emission factor is for oil platforms in shallow water, and one emission factor is for oil platforms in deep water. Emission factors are held constant for the period 1990 through 2009. The number of platforms in shallow water and the number of platforms in deep water are used as activity factors and are taken from Bureau of Ocean Energy Management, Regulation, and Enforcement (BOEMRE) (formerly Minerals Management Service) statistics (BOEMRE 2010a-c). For oil storage tanks, the emissions factor was calculated as the total emissions per barrel of crude charge from E&P Tank data weighted by the distribution of produced crude oil gravities from the HPDI production database (EPA 1999, HPDI 2009).

For some years, complete activity factor data were not available. In such cases, one of three approaches was employed. Where appropriate, the activity factor was calculated from related statistics using ratios developed for EPA (1996). For example, EPA (1996) found that the number of heater treaters (a source of CH_4 emissions) is related to both number of producing wells and annual production. To estimate the activity factor for heater treaters, reported statistics for wells and production were used, along with the ratios developed for EPA (1996). In other cases, the activity factor was held constant from 1990 through 2009 based on EPA (1999). Lastly, the previous year's data were used when data for the current year were unavailable. The CH_4 and CO_2 sources in the production sector share common activity factors. See Annex 3.5 for additional detail.

Among the more important references used to obtain activity factors are the Energy Information Administration annual and monthly reports (EIA 1990 through 2010, 1995 through 2010, 1995 through 2010a-b), Methane Emissions from the Natural Gas Industry by the Gas Research Institute and EPA (EPA/GRI 1996a-d), Estimates of Methane Emissions from the U.S. Oil Industry (EPA 1999), consensus of industry peer review panels, BOEMRE reports (BOEMRE 2005, 2010a-c), analysis of BOEMRE data (EPA 2005, BOEMRE 2004), the Oil & Gas Journal (OGJ 2010a,b), the Interstate Oil and Gas Compact Commission (IOGCC 2008), and the United States Army Corps of Engineers (1995-2008).

The methodology for estimating CO_2 emissions from petroleum systems combines vented, fugitive, and process upset emissions sources from 29 activities for crude oil production field operations and one activity from petroleum refining. Emissions are estimated for each activity by multiplying emission factors by their corresponding activity factors. The emission factors for CO_2 are estimated by multiplying the CH_4 emission factors by a conversion factor, which is the ratio of CO_2 content and methane content in produced associated gas. The only exceptions to this methodology are the emission factors for crude oil storage tanks, which are obtained from E&P Tank simulation runs, and the emission factor for asphalt blowing, which was derived using the methodology and sample data from API (2009).

Uncertainty and Time-Series Consistency

This section describes the analysis conducted to quantify uncertainty associated with the estimates of emissions from petroleum systems. Performed using @RISK software and the IPCC-recommended Tier 2 methodology (Monte Carlo Simulation technique), the method employed provides for the specification of probability density functions for key variables within a computational structure that mirrors the calculation of the Inventory estimate. The results provide the range within which, with 95 percent certainty, emissions from this source category are likely to fall.

The detailed, bottom-up Inventory analysis used to evaluate U.S. petroleum systems reduces the uncertainty related to the CH_4 emission estimates in comparison to a top-down approach. However, some uncertainty still remains. Emission factors and activity factors are based on a combination of measurements, equipment design data, engineering calculations and studies, surveys of selected facilities and statistical reporting. Statistical uncertainties arise from natural variation in measurements, equipment types, operational variability and survey and statistical methodologies. Published activity factors are not available every year for all 64 activities analyzed for petroleum systems; therefore, some are estimated. Because of the dominance of the seven major sources, which account for 92 percent of the total methane emissions, the uncertainty surrounding these seven sources has been estimated most rigorously, and serves as the basis for determining the overall uncertainty of petroleum systems emission estimates.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 3-45. Petroleum systems CH_4 emissions in 2009 were estimated to be between 23.5 and 76.9 Tg CO_2 Eq., while CO_2 emissions were estimated to be between 0.4 and 1.2 Tg CO_2 Eq. at a 95 percent confidence level. This indicates a range of 24 percent below to 149 percent above the 2009 emission estimates of 30.9 and 0.5 Tg CO_2 Eq. for CH_4 and CO_2, respectively.

Table 3-45: Tier 2 Quantitative Uncertainty Estimates for CH_4 Emissions from Petroleum Systems (Tg CO_2 Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO_2 Eq.)[b]	Uncertainty Range Relative to Emission Estimate[a]			
			(Tg CO_2 Eq.)		(%)	
			Lower Bound[b]	Upper Bound[b]	Lower Bound[b]	Upper Bound[b]
Petroleum Systems	CH_4	30.9	23.5	76.9	-24%	149%
Petroleum Systems	CO_2	0.5	0.4	1.2	-24%	149%

[a] Range of 2009 relative uncertainty predicted by Monte Carlo Simulation, based on 1995 base year activity factors, for a 95 percent confidence interval.
[b] All reported values are rounded after calculation. As a result, lower and upper bounds may not be duplicable from other rounded values as shown in table.
Note: Totals may not sum due to independent rounding

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification Discussion

As part of QA/QC and verification activities done for the Inventory, potential improvements were identified, which include a new emissions source associated with fixed roof storage tank emissions in the production segment. In some production areas the separator liquid level may drop too low such that the produced associated gas blows through the dump valve and vents through the storage tank. This data was included where available for the Inventory (see Recalculation discussion below). More data will be necessary to potentially add this as a separate source from storage tank flashing emissions and also to represent the true scope of activity across the United States.

Recalculations Discussion

Most revisions for the current Inventory relative to the previous report were due to updating previous years' data with revised data from existing data sources. Well completion venting, well drilling, and offshore platform activity factors were updated from existing data sources from 1990 onward.

Additionally, the emission factor for venting from fixed roof storage tanks in the crude oil production segment was revised. Using the same E&P Tank sample data runs on crude oil gravities ranging up to 45˚API, a new national level flashing emissions factor was developed by using a large sample of production data, sorted by gravity, available from the HPDI database.

A study prepared for the Texas Environmental Research Consortium measured emissions rates from several oil and condensate tanks in Texas (TERC 2009). This data was plotted and compared to the flashing emissions simulated via E&P Tank simulation. EPA observed that additional emissions beyond the flashing were present in approximately 50 percent of the tanks. These emissions may be attributed to separator dump valves malfunctioning or other methods of associated gas entering the tank and venting from the roof. Because the dataset was limited to

represent production from only 14 counties that represent 0.5 percent of U.S. production, the national emission factor was scaled up such that only production from these counties is affected by the occurrence of associated gas venting through the storage tank.

Planned Improvements

As noted above, nearly all emission factors used in the development of the petroleum systems estimates were taken from EPA (1995, 1996, 1999), with the remaining emission factors taken from EPA default values (EPA 2005) and a consensus of industry peer review panels. These emission factors will be reviewed as part of future Inventory work. Results of this review and analysis will be incorporated into future inventories, as appropriate.

Malfunctioning separator dump valves is not an occurrence isolated to the Texas counties in which the sample data was obtained. New data will be reviewed as they become available on this emissions source and emissions updated, as appropriate.

Data collected through EPA's Greenhouse Gas Reporting Program will be reviewed for potential improvements to petroleum systems emissions sources. The rule will collect actual activity data and improved quantification methods from those used in several of the studies which form the basis of this Inventory. This data will be incorporated as appropriate into the current Inventory to improve the accuracy and uncertainty of the emissions estimates. In particular, EPA will investigate whether certain emissions sources currently accounted for in the Energy sector should be separately accounted for in the petroleum systems inventory (e.g., CO_2 process emissions from hydrogen production).

In 2010, all U.S. petroleum refineries were required to collect information on their greenhouse gas emissions. This data will be reported to EPA through its Greenhouse Gas Reporting Program in 2011. Data collected under this program will be evaluated for use in future inventories to improve the calculation of national emissions from petroleum systems.

[BEGIN BOX]

Box 3-3. Carbon Dioxide Transport, Injection, and Geological Storage

Carbon dioxide is produced, captured, transported, and used for Enhanced Oil Recovery (EOR) as well as commercial and non-EOR industrial applications. This CO_2 is produced from both naturally-occurring CO_2 reservoirs and from industrial sources such as natural gas processing plants and ammonia plants. In the current Inventory, emissions from naturally-produced CO_2 are estimated based on the application.

In the current Inventory report, the CO_2 that is used in non-EOR industrial and commercial applications (e.g., food processing, chemical production) is assumed to be emitted to the atmosphere during its industrial use. These emissions are discussed in the Carbon Dioxide Consumption section. The naturally-occurring CO_2 used in EOR operations is assumed to be fully sequestered. Additionally, all anthropogenic CO_2 emitted from natural gas processing and ammonia plants is assumed to be emitted to the atmosphere, regardless of whether the CO_2 is captured or not. These emissions are currently included in the Natural Gas Systems and the Ammonia Production sections of the Inventory report, respectively.

IPCC (IPCC, 2006) included, for the first time, methodological guidance to estimate emissions from the capture, transport, injection, and geological storage of CO_2. The methodology is based on the principle that the carbon capture and storage system should be handled in a complete and consistent manner across the entire Energy sector. The approach accounts for CO_2 captured at natural and industrial sites as well as emissions from capture, transport, and use. For storage specifically, a Tier 3 methodology is outlined for estimating and reporting emissions based on site-specific evaluations. However, IPCC (IPCC, 2006) notes that if a national regulatory process exists, emissions information available through that process may support development of CO_2 emissions estimates for geologic storage.

Beginning in 2010, facilities that conduct geologic sequestration of CO_2 and all other facilities that inject CO_2 underground will be required to calculate and report greenhouse gas data annually to EPA through its Greenhouse

Gas Reporting Program. The Greenhouse Gas Reporting Rule requires greenhouse gas reporting from facilities that inject CO_2 underground for geologic sequestration, and requires greenhouse gas reporting from all other facilities that inject CO_2 underground for any reason, including enhanced oil and gas recovery. Beginning in 2010, facilities conducting geologic sequestration of CO_2 are required to develop and implement an EPA-approved site-specific monitoring, reporting and verification (MRV) plan, and to report the amount of CO_2 sequestered using a mass balance approach. Data from this program, which will be reported to EPA in early 2012, for the 2011 calendar year, will provide additional facility-specific information about the carbon capture, transport and storage chain, EPA intends to evaluate that information closely and consider opportunities for improving our current inventory estimates.

Preliminary estimates indicate that the amount of CO_2 captured from industrial and natural sites is 47.3 Tg CO_2 (47,340 Gg CO_2) (see Table 3-46 and Table 3-47). Site-specific monitoring and reporting data for CO_2 injection sites (i.e., EOR operations) were not readily available, therefore, these estimates assume all CO_2 is emitted.

Table 3-46: Potential Emissions from CO_2 Capture and Transport (Tg CO_2 Eq.)

Year	1990	2000	2005	2006	2007	2008	2009
Acid Gas Removal Plants	4.8	2.3	5.8	6.2	6.4	6.6	7.0
Naturally Occurring CO_2	20.8	23.2	28.3	30.2	33.1	36.1	39.7
Ammonia Production Plants	+	0.7	0.7	0.7	0.7	0.6	0.6
Pipelines Transporting CO_2	+	+	+	+	+	+	+
Total	**25.6**	**26.1**	**34.7**	**37.1**	**40.1**	**43.3**	**47.3**

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

Table 3-47: Potential Emissions from CO_2 Capture and Transport (Gg)

Year	1990	2000	2005	2006	2007	2008	2009
Acid Gas Removal Plants	4,832	2,264	5,798	6,224	6,088	6,630	7,035
Naturally Occurring CO_2	20,811	23,208	28,267	30,224	33,086	36,102	39,725
Ammonia Production Plants	+	676	676	676	676	580	580
Pipelines Transporting CO_2	8	8	7	7	7	8	8
Total	**25,643**	**26,149**	**34,742**	**37,124**	**40,141**	**43,311**	**47,340**

+ Does not exceed 0.5 Gg.
Note: Totals do not include emissions from pipelines transporting CO_2
Note; Totals may not sum due to independent rounding.

[END BOX]

3.8. Energy Sources of Indirect Greenhouse Gas Emissions

In addition to the main greenhouse gases addressed above, many energy-related activities generate emissions of indirect greenhouse gases. Total emissions of nitrogen oxides (NO_x), carbon monoxide (CO), and non-CH_4 volatile organic compounds (NMVOCs) from energy-related activities from 1990 to 2009 are reported in Table 3-48.

Table 3-48: NO_x, CO, and NMVOC Emissions from Energy-Related Activities (Gg)

Gas/Source	1990	2000	2005	2006	2007	2008	2009
NO_x	**21,106**	**18,477**	**15,319**	**14,473**	**13,829**	**13,012**	**10,887**
Mobile Combustion	10,862	10,199	9,012	8,488	7,965	7,441	6,206
Stationary Combustion	10,023	8,053	5,858	5,545	5,432	5,148	4,159
Oil and Gas Activities	139	111	321	319	318	318	393
Incineration of Waste	82	114	129	121	114	106	128
*International Bunker Fuels**	*2,020*	*1,344*	*1,703*	*1,793*	*1,791*	*1,917*	*1,651*
CO	**125,640**	**89,714**	**69,062**	**65,399**	**61,739**	**58,078**	**49,647**
Mobile Combustion	119,360	83,559	62,692	58,972	55,253	51,533	43,355
Stationary Combustion	5,000	4,340	4,649	4,695	4,744	4,792	4,543

Incineration of Waste	978	1,670	1,403	1,412	1,421	1,430	1,403
Oil and Gas Activities	302	146	318	319	320	322	345
*International Bunker Fuels**	*130*	*128*	*132*	*161*	*160*	*165*	*149*
NMVOCs	**12,620**	**8,952**	**7,798**	**7,702**	**7,604**	**7,507**	**5,333**
Mobile Combustion	10,932	7,229	6,330	6,037	5,742	5,447	4,151
Stationary Combustion	912	1,077	716	918	1,120	1,321	424
Oil and Gas Activities	554	388	510	510	509	509	599
Incineration of Waste	222	257	241	238	234	230	159
*International Bunker Fuels**	*61*	*45*	*54*	*59*	*59*	*62*	*57*

* These values are presented for informational purposes only and are not included in totals.
Note: Totals may not sum due to independent rounding.

Methodology

These emission estimates were obtained from preliminary data (EPA 2010, EPA 2009), and disaggregated based on EPA (2003), which, in its final iteration, will be published on the National Emission Inventory (NEI) Air Pollutant Emission Trends web site. Emissions were calculated either for individual categories or for many categories combined, using basic activity data (e.g., the amount of raw material processed) as an indicator of emissions. National activity data were collected for individual categories from various agencies. Depending on the category, these basic activity data may include data on production, fuel deliveries, raw material processed, etc.

Activity data were used in conjunction with emission factors, which together relate the quantity of emissions to the activity. Emission factors are generally available from the EPA's Compilation of Air Pollutant Emission Factors, AP-42 (EPA 1997). The EPA currently derives the overall emission control efficiency of a source category from a variety of information sources, including published reports, the 1985 National Acid Precipitation and Assessment Program emissions inventory, and other EPA databases.

Uncertainty and Time-Series Consistency

Uncertainties in these estimates are partly due to the accuracy of the emission factors used and accurate estimates of activity data. A quantitative uncertainty analysis was not performed.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

3.9. International Bunker Fuels (IPCC Source Category 1: Memo Items)

Emissions resulting from the combustion of fuels used for international transport activities, termed international bunker fuels under the UNFCCC, are 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.[96] These decisions are reflected in the IPCC methodological guidance, including the 2006 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 2006).[97]

Greenhouse gases emitted from the combustion of international bunker fuels, like other fossil fuels, include CO_2, CH_4 and N_2O. Two transport modes are addressed under the IPCC definition of international bunker fuels: aviation and marine.[98] Emissions from ground transport activities—by road vehicles and trains—even when crossing

[96] 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).

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

[98] Most emission related international aviation and marine regulations are under the rubric of the International Civil Aviation

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.[99]

Emissions of CO_2 from aircraft are essentially a function of fuel use. CH_4 and N_2O emissions also depend upon engine characteristics, flight conditions, and flight phase (i.e., take-off, climb, cruise, decent, and landing). CH_4 is the product of incomplete combustion and occur mainly during the landing and take-off phases. In jet engines, N_2O is primarily produced by the oxidation of atmospheric nitrogen, and the majority of emissions occur during the cruise phase. 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 generally classified as cargo and passenger carrying, military (i.e., U.S. 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. CO_2 is the primary greenhouse gas emitted from marine shipping.

Overall, aggregate greenhouse gas emissions in 2009 from the combustion of international bunker fuels from both aviation and marine activities were 124.4 Tg CO_2 Eq., or ten percent above emissions in 1990 (see Table 3-49 and Table 3-50). Emissions from international flights and international shipping voyages departing from the United States have increased by 49 percent and decreased by 18 percent, respectively, since 1990. The majority of these emissions were in the form of CO_2; however, small amounts of CH_4 and N_2O were also emitted.

Table 3-49: CO_2, CH_4, and N_2O Emissions from International Bunker Fuels (Tg CO_2 Eq.)

Gas/Mode	1990	2000	2005	2006	2007	2008	2009
CO_2	**111.8**	**98.5**	**109.7**	**128.4**	**127.6**	**133.7**	**123.1**
Aviation	46.4	58.8	56.7	74.6	73.8	75.5	69.4
Marine	65.4	39.7	53.0	53.8	53.9	58.2	53.7
CH_4	**0.2**	**0.1**	**0.1**	**0.2**	**0.2**	**0.2**	**0.1**
Aviation	+	+	+	+	+	+	+
Marine	0.1	0.1	0.1	0.1	0.1	0.1	0.1
N_2O	**1.1**	**0.9**	**1.0**	**1.2**	**1.2**	**1.2**	**1.1**
Aviation	0.5	0.6	0.6	0.8	0.8	0.8	0.7
Marine	0.5	0.3	0.4	0.4	0.4	0.5	0.4
Total	**113.0**	**99.5**	**110.9**	**129.7**	**129.0**	**135.1**	**124.4**

+ Does not exceed 0.05 Tg CO_2 Eq.

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

Table 3-50: CO_2, CH_4 and N_2O Emissions from International Bunker Fuels (Gg)

Gas/Mode	1990	2000	2005	2006	2007	2008	2009
CO_2	**111,828**	**98,482**	**109,750**	**128,384**	**127,618**	**133,704**	**123,127**
Aviation	46,399	58,785	56,736	74,552	73,762	75,508	69,404
Marine	65,429	39,697	53,014	53,832	53,856	58,196	53,723
CH_4	**8**	**6**	**7**	**8**	**8**	**8**	**7**
Aviation	2	2	2	2	2	2	2

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).

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

Marine	7	4	5	5	5	6	5
N_2O	**3**	**3**	**3**	**4**	**4**	**4**	**4**
Aviation	2	2	2	2	2	2	2
Marine	2	1	1	1	1	1	1

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

Methodology

Emissions of CO_2 were estimated by applying C content and fraction oxidized factors to fuel consumption activity data. This approach is analogous to that described under CO_2 from Fossil Fuel Combustion. C content and fraction oxidized factors for jet fuel, distillate fuel oil, and residual fuel oil were taken directly from EIA and are presented in Annex 2.1, Annex 2.2, and Annex 3.7 of this Inventory. Density conversions were taken from Chevron (2000), ASTM (1989), and USAF (1998). Heat content for distillate fuel oil and residual fuel oil were taken from EIA (2010) and USAF (1998), and heat content for jet fuel was taken from EIA (2010). A complete description of the methodology and a listing of the various factors employed can be found in Annex 2.1. See Annex 3.7 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 and N_2O were calculated by multiplying emission factors by measures of fuel consumption by fuel type and mode. Emission factors used in the calculations of CH_4 and N_2O 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 and 0.1 for N_2O For marine vessels consuming either distillate diesel or residual fuel oil the following values (g/MJ), were employed: 0.32 for CH_4 and 0.08 for N_2O. Activity data for aviation included solely jet fuel consumption statistics, while the marine mode included both distillate diesel and residual fuel oil.

Activity data on aircraft fuel consumption for inventory years 2000 through 2005 were developed using the FAA's System for assessing Aviation's Global Emissions (SAGE) model (FAA 2006). That tool has been subsequently replaced by the Aviation Environmental Design Tool (AEDT), which calculates noise in addition to aircraft fuel burn and emissions for flights globally in a given year (FAA 2010). Data for inventory years 2006 through 2009 were developed using AEDT.

International aviation bunker fuel consumption from 1990 to 2009 was calculated by assigning the difference between the sum of domestic activity data (in Tbtu) from SAGE and the AEDT, and the reported EIA transportation jet fuel consumption to the international bunker fuel category for jet fuel from EIA (2010). 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 Service's 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 2011). 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 3-51. See Annex 3.7 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 2010) for 1990 through 2001, 2007, through 2009, and the Department of Homeland Security's Bunker Report for 2003 through 2006 (DHS 2008). Fuel consumption data for 2002 was interpolated due to inconsistencies in reported fuel consumption data. Activity data on distillate diesel consumption by military vessels departing from U.S. ports were provided by DESC (2011). 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 3-52.

Table 3-51: Aviation Jet Fuel Consumption for International Transport (Million Gallons)

Nationality	**1990**	**2000**	**2005**	**2006**	**2007**	**2008**	**2009**

U.S. and Foreign Carriers	4,934		6,157		5,943	7,809	7,726	7,909	7,270
U.S. Military	862		480		462	400	410	386	368
Total	**5,796**		**6,638**		**6,405**	**8,209**	**8,137**	**8,295**	**7,638**

Note: Totals may not sum due to independent rounding.

Table 3-52: Marine Fuel Consumption for International Transport (Million Gallons)

Fuel Type	1990		2000		2005	2006	2007	2008	2009
Residual Fuel Oil	4,781		2,967		3,881	4,004	4,059	4,373	4,040
Distillate Diesel Fuel & Other	617		290		444	446	358	445	426
U.S. Military Naval Fuels	522		329		471	414	444	437	384
Total	**5,920**		**3,586**		**4,796**	**4,864**	**4,861**	**5,254**	**4,850**

Note: Totals may not sum due to independent rounding.

Uncertainty and Time-Series Consistency

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.[100] 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.

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. Total aircraft and ship fuel use estimates were developed from DoD records, which document fuel sold to the Navy and Air Force from the Defense Logistics Agency. These data may slightly over or under estimate actual total fuel use in aircraft and ships because each Service may have procured fuel from, and/or may have sold to, traded with, and/or given fuel to other ships, aircraft, governments, or other entities. There are uncertainties in aircraft operations and training activity data. Estimates for the quantity of fuel actually used in Navy and Air Force flying activities reported as bunker fuel emissions had to be 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, which 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 uncertainty associated with ground fuel estimates for 1997 through 2001. Small fuel quantities may have been used in vehicles or equipment other than that which was assumed for each fuel type.

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 using the original set from 1995. The data were adjusted for trends in fuel use based on a closely correlating, but not matching, data set. 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 emission estimates could be reduced through additional data collection.

Although aggregate fuel consumption data have 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 separately using fuel consumption data, while landing and take-off (LTO) cycle data be used to estimate

[100] See uncertainty discussions under Carbon Dioxide Emissions from Fossil Fuel Combustion.

near-ground level emissions of gases other than CO_2.[101]

There is also concern as to the reliability of the existing DOC (1991 through 2010) data on marine vessel fuel consumption reported at U.S. customs stations due to the significant degree of inter-annual variation.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2008. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

A source-specific QA/QC plan for international bunker fuels was developed and implemented. This effort included a Tier 1 analysis, as well as portions of a Tier 2 analysis. The Tier 2 procedures that were implemented involved checks specifically focusing on the activity data and emission factor sources and methodology used for estimating CO_2, CH_4, and N_2O from international bunker fuels in the United States. Emission totals for the different sectors and fuels were compared and trends were investigated. No corrective actions were necessary.

Recalculations Discussion

Slight changes to emission estimates are due to revisions made to historical activity data for aviation jet fuel consumption using the FAA's AEDT. These historical data changes resulted in changes to the emission estimates for 1990 through 2008 relative to the previous Inventory, which averaged to an annual decrease in emissions from international bunker fuels of 0.13 Tg CO_2 Eq. (0.1 percent) in CO_2 emissions, an annual decrease of less than 0.01 Tg CO_2 Eq. (0.05 percent) in CH_4 emissions, and an annual decrease of less than 0.01 Tg CO_2 Eq. (0.1 percent) in N_2O emissions.

3.10. Wood Biomass and Ethanol Consumption (IPCC Source Category 1A)

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 CO_2 in addition to CH_4 and N_2O already covered in this chapter. In line with the reporting requirements for inventories submitted under the UNFCCC, CO_2 emissions from biomass combustion have been estimated separately from fossil fuel CO_2 emissions and are not directly included in the energy sector contributions to U.S. totals. In accordance with IPCC methodological guidelines, any such emissions are calculated by accounting for net carbon (C) fluxes from changes in biogenic C reservoirs in wooded or crop lands. For a more complete description of this methodological approach, see the Land Use, Land-Use Change, and Forestry chapter (Chapter 7), which accounts for the contribution of any resulting CO_2 emissions to U.S. totals within the Land Use, Land-Use Change and Forestry sector's approach.

In 2009, total CO_2 emissions from the burning of woody biomass in the industrial, residential, commercial, and electricity generation sectors were approximately 183.8 Tg CO_2 Eq. (183,777 Gg) (see Table 3-53 and Table 3-54). As the largest consumer of woody biomass, the industrial sector was responsible for 62 percent of the CO_2 emissions from this source. Emissions from this sector decreased from 2008 to 2009 due to a corresponding decrease in wood consumption. The residential sector was the second largest emitter, constituting 24 percent of the total, while the commercial and electricity generation sectors accounted for the remainder.

Table 3-53: CO_2 Emissions from Wood Consumption by End-Use Sector (Tg CO_2 Eq.)

End-Use Sector	1990	2000	2005	2006	2007	2008	2009
Industrial	135.3	153.6	136.3	138.2	132.6	126.1	114.2
Residential	59.8	43.3	44.3	40.2	44.3	46.4	44.3

[101] U.S. aviation emission estimates for CO, NO_x, and NMVOCs are reported by EPA's National Emission Inventory (NEI) Air Pollutant Emission Trends web site, and reported under the Mobile Combustion section. It should be noted that these estimates 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 reported under the Mobile Combustion section 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. The estimates in Mobile Combustion are also likely to include emissions from ocean-going vessels departing from U.S. ports on international voyages.

Commercial	6.8	7.4	7.2	6.7	7.2	7.5	7.4
Electricity Generation	13.3	13.9	19.1	18.7	19.2	18.3	17.8
Total	**215.2**	**218.1**	**206.9**	**203.8**	**203.3**	**198.4**	**183.8**

Note: Totals may not sum due to independent rounding.

Table 3-54: CO_2 Emissions from Wood Consumption by End-Use Sector (Gg)

End-Use Sector	1990	2000	2005	2006	2007	2008	2009
Industrial	135,348	153,559	136,269	138,207	132,642	126,145	114,222
Residential	59,808	43,309	44,340	40,215	44,340	46,402	44,340
Commercial	6,779	7,370	7,182	6,675	7,159	7,526	7,406
Electricity Generation	13,252	13,851	19,074	18,748	19,175	18,288	17,809
Total	**215,186**	**218,088**	**206,865**	**203,846**	**203,316**	**198,361**	**183,777**

Note: Totals may not sum due to independent rounding.

Biomass-derived fuel consumption in the United States transportation sector consisted primarily of ethanol use. 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.

In 2009, the United States consumed an estimated 894 trillion Btu of ethanol, and as a result, produced approximately 61.2 Tg CO_2 Eq. (61,231 Gg) (see Table 3-55 and Table 3-56) of CO_2 emissions. Ethanol production and consumption has grown steadily every year since 1990, with the exception of 1996 due to short corn supplies and high prices in that year.

Table 3-55: CO_2 Emissions from Ethanol Consumption (Tg CO_2 Eq.)

End-Use Sector	1990	2000	2005	2006	2007	2008	2009
Transportation	4.1	9.2	22.4	30.3	38.1	53.8	60.2
Industrial	0.1	0.1	0.5	0.7	0.7	0.8	0.9
Commercial	+	+	0.1	0.1	0.1	0.1	0.2
Total	**4.2**	**9.4**	**23.0**	**31.0**	**38.9**	**54.8**	**61.2**

+ Does not exceed 0.05 Tg CO_2 Eq.

Table 3-56: CO_2 Emissions from Ethanol Consumption (Gg)

End-Use Sector	1990	2000	2005	2006	2007	2008	2009
Transportation[a]	4,139	9,239	22,427	30,255	38,138	53,827	60,176
Industrial	56	87	469	662	674	798	892
Commercial	34	26	60	86	135	146	163
Total	**4,229**	**9,352**	**22,956**	**31,002**	**38,946**	**54,770**	**61,231**

[a] See Annex 3.2, Table A-88 for additional information on transportation consumption of these fuels.

Methodology

Woody biomass emissions were estimated by applying two EIA gross heat contents (Lindstrom 2006) to U.S. consumption data (EIA 2010) (see Table 3-57), provided in energy units for the industrial, residential, commercial, and electric generation sectors. One heat content (16.95 MMBtu/MT wood and wood waste) was applied to the industrial sector's consumption, while the other heat content (15.43 MMBtu/MT wood and wood waste) was applied to the consumption data for the other sectors. An EIA emission factor of 0.434 MT C/MT wood (Lindstrom 2006) was then applied to the resulting quantities of woody biomass to obtain CO_2 emission estimates. It was assumed that the woody biomass contains black liquor and other wood wastes, has a moisture content of 12 percent, and is converted into CO_2 with 100 percent efficiency. The emissions from ethanol consumption were calculated by applying an emission factor of 18.67 Tg C/QBtu (EPA 2010) to U.S. ethanol consumption estimates that were provided in energy units (EIA 2010) (see Table 3-58).

Table 3-57: Woody Biomass Consumption by Sector (Trillion Btu)

End-Use Sector	1990	2000	2005	2006	2007	2008	2009
Industrial	1,442	1,636	1,452	1,472	1,413	1,344	1,217

Residential	580	420	430	390	430	450	430
Commercial	66	71	70	65	69	73	72
Electricity Generation	129	134	185	182	186	177	173
Total	**2,216**	**2,262**	**2,136**	**2,109**	**2,098**	**2,044**	**1,891**

Table 3-58: Ethanol Consumption by Sector (Trillion Btu)

End-Use Sector	1990	2000	2005	2006	2007	2008	2009
Transportation	60.5	135.0	327.6	442.0	557.1	786.3	879.0
Industrial	0.8	1.3	6.8	9.7	9.8	11.7	13.0
Commercial	0.5	0.4	0.9	1.3	2.0	2.1	2.4
Total	**61.8**	**136.6**	**335.3**	**452.9**	**568.9**	**800.1**	**894.5**

Uncertainty and Time-Series Consistency

It is assumed that the combustion efficiency for woody biomass is 100 percent, which is believed to be an overestimate of the efficiency of wood combustion processes in the United States. Decreasing the combustion efficiency would decrease emission estimates. Additionally, the heat content applied to the consumption of woody biomass in the residential, commercial, and electric power sectors is unlikely to be a completely accurate representation of the heat content for all the different types of woody biomass consumed within these sectors. 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.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

Recalculations Discussion

Wood consumption values were revised for 2006 through 2008 based on updated information from EIA's Annual Energy Review (EIA 2010). This adjustment of historical data for wood biomass consumption resulted in an average annual decrease in emissions from wood biomass consumption of 0.8 Tg CO_2 Eq. (0.4 percent) from 1990 through 2008. The C content coefficient for ethanol was also revised to be consistent with the carbon content coefficients used for EPA's Mandatory Greenhouse Gas Reporting Rule. Slight adjustments were made to ethanol consumption based on updated information from EIA (2010), which slightly decreased estimates for ethanol consumed. As a result of these adjustments, average annual emissions from ethanol consumption increased by about 0.3 Tg CO_2 Eq. (1.9 percent) relative to the previous Inventory.

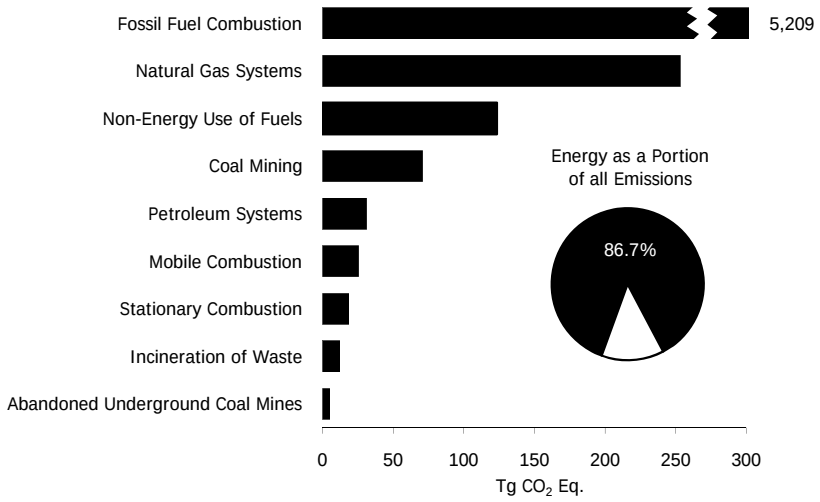

Figure 3-1: 2009 Energy Chapter Greenhouse Gas Sources

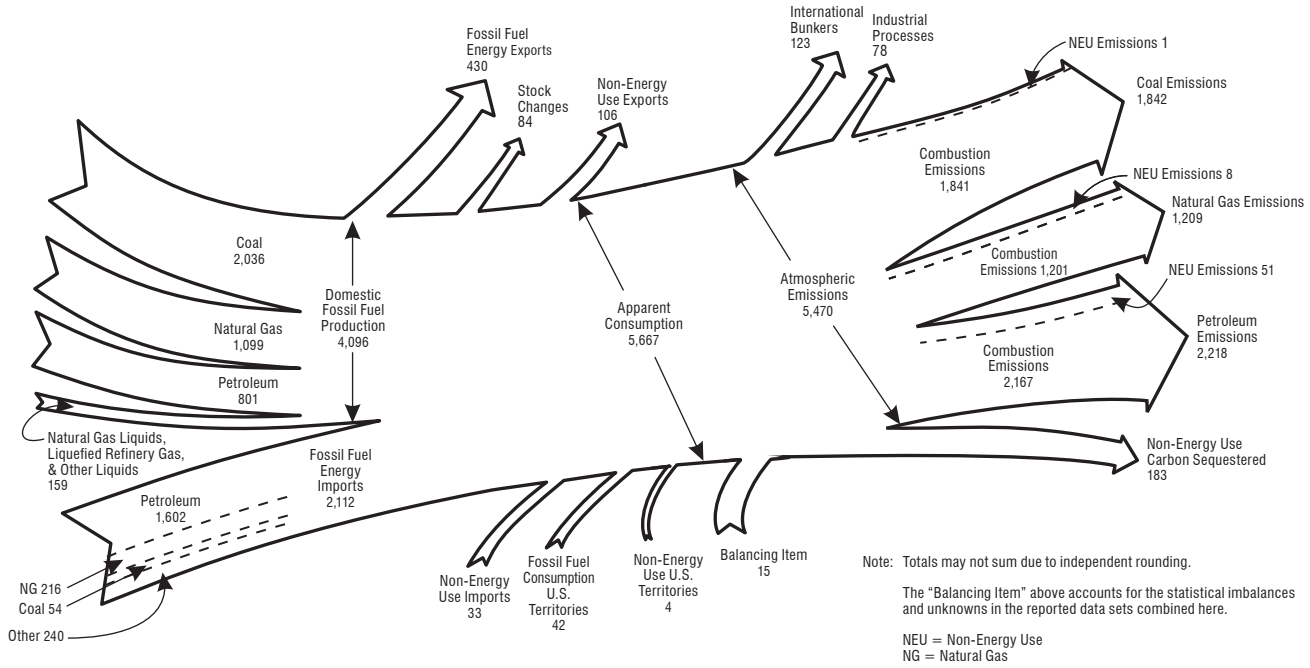

Figure 3-2 2009 U.S. Fossil Carbon Flows (Tg CO_2 Eq.)

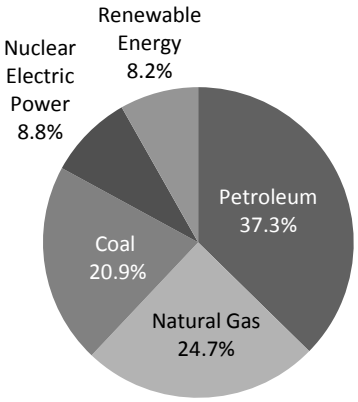

Figure 3-3: 2009 U.S. Energy Consumption by Energy Source

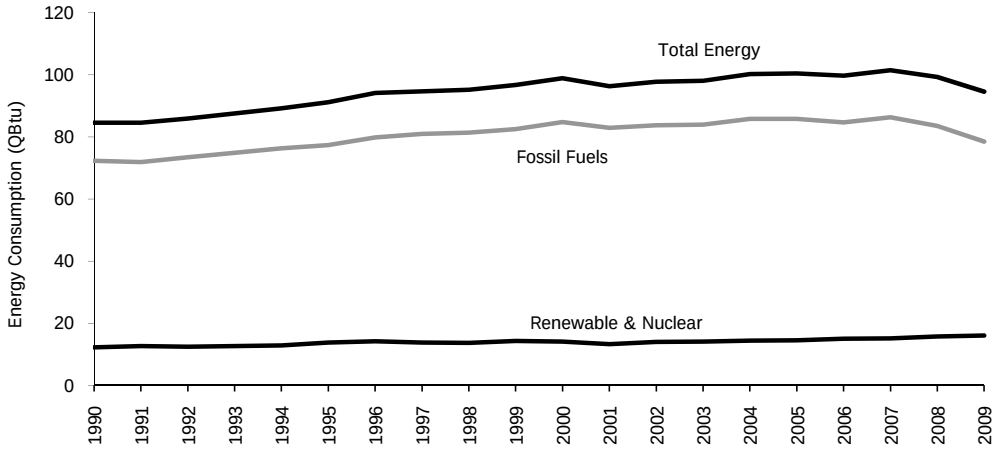

Figure 3-4: U.S. Energy Consumption (Quadrillion Btu)

Note: Expressed as gross calorific values.

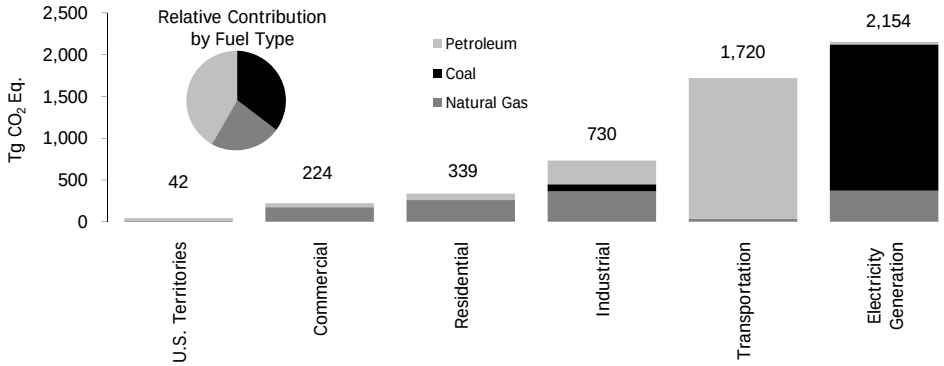

Figure 3-5: 2009 CO_2 Emissions from Fossil Fuel Combustion by Sector and Fuel Type

Note: The electricity generation sector also includes emissions of less than 0.5 Tg CO_2 Eq. from geothermal-based electricity generation.

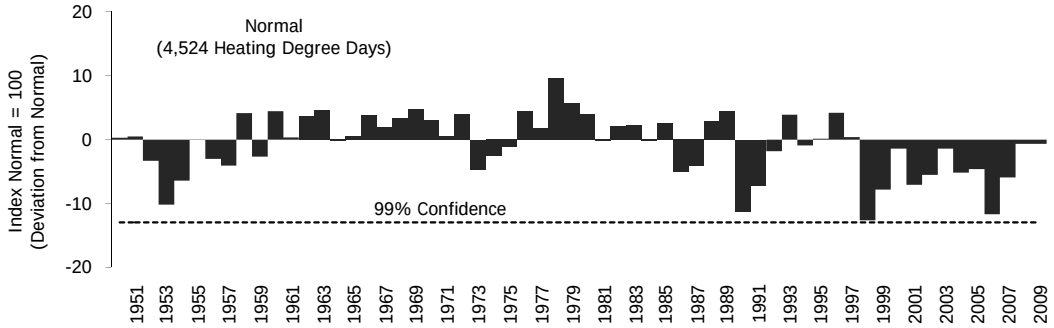

Figure 3-6: Annual Deviations from Normal Heating Degree Days for the United States (1950-2009)
Note: Climatological normal data are highlighted.
Statistical confidence interval for "normal" climatology period of 1971 through 2000.

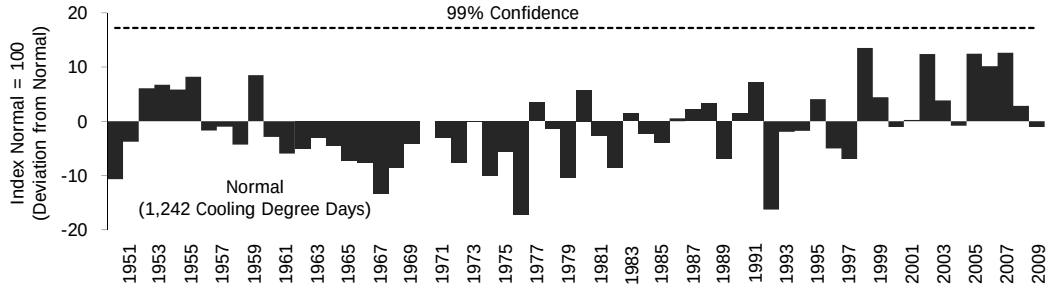

Figure 3-7: Annual Deviations from Normal Cooling Degree Days for the United States (1950-2009)
Note: Climatological normal data are highlighted.
Statistical confidence interval for "normal" climatology period of 1971 through 2000.

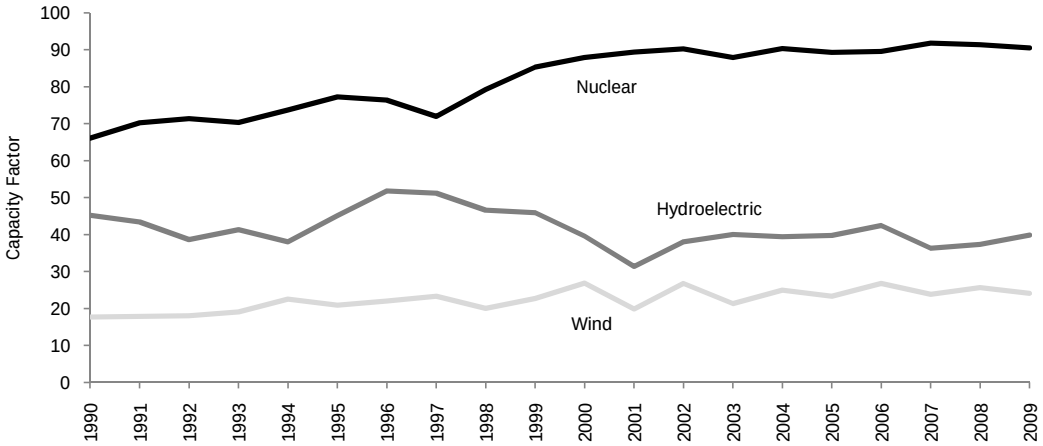

Figure 3-8: Nuclear, Hydroelectric, and Wind Power Plant Capacity Factors in the United States (1990-2009)

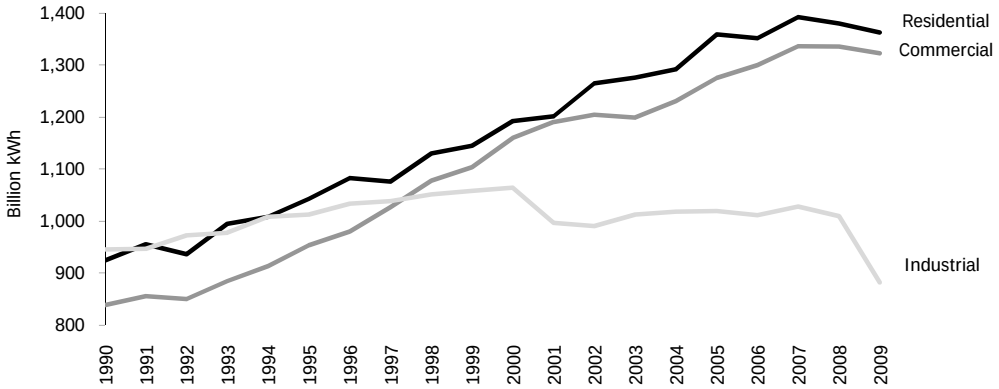

Figure 3-9: Electric Generation Retail Sales by End-Use Sector
Note: The transportation end-use sector consumes minor quanties of electricity.

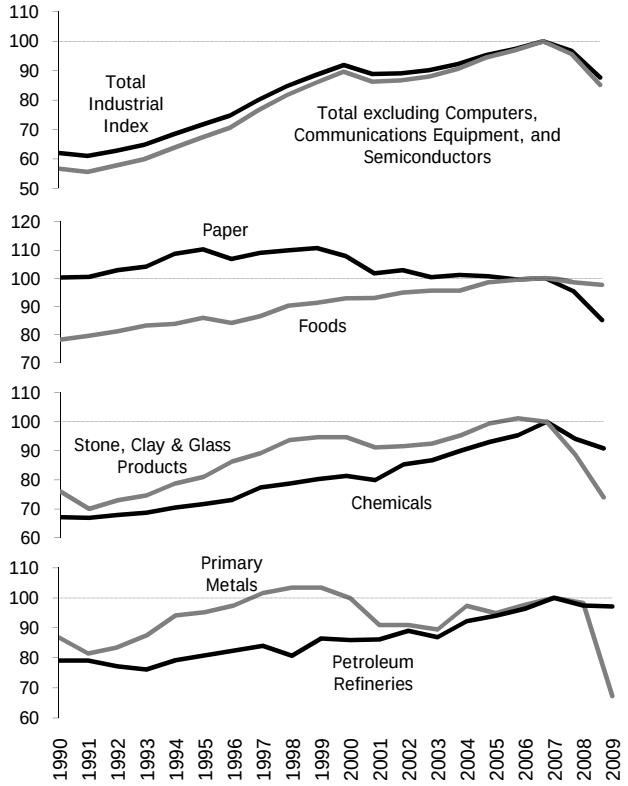

Figure 3-10: Industrial Production Indexes (Index 2007=100)

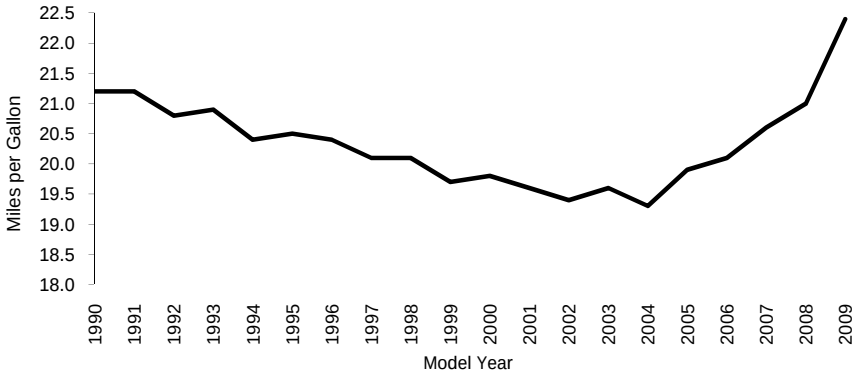

Figure 3-11: Sales-Weighted Fuel Economy of New Passenger Cars and Light-Duty Trucks, 1990-2009

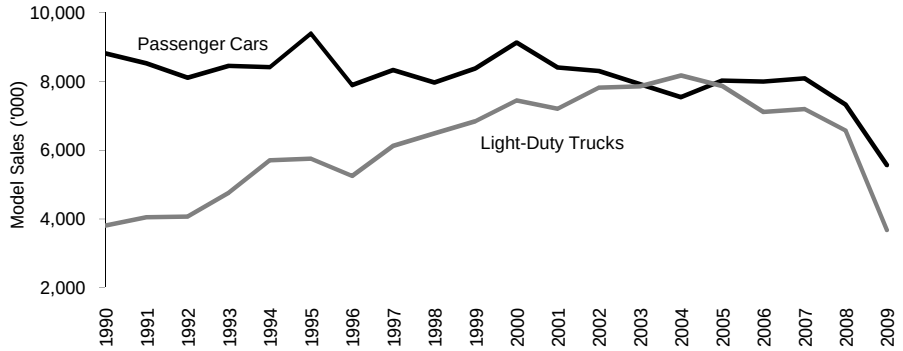

Figure 3-12: Sales of New Passenger Cars and Light-Duty Trucks, 1990-2009

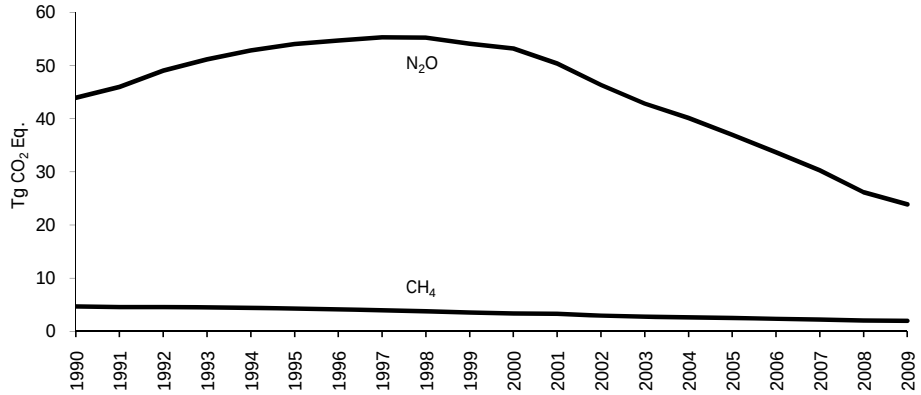

Figure 3-13: Mobile Source CH_4 and N_2O Emissions

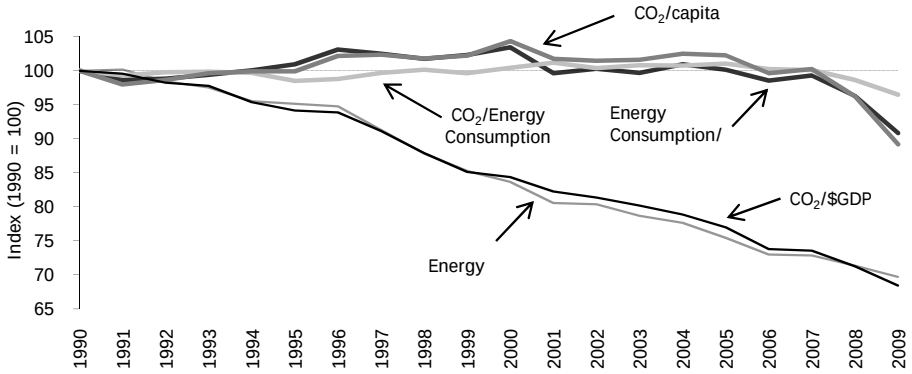

Figure 3-14: U.S. Energy Consumption and Energy-Related CO_2 Emissions Per Capita and Per Dollar GDP