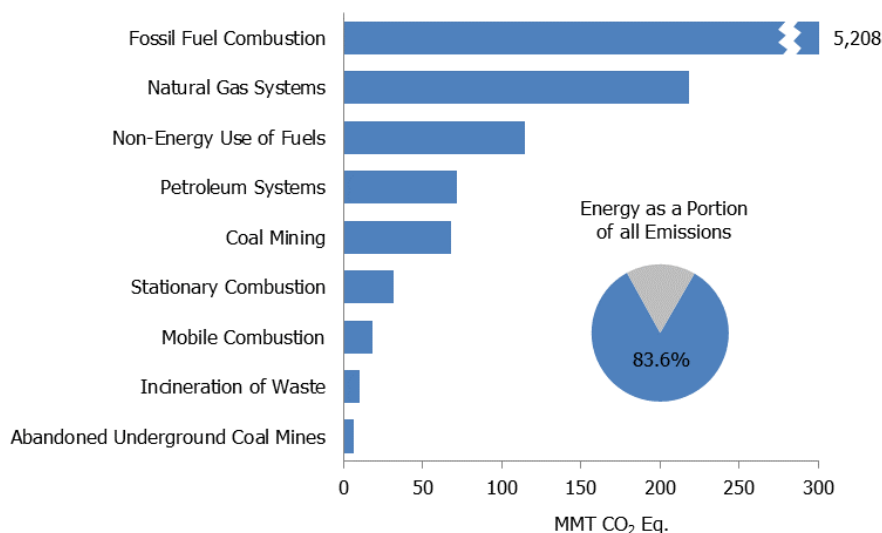


3. Energy

Energy-related activities were the primary sources of U.S. anthropogenic greenhouse gas emissions, accounting for 83.6 percent of total greenhouse gas emissions on a carbon dioxide (CO₂) equivalent basis in 2014.¹ This included 97, 45, and 10 percent of the nation's CO₂, methane (CH₄), and nitrous oxide (N₂O) emissions, respectively. Energy-related CO₂ emissions alone constituted 78.3 percent of national emissions from all sources on a CO₂ equivalent basis, while the non-CO₂ emissions from energy-related activities represented a much smaller portion of total national emissions (5.4 percent collectively).

Emissions from fossil fuel combustion comprise the vast majority of energy-related emissions, with CO₂ being the primary gas emitted (see Figure 3-1). Globally, approximately 32,190 million metric tons (MMT) of CO₂ were added to the atmosphere through the combustion of fossil fuels in 2013, of which the United States accounted for approximately 16 percent.² Due to their relative importance, fossil fuel combustion-related CO₂ emissions are considered separately, and in more detail than other energy-related emissions (see Figure 3-2). Fossil fuel combustion also emits CH₄ and N₂O. Stationary combustion of fossil fuels was the second-largest source of N₂O emissions in the United States and mobile fossil fuel combustion was the fourth-largest source.

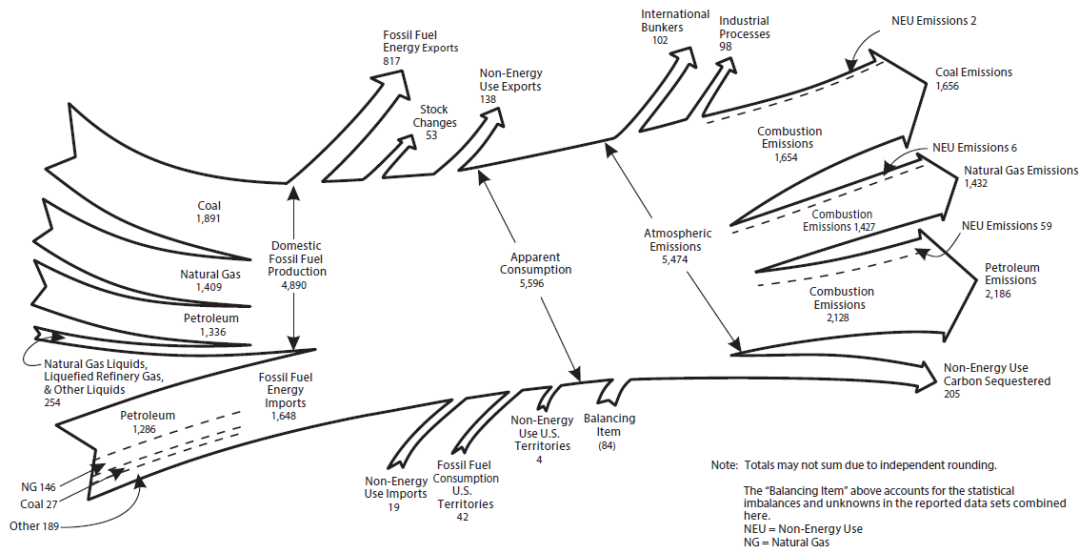
Figure 3-1: 2014 Energy Chapter Greenhouse Gas Sources (MMT CO₂ Eq.)



¹ Estimates are presented in units of million metric tons of carbon dioxide equivalent (MMT CO₂ Eq.), which weight each gas by its global warming potential, or GWP, value. See section on global warming potentials in the Executive Summary.

² Global CO₂ emissions from fossil fuel combustion were taken from International Energy Agency *CO₂ Emissions from Fossil Fuels Combustion – Highlights* <<https://www.iea.org/publications/freepublications/publication/CO2EmissionsFromFuelCombustionHighlights2015.pdf>> IEA (2015).

Figure 3-2: 2014 U.S. Fossil Carbon Flows (MMT CO₂ 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 CH₄ from natural gas systems, petroleum systems, and coal mining. Table 3-1 summarizes emissions from the Energy sector in units of MMT CO₂ Eq., while unweighted gas emissions in kilotons (kt) are provided in Table 3-2. Overall, emissions due to energy-related activities were 5,746.2 MMT CO₂ Eq. in 2014,³ an increase of 7.9 percent since 1990.

Table 3-1: CO₂, CH₄, and N₂O Emissions from Energy (MMT CO₂ Eq.)

Gas/Source	1990	2005	2010	2011	2012	2013	2014
CO₂	4,908.8	5,932.5	5,520.0	5,386.6	5,179.7	5,330.8	5,377.9
Fossil Fuel Combustion	4,740.7	5,747.1	5,358.3	5,227.7	5,024.7	5,157.6	5,208.2
Electricity Generation	1,820.8	2,400.9	2,258.4	2,157.7	2,022.2	2,038.1	2,039.3
Transportation	1,493.8	1,887.0	1,728.3	1,707.6	1,696.8	1,713.0	1,737.6
Industrial	842.5	828.0	775.5	773.3	782.9	812.2	813.3
Residential	338.3	357.8	334.6	326.8	282.5	329.7	345.1
Commercial	217.4	223.5	220.1	220.7	196.7	221.0	231.9
U.S. Territories	27.9	49.9	41.4	41.5	43.6	43.5	41.0
Non-Energy Use of Fuels	118.1	138.9	114.1	108.5	105.6	121.7	114.3
Natural Gas Systems	37.7	30.1	32.4	35.7	35.2	38.5	42.4
Incineration of Waste	8.0	12.5	11.0	10.5	10.4	9.4	9.4
Petroleum Systems	3.6	3.9	4.2	4.2	3.9	3.7	3.6
Biomass-Wood ^a	215.2	206.9	192.5	195.2	194.9	211.6	217.7
International Bunker Fuels ^a	103.5	113.1	117.0	111.7	105.8	99.8	103.2
Biomass-Ethanol ^a	4.2	22.9	72.6	72.9	72.8	74.7	76.1
CH₄	363.3	307.0	318.5	313.3	312.5	321.2	328.3
Natural Gas Systems	206.8	177.3	166.2	170.1	172.6	175.6	176.1
Petroleum Systems	38.7	48.8	54.1	56.3	58.4	64.7	68.1
Coal Mining	96.5	64.1	82.3	71.2	66.5	64.6	67.6
Stationary Combustion	8.5	7.4	7.1	7.1	6.6	8.0	8.1
Abandoned Underground Coal							
Mines	7.2	6.6	6.6	6.4	6.2	6.2	6.3
Mobile Combustion	5.6	2.7	2.3	2.2	2.2	2.1	2.0
Incineration of Waste	+	+	+	+	+	+	+
International Bunker Fuels ^a	0.2	0.1	0.1	0.1	0.1	0.1	0.1

³ Following the revised reporting requirements under the UNFCCC, this Inventory report presents CO₂ equivalent values based on the IPCC Fourth Assessment Report (AR4) GWP values. See the Introduction chapter for more information.

N₂O	53.6	55.0	46.1	44.0	41.7	41.4	40.0
Stationary Combustion	11.9	20.2	22.2	21.3	21.4	22.9	23.4
Mobile Combustion	41.2	34.4	23.6	22.4	20.0	18.2	16.3
Incineration of Waste	0.5	0.4	0.3	0.3	0.3	0.3	0.3
<i>International Bunker Fuels^a</i>	<i>0.9</i>	<i>1.0</i>	<i>1.0</i>	<i>1.0</i>	<i>0.9</i>	<i>0.9</i>	<i>0.9</i>
Total	5,324.9	6,294.5	5,884.6	5,744.0	5,533.9	5,693.5	5,746.2

+ Does not exceed 0.05 MMT CO₂ Eq.

^a 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: CO₂, CH₄, and N₂O Emissions from Energy (kt)

Gas/Source	1990	2005	2010	2011	2012	2013	2014
CO₂	4,908,041	5,932,474	5,519,975	5,386,609	5,179,749	5,330,837	5,377,857
Fossil Fuel Combustion	4,740,671	5,747,142	5,358,292	5,227,690	5,024,685	5,157,583	5,208,207
Non-Energy Use of Fuels	118,114	138,876	114,063	108,515	105,624	121,682	114,311
Natural Gas Systems	37,732	30,076	32,439	35,662	35,203	38,457	42,351
Incineration of Waste	7,972	12,454	11,026	10,550	10,362	9,421	9,421
Petroleum Systems	3,553	3,927	4,154	4,192	3,876	3,693	3,567
<i>Biomass – Wood^a</i>	<i>215,186</i>	<i>206,901</i>	<i>192,462</i>	<i>195,182</i>	<i>194,903</i>	<i>211,581</i>	<i>217,654</i>
<i>International Bunker Fuels^a</i>	<i>103,463</i>	<i>113,139</i>	<i>116,992</i>	<i>111,660</i>	<i>105,805</i>	<i>99,763</i>	<i>103,201</i>
<i>Biomass – Ethanol^a</i>	<i>4,227</i>	<i>22,943</i>	<i>72,647</i>	<i>72,881</i>	<i>72,827</i>	<i>74,743</i>	<i>76,075</i>
CH₄	14,532	12,281	12,741	12,533	12,498	12,848	13,132
Natural Gas Systems	8,270	7,093	6,647	6,803	6,906	7,023	7,045
Petroleum Systems	1,550	1,953	2,163	2,251	2,335	2,588	2,726
Coal Mining	3,860	2,565	3,293	2,849	2,658	2,584	2,703
Stationary Combustion	339	296	283	283	265	320	324
Abandoned Underground							
Coal Mines	288	264	263	257	249	249	253
Mobile Combustion	226	110	91	90	86	84	82
Incineration of Waste	+	+	+	+	+	+	+
<i>International Bunker Fuels^a</i>	<i>7</i>	<i>5</i>	<i>6</i>	<i>5</i>	<i>4</i>	<i>3</i>	<i>3</i>
N₂O	180	185	155	148	140	139	134
Stationary Combustion	40	68	74	71	72	77	79
Mobile Combustion	138	115	79	75	67	61	55
Incineration of Waste	2	1	1	1	1	1	1
<i>International Bunker Fuels^a</i>	<i>3</i>	<i>3</i>	<i>3</i>	<i>3</i>	<i>3</i>	<i>3</i>	<i>3</i>

+ Does not exceed 0.5 kt

^a 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.

Box 3-1: Methodological Approach for Estimating and Reporting U.S. Emissions and Sinks

In following the United Nations Framework Convention on Climate Change (UNFCCC) requirement under Article 4.1 to develop and submit national greenhouse gas emission inventories, the emissions and sinks presented in this report and this chapter, are organized by source and sink categories and calculated using internationally-accepted methods provided by the Intergovernmental Panel on Climate Change (IPCC). Additionally, the calculated emissions and sinks in a given year for the United States are presented in a common manner in line with the UNFCCC reporting guidelines for the reporting of inventories under this international agreement. The use of consistent methods to calculate emissions and sinks by all nations providing their inventories to the UNFCCC ensures that these reports are comparable. In this regard, U.S. emissions and sinks reported in this inventory report are comparable to emissions and sinks reported by other countries. Emissions and sinks provided in this Inventory do not preclude alternative examinations, but rather, this Inventory presents emissions and sinks in a common format consistent with how countries are to report Inventories under the UNFCCC. The report itself, and this chapter, follows this standardized format, and provides an explanation of the IPCC methods used to calculate emissions and sinks, and the manner in which those calculations are conducted.

Box 3-2: Energy Data from the Greenhouse Gas Reporting Program

On October 30, 2009, the U.S. Environmental Protection Agency (EPA) published a rule for the mandatory reporting of greenhouse gases from large greenhouse gas emissions sources in the United States. Implementation of 40 CFR Part 98 is referred to as the Greenhouse Gas Reporting Program (GHGRP). 40 CFR Part 98 applies to direct greenhouse gas emitters, fossil fuel suppliers, industrial gas suppliers, and facilities that inject CO₂ underground for sequestration or other reasons. Reporting is at the facility level, except for certain suppliers of fossil fuels and industrial greenhouse gases. 40 CFR part 98 requires reporting by 41 industrial categories. Data reporting by affected facilities included the reporting of emissions from fuel combustion at that affected facility. In general, the threshold for reporting is 25,000 metric tons or more of CO₂ Eq. per year.

The GHGRP dataset and the data presented in this Inventory report are complementary and, as indicated in the respective planned improvements sections for source categories in this chapter, EPA is analyzing how to use facility-level GHGRP data to improve the national estimates presented in this Inventory (see, also, Box 3-4). Most methodologies used in EPA's GHGRP are consistent with IPCC, though for EPA's GHGRP, facilities collect detailed information specific to their operations according to detailed measurement standards, which may differ with the more aggregated data collected for the Inventory to estimate total, national U.S. emissions. It should be noted that the definitions and provisions for reporting fuel types in EPA's GHGRP may differ from those used in the Inventory in meeting the UNFCCC reporting guidelines. In line with the UNFCCC reporting guidelines, the inventory report is a comprehensive accounting of all emissions from fuel types identified in the IPCC guidelines and provides a separate reporting of emissions from biomass. Further information on the reporting categorizations in EPA's GHGRP and specific data caveats associated with monitoring methods in EPA's GHGRP has been provided on the GHGRP website.

EPA presents the data collected by its GHGRP through a data publication tool that allows data to be viewed in several formats including maps, tables, charts and graphs for individual facilities or groups of facilities.

3.1 Fossil Fuel Combustion (IPCC Source Category 1A)

Emissions from the combustion of fossil fuels for energy include the gases CO₂, CH₄, and N₂O. Given that CO₂ is the primary gas emitted from fossil fuel combustion and represents the largest share of U.S. total emissions, CO₂ 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 CO₂ from fossil fuel combustion also differ from the estimation of CH₄ and N₂O 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 CO₂, CH₄, and N₂O emissions from fossil fuel combustion are presented in Table 3-3 and Table 3-4.

Table 3-3: CO₂, CH₄, and N₂O Emissions from Fossil Fuel Combustion (MMT CO₂ Eq.)

Gas	1990	2005	2010	2011	2012	2013	2014
CO ₂	4,740.7	5,747.1	5,358.3	5,227.7	5,024.7	5,157.6	5,208.2
CH ₄	14.1	10.2	9.3	9.3	8.8	10.1	10.1
N ₂ O	53.1	54.7	45.8	43.8	41.5	41.2	39.8
Total	4,807.9	5,812.0	5,413.4	5,280.8	5,074.9	5,208.8	5,258.1

Note: Totals may not sum due to independent rounding

Table 3-4: CO₂, CH₄, and N₂O Emissions from Fossil Fuel Combustion (kt)

Gas	1990	2005	2010	2011	2012	2013	2014
CO ₂	4,740,671	5,747,142	5,358,292	5,227,690	5,024,685	5,157,583	5,208,207
CH ₄	565	406	372	374	352	404	405
N ₂ O	178	183	154	147	139	138	133

CO₂ from Fossil Fuel Combustion

Carbon dioxide is the primary gas emitted from fossil fuel combustion and represents the largest share of U.S. total greenhouse gas emissions. CO₂ emissions from fossil fuel combustion are presented in Table 3-5. In 2014, CO₂ emissions from fossil fuel combustion increased by 1.0 percent relative to the previous year. The increase in CO₂ emissions from fossil fuel combustion was a result of multiple factors, including: (1) colder winter conditions in the first quarter of 2014 resulting in an increased demand for heating fuel in the residential and commercial sectors; (2) an increase in transportation emissions resulting from an increase in vehicle miles traveled (VMT) and fuel use across on-road transportation modes; and (3) an increase in industrial production across multiple sectors resulting in slight increases in industrial sector emissions.⁴ In 2014, CO₂ emissions from fossil fuel combustion were 5,208.2 MMT CO₂ Eq., or 9.9 percent above emissions in 1990 (see Table 3-5).⁵

Table 3-5: CO₂ Emissions from Fossil Fuel Combustion by Fuel Type and Sector (MMT CO₂ Eq.)

Fuel/Sector	1990	2005	2010	2011	2012	2013	2014
Coal	1,718.4	2,112.3	1,927.7	1,813.9	1,592.8	1,654.4	1,653.7
Residential	3.0	0.8	NO	NO	NO	NO	NO
Commercial	12.0	9.3	6.6	5.8	4.1	3.9	4.5
Industrial	155.3	115.3	90.1	82.0	74.1	75.7	75.3
Transportation	NE	NE	NE	NE	NE	NE	NE
Electricity Generation	1,547.6	1,983.8	1,827.6	1,722.7	1,511.2	1,571.3	1,570.4
U.S. Territories	0.6	3.0	3.4	3.4	3.4	3.4	3.4
Natural Gas	1,000.3	1,166.7	1,272.1	1,291.5	1,352.6	1,391.2	1,426.6
Residential	238.0	262.2	258.6	254.7	224.8	266.2	277.6
Commercial	142.1	162.9	167.7	170.5	156.9	179.1	189.2
Industrial	408.9	388.5	407.2	417.3	434.8	451.9	466.0
Transportation	36.0	33.1	38.1	38.9	41.3	47.0	47.6
Electricity Generation	175.3	318.8	399.0	408.8	492.2	444.0	443.2
U.S. Territories	NO	1.3	1.5	1.4	2.6	3.0	3.0
Petroleum	2,021.5	2,467.8	2,158.2	2,121.9	2,078.9	2,111.6	2,127.5
Residential	97.4	94.9	76.0	72.2	57.7	63.4	67.5
Commercial	63.3	51.3	45.8	44.5	35.7	38.0	38.2
Industrial	278.3	324.2	278.2	274.0	274.1	284.6	271.9
Transportation	1,457.7	1,854.0	1,690.2	1,668.8	1,655.4	1,666.0	1,690.0
Electricity Generation	97.5	97.9	31.4	25.8	18.3	22.4	25.3
U.S. Territories	27.2	45.6	36.5	36.7	37.6	37.1	34.6
Geothermal^a	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Total	4,740.7	5,747.1	5,358.3	5,227.7	5,024.7	5,157.6	5,208.2

+ Does not exceed 0.05 MMT CO₂ Eq.

NE (Not estimated)

⁴ Further details on industrial sector combustion emissions are provided by EPA's GHGRP <<http://ghgdata.epa.gov/ghgp/main.do>>.

⁵ An additional discussion of fossil fuel emission trends is presented in the Trends in U.S. Greenhouse Gas Emissions Chapter.

NO (Not occurring)

^a Although not technically a fossil fuel, geothermal energy-related CO₂ emissions are included for reporting purposes.

Note: Totals may not sum due to independent rounding.

Trends in CO₂ 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).

Carbon dioxide 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.⁶ 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 CO₂ Emissions and Total 2014 Emissions from Fossil Fuel Combustion for Selected Fuels and Sectors (MMT CO₂ Eq. and Percent)

Sector	Fuel Type	2010 to 2011		2011 to 2012		2012 to 2013		2013 to 2014		Total 2014
Electricity Generation	Coal	-104.9	-5.7%	-211.5	-12.3%	60.1	4.0%	-0.9	-0.1%	1,570.4
Electricity Generation	Natural Gas	9.8	2.5%	83.5	20.4%	-48.3	-9.8%	-0.8	-0.2%	443.2
Electricity Generation	Petroleum	-5.6	-17.8%	-7.5	-29.0%	4.1	22.3%	2.9	12.8%	25.3
Transportation ^a	Petroleum	-21.4	-1.3%	-13.3	-0.8%	10.6	0.6%	24.0	1.4%	1,690.0
Residential	Natural Gas	-3.9	-1.5%	-29.8	-11.7%	41.4	18.4%	11.4	4.3%	277.6
Commercial	Natural Gas	2.7	1.6%	-13.6	-8.0%	22.3	14.2%	10.0	5.6%	189.2
Industrial	Coal	-8.1	-9.0%	-7.9	-9.7%	1.7	2.3%	-0.4	-0.6%	75.3
Industrial	Natural Gas	10.1	2.5%	17.5	4.2%	17.1	3.9%	14.2	3.1%	466.0
All Sectors^b	All Fuels^b	-130.6	-2.4%	-203.0	-3.9%	132.9	2.6%	50.6	1.0%	5,208.2

^a Excludes emissions from International Bunker Fuels.

^b Includes fuels and sectors not shown in table.

Note: Totals may not sum due to independent rounding.

In the United States, 82 percent of the energy consumed in 2014 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 (8 percent) and by a variety of renewable energy sources (10 percent), primarily hydroelectric power, wind energy and biofuels (EIA 2016).⁷ Specifically, petroleum supplied the largest share of domestic energy demands, accounting for 35 percent of total U.S. energy consumption in 2014. Natural gas and coal followed in order of energy demand importance, accounting for approximately 28 percent and 19 percent of total U.S. energy 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 2016).

⁶ Based on national aggregate carbon content of all coal, natural gas, and petroleum fuels combusted in the United States.

⁷ Renewable energy, as defined in EIA's energy statistics, includes the following energy sources: hydroelectric power, geothermal energy, biofuels, solar energy, and wind energy.

Figure 3-3: 2014 U.S. Energy Consumption by Energy Source (Percent)

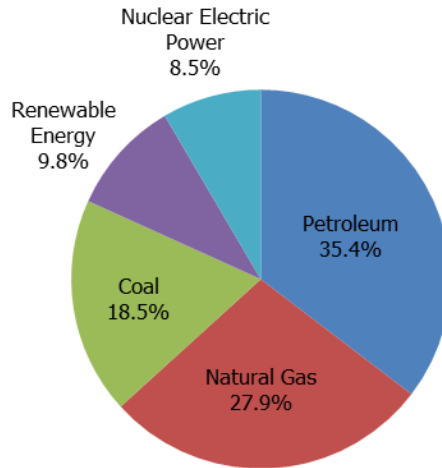


Figure 3-4: U.S. Energy Consumption (Quadrillion Btu)

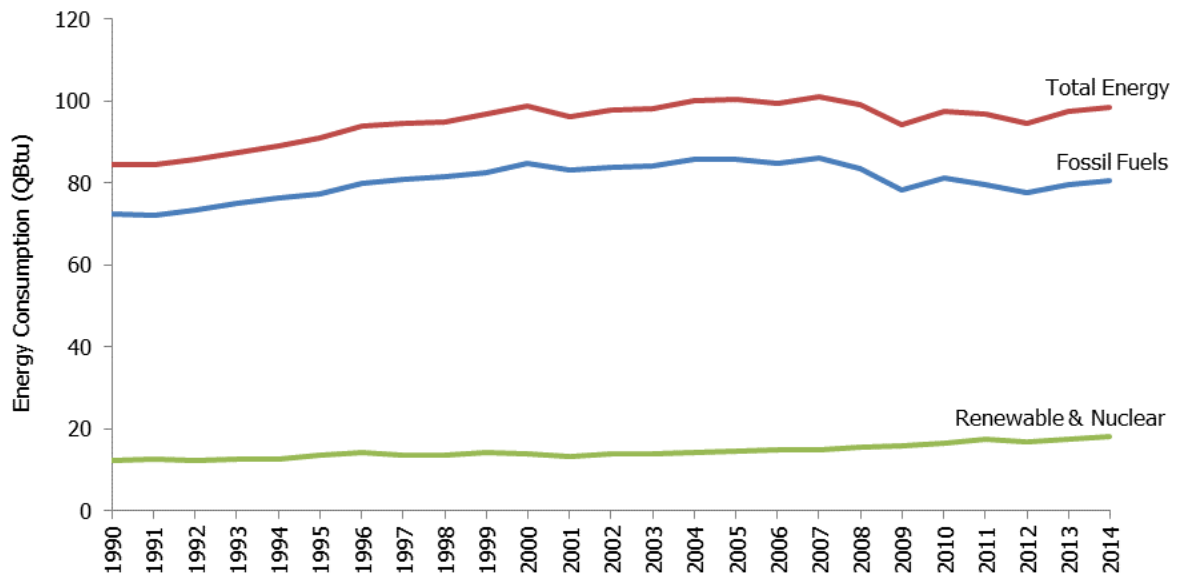
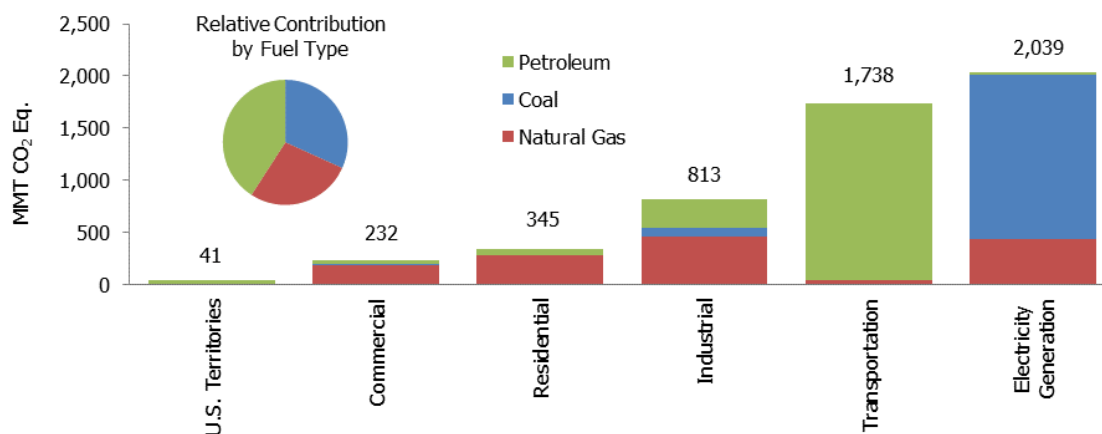


Figure 3-5: 2014 CO₂ Emissions from Fossil Fuel Combustion by Sector and Fuel Type (MMT CO₂ Eq.)



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 CO₂ and smaller amounts of other gases, including CH₄, CO, and NMVOCs.⁸ These other C containing non-CO₂ gases are emitted as a byproduct of incomplete fuel combustion, but are, for the most part, eventually oxidized to CO₂ in the atmosphere. Therefore, it is assumed all of the C in fossil fuels used to produce energy is eventually converted to atmospheric CO₂.

Box 3-3: Weather and Non-Fossil Energy Effects on CO₂ from Fossil Fuel Combustion Trends

In 2014, weather conditions, and a very cold first quarter of the year in particular, caused a significant increase in energy demand for heating fuels and is reflected in the increased residential emissions during the early part of the year (EIA 2016). The United States in 2014 also experienced a cooler winter overall compared to 2013, as heating degree days increased (1.9 percent). Cooling degree days decreased by 0.6 percent and despite this decrease in cooling degree days, electricity demand to cool homes still increased slightly. Colder winter conditions compared to 2013 resulted in a significant increase in the amount of energy required for heating, and heating degree days in the United States were 0.6 percent above normal for the first time since 2003 (see Figure 3-6). Summer conditions were slightly cooler in 2014 compared to 2013, and summer temperatures were warmer than normal, with cooling degree days 6.7 percent above normal (see Figure 3-7) (EIA 2016).⁹

⁸ See the sections entitled Stationary Combustion and Mobile Combustion in this chapter for information on non-CO₂ gas emissions from fossil fuel combustion.

⁹ Degree days are relative measurements of outdoor air temperature. Heating degree days are deviations of the mean daily temperature below 65 degrees Fahrenheit, while cooling degree days are deviations of the mean daily temperature above 65 degrees Fahrenheit. Heating degree days have a considerably greater effect 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).

Figure 3-6: Annual Deviations from Normal Heating Degree Days for the United States (1950–2014, Index Normal = 100)

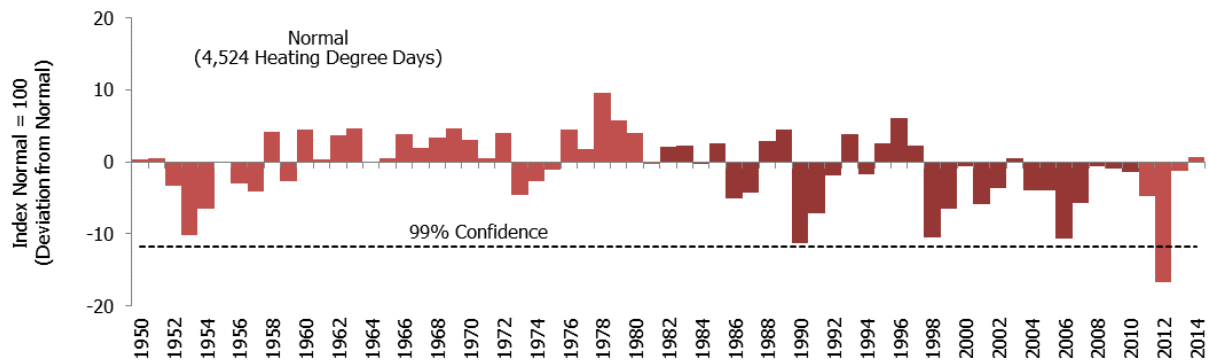
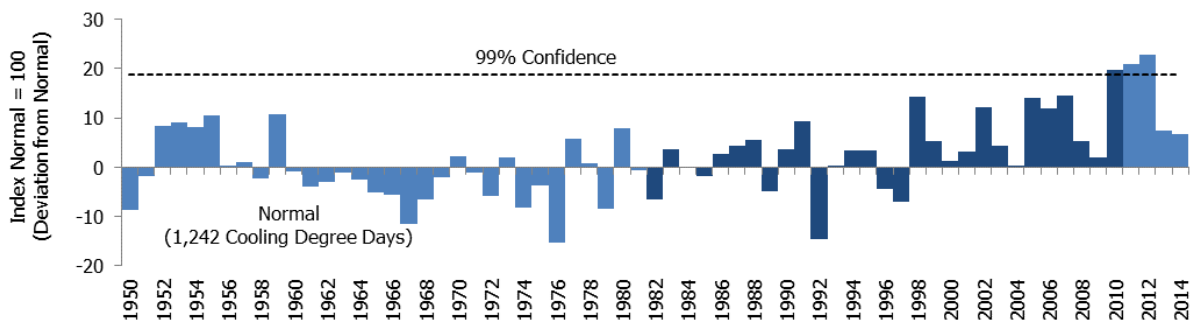


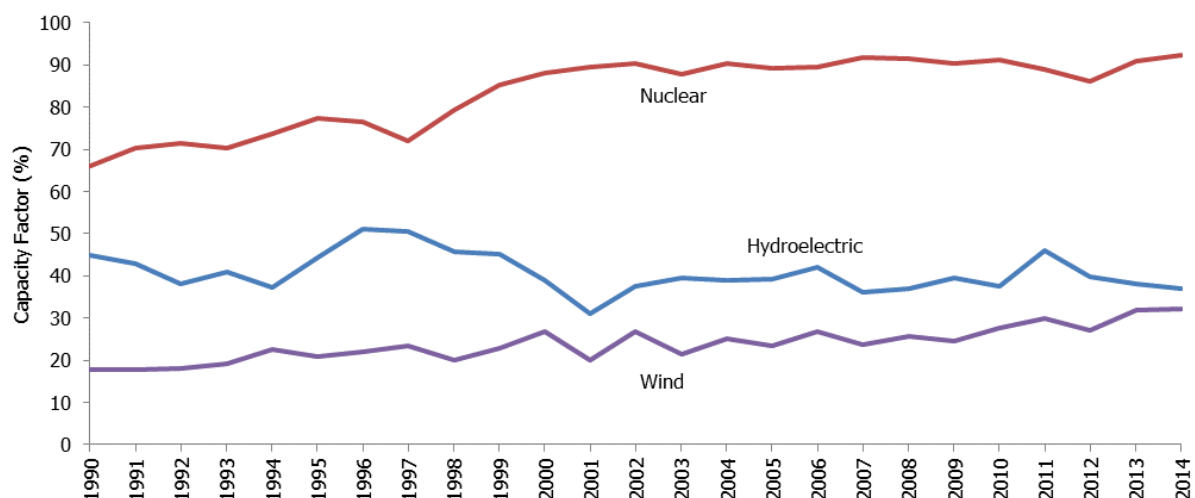
Figure 3-7: Annual Deviations from Normal Cooling Degree Days for the United States (1950–2014, Index Normal = 100)



Although no new U.S. nuclear power plants have been constructed in recent years, the utilization (i.e., capacity factors)¹⁰ of existing plants in 2014 remained high at 92 percent. Electricity output by hydroelectric power plants decreased in 2014 by approximately 3 percent. In recent years, the wind power sector has been showing strong growth, such that, on the margin, it is becoming a relatively important electricity source. Electricity generated by nuclear plants in 2014 provided more than 3 times as much of the energy generated in the United States from hydroelectric plants (EIA 2016). Nuclear, hydroelectric, and wind power capacity factors since 1990 are shown in Figure 3-8.

¹⁰ 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 (2016).

Figure 3-8: Nuclear, Hydroelectric, and Wind Power Plant Capacity Factors in the United States (1990–2014, Percent)



Fossil Fuel Combustion Emissions by Sector

In addition to the CO₂ emitted from fossil fuel combustion, CH₄ and N₂O are emitted from stationary and mobile combustion as well. Table 3-7 provides an overview of the CO₂, CH₄, and N₂O emissions from fossil fuel combustion by sector.

Table 3-7: CO₂, CH₄, and N₂O Emissions from Fossil Fuel Combustion by Sector (MMT CO₂ Eq.)

End-Use Sector	1990	2005	2010	2011	2012	2013	2014
Electricity Generation	1,828.5	2,417.4	2,277.4	2,175.8	2,040.5	2,057.7	2,059.4
CO ₂	1,820.8	2,400.9	2,258.4	2,157.7	2,022.2	2,038.1	2,039.3
CH ₄	0.3	0.5	0.5	0.4	0.4	0.4	0.4
N ₂ O	7.4	16.0	18.5	17.6	17.8	19.1	19.6
Transportation	1,540.6	1,924.1	1,754.2	1,732.3	1,718.9	1,733.3	1,756.0
CO ₂	1,493.8	1,887.0	1,728.3	1,707.6	1,696.8	1,713.0	1,737.6
CH ₄	5.6	2.7	2.3	2.2	2.2	2.1	2.0
N ₂ O	41.2	34.4	23.6	22.4	20.0	18.2	16.3
Industrial	847.4	832.7	779.3	777.3	786.9	816.2	817.2
CO ₂	842.5	828.0	775.5	773.3	782.9	812.2	813.3
CH ₄	1.8	1.7	1.4	1.5	1.5	1.5	1.5
N ₂ O	3.1	2.9	2.4	2.5	2.5	2.4	2.4
Residential	344.6	362.8	339.4	331.7	287.0	335.6	351.1
CO ₂	338.3	357.8	334.6	326.8	282.5	329.7	345.1
CH ₄	5.2	4.1	4.0	4.0	3.7	5.0	5.0
N ₂ O	1.0	0.9	0.8	0.8	0.7	1.0	1.0
Commercial	218.8	224.9	221.5	222.1	197.9	222.4	233.3
CO ₂	217.4	223.5	220.1	220.7	196.7	221.0	231.9
CH ₄	1.0	1.1	1.1	1.0	0.9	1.0	1.1
N ₂ O	0.4	0.3	0.3	0.3	0.3	0.3	0.3

U.S. Territories^a	28.0	50.1	41.6	41.7	43.7	43.7	41.2
Total	4,807.9	5,812.0	5,413.4	5,280.8	5,074.9	5,208.8	5,258.1

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

Notes: 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.

Other than CO₂, gases emitted from stationary combustion include the greenhouse gases CH₄ and N₂O and the indirect greenhouse gases NO_x, CO, and NMVOCs.¹¹ Methane and N₂O 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. Nitrous oxide 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. Methane emissions from stationary combustion are primarily a function of the CH₄ content of the fuel and combustion efficiency.

Mobile combustion produces greenhouse gases other than CO₂, including CH₄, N₂O, and indirect greenhouse gases including NO_x, CO, and NMVOCs. As with stationary combustion, N₂O 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. N₂O 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. Carbon monoxide emissions are highest when air-fuel mixtures have less oxygen than required for complete combustion. These emissions occur especially in idle, low speed, and cold start conditions. Methane and NMVOC emissions from motor vehicles are a function of the CH₄ 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 CH₄ and N₂O from transportation.¹² Emissions from U.S. Territories are also calculated separately due to a lack of end-use-specific consumption data. This method assumes that emissions from combustion sources are distributed across the four end-use sectors based on the ratio of electricity consumption in that sector. The results of this alternative method are presented in Table 3-8.

Table 3-8: CO₂, CH₄, and N₂O Emissions from Fossil Fuel Combustion by End-Use Sector (MMT CO₂ Eq.)

End-Use Sector	1990	2005	2010	2011	2012	2013	2014
Transportation	1,543.7	1,928.9	1,758.7	1,736.6	1,722.8	1,737.4	1,760.1
CO ₂	1,496.8	1,891.8	1,732.7	1,711.9	1,700.6	1,717.0	1,741.7
CH ₄	5.6	2.7	2.3	2.2	2.2	2.1	2.0
N ₂ O	41.2	34.4	23.7	22.5	20.1	18.2	16.4
Industrial	1,537.0	1,574.3	1,425.7	1,407.2	1,385.0	1,416.6	1,416.6
CO ₂	1,529.2	1,564.6	1,416.5	1,398.0	1,375.7	1,407.0	1,406.8
CH ₄	2.0	1.9	1.6	1.6	1.6	1.6	1.6
N ₂ O	5.9	7.8	7.6	7.6	7.7	8.0	8.2
Residential	940.2	1,224.9	1,186.5	1,129.0	1,018.8	1,077.6	1,093.6
CO ₂	931.4	1,214.1	1,174.6	1,117.5	1,007.8	1,064.6	1,080.3
CH ₄	5.4	4.2	4.2	4.2	3.9	5.1	5.2
N ₂ O	3.4	6.6	7.7	7.3	7.1	7.9	8.1

¹¹ Sulfur dioxide (SO₂) emissions from stationary combustion are addressed in Annex 6.3.

¹² Separate calculations were performed for transportation-related CH₄ and N₂O. The methodology used to calculate these emissions are discussed in the mobile combustion section.

Commercial	759.1	1,033.7	1,000.9	966.3	904.5	933.6	946.7
CO ₂	755.4	1,026.8	993.0	958.8	897.0	925.5	938.4
CH ₄	1.1	1.2	1.2	1.2	1.1	1.2	1.2
N ₂ O	2.5	5.7	6.6	6.3	6.4	6.9	7.1
U.S. Territories^a	28.0	50.1	41.6	41.7	43.7	43.7	41.2
Total	4,807.9	5,812.0	5,413.4	5,280.8	5,074.9	5,208.8	5,258.1

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

Notes: 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.

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 CO₂ emissions from fossil fuel combustion by stationary sources. The CO₂ emitted is closely linked to the type of fuel being combusted in each sector (see Methodology section of CO₂ from Fossil Fuel Combustion). Other than CO₂, gases emitted from stationary combustion include the greenhouse gases CH₄ and N₂O. Table 3-10 and Table 3-11 present CH₄ and N₂O emissions from the combustion of fuels in stationary sources.¹³ Methane and N₂O emissions from stationary combustion sources depend upon fuel characteristics, combustion technology, pollution control equipment, ambient environmental conditions, and operation and maintenance practices. Nitrous oxide 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. Methane emissions from stationary combustion are primarily a function of the CH₄ content of the fuel and combustion efficiency. The CH₄ and N₂O emission estimation methodology was revised in 2010 to utilize the facility-specific technology and fuel use data reported to EPA's Acid Rain Program (see Methodology section for CH₄ and N₂O from stationary combustion). Please refer to Table 3-7 for the corresponding presentation of all direct emission sources of fuel combustion.

Table 3-9: CO₂ Emissions from Stationary Fossil Fuel Combustion (MMT CO₂ Eq.)

Sector/Fuel Type	1990	2005	2010	2011	2012	2013	2014
Electricity Generation	1,820.8	2,400.9	2,258.4	2,157.7	2,022.2	2,038.1	2,039.3
Coal	1,547.6	1,983.8	1,827.6	1,722.7	1,511.2	1,571.3	1,570.4
Natural Gas	175.3	318.8	399.0	408.8	492.2	444.0	443.2
Fuel Oil	97.5	97.9	31.4	25.8	18.3	22.4	25.3
Geothermal	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Industrial	842.5	828.0	775.5	773.3	782.9	812.2	813.3
Coal	155.3	115.3	90.1	82.0	74.1	75.7	75.3
Natural Gas	408.9	388.5	407.2	417.3	434.8	451.9	466.0
Fuel Oil	278.3	324.2	278.2	274.0	274.1	284.6	271.9
Commercial	217.4	223.5	220.1	220.7	196.7	221.0	231.9
Coal	12.0	9.3	6.6	5.8	4.1	3.9	4.5
Natural Gas	142.1	162.9	167.7	170.5	156.9	179.1	189.2
Fuel Oil	63.3	51.3	45.8	44.5	35.7	38.0	38.2
Residential	338.3	357.8	334.6	326.8	282.5	329.7	345.1
Coal	3.0	0.8	NO	NO	NO	NO	NO
Natural Gas	238.0	262.2	258.6	254.7	224.8	266.2	277.6
Fuel Oil	97.4	94.9	76.0	72.2	57.7	63.4	67.5
U.S. Territories	27.9	49.9	41.4	41.5	43.6	43.5	41.0

¹³ Since emission estimates for U.S. Territories cannot be disaggregated by gas in Table 3-10 and Table 3-11, the values for CH₄ and N₂O exclude U.S. territory emissions.

Coal	0.6		3.0		3.4	3.4	3.4	3.4	3.4
Natural Gas	NO		1.3		1.5	1.4	2.6	3.0	3.0
Fuel Oil	27.2		45.6		36.5	36.7	37.6	37.1	34.6
Total	3,246.9		3,860.1		3,630.0	3,520.1	3,327.9	3,444.6	3,470.6

+ Does not exceed 0.05 MMT CO₂ Eq.

NO - Not occurring

Note: Totals may not sum due to independent rounding.

Table 3-10: CH₄ Emissions from Stationary Combustion (MMT CO₂ Eq.)

Sector/Fuel Type	1990	2005	2010	2011	2012	2013	2014
Electric Power	0.3	0.5	0.5	0.4	0.4	0.4	0.4
Coal	0.3	0.3	0.3	0.3	0.2	0.2	0.2
Fuel Oil	+	+	+	+	+	+	+
Natural gas	0.1	0.1	0.2	0.2	0.2	0.2	0.2
Wood	+	+	+	+	+	+	+
Industrial	1.8	1.7	1.5	1.5	1.5	1.5	1.5
Coal	0.4	0.3	0.2	0.2	0.2	0.2	0.2
Fuel Oil	0.2	0.2	0.2	0.1	0.1	0.2	0.1
Natural gas	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Wood	1.0	1.0	0.9	0.9	1.0	0.9	0.9
Commercial	1.0	1.1	1.1	1.0	0.9	1.0	1.1
Coal	+	+	+	+	+	+	+
Fuel Oil	0.2	0.2	0.2	0.2	0.1	0.1	0.1
Natural gas	0.3	0.4	0.4	0.4	0.4	0.4	0.4
Wood	0.5	0.5	0.5	0.5	0.4	0.5	0.5
Residential	5.2	4.1	4.0	4.0	3.7	5.0	5.0
Coal	0.2	0.1	NO	NO	NO	NO	NO
Fuel Oil	0.3	0.3	0.3	0.3	0.2	0.2	0.2
Natural Gas	0.5	0.6	0.6	0.6	0.5	0.6	0.6
Wood	4.1	3.1	3.1	3.2	3.0	4.1	4.1
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	0.1
Natural Gas	NO	+	+	+	+	+	+
Wood	NO	NO	NO	NO	NO	NO	NO
Total	8.5	7.4	7.1	7.1	6.6	8.0	8.1

+ Does not exceed 0.05 MMT CO₂ Eq.

Note: Totals may not sum due to independent rounding.

Table 3-11: N₂O Emissions from Stationary Combustion (MMT CO₂ Eq.)

Sector/Fuel Type	1990	2005	2010	2011	2012	2013	2014
Electricity Generation	7.4	16.0	18.5	17.6	17.8	19.1	19.6
Coal	6.3	11.6	12.5	11.5	10.2	12.1	12.4
Fuel Oil	0.1	0.1	+	+	+	+	+
Natural Gas	1.0	4.3	5.9	6.1	7.5	7.0	7.2
Wood	+	+	+	+	+	+	+
Industrial	3.1	2.9	2.5	2.4	2.4	2.4	2.4
Coal	0.7	0.5	0.4	0.4	0.4	0.4	0.4
Fuel Oil	0.5	0.5	0.4	0.4	0.3	0.4	0.3
Natural Gas	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Wood	1.6	1.6	1.4	1.5	1.5	1.5	1.5
Commercial	0.4	0.3	0.3	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	0.1
Wood	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Residential	1.0	0.9	0.8	0.8	0.7	1.0	1.0	
Coal	+	+	NO	NO	NO	NO	NO	NO
Fuel Oil	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Natural Gas	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Wood	0.7	0.5	0.5	0.5	0.5	0.7	0.7	0.7
U.S. Territories	0.1	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	0.1
Natural Gas	NO	+	+	+	+	+	+	+
Wood	NO	NO	NO	NO	NO	NO	NO	NO
Total	11.9	20.2	22.2	21.3	21.4	22.9	23.4	

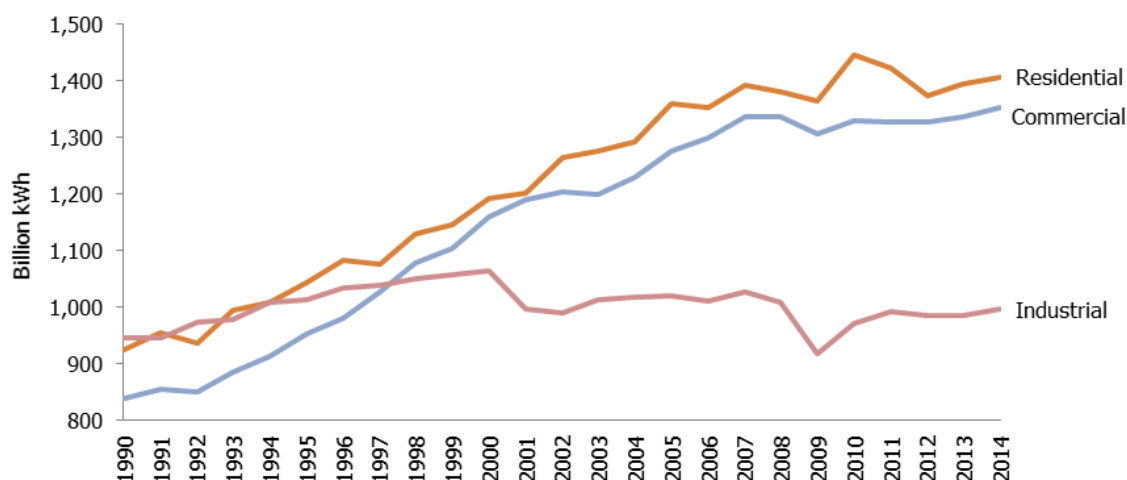
+ Does not exceed 0.05 MMT CO₂ Eq.

Note: Totals may not sum due to independent rounding.

Electricity Generation

The process of generating electricity is the single largest source of CO₂ emissions in the United States, representing 37 percent of total CO₂ emissions from all CO₂ emissions sources across the United States. Methane and N₂O accounted for a small portion of emissions from electricity generation, representing less than 0.1 percent and 1.0 percent, respectively. Electricity generation also accounted for the largest share of CO₂ emissions from fossil fuel combustion, approximately 39.2 percent in 2014. Methane and N₂O from electricity generation represented 4.4 and 49.3 percent of total methane and N₂O emissions from fossil fuel combustion in 2014, 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). Electricity generators, including those using low-CO₂ emitting technologies, relied on coal for approximately 39 percent of their total energy requirements in 2014. Recently an increase in the carbon intensity of fuels consumed to generate electricity has occurred due to an increase in coal consumption, and decreased natural gas consumption and other generation sources. Total U.S. electricity generators used natural gas for approximately 27 percent of their total energy requirements in 2014 (EIA 2015a).

Figure 3-9: Electricity Generation Retail Sales by End-Use Sector (Billion kWh)



The electric power industry includes all power producers, consisting of both regulated utilities and non-utilities (e.g. independent power producers, qualifying co-generators, 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, while the other sectors consist of those producers that indicate their primary business is something other than the production of electricity.¹⁴

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 2014 increased approximately 0.9 percent and 1.1 percent, respectively. The trend in the residential and commercial sectors can largely be attributed to colder, more energy-intensive winter conditions compared to 2013. Electricity sales to the industrial sector in 2014 increased approximately 1.2 percent. Overall, in 2014, the amount of electricity generated (in kWh) increased approximately 1.1 percent relative to the previous year, while CO₂ emissions from the electric power sector increased by 0.1 percent. The increase in CO₂ emissions, despite the relatively larger increase in electricity generation was a result of a slight decrease in the consumption of coal and natural gas for electricity generation by 0.1 percent and 0.2 percent, respectively, in 2014, and an increase in the consumption of petroleum for electricity generation by 15.8 percent.

Industrial Sector

Industrial sector CO₂, CH₄, and N₂O, emissions accounted for 16, 15, and 6 percent of CO₂, CH₄, and N₂O, emissions from fossil fuel combustion, respectively. Carbon dioxide, CH₄, and N₂O 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 2016 and EIA 2009b).

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.¹⁵ 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.

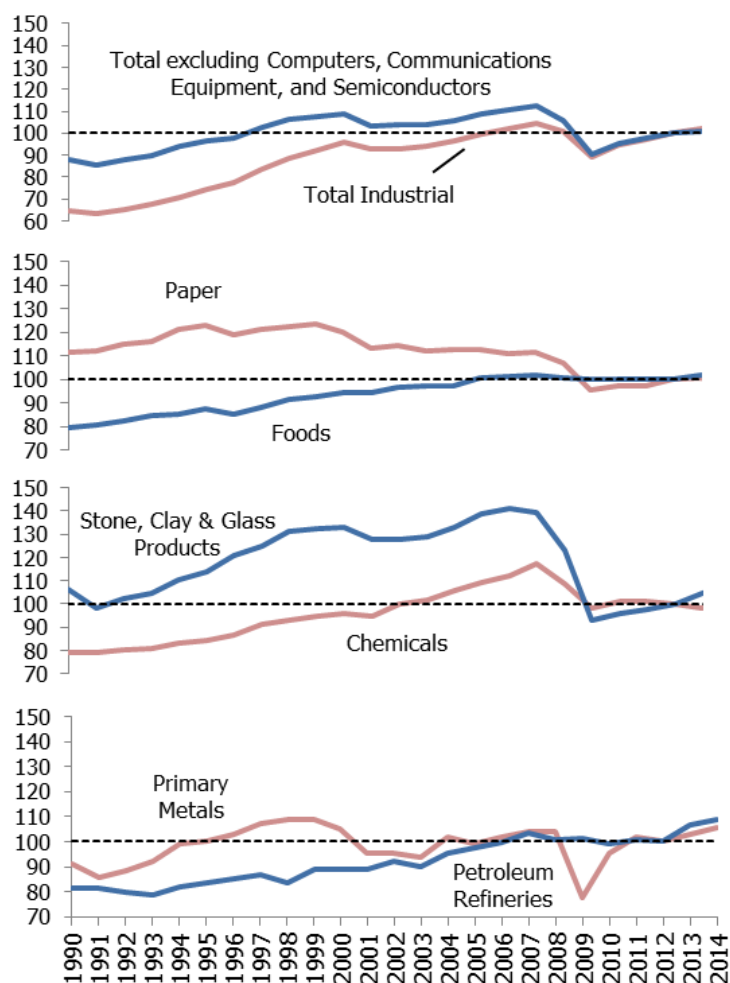
From 2013 to 2014, total industrial production and manufacturing output increased by 3.7 percent (FRB 2015). Over this period, output increased across production indices for Food, Petroleum Refineries, Chemicals, Primary Metals, and Nonmetallic Mineral Products, and decreased slightly for Paper (see Figure 3-10). Through EPA's Greenhouse Gas Reporting Program (GHGRP), industrial trends can be discerned from the overall EIA industrial fuel consumption data used for these calculations. For example, from 2013 to 2014 the underlying EIA data showed increased consumption of natural gas and a decrease in petroleum fuels in the industrial sector. EPA's GHGRP data highlights that chemical manufacturing and nonmetallic mineral products were contributors to these trends.¹⁶

¹⁴ 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).

¹⁵ 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.

¹⁶ Further details on industrial sector combustion emissions are provided by EPA's GHGRP. See <<http://ghgdata.epa.gov/ghgp/main.do>>.

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



Despite the growth in industrial output (64 percent) and the overall U.S. economy (78 percent) from 1990 to 2014, CO₂ emissions from fossil fuel combustion in the industrial sector decreased by 3.5 percent over the same time series. 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 2014, CO₂, CH₄, and N₂O emissions from fossil fuel combustion and electricity use within the industrial end-use sector totaled 1,416.6 MMT CO₂ Eq., or approximately equal to 2013 emissions.

Residential and Commercial Sectors

Residential and commercial sector CO₂ emissions accounted for 7 and 4 percent of CO₂ emissions from fossil fuel combustion, CH₄ emissions accounted for 49 and 11 percent of CH₄ emissions from fossil fuel combustion, and N₂O emissions accounted for 2 and 1 percent of N₂O 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 2014, CO₂, CH₄, and N₂O emissions from fossil fuel combustion and electricity use within the residential and commercial end-use sectors were 1,093.6 MMT CO₂ Eq. and 946.7 MMT CO₂ Eq., respectively. Total CO₂, CH₄, and N₂O emissions from fossil fuel combustion and electricity use within the residential and commercial end-use sectors increased by 1.5 and 1.4 percent from 2013 to 2014, 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).

In 2014, combustion emissions from natural gas consumption represent 80 and 82 percent of the direct fossil fuel CO₂ emissions from the residential and commercial sectors, respectively. Natural gas combustion CO₂ emissions from the residential and commercial sectors in 2014 increased by 4.3 percent and 5.6 percent from 2013 levels, respectively.

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 in the Methodology section for CO₂ 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, CO₂, CH₄, and N₂O 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 and Mobile Combustion

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.

Transportation End-Use Sector

The transportation end-use sector accounted for 1,760.1 MMT CO₂ Eq. in 2014, which represented 33 percent of CO₂ emissions, 20 percent of CH₄ emissions, and 41 percent of N₂O emissions from fossil fuel combustion, respectively.¹⁷ Fuel purchased in the United States for international aircraft and marine travel accounted for an additional 104.2 MMT CO₂ Eq. in 2014; these emissions are recorded as international bunkers and are not included in U.S. totals according to UNFCCC reporting protocols.

From 1990 to 2014, transportation emissions from fossil fuel combustion rose by 14 percent due, in large part, to increased demand for travel with limited gains in fuel efficiency for much of this time period. The number of vehicle miles traveled (VMT) by light-duty motor vehicles (passenger cars and light-duty trucks) increased 37 percent from 1990 to 2014, as a result of a confluence of factors including population growth, economic growth, urban sprawl, and periods of low fuel prices.

From 2013 to 2014, CO₂ emissions from the transportation end-use sector increased by 1.4 percent.¹⁸ The increase in emissions can largely be attributed to small increases in VMT and fuel use across many on-road transportation modes. Commercial aircraft emissions have decreased 18 percent since 2007.¹⁹ Decreases in jet fuel emissions (excluding bunkers) since 2007 are due in part to improved operational efficiency that results in more direct flight routing, improvements in aircraft and engine technologies to reduce fuel burn and emissions, and the accelerated retirement of older, less fuel efficient aircraft.

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 CO₂ from fossil fuel combustion, which increased by 16 percent from 1990 to

¹⁷ Note that these totals include CO₂, CH₄ and N₂O emissions from some sources in the U.S. Territories (ships and boats, recreational boats, non-transportation mobile sources) and CH₄ and N₂O emissions from transportation rail electricity.

¹⁸ Note that this value does not include lubricants.

¹⁹ Commercial aircraft, as modeled in FAA's AEDT, consists of passenger aircraft, cargo, and other chartered flights.

2014. Annex 3.2 presents the total emissions from all transportation and mobile sources, including CO₂, N₂O, CH₄, and HFCs.

Transportation Fossil Fuel Combustion CO₂ Emissions

Domestic transportation CO₂ emissions increased by 16 percent (244.8 MMT CO₂) between 1990 and 2014, an annualized increase of 0.7 percent. Among domestic transportation sources, light-duty vehicles (including passenger cars and light-duty trucks) represented 60 percent of CO₂ emissions from fossil fuel combustion, medium- and heavy-duty trucks and buses 24 percent, commercial aircraft 7 percent, and other sources 9 percent. See Table 3-12 for a detailed breakdown of transportation CO₂ emissions by mode and fuel type.

Almost all of the energy consumed by the transportation sector is petroleum-based, including motor gasoline, diesel fuel, jet fuel, and residual oil. Carbon dioxide emissions from the combustion of ethanol and biodiesel for transportation purposes, along with the emissions associated with the agricultural and industrial processes involved in the production of biofuel, are captured in other Inventory sectors.²⁰ Ethanol consumption from the transportation sector has increased from 0.7 billion gallons in 1990 to 12.9 billion gallons in 2014, while biodiesel consumption has increased from 0.01 billion gallons in 2001 to 1.4 billion gallons in 2014. For further information, see the section on biofuel consumption at the end of this chapter and Table A-93 in Annex 3.2.

Carbon dioxide emissions from passenger cars and light-duty trucks totaled 1,046.9 MMT CO₂ in 2014, an increase of 10 percent (96.4 MMT CO₂) from 1990 due, in large part, to increased demand for travel as fleetwide light-duty vehicle fuel economy was relatively stable (average new vehicle fuel economy declined slowly from 1990 through 2004 and then increased more rapidly from 2005 through 2014). Carbon dioxide emissions from passenger cars and light-duty trucks peaked at 1,181.1 MMT CO₂ in 2004, and since then have declined about 11 percent. The decline in new light-duty vehicle fuel economy between 1990 and 2004 (Figure 3-11) reflected the increasing market share of light-duty trucks, which grew from about 30 percent of new vehicle sales in 1990 to 48 percent in 2004. Starting in 2005, the rate of VMT growth slowed while average new vehicle fuel economy began to increase. Average new vehicle fuel economy has improved almost every year since 2005, and the truck share has decreased to about 41 percent of new vehicles in model year 2014 (EPA 2015a).

Medium- and heavy-duty truck CO₂ emissions increased by 75 percent from 1990 to 2014. This increase was largely due to a substantial growth in medium- and heavy-duty truck VMT, which increased by 94 percent between 1990 and 2014.²¹ Carbon dioxide from the domestic operation of commercial aircraft increased by 5 percent (5.3 MMT CO₂) from 1990 to 2014.²² Across all categories of aviation, excluding international bunkers, CO₂ emissions decreased by 20 percent (37.3 MMT CO₂) between 1990 and 2014.²³ This includes a 56 percent (19.6 MMT CO₂) decrease in CO₂ emissions from domestic military operations.

Transportation sources also produce CH₄ and N₂O; these emissions are included in Table 3-13 and Table 3-14 and in the “Mobile Combustion” Section. Annex 3.2 presents total emissions from all transportation and mobile sources, including CO₂, CH₄, N₂O, and HFCs.

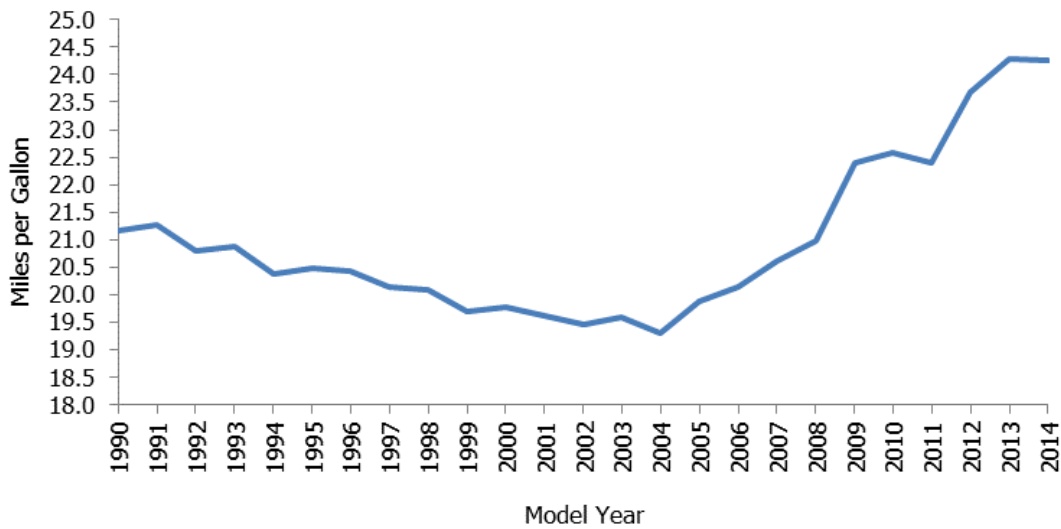
²⁰ Biofuel estimates are presented in the Energy chapter for informational purposes only, in line with IPCC methodological guidance and UNFCCC reporting obligations. Net carbon fluxes from changes in biogenic carbon reservoirs in croplands are accounted for in the estimates for Land Use, Land-Use Change, and Forestry (see Chapter 6). More information and additional analyses on biofuels are available at EPA’s “Renewable Fuels: Regulations & Standards;” See <<http://www.epa.gov/otaq/fuels/renewablefuels/regulations.htm>>.

²¹ While FHWA data shows consistent growth in medium- and heavy-duty truck VMT over the 1990 to 2014 time period, part of the growth reflects a method change for estimating VMT starting in 2007. This change in methodology in FHWA’s VM-1 table resulted in large changes in VMT by vehicle class, thus leading to a shift in VMT and emissions among on-road vehicle classes in the 2007 to 2014 time period. During the time period prior to the method change (1990-2006), VMT for medium- and heavy-duty trucks increased by 51 percent.

²² Commercial aircraft, as modeled in FAA’s AEDT, consists of passenger aircraft, cargo, and other chartered flights.

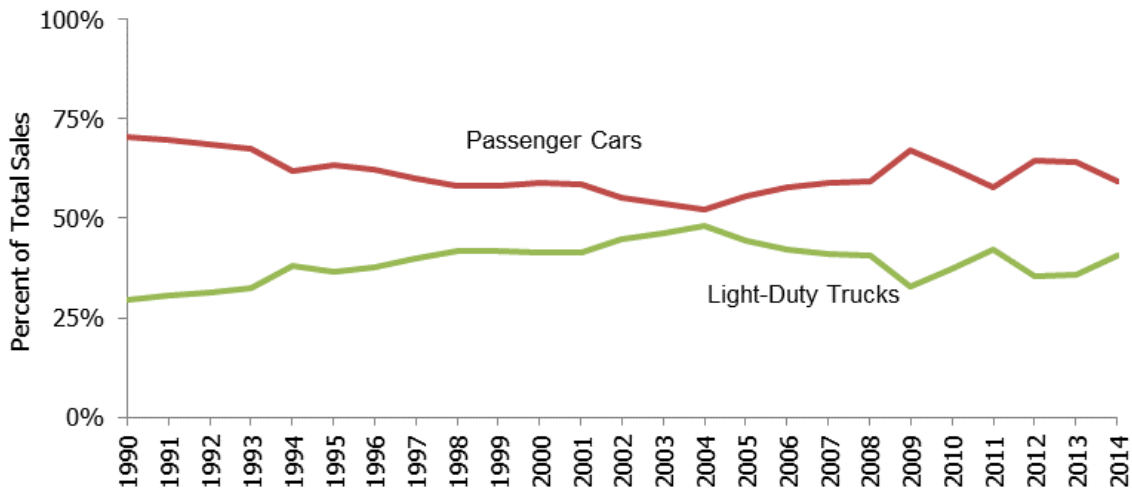
²³ Includes consumption of jet fuel and aviation gasoline. Does not include aircraft bunkers, which are not included in national emission totals, in line with IPCC methodological guidance and UNFCCC reporting obligations.

Figure 3-11: Sales-Weighted Fuel Economy of New Passenger Cars and Light-Duty Trucks, 1990–2014 (miles/gallon)



Source: EPA (2015)

Figure 3-12: Sales of New Passenger Cars and Light-Duty Trucks, 1990–2014 (Percent)



Source: EPA (2015)

Table 3-12: CO₂ Emissions from Fossil Fuel Combustion in Transportation End-Use Sector (MMT CO₂ Eq.)

Fuel/Vehicle Type	1990	2005	2010 ^a	2011	2012	2013	2014
Gasoline^b	983.5	1,183.7	1,092.5	1,068.8	1,064.7	1,065.6	1,083.8
Passenger Cars	621.4	655.9	738.2	732.8	731.4	731.4	733.5
Light-Duty Trucks	309.1	477.2	295.0	280.4	277.4	277.7	293.5

Medium- and Heavy-Duty Trucks ^c	38.7	34.8	42.3	38.9	38.7	39.5	40.0
Buses	0.3	0.4	0.7	0.7	0.8	0.8	0.9
Motorcycles	1.7	1.6	3.6	3.6	4.1	3.9	3.8
Recreational Boats ^d	12.2	13.9	12.6	12.4	12.3	12.3	12.2
Distillate Fuel Oil (Diesel)^{b,e}	262.9	457.5	422.0	430.0	427.5	433.9	447.6
Passenger Cars	7.9	4.2	3.7	4.1	4.1	4.1	4.1
Light-Duty Trucks	11.5	25.8	12.5	13.0	12.9	12.9	13.9
Medium- and Heavy-Duty Trucks ^c	190.5	360.2	342.7	344.4	344.4	350.0	361.3
Buses	8.0	10.6	13.5	14.4	15.4	15.5	16.6
Rail	35.5	45.5	38.6	40.4	39.5	40.1	41.7
Recreational Boats	2.0	3.2	3.6	3.6	3.7	3.7	3.8
Ships and Other Boats ^f	7.5	8.0	7.4	10.1	7.5	7.5	6.2
<i>International Bunker Fuels^g</i>	<i>11.7</i>	<i>9.4</i>	<i>9.5</i>	<i>7.9</i>	<i>6.8</i>	<i>5.6</i>	<i>6.1</i>
Jet Fuel	184.2	189.3	151.5	146.6	143.4	147.1	148.6
Commercial Aircraft ^h	109.9	132.7	113.3	114.6	113.3	114.3	115.2
Military Aircraft	35.0	19.4	13.6	11.6	12.1	11.0	15.4
General Aviation Aircraft	39.4	37.3	24.6	20.4	18.0	21.8	18.0
<i>International Bunker Fuels^g</i>	<i>38.0</i>	<i>60.1</i>	<i>61.0</i>	<i>64.8</i>	<i>64.5</i>	<i>65.7</i>	<i>69.4</i>
<i>International Bunker Fuels from Commercial Aviation</i>	<i>30.0</i>	<i>55.6</i>	<i>57.4</i>	<i>61.7</i>	<i>61.4</i>	<i>62.8</i>	<i>66.3</i>
Aviation Gasoline	3.1	2.4	1.9	1.9	1.7	1.5	1.5
General Aviation Aircraft	3.1	2.4	1.9	1.9	1.7	1.5	1.5
Residual Fuel Oil	22.6	19.3	20.4	19.4	15.8	15.1	5.8
Ships and Other Boats ^f	22.6	19.3	20.4	19.4	15.8	15.1	5.8
<i>International Bunker Fuels^g</i>	<i>53.7</i>	<i>43.6</i>	<i>46.5</i>	<i>38.9</i>	<i>34.5</i>	<i>28.5</i>	<i>27.7</i>
Natural Gas	36.0	33.1	38.1	38.9	41.3	47.0	47.6
Passenger Cars	+	+	+	+	+	+	+
Light-Duty Trucks	+	+	+	+	+	+	+
Buses	+	0.8	1.1	1.1	1.0	1.1	1.1
Pipeline ⁱ	36.0	32.2	37.1	37.8	40.3	45.9	46.5
LPG	1.4	1.7	1.8	2.1	2.3	2.7	2.7
Light-Duty Trucks	0.6	1.3	1.3	1.5	1.6	1.9	1.9
Medium- and Heavy-Duty Trucks ^c	0.8	0.4	0.6	0.6	0.7	0.8	0.8
Buses	+	+	+	+	+	+	+
Electricity	3.0	4.7	4.5	4.3	3.9	4.0	4.1
Rail	3.0	4.7	4.5	4.3	3.9	4.0	4.1
Ethanol^j	4.1	22.4	71.3	71.5	71.5	73.4	74.8
Total	1,496.8	1,891.8	1,732.7	1,711.9	1,700.6	1,717.0	1,741.7
Total (Including Bunkers)^g	1,600.3	2,004.9	1,849.7	1,823.6	1,806.4	1,816.8	1,844.9

+ Does not exceed 0.05 MMT CO₂ Eq.

^a In 2011 FHWA changed its methods for estimating vehicle miles traveled (VMT) and related data. These methodological changes included how vehicles are classified, moving from a system based on body-type to one that is based on wheelbase. These changes were first incorporated for the 1990 through 2010 Inventory and apply to the 2007 through 2014 time period. This resulted in large changes in VMT and fuel consumption data by vehicle class, thus leading to a shift in emissions among on-road vehicle classes.

^b Gasoline and diesel highway vehicle fuel consumption estimates are based on data from FHWA Highway Statistics Table VM-1 and MF-27 (FHWA 1996 through 2015). These fuel consumption estimates are combined with estimates of fuel shares by vehicle type from DOE's TEDB Annex Tables A.1 through A.6 (DOE 1993 through 2015). TEDB data for 2014 has not been published yet, therefore 2013 data is used as a proxy.

^c Includes medium- and heavy-duty trucks over 8,500 lbs.

^d In 2015, EPA incorporated the NONROAD2008 model into MOVES2014. The current Inventory uses the NONROAD component of MOVES2014a for years 1999 through 2014. This update resulted in small changes (less than two percent) to the 1999 through 2013 time series for NONROAD fuel consumption due to differences in the gasoline and diesel default fuel densities used within the model iterations.

^e Updates to the distillate fuel oil heat content data from EIA for years 1993 through 2014 resulted in changes to the time series for energy consumption and emissions compared to the previous Inventory.

^f Note that large year over year fluctuations in emission estimates partially reflect nature of data collection for these sources.

^g 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.

^h Commercial aircraft, as modeled in FAA's AEDT, consists of passenger aircraft, cargo, and other chartered flights.

ⁱ Pipelines reflect CO₂ emissions from natural gas powered pipelines transporting natural gas.

^j Ethanol estimates are presented for informational purposes only. See Section 3.10 of this chapter and the estimates in Land Use, Land-Use Change, and Forestry (see Chapter 6), in line with IPCC methodological guidance and UNFCCC reporting obligations, for more information on ethanol.

Notes: 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. In addition, this table does not include CO₂ emissions from U.S. Territories, since these are covered in a separate chapter of the Inventory. Totals may not sum due to independent rounding.

Mobile Fossil Fuel Combustion CH₄ and N₂O Emissions

Mobile combustion includes emissions of CH₄ and N₂O from all transportation sources identified in the U.S.

Inventory with the exception of pipelines and electric locomotives;²⁴ 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.).²⁵ Annex 3.2 includes a summary of all emissions from both transportation and mobile sources. Table 3-13 and Table 3-14 provide mobile fossil fuel CH₄ and N₂O emission estimates in MMT CO₂ Eq.²⁶

Mobile combustion was responsible for a small portion of national CH₄ emissions (0.3 percent) but was the fourth largest source of U.S. N₂O emissions (4.0 percent). From 1990 to 2014, mobile source CH₄ emissions declined by 64 percent, to 2.0 MMT CO₂ Eq. (82 kt CH₄), due largely to control technologies employed in on-road vehicles since the mid-1990s to reduce CO, NO_x, NMVOC, and CH₄ emissions. Mobile source emissions of N₂O decreased by 60 percent, to 16.3 MMT CO₂ Eq. (55 kt N₂O). Earlier generation control technologies initially resulted in higher N₂O emissions, causing a 28 percent increase in N₂O emissions from mobile sources between 1990 and 1997. Improvements in later-generation emission control technologies have reduced N₂O output, resulting in a 69 percent decrease in mobile source N₂O emissions from 1997 to 2014 (Figure 3-13). Overall, CH₄ and N₂O emissions were predominantly from gasoline-fueled passenger cars and light-duty trucks.

²⁴ Emissions of CH₄ from natural gas systems are reported separately. More information on the methodology used to calculate these emissions are included in this chapter and Annex 3.4.

²⁵ See the methodology sub-sections of the CO₂ from Fossil Fuel Combustion and CH₄ and N₂O from Mobile Combustion sections of this chapter. Note that N₂O and CH₄ emissions are reported using different categories than CO₂. CO₂ emissions are reported by end-use sector (Transportation, Industrial, Commercial, Residential, U.S. Territories), and generally adhere to a top-down approach to estimating emissions. CO₂ emissions from non-transportation sources (e.g., lawn and garden equipment, farm equipment, construction equipment) are allocated to their respective end-use sector (i.e., construction equipment CO₂ emissions are included in the Commercial end-use sector instead of the Transportation end-use sector). CH₄ and N₂O emissions are reported using the "Mobile Combustion" category, which includes non-transportation mobile sources. CH₄ and N₂O emissions estimates are bottom-up estimates, based on total activity (fuel use, VMT) and emissions factors by source and technology type. These reporting schemes are in accordance with IPCC guidance. For informational purposes only, CO₂ emissions from non-transportation mobile sources are presented separately from their overall end-use sector in Annex 3.2.

²⁶ See Annex 3.2 for a complete time series of emission estimates for 1990 through 2014.

Figure 3-13: Mobile Source CH₄ and N₂O Emissions (MMT CO₂ Eq.)

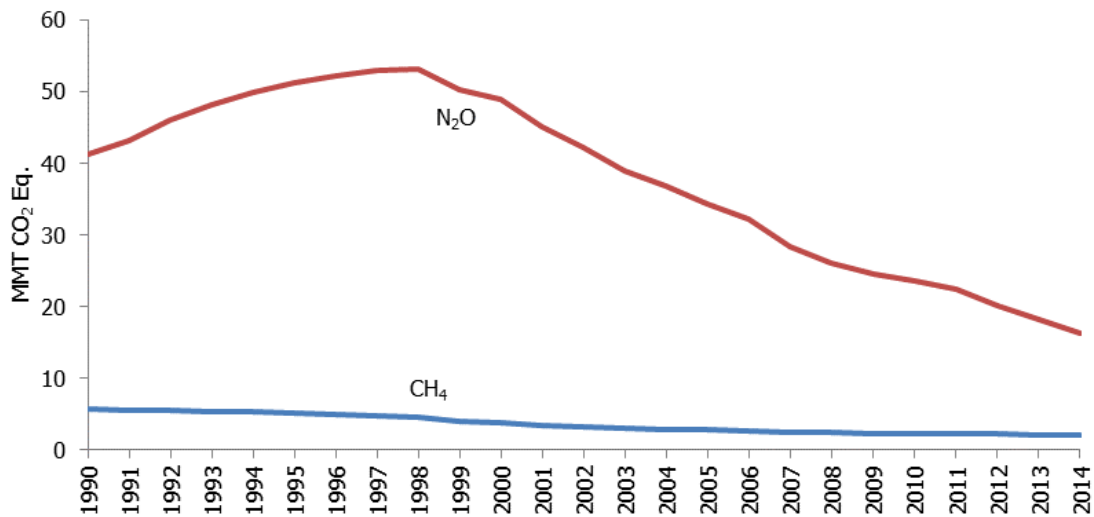


Table 3-13: CH₄ Emissions from Mobile Combustion (MMT CO₂ Eq.)

Fuel Type/Vehicle Type ^a	1990	2005	2010	2011	2012	2013	2014
Gasoline On-Road^b	5.2	2.2	1.7	1.6	1.5	1.5	1.4
Passenger Cars	3.2	1.2	1.2	1.2	1.1	1.0	1.0
Light-Duty Trucks	1.7	0.8	0.4	0.4	0.3	0.3	0.3
Medium- and Heavy-Duty Trucks and Buses	0.3	0.1	0.1	0.1	0.1	0.1	0.1
Motorcycles	+	+	+	+	+	+	+
Diesel On-Road^b	+	+	+	+	+	+	+
Passenger Cars	+	+	+	+	+	+	+
Light-Duty Trucks	+	+	+	+	+	+	+
Medium- and Heavy-Duty Trucks and Buses	+	+	+	+	+	+	+
Alternative Fuel On-Road^c	+	+	+	+	+	+	+
Non-Road^d	0.4	0.5	0.5	0.5	0.6	0.6	0.6
Ships and Boats	+	+	+	+	+	+	+
Rail ^e	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Aircraft	0.1	0.1	+	+	+	+	+
Agricultural Equipment ^f	0.1	0.2	0.2	0.2	0.2	0.2	0.2
Construction/Mining Equipment ^g	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Other ^h	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	5.6	2.7	2.3	2.2	2.2	2.1	2.0

+ Does not exceed 0.05 MMT CO₂ Eq.

^a See Annex 3.2 for definitions of on-road vehicle types.

^b Gasoline and diesel highway vehicle mileage are based on data from FHWA Highway Statistics Table VM-1 (FHWA 1996 through 2015). These mileage consumption estimates are combined with estimates of fuel shares by vehicle type from DOE's TEDB Annex Tables A.1 through A.6 (DOE 1993 through 2015). TEDB data for 2014 has not been published yet, therefore 2013 data is used as a proxy.

^c In 2015, EIA changed its methods for estimating AFV fuel consumption. These methodological changes included how vehicle counts are estimated, moving from estimates based on modeling to one that is based on survey data. EIA now publishes data about fuel use and number of vehicles for only four types of AFV fleets: federal government, state government, transit agencies, and fuel providers. These changes were first incorporated in the current inventory and apply to the 1990 through 2014 time period. This resulted in large reductions in AFV VMT, thus leading to a shift in VMT to conventional on-road vehicle classes.

^dIn 2015, EPA incorporated the NONROAD2008 model into MOVES2014. The current Inventory uses the NONROAD component of MOVES2014a for years 1999 through 2014. This update resulted in small changes (less than 2 percent) to the 1999 through 2013 time series for NONROAD fuel consumption due to differences in the gasoline and diesel default fuel densities used within the model iterations.

^eRail emissions do not include emissions from electric powered locomotives. Class II and Class III diesel consumption data for 2014 is not available yet, therefore 2013 data is used as a proxy.

^fIncludes equipment, such as tractors and combines, as well as fuel consumption from trucks that are used off-road in agriculture.

^gIncludes equipment, such as cranes, dumpers, and excavators, as well as fuel consumption from trucks that are used off-road in construction.

^h“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.

Notes: In 2011, FHWA changed its methods for estimating vehicle miles traveled (VMT) and related data. These methodological changes included how vehicles are classified, moving from a system based on body-type to one that is based on wheelbase. These changes were first incorporated for the 1990 through 2010 Inventory and apply to the 2007 through 2014 time period. This resulted in large changes in VMT and fuel consumption data by vehicle class, thus leading to a shift in emissions among on-road vehicle classes. Totals may not sum due to independent rounding.

Table 3-14: N₂O Emissions from Mobile Combustion (MMT CO₂ Eq.)

Fuel Type/Vehicle Type ^a	1990	2005	2010	2011	2012	2013	2014
Gasoline On-Road^b	37.5	29.9	19.2	18.0	15.7	13.8	12.1
Passenger Cars	24.1	15.9	12.9	12.3	10.7	9.3	7.9
Light-Duty Trucks	12.8	13.2	5.5	5.0	4.4	3.9	3.6
Medium- and Heavy-Duty Trucks and Buses	0.5	0.8	0.8	0.7	0.6	0.6	0.5
Motorcycles	+	+	+	+	+	+	+
Diesel On-Road^b	0.2	0.3	0.4	0.4	0.4	0.4	0.4
Passenger Cars	+	+	+	+	+	+	+
Light-Duty Trucks	+	+	+	+	+	+	+
Medium- and Heavy-Duty Trucks and Buses	0.2	0.3	0.4	0.4	0.4	0.4	0.4
Alternative Fuel On-Road^c	+	+	+	0.1	0.1	0.1	0.1
Non-Road^d	3.5	4.1	4.0	4.0	3.9	3.9	3.8
Ships and Boats	0.6	0.6	0.8	0.8	0.7	0.7	0.5
Rail ^e	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Aircraft	1.7	1.8	1.4	1.4	1.3	1.4	1.4
Agricultural Equipment ^f	0.2	0.4	0.4	0.4	0.4	0.4	0.4
Construction/Mining Equipment ^g	0.3	0.5	0.6	0.6	0.6	0.6	0.6
Other ^h	0.4	0.6	0.6	0.6	0.6	0.6	0.6
Total	41.2	34.4	23.6	22.4	20.0	18.2	16.3

+ Does not exceed 0.05 MMT CO₂ Eq.

^a See Annex 3.2 for definitions of on-road vehicle types.

^b Gasoline and diesel highway vehicle mileage are based on data from FHWA Highway Statistics Table VM-1 (FHWA 1996 through 2015). These mileage consumption estimates are combined with estimates of fuel shares by vehicle type from DOE's TEDB Annex Tables A.1 through A.6 (DOE 1993 through 2015). TEDB data for 2014 has not been published yet, therefore 2013 data is used as a proxy.

^c In 2015, EIA changed its methods for estimating AFV fuel consumption. These methodological changes included how vehicle counts are estimated, moving from estimates based on modeling to one that is based on survey data. EIA now publishes data about fuel use and number of vehicles for only four types of AFV fleets: federal government, state government, transit agencies, and fuel providers. These changes were first incorporated in the current Inventory and apply to the 1990 through 2014 time period. This resulted in large reductions in AFV VMT, thus leading to a shift in VMT to conventional on-road vehicle classes.

^d In 2015, EPA incorporated the NONROAD2008 model into MOVES2014. The current Inventory uses the NONROAD component of MOVES2014a for years 1999 through 2014. This update resulted in small changes (less than two percent) to the 1999 through 2013 time series for NONROAD fuel consumption due to differences in the gasoline and diesel default fuel densities used within the model iterations.

^e Rail emissions do not include emissions from electric powered locomotives. Class II and Class III diesel consumption data for 2014 is not available yet, therefore 2013 data is used as a proxy.

^f Includes equipment, such as tractors and combines, as well as fuel consumption from trucks that are used off-road in agriculture.

^g Includes equipment, such as cranes, dumpers, and excavators, as well as fuel consumption from trucks that are used off-road in construction.

^h "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.

Notes: In 2011, FHWA changed its methods for estimating vehicle miles traveled (VMT) and related data. These methodological changes included how vehicles are classified, moving from a system based on body type to one that is based on wheelbase. These changes were first incorporated for the 1990 through 2010 Inventory and apply to the 2007 through 2014 time period. This resulted in large changes in VMT and fuel consumption data by vehicle class, thus leading to a shift in emissions among on-road vehicle classes. Totals may not sum due to independent rounding.

CO₂ from Fossil Fuel Combustion

Methodology

The methodology used by the United States for estimating CO₂ 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).²⁷ The use of the most recently published calculation methodologies by the IPCC, as contained in the *2006 IPCC Guidelines*, is considered to improve the rigor and accuracy of this Inventory and is fully in line with IPCC Good Practice Guidance. 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 EIA of the U.S. Department of Energy (DOE), primarily from the Monthly Energy Review and published supplemental tables on petroleum product detail (EIA 2016). The EIA does not include territories in its national energy statistics, so fuel consumption data for territories were collected separately from EIA's International Energy Statistics (EIA 2014) and Jacobs (2010).²⁸

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 four years). These consumption data sets help inform the annual surveys to arrive at the national total and sectoral breakdowns for that total.²⁹

²⁷ The IPCC Tier 3B methodology is used for estimating emissions from commercial aircraft.

²⁸ 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 total emissions of 41.2 MMT CO₂ Eq. in 2014.

²⁹ See IPCC Reference Approach for estimating CO₂ emissions from fossil fuel combustion in Annex 4 for a comparison of U.S. estimates using top-down and bottom-up approaches.

Also, 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).³⁰

2. *Subtract uses accounted for in the Industrial Processes and Product Use 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 and Product Use chapter, as they were consumed during non-energy related industrial activity. To make these adjustments, additional data were collected from AISI (2004 through 2013), Coffeyville (2014), U.S. Census Bureau (2011), EIA (2016), USGS (1991 through 2011), USGS (1994 through 2011), USGS (1995, 1998, 2000 through 2002), USGS (2007), USGS (2009), USGS (2010), USGS (2011), USGS (1991 through 2010a), USGS (1991 through 2010b), USGS (2012a) and USGS (2012b).³¹
3. *Adjust for conversion of fuels and exports of CO₂.* Fossil fuel consumption estimates are adjusted downward to exclude fuels created from other fossil fuels and exports of CO₂.³² 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.³³ Since October 2000, the Dakota Gasification Plant has been exporting CO₂ to Canada by pipeline. Since this CO₂ is not emitted to the atmosphere in the United States, energy used to produce this CO₂ is subtracted from energy consumption statistics. To make these adjustments, additional data for ethanol were collected from EIA (2015), data for synthetic natural gas were collected from EIA (2014), and data for CO₂ exports were collected from the Eastman Gasification Services Company (2011), Dakota Gasification Company (2006), Fitzpatrick (2002), Erickson (2003), EIA (2008) and DOE (2012).
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 data from the Federal Highway Administration 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 to match the value obtained from the bottom-up analysis. As the total distillate and motor gasoline consumption estimate from EIA are considered to be accurate at the national level, the distillate and motor gasoline consumption totals for the residential, commercial, and industrial sectors were adjusted proportionately. The data sources used in the bottom-up analysis of transportation fuel consumption include AAR (2008 through 2015), Benson (2002 through 2004), DOE (1993 through 2015), EIA (2007), EIA (1991 through 2015), EPA (2015c), and FHWA (1996 through 2015).³⁴

³⁰ 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.

³¹ 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 and Product Use chapter.

³² Energy statistics from EIA (2015) are already adjusted downward to account for ethanol added to motor gasoline, and biogas in natural gas.

³³ These adjustments are explained in greater detail in Annex 2.1.

³⁴ The source of highway vehicle VMT and fuel consumption is FHWA's VM-1 table. In 2011, FHWA changed its methods for estimating data in the VM-1 table. These methodological changes included how vehicles are classified, moving from a system based on body type to one that is based on wheelbase. These changes were first incorporated for the 1990 to 2010 Inventory and apply to the 2007 to 2014 time period. This resulted in large changes in VMT and fuel consumption data by vehicle class, thus leading to a shift in emissions among on-road vehicle classes. For example, the category "Passenger Cars" has been replaced by "Light-duty Vehicles-Short Wheelbase" and "Other 2 axle-4 Tire Vehicles" has been replaced by "Light-duty Vehicles, Long Wheelbase." This change in vehicle classification has moved some smaller trucks and sport utility vehicles from the light truck category to the passenger vehicle category in this emission inventory. These changes are reflected in a large drop in light-truck emissions between 2006 and 2007.

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 (2016).
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).³⁵ The Office of the Under Secretary of Defense (Installations and Environment) and the Defense Logistics Agency Energy (DLA Energy) of the U.S. Department of Defense (DoD) (DLA Energy 2015) supplied data on military jet fuel and marine fuel use. Commercial jet fuel use was obtained from FAA (2016); residual and distillate fuel use for civilian marine bunkers was obtained from DOC (1991 through 2014) for 1990 through 2001 and 2007 through 2014, 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 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 CO₂. 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 GHGRP (EPA 2010). A discussion of the methodology used to develop the C content coefficients are presented in Annexes 2.1 and 2.2.
8. *Estimate CO₂ Emissions.* Total CO₂ 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. Heat contents and densities were obtained from EIA (2016) and USAF (1998).³⁶
 - For on-road vehicles, annual estimates of combined motor gasoline and diesel fuel consumption by vehicle category were obtained from FHWA (1996 through 2014); for each vehicle category, the percent gasoline, diesel, and other (e.g., CNG, LPG) fuel consumption are estimated using data from DOE (1993 through 2013).
 - For non-road vehicles, activity data were obtained from AAR (2008 through 2015), APTA (2007 through 2015), APTA (2006), BEA (2016), Benson (2002 through 2004), DOE (1993 through 2015), DLA Energy (2015), DOC (1991 through 2015), DOT (1991 through 2015), EIA (2009a), EIA (2016), EIA (2013), EIA (1991 through 2015), EPA (2015c), and Gaffney (2007).

³⁵ See International Bunker Fuels section in this chapter for a more detailed discussion.

³⁶ For a more detailed description of the data sources used for the analysis of the transportation end use sector see the Mobile Combustion (excluding CO₂) and International Bunker Fuels sections of the Energy chapter, Annex 3.2, and Annex 3.8.

- For jet fuel used by aircraft, CO₂ emissions from commercial aircraft were developed by the U.S. Federal Aviation Administration (FAA) using a Tier 3B methodology, consistent IPCC (2006) (see Annex 3.3). Carbon dioxide emissions from other aircraft were calculated directly based on reported consumption of fuel as reported by EIA. Allocation to domestic military uses was made using DoD data (see Annex 3.8). General aviation jet fuel consumption is calculated as the remainder of total jet fuel use (as determined by EIA) nets all other jet fuel use as determined by FAA and DoD. For more information, see Annex 3.2.

Box 3-4: Uses of Greenhouse Gas Reporting Program Data and Improvements in Reporting Emissions from Industrial Sector Fossil Fuel Combustion

As described in the calculation methodology, total fossil fuel consumption for each year is based on aggregated end-use sector consumption published by the EIA. The availability of facility-level combustion emissions through EPA's Greenhouse Gas Reporting Program (GHGRP) has provided an opportunity to better characterize the industrial sector's energy consumption and emissions in the United States, through a disaggregation of EIA's industrial sector fuel consumption data from select industries.

For EPA's GHGRP 2010, 2011, 2012, 2013, and 2014 reporting years, facility-level fossil fuel combustion emissions reported through the GHGRP were categorized and distributed to specific industry types by utilizing facility-reported NAICS codes (as published by the U.S. Census Bureau). As noted previously in this report, the definitions and provisions for reporting fuel types in EPA's GHGRP include some differences from the Inventory's use of EIA national fuel statistics to meet the UNFCCC reporting guidelines. The IPCC has provided guidance on aligning facility-level reported fuels and fuel types published in national energy statistics, which guided this exercise.³⁷

This year's effort represents an attempt to align, reconcile, and coordinate the facility-level reporting of fossil fuel combustion emissions under EPA's GHGRP with the national-level approach presented in this report. Consistent with recommendations for reporting the Inventory to the UNFCCC, progress was made on certain fuel types for specific industries and has been included in the Common Reporting Format (CRF) tables that are submitted to the UNFCCC along with this report.³⁸ For the current exercise, the efforts in reconciling fuels focused on standard, common fuel types (e.g., natural gas, distillate fuel oil, etc.) where the fuels in EIA's national statistics aligned well with facility-level GHGRP data. For these reasons, the current information presented in the CRF tables should be viewed as an initial attempt at this exercise. Additional efforts will be made for future Inventory reports to improve the mapping of fuel types, and examine ways to reconcile and coordinate any differences between facility-level data and national statistics. Additionally, this year's analysis expanded this effort through the full time series presented in the CRF tables. Analyses were conducted linking GHGRP facility-level reporting with the information published by EIA in its MECS data in order to disaggregate the full 1990 through 2014 time series in the CRF tables. It is believed that the current analysis has led to improvements in the presentation of data in the Inventory, but further work will be conducted, and future improvements will be realized in subsequent Inventory reports.

Additionally, to assist in the disaggregation of industrial fuel consumption, EIA will now synthesize energy consumption data using the same procedure as is used for the last historical (benchmark) year of the Annual Energy Outlook (AEO). This procedure reorganizes the most recent data from the Manufacturing Energy Consumption Survey (MECS) (conducted every four years) into the nominal data submission year using the same energy-economy integrated model used to produce the AEO projections, the National Energy Modeling System (NEMS). EIA believes this "nowcasting" technique provides an appropriate estimate of energy consumption for the CRF.

To address gaps in the time series, EIA performs a NEMS model projection, using the MECS baseline sub-sector energy consumption. The NEMS model accounts for changes in factors that influence industrial sector energy consumption, and has access to data which may be more recent than MECS, such as industrial sub-sector macro industrial output (i.e., shipments) and fuel prices. By evaluating the impact of these factors on industrial subsector

³⁷ See Section 4 "Use of Facility-Level Data in Good Practice National Greenhouse Gas Inventories" of the IPCC meeting report, and specifically the section on using facility-level data in conjunction with energy data, at <http://www.ipcc-nggip.iges.or.jp/meeting/pdfiles/1008_Model_and_Facility_Level_Data_Report.pdf>.

³⁸ See <<http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html>>.

energy consumption, NEMS can anticipate changes to the energy shares occurring post-MECS and can provide a way to appropriately disaggregate the energy-related emissions data into the CRF.

While the fuel consumption values for the various manufacturing sub-sectors are not directly surveyed for all years, they represent EIA's best estimate of historical consumption values for non-MECS years. Moreover, as an integral part of each AEO publication, this synthetic data series is likely to be maintained consistent with all available EIA and non-EIA data sources even as the underlying data sources evolve for both manufacturing and non-manufacturing industries alike.

Other sectors' fuel consumption (commercial, residential, transportation) will be benchmarked with the latest aggregate values from the Monthly Energy Review.³⁹ EIA will work with EPA to back cast these values to 1990.

Box 3-5: Carbon Intensity of U.S. Energy Consumption

Fossil fuels are the dominant source of energy in the United States, and CO₂ is the dominant greenhouse gas emitted as a product from their combustion. Energy-related CO₂ 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 MMT CO₂ Eq./Qbtu for natural gas to upwards of 95 MMT CO₂ Eq./Qbtu for coal and petroleum coke.⁴⁰ 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 the purposes of following reporting guidelines and maintaining the focus of this section, renewable energy and nuclear electricity and consumption are not included in the totals shown in Table 3-15 in order to focus attention on fossil fuel combustion as detailed in this chapter. 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 MMT CO₂ 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 (MMT CO₂ Eq./Qbtu)

Sector	1990	2005	2010	2011	2012	2013	2014
Residential ^a	57.4	56.6	55.8	55.7	55.5	55.3	55.4
Commercial ^a	59.1	57.5	56.8	56.6	56.1	55.8	55.8
Industrial ^a	64.3	64.3	62.9	62.4	62.0	61.8	61.5
Transportation ^a	71.1	71.4	71.5	71.5	71.5	71.4	71.4
Electricity Generation ^b	87.3	85.8	83.5	82.9	79.9	81.3	81.3
U.S. Territories ^c	73.0	73.4	73.1	73.1	72.4	72.1	71.6
All Sectors^c	73.0	73.5	72.4	72.0	70.9	70.9	70.7

^a Does not include electricity or renewable energy consumption.

³⁹ See <<http://www.eia.gov/totalenergy/data/monthly/>>.

⁴⁰ One exajoule (EJ) is equal to 10¹⁸ joules or 0.9478 Qbtu.

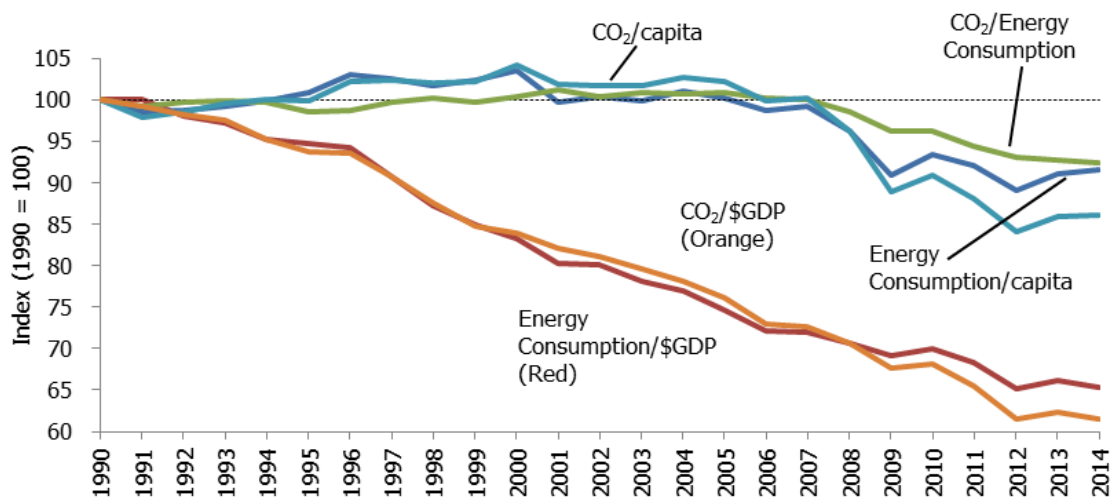
^b Does not include electricity produced using nuclear or renewable energy.

^c Does not include nuclear or renewable energy consumption.

Note: Excludes non-energy fuel use emissions and consumption.

Over the twenty-five-year period of 1990 through 2014, 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 2014 was approximately 8.5 percent below levels in 1990 (see Figure 3-14). To differentiate these estimates from those of Table 3-15, the C intensity trend shown in Figure 3-14 and described below includes nuclear and renewable energy EIA data to provide a comprehensive economy-wide picture of energy consumption. 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 CO₂ emissions per dollar of gross domestic product (GDP) have both declined since 1990 (BEA 2016).

Figure 3-14: U.S. Energy Consumption and Energy-Related CO₂ Emissions Per Capita and Per Dollar GDP



C intensity estimates were developed using nuclear and renewable energy data from EIA (2016), EPA (2010a), and fossil fuel consumption data as discussed above and presented in Annex 2.1.

Uncertainty and Time-Series Consistency

For estimates of CO₂ from fossil fuel combustion, the amount of CO₂ 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 CO₂ 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 CO₂ 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 CO₂ 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. The amount of CO₂ 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 CO₂ 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 CO₂ 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 Approach 2 uncertainty estimation methodology, Monte Carlo Stochastic Simulation technique, with @RISK software. For this uncertainty estimation, the inventory estimation model for CO₂ 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 CO₂ 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.⁴¹ 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.⁴²

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).⁴³ For purposes of this uncertainty analysis, each input variable was simulated 10,000 times through Monte Carlo sampling.

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 3-16. Fossil fuel combustion CO₂ emissions in 2014 were estimated to be between 5,102.4 and 5,457.4 MMT CO₂ Eq. at a 95 percent confidence level. This indicates a range of 2 percent below to 5 percent above the 2014 emission estimate of 5,208.2 MMT CO₂ Eq.

⁴¹ 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.

⁴² 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.

⁴³ 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.

Table 3-16: Approach 2 Quantitative Uncertainty Estimates for CO₂ Emissions from Energy-Related Fossil Fuel Combustion by Fuel Type and Sector (MMT CO₂ Eq. and Percent)

Fuel/Sector	2014 Emission Estimate (MMT CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate ^a			
		(MMT CO ₂ Eq.)		(%)	
		Lower Bound	Upper Bound	Lower Bound	Upper Bound
Coal^b	1,653.7	1,596.3	1,809.1	-3%	9%
Residential	NE	NE	NE	NE	NE
Commercial	4.5	4.3	5.2	-5%	15%
Industrial	75.3	71.8	87.2	-5%	16%
Transportation	NE	NE	NE	NE	NE
Electricity Generation	1,570.4	1,509.0	1,721.0	-4%	10%
U.S. Territories	3.4	3.0	4.0	-13%	19%
Natural Gas^b	1,426.6	1,411.4	1,492.7	-1%	5%
Residential	277.6	269.7	297.1	-3%	7%
Commercial	189.2	183.8	202.4	-3%	7%
Industrial	466.0	452.1	499.6	-3%	7%
Transportation	47.6	46.3	51.0	-3%	7%
Electricity Generation	443.2	430.4	465.6	-3%	5%
U.S. Territories	3.0	2.6	3.5	-12%	17%
Petroleum^b	2,127.5	1,997.0	2,251.9	-6%	6%
Residential	67.5	63.8	71.0	-5%	5%
Commercial	38.2	36.3	40.0	-5%	5%
Industrial	271.9	219.1	321.2	-19%	18%
Transportation	1,690.0	1,577.3	1,800.7	-7%	7%
Electric Utilities	25.3	24.1	27.3	-5%	8%
U.S. Territories	34.6	31.9	38.5	-8%	11%
Total (excluding Geothermal)^b	5,207.8	5,102.0	5,457.0	-2%	5%
Geothermal	0.4	NE	NE	NE	NE
Total (including Geothermal)^{b,c}	5,208.2	5,102.4	5,457.4	-2%	5%

NE (Not Estimated)

^a Range of emission estimates predicted by Monte Carlo Stochastic 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 CO₂ emissions from geothermal production.

Methodological recalculations were applied to the entire time series to ensure time-series consistency from 1990 through 2014. 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 CO₂ 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 CO₂ 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 2016) updated energy consumption statistics across the time series relative to the previous Inventory. One such revision is the historical coal and petroleum product consumption in the industrial sector for the entire time series. In addition, EIA revised 2013 natural gas consumption in the

transportation sector and 2013 kerosene and Liquefied Petroleum Gas (LPG) consumption in the residential and commercial sectors.

Kerosene consumption increased in the residential sector by 9 percent in 2013 and decreased by 14 and 25 percent in the commercial and industrial sectors in 2013, respectively. Transportation sector distillate fuel consumption decreased by 0.4 percent across the entire time series.

In early 2015, EIA revised the heat content used to calculate the energy of distillate fuel oil consumption. Previously, a single constant factor (5.825 MMBtu/barrel) from EIA's Monthly Energy Review (MER) Table A1 was applied to the volumetric data. For the January 2015 release, this single constant factor in Table A1 was replaced with heat content factors for distillate fuel oil by sulfur content. Instead of using the factor(s) listed in Table A1, EIA began to use an annually variable quantity-weighted factor (5.774 MMBtu/barrel for 2013) that was added to Table A3. EIA notes that quantity-weighted averages of the sulfur-content categories of distillate fuel oil are calculated by using heat content values shown in Table A1, and that these values exclude renewable diesel fuel (including biodiesel) blended into distillate fuel oil.

Overall, these changes resulted in an average annual decrease of 1.1 MMT CO₂ Eq. (less than 0.1 percent) in CO₂ emissions from fossil fuel combustion for the period 1990 through 2013, relative to the previous report.

Planned Improvements

To reduce uncertainty of CO₂ 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 CO₂ 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.

The availability of facility-level combustion emissions through EPA's GHGRP will continue to be examined to help better characterize the industrial sector's energy consumption in the United States, and further classify business establishments according to industrial economic activity type. Most methodologies used in EPA's GHGRP are consistent with IPCC, though for EPA's GHGRP, facilities collect detailed information specific to their operations according to detailed measurement standards, which may differ with the more aggregated data collected for the Inventory to estimate total, national U.S. emissions. In addition, and unlike the reporting requirements for this chapter under the UNFCCC reporting guidelines, some facility-level fuel combustion emissions reported under the GHGRP may also include industrial process emissions.⁴⁴ In line with UNFCCC reporting guidelines, fuel combustion emissions are included in this chapter, while process emissions are included in the Industrial Processes and Product Use chapter of this report. In examining data from EPA's GHGRP that would be useful to improve the emission estimates for the CO₂ from fossil fuel combustion category, particular attention will also be made to ensure time series consistency, as the facility-level reporting data from EPA's GHGRP are not available for all inventory years as reported in this Inventory. Additional analyses will be conducted to align reported facility-level fuel types and IPCC fuel types per the national energy statistics. Additional work will commence to ensure CO₂ emissions from biomass are separated in the facility-level reported data, and maintaining consistency with national energy statistics provided by EIA. In implementing improvements and integration of data from EPA's GHGRP, the latest guidance from the IPCC on the use of facility-level data in national inventories will continue to be relied upon.⁴⁵

Another planned improvement is to 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 is currently being investigated.

An additional potential improvement is to include CO₂ emissions from natural gas (LNG and CNG) use in medium- and heavy-duty trucks, light trucks and passenger cars. Currently data from the Transportation Energy Data book is

⁴⁴ See <<http://unfccc.int/resource/docs/2006/sbsta/eng/09.pdf>>.

⁴⁵ See <http://www.ipcc-nggip.iges.or.jp/meeting/pdffiles/1008_Model_and_Facility_Level_Data_Report.pdf>.

used to allocate CO₂ emissions to vehicle categories. However, this data source only estimates natural gas use in buses. We are currently investigating the use of alternative data sources from the EIA that would allow some of the CO₂ from natural gas consumption to be allocated to these other vehicle categories.

In addition, we are investigating an approach to account for CO₂ emissions from the use of urea-based additives in catalytic converters for on-road vehicles between 2010 and 2014. The approach would utilize the MOVES model to estimate fuel use by diesel vehicles with urea-based catalysts. The *2006 IPCC Guidelines* estimates urea use between one and three percent of diesel fuel used.

CH₄ and N₂O from Stationary Combustion

Methodology

Methane and N₂O emissions from stationary combustion were estimated by multiplying fossil fuel and wood consumption data by emission factors (by sector and fuel type for industrial, residential, commercial, and U.S. Territories; and by fuel and technology type for the electric power sector). Beginning with the current Inventory report, the electric power sector utilizes a Tier 2 methodology, whereas all other sectors utilize a Tier 1 methodology. The activity data and emission factors used are described in the following subsections.

Industrial, Residential, Commercial, and U.S. Territories

National coal, natural gas, fuel oil, and wood consumption data were grouped by sector: industrial, commercial, residential, and U.S. Territories. For the CH₄ and N₂O estimates, wood consumption data for the United States was obtained from EIA's Monthly Energy Review (EIA 2016). Fuel consumption data for coal, natural gas, and fuel oil for the United States were also obtained from EIA's Monthly Energy Review and unpublished supplemental tables on petroleum product detail (EIA 2016). Because the United States does not include territories in its national energy statistics, fuel consumption data for territories were provided separately by EIA's International Energy Statistics (EIA 2014) and Jacobs (2010).⁴⁶ Fuel consumption for the industrial sector was adjusted to subtract out construction and agricultural use, which is reported under mobile sources.⁴⁷ Construction and agricultural fuel use was obtained from EPA (2014). 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. Tier 1 default emission factors for these three 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.

Electric Power Sector

The electric power sector now uses a Tier 2 emission estimation methodology as fuel consumption for the electricity generation sector by control-technology type was obtained from EPA's Acid Rain Program Dataset (EPA 2015a). This combustion technology- and fuel-use data was available by facility from 1996 to 2014. The Tier 2 emission factors used were taken from IPCC (2006), which in turn are based on emission factors published by EPA.

Since there was a difference between the EPA (2015a) and EIA (2016) total energy consumption estimates, the remaining energy consumption from EIA (2016) was apportioned to each combustion technology type and fuel combination using a ratio of energy consumption by technology type from 1996 to 2014.

Energy consumption estimates were not available from 1990 to 1995 in the EPA (2015a) dataset, and as a result, consumption was calculated using total electric power consumption from EIA (2016) and the ratio of combustion technology and fuel types from EPA (2015a). The consumption estimates from 1990 to 1995 were estimated by

⁴⁶ U.S. Territories data also include combustion from mobile activities because data to allocate territories' energy use were unavailable. For this reason, CH₄ and N₂O emissions from combustion by U.S. Territories are only included in the stationary combustion totals.

⁴⁷ 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.

applying the 1996 consumption ratio by combustion technology type to the total EIA consumption for each year from 1990 to 1995. Emissions were estimated by multiplying fossil fuel and wood consumption by technology- and fuel-specific Tier 2 IPCC emission factors.

Lastly, there were significant differences between wood biomass consumption in the electric power sector between the EPA (2015a) and EIA (2016) datasets. The higher wood biomass consumption from EIA (2016) in the electric power sector was distributed to the residential, commercial, and industrial sectors according to their percent share of wood biomass energy consumption calculated from EIA (2016).

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

Methane 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 CH₄ and N₂O 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 Approach 2 uncertainty estimation methodology, Monte Carlo Stochastic Simulation technique, with @RISK software.

The uncertainty estimation model for this source category was developed by integrating the CH₄ and N₂O stationary source inventory estimation models with the model for CO₂ 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 CO₂ 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 N₂O emission factors, based on the SAIC/EIA (2001) report.⁴⁸ For these variables, the uncertainty ranges were assigned to the input variables based on the data reported in SAIC/EIA (2001).⁴⁹ However, the CH₄ emission factors differ from those used by EIA. These factors and uncertainty ranges are based on IPCC default uncertainty estimates (IPCC 2006).

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 3-17. Stationary combustion CH₄ emissions in 2014 (*including* biomass) were estimated to be between 4.8 and 20.6 MMT CO₂ Eq. at a 95 percent confidence level. This indicates a range of 41 percent below to 155 percent above the 2014 emission estimate of 8.1 MMT CO₂ Eq.⁵⁰ Stationary combustion N₂O emissions in 2014 (*including* biomass) were estimated to be between 17.9 and 34.2 MMT CO₂ Eq. at a 95 percent confidence level. This indicates a range of 24 percent below to 46 percent above the 2014 emissions estimate of 23.4 MMT CO₂ Eq.

⁴⁸ 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.

⁴⁹ 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.

⁵⁰ 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.

Table 3-17: Approach 2 Quantitative Uncertainty Estimates for CH₄ and N₂O Emissions from Energy-Related Stationary Combustion, Including Biomass (MMT CO₂ Eq. and Percent)

Source	Gas	2014 Emission Estimate (MMT CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate ^a (MMT CO ₂ Eq.)			
			Lower Bound	Upper Bound	Lower Bound (%)	Upper Bound (%)
Stationary Combustion	CH ₄	8.1	4.8	20.6	-41%	+155%
Stationary Combustion	N ₂ O	23.4	17.9	34.2	-24%	+46%

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

The uncertainties associated with the emission estimates of CH₄ and N₂O are greater than those associated with estimates of CO₂ from fossil fuel combustion, which mainly rely on the carbon content of the fuel combusted. Uncertainties in both CH₄ and N₂O 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 2014. 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 CH₄, N₂O, 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

Methane and N₂O emissions from stationary sources (excluding CO₂) across the entire time series were revised due to revised data from EIA (2016) and EPA (2015a) relative to the previous Inventory. The CH₄ emission estimates were also revised due to a corrected emission factor for Natural Gas Combined Cycle gas turbines that was corrected from 1 g/GJ to 4 g/GJ, per IPCC (2006). The historical data changes resulted in an average annual increase of less than 0.1 MMT CO₂ Eq. (less than 0.1 percent) in CH₄ emissions, and an average annual decrease of less than 0.1 MMT CO₂ Eq. (less than 0.1 percent) in N₂O emissions from stationary combustion for the period 1990 through 2013.

Planned Improvements

Several items are being evaluated to improve the CH₄ and N₂O 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.

Future improvements to the CH₄ and N₂O from Stationary Combustion category involve research into the availability of CH₄ and N₂O from stationary combustion data, and analyzing data reported under EPA's GHGRP. In examining data from EPA's GHGRP that would be useful to improve the emission estimates for CH₄ and N₂O from Stationary Combustion category, particular attention will be made to ensure time series consistency, as the facility-level reporting data from EPA's GHGRP are not available for all Inventory years as reported in this Inventory. In

implementing improvements and integration of data from EPA's GHGRP, the latest guidance from the IPCC on the use of facility-level data in national inventories will be relied upon.⁵¹

CH₄ and N₂O from Mobile Combustion

Methodology

Estimates of CH₄ and N₂O 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 CH₄ and N₂O emissions from mobile combustion and the emission factors used in the calculations is provided in Annex 3.2.

On-Road Vehicles

Estimates of CH₄ and N₂O 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) are based on VMT and emission factors by vehicle and fuel type.⁵²

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 CO₂, CO, HC, NO_x, and PM from vehicles under various conditions, to approximate average driving characteristics.⁵³

Emission factors for AFVs were first 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 AFVs is provided in Annex 3.2.

Annual VMT data for 1990 through 2014 were obtained from the Federal Highway Administration's (FHWA) Highway Performance Monitoring System database as reported in Highway Statistics (FHWA 1996 through 2015).⁵⁴ VMT estimates were then allocated from FHWA's vehicle categories to fuel-specific vehicle categories

⁵¹ See <http://www.ipcc-nggip.iges.or.jp/meeting/pdfiles/1008_Model_and_Facility_Level_Data_Report.pdf>.

⁵² 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.

⁵³ Additional information regarding the model can be found online at <<http://www.epa.gov/OMS/m6.htm>>.

⁵⁴ The source of VMT is FHWA's VM-1 table. In 2011, FHWA changed its methods for estimating data in the VM-1 table. These methodological changes included how vehicles are classified, moving from a system based on body-type to one that is based on wheelbase. These changes were first incorporated for the 1990 through 2010 Inventory and apply to the 2007 through

using the calculated shares of vehicle fuel use for each vehicle category by fuel type reported in DOE (1993 through 2015) and information on total motor vehicle fuel consumption by fuel type from FHWA (1996 through 2015). VMT for AFVs were estimated based on Browning (2015). The age distributions of the U.S. vehicle fleet were obtained from EPA (2015b, 2000), and the average annual age-specific vehicle mileage accumulation of U.S. vehicles were obtained from EPA (2015b).

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 (1994a, 1994b, 1998, 1999a) and IPCC (2006).

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 N₂O and CH₄ per kilogram of fuel consumed).⁵⁵ Activity data were obtained from AAR (2008 through 2015), APTA (2007 through 2015), APTA (2006), BEA (1991 through 2015), Benson (2002 through 2004), DHS (2008), DLA Energy (2015), DOC (1991 through 2015), DOE (1993 through 2015), DOT (1991 through 2015), EIA (2002, 2007, 2015a), EIA (2007 through 2015), EIA (1991 through 2015), EPA (2015b), Esser (2003 through 2004), FAA (2016), FHWA (1996 through 2015), Gaffney (2007), and Whorton (2006 through 2014). Emission factors for non-road modes were taken from IPCC (2006) and Browning (2009).

Uncertainty and Time-Series Consistency

A quantitative uncertainty analysis was conducted for the mobile source sector using the IPCC-recommended Approach 2 uncertainty estimation methodology, Monte Carlo Stochastic Simulation technique, using @RISK software. The uncertainty analysis was performed on 2014 estimates of CH₄ and N₂O 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) 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. For more information, see Section 1.7 Uncertainty Analysis of Emission Estimates. However, a much higher level of uncertainty is associated with CH₄ and N₂O emission factors due to limited emission test data, and because, unlike CO₂ emissions, the emission pathways of CH₄ and N₂O are highly complex.

Mobile combustion CH₄ emissions from all mobile sources in 2014 were estimated to be between 1.8 and 2.4 MMT CO₂ Eq. at a 95 percent confidence level. This indicates a range of 12 percent below to 18 percent above the corresponding 2014 emission estimate of 2.0 MMT CO₂ Eq. Also at a 95 percent confidence level, mobile combustion N₂O emissions from mobile sources in 2014 were estimated to be between 15.7 and 20.7 MMT CO₂ Eq., indicating a range of 4 percent below to 27 percent above the corresponding 2014 emission estimate of 16.3 MMT CO₂ Eq.

2014 time period. This resulted in large changes in VMT by vehicle class, thus leading to a shift in emissions among on-road vehicle classes. For example, the category "Passenger Cars" has been replaced by "Light-duty Vehicles-Short Wheelbase" and "Other 2 axle-4 Tire Vehicles" has been replaced by "Light-duty Vehicles, Long Wheelbase." This change in vehicle classification has moved some smaller trucks and sport utility vehicles from the light truck category to the passenger vehicle category in this Inventory. These changes are reflected in a large drop in light-truck emissions between 2006 and 2007.

⁵⁵ 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: Approach 2 Quantitative Uncertainty Estimates for CH₄ and N₂O Emissions from Mobile Sources (MMT CO₂ Eq. and Percent)

Source	Gas	2014 Emission Estimate ^a (MMT CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate ^a			
			(MMT CO ₂ Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Mobile Sources	CH ₄	2.0	1.8	2.4	-12%	+18%
Mobile Sources	N ₂ O	16.3	15.7	20.7	-4%	+27%

^a Range of emission estimates predicted by Monte Carlo Stochastic 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 Approach 2 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 CH₄ and N₂O please refer to the Uncertainty Annex.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2014. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

A source-specific Quality Assurance/Quality Control 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

Decreases to CH₄ and N₂O emissions from mobile combustion are largely due to updates made to the Motor Vehicle Emissions Simulator (MOVES 2014a) model that is used to estimate on-road gasoline vehicle distribution and mileage across the time series. These changes are due to the updated MOVES age distributions for years 1999 through 2013 in this year's Inventory. These changes in the age distribution increased the percentage of vehicles and VMT for some vehicle types in newer model years that have better emissions control technology. For aircrafts, a weighted jet fuel heat content was applied to the jet fuel N₂O emissions calculation. The weighted factor accounts for the different heat contents of jet fuels used in commercial aviation, general aviation and the military. This resulted in a 0.4 percent increase in the heat content and a similar increase in N₂O emissions.

Estimates of alternative fuel vehicle mileage were also revised to reflect updates made to Energy Information Administration (EIA) data on alternative fuel use and vehicle counts. The energy economy ratios (EERs) in the alternative fuel vehicle analysis were also updated in this Inventory. EERs are the ratio of the gasoline equivalent fuel economy of a given technology to that of conventional gasoline or diesel vehicles. These were taken from the Argonne National Laboratory's GREET model (ANL 2015). Most of the energy economy ratios were within 10 percent of their previous values. More significant changes occurred with Neighborhood Electric Vehicles (NEVs) (-26 percent), Electric Vehicles (EVs) (17 percent), Hydrogen Fuel Cell Vehicles (-15 percent), Neat Methanol Internal Combustion Engines (ICEs) (12 percent), Neat Ethanol ICEs (25 percent), LPG ICEs (11 percent) and LPG Bi-fuel (11 percent). Increases in EERs increase miles per gallon, estimated VMT, and emissions.

Overall, these changes resulted in an average annual decrease of 0.1 MMT CO₂ Eq. (4 percent) in CH₄ emissions and an average annual decrease of 1.4 MMT CO₂ Eq. (3 percent) in N₂O emissions from mobile combustion for the period 1990 through 2013, relative to the previous report.

Planned Improvements

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

- 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 is currently being investigated. Additionally, the feasibility of including data from a broader range of domestic and international sources for domestic bunker fuels, including data from studies such as the *Third IMO GHG Study 2014*, is being considered.
- 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. 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).

CO₂ 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 60 percent of the total C consumed for non-energy purposes was stored in products, and not released to the atmosphere; the remaining 40 percent was emitted.

There are several areas in which non-energy uses of fossil fuels are closely related to other parts of this Inventory. For example, some of the NEU products release CO₂ 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 CO₂ emissions accounted for in the Industrial Processes and Product Use 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 adjust for the effect of net exports on the mass of C in non-energy applications.

As shown in Table 3-19, fossil fuel emissions in 2014 from the non-energy uses of fossil fuels were 114.3 MMT CO₂ Eq., which constituted approximately 2 percent of overall fossil fuel emissions. In 2014, the consumption of fuels for non-energy uses (after the adjustments described above) was 4,761.2 TBtu, an increase of 6.3 percent since 1990 (see Table 3-20). About 55.9 MMT (205.1 MMT CO₂ Eq.) of the C in these fuels was stored, while the remaining 31.2 MMT C (114.3 MMT CO₂ Eq.) was emitted.

Table 3-19: CO₂ Emissions from Non-Energy Use Fossil Fuel Consumption (MMT CO₂ Eq. and percent)

Year	1990	2005	2010	2011	2012	2013	2014
Potential Emissions	312.1	377.5	325.1	316.6	311.9	327.1	319.5
C Stored	194.0	238.6	211.0	208.1	206.2	205.4	205.1
Emissions as a % of Potential	38%	37%	35%	34%	34%	37%	36%
Emissions	118.1	138.9	114.1	108.5	105.6	121.7	114.3

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 (2013, 2015b) (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 and Product Use chapter.^{56,57} 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 the Energy 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 (2006), 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	2005	2010	2011	2012	2013	2014
Industry	4,215.8	5,110.9	4,572.7	4,470.2	4,377.4	4,621.4	4,571.6
Industrial Coking Coal	+	80.4	64.8	60.8	132.5	119.6	23.0
Industrial Other Coal	8.2	11.9	10.3	10.3	10.3	10.3	10.3
Natural Gas to Chemical Plants	281.6	260.9	298.7	297.1	292.7	297.0	305.1

⁵⁶ 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.

⁵⁷ Some degree of double counting may occur between these estimates of non-energy use of fuels and process emissions from petrochemical production presented in the Industrial Processes and Product Use sector. Data integration is not feasible at this time as feedstock data from EIA used to estimate non-energy uses of fuels are aggregated by fuel type, rather than disaggregated by both fuel type and particular industries (e.g., petrochemical production) as currently collected through EPA’s GHGRP and used for the petrochemical production category.

Asphalt & Road Oil	1,170.2	1,323.2	877.8	859.5	826.7	783.3	792.6
LPG	1,120.5	1,610.1	1,834.0	1,865.7	1,887.3	2,062.9	2,109.4
Lubricants	186.3	160.2	149.5	141.8	130.5	138.1	144.0
Pentanes Plus	117.6	95.5	75.3	26.4	40.3	45.4	43.5
Naphtha (<401 °F)	326.3	679.6	474.5	469.4	432.2	498.8	435.2
Other Oil (>401 °F)	662.1	499.5	433.2	368.2	267.4	209.1	236.2
Still Gas	36.7	67.7	147.8	163.6	160.6	166.7	164.6
Petroleum Coke	27.2	105.2	+	+	+	+	+
Special Naphtha	100.9	60.9	25.3	21.8	14.1	96.6	104.4
Distillate Fuel Oil	7.0	11.7	5.8	5.8	5.8	5.8	5.8
Waxes	33.3	31.4	17.1	15.1	15.3	16.5	14.8
Miscellaneous Products	137.8	112.8	158.7	164.7	161.6	171.2	182.7
Transportation	176.0	151.3	141.2	133.9	123.2	130.4	136.0
Lubricants	176.0	151.3	141.2	133.9	123.2	130.4	136.0
U.S. Territories	86.7	121.9	56.4	56.7	58.1	57.4	53.6
Lubricants	0.7	4.6	1.0	1.0	1.0	1.0	1.0
Other Petroleum (Misc. Prod.)	86.0	117.3	55.4	55.7	57.1	56.4	52.6
Total	4,478.5	5,384.1	4,770.3	4,660.9	4,558.7	4,809.2	4,761.2

+ Does not exceed 0.05 TBtu

NA - Not Applicable

Note: Totals may not sum due to independent rounding.

Table 3-21: 2014 Adjusted Non-Energy Use Fossil Fuel Consumption, Storage, and Emissions

Sector/Fuel Type	Adjusted Non-Energy Use ^a (TBtu)	Carbon Content Coefficient (MMT C/QBtu)	Potential Carbon (MMT C)	Storage Factor	Carbon Stored (MMT C)	Carbon Emissions (MMT C)	Carbon Emissions (MMT CO ₂ Eq.)
Industry	4,571.6	NA	83.3	NA	55.6	27.7	101.6
Industrial Coking Coal	23.0	31.00	0.7	0.04	0.1	0.6	2.4
Industrial Other Coal	10.3	25.82	0.3	0.65	0.2	0.1	0.3
Natural Gas to							
Chemical Plants	305.1	14.46	4.4	0.65	2.9	1.5	5.6
Asphalt & Road Oil	792.6	20.55	16.3	1.00	16.2	0.1	0.3
LPG	2,109.4	17.06	36.0	0.65	23.6	12.4	45.6
Lubricants	144.0	20.20	2.9	0.09	0.3	2.6	9.7
Pentanes Plus	43.5	19.10	0.8	0.65	0.5	0.3	1.1
Naphtha (<401° F)	435.2	18.55	8.1	0.65	5.3	2.8	10.2
Other Oil (>401° F)	236.2	20.17	4.8	0.65	3.1	1.6	6.0
Still Gas	164.6	17.51	2.9	0.65	1.9	1.0	3.6
Petroleum Coke	+	27.85	+	0.04	+	+	+
Special Naphtha	104.4	19.74	2.1	0.65	1.3	0.7	2.6
Distillate Fuel Oil	5.8	20.17	0.1	0.04	0.1	0.1	0.2
Waxes	14.8	19.80	0.3	0.58	0.2	0.1	0.5
Miscellaneous Products	182.7	20.31	3.7	0.04	0.0	3.7	13.6
Transportation	136.0	NA	2.7	NA	0.3	2.5	9.1
Lubricants	136.0	20.20	2.7	0.09	0.3	2.5	9.1
U.S. Territories	53.6	NA	1.1	NA	0.1	1.0	3.5
Lubricants	1.0	20.20	+	0.09	+	+	0.1
Other Petroleum (Misc. Prod.)	52.6	20.00	1.1	0.04	0.1	0.9	3.5
Total	4,761.2		87.1		55.9	31.2	114.3

+ Does not exceed 0.05 TBtu

NA - 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 2015a), *Toxics Release Inventory, 1998* (2000b), *Biennial Reporting System* (EPA 2004, 2009), *Resource Conservation and Recovery Act Information System* (EPA 2013b, 2015b), pesticide sales and use estimates (EPA 1998, 1999, 2002, 2004, 2011), and the Chemical Data Access Tool (EPA 2012); the EIA Manufacturer's Energy Consumption Survey (MECS) (EIA 1994, 1997, 2001, 2005, 2010, 2013b, 2015b); the National Petrochemical & Refiners Association (NPRA 2002); the U.S. Bureau of the Census (1999, 2004, 2009); Bank of Canada (2012, 2013, 2014); Financial Planning Association (2006); INEGI (2006); the United States International Trade Commission (1990-2015); Gosselin, Smith, and Hodge (1984); EPA's Municipal Solid Waste (MSW) Facts and Figures (EPA 2013a; 2014a); the Rubber Manufacturers' Association (RMA 2009, 2011, 2014); the International Institute of Synthetic Rubber Products (IISRP 2000, 2003); the Fiber Economics Bureau (FEB 2001-2013); the EPA Chemical Data Access Tool (CDAT) (EPA 2014b); the American Chemistry Council (ACC 2003-2011, 2012, 2013, 2014a, 2014b, 2015); and the *Guide to the Business of Chemistry* (ACC 2015b). 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 Approach 2 methodology (Monte Carlo Stochastic 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 3-20 and Table 3-21), the storage factors were taken directly from IPCC (2006), 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 Approach 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 2014 was estimated to be between 86.2 and 162.9 MMT CO₂ Eq. at a 95 percent confidence level. This indicates a range of 25 percent below to 42 percent above the 2014 emission estimate of 114.3 MMT CO₂ 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: Approach 2 Quantitative Uncertainty Estimates for CO₂ Emissions from Non-Energy Uses of Fossil Fuels (MMT CO₂ Eq. and Percent)

Source	Gas	2014 Emission Estimate (MMT CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate ^a			
			(MMT CO ₂ Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Feedstocks	CO ₂	75.1	49.6	125.3	-34%	67%
Asphalt	CO ₂	0.3	0.1	0.6	-57%	117%
Lubricants	CO ₂	18.9	15.5	21.9	-18%	16%
Waxes	CO ₂	0.5	0.3	0.7	-28%	63%
Other	CO ₂	19.6	14.1	21.7	-28%	11%
Total	CO₂	114.3	86.2	162.9	-25%	42%

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

Note: Totals may not sum due to independent rounding.

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

Source	Gas	2014 Storage Factor (%)	Uncertainty Range Relative to Emission Estimate ^a			
			(%)		(% Relative)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Feedstocks	CO ₂	65%	52%	72%	-20%	10%
Asphalt	CO ₂	99.6%	99.1%	99.8%	-0.5%	0.25%
Lubricants	CO ₂	9%	4%	17%	-57%	88%
Waxes	CO ₂	58%	49%	70%	-15%	22%
Other	CO ₂	4%	4%	24%	-3%	479%

^a Range of emission estimates predicted by Monte Carlo Stochastic 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 2014. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

A source-specific Quality Assurance/Quality Control 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 2013 as well as their trends across the time series.

Petrochemical input data reported by EIA will continue to be investigated in an attempt to address an input/output discrepancy in the NEU model. 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. Starting in 2001 through 2009, outputs exceeded inputs. In 2010 and 2011, inputs exceeded outputs, and in 2012, outputs slightly exceeded inputs. A portion of this discrepancy has been reduced and two strategies have been developed to address the remaining portion (see Planned Improvements, below).

Recalculations Discussion

A number of updates to historical production values were included in the most recent Monthly Energy Review; these have been populated throughout this document.

Planned Improvements

There are several improvements planned for the future:

- Analyzing the fuel and feedstock data from EPA's GHGRP to better disaggregate CO₂ emissions in NEU model and CO₂ process emissions from petrochemical production.
- More accurate accounting of C in petrochemical feedstocks. EPA has worked with EIA to determine the cause of input/output discrepancies in the C mass balance contained within the NEU model. In the future, two strategies to reduce or eliminate this discrepancy will continue to be pursued. First, accounting of C in imports and exports will be improved. The import/export adjustment methodology will be examined to ensure that net exports of intermediaries such as ethylene and propylene are fully accounted for. Second, reconsider the use of top-down C input calculation in estimating emissions will be reconsidered. Alternative approaches that rely more substantially on the bottom-up C output calculation will be considered instead.
- Response to potential changes in NEU input data. In 2013 EIA initiated implementation of new data reporting definitions for Natural Gas Liquids (NGL) and Liquefied Petroleum Gases (LPG); the new definitions may affect the characterization of the input data that EIA provides for the NEU model and may therefore result in the need for changes to the NEU methodology. EIA also obtains and applies proprietary data for LPG inputs that are not directly applied as NEU input data because the data are proprietary. The potential use of the proprietary data (in an aggregated, non-proprietary form) as inputs to the NEU model will be investigated with EIA.
- 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). A better understanding of these trends will be pursued to identify any mischaracterized or misreported fuel consumption for non-energy uses. For example, "miscellaneous

products” category includes miscellaneous products that are not reported elsewhere in the EIA data set. The EIA does not have firm data concerning the amounts of various products that are being reported in the “miscellaneous products” category; however, EIA has indicated that recovered sulfur from petroleum and natural gas processing, and potentially also C black feedstock could be reported in this category. Recovered sulfur would not be reported in the NEU calculation or elsewhere in the Inventory.

- Updating the average C content of solvents was researched, 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 C in solvents. Additional sources of solvents data will be identified in order to update the C content assumptions.
- Updating the average C content of cleansers (soaps and detergents) was researched; although production and consumption data for cleansers are published every 5 years by the Census Bureau, the composition (C content) of cleansers has not been recently updated. Recently available composition data sources may facilitate updating the average C content for this category.
- Revising the methodology for consumption, production, and C content of plastics was researched; because of recent changes to the type of data publicly available for plastics, the NEU model for plastics applies data obtained from personal communications. Potential revisions to the plastics methodology to account for the recent changes in published data will be investigated.
- 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, 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 analyzing C fate similar to those described in Annex 2.3 or deferring to more updated default storage factors from IPCC where available.
- Reviewing the storage of carbon black across various sectors in the Inventory; in particular, the carbon black abraded and stored in tires.

Box 3-6: Reporting of Lubricants, Waxes, and Asphalt and Road Oil Product Use in Energy Sector

IPCC (2006) provides methodological guidance to estimate emissions from the first use of fossil fuels as a product for primary purposes other than combustion for energy purposes (including lubricants, paraffin waxes, bitumen/asphalt, and solvents) under the Industrial Processes and Product Use (IPPU) sector.⁵⁸ In this Inventory, C storage and C emissions from product use of lubricants, waxes, and asphalt and road oil are reported under the Energy sector in the Carbon Emitted from Non-Energy Uses of Fossil Fuels source category (IPCC Source Category 1A).⁵⁹

The emissions are reported in the Energy sector, as opposed to the IPPU sector, to reflect national circumstances in its choice of methodology and to increase transparency of this source category’s unique country-specific data sources and methodology. The country-specific methodology used for the Carbon Emitted from Non-Energy Uses of Fossil Fuels source category is based on a carbon balance (i.e., C inputs-outputs) calculation of the aggregate amount of fossil fuels used for non-energy uses, including inputs of lubricants, waxes, asphalt and road oil (see Section 3.2, Table 3-21). For those inputs, U.S. country-specific data on C stocks and flows are used to develop carbon storage factors, which are calculated as the ratio of the C stored by the fossil fuel non-energy products to the total C content of the fuel consumed, taking into account losses in the production process and during product use.⁶⁰ The country-specific methodology to reflect national circumstances starts with the aggregate amount of fossil fuels used for non-energy uses and applies a C balance calculation, breaking out the C emissions from non-energy use of

⁵⁸ See Volume 3: Industrial Processes and Product Use, Chapter 5: Non-Energy Products from Fuels and Solvent Use of the *2006 IPCC Guidelines for National Greenhouse Gas Inventories* (IPCC 2006).

⁵⁹ Non-methane volatile organic compound (NMVOC) emissions from solvent use are reported separately in the IPPU sector, following Chapter 5 of the *2006 IPCC Guidelines*.

⁶⁰ Data and calculations for lubricants and waxes and asphalt and road oil are in Annex 2.3: Methodology and Data for Estimating CO₂ Emissions from Fossil Fuel Combustion.

lubricants, waxes, and asphalt and road oil. Due to U.S. national circumstances, reporting these C emissions separately under IPPU would involve making artificial adjustments to both the C inputs and C outputs of the non-energy use C balance. These artificial adjustments would also result in the C emissions for lubricants, waxes, and asphalt and road oil being reported under IPPU, while the C storage for lubricants, waxes, and asphalt and road oil would be reported under Energy. To avoid presenting an incomplete C balance and a less transparent approach for the Carbon Emitted from Non-Energy Uses of Fossil Fuels source category calculation, the entire calculation of C storage and C emissions is therefore conducted in the Non-Energy Uses of Fossil Fuels category calculation methodology, and both the C storage and C emissions for lubricants, waxes, and asphalt and road oil are reported under the Energy sector.

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 and Madtes 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 scrap 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, scrap tires are combusted for energy recovery in industrial and utility boilers, pulp and paper mills, and cement kilns. Incineration of waste results in conversion of the organic inputs to CO₂. According to IPCC guidelines, when the CO₂ emitted is of fossil origin, it is counted as a net anthropogenic emission of CO₂ 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 in scrap tires—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, scrap tires (which contain synthetic 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 C mass balance for non-energy uses of fossil fuels.

Approximately 29.6 million metric tons of MSW were incinerated in the United States in 2013 (EPA 2015). Data for the amount of MSW incinerated in 2014 were not available, so data for 2014 was assumed to be equal to data for 2013. CO₂ emissions from incineration of waste rose 18 percent since 1990, to an estimated 9.4 MMT CO₂ Eq. (9,421 kt) in 2014, as the volume of scrap 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 CH₄ and N₂O emissions (De Soete 1993; IPCC 2006). Methane emissions from the incineration of waste were estimated to be less than 0.05 MMT CO₂ Eq. (less than 0.5 kt CH₄) in 2014, and have not changed significantly since 1990. Nitrous oxide emissions from the incineration of waste were estimated to be 0.3 MMT CO₂ Eq. (1 kt N₂O) in 2014, and have not changed significantly since 1990.

Table 3-24: CO₂, CH₄, and N₂O Emissions from the Incineration of Waste (MMT CO₂ Eq.)

Gas/Waste Product	1990	2005	2010	2011	2012	2013	2014 ^a
CO ₂	8.0	12.5	11.0	10.5	10.4	9.4	9.4
Plastics	5.6	6.9	6.0	5.8	5.7	4.9	4.9
Synthetic Rubber in Tires	0.3	1.6	1.5	1.4	1.3	1.2	1.2

Carbon Black in Tires	0.4	2.0	1.8	1.7	1.5	1.4	1.4
Synthetic Rubber in MSW	0.9	0.8	0.7	0.7	0.7	0.7	0.7
Synthetic Fibers	0.8	1.2	1.1	1.1	1.1	1.3	1.3
CH₄	+	+	+	+	+	+	+
N₂O	0.5	0.4	0.3	0.3	0.3	0.3	0.3
Total	8.4	12.8	11.4	10.9	10.7	9.7	9.7

^a Set equal to 2013 value.

Table 3-25: CO₂, CH₄, and N₂O Emissions from the Incineration of Waste (kt)

Gas/Waste Product	1990	2005	2010	2011	2012	2013	2014 ^a
CO₂	7,972	12,454	11,026	10,550	10,362	9,421	9,421
Plastics	5,588	6,919	5,969	5,757	5,709	4,857	4,857
Synthetic Rubber in Tires	308	1,599	1,461	1,363	1,262	1,158	1,158
Carbon Black in Tires	385	1,958	1,783	1,663	1,537	1,412	1,412
Synthetic Rubber in MSW	854	765	701	712	705	729	729
Synthetic Fibers	838	1,212	1,112	1,056	1,149	1,265	1,265
CH₄	+	+	+	+	+	+	+
N₂O	2	1	1	1	1	1	1

^a Set equal to 2013 value.

Methodology

Emissions of CO₂ from the incineration of waste include CO₂ generated by the incineration of plastics, synthetic fibers, and synthetic rubber in MSW, as well as the incineration of synthetic rubber and carbon black in scrap 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, carbon black, and synthetic fibers. Each type of synthetic rubber has a discrete C content, and carbon black is 100 percent C. Emissions of CO₂ were calculated based on the amount of scrap tires used for fuel and the synthetic rubber and carbon black content of scrap tires.

More detail on the methodology for calculating emissions from each of these waste incineration sources is provided in Annex 3.7.

For each of the methods used to calculate CO₂ 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 in MSW, 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 2000 through 2003, 2005 through 2014), *Advancing Sustainable Materials Management: Facts and Figures 2013: Assessing Trends in Material Generation, Recycling and Disposal in the United States* (EPA 2015) and detailed unpublished backup data for some years not shown in the reports (Schneider 2007). For 2014, the amount of MSW incinerated was assumed to be equal to that in 2013, due to the lack of available data. The proportion of total waste discarded that is incinerated was derived from Shin (2014). Data on total waste incinerated was not available for 2012 through 2014, so these values were assumed to equal to the 2011 value. For synthetic rubber and carbon black in scrap tires, information was obtained from U.S. Scrap Tire Management Summary for 2005 through 2013 data (RMA 2014). Average C contents for the “Other” plastics category and synthetic rubber in municipal solid wastes were calculated from 1998 and 2002 production statistics: C content for 1990 through 1998 is based on the 1998 value; C content for 1999 through 2001 is the average of 1998 and 2002 values; and C 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 2012a).

The assumption that 98 percent of organic C is oxidized (which applies to all waste incineration categories for CO₂ 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 CH₄ and N₂O. These emissions were calculated as a function of the total estimated mass of waste incinerated and emission factors. As noted above, CH₄ and N₂O 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 for 2009 and 2010 were interpolated between 2008 and 2011 values. Data for 2011 were derived from Shin (2014). Data on total waste incinerated was not available in the *BioCycle* data set for 2012 through 2014, so these values were assumed to equal the 2011 *BioCycle* data set value.

Table 3-26 provides data on municipal solid waste discarded and percentage combusted for the total waste stream. The emission factors of N₂O and CH₄ emissions per quantity of municipal solid waste combusted are default emission factors for the default continuously-fed stoker unit MSW incineration technology type and were taken from IPCC (2006).

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

Year	Waste Discarded	Waste Incinerated	Incinerated (% of Discards)
1990	235,733,657	30,632,057	13.0%
2005	259,559,787	25,973,520	10.0%
2010	271,592,991	22,714,122	8.0%
2011	273,116,704	20,756,870	7.6%
2012	273,116,704 ^a	20,756,870	7.6%
2013	273,116,704 ^a	20,756,870	7.6%
2014	273,116,704 ^a	20,756,870	7.6%

^a Assumed equal to 2011 value.
Source: van Haaren et al. (2010)

Uncertainty and Time-Series Consistency

An Approach 2 Monte Carlo analysis was performed to determine the level of uncertainty surrounding the estimates of CO₂ emissions and N₂O emissions from the incineration of waste (given the very low emissions for CH₄, no uncertainty estimate was derived). IPCC Approach 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 N₂O 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 Approach 2 quantitative uncertainty analysis are summarized in Table 3-27. Waste incineration CO₂ emissions in 2014 were estimated to be between 8.5 and 11.5 MMT CO₂ Eq. at a 95 percent confidence level.

This indicates a range of 10 percent below to 14 percent above the 2014 emission estimate of 9.4 MMT CO₂ Eq. Also at a 95 percent confidence level, waste incineration N₂O emissions in 2014 were estimated to be between 0.1 and 0.8 MMT CO₂ Eq. This indicates a range of 53 percent below to 163 percent above the 2014 emission estimate of 0.3 MMT CO₂ Eq.

Table 3-27: Approach 2 Quantitative Uncertainty Estimates for CO₂ and N₂O from the Incineration of Waste (MMT CO₂ Eq. and Percent)

Source	Gas	2014 Emission Estimate (MMT CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate ^a			
			(MMT CO ₂ Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Incineration of Waste	CO ₂	9.4	8.5	11.5	-10%	+14%
Incineration of Waste	N ₂ O	0.3	0.1	0.8	-53%	+163%

^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 2014. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

A source-specific Quality Assurance/Quality Control 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

For the current Inventory, emission estimates for 2013 have been updated based on *Advancing Sustainable Materials Management: Facts and Figures 2013: Assessing Trends in Material Generation, Recycling and Disposal in the United States* (EPA 2015).

The data which calculates the percent incineration was updated in the current Inventory. *Biocycle* has not released a new State of Garbage in America Report since 2010 (with 2008 data), which used to be a semi-annual publication which publishes the results of the nation-wide MSW survey. The results of the survey have been published in Shin 2014. This provided updated incineration data for 2011, so the generation and incineration data for 2012 through 2014 are assumed equivalent to the 2011 values. The data for 2009 and 2010 were based on interpolations between 2008 and 2011.

Planned Improvements

The availability of facility-level waste incineration data through EPA's Greenhouse Gas Reporting Program (GHGRP) will be examined to help better characterize waste incineration operations in the United States. This characterization could include future improvements as to the operations involved in waste incineration for energy, whether in the power generation sector or the industrial sector. Additional examinations will be necessary as, unlike the reporting requirements for this chapter under the UNFCCC reporting guidelines,⁶¹ some facility-level waste incineration emissions reported under EPA's GHGRP may also include industrial process emissions. In line with UNFCCC reporting guidelines, emissions for waste incineration with energy recovery are included in this chapter, while process emissions are included in the Industrial Processes and Product Use chapter of this report. In

⁶¹ See <<http://unfccc.int/resource/docs/2006/sbsta/eng/09.pdf>>.

examining data from EPA’s GHGRP that would be useful to improve the emission estimates for the waste incineration category, particular attention will also be made to ensure time series consistency, as the facility-level reporting data from EPA’s GHGRP are not available for all inventory years as reported in this Inventory. Additionally, analyses will focus on ensuring CO₂ emissions from the biomass component of waste are separated in the facility-level reported data, and on maintaining consistency with national waste generation and fate statistics currently used to estimate total, national U.S. greenhouse gas emissions. In implementing improvements and integration of data from EPA’s GHGRP, the latest guidance from the IPCC on the use of facility-level data in national inventories will be relied upon.⁶² GHGRP data is available for MSW combustors, which contains information on the CO₂, CH₄, and N₂O emissions from MSW combustion, plus the fraction of the emissions that are biogenic. To calculate biogenic versus total CO₂ emissions, a default biogenic fraction of 0.6 is used. The biogenic fraction will be calculated using the current input data and assumptions to verify the current MSW emission estimates.

If GHGRP data would not provide a more accurate estimate of the amount of solid waste combusted, new data sources for the total MSW generated will be explored given that the data previously published semi-annually in Biocycle (van Haaren et al. 2010) has ceased to be published, according to the authors. Equivalent data was derived from Shin (2014) for 2011. A new methodology would be developed based on the available data within the annual update of EPA’s *Advancing Sustainable Materials Management: Facts and Figures 2013: Assessing Trends in Material Generation, Recycling and Disposal in the United States* (EPA 2015). In developing the new methodology, appropriate assumptions would need to be made to ensure that the MSW figures included all waste. Additionally, the carbon content of the synthetic fiber will be updated based on each year’s production mix.

Additional improvements will be conducted to improve the transparency in the current reporting of waste incineration. Currently, hazardous industrial waste incineration is included within the overall calculations for the Carbon Emitted from Non-Energy Uses of Fossil Fuels category. Waste incineration activities that do not include energy recovery will be examined. Synthetic fibers within scrap tires are not included in this analysis and will be explored for future inventories. The carbon content of fibers within scrap tires would be used to calculate the associated incineration emissions. Updated fiber content data from the Fiber Economics Bureau will also be explored.

3.4 Coal Mining (IPCC Source Category 1B1a)

Three types of coal mining–related activities release CH₄ to the atmosphere: underground mining, surface mining, and post-mining (i.e., coal-handling) activities. While surface mines account for the majority of U.S. coal production, underground coal mines contribute the largest share of CH₄ emissions (see Table 3-29 and Table 3-30) due to the higher CH₄ content of coal in the deeper underground coal seams. In 2014, 345 underground coal mines and 613 surface mines were operating in the United States. In recent years the total number of active coal mines in the United States has declined. In 2014, the United States was the second largest coal producer in the world (906 MMT), after China (3,650 MMT) and followed by India (668 MMT) (IEA 2015).

Table 3-28: Coal Production (kt)

Year	Underground		Surface		Total	
	Number of Mines	Production	Number of Mines	Production	Number of Mines	Production
1990	1,683	384,244	1,656	546,808	3,339	931,052
2005	586	334,398	789	691,448	1,398	1,025,846
2010	497	305,862	760	676,177	1,257	982,039
2011	508	313,529	788	684,807	1,296	998,337
2012	488	310,608	719	610,307	1,207	920,915
2013	395	309,546	637	581,270	1,032	890,815
2014	345	321,783	613	583,974	958	905,757

⁶² See <http://www.ipcc-nggip.iges.or.jp/meeting/pdffiles/1008_Model_and_Facility_Level_Data_Report.pdf>.

Underground mines liberate CH₄ from ventilation systems and from degasification systems. Ventilation systems pump air through the mine workings to dilute noxious gases and ensure worker safety; these systems can exhaust significant amounts of CH₄ to the atmosphere in low concentrations. Degasification systems are wells drilled from the surface or boreholes drilled inside the mine that remove large, often highly concentrated volumes of CH₄ before, during, or after mining. Some mines recover and use CH₄ generated from ventilation and degasification systems, thereby reducing emissions to the atmosphere.

Surface coal mines liberate CH₄ as the overburden is removed and the coal is exposed to the atmosphere. CH₄ emissions are normally a function of coal rank (a classification related to the percentage of carbon in the coal) and depth. Surface coal mines typically produce lower-rank coals and remove less than 250 feet of overburden, so their level of emissions is much lower than from underground mines.

In addition, CH₄ is released during post-mining activities, as the coal is processed, transported, and stored for use.

Total CH₄ emissions in 2014 were estimated to be 2,703 kt (67.6 MMT CO₂ eq.), a decline of 30 percent since 1990 (see Table 3-29 and Table 3-30). Of this amount, underground mines accounted for approximately 73 percent, surface mines accounted for 14 percent, and post-mining emissions accounted for 13 percent.

Table 3-29: CH₄ Emissions from Coal Mining (MMT CO₂ Eq.)

Activity	1990	2005	2010	2011	2012	2013	2014
Underground (UG) Mining	74.2	42.0	61.6	50.2	47.3	46.2	49.1
Liberated	80.8	59.7	85.2	71.0	65.8	65.8	65.7
Recovered & Used	(6.6)	(17.7)	(23.6)	(20.8)	(18.5)	(19.6)	(16.6)
Surface Mining	10.8	11.9	11.5	11.6	10.3	9.7	9.6
Post-Mining (UG)	9.2	7.6	6.8	6.9	6.7	6.6	6.7
Post-Mining (Surface)	2.3	2.6	2.5	2.5	2.2	2.1	2.1
Total	96.5	64.1	82.3	71.2	66.5	64.6	67.6

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

Table 3-30: CH₄ Emissions from Coal Mining (kt)

Activity	1990	2005	2010	2011	2012	2013	2014
UG Mining	2,968	1,682	2,463	2,008	1,891	1,849	1,964
Liberated	3,234	2,390	3,406	2,839	2,631	2,633	2,627
Recovered & Used	(266)	(708)	(943)	(831)	(740)	(784)	(662)
Surface Mining	430	475	461	465	410	388	386
Post-Mining (UG)	368	306	270	276	268	263	270
Post-Mining (Surface)	93	103	100	101	89	84	84
Total	3,860	2,565	3,293	2,849	2,658	2,584	2,703

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

Methodology

The methodology for estimating CH₄ emissions from coal mining consists of two steps:

- Estimate emissions from underground mines. These emissions have two sources: ventilation systems and degasification systems. They are estimated on a mine-by-mine basis, then summed to determine total CH₄ liberated. The CH₄ recovered and used is then subtracted from this total, resulting in an estimate of net emissions to the atmosphere.
- Estimate CH₄ emissions from surface mines and post-mining activities. Unlike the methodology for underground mines, which uses mine-specific data, the methodology for estimating emissions from surface mines and post-mining activities consists of multiplying basin-specific coal production by basin-specific gas content and an emission factor.

Step 1: Estimate CH₄ Liberated and CH₄ Emitted from Underground Mines

Underground mines generate CH₄ from ventilation systems and from degasification systems. Some mines recover and use the generated CH₄, thereby reducing emissions to the atmosphere. Total CH₄ emitted from underground mines equals the CH₄ liberated from ventilation systems, plus the CH₄ liberated from degasification systems, minus the CH₄ recovered and used.

Step 1.1: Estimate CH₄ Liberated from Ventilation Systems

To estimate CH₄ liberated from ventilation systems, EPA uses data collected through its Greenhouse Gas Reporting Program (GHGRP) (subpart FF, “Underground Coal Mines”), data provided by the U.S. Mine Safety and Health Administration (MSHA), and occasionally data collected from other sources on a site-specific level (e.g., state data). Since 2011, the nation’s “gassiest” underground coal mines—those that liberate more than 36,500,000 actual cubic feet of CH₄ per year (about 14,700 MT CO₂ eq.)—have been required to report to EPA’s GHGRP (EPA 2015).⁶³ Mines that report to the GHGRP must report quarterly measurements of CH₄ emissions from ventilation systems to EPA; they have the option of recording their own measurements, or using the measurements taken by MSHA as part of that agency’s quarterly safety inspections of all mines in the United States with detectable CH₄ concentrations.⁶⁴

Since 2013, ventilation emission estimates have been calculated based on both GHGRP data submitted by underground mines that recorded their own measurements, and on quarterly measurement data obtained directly from MSHA for the remaining mines (not MSHA data reported by the mines to the GHGRP).⁶⁵ The quarterly measurements are used to determine the average daily emissions rate for the reporting year quarter.

Step 1.2: Estimate CH₄ Liberated from Degasification Systems

Particularly gassy underground mines also use degasification systems (e.g., wells or boreholes) to remove CH₄ before, during, or after mining. This CH₄ can then be collected for use or vented to the atmosphere. Twenty-five mines used degasification systems in 2014, and the CH₄ removed through these systems was reported to EPA’s GHGRP (EPA 2015). Based on the weekly measurements reported to EPA’s GHGRP, degasification data summaries for each mine were added together to estimate the CH₄ liberated from degasification systems. Sixteen of the 25 mines with degasification systems had operational CH₄ recovery and use projects (see step 1.3 below), and GHGRP reports show the remaining nine mines vented CH₄ from degasification systems to the atmosphere.⁶⁶

Degasification volumes for the life of any pre-mining wells are attributed to the mine as emissions in the year in which the well is mined through.⁶⁷ EPA’s GHGRP does not require gas production from virgin coal seams (coalbed methane) to be reported by coal mines under subpart FF. Most pre-mining wells drilled from the surface are considered coalbed methane wells and are reported under another subpart of the program (subpart W, “Petroleum and Natural Gas Systems”). As a result, for the 10 mines with degasification systems that include pre-mining wells, GHGRP information was supplemented with historical data from state gas well production databases (GSA 2016, WVGES 2015), as well as with mine-specific information regarding the dates on which the pre-mining wells are mined through (JWR 2010, El Paso 2009).

Degasification information reported to EPA’s GHGRP by underground coal mines was the primary source of data used to develop estimates of CH₄ liberated from degasification systems. Data reported to EPA’s GHGRP were used to estimate CH₄ liberated from degasification systems at 20 of the 25 mines that employed degasification systems in 2014. For the other five mines (all with pre-mining wells from which CH₄ was recovered), GHGRP data—along with supplemental information from state gas production databases (GSA 2016, WVGES 2015)—were used to

⁶³ Underground coal mines report to EPA under Subpart FF of the GHGRP. In 2014, 128 underground coal mines reported to the program.

⁶⁴ MSHA records coal mine CH₄ readings with concentrations of greater than 50 ppm (parts per million) CH₄. Readings below this threshold are considered non-detectable.

⁶⁵ EPA has determined that certain mines are having difficulty interpreting the MSHA data so that they report them correctly to the GHGRP. EPA is working with these mines to correct their GHGRP reports, and in the meantime is relying on data obtained directly from MSHA for purposes of the national inventory.

⁶⁶ Several of the mines venting CH₄ from degasification systems use a small portion the gas to fuel gob well blowers in remote locations where electricity is not available. However, this CH₄ use is not considered to be a formal recovery and use project.

⁶⁷ A well is “mined through” when coal mining development or the working face intersects the borehole or well.

estimate CH₄ liberated from degasification systems. For one mine, due to a lack of mine-provided information used in prior years and a GHGRP reporting discrepancy, the CH₄ liberated was based on both the reported GHGRP data (for the vented portion of CH₄ recovered) and an estimate from historical mine-provided CH₄ recovery and use rates based on gas sales records (JWR 2010, El Paso 2009).

Step 1.3: Estimate CH₄ Recovered from Ventilation and Degasification Systems, and Utilized or Destroyed (Emissions Avoided)

Sixteen mines had CH₄ recovery and use projects in place in 2014. Fourteen of these mines sold the recovered CH₄ to a pipeline, including one that also used CH₄ to fuel a thermal coal dryer. In addition, one mine used recovered CH₄ for electrical power generation, and one used recovered CH₄ to heat mine ventilation air.

Ten of the 16 mines deployed degasification systems in 2014; for those mines, estimates of CH₄ recovered from the systems were exclusively based on GHGRP data. Based on weekly measurements, the GHGRP degasification destruction data summaries for each mine were added together to estimate the CH₄ recovered and used from degasification systems.

All 10 mines with degasification systems used pre-mining wells as part of those systems, but only four of them intersected pre-mining wells in 2014. GHGRP and supplemental data were used to estimate CH₄ recovered and used at two of these four mines; supplemental data alone (GSA 2016) were used for the other two mines, which reported to EPA's GHGRP as a single entity. Supplemental information was used for these four mines because estimating CH₄ recovery and use from pre-mining wells requires additional data (not reported under subpart FF of EPA's GHGRP, see discussion in step 1.2 above) to account for the emissions avoided. The supplemental data came from state gas production databases, as well as mine-specific information on the timing of mined-through pre-mining wells.

GHGRP information was not used to estimate CH₄ recovered and used at two mines. At one of these mines, a portion (16 percent) of reported CH₄ vented was applied to an ongoing mine air heating project. Because of a lack of mine-provided information used in prior years and a GHGRP reporting discrepancy, the 2014 CH₄ recovered and used at the other mine was based on an estimate from historical mine-provided CH₄ recovery and use rates (including emissions avoided from pre-mining wells).

In 2014, one mine destroyed a portion of its CH₄ emissions from ventilation systems using thermal oxidation technology. The amount of CH₄ recovered and destroyed by the project was determined through publicly-available emission reduction project information (CAR 2015).

Step 2: Estimate CH₄ Emitted from Surface Mines and Post-Mining Activities

Mine-specific data were not available for estimating CH₄ emissions from surface coal mines or for post-mining activities. For surface mines, basin-specific coal production obtained from the Energy Information Administration's Annual Coal Report (EIA 2015) was multiplied by basin-specific CH₄ contents (EPA 1996, 2005) and a 150 percent emission factor (to account for CH₄ from over- and under-burden) to estimate CH₄ emissions (see King 1994, Saghafi 2013). For post-mining activities, basin-specific coal production was multiplied by basin-specific gas contents and a mid-range 32.5 percent emission factor for CH₄ desorption during coal transportation and storage (Creedy 1993). Basin-specific *in situ* gas content data were compiled from AAPG (1984) and USBM (1986).

Uncertainty and Time-Series Consistency

A quantitative uncertainty analysis was conducted for the coal mining source category using the IPCC-recommended Approach 2 uncertainty estimation methodology. Because emission estimates from underground ventilation systems were based on actual measurement data from EPA's GHGRP or from MSHA, uncertainty is relatively low. A degree of imprecision was introduced because the ventilation air measurements used were not continuous but rather quarterly instantaneous readings that were used to determine the average daily emissions rate for the quarter. Additionally, the measurement equipment used can be expected to have resulted in an average of 10 percent overestimation of annual CH₄ emissions (Mutmanský & Wang 2000). GHGRP data were used for a significant number of the mines that reported their own measurements to the program beginning in 2013; however, the equipment uncertainty is applied to both GHGRP and MSHA data.

Estimates of CH₄ recovered by degasification systems are relatively certain for utilized CH₄ because of the availability of GHGRP data and gas sales information. Many of the recovery estimates use data on wells within 100 feet of a mined area. However, uncertainty 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 estimated.

EPA's GHGRP requires weekly CH₄ monitoring of mines that report degasification systems, and continuous CH₄ monitoring is required for utilized CH₄ on- or off-site. Since 2012, GHGRP data have been used to estimate CH₄ emissions from vented degasification wells, reducing the uncertainty associated with prior MSHA estimates used for this subsource. Beginning in 2013, GHGRP data were also used for determining CH₄ recovery and use at mines without publicly available gas usage or sales records, which has reduced the uncertainty from previous estimation methods that were based on information from coal industry contacts.

Surface mining and post-mining emissions are associated with considerably more uncertainty than underground mines, because of the difficulty in developing accurate emission factors from field measurements. However, since underground emissions constitute 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 Approach 2 quantitative uncertainty analysis are summarized in Table 3-31. Coal mining CH₄ emissions in 2014 were estimated to be between 59.9 and 77.4 MMT CO₂ eq. at a 95 percent confidence level. This indicates a range of 11.9 percent below to 15.3 percent above the 2014 emission estimate of 67.6 MMT CO₂ eq.

Table 3-31: Approach 2 Quantitative Uncertainty Estimates for CH₄ Emissions from Coal Mining (MMT CO₂ Eq. and Percent)

Source	Gas	2014 Emission Estimate (MMT CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate ^a (MMT CO ₂ Eq.)			
			Lower Bound	Upper Bound	Lower Bound (%)	Upper Bound (%)
Coal mining	CH ₄	67.6	59.9	77.4	-11.9%	+15.3%

^a Range of emission estimates predicted by Monte Carlo stochastic simulation for a 95 percent confidence interval.
Note: Emissions values are presented in CO₂ equivalent mass units using IPCC AR4 GWP values.

Methodological recalculations were applied to the entire time-series to ensure consistency from 1990 through 2014. Details on the emission trends through time are described in more detail in the methodology section.

Recalculations Discussion

For the current Inventory, no recalculations were performed on prior inventory years.

Planned Improvements

Future improvements to the coal mining category will include continued analysis and integration into the national inventory of the degasification quantities and ventilation emissions data reported by underground coal mines to EPA's GHGRP. A higher reliance on EPA's GHGRP will provide greater consistency and accuracy in future inventories. MSHA data will serve as a quality assurance tool for validating GHGRP data. Reconciliation of the GHGRP and Inventory data sets is still in progress. In implementing improvements and integrating data from EPA's GHGRP, the latest guidance from the IPCC on the use of facility-level data in national inventories will be relied on (IPCC 2011).

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

Underground coal mines contribute the largest share of coal mine methane (CMM) emissions, with active underground mines the leading source of underground emissions. However, mines also continue to release CH₄ 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 CH₄ that may find its way to surface structures through overburden fractures. As work stops within the mines, CH₄ liberation decreases but it does not stop completely. Following an initial decline, abandoned mines can liberate CH₄ 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 CH₄ 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.

Annual gross abandoned mine CH₄ emissions ranged from 7.2 to 10.8 MMT CO₂ Eq. from 1990 through 2014, varying, in general, by less than 1 percent 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 (10.8 MMT CO₂ Eq.) due to the large number of gassy mine⁶⁸ closures from 1994 to 1996 (72 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. Since 2002, there have been fewer than twelve gassy mine closures each year. There were seven gassy mine closures in 2014. In 2014, gross abandoned mine emissions decreased slightly to 8.7 MMT CO₂ Eq. (see Table 3-32 and Table 3-33). Gross emissions are reduced by CH₄ recovered and used at 37 mines, resulting in net emissions in 2014 of 6.3 MMT CO₂ Eq.

Table 3-32: CH₄ Emissions from Abandoned Coal Mines (MMT CO₂ Eq.)

Activity	1990	2005	2010	2011	2012	2013	2014
Abandoned Underground Mines	7.2	8.4	9.7	9.3	8.9	8.8	8.7
Recovered & Used	+	1.8	3.2	2.9	2.7	2.6	2.4
Total	7.2	6.6	6.6	6.4	6.2	6.2	6.3

+ Does not exceed 0.05 MMT CO₂ Eq.

Note: Totals may not sum due to independent rounding.

⁶⁸ A mine is considered a “gassy” mine if it emits more than 100 thousand cubic feet of CH₄ per day (100 mcf/d).

Table 3-33: CH₄ Emissions from Abandoned Coal Mines (kt)

Activity	1990	2005	2010	2011	2012	2013	2014
Abandoned Underground Mines	288	334	389	373	358	353	350
Recovered & Used	+	70	126	116	109	104	97
Total	288	264	263	257	249	249	253

+ Does not exceed 0.5 kt

Note: Totals may not sum due to independent rounding.

Methodology

Estimating CH₄ 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 CH₄ 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 CH₄ 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 CH₄ emissions over time for a given abandoned 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 CH₄ leaves the system, the reservoir pressure (Pr) declines as described by the isotherm's characteristics. The emission rate declines because the mine pressure (Pw) is essentially constant at atmospheric pressure for a vented mine, and the productivity index (PI), which is expressed as the flow rate per unit of pressure change, is essentially constant at the pressures of interest (atmospheric to 30 psia). The CH₄ flow rate is determined by the laws of gas flow through porous media, such as Darcy's Law. 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:

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

where,

- q = Gas flow rate at time t in million cubic feet per day (mmcf/d)
- q_i = Initial gas flow rate at time zero (t₀), mmcf/d
- b = The hyperbolic exponent, dimensionless
- D_i = Initial decline rate, 1/yr
- t = Elapsed time from t₀ (years)

This equation is applied to mines of various initial emission rates that have similar initial pressures, permeability and adsorption isotherms (EPA 2004).

The decline curves created to model the gas emission rate of coal mines must account for factors that decrease the rate of emissions 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 will no longer have any measurable CH₄ emissions. Based on this assumption, an average decline rate for flooded 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 2004).

$$q = q_i e^{-Dt}$$

where,

- q = Gas flow rate at time t in mmcf/d
- q_i = Initial gas flow rate at time zero (t₀), mmcf/d
- D = Decline rate, 1/yr
- t = Elapsed time from t₀ (years)

Seals have an inhibiting effect on the rate of flow of CH₄ into the atmosphere compared to the flow rate that would exist if the mine had an open vent. The total volume emitted will be the same, but emissions will occur over a longer period of time. The methodology, therefore, treats the emissions prediction from a sealed mine similarly to the emissions prediction from a vented mine, but uses a lower initial rate depending on the degree of sealing. A computational fluid dynamics simulator was used with the conceptual abandoned mine model to predict the decline curve for inhibited flow. The percent sealed is defined as $100 \times (1 - [\text{initial emissions from sealed mine} / \text{emission rate at abandonment prior to sealing}])$. 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 2004).

For active coal mines, those mines producing over 100 thousand cubic feet per day (mcf/d) account for 98 percent of all CH₄ emissions. This same relationship is assumed for abandoned mines. It was determined that the 500 abandoned mines closed after 1972 produced emissions greater than 100 mcf/d when active. Further, the status of 291 of the 500 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 CH₄ flow to the atmosphere). The remaining 42 percent of the mines whose status is unknown were placed in one of these three categories by applying a probability distribution analysis based on the known status of other mines located in the same coal basin (EPA 2004).

Table 3-34: Number of Gassy Abandoned Mines Present in U.S. Basins in 2014, grouped by Class according to Post-Abandonment State

Basin	Sealed	Vented	Flooded	Total Known	Unknown	Total Mines
Central Appl.	37	25	51	113	137	250
Illinois	32	3	14	49	27	76
Northern Appl.	43	22	16	81	36	117
Warrior Basin	0	0	16	16	0	16
Western Basins	27	3	2	32	9	41
Total	139	53	99	291	209	500

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

During the 1970s, 78 percent of CH₄ 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 the 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 CH₄ emissions rates during the 1970s (EPA 2004).

Abandoned mine emission estimates are based on all closed mines known to have active mine CH₄ ventilation emission rates greater than 100 mcf/d 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 (MSHA 2015). 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. CH₄ degasification amounts were added to the quantity of CH₄ vented to determine the total CH₄ liberation rate for all mines that closed between 1992 and 2014. Since the sample of gassy mines is assumed to

account for 78 percent of the pre-1972 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 2014, emission totals were downwardly adjusted to reflect abandoned mine CH₄ emissions avoided from those mines. The Inventory totals were not adjusted for abandoned mine reductions from 1990 through 1992 because no data was reported for abandoned coal mining CH₄ 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) CH₄ 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 rather 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 Approach 2 quantitative uncertainty analysis are summarized in Table 3-35. Annual abandoned coal mine CH₄ emissions in 2014 were estimated to be between 5.2 and 7.9 MMT CO₂ Eq. at a 95 percent confidence level. This indicates a range of 18 percent below to 24 percent above the 2014 emission estimate of 6.3 MMT CO₂ Eq. One of the reasons for the relatively narrow range is that mine-specific data is available for use in the methodology for mines closed after 1972. Emissions from mines closed prior to 1972 have the largest degree of uncertainty because no mine-specific CH₄ liberation rates exist.

Table 3-35: Approach 2 Quantitative Uncertainty Estimates for CH₄ Emissions from Abandoned Underground Coal Mines (MMT CO₂ Eq. and Percent)

Source	Gas	2014 Emission Estimate (MMT CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate ^a			
			Lower Bound	Upper Bound	Lower Bound (%)	Upper Bound (%)
Abandoned Underground Coal Mines	CH ₄	6.3	5.2	7.9	-18%	+24%

^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 2014. Details on the emission trends through time are described in more detail in the Methodology section, above.

3.6 Petroleum Systems (IPCC Source Category 1B2a)

Methane emissions from petroleum systems are primarily associated with onshore and offshore crude oil production, transportation, and refining operations. During these activities, CH₄ is released to the atmosphere as fugitive emissions, vented emissions, emissions from operational upsets, and emissions from fuel combustion. Fugitive and vented CO₂ emissions from petroleum systems are primarily associated with crude oil production and refining

operations but are negligible in transportation operations. Total CH₄ emissions from petroleum systems in 2014 were 68.1 MMT CO₂ Eq. (2,726 kt).

Production Field Operations. Production field operations account for approximately 99 percent of total CH₄ emissions from petroleum systems. Vented CH₄ from field operations account for approximately 92 percent of the net emissions from the production sector, fugitive emissions are approximately 5 percent, uncombusted CH₄ emissions (i.e., unburned fuel) account for approximately 4 percent, and process upset emissions are 0.1 percent. The most dominant sources of emissions from production field operations are pneumatic controllers, oil tanks, chemical injection pumps, offshore oil platforms, hydraulic fractured oil well completions, gas engines, and oil wellheads. These sources alone emit over 95 percent of the production field operations emissions. The remaining 5 percent of the emissions are distributed among around 20 additional activities.

Since 1990, CH₄ emissions from production field operations have increased by nearly 80 percent. Total methane emissions (from all segments) have increased by around 5 percent from 2013 levels.

Vented CO₂ associated with production field operations account for approximately 99 percent of the total CO₂ emissions from production field operations, while fugitive and process upsets together account for approximately 1 percent of the emissions. The most dominant sources of CO₂ emissions are oil tanks, pneumatic controllers, chemical injection pumps, and offshore oil platforms. These five sources together account for slightly over 97 percent of the non-combustion CO₂ emissions from production field operations, while the remaining 3 percent of the emissions is distributed among around 20 additional activities. Note that CO₂ from associated gas flaring is accounted in natural gas systems production emissions. Total CO₂ emissions from flaring for both natural gas and oil were 20.8 MMT CO₂ Eq. in 2014.

Crude Oil Transportation. Crude oil transportation activities account for approximately 0.3 percent of total CH₄ emissions from the oil industry. Venting from tanks, truck loading, rail loading, and marine vessel loading operations account for 84 percent of CH₄ emissions from crude oil transportation. Fugitive emissions, almost entirely from floating roof tanks, account for approximately 12 percent of CH₄ emissions from crude oil transportation. The remaining 4 percent is distributed between two additional sources within the vented emissions category (i.e., pump station maintenance and pipeline pigging), and fugitive emissions from pump stations.

Since 1990, CH₄ emissions from transportation have increased by almost 24 percent. However, because emissions from crude oil transportation account for such a small percentage of the total emissions from the petroleum industry, this has had little impact on the overall emissions. Methane emissions from transportation have increased by approximately 13 percent from 2013 levels.

Crude Oil Refining. Crude oil refining processes and systems account for approximately 1 percent of total CH₄ emissions from the oil industry because most of the CH₄ in crude oil is removed or escapes before the crude oil is delivered to the refineries. There is an insignificant amount of CH₄ in all refined products. Within refineries, combustion emissions account for slightly over 50 percent of the CH₄ emissions, while vented and fugitive emissions account for approximately 31 and 19 percent, respectively. Flare emissions are the primary combustion emissions contributor, accounting for approximately 79 percent of combustion CH₄ emissions. Refinery system blowdowns for maintenance and process vents are the primary venting contributors (96 percent). Most of the fugitive CH₄ emissions from refineries are from equipment leaks and storage tanks (89 percent).

Methane emissions from refining of crude oil have decreased by approximately 1.4 percent since 1990; however, similar to the transportation subcategory, this decrease has had little effect on the overall emissions of CH₄. Since 1990, CH₄ emissions from crude oil refining have fluctuated between 23 and 28 kt.

Flare emissions from crude oil refining accounts for slightly more than 94 percent of the total CO₂ emissions in petroleum systems. Refinery CO₂ emissions decreased by slightly more than 7 percent from 1990 to 2014.

Table 3-36: CH₄ Emissions from Petroleum Systems (MMT CO₂ Eq.)

Activity	1990	2005	2010	2011	2012	2013	2014
Production Field Operations							
(Potential)	38.0	48.9	54.8	56.6	58.7	64.7	68.1
Pneumatic controller venting ^a	19.0	30.2	33.2	33.7	33.3	37.7	39.2
Tank venting	6.3	4.7	5.3	5.5	7.0	8.2	9.9
Combustion & process upsets	2.9	2.3	2.5	2.5	2.7	2.9	3.1
Misc. venting & fugitives	8.4	10.5	12.5	13.5	14.3	14.3	14.5

Wellhead fugitives	1.5	1.2	1.4	1.4	1.5	1.5	1.5
Production Voluntary Reductions	(0.0)	(0.9)	(1.5)	(1.1)	(1.1)	(0.8)	(0.8)
Production Field Operations (Net)	38.0	48.0	53.3	55.4	57.5	63.9	67.4
Crude Oil Transportation	0.2	0.1	0.1	0.1	0.2	0.2	0.2
Refining	0.6	0.7	0.6	0.7	0.7	0.6	0.6
Total	38.7	48.8	54.1	56.3	58.4	64.7	68.1

^a Values presented in this table for pneumatic controllers are net emissions. The revised methodology for the 2016 (current) Inventory incorporates GHGRP subpart W activity and emissions data, and is detailed in the Recalculations Discussion section.

Notes: Totals may not sum due to independent rounding. Parentheses indicate emissions reductions.

Table 3-37: CH₄ Emissions from Petroleum Systems (kt)

Activity	1990	2005	2010	2011	2012	2013	2014
Production Field Operations (Potential)	1,519	1,957	2,193	2,263	2,347	2,586	2,725
Pneumatic controller venting ^a	761	1,209	1,328	1,346	1,332	1,509	1,567
Tank venting	250	188	210	220	278	330	396
Combustion & process upsets	115	91	98	101	108	114	122
Misc. venting & fugitives	334	421	502	540	570	573	578
Wellhead fugitives	59	48	54	56	59	60	62
Production Voluntary Reductions	(0)	(36)	(60)	(45)	(45)	(31)	(31)
Production Field Operations (Net)	1,519	1,921	2,133	2,218	2,302	2,556	2,694
Crude Oil Transportation	7	5	5	5	6	7	8
Refining	24	27	26	28	27	26	23
Total	1,550	1,953	2,163	2,251	2,335	2,588	2,726

^a Values presented in this table for pneumatic controllers are net emissions. The revised methodology for the 2016 (current) Inventory incorporates GHGRP subpart W activity and emissions data, and is detailed in the Recalculations Discussion section.

Notes: Totals may not sum due to independent rounding. Parentheses indicate emissions reductions.

Table 3-38: CO₂ Emissions from Petroleum Systems (MMT CO₂ Eq.)

Activity	1990	2005	2010	2011	2012	2013	2014
Production Field Operations	0.4	0.3	0.4	0.4	0.5	0.6	0.6
Pneumatic controller venting	+	0.1	0.1	0.1	0.1	0.1	0.1
Tank venting	0.3	0.2	0.3	0.3	0.4	0.4	0.5
Misc. venting & fugitives	+	+	+	+	+	+	+
Wellhead fugitives	+	+	+	+	+	+	+
Process upsets	+	+	+	+	+	+	+
Crude Refining	3.2	3.6	3.8	3.8	3.4	3.1	2.9
Total	3.6	3.9	4.2	4.2	3.9	3.7	3.6

+ Does not exceed 0.05 MMT CO₂ Eq.

Note: Totals may not sum due to independent rounding.

Table 3-39: CO₂ Emissions from Petroleum Systems (kt)

Activity	1990	2005	2010	2011	2012	2013	2014
Production Field Operations	391	338	379	395	473	550	640
Pneumatic controller venting	42	67	74	75	74	84	87
Tank venting	328	246	276	288	365	432	519
Misc. venting & fugitives	17	21	26	28	30	30	30
Wellhead fugitives	3	3	3	3	3	3	3
Process upsets	0.2	0.1	0.2	0.2	0.2	0.2	0.2
Crude Refining	3,162	3,589	3,775	3,797	3,404	3,143	2,927
Total	3,553	3,927	4,154	4,192	3,876	3,693	3,567

Note: Totals may not sum due to independent rounding.

Methodology

The estimates of CH₄ emissions from petroleum systems are largely based on GRI/EPA 1996, EPA 1999, and EPA's GHGRP data (EPA 2015a). Petroleum Systems includes emission estimates for activities occurring in petroleum systems from the oil wellhead through crude oil refining, including activities for crude oil production field operations, crude oil transportation activities, and refining operations. Annex 3.5 provides detail on the emission estimates for these activities. The estimates of CH₄ emissions from petroleum systems do not include emissions downstream of oil refineries because these emissions are negligible.

Emissions are estimated for each activity by multiplying emission factors (e.g., emission rate per equipment or per activity) by the corresponding activity data (e.g., equipment count or frequency of activity).

References for emission factors include DrillingInfo (2015), "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 and BOEM reports (BOEMRE 2004, BOEM 2011), analysis of BOEMRE data (EPA 2005, BOEMRE 2004), and the GHGRP (2010 through 2014).

Emission factors from EPA 1999 are used for all activities except those related to pneumatic controllers, chemical injection pumps, hydraulic fractured oil well completions, offshore oil production, field storage tanks, and refineries. The emission factors for pneumatic controllers venting and chemical injection pumps were developed using EPA's GHGRP data for reporting year 2014. Emission factors for hydraulically fractured (HF) oil well completions (controlled and uncontrolled) were developed using data analyzed for the 2015 NSPS OOOOa proposal (EPA 2015b). 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 2011). For offshore oil production, two emission factors were calculated using data collected for all federal offshore platforms (EPA 2015c, BOEM 2014), one for oil platforms in shallow water, and one for oil platforms in deep water. For all sources, emission factors are held constant for the period 1990 through 2014.

References for activity data include DrillingInfo (2015), the Energy Information Administration annual and monthly reports (EIA 1990 through 2015), (EIA 1995 through 2015a, 2015b), "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 and BOEM reports (BOEMRE 2004, BOEM 2011), analysis of BOEMRE data (EPA 2005, BOEMRE 2004), the Oil & Gas Journal (OGJ 2015), the Interstate Oil and Gas Compact Commission (IOGCC 2012), the United States Army Corps of Engineers, (1995 through 2015), and the GHGRP (2010 through 2014).

For many sources, complete activity data were not available for all years of the time series. In such cases, one of three approaches was employed. Where appropriate, the activity data were calculated from related statistics using ratios developed based on EPA 1996, and/or GHGRP data. In other cases, the activity data were held constant from 1990 through 2014 based on EPA (1999). Lastly, the previous year's data were used when data for the current year were unavailable. For offshore production, the number of platforms in shallow water and the number of platforms in deep water are used as activity data and are taken from Bureau of Ocean Energy Management (BOEM) (formerly Bureau of Ocean Energy Management, Regulation, and Enforcement [BOEMRE]) datasets (BOEM 2011a,b,c).

For petroleum refining activities, 2010 to 2014 emissions were directly obtained from EPA's GHGRP. All refineries have been required to report CH₄ and CO₂ emissions for all major activities since 2010. The national totals of these emissions for each activity were used for the 2010 to 2014 emissions. The national emission totals for each activity were divided by refinery feed rates for those four Inventory years to develop average activity-specific emission factors, which were used to estimate national emissions for each refinery activity from 1990 to 2009 based on national refinery feed rates for each year (EPA 2015d).

The Inventory estimate for Petroleum Systems takes into account Natural Gas STAR reductions. Voluntary reductions included in the Petroleum Systems calculations were those reported to Natural Gas STAR for the following activities: artificial lift - gas lift; artificial lift - use compression; artificial lift - use pumping unit; consolidate crude oil production and water storage tanks; lower heater-treater temperature; re-inject gas for enhanced oil recovery; re-inject gas into crude; and route casinghead gas to vapor recovery unit or compressor.

The methodology for estimating CO₂ emissions from petroleum systems includes calculation of vented, fugitive, and process upset emissions sources from 29 activities for crude oil production field operations and three activities from petroleum refining. Generally, emissions are estimated for each activity by multiplying CO₂ emission factors by their corresponding activity data. The emission factors for CO₂ are generally estimated by multiplying the CH₄ emission factors by a conversion factor, which is the ratio of CO₂ content and CH₄ content in produced associated gas. One exception to this methodology is the set of emission factors for crude oil storage tanks, which are obtained from E&P Tank simulation runs, and the emission factors for offshore oil production (shallow and deep water), which were derived using data from BOEM (EPA 2015c, BOEM 2014). Other exceptions to this methodology are the three petroleum refining activities (i.e., flares, asphalt blowing, and process vents); the CO₂ emissions data for 2010 to 2014 were directly obtained from the GHGRP. The 2010 to 2013 CO₂ emissions data from GHGRP along with the refinery feed data for 2010 to 2013 were used to derive CO₂ emission factors (i.e., sum of activity emissions/sum of refinery feed) which were then applied to the annual refinery feed to estimate CO₂ emissions for 1990 to 2009.

Uncertainty and Time-Series Consistency

The most recent uncertainty analysis for the petroleum systems emission estimates in the Inventory was conducted for the 1990 to 2009 Inventory that was released in 2011. Since the analysis was last conducted, several of the methods used in the Inventory have changed, and industry practices and equipment have evolved. In addition, new studies and other data sources such as those discussed in the sections below offer improvement to understanding and quantifying the uncertainty of some emission source estimates. EPA is planning an update to the uncertainty analysis conducted for the 2011 Inventory to reflect the new information. It is difficult to project whether updated uncertainty bounds around CH₄ emission estimates would be wider, tighter, or about the same as the current uncertainty bounds that were developed for the Inventory published in 2011 (i.e., minus 24 percent and plus 149 percent). Details on EPA's planned uncertainty analysis are described in the Planned Improvements section.

EPA conducted a quantitative uncertainty analysis for the 2011 Inventory to determine the level of uncertainty surrounding estimates of emissions from petroleum systems using the IPCC-recommended Approach 2 methodology (Monte Carlo Simulation technique). The @RISK software model was used to quantify the uncertainty associated with the emission estimates using the 7 highest-emitting sources ("top 7 sources") for the year 2010. The @RISK 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 IPCC guidance notes that in using this method, "some uncertainties that are not addressed by statistical means may exist, including those arising from omissions or double counting, or other conceptual errors, or from incomplete understanding of the processes that may lead to inaccuracies in estimates developed from models." As a result, the understanding of the uncertainty of emission estimates for this category evolves and improves as the underlying methodologies and datasets improve.

The uncertainty analysis conducted for the 2011 Inventory has not yet been updated for the 1990 through 2014 Inventory years; instead, EPA has applied the uncertainty percentage ranges calculated previously to 2014 emission estimates. The majority of sources in the current Inventory were calculated using the same emission factors and activity data for which PDFs were developed in the 1990 through 2009 uncertainty analysis. However, as discussed in the Methodology and Recalculations Discussion sections, EPA has revised the methodology and data for many emission sources. Given these revisions, the 2009 uncertainty ranges applied may not reflect the uncertainty associated with the recently revised emission factors and activity data sources.

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 2014, based on the previously conducted uncertainty assessment using the recommended IPCC methodology. The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 3-40. Petroleum systems CH₄ emissions in 2014 were estimated to be between 51.8 and 101.5 MMT CO₂ Eq., while CO₂ emissions were estimated to be between 2.7 and 5.4 MMT CO₂ Eq. at a 95 percent confidence level, based on previously calculated uncertainty. This indicates a range of 24 percent below to 149 percent above the 2014 emission estimates of 68.1 and 3.6 MMT CO₂ Eq. for CH₄ and CO₂, respectively.

Table 3-40: Approach 2 Quantitative Uncertainty Estimates for CH₄ Emissions from Petroleum Systems (MMT CO₂ Eq. and Percent)

Source	Gas	2014 Emission Estimate (MMT CO ₂ Eq.) ^b	Uncertainty Range Relative to Emission Estimate ^a			
			(MMT CO ₂ Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Petroleum Systems	CH ₄	68.1	51.8	101.5	-24%	149%
Petroleum Systems	CO ₂	3.6	2.7	5.4	-24%	149%

^a Range of 2014 relative uncertainty predicted by Monte Carlo Stochastic 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.

EPA compared the quantitative uncertainty estimate for CH₄ emissions from petroleum systems to those reported in the recently published study by Lyon et al., (2015) (see “Additional Information and Updates under Consideration for Natural Gas and Petroleum Systems Uncertainty Estimates” [EPA 2016a]).⁶⁹ Lyon et al., (2015) used the Monte Carlo simulation technique to examine uncertainty bounds for the estimates developed by that study for the Barnett Shale. The uncertainty range in the study differ from those of EPA. However, it is difficult to extrapolate an uncertainty range from this study that can be applied to the Inventory estimate because the coverage of the Lyon et al. (2015) study is limited to the 25-county Barnett Shale area, the reported estimate encompasses natural gas in addition to petroleum system emissions, and the two estimates use different methodologies and data sources.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2014. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification Discussion

The petroleum system emission estimates in the Inventory are continually being reviewed and assessed to determine whether emission factors and activity factors accurately reflect current industry practices. A QA/QC analysis was performed for data gathering and input, documentation, and calculation. QA/QC checks are consistently conducted to minimize human error in the model calculations. EPA performs a thorough review of information associated with new studies, GHGRP data, regulations, public webcasts, and the Natural Gas STAR Program to assess whether the assumptions in the Inventory are consistent with current industry practices. In addition, EPA receives feedback through the annual expert and public review period. Feedback received is noted in the Recalculations and Planned Improvement sections.

Recalculations Discussion

The EPA received information and data related to the emission estimates through the Inventory preparation process, previous Inventories’ formal public notice periods, GHGRP data, and new studies. The EPA carefully evaluated relevant information available, and made revisions to the production segment methodology for the 2016 (current) Inventory including revised equipment activity data, revised pneumatic controller activity and emissions data, and included a separate estimate for hydraulically fractured oil well completions, which previously were not estimated as a distinct subcategory of oil well completions.

In February 2016, the EPA released a draft memorandum, “Revisions under Consideration for Natural Gas and Petroleum Production Emissions,” that discussed the changes under consideration and requested stakeholder

⁶⁹ See <<https://www3.epa.gov/climatechange/ghgemissions/usinventoryreport/natural-gas-systems.html>>.

feedback on those changes. Please see <https://www3.epa.gov/climatechange/ghgemissions/usinventoryreport/natural-gas-systems.html>.

The combined impact of revisions to 2013 petroleum production segment emissions, compared to the 1990-2013 Inventory, is an increase in CH₄ emissions from 24.2 to 63.9 MMT CO₂ Eq. (40 MMT CO₂ Eq., or 164 percent).

The recalculations resulted in an average increase in emission estimates across the 1990 to 2013 time series, compared to the previous (2015) Inventory, of 21 MMT CO₂ Eq., or an 85 percent. The largest increases in the estimate occurred in later years of the time series.

Production

This section references the final 2016 (current) Inventory memorandum, “Revisions to Natural Gas and Petroleum Production Emissions” (EPA 2016b).⁷⁰ “Revisions to Natural Gas and Petroleum Production Emissions” contains further details and documentation of recalculations (EPA 2016b).

Updated activity factors for fugitives, pumps and controllers

Using newly available GHGRP activity data, the EPA developed activity factors (i.e., counts per oil well) for separators, headers, heater-treaters, pneumatic pumps, and pneumatic controllers. EPA reviewed this new data source and the previous data, assessed stakeholder feedback, and determined that the previous data source represents activities from the time period in which the data were collected (early 1990s) and the new GHGRP data source represents activities from recent years. The EPA applied the updated activity factors to calculate emissions from these sources for year 2011-on in the 2016 (current) Inventory petroleum production segment, while retaining the previous activity factors for 1990 through 1992. For years 1993 through 2010, the EPA calculated equipment counts by linearly interpolating between the data points of calculated national equipment counts in 1992 (based on GRI/EPA) and calculated national equipment counts in 2011 (based on GHGRP). This reflects an assumed gradual transition from the counts observed in the 1996 study and the counts observed in the recent GHGRP data.

For the year 2013, the CH₄ emissions increase due to use of revised activity factors for major equipment and pneumatic pumps is approximately 4.2 MMT CO₂ Eq.

Table 3-41: CH₄ Emissions from Sources with Updates to use GHGRP Data (MMT CO₂ Eq.)

Type	Source	1990	2005	2010	2013	2014
Venting	Chemical Injection Pumps	1.2	3.4	4.3	4.7	4.8
	<i>Previous-Chemical</i>					
<i>Venting</i>	<i>Injection Pumps</i>	<i>1.4</i>	<i>1.2</i>	<i>1.3</i>	<i>1.4</i>	
Fugitive	Oil Wellheads	1.5	1.2	1.4	1.5	1.5
<i>Fugitive</i>	<i>Previous-Oil Wellheads</i>	<i>1.5</i>	<i>1.2</i>	<i>1.3</i>	<i>1.5</i>	
Fugitive	Separators	0.3	0.6	0.8	0.8	0.9
<i>Fugitive</i>	<i>Previous-Separators</i>	<i>0.3</i>	<i>0.2</i>	<i>0.2</i>	<i>0.3</i>	
Fugitive	Heater/Treaters	0.3	0.3	0.4	0.4	0.4
<i>Fugitive</i>	<i>Previous-Heater/Treaters</i>	<i>0.3</i>	<i>0.2</i>	<i>0.3</i>	<i>0.3</i>	
Fugitive	Headers	0.1	0.2	0.2	0.2	0.2
<i>Fugitive</i>	<i>Previous-Headers</i>	<i>0.1</i>	<i>0.1</i>	<i>0.1</i>	<i>0.1</i>	
Fugitive	Compressors	0.1	+	+	0.1	0.1
<i>Fugitive</i>	<i>Previous-Compressors</i>	<i>0.1</i>	+	+	+	

+ Does not exceed 0.05 MMT CO₂ Eq.

Note: Values in *italics* are from the previous Inventory.

Using the GHGRP data, the EPA has also developed technology-specific activity data and emission factors for pneumatic controllers. Data reported under EPA’s GHGRP allow for development of emission factors specific to bleed type (continuous high bleed, continuous low bleed, and intermittent bleed) and separation of activity data into these categories. EPA used this separation of pneumatic controller counts by bleed types and emission factors developed from reported GHGRP data. Comparing the updated 2013 estimate to the previous Inventory 2013

⁷⁰ See <<https://www3.epa.gov/climatechange/ghgemissions/usinventoryreport/natural-gas-systems.html>>.

estimate, the impact of using bleed type-specific emission factors and activity data developed from GHGRP data is an increase of approximately 26 MMT CO₂ Eq. Over the 1990 through 2013 time series, the average increase due to the recalculation is 16 MMT CO₂ Eq.

Table 3-42: CH₄ Emissions from Pneumatic Controllers (MMT CO₂ Eq.)

Source	1990	2005	2010	2013	2014
All	19.0	30.2	33.2	37.7	39.2
High bleed	17.8	17.5	12.6	5.5	4.7
Low bleed	1.2	1.8	2.0	1.4	1.2
Intermittent bleed	+	10.9	18.6	30.9	33.3
<i>Previous-All</i>	<i>12.2</i>	<i>10.1</i>	<i>10.8</i>	<i>11.9</i>	<i>NA</i>
<i>Previous-High bleed</i>	<i>9.5</i>	<i>7.8</i>	<i>8.4</i>	<i>9.2</i>	<i>NA</i>
<i>Previous-Low bleed</i>	<i>2.8</i>	<i>2.3</i>	<i>2.4</i>	<i>2.7</i>	<i>NA</i>

+ Does not exceed 0.05 MMT CO₂ Eq.

NA – Not applicable

Note: Values in *italics* are from the previous Inventory.

The EPA’s approach to revising the Inventory methodology by incorporating technology-specific GHGRP data for pneumatic controllers resulted in net emissions being directly calculated for these sources in each time series year. This methodology revision obviates the need to apply Gas STAR reductions data for pneumatic controllers as had been done in previous Inventories. EPA removed the pneumatic controller Gas STAR reductions from its calculations.

Oil Well Completions

The Inventory previously did not distinguish between oil well completions and workovers with hydraulic fracturing (HF) and oil well completions and workovers without hydraulic fracturing. The Inventory emission factors for all oil well completions and workovers were developed using an assumption that all oil well workovers and completions are flared. In the current Inventory, an estimate for the subcategories of oil well completions with hydraulic fracturing with and without controls was included. This estimate was developed using an uncontrolled emission factor developed as part of the analysis supporting the OOOOa NSPS proposal (7.5 tons CH₄/completion)⁷¹, and a controlled emission factor that assumes 95 percent control efficiency (0.4 tons CH₄/completion). For the OOOOa proposal analysis, EPA extracted gas production data from oil well records in DrillingInfo, and developed average daily gas production rates (over the first month of production) for wells that were determined to have been completed with hydraulic fracturing in 2012. The average value for these wells was 255.47 Mcf/day. This was then multiplied by a 3 day completion duration, and a methane content value of 47 percent to develop the uncontrolled factor. Total annual national HF oil well completion data were developed from DrillingInfo data (DrillingInfo 2015). The Inventory uses the NSPS OOOOa proposal information for the percentage of oil well completions that are controlled due to state regulations, 7 percent and applies that value beginning in 2008. It is assumed in the inventory estimate that prior to 2008, all oil well completions with HF are uncontrolled. The inventory continues to use one estimate for workover emissions for completions of all types (i.e. both hydraulically fractured and non-hydraulically fractured). This recalculation results in a 3 MMT CO₂ Eq. increase from the previous 2013 estimate for completions and workovers, and an average increase of 1 MMT CO₂ Eq. over the 1990 through 2013 time series.

Table 3-43: CH₄ Emissions from Oil Well Completions and Workovers (C&W) (MMT CO₂ Eq.)

Source	1990	2005	2010	2013	2014
HF Completions	0.6	0.9	1.7	3.0	3.0
NonHF Completions	+	+	+	+	+
Workovers (HF and nonHF)	+	+	+	+	+
Total C&W	0.6	0.9	1.7	3.0	3.0

⁷¹ The value presented in the NSPS proposal, 9.72 short tons was the average emissions calculated for the subset of HF oil well completions with GOR >300 scf/bbl. The inventory averaged emissions from the same base data set, without the GOR <300 scf/bbl exclusion, so that for the inventory, the emission factor can be applied to all HF oil well completions in the U.S., including those with lower GOR.

Previous Total C&W + ■ + ■ + ■ + *NA*

+ Does not exceed 0.05 MMT CO₂ Eq.

Note: Values in *italics* are from the previous Inventory.

Planned Improvements

In response to the public review draft and earlier released memorandum outlining potential revisions to the production segment, EPA received feedback from stakeholders that will be further considered to refine future Inventories.

In the production segment, some commenters suggested that the approach taken overestimates equipment counts in the production segment, while others suggested that the approach was appropriate. The EPA will further consider how activity factors developed from GHGRP data may over- or under-represent equipment counts for non-GHGRP facilities (those not meeting the emissions reporting threshold). Preliminary assessment by EPA of this issue by disaggregating GHGRP reporter data by number of wells reported indicated that reporters with fewer wells had higher equipment counts per well than average. EPA will continue to explore other methods to assess whether the non-GHGRP population may have different average equipment counts than the reporting population and how this may be reflected in the Inventory. EPA will continue to assess GHGRP data for additional updates to the inventory. While comments received supported the update to include hydraulically fractured oil well completions as a distinct subcategory category, commenters differed on the recommended data for the update (DI Desktop approach versus GHGRP data). EPA will review the first year of reported GHGRP data on hydraulically fractured oil well completions and workovers and will consider how it may be used to update the inventory. Additionally, EPA received comments suggesting that EPA use associated gas venting and flaring data from GHGRP and apply it to the population of associated gas wells in the Inventory, to address the concern that casinghead gas emissions occur at a wider set of associated gas wells, not only at stripper wells. EPA will investigate the appropriateness of using associated gas venting and flaring data from the GHGRP to replace or supplement current estimates of casinghead gas venting from stripper wells in the 2017 Inventory.

In response to the public review memoranda, EPA also received feedback from stakeholders on aspects of emission sources that were not significantly revised in the 2016 (current) Inventory. Stakeholders noted that data generated by Allen et al. in recent studies of pneumatic controller emissions in the production segment might be used to develop a separate emission factor for malfunctioning devices (in addition to the bleed type-specific factors developed from GHGRP data and used in the 2016 [current] Inventory). EPA will evaluate available data studies on this emission source.

EPA will continue to consider stakeholder feedback on the methodology used to develop counts of active oil wells across the time series.

EPA will continue to consider methods to refine the time series. For many sources with, the time series calculations rely on linear interpolation between 1990's data points and 2011 data points.

Abandoned wells are not currently accounted for in the Inventory. EPA is seeking appropriate emission factors and national activity data available to calculate these emissions. Commenters supported including this source category, noted the currently data is limited, and suggested reviewing data that will become available in the future.

Uncertainty

As discussed in the Recalculations Discussion section above, EPA made several revisions to the methodology and data for the 2016 (current) Inventory. As noted in the Uncertainty section above, EPA has not yet updated its uncertainty analysis to reflect this new information. It is difficult to project whether the uncertainty bounds around CH₄ emission estimates would be wider, tighter, or about the same as the current uncertainty bounds that were developed for the Inventory published in 2011 (i.e., minus 24 percent and plus 149 percent) given these revisions.

To update its uncertainty analysis, EPA will conduct a formal quantitative uncertainty analysis similar to that conducted for the 2011 Inventory using the IPCC-recommended Approach 2 methodology (Monte Carlo Simulation technique) using new data and taking into account stakeholder input received. For more information, please see “Additional Information and Updates under Consideration for Natural Gas and Petroleum Systems Uncertainty

Estimates” (EPA 2016a).⁷² As in the 2011 Inventory analysis, EPA will first identify a select number of top-emitting emission sources for each source category. Refer to “Additional Information and Updates under Consideration for Natural Gas and Petroleum Systems Uncertainty Estimates” for more information on planned improvements regarding uncertainty (EPA 2016a).

Box 3-7: 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 CO₂ is produced from both naturally-occurring CO₂ reservoirs and from industrial sources such as natural gas processing plants and ammonia plants. In the Inventory, emissions from naturally-produced CO₂ are estimated based on the specific application.

In the Inventory, CO₂ 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 CO₂ used in EOR operations is assumed to be fully sequestered. Additionally, all anthropogenic CO₂ emitted from natural gas processing and ammonia plants is assumed to be emitted to the atmosphere, regardless of whether the CO₂ 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 includes methodological guidance to estimate emissions from the capture, transport, injection, and geological storage of CO₂. 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 CO₂ 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 CO₂ emissions estimates for geologic storage.

In the United States, facilities that produce CO₂ for various end-use applications (including capture facilities such as acid gas removal plants and ammonia plants), importers of CO₂, exporters of CO₂, facilities that conduct geologic sequestration of CO₂, and facilities that inject CO₂ underground (including facilities conducting EOR), are required to report greenhouse gas data annually to EPA through its GHGRP. Facilities conducting geologic sequestration of CO₂ are required to develop and implement an EPA-approved site-specific monitoring, reporting and verification plan, and to report the amount of CO₂ sequestered using a mass balance approach.

Available GHGRP data relevant for this inventory estimate consists of national-level annual quantities of CO₂ captured and extracted for EOR applications for 2010 to 2014. In the current Inventory, the previous estimates for 2010 to 2013 were replaced with GHGRP data for 2010 to 2013, and estimates for 2014 were directly taken from the reported GHGRP data for 2014. For the year 2013, this update has resulted in an increase of approximately 28 percent over the previous estimate. Using the GHGRP data has resulted in an average annual increase of approximately 11 MMT CO₂ Eq., or by approximately 25 percent, over the time series 2010 through 2013.

EPA will continue to evaluate the availability of additional GHGRP data and other opportunities for improving the emission estimates.

These estimates indicate that the amount of CO₂ captured and extracted from industrial and natural sites for EOR applications in 2014 is 59.3 MMT CO₂ Eq. (59,318 kt) (see Table 3-44 and Table 3-45). Site-specific monitoring and reporting data for CO₂ injection sites (i.e., EOR operations) were not readily available, therefore, these estimates assume all CO₂ is emitted.

Table 3-44: Potential Emissions from CO₂ Capture and Extraction for EOR Operations (MMT CO₂ Eq.)

Stage	1990	2005	2010	2011	2012	2013	2014
Capture Facilities	4.8	6.5	9.9	9.9	9.3	12.2	13.1
Extraction Facilities	20.8	28.3	44.8	48.4	48.9	47.0	46.2
Total	25.6	34.7	54.7	58.2	58.1	59.2	59.3

⁷² See <<https://www3.epa.gov/climatechange/ghgemissions/usinventoryreport/natural-gas-systems.html>>.

Table 3-45: Potential Emissions from CO₂ Capture and Extraction for EOR Operations (kt)

Stage	1990	2005	2010	2011	2012	2013	2014
Capture Facilities	4,832	6,475	9,900	9,877	9,267	12,205	13,093
Extraction Facilities	20,811	28,267	44,759	48,370	48,869	46,984	46,225
Total	25,643	34,742	54,659	58,247	58,136	59,189	59,318

3.7 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 176.1 MMT CO₂ Eq. (7,045 kt) of CH₄ in 2014, a 15 percent decrease compared to 1990 emissions, and a slight (i.e., less than 1 percent) increase compared to 2013 emissions (see Table 3-46, Table 3-47, and Table 3-48) and 42.4 MMT CO₂ Eq. (42,351 kt) of non-combustion CO₂ in 2014, a 12 percent increase compared to 1990 emissions.

The 1990 to 2014 trend is not consistent across segments. Overall, the 1990 to 2014 decrease in CH₄ emissions is due primarily to the decrease in emissions from in the transmission/storage and distribution segments. Over the same time period, the production and processing segments saw increased methane emissions, of 31 and 13 percent, respectively. Natural gas systems also emitted 42.4 MMT CO₂ Eq. (42,351 kt) of non-combustion CO₂ in 2014, a 12 percent increase compared to 1990 emissions, and a 10 percent increase from 2013 emissions (see Table 3-49 and Table 3-50). Both the 1990 to 2014 and the 2013 to 2014 increases in CO₂ are due primarily to flaring; the volume of gas flared increased 93 percent from 1990 and 12 percent from 2013.

CH₄ and non-combustion CO₂ emissions from natural gas systems include those resulting from normal operations, routine maintenance, and system upsets. Emissions from normal operations include: natural gas engine and turbine uncombusted exhaust, bleed and discharge emissions from pneumatic controllers, 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 CH₄ and non-combustion CO₂ emissions are discussed.

Production (including gathering and boosting). In the production stage, wells are used to withdraw raw gas from underground formations. Emissions arise from the wells themselves, and well-site gas treatment facilities such as dehydrators and separators. Gathering and boosting emission sources are not reported under a unique segment, but are included within the production sector. The gathering and boosting segment of natural gas systems comprises gathering and boosting stations (with multiple emission sources on site) and gathering pipelines. The gathering and boosting stations receive natural gas from production sites and transfer it, via gathering pipelines, to transmission pipelines or processing facilities (custody transfer points are typically used to segregate sources between each segment). Emissions from production (including gathering and boosting) account for 62 percent of CH₄ emissions and 44 percent of non-combustion CO₂ emissions from natural gas systems in 2014. Emissions from gathering stations, pneumatic controllers, kimray pumps, liquids unloading, condensate tanks, gathering pipeline leaks, and offshore platforms account for the majority of CH₄ emissions in 2014. Flaring emissions account for the majority of the non-combustion CO₂ emissions. CH₄ emissions from production increased by 31 percent from 1990 to 2014, due primarily to increases in emissions from gathering and boosting stations (due to an increase in the number of stations), increases in emissions from pneumatic controllers (due to an increase in the number of controllers, particularly in the number of intermittent bleed controllers), and condensate tanks (due to an increase in condensate produced). CO₂ emissions from production increased 88 percent from 1990 to 2014 due primarily to increases in flaring.

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 CH₄ emissions from compressors, including compressor seals, are the primary emission source from this stage. The majority of non-combustion CO₂ emissions come from acid gas removal (AGR) units, which are designed to remove CO₂ from natural gas. Processing plants account for 14 percent of CH₄ emissions and 56 percent of non-combustion CO₂ emissions from natural gas systems. CH₄ emissions from processing increased by 13 percent from 1990 to 2014 as emissions from compressors increased along with the quantity of gas produced. CO₂ emissions from processing decreased by 15 percent from 1990 to 2014, as a result of a decrease in acid gas removal emissions.

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 U.S. transmission system. Fugitive CH₄ emissions from these compressor stations, and venting from pneumatic controllers account for the majority of the emissions from this stage. Uncombusted engine exhaust and pipeline venting are also sources of CH₄ emissions from transmission. 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 storage. CH₄ emissions from the transmission and storage sector account for approximately 18 percent of emissions from natural gas systems, while CO₂ emissions from transmission and storage account for less than 1 percent of the non-combustion CO₂ emissions from natural gas systems. CH₄ emissions from this source decreased by 45 percent from 1990 to 2014 due to reduced compressor station emissions (including emissions from compressors and fugitives). CO₂ emissions from transmission and storage have decreased by 37 percent from 1990 to 2014, also due to reduced compressor station emissions.

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 1,264,340 miles of distribution mains in 2014, an increase of over 320,000 miles since 1990 (PHMSA 2015). Distribution system emissions, which account for 6 percent of CH₄ emissions from natural gas systems and less than 1 percent of non-combustion CO₂ emissions, result mainly from fugitive emissions from pipelines and stations. An increased use of plastic piping, which has lower emissions than other pipe materials, has reduced both CH₄ and CO₂ emissions from this stage, as have station upgrades at metering and regulating (M&R) stations. Distribution system CH₄ emissions in 2014 were 74 percent lower than 1990 levels (changed from 43.5 MMT CO₂ Eq. to 11.1 MMT CO₂ Eq.), while distribution CO₂ emissions in 2014 were 72 percent lower than 1990 levels (CO₂ emission from this segment are less than 0.1 MMT CO₂ Eq. across the time series).

Total CH₄ emissions for the four major stages of natural gas systems are shown in MMT CO₂ Eq. (Table 3-46) and kt (Table 3-47). Table 3-48 provides additional information on how the estimates in Table 3-46 were calculated. Table 3-48 shows the calculated CH₄ release (i.e., potential emissions before any controls are applied) from each stage, and the amount of CH₄ that is estimated to have been flared, captured, or otherwise controlled, and therefore not emitted to the atmosphere. Subtracting the value for CH₄ that is controlled, from the value for calculated potential release of CH₄, results in the total emissions values. More disaggregated information on potential emissions and emissions is available in Annex 3.6. See Methodology for Estimating CH₄ and CO₂ Emissions from Natural Gas Systems.

Table 3-46: CH₄ Emissions from Natural Gas Systems (MMT CO₂ Eq.)^a

Stage	1990	2005	2010	2011	2012	2013	2014
Field Production	83.4	108.1	108.3	108.8	111.1	110.7	109.0
Processing	21.3	16.4	17.9	21.3	22.3	22.6	24.0
Transmission and Storage	58.6	30.7	27.5	28.8	27.9	30.8	32.1
Distribution	43.5	22.1	12.5	11.2	11.4	11.5	11.1
Total	206.8	177.3	166.2	170.1	172.6	175.6	176.1

^a These values represent CH₄ emitted to the atmosphere. CH₄ that is captured, flared, or otherwise controlled (and not emitted to the atmosphere) has been calculated and removed from emission totals.

Note: Totals may not sum due to independent rounding.

Table 3-47: CH₄ Emissions from Natural Gas Systems (kt)^a

Stage	1990	2005	2010	2011	2012	2013	2014
Field Production	3,335	4,326	4,330	4,352	4,442	4,429	4,359
Processing	852	655	717	851	890	904	960
Transmission and Storage	2,343	1,230	1,100	1,152	1,116	1,232	1,282
Distribution	1,741	884	500	449	457	458	444
Total	8,270	7,093	6,647	6,803	6,906	7,023	7,045

^a These values represent CH₄ emitted to the atmosphere. CH₄ that is captured, flared, or otherwise controlled (and not emitted to the atmosphere) has been calculated and removed from emission totals.

Note: Totals may not sum due to independent rounding.

Table 3-48: Calculated Potential CH₄ and Captured/Combusted CH₄ from Natural Gas Systems (MMT CO₂ Eq.)

	1990	2005	2010	2011	2012	2013	2014
Calculated Potential^a	206.9	202.7	196.3	196.5	199.6	202.3	203.8
Field Production	83.5	115.7	120.5	121.3	123.6	124.2	123.3
Processing	21.3	20.6	23.6	25.2	26.2	26.5	27.9
Transmission and Storage	58.6	43.1	38.3	37.3	37.3	39.1	40.4
Distribution	43.5	23.3	13.9	12.7	12.5	12.5	12.1
Captured/Combusted^b	0.1	25.4	30.1	26.4	27.0	26.7	27.7
Field Production	0.1	7.6	12.2	12.5	12.5	13.5	14.4
Processing	+	4.2	5.7	3.9	3.9	3.9	4.0
Transmission and Storage	+	12.4	10.8	8.5	9.4	8.3	8.4
Distribution	+	1.2	1.4	1.5	1.1	1.0	1.0
Net Emissions	206.8	177.3	166.2	170.1	172.6	175.6	176.1
Field Production	83.4	108.1	108.3	108.8	111.1	110.7	109.0
Processing	21.3	16.4	17.9	21.3	22.3	22.6	24.0
Transmission and Storage	58.6	30.7	27.5	28.8	27.9	30.8	32.1
Distribution	43.5	22.1	12.5	11.2	11.4	11.5	11.1

+ Does not exceed 0.1 MMT CO₂ Eq.

^a In this context, “potential” means the total emissions calculated before voluntary reductions and regulatory controls are applied.

^b In 2014, over half of the capture and combustion accounted here is in the production segment, while 14 percent is from processing, 30 percent from transmission and storage, and 4 percent from distribution. For additional information, please see Annex 3.6.

Note: Totals may not sum due to independent rounding.

Table 3-49: Non-combustion CO₂ Emissions from Natural Gas Systems (MMT CO₂ Eq.)

Stage	1990	2005	2010	2011	2012	2013	2014
Field Production	9.9	8.3	11.0	14.1	13.7	16.6	18.6
Processing	27.8	21.7	21.3	21.5	21.5	21.8	23.7
Transmission and Storage	0.1	+	+	+	+	+	+
Distribution	0.1	+	+	+	+	+	+
Total	37.7	30.1	32.4	35.7	35.2	38.5	42.4

+ Does not exceed 0.1 MMT CO₂ Eq.

Note: Totals may not sum due to independent rounding.

Table 3-50: Non-combustion CO₂ Emissions from Natural Gas Systems (kt)

Stage	1990	2005	2010	2011	2012	2013	2014
Field Production	9,857	8,260	11,041	14,146	13,684	16,649	18,585
Processing	27,763	21,746	21,346	21,466	21,469	21,756	23,713

Transmission and Storage	62	43	37	36	35	37	39
Distribution	50	27	16	15	14	14	14
Total	37,732	30,076	32,439	35,662	35,203	38,457	42,351

Note: Totals may not sum due to independent rounding.

Methodology

The methodology for natural gas emissions estimates presented in this Inventory involves the calculation of CH₄ and CO₂ emissions for over 100 emissions sources, and then the summation of emissions for each natural gas segment.

The approach for calculating emissions for natural gas systems generally involves the application of emission factors to activity data. For some sources, the approach uses what are considered “potential methane factors,” and reduction data to calculate net emissions; for other sources, the approach uses technology-specific emission factors or emission factors that vary over time to take into account changes to technologies and practices, and these calculate net emissions directly.

The approach of calculating potential CH₄ and then applying reductions data to calculate net emissions was used to ensure a time series that reflects real emission trends. As noted below, key data on emissions from many sources are from 1996 GRI/EPA report containing data collected in 1992. Since the time of this study, practices and technologies have changed. While this study still represents best available data for some emission sources, using these emission factors alone to represent actual emissions without adjusting for emissions controls would, in many cases, overestimate emissions. As updated emission factors reflecting changing practices are not available for some sources, the 1992 emission factors continue to be used for some sources for all years of the Inventory, but they are considered to be potential emissions factors, representing what emissions would be if practices and technologies had not changed over time. For the Inventory, the calculated potential emissions are adjusted using data on reductions reported to the Natural Gas STAR program, and data on regulations that result in CH₄ reductions. The revisions in the current inventory (see Recalculations Discussion below) result in net emission approaches being used for many sources in the inventory.

The calculation of emissions from natural gas systems is outlined below:

Step 1. Calculate Potential Methane (or Net Methane) – Collect activity data on production and equipment in use and apply emission factors (i.e., scf gas per unit or activity)

Step 2. Compile Reductions Data – Calculate the amount of the methane that is not emitted, using data on voluntary action and regulations

Step 3. Calculate Net Emissions – Deduct methane that is not emitted from the total methane potential estimates to develop net CH₄ emissions, and calculate CO₂ emissions

Step 1. Calculate Potential Methane (or Net Methane)—Collect activity data on production and equipment in use and apply emission factors

In the first step, potential CH₄ is calculated by multiplying activity data (such as miles of pipeline or number of wells) by factors that relate that activity data to potential CH₄. Potential CH₄ is the amount of CH₄ that would be emitted in the absence of any control technology or mitigation activity. It is important to note that potential CH₄ factors in most cases do not represent emitted CH₄, and must be adjusted for any emissions-reducing technologies, or practices, as appropriate. For more information, please see the Annex.

Potential Methane Factors and Net Emission Factors

A primary basis for estimates of CH₄ and non-combustion-related CO₂ emissions from the U.S. natural gas industry is a detailed study by the Gas Research Institute (GRI) and EPA (EPA/GRI 1996). The EPA/GRI study developed over 80 CH₄ emission factors to characterize emissions from the various components within the operating stages of the U.S. natural gas system. The EPA/GRI study was based on a combination of process engineering studies, collection of activity data, and measurements at representative gas facilities conducted in the early 1990s. Methane compositions from the Gas Technology Institute (GTI, formerly GRI) Unconventional Natural Gas and Gas

Composition Databases (GTI 2001) are adjusted year to year using gross production for oil and gas supply National Energy Modeling System (NEMS) regions from the EIA. Therefore, emission factors may vary from year to year due to slight changes in the CH₄ composition for each NEMS oil and gas supply module region. The emission factors used to estimate CH₄ were also used to calculate non-combustion CO₂ emissions. Data from GTI 2001 were used to adapt the CH₄ emission factors into non-combustion related CO₂ emission factors. Additional information about CO₂ content in transmission quality natural gas was obtained from numerous U.S. transmission companies to help further develop the non-combustion CO₂ emission factors.

Although the Inventory primarily uses EPA/GRI emission factors (especially for early years of the time series), EPA has made revisions to the potential factor methodology in the emissions estimates for several sources in recent Inventories. For gas well completions and workovers (refracturing) with hydraulic fracturing, EPA uses its Greenhouse Gas Reporting Program (GHGRP) Subpart W data to stratify the emission sources into four different categories and developed CH₄ emission factors for each category. For liquids unloading, EPA calculates national emissions through the use of region-specific emission factors developed from well data collected in a survey conducted by API/ANGA (API/ANGA 2012). In the current Inventory, EPA has used data generated by studies and the GHGRP to develop emission factors that are control category-specific (e.g., bleed rate-specific emission factors for pneumatic controllers in the production and transmission and storage segments) and to reflect current practices for activities (e.g., distribution M&R station emission factors for recent years). For these sources, the emission factors are not potential factors, but are instead factors for net emissions.

See Annex 3.6 for more detailed information on the methodology and data used to calculate CH₄ and non-combustion CO₂ emissions from natural gas systems.

Activity Data

Activity data were taken from the following sources: DrillingInfo, Inc (DrillingInfo 2015); American Gas Association (AGA 1991 through 1998); Bureau of Ocean Energy Management, Regulation and Enforcement (previous Minerals and Management Service) (BOEMRE 2011a, 2011b, 2011c, 2011d); Natural Gas Liquids Reserves Report (EIA 2005); Natural Gas Monthly (EIA 2015a, 2015b, 2015c); the Natural Gas STAR Program annual emissions savings (EPA 2013c); Oil and Gas Journal (OGJ 1997 through 2015); Pipeline and Hazardous Materials Safety Administration (PHMSA 2015a, 2015b); Federal Energy Regulatory Commission (FERC 2015); Greenhouse Gas Reporting Program (EPA 2015); other Energy Information Administration data and publications (EIA 2001, 2004, 2012, 2013, 2014); (EPA 1999); Conservation Commission (Wyoming 2015); and the Alabama State Oil and Gas Board (Alabama 2015).

For a few sources, recent direct activity data are not available. For these sources, either 2013 data was used as a proxy for 2014 data, or a set of industry activity data drivers was developed and used to calculate activity data over the time series. 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. More information on activity data and drivers is available in Annex 3.6.

Step 2. Compile Reductions Data—Calculate the amount of the CH₄ that is not emitted, using data on voluntary action and regulations

The emissions calculated in Step 1 above for many sources represent potential emissions from an activity, and do not take into account use of technologies and practices that reduce emissions. To take into account use of such technologies, data, where available, are collected on both regulatory and voluntary reductions. Regulatory actions taken into account using this method include National Emission Standards for Hazardous Air Pollutants (NESHAP) regulations for dehydrator vents and condensate tanks. Voluntary reductions included in the Inventory are those reported to Natural Gas STAR. For more information on these reductions, please see Annex 3.6. The emission estimates presented in Table 3-46 and Table 3-47 are the CH₄ that is emitted to the atmosphere (i.e., net emissions), not potential emissions without capture or flaring.

The Inventory also includes the impacts of the New Source Performance Standards (NSPS) Subpart OOOO, which came into effect in October 2012. By separating gas well completions and workovers with hydraulic fracturing into four categories and developing control technology-specific CH₄ emission factors for each category, EPA is implicitly accounting for Subpart OOOO reductions from hydraulically fractured gas wells. The method for calculating emissions from pneumatic controllers (by bleed rate category) also implicitly accounts for NSPS reductions in the high bleed pneumatic controller category.

The use of data from the EPA's GHGRP and recent studies to revise certain emission factors as discussed above obviated the need to apply Gas STAR or other reductions data for those sources (i.e., the calculated emissions were already net emissions, instead of potential emissions). More information is in the Recalculations Discussion below.

Step 3. Calculate Net Emissions—Deduct CH₄ that is not emitted from the total CH₄ potential estimates to develop net CH₄ emissions, and calculate CO₂ emissions

In the final step, emission reductions from voluntary and regulatory actions are deducted from the total calculated potential emissions to estimate the net emissions that are presented in Table 3-46, and included in the Inventory totals. As discussed above, for a number of categories (e.g., liquids unloading, condensate tanks, gas well completions and workovers with hydraulic fracturing, gathering stations, centrifugal compressors, pneumatic controllers, transmission and storage station fugitives, M&R stations, and pipeline leaks) emissions are calculated directly using emission factors that vary by technology or over time and account for any control measures in place that reduce CH₄ emissions.

Uncertainty and Time-Series Consistency

The most recent uncertainty analysis for the natural gas and petroleum systems emission estimates in the Inventory was conducted for the 1990 to 2009 Inventory report that was released in 2011. Since the analysis was last conducted, several of the methods used in the Inventory have changed, and industry practices and equipment have evolved. In addition, new studies (e.g., Lamb, et al. 2015; Lyon, et al. 2015; Marchese, et al. 2015; Zimmerle, et al. 2015) and other data sources such as those discussed in the sections below offer improvement to understanding and quantifying the uncertainty of some emission source estimates. EPA is planning an update to the uncertainty analysis conducted for the 2011 Inventory to reflect the new information. At this time, it is difficult to project whether updated uncertainty bounds around CH₄ emission estimates would be wider, tighter, or about the same as the current uncertainty bounds that were developed for the Inventory published in 2011 (i.e., minus 19 percent and plus 30 percent) given the extensive nature of these revisions.

Details on EPA's planned uncertainty analysis are described in the Planned Improvements section.

EPA conducted a quantitative uncertainty analysis for the 2011 Inventory to determine the level of uncertainty surrounding estimates of emissions from natural gas systems using the IPCC-recommended Approach 2 methodology (Monte Carlo Simulation technique). The @RISK software model was used to quantify the uncertainty associated with the emissions estimates using the 12 highest-emitting sources ("top 12 sources") for the year 2009. The @RISK 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 IPCC guidance notes that in using this method, "some uncertainties that are not addressed by statistical means may exist, including those arising from omissions or double counting, or other conceptual errors, or from incomplete understanding of the processes that may lead to inaccuracies in estimates developed from models." As a result, the understanding of the uncertainty of emissions estimates for this category evolves and improves as the underlying methodologies and datasets improve.

The uncertainty analysis conducted for the 2011 Inventory has not yet been updated for this inventory; instead, EPA has applied the uncertainty percentage ranges calculated previously for 2009 to the 2014 emissions estimates. As discussed in the Recalculations Discussion section, EPA has used findings from multiple recently published studies along with GHGRP Subpart W data to revise the emission factors and activity data for many emission sources. Given these substantive revisions, it is unlikely that the 2009 uncertainty ranges applied will reflect the uncertainty associated with the recently revised emission factors and activity data sources. Details on an updated uncertainty analysis to reflect recent recalculations are described in the Planned Improvements section.

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 2014, based on the previously conducted uncertainty assessment using the recommended IPCC methodology. The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 3-51. Natural gas systems CH₄ emissions in 2014 were estimated to be between 142.7 and 229.0 MMT CO₂ Eq. at a 95 percent confidence level, based on previously calculated uncertainty. Natural gas systems non-energy CO₂ emissions in 2014 were estimated to be between 34.3 and 55.1 MMT CO₂ Eq. at a 95 percent confidence level.

Table 3-51: Approach 2 Quantitative Uncertainty Estimates for CH₄ and Non-energy CO₂ Emissions from Natural Gas Systems (MMT CO₂ Eq. and Percent)

Source	Gas	2014 Emission Estimate (MMT CO ₂ Eq.) ^b	Uncertainty Range Relative to Emission Estimate ^a (MMT CO ₂ Eq.)			
			Lower Bound ^b		Upper Bound ^b	
Natural Gas Systems	CH ₄	176.1	142.7	229.0	-19%	+30%
Natural Gas Systems ^c	CO ₂	42.4	34.3	55.1	-19%	+30%

^a Range of emission estimates estimated by applying the 95 percent confidence intervals obtained from the Monte Carlo Simulation analysis conducted for the year 2009.

^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 3-46 and Table 3-47.

^c An uncertainty analysis for the non-energy CO₂ emissions was not performed. The relative uncertainty estimated (expressed as a percent) from the CH₄ uncertainty analysis was applied to the point estimate of non-energy CO₂ emissions

EPA compared the quantitative uncertainty estimates for CH₄ emissions in recent years from natural gas systems to those reported in recently published studies (see “Additional Information and Updates under Consideration for Natural Gas and Petroleum Systems Uncertainty Estimates” [EPA 2016a]).⁷³ All studies reviewed for uncertainty information used the Monte Carlo simulation technique to examine uncertainty bounds for the estimates reported which is in line with the IPCC recommended Approach 2 methodology. The uncertainty ranges in the reported studies differ from those of EPA. However, it is difficult to extrapolate uncertainty ranges from these studies to apply to the Inventory estimates because the Inventory source category level uncertainty analysis is not directly comparable to source- or segment-specific uncertainty analyses in these studies. Further, the methodologies and data sources used in estimating CH₄ emissions in these studies differ significantly from the studies underlying previous Inventory methodologies.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2014. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification Discussion

The natural gas emission estimates in the Inventory are continually being reviewed and assessed to determine whether emission factors and activity factors accurately reflect current industry practices. A QA/QC analysis was performed for data gathering and input, documentation, and calculation. QA/QC checks are consistently conducted to minimize human error in the model calculations. EPA performs a thorough review of information associated with new studies, GHGRP data, regulations, public webcasts, and the Natural Gas STAR Program to assess whether the assumptions in the Inventory are consistent with current industry practices. In addition, EPA receives feedback through annual expert and public review periods. Feedback received is noted in the Recalculations and Planned Improvement sections.

Recalculations Discussion

The EPA received information and data related to the emission estimates through the Inventory preparation process, previous Inventories’ formal public notice periods, GHGRP data, and new studies. The EPA carefully evaluated relevant information available, and made several updates, including revisions to production segment activity data, production segment pneumatic controller activity and emissions data, gathering and boosting facility emissions, transmission and storage station activity and emissions data, distribution segment emissions data for pipelines, distribution segment M&R station activity and emissions data, and distribution segment customer meter emissions data.

⁷³ See <<https://www3.epa.gov/climatechange/ghgemissions/usinventoryreport/natural-gas-systems.html>>.

From December 2015 through February 2016, the EPA released four draft memoranda that discussed the changes under consideration and requested stakeholder feedback on those changes. See “Revisions under Consideration for Natural Gas and Petroleum Production Emissions,” “Revisions under Consideration for Gathering and Boosting Emissions,” “Revisions under Consideration for Transmission and Storage Emissions,” and “Revisions under Consideration for Distribution Emissions,” available at <https://www3.epa.gov/climatechange/ghgemissions/usinventoryreport/natural-gas-systems.html>.

The impact of all revisions to natural gas systems is an increase of 18 MMT CO₂ Eq., or 12 percent, comparing the 2013 value from last year’s Inventory to the current Inventory. Over the time series, the average change is an increase of 13 MMT CO₂ Eq., or 7 percent.

Recalculations for the production segment (including gathering and boosting facilities) resulted in a large increase in the 2013 CH₄ emission estimate, from 47.0 MMT CO₂ Eq. in the previous (2015) Inventory, to 110.7 MMT CO₂ Eq. in the current (2016) Inventory, or 136 percent. Over the time series, the average change is an increase of 35 MMT CO₂ Eq., or 57 percent.

Although there were no methodological updates to the processing segment, recalculations due to updated data (specifically data on national dry gas production in 2013, which were revised slightly downwards) impacted emissions estimates, resulting in a decrease of 0.1 MMT CO₂ Eq., or less than 1 percent comparing the 2013 value from last year’s Inventory to the current Inventory. Over the time series, the average change was less than 1 percent.

Recalculations for the transmission and storage segment resulted in a large decrease in the 2013 CH₄ emission estimate, from 54.4 MMT CO₂ Eq. in the previous (2015) Inventory, to 30.8 MMT CO₂ Eq. in the current (2016) Inventory, or 43 percent. Over the time series, the average change is a decrease of 13 MMT CO₂ Eq., or 25 percent.

Recalculations for the distribution segment also resulted in a large decrease in the 2013 CH₄ emission estimate, from 33.3 MMT CO₂ Eq. in the previous (2015) Inventory, to 11.5 MMT CO₂ Eq. in the current (2016) Inventory, or 65 percent. Over the time series, the average change is a decrease of 9 MMT CO₂ Eq., or 27 percent.

Production

This section references the final 2016 (current) Inventory production segment supporting memoranda: “Revisions to Natural Gas and Petroleum Production Emissions” and “Revisions to Natural Gas Gathering and Boosting Emissions” (EPA 2016b and EPA 2016c).⁷⁴ These memoranda contain further details and documentation of recalculations.

Using newly available GHGRP activity data, the EPA developed activity factors (i.e., counts per gas well) for in-line heaters, separators, dehydrators, compressors, meters/piping, pneumatic pumps, and pneumatic controllers. EPA reviewed this new data source and the previous data, assessed stakeholder feedback, and determined that the previous data source represents activities from the time period in which the data were collected (early 1990s) and the new GHGRP data source represents activities from recent years. The EPA applied the updated activity factors to calculate emissions from these sources for the years from 2011 to 2014 in the 2016 (current) Inventory natural gas production segment, while retaining the previous activity factors for 1990 to 1992. For years 1993 through 2010, the EPA calculated equipment counts by linearly interpolating between the data points of per well equipment counts in 1992 (based on GRI/EPA) and per well equipment counts in 2011 (based on GHGRP). This reflects an assumed gradual transition from the counts per well observed in the 1996 study and the counts observed in the recent GHGRP data.

The production segment activity data revisions not only reflect more current information on activity, but also tailor these emission sources to specifically reflect activity occurring at well pad facilities and not at gathering/centralized facilities. As discussed below and in the two supporting memoranda for the production segment, EPA has also implemented revisions to the gathering and boosting sub-segment so that equipment leaks from both types of facilities are fully, but separately, represented. In the public review draft, EPA noted potential issues with ensuring that vented emissions from certain equipment (e.g., pneumatic controllers, chemical injection pumps, dehydrator vents, and Kimray pumps) are not double-counted or inadvertently excluded due to these methodological revisions.

⁷⁴ See <<https://www3.epa.gov/climatechange/ghgemissions/usinventoryreport/natural-gas-systems.html>>.

The 2016 (current) Inventory methodology for these sources generally addresses this concern. Please refer to “Revisions to Natural Gas and Petroleum Production Emissions” for more information (EPA 2015b).

The impact of using activity factors developed from GHGRP data is an increase in emissions. This increase is shown in Table 3-52. For the year 2013, compared to the previous Inventory, the calculated CH₄ emissions increase due to use of revised activity factors for heaters, separators, dehydrators, compressors, and meters/piping is approximately 0.4 MMT CO₂ Eq. In addition, as dehydrator counts are an input to the calculation of emissions from the dehydrator vent and Kimray pump source, the revision to activity data impacted those estimates as well, resulting in a decrease of 2 MMT CO₂ Eq. for dehydrator vents, and 7 MMT CO₂ Eq. for Kimray pumps (comparing updated 2013 estimate to previous 2013 estimate). For chemical injection pumps, in addition to updating the activity data, emission factors were also recalculated using GHGRP data. This recalculation resulted in an increase in calculated emissions from chemical pumps for 2013 of 1.7 MMT CO₂ Eq., compared with the previous inventory estimate for 2013.

Table 3-52: CH₄ Emissions from Sources with Updates to use GHGRP Data (MMT CO₂ Eq.)

Type	Source	1990	2005	2010	2013	2014
Venting	Chemical Injection Pumps	0.7	2.4	3.3	3.2	3.2
	<i>Previous-Chemical</i>					
<i>Venting</i>	<i>Injection Pumps</i>	<i>0.7</i>	<i>1.4</i>	<i>1.6</i>	<i>1.5</i>	<i>NA</i>
Fugitive	Dehydrators	0.4	0.3	0.2	0.2	0.2
<i>Fugitive</i>	<i>Previous-Dehydrators</i>	<i>0.4</i>	<i>0.7</i>	<i>0.8</i>	<i>0.8</i>	<i>NA</i>
Fugitive	Separators	1.1	2.4	3.0	3.0	3.0
<i>Fugitive</i>	<i>Previous-Separators</i>	<i>1.1</i>	<i>2.1</i>	<i>2.6</i>	<i>2.6</i>	<i>NA</i>
Fugitive	Heaters	0.3	0.5	0.6	0.6	0.6
<i>Fugitive</i>	<i>Previous- Heaters</i>	<i>0.3</i>	<i>0.7</i>	<i>0.8</i>	<i>0.8</i>	<i>NA</i>
Fugitive	Meters/Piping	1.2	2.3	2.7	2.7	2.7
<i>Fugitive</i>	<i>Previous-Meters/Piping</i>	<i>1.3</i>	<i>2.2</i>	<i>2.7</i>	<i>2.6</i>	<i>NA</i>
Fugitive	Compressors	0.8	1.9	2.4	2.4	2.4
<i>Fugitive</i>	<i>Previous-Compressors</i>	<i>0.9</i>	<i>1.5</i>	<i>1.8</i>	<i>1.7</i>	<i>NA</i>

NA – Not applicable

Note: Values in *italics* are from the previous Inventory.

Using the GHGRP data, the EPA also developed technology-specific activity data and emission factors for pneumatic controllers. Reported data under the GHGRP allow for the development of pneumatic controller emission factors specific to bleed type (continuous high bleed, continuous low bleed, and intermittent bleed) and the associated break-out of activity data into these categories. These revised emission factors and bleed type-specific activity data reflect net emissions. Comparing the updated 2013 estimate to the previous Inventory 2013 estimate, the impact of using bleed type-specific emission factors and activity data developed from GHGRP data on pneumatic controller emissions is an increase of approximately 18.0 MMT CO₂ Eq., as shown in Table 3-53.

Table 3-53: CH₄ Emissions from Pneumatic Controllers (MMT CO₂ Eq.)

Source	1990	2005	2010	2013	2014
All	13.9	27.0	31.2	31.5	27.6
High bleed	+	12.1	10.9	4.8	3.3
Low bleed	8.4	0.6	1.1	0.6	1.0
Intermittent bleed	5.5	14.3	19.2	26.0	23.3
<i>Previous-All</i>	<i>13.4</i>	<i>20.2</i>	<i>16.2</i>	<i>13.5</i>	<i>NA</i>

+ Does not exceed 0.05 MMT CO₂ Eq.

NA – Not applicable

Note: Values in *italics* are from the previous Inventory.

The 2015 Marchese et al. study assessed CH₄ emissions from an expanded universe of gathering stations compared with what was previously included in the Inventory. The Marchese et al. study analyzed emissions from five different types of gathering stations: compression only; compression and dehydration; compression, dehydration, and acid gas removal; dehydration only; and dehydration and acid gas removal. Previous Inventories estimated emissions from only gathering compression stations. In this Inventory, the EPA has applied a station-level emission factor and national activity estimates developed from the Marchese et al. data. See “Revisions to Natural Gas

Gathering and Boosting Emissions” for more information (EPA 2016c).⁷⁵ The impact of using revised activity data and emission factors for gathering stations cannot be straightforwardly determined based on the structure of previous Inventories (e.g., dehydrator emissions in previous inventories are not differentiated between well pad and gathering facility locations); however, due to the activity data revision alone, production segment emissions greatly increase compared to previous estimates. The station-level emission factor was applied to all years of the time series, and current activity data estimates were replaced with station counts based on the Marchese et al. estimate (scaled for earlier years based on national natural gas marketed production). Methane emissions from gathering and boosting are shown in Table 3-54.

Table 3-54: CH₄ Emissions from Gathering and Boosting (MMT CO₂ Eq.)

Source	1990	2005	2010	2013	2014
Gathering and Boosting Stations	23.9	27.7	35.8	43.3	46.6

The EPA’s approach for revising the Inventory methodology to incorporate GHGRP data and Marchese et al. data obviates the need to apply Gas STAR reductions data for certain sources in the production segment. EPA carried forward reported reductions for sources that are not being revised to use a net emission factor approach. There are also significant Gas STAR reductions in the production segment that are not classified as applicable to specific emission sources (“other voluntary reductions” are 18 MMT CO₂ Eq. of CH₄ in year 2014). To address potential double-counting of reductions, a scaling factor was applied to the “other voluntary reductions” to reduce this reported amount based on an estimate of the fraction of those reductions that occur in the sources that are now calculated using net emissions approaches. This fraction was developed by dividing the net emissions from sources with net emissions approaches, by the total production segment emissions (without deducting the Gas STAR reductions). The result for 2014, is that approximately 50 percent of the reductions were estimated to occur in sources for which net emissions are now calculated, which yields an adjusted “other voluntary reduction” number of 9 MMT CO₂ Eq.

Transmission and Storage

This section references the final 2016 (current) Inventory Transmission and Storage supporting memorandum: “Revisions to Natural Gas Transmission and Storage Emissions” (EPA 2016d).⁷⁶ This memorandum contains further details and documentation of recalculations.

For transmission and storage non-compressor fugitive emissions in the 2016 (current) Inventory, EPA used Zimmerle et al. data to develop the activity data for transmission stations (“Alternative” approach) and EIA data on active storage fields, along with the Zimmerle estimate of storage stations per storage field to develop storage station counts. The EPA then applied emission factors from Zimmerle et al. to calculate emissions for fugitives from these sources.

Interpolation was used to create time series consistency between earlier years’ emission factors (1990-1992) that generally rely on data from GRI/EPA 1996 and the Zimmerle et al. emission factors for recent years. However, the station fugitive emission factors in previous Inventories included station fugitives but not compressor fugitives, and separate emission factors were applied for compressor emissions (including compressor fugitive and vented sources). Because Zimmerle et al. grouped compressor fugitives with station fugitives, the two sets of emission factors (GRI/EPA and Zimmerle et al.) cannot be directly compared. Therefore in the 2016 (current) Inventory, the EPA calculated total station-level emission factors for transmission and storage stations that include station and compressor fugitive sources as well as compressor vented sources.

In the 2016 (current) Inventory, the EPA incorporated Zimmerle et al. national population estimates of reciprocating and centrifugal compressor activity data, along with the GHGRP break out between centrifugal compressor seal types (wet versus dry seals), and Zimmerle et al. emission factor data, in development of emission estimates for compressors in transmission and storage.

⁷⁵ See <<https://www3.epa.gov/climatechange/ghgemissions/usinventoryreport/natural-gas-systems.html>>.

⁷⁶ See <<https://www3.epa.gov/climatechange/ghgemissions/usinventoryreport/natural-gas-systems.html>>.

In order to create time series consistency between earlier years' compressor count estimates (1990 to 1992) and the most recent years' compressor count estimates (2012 to 2014) that were calculated from Zimmerle et al. and GHGRP data, compressor counts for the years 1993 through 2011 were calculated using linear interpolation between the data endpoints of 1992 and 2012.

The overall impact of using revised emissions data and activity data from Zimmerle et al. and GHGRP is a decrease in emissions for station fugitives and compressors. For the year 2013, the CH₄ emissions decrease due to use of revised emission factors and activity data for transmission and storage station fugitives and compressor venting is approximately 18.4 MMT CO₂ Eq. Methane emissions from transmission stations are shown in Table 3-55, while methane emissions from storage stations are shown in Table 3-56.

Table 3-55: CH₄ Emissions from Transmission Stations (MMT CO₂ Eq.)

Source	1990	2005	2010	2013	2014
Station Total Emissions	27.5	16.7	13.0	13.4	14.3
Station + Compressor					
Fugitive Emissions	NA	NA	NA	2.7	2.9
Reciprocating Compressor	NA	NA	NA	7.9	8.5
Centrifugal Compressor (wet seals)	NA	NA	NA	1.4	1.5
Centrifugal Compressor (dry seals)	NA	NA	NA	1.3	1.4
<i>Previous-Station Total</i>	<i>27.5</i>	<i>28.1</i>	<i>28.5</i>	<i>28.3</i>	<i>NA</i>
<i>Previous-Station Fugitives^a</i>	<i>2.7</i>	<i>2.8</i>	<i>2.8</i>	<i>2.8</i>	<i>NA</i>
<i>Previous-Reciprocating Compressor^a</i>	<i>18.6</i>	<i>19.2</i>	<i>19.4</i>	<i>19.3</i>	<i>NA</i>
<i>Previous-Centrifugal Compressor (wet seals)^a</i>	<i>6.2</i>	<i>5.9</i>	<i>5.9</i>	<i>5.8</i>	<i>NA</i>
<i>Previous-Centrifugal Compressor (dry seals)^a</i>	<i>+</i>	<i>0.3</i>	<i>0.4</i>	<i>0.4</i>	<i>NA</i>

+ Does not exceed 0.05 MMT CO₂ Eq.

NA – Not applicable

*These values from the previous inventory cannot be compared to the estimates in this Inventory as the source categories have different definitions in their respective data sources (e.g., one includes certain fugitives, one does not).

Note: Values in *italics* are from the previous Inventory.

Table 3-56: CH₄ Emissions from Storage Stations (MMT CO₂ Eq.)

Source	1990	2005	2010	2013	2014
Station Total Emissions	6.1	4.1	3.5	3.3	3.3
Station + Compressor					
Fugitive Emissions	NA	NA	NA	0.6	0.6
Reciprocating Compressor	NA	NA	NA	2.7	2.7
Centrifugal Compressor (wet seals)	NA	NA	NA	NA	NA
Centrifugal Compressor (dry seals)	NA	NA	NA	NA	NA
<i>Previous-Station Total</i>	<i>6.1</i>	<i>6.7</i>	<i>6.6</i>	<i>6.8</i>	<i>NA</i>
<i>Previous-Station Fugitives^a</i>	<i>1.4</i>	<i>1.5</i>	<i>1.5</i>	<i>1.5</i>	<i>NA</i>
<i>Previous-Reciprocating Compressor^a</i>	<i>3.9</i>	<i>4.3</i>	<i>4.3</i>	<i>4.4</i>	<i>NA</i>
<i>Previous-Centrifugal Compressor (wet seals)^a</i>	<i>0.8</i>	<i>0.8</i>	<i>0.7</i>	<i>0.6</i>	<i>NA</i>
<i>Previous-Centrifugal Compressor (dry seals)^a</i>	<i>+</i>	<i>0.1</i>	<i>0.2</i>	<i>0.3</i>	<i>NA</i>

+ Does not exceed 0.05 MMT CO₂ Eq.

NA – Not applicable

* These values from the previous inventory cannot be compared to the estimates in this Inventory as the source categories have different definitions in their respective data sources (e.g., one includes certain fugitives, one does not).

Note: Values in *italics* are from the previous Inventory.

In the 2016 (current) Inventory, the transmission and storage pneumatic controller emissions have been calculated using the GHGRP data on controllers per station and emission factors. The overall impact of using revised emissions data and activity data from GHGRP was a decrease in emissions from transmission station pneumatic controllers and a slight decrease in emissions from storage station pneumatic controllers for recent time series years. For the year 2013, the CH₄ emissions decrease due to use of revised emission factors and activity data for transmission and storage station pneumatic controllers is 5.0 MMT CO₂ Eq. Methane emissions from transmission segment pneumatic controllers are shown in Table 3-57, while methane emissions from storage segment pneumatic controllers are shown in Table 3-58.

In order to create time series consistency between earlier years' pneumatic controller data (1990 to 1992) and the most recent years' data (2011 to 2014) when populating intermediate years, the EPA retained counts and estimates of weighted average emissions per controller in early years, then linearly interpolated the total count and weighted average emissions per controller in year 2011.

Table 3-57: CH₄ Emissions from Transmission Segment Pneumatic Controllers (MMT CO₂ Eq.)

Source	1990	2005	2010	2013	2014
All	5.3	1.8	0.9	0.7	0.7
High bleed	NA	NA	NA	0.3	0.3
Low bleed	NA	NA	NA	0.3	0.4
Intermittent bleed	NA	NA	NA	+	+
<i>Previous-All</i>	<i>5.3</i>	<i>5.2</i>	<i>5.3</i>	<i>5.2</i>	<i>NA</i>

+ Does not exceed 0.05 MMT CO₂ Eq.

NA – Not applicable

Note: Values in *italics* are from the previous Inventory.

Table 3-58: CH₄ Emissions from Storage Segment Pneumatic Controllers (MMT CO₂ Eq.)

Source	1990	2005	2010	2013	2014
All	1.1	0.9	0.7	0.8	0.7
High bleed	NA	NA	NA	0.6	0.6
Low bleed	NA	NA	NA	0.1	0.1
Intermittent bleed	NA	NA	NA	+	+
<i>Previous-All</i>	<i>1.1</i>	<i>1.2</i>	<i>1.2</i>	<i>1.3</i>	<i>NA</i>

+ Does not exceed 0.05 MMT CO₂ Eq.

NA – Not applicable

Note: Values in *italics* are from the previous Inventory.

The EPA's approach for revising the inventory methodology to incorporate Zimmerle et al. and GHGRP data in the transmission and storage segment resulted in net emissions being directly calculated for revised sources in each time series year. This obviated the need to apply Gas STAR reductions data for these sources. Previous Inventories have applied Gas STAR reductions to other specific transmission and storage segment sources including compressor engine and pipeline venting. EPA carried forward reported reductions for these sources since they are not being revised to use a net emission factor approach. There are also Gas STAR reductions in the transmission and storage segment that are not classified as applicable to specific emission sources ("other voluntary reductions" are 3.6 MMT CO₂ Eq. CH₄ in year 2013). Some portion of the "other voluntary reductions" might apply to the emission sources for which the EPA has revised the methodology to use a net emission factor approach. The EPA is investigating potential disaggregation of "other voluntary reductions." The EPA has retained Gas STAR reductions classified as "other voluntary reductions," without adjustment, in the 2016 (current) Inventory.

Distribution

This section references the final 2016 (current) Inventory Distribution supporting memorandum: “Revisions to Natural Gas Distribution Emissions” (EPA 2016e).⁷⁷ This memorandum contains further details and documentation of recalculations.

For metering and regulating (M&R) stations, for the years from 2011 to 2014, in the 2016 (current) Inventory, the EPA used GHGRP reported activity data for counts of above ground and below ground stations. The EPA scaled the GHGRP station counts to the national level based on the miles of distribution pipeline main reported by GHGRP reporters, compared to the PHMSA national total miles of distribution pipeline main. The EPA then applied the existing inventory (from GRI) break out of station inlet pressure categories to the scaled counts of above ground and below ground M&R stations, and the station-level emission factors from Lamb et al. For years from 1990 to 2010, EPA used the previous inventory activity data for station counts. EPA used linear interpolation between GRI/EPA emission factors in early years (1990 to 1992) and Lamb et al. emission factors in recent years (2011 to 2014) for M&R stations.

For the year 2013, the M&R stations CH₄ emissions decrease due to use of revised emission factors and activity data is approximately 13.6 MMT CO₂ Eq. Methane emissions from M&R stations are shown in Table 3-59.

Table 3-59: CH₄ Emissions from M&R Stations (MMT CO₂ Eq.)

Source	1990	2005	2010	2013	2014
M&R	10.5	4.9	1.1	0.9	0.7
<i>Previous--M&R</i>	8.2	9.1	9.0	9.3	NA
R-Vault	+	0.1	0.1	+	+
<i>Previous--R-Vault</i>	+	+	+	+	NA
Reg	6.3	2.8	0.6	0.4	0.3
<i>Previous--Reg</i>	4.9	5.4	5.4	5.6	NA

+ Does not exceed 0.05 MMT CO₂ Eq.

NA – Not applicable

Note: Values in *italics* are from the previous Inventory.

For pipeline leaks, in the 2016 (current) Inventory, the EPA used the previous activity data sources for miles of pipeline by material (PHMSA) and for leaks per mile (GRI), and Lamb et al., data on emissions per leak for recent years of the time series. For the year 2013, the pipeline leaks CH₄ emissions decrease due to use of revised emission factors is approximately 9.2 MMT CO₂ Eq. Methane emissions from pipeline leaks are shown in Table 3-60.

EPA used linear interpolation between GRI/EPA emission factors in early years (1990 to 1992) and Lamb et al. emission factors in recent years (2011 to 2014) for pipeline leaks.

Table 3-60: CH₄ Emissions from Pipeline Leaks (MMT CO₂ Eq.)

Source	1990	2005	2010	2013	2014
Mains	14.7	6.7	4.5	3.9	3.8
<i>Previous--Mains</i>	14.7	11.8	11.3	10.7	NA
Services	8.2	4.0	2.6	2.2	2.1
<i>Previous--Services</i>	8.2	6.2	5.1	4.6	NA

NA – Not applicable

Note: Values in *italics* are from the previous Inventory.

In the 2016 (current) Inventory, the EPA revised the emission factors for residential customer meters and commercial/ industrial customer meters. The EPA recalculated the residential customer meter emission factor by combining data from the 1996 GRI/EPA study (basis for previous Inventory emission factor) with more recent data from a GTI 2009 study and Clearstone 2011 study. The EPA weighted emission factors developed in each study by the number of meters surveyed in each study to develop the revised emission factor. In the 2016 (current) Inventory, the EPA applied the GTI 2009 commercial customer meter emission factor to the total count of commercial and

⁷⁷ See <<https://www3.epa.gov/climatechange/ghgemissions/usinventoryreport/natural-gas-systems.html>>.

industrial meters in the GHG Inventory. In addition, the EPA used an updated data source, identified by commenters on the public review Distribution memorandum for national customer meter counts (EIA data); previously, national customer meter counts were scaled from a 1992 base year value, but are now available directly for every year of the time series from EIA. For the year 2013, the customer meters CH₄ emissions increase due to use of revised emission factors and activity data is approximately 0.3 MMT CO₂ Eq. Methane emissions from customer meters are shown in Table 3-61.

For pipeline blowdowns and mishaps/dig-ins, the previous Inventories used base year 1992 distribution main and service miles and scaled the value for non-1992 years using relative residential gas consumption. However, scaling mileage based on residential gas consumption introduced volatility across the time series that does not likely correlate to pipeline mileage trends (as gas consumption is affected by other factors such as equipment efficiency and climate). In the 2016 (current) Inventory, the EPA used PHMSA data directly for the activity data in each time series year. The overall impact of using the revised activity data for pipeline blowdowns and mishaps/dig-ins is an increase in emissions. For the year 2013, the pipeline blowdowns CH₄ emissions increase due to use of revised activity data is approximately 0.04 MMT CO₂ Eq.; and for mishaps/dig-ins is approximately 0.6 MMT CO₂ Eq. Methane emissions from pipeline blowdown and mishaps/dig-ins are shown in Table 3-61.

Table 3-61: CH₄ Emissions for Other Distribution Sources (MMT CO₂ Eq.)

Source	1990	2005	2010	2013	2014
Residential Meters	1.5	1.9	1.9	2.0	2.0
<i>Previous--Residential Meters</i>	2.6	2.8	2.8	2.9	NA
Commercial/Industry Meters	1.1	1.3	1.3	1.4	1.4
<i>Previous--Commercial/Industry Meters</i>	0.1	0.1	0.1	0.1	NA
Pressure Relief Valve Releases	+	+	+	+	+
<i>Previous--Pressure Relief Valve Releases</i>	+	+	+	+	NA
Pipeline Blowdowns	0.1	0.1	0.1	0.1	0.1
<i>Previous--Pipeline Blowdown</i>	0.1	0.1	0.1	0.1	NA
Mishaps (Dig-ins)	1.2	1.5	1.6	1.6	1.7
<i>Previous--Mishaps (Dig-ins)</i>	0.9	1.0	1.0	1.0	NA

+ Does not exceed 0.05 MMT CO₂ Eq.

NA – Not applicable

Note: Values in *italics* are from the previous Inventory.

The EPA’s approach for revising the Inventory methodology to incorporate Lamb et al. and subpart W data in the distribution segment resulted in net emissions being directly calculated for M&R stations, pipeline leaks, and customer meters in each time series year. This obviates the need to apply Gas STAR reductions data for these sources. Previous Inventories have also applied Gas STAR reductions to mishaps/dig-ins. EPA carried forward reported reductions for this source since it is not being revised to use a net emission factor approach. There are also Gas STAR reductions in the distribution segment that are not classified as applicable to specific emission sources (“other voluntary reductions” are 1.0 MMT CO₂ Eq. CH₄ in year 2013). Some portion of the “other voluntary reductions” might apply to the emission sources for which the EPA has revised methodology to use a net emission factor approach. The EPA is investigating potential disaggregation of “other voluntary reductions.” The EPA has retained Gas STAR reductions classified as “other voluntary reductions” unadjusted in the 2016 (current) Inventory.

Planned Improvements

Production Segment Estimates

In response to the public review draft and earlier released memorandum outlining potential revisions to the production and gathering and boosting segment, EPA received feedback from stakeholders that will be further considered to refine future Inventories.

In the production segment, some commenters suggested that the approach taken overestimates equipment counts in the production segment, while others suggested that the approach was appropriate. The EPA will further consider

how activity factors developed from GHGRP data may over- or under-represent equipment counts for non-GHGRP facilities (those not meeting the emissions reporting threshold). Preliminary assessment by EPA of this issue by disaggregating GHGRP reporter data by number of wells reported indicated that reporters with fewer wells had higher equipment counts per well than average. EPA will continue to explore other methods to assess whether the non-GHGRP population may have different average equipment counts than the reporting population and how this may be reflected in the Inventory. The EPA will also consider calculation of activity factors from GHGRP data (equipment and pneumatic controller counts per well) on a more granular basis, such as by geologic basin. EPA will continue to consider stakeholder feedback on the methodology used to develop counts of active wells (non-associated gas wells and gas wells with hydraulic fracturing) across the time series.

In response to the public review memoranda, EPA also received feedback from stakeholders on aspects of emission sources that were not significantly revised in the 2016 (current) Inventory. Stakeholders noted that data generated by Allen et al. in recent studies of pneumatic controller emissions in the production segment might be used to develop a separate emission factor for malfunctioning devices (in addition to the bleed type-specific factors developed from GHGRP data and used in the 2016 (current) Inventory). Stakeholders also recommended further investigating the emissions estimation methodology for gathering pipeline emissions, as the current factor is based on leak measurements from distribution mains conducted in the early 1990s. EPA will evaluate available data studies on this emission sources, and also take into account material-specific gathering pipeline activity data that will be available through the GHGRP.

EPA is considering updates to its estimates for liquids unloading. Data from a 2012 report published by the American Petroleum Institute (API) and America's Natural Gas Alliance (ANGA) were used to develop regional activity data and regional emission factors for gas well liquids unloading activities for Natural Gas Systems. EPA is considering how data from GHGRP and/or Allen et al. (2014a) can be used to update the Inventory estimates for this source.⁷⁸ Some commenters supported the use of scaled-up GHGRP data to calculate emissions from this source. Using the general scale up approach used for other production sources gives an approximation of a national estimate of 10 MMT CO₂ Eq. for 2013 (4.6 MMT CO₂ Eq. was reported from liquids unloading in 2013, from a total reported 208,991 wellheads estimated to be in the natural gas segment. The Inventory national well count total for 2013 is 454,491), compared with 6.5 MMT CO₂ Eq. in the current inventory.

EPA received mixed feedback on the update for gathering stations, with some commenters supporting the use of the Marchese et al. data, and others not supporting the update and recommending waiting for GHGRP data to update emissions from this source. Additionally, commenters recommended that EPA separate out emissions from gathering and boosting facilities from those from field production sites and noted that upcoming studies and GHGRP data may inform emissions estimates from this source. In the 2016 (current) Inventory, the EPA has presented gathering facility and gathering pipeline emissions as a "Gathering and Boosting" subsegment within the production segment; EPA will continue to consider how these sources may be presented in future Inventories. To address potential double counting, condensate storage tanks might be disaggregated between well pad facilities and gathering facilities in future Inventories. Stakeholder feedback included suggestions on how data from the Marchese et al. study and GHGRP data might be used, which EPA will consider for next year's inventory. One commenter suggested that the potential overlap count be estimated to be 3.4 percent of the emissions from condensate tanks.

Processing Estimates

Commenters recommended consideration of recent data sources (Marchese et al. 2015 and GHGRP) for revisions to gas processing segment estimates. Commenters had mixed feedback on these data sources with some commenters supporting use of Marchese et al. and other supporting use of GHGRP data.

⁷⁸ Please see the memorandum "Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2013: Potential Revisions to Liquids Unloading Estimates" (EPA 2015e) available at <<http://www.epa.gov/climatechange/ghgemissions/usinventoryreport/natural-gas-systems.html>>

Transmission and Storage Estimates

In response to the public review memorandum outlining potential revisions to the transmission and storage segment, EPA received feedback from stakeholders that will be further considered to refine implementation of the 2016 revisions in future Inventories and to implement additional revisions. The EPA will consider approaches to developing average emission factors that integrate data from both recent studies and subpart W data. The EPA will seek more data to support or replace the Zimmerle et al. study assumption of 0.89 storage stations per field. The EPA will take into account findings emerging from ongoing research efforts by groups such as API (to better characterize emissions from pneumatic controllers) and Pipeline Research Council International (to analyze subpart W data). The EPA will also investigate potential revisions to certain emission sources not addressed in recent revisions but highlighted by commenters, including reciprocating compressor engines and storage tank dump valves.

In fall of 2015, a well in a California storage field began leaking methane at an estimated rate of 50 tons of CH₄ per day. The well was permanently sealed in February of 2016. EPA plans to include 2015 emissions from this source in next year's inventory (2017 report covering 1990 to 2015 emissions). EPA will review and potentially incorporate estimates of emissions from the leak, such as estimates developed by the California Air Resources Board (CARB). For information on CARB estimates, see http://www.arb.ca.gov/research/aliso_canyon_natural_gas_leak.htm.

Distribution Estimates

In response to the public review memorandum outlining potential revisions to the distribution segment, EPA received feedback from stakeholders that will be further considered to refine implementation of the 2016 revisions in future Inventories and to implement additional revisions. The EPA will assess differences between the Lamb et al. study and characteristics of the GHGRP population. The EPA will consider current interpolation approaches to use GRI factors later into the time series (e.g., if information is received indicating a specific time frame for the transition to lower-emitting equipment and practices). The EPA will assess whether available data support methodological revisions to differentiate new versus vintage plastic pipelines in the Inventory. The EPA will assess any new data on commercial or industrial meters to potentially improve the current emission factor. While most commenters supported updates to this segment, several commenters did not, referring to top down (e.g., tall tower) studies indicating the emissions may be higher than previously estimated, not lower. The EPA will continue to assess new top down and bottom up data in this segment.

Upcoming new data

GHGRP

Beginning in March 2016, GHGRP reporters will report data for gathering facilities over the GHGRP reporting threshold. The EPA will consider use of this data to update its estimates in the Inventory.

Commenters on recent Inventory drafts have recommended that EPA analyze and screen GHGRP data and exclude or correct outliers. Commenters have also recommended use of only measured GHGRP data in some cases. The EPA plans to continue reviewing data reported to its GHGRP for potential updates to data and methodology across all segments of natural gas systems.

Methane Challenge

In March 2016, EPA launched the Methane Challenge Program, through which oil and gas companies can make and track ambitious commitments to reduce methane emissions. EPA will assess new data received by the Methane Challenge Program on an ongoing basis, which may be used to confirm or improve existing estimates and assumptions.

Other Updates

EPA is evaluating several other sources for potential updates to future Inventories.

Abandoned wells are not currently accounted for in the Inventory. EPA is seeking appropriate emission factors and national activity data available to calculate these emissions. Commenters supported including this source category, noted the currently data is limited, and suggested reviewing data that will become available in the future.

The EPA continues to seek stakeholder feedback on natural gas systems super-emitter sources. The EPA will continue reviewing studies that could support potential revisions to inventory estimates, such as information from the Barnett Shale Campaign (e.g., Zavala et al. 2015). Several commenters noted superemitters detected and modeled in the Zimmerle et al. study but not incorporated into the inventory revision. In Zimmerle et al., superemitters were estimated to contribute 2.5 MMT CO₂ Eq. emissions to the study total estimate of emissions transmission and storage sources. The EPA will consider how unassigned superemitter emissions could be incorporated into the Inventory. EPA received mixed feedback on this issue with some commenters urging EPA to incorporate an estimate for superemitters, and others stating that inclusion of an estimate of unassigned superemitter emissions would be inappropriate and could result in double counting.

Uncertainty

As discussed in the Recalculations Discussion section above, EPA made several revisions in the 2016 (current) Inventory using information provided in recently published studies and the GHGRP Subpart W data, primarily including revisions to: production segment major equipment activity data, production segment pneumatic controller activity and emissions data, gathering and boosting facility activity and emissions data, transmission and storage station activity and emissions data, distribution pipelines emissions data, distribution M&R station activity and emissions data, and distribution customer meter emissions data. As noted in the Uncertainty section above, EPA has not yet updated its uncertainty analysis to reflect this new information. At the present time, it is difficult to project whether updated uncertainty bounds around CH₄ emission estimates would be wider, tighter, or about the same as the current uncertainty bounds that were developed for the Inventory published in 2011 (i.e., minus 19 percent and plus 30 percent) given the extensive nature of these revisions.

To update its uncertainty analysis, EPA will conduct a formal quantitative uncertainty analysis similar to that conducted for the 2011 Inventory using the IPCC-recommended Approach 2 methodology (Monte Carlo Simulation technique) using new data and taking into account stakeholder input received. For more information, please see the Uncertainty Memorandum (EPA 2016a). As in the 2011 Inventory analysis, EPA will first identify a select number of top-emitting emission sources for each source category. Note that to compile the top-emitting list of emission sources for natural gas systems, individual emission sources were analyzed at the NEMS region level for the production segment (because certain emission factors vary by region for many production sources), and at the national level for other segments. EPA is considering removing the NEMS region disaggregation in future Inventories, and potentially replacing it with a different level of disaggregation, such as at the sub-basin level. Refer to “Additional Information and Updates under Consideration for Natural Gas and Petroleum Systems Uncertainty (EPA 2016a) for more information on planned improvements regarding uncertainty.”⁷⁹

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-CH₄ volatile organic compounds (NMVOCs) from energy-related activities from 1990 to 2014 are reported in Table 3-62.

Table 3-62: NO_x, CO, and NMVOC Emissions from Energy-Related Activities (kt)

Gas/Source	1990	2005	2010	2011	2012	2013	2014
NO _x	21,106	16,602	12,004	11,796	11,051	10,557	9,995

⁷⁹ See <<https://www3.epa.gov/climatechange/ghgemissions/usinventoryreport/natural-gas-systems.html>>.

Mobile Combustion	10,862	10,295	7,290	7,294	6,788	6,283	5,777
Stationary Combustion	10,023	5,858	4,092	3,807	3,567	3,579	3,522
Oil and Gas Activities	139	321	545	622	622	622	622
Waste Combustion	82	128	77	73	73	73	73
<i>International Bunker Fuels^a</i>	<i>1,956</i>	<i>1,704</i>	<i>1,790</i>	<i>1,553</i>	<i>1,398</i>	<i>1,139</i>	<i>1,138</i>
CO	125,640	64,985	45,148	44,088	42,273	40,459	38,643
Mobile Combustion	119,360	58,615	39,475	38,305	36,491	34,676	32,861
Stationary Combustion	5,000	4,648	4,103	4,170	4,170	4,170	4,169
Waste Combustion	978	1,403	1,084	1,003	1,003	1,003	1,003
Oil and Gas Activities	302	318	487	610	610	610	610
<i>International Bunker Fuels^a</i>	<i>103</i>	<i>133</i>	<i>136</i>	<i>137</i>	<i>133</i>	<i>129</i>	<i>135</i>
NMVOCs	12,620	7,191	7,464	7,759	7,449	7,139	6,830
Mobile Combustion	10,932	5,724	4,591	4,562	4,252	3,942	3,632
Oil and Gas Activities	554	510	2,205	2,517	2,517	2,517	2,517
Stationary Combustion	912	716	576	599	599	599	599
Waste Combustion	222	241	92	81	81	81	81
<i>International Bunker Fuels^a</i>	<i>57</i>	<i>54</i>	<i>56</i>	<i>51</i>	<i>46</i>	<i>41</i>	<i>42</i>

^a These values are presented for informational purposes only and are not included in totals.

Note: Totals may not sum due to independent rounding.

Methodology

Emission estimates for 1990 through 2014 were obtained from data published on the National Emission Inventory (NEI) Air Pollutant Emission Trends web site (EPA 2015), and disaggregated based on EPA (2003). Emission estimates for 2012, 2013, and 2014 for non-EGU and non-mobile sources are held constant from 2011 in EPA (2015). 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 applications from various agencies.

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 2014. 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.⁸⁰ These decisions are reflected in the IPCC methodological guidance, including IPCC (2006), 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).⁸¹

Two transport modes are addressed under the IPCC definition of international bunker fuels: aviation and marine.⁸² Greenhouse gases emitted from the combustion of international bunker fuels, like other fossil fuels, include CO₂, CH₄ and N₂O for marine transport modes, and CO₂ and N₂O for aviation transport modes. Emissions from ground transport activities—by road vehicles and trains—even when crossing international borders are allocated to the country where the fuel was loaded into the vehicle and, therefore, are not counted as bunker fuel emissions.

The IPCC guidelines distinguish between different modes of air traffic. Civil aviation comprises aircraft used for the commercial transport of passengers and freight, military aviation comprises aircraft under the control of national armed forces, and general aviation applies to recreational and small corporate aircraft. The IPCC guidelines further define international bunker fuel use from civil aviation as the fuel combusted for civil (e.g., commercial) aviation purposes by aircraft arriving or departing on international flight segments. However, as mentioned above, and in keeping with the IPCC guidelines, only the fuel purchased in the United States and used by aircraft taking-off (i.e., departing) from the United States are reported here. The standard fuel used for civil aviation is kerosene-type jet fuel, while the typical fuel used for general aviation is aviation gasoline.⁸³

Emissions of CO₂ from aircraft are essentially a function of fuel use. Nitrous oxide emissions also depend upon engine characteristics, flight conditions, and flight phase (i.e., take-off, climb, cruise, decent, and landing). Recent data suggest that little or no CH₄ is emitted by modern engines (Anderson et al. 2011), and as a result, CH₄ emissions from this category are considered zero. In jet engines, N₂O 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. Carbon dioxide is the primary greenhouse gas emitted from marine shipping.

Overall, aggregate greenhouse gas emissions in 2014 from the combustion of international bunker fuels from both aviation and marine activities were 104.2 MMT CO₂ Eq., or 0.3 percent below emissions in 1990 (see Table 3-63 and Table 3-64). Emissions from international flights and international shipping voyages departing from the United States have increased by 82.5 percent and decreased by 48.4 percent, respectively, since 1990. The majority of these emissions were in the form of CO₂; however, small amounts of CH₄ (from marine transport modes) and N₂O were also emitted.

Table 3-63: CO₂, CH₄, and N₂O Emissions from International Bunker Fuels (MMT CO₂ Eq.)

Gas/Mode	1990	2005	2010	2011	2012	2013	2014
CO₂	103.5	113.1	117.0	111.7	105.8	99.8	103.2
Aviation	38.0	60.1	61.0	64.8	64.5	65.7	69.4
<i>Commercial</i>	30.0	55.6	57.4	61.7	61.4	62.8	66.3
<i>Military</i>	8.1	4.5	3.6	3.1	3.1	2.9	3.1
Marine	65.4	53.0	56.0	46.9	41.3	34.1	33.8
CH₄	0.2	0.1	0.1	0.1	0.1	0.1	0.1

⁸⁰ 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).

⁸¹ Note that the definition of international bunker fuels used by the UNFCCC differs from that used by the International Civil Aviation Organization.

⁸² Most emission related international aviation and marine regulations are under the rubric of the International Civil Aviation Organization (ICAO) or the International Maritime Organization (IMO), which develop international codes, recommendations, and conventions, such as the International Convention of the Prevention of Pollution from Ships (MARPOL).

⁸³ Naphtha-type jet fuel was used in the past by the military in turbojet and turboprop aircraft engines.

Aviation ^a	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Marine	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1
N₂O	0.9	1.0	1.0	1.0	0.9	0.9	0.9	0.9
Aviation	0.4	0.6	0.6	0.6	0.6	0.6	0.6	0.7
Marine	0.5	0.4	0.4	0.4	0.3	0.2	0.2	0.2
Total	104.5	114.2	118.1	112.8	106.8	100.7	104.2	

^a CH₄ emissions from aviation are estimated to be zero.

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

Table 3-64: CO₂, CH₄, and N₂O Emissions from International Bunker Fuels (kt)

Gas/Mode	1990	2005	2010	2011	2012	2013	2014
CO₂	103,463	113,139	116,992	111,660	105,805	99,763	103,201
Aviation	38,034	60,125	60,967	64,790	64,524	65,664	69,411
Marine	65,429	53,014	56,025	46,870	41,281	34,099	33,791
CH₄	7	5	6	5	4	3	3
Aviation ^a	0	0	0	0	0	0	0
Marine	7	5	6	5	4	3	3
N₂O	3	3	3	3	3	3	3
Aviation	1	2	2	2	2	2	2
Marine	2	1	1	1	1	1	1

^a CH₄ emissions from aviation are estimated to be zero.

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

Table 3-65: Aviation CO₂ and N₂O Emissions for International Transport (MMT CO₂ Eq.)

Aviation Mode	1990	2005	2010	2011	2012	2013	2014
Commercial Aircraft	30.0	55.6	57.4	61.7	61.4	62.8	66.3
Military Aircraft	8.1	4.5	3.6	3.1	3.1	2.9	3.1
Total	38.0	60.1	61.0	64.8	64.5	65.7	69.4

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

Methodology

Emissions of CO₂ were estimated by applying C content and fraction oxidized factors to fuel consumption activity data. This approach is analogous to that described under Section 3.1 – CO₂ from Fossil Fuel Combustion. Carbon 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 3.8 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 (2016) and USAF (1998), and heat content for jet fuel was taken from EIA (2016). A complete description of the methodology and a listing of the various factors employed can be found in Annex 2.1. See Annex 3.8 for a specific discussion on the methodology used for estimating emissions from international bunker fuel use by the U.S. military.

Emission estimates for CH₄ and N₂O were calculated by multiplying emission factors by measures of fuel consumption by fuel type and mode. Emission factors used in the calculations of CH₄ and N₂O emissions were obtained from the *2006 IPCC Guidelines* (IPCC 2006). For aircraft emissions, the following values, in units of grams of pollutant per kilogram of fuel consumed (g/kg), were employed: 0.1 for N₂O (IPCC 2006). For marine vessels consuming either distillate diesel or residual fuel oil the following values (g/MJ), were employed: 0.32 for CH₄ and 0.08 for N₂O. 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 domestic and international aircraft fuel consumption were developed by the U.S. Federal Aviation Administration (FAA) using radar-informed data from the FAA Enhanced Traffic Management System (ETMS) for 1990, 2000 through 2014 as modeled with the Aviation Environmental Design Tool (AEDT). This bottom-up approach is built from modeling dynamic aircraft performance for each flight occurring within an individual calendar year. The analysis incorporates data on the aircraft type, date, flight identifier, departure time, arrival time, departure airport, arrival airport, ground delay at each airport, and real-world flight trajectories. To generate results for a given flight within AEDT, the radar-informed aircraft data is correlated with engine and aircraft performance data to calculate fuel burn and exhaust emissions. Information on exhaust emissions for in-production aircraft engines comes from the International Civil Aviation Organization (ICAO) Aircraft Engine Emissions Databank (EDB). This bottom-up approach is in accordance with the Tier 3B method from the 2006 IPCC Guidelines (IPCC 2006).

International aviation CO₂ estimates for 1990 and 2000 through 2014 are obtained from FAA’s AEDT model (FAA 2016). The radar-informed method that was used to estimate CO₂ emissions for commercial aircraft for 1990, and 2000 through 2014 is not possible for 1991 through 1999 because the radar data set is not available for years prior to 2000. FAA developed OAG schedule-informed inventories modeled with AEDT and great circle trajectories for 1990, 2000 and 2010. Because fuel consumption and CO₂ emission estimates for years 1991 through 1999 are unavailable, consumption estimates for these years were calculated using fuel consumption estimates from the Bureau of Transportation Statistics (DOT 1991 through 2013), adjusted based on 2000 through 2005 data.

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 from DoD’s Defense Logistics Agency Energy (DLA Energy 2015). 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 3-66. See Annex 3.8 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 2015) for 1990 through 2001, 2007 through 2014, 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 DLA Energy (2015). The total amount of fuel provided to naval vessels was reduced by 21 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 3-67.

Table 3-66: Aviation Jet Fuel Consumption for International Transport (Million Gallons)

Nationality	1990	2005	2010	2011	2012	2013	2014
U.S. and Foreign Carriers	3,222	5,983	6,173	6,634	6,604	6,748	7,126
U.S. Military	862	462	367	319	321	294	318
Total	4,084	6,445	6,540	6,953	6,925	7,042	7,445

Note: Totals may not sum due to independent rounding.

Table 3-67: Marine Fuel Consumption for International Transport (Million Gallons)

Fuel Type	1990	2005	2010	2011	2012	2013	2014
Residual Fuel Oil	4,781	3,881	4,141	3,463	3,069	2,537	2,466
Distillate Diesel Fuel & Other	617	444	476	393	280	235	261
U.S. Military Naval Fuels	522	471	448	382	381	308	331
Total	5,920	4,796	5,065	4,237	3,730	3,081	3,058

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.⁸⁴ 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 CO₂ in the *2006 IPCC Guidelines* (IPCC 2006) is to use data by specific aircraft type, number of individual flights and, ideally, movement data to better differentiate between domestic and international aviation and to facilitate estimating the effects of changes in technologies. The IPCC also

⁸⁴ See uncertainty discussions under Carbon Dioxide Emissions from Fossil Fuel Combustion.

recommends that cruise altitude emissions be estimated separately using fuel consumption data, while landing and take-off (LTO) cycle data be used to estimate near-ground level emissions of gases other than CO₂.⁸⁵

There is also concern regarding the reliability of the existing DOC (2015) 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 2014. 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 CO₂, CH₄, and N₂O 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.

Planned Improvements

The feasibility of including data from a broader range of domestic and international sources for bunker fuels, including data from studies such as the Third IMO GHG Study 2014, is being considered.

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 generates CO₂ in addition to CH₄ and N₂O already covered in this chapter. In line with the reporting requirements for inventories submitted under the UNFCCC, CO₂ emissions from biomass combustion have been estimated separately from fossil fuel CO₂ 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 6), which accounts for the contribution of any resulting CO₂ emissions to U.S. totals within the Land Use, Land-Use Change, and Forestry sector's approach.

In 2014, total CO₂ emissions from the burning of woody biomass in the industrial, residential, commercial, and electricity generation sectors were approximately 217.7 MMT CO₂ Eq. (217,654 kt) (see Table 3-68 and Table 3-69). As the largest consumer of woody biomass, the industrial sector was responsible for 57.1 percent of the CO₂ emissions from this source. The residential sector was the second largest emitter, constituting 27.5 percent of the total, while the commercial and electricity generation sectors accounted for the remainder.

⁸⁵ 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.

Table 3-68: CO₂ Emissions from Wood Consumption by End-Use Sector (MMT CO₂ Eq.)

End-Use Sector	1990	2005	2010	2011	2012	2013	2014
Industrial	135.3	136.3	119.5	122.9	125.7	123.1	124.4
Residential	59.8	44.3	45.4	46.4	43.3	59.8	59.8
Commercial	6.8	7.2	7.4	7.1	6.3	7.2	7.6
Electricity Generation	13.3	19.1	20.2	18.8	19.6	21.4	25.9
Total	215.2	206.9	192.5	195.2	194.9	211.6	217.7

Note: Totals may not sum due to independent rounding.

Table 3-69: CO₂ Emissions from Wood Consumption by End-Use Sector (kt)

End-Use Sector	1990	2005	2010	2011	2012	2013	2014
Industrial	135,348	136,269	119,537	122,865	125,724	123,149	124,369
Residential	59,808	44,340	45,371	46,402	43,309	59,808	59,808
Commercial	6,779	7,218	7,385	7,131	6,257	7,235	7,569
Electricity Generation	13,252	19,074	20,169	18,784	19,612	21,389	25,908
Total	215,186	206,901	192,462	195,182	194,903	211,581	217,654

Note: Totals may not sum due to independent rounding.

The transportation sector is responsible for most of the ethanol consumption in the United States. Ethanol is currently produced primarily from corn grown in the Midwest, but it can be produced from a variety of biomass feedstocks. Most ethanol for transportation use is blended with gasoline to create a 90 percent gasoline, 10 percent by volume ethanol blend known as E-10 or gasohol.

In 2014, the United States consumed an estimated 1,111.3 trillion Btu of ethanol, and as a result, produced approximately 76.1 MMT CO₂ Eq. (76,075 kt) (see Table 3-70 and Table 3-71) of CO₂ emissions. Ethanol production and consumption has grown significantly since 1990 due to the favorable economics of blending ethanol into gasoline and federal policies that have encouraged use of renewable fuels.

Table 3-70: CO₂ Emissions from Ethanol Consumption (MMT CO₂ Eq.)

End-Use Sector	1990	2005	2010	2011	2012	2013	2014
Transportation ^a	4.1	22.4	71.3	71.5	71.5	73.4	74.8
Industrial	0.1	0.5	1.1	1.1	1.1	1.2	1.0
Commercial	+	0.1	0.2	0.2	0.2	0.2	0.3
Total	4.2	22.9	72.6	72.9	72.8	74.7	76.1

+ Does not exceed 0.05 MMT CO₂ Eq.

^a See Annex 3.2, Table A-94 for additional information on transportation consumption of these fuels.

Note: Totals may not sum due to independent rounding.

Table 3-71: CO₂ Emissions from Ethanol Consumption (kt)

End-Use Sector	1990	2005	2010	2011	2012	2013	2014
Transportation ^a	4,136	22,414	71,287	71,537	71,510	73,359	74,810
Industrial	56	468	1,134	1,146	1,142	1,202	987
Commercial	34	60	226	198	175	183	277
Total	4,227	22,943	72,647	72,881	72,827	74,743	76,075

^a See Annex 3.2, Table A-94 for additional information on transportation consumption of these fuels.

Note: Totals may not sum due to independent rounding.

Methodology

Woody biomass emissions were estimated by applying two EIA gross heat contents (Lindstrom 2006) to U.S. consumption data (EIA 2016) (see Table 3-72), 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 CO₂ 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 CO₂ with 100 percent efficiency. The emissions from ethanol consumption were calculated by applying an emission factor of 18.67 MMT C/QBtu (EPA 2010) to U.S. ethanol consumption estimates that were provided in energy units (EIA 2016) (see Table 3-73).

Table 3-72: Woody Biomass Consumption by Sector (Trillion Btu)

End-Use Sector	1990	2005	2010	2011	2012	2013	2014
Industrial	1,441.9	1,451.7	1,273.5	1,308.9	1,339.4	1,312.0	1,325.0
Residential	580.0	430.0	440.0	450.0	420.0	580.0	580.0
Commercial	65.7	70.0	71.6	69.2	60.7	70.2	73.4
Electricity Generation	128.5	185.0	195.6	182.2	190.2	207.4	251.3
Total	2,216.2	2,136.7	1,980.7	2,010.2	2,010.3	2,169.5	2,229.6

Note: Totals may not sum due to independent rounding.

Table 3-73: Ethanol Consumption by Sector (Trillion Btu)

End-Use Sector	1990	2005	2010	2011	2012	2013	2014
Transportation	60.4	327.4	1,041.4	1,045.0	1,044.6	1,071.6	1,092.8
Industrial	0.8	6.8	16.6	16.7	16.7	17.6	14.4
Commercial	0.5	0.9	3.3	2.9	2.6	2.7	4.1
Total	61.7	335.1	1,061.2	1,064.6	1,063.8	1,091.8	1,111.3

Note: Totals may not sum due to independent rounding.

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 2014. Details on the emission trends through time are described in more detail in the Methodology section, above.

Recalculations Discussion

Wood consumption values for 2013 were revised relative to the previous Inventory based on updated information from EIA's *Monthly Energy Review* (EIA 2016). These revisions of historical data for wood biomass consumption resulted in an average annual increase in emissions from wood biomass consumption of 0.1 MMT CO₂ Eq. (less than 0.1 percent) from 1990 through 2013. Ethanol consumption values remained constant relative to the previous Inventory throughout the entire time-series.

Planned Improvements

The availability of facility-level combustion emissions through EPA's Greenhouse Gas Reporting Program (GHGRP) will be examined to help better characterize the industrial sector's energy consumption in the United States, and further classify business establishments according to industrial economic activity type. Most methodologies used in EPA's GHGRP are consistent with IPCC, though for EPA's GHGRP, facilities collect detailed information specific to their operations according to detailed measurement standards, which may differ with the more aggregated data collected for the Inventory to estimate total, national U.S. emissions. In addition, and unlike the reporting requirements for this chapter under the UNFCCC reporting guidelines, some facility-level fuel combustion emissions reported under the GHGRP may also include industrial process emissions.⁸⁶ In line with UNFCCC reporting guidelines, fuel combustion emissions are included in this chapter, while process emissions are included in the Industrial Processes and Product Use chapter of this report. In examining data from EPA's GHGRP that would be useful to improve the emission estimates for the CO₂ from biomass combustion category, particular attention will also be made to ensure time series consistency, as the facility-level reporting data from EPA's GHGRP are not available for all inventory years as reported in this Inventory. Additionally, analyses will focus on aligning reported facility-level fuel types and IPCC fuel types per the national energy statistics, ensuring CO₂ emissions from biomass are separated in the facility-level reported data, and maintaining consistency with national energy statistics provided by EIA. In implementing improvements and integration of data from EPA's GHGRP, the latest guidance from the IPCC on the use of facility-level data in national inventories will be relied upon.⁸⁷

⁸⁶ See <<http://unfccc.int/resource/docs/2006/sbsta/eng/09.pdf>>.

⁸⁷ See <http://www.ipcc-nggip.iges.or.jp/meeting/pdfiles/1008_Model_and_Facility_Level_Data_Report.pdf>.