3. Energy

Energy-related activities were the primary sources of U.S. anthropogenic greenhouse gas emissions, accounting for 82.0 percent of total gross greenhouse gas emissions on a carbon dioxide (CO_2) equivalent basis in 2022.[1] This included 96.5, 40.2, and 10.8 percent of the nation's CO_2, methane (CH_4), and nitrous oxide (N_2O) emissions, respectively.[2] Energy-related CO_2 emissions alone constituted 76.9 percent of total gross U.S. greenhouse gas emissions from all sources on a CO_2-equivalent basis, while the non-CO_2 emissions from energy-related activities represented a much smaller portion of total gross national emissions (5.1 percent collectively).

Emissions from fossil fuel combustion contribute the vast majority of energy-related emissions, with CO_2 being the primary gas emitted (see Figure 3-1 and Figure 3-2). Globally, approximately 33,500 million metric tons (MMT) of CO_2 were added to the atmosphere through the combustion of fossil fuels in 2022, of which the United States accounted for approximately 14 percent.[3] Due to their relative importance over time (see Figure 3-2), fossil fuel combustion-related CO_2 emissions are considered in more detail than other energy-related emissions in this report (see Figure 3-3).

Fossil fuel combustion also emits CH_4 and N_2O. Stationary combustion of fossil fuels was the second largest source of N_2O emissions in the United States and mobile fossil fuel combustion was the fifth largest source. Energy-related activities other than fuel combustion, such as the production, transmission, storage, and distribution of fossil fuels, also emit greenhouse gases. These emissions consist primarily of fugitive CH_4 emissions from natural gas systems, coal mining, and petroleum systems.

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

[2] The contribution of energy non-CO_2 emissions is based on gross totals so excludes LULUCF methane (CH_4) and nitrous oxide (N_2O) emissions. The contribution of energy-related methane (CH_4) and (N_2O) including LULUCF non-CO_2 emissions, is 37.1 percent and 9.8 percent respectively.

[3] Global CO_2 emissions from fossil fuel combustion were taken from International Energy Agency *Global energy-related CO_2 emissions, 2022.* Available at: https://www.iea.org/reports/co2-emissions-in-2022 (IEA 2022).

Figure 3-1: 2022 Energy Sector Greenhouse Gas Sources

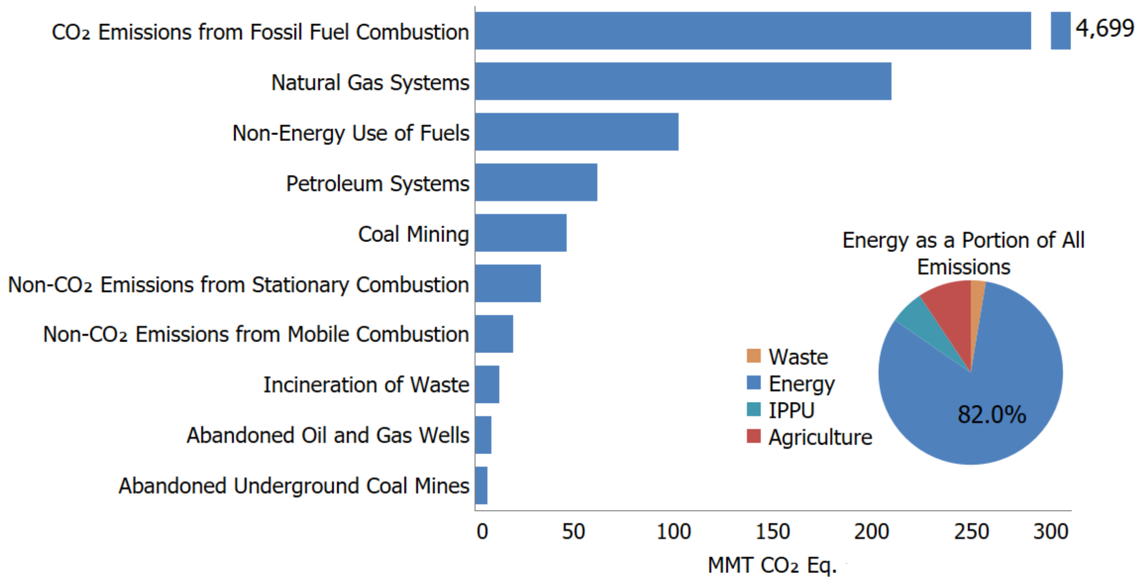


Figure 3-2: Trends in Energy Sector Greenhouse Gas Sources

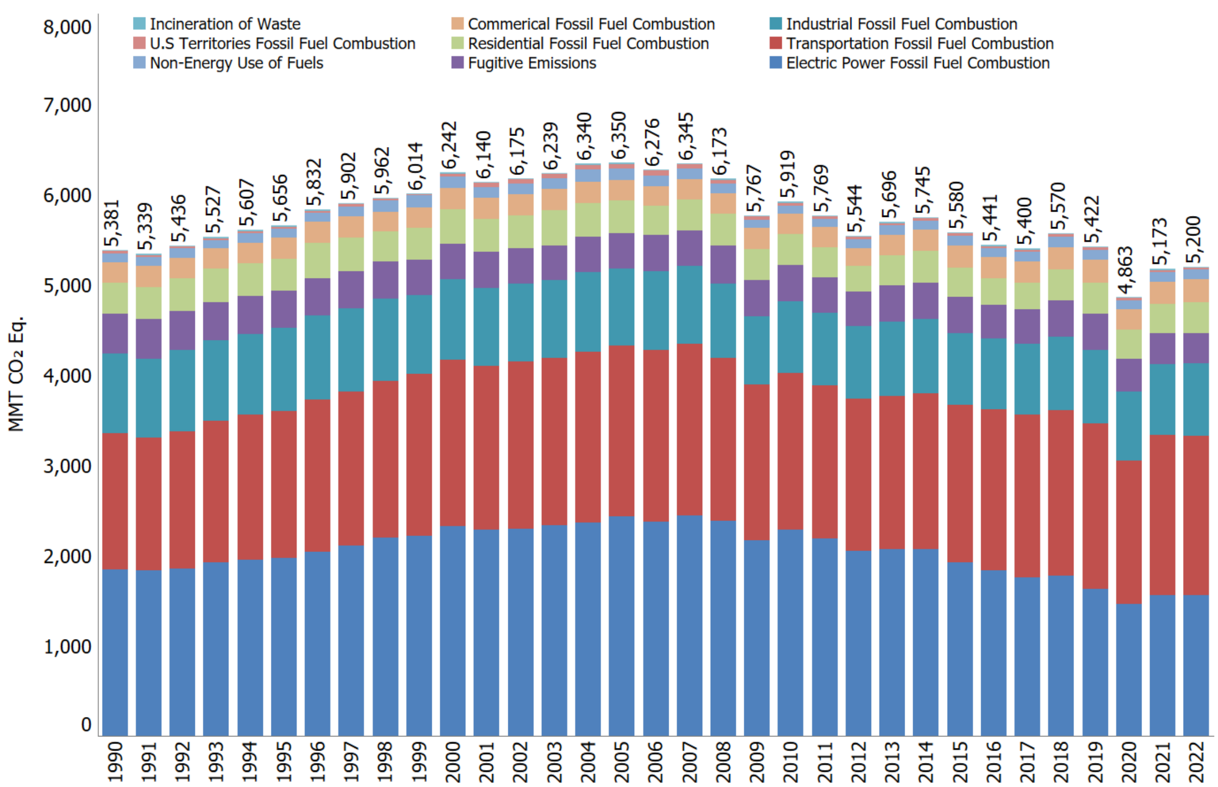


Figure 3-3: 2022 U.S. Fossil Carbon Flows (MMT CO_2 Eq.)

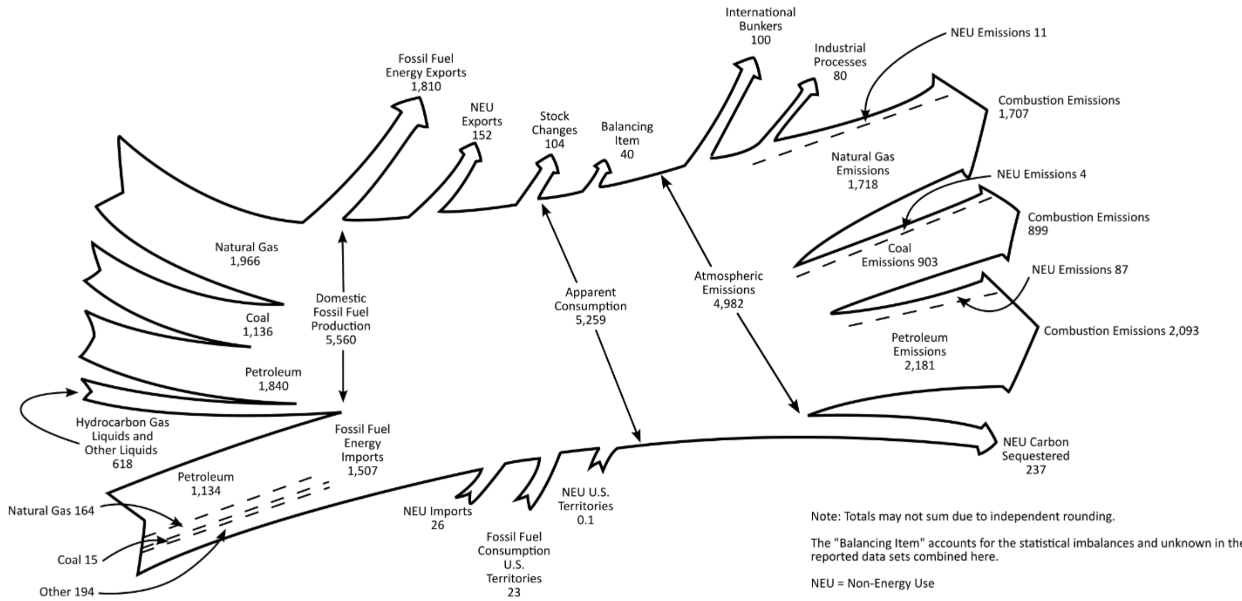


Table 3-1 summarizes emissions from the Energy sector in units of MMT CO_2 Eq., while unweighted gas emissions in kilotons (kt) are provided in Table 3-2. Overall, emissions due to energy-related activities were 5,199.8 MMT CO_2 Eq. in 2022,[4] a decrease of 3.4 percent since 1990 and an increase of 0.5 percent since 2021. The increase in emissions in 2021 and 2022 was due to continued rebounding activity levels after the coronavirus (COVID-19) pandemic reduced overall demand for fossil fuels across all sectors in 2020. Longer term trends are driven by a number of factors including a shift from coal to natural gas and renewables in the electric power sector.

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

Gas/Source	1990	2005	2018	2019	2020	2021	2022
CO_2	**4,910.9**	**5,923.1**	**5,190.6**	**5,059.1**	**4,520.2**	**4,840.7**	**4,875.5**
Fossil Fuel Combustion	4,752.2	5,744.1	4,988.2	4,852.6	4,341.7	4,654.3	4,699.4
Transportation	*1,468.9*	*1,858.6*	*1,813.1*	*1,816.6*	*1,572.8*	*1,753.5*	*1,751.3*
Electricity Generation	*1,820.0*	*2,400.1*	*1,753.4*	*1,606.7*	*1,439.6*	*1,540.9*	*1,531.7*
Industrial	*876.5*	*847.6*	*810.5*	*809.8*	*762.0*	*780.5*	*801.1*
Residential	*338.6*	*358.9*	*338.9*	*342.9*	*314.8*	*318.0*	*334.1*
Commercial	*228.3*	*227.1*	*246.3*	*251.7*	*229.3*	*237.5*	*258.7*
U.S. Territories	*20.0*	*51.9*	*25.9*	*24.8*	*23.3*	*23.8*	*22.6*
Non-Energy Use of Fuels	99.1	125.0	118.4	106.5	97.8	111.6	102.8
Natural Gas Systems	32.4	26.3	32.8	38.5	36.7	35.8	36.5
Petroleum Systems	9.6	10.2	34.8	45.5	28.9	24.1	22.0
Incineration of Waste	12.9	13.3	13.3	12.9	12.9	12.5	12.4
Coal Mining	4.6	4.2	3.1	3.0	2.2	2.5	2.5
Abandoned Oil and Gas Wells	+	+	+	+	+	+	+
Biomass-Wood[a]	*215.2*	*206.9*	*220.0*	*217.7*	*190.6*	*192.5*	*195.3*
International Bunker Fuels[b]	*103.6*	*113.3*	*124.3*	*113.6*	*69.6*	*80.2*	*98.2*
Biofuels-Ethanol[a]	*4.2*	*22.9*	*81.9*	*82.6*	*71.8*	*79.1*	*79.6*

[4] Following the current reporting requirements under the UNFCCC, this Inventory report presents CO_2 equivalent values based on the IPCC *Fifth Assessment Report* (AR5) GWP values. See Chapter 1, Introduction for more information.

Gas/Source	1990	2005	2018	2019	2020	2021	2022
Biofuels-Biodiesel[a]	*0.0*	*0.9*	*17.9*	*17.1*	*17.7*	*16.1*	*15.6*
Biomass-MSW[a]	*18.5*	*14.7*	*16.1*	*15.7*	*15.6*	*15.3*	*14.9*
CH_4	**409.0**	**358.5**	**336.2**	**321.7**	**305.3**	**293.3**	**282.4**
Natural Gas Systems	218.8	210.1	190.3	188.7	180.3	174.6	173.1
Coal Mining	108.1	71.5	59.1	53.0	46.2	44.7	43.6
Petroleum Systems	49.4	48.2	59.0	52.2	53.3	48.6	39.6
Stationary Combustion	9.7	8.8	9.6	9.8	8.0	8.0	8.6
Abandoned Oil and Gas Wells	7.8	8.2	8.4	8.5	8.5	8.6	8.5
Abandoned Underground Coal Mines	8.1	7.4	6.9	6.6	6.5	6.3	6.3
Mobile Combustion	7.2	4.3	2.8	2.9	2.5	2.6	2.6
Incineration of Waste	+	+	+	+	+	+	+
International Bunker Fuels[b]	*0.2*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*
N_2O	**61.2**	**67.9**	**43.2**	**41.6**	**37.1**	**39.2**	**41.9**
Stationary Combustion	22.3	30.5	25.1	22.2	20.5	22.0	24.7
Mobile Combustion	38.4	37.0	17.7	19.1	16.1	16.8	16.7
Incineration of Waste	0.4	0.3	0.4	0.4	0.3	0.4	0.3
Natural Gas Systems	+	+	+	+	+	+	0.2
Petroleum Systems	+	+	+	+	+	+	+
International Bunker Fuels[b]	*0.8*	*0.9*	*1.0*	*0.9*	*0.5*	*0.6*	*0.8*
Total	**5,381.0**	**6,349.5**	**5,570.0**	**5,422.4**	**4,862.6**	**5,173.3**	**5,199.8**

+ Does not exceed 0.05 MMT CO_2 Eq.

[a] Emissions from biomass and biofuel consumption are not included specifically in summing energy sector totals. Net carbon fluxes from changes in biogenic carbon reservoirs are accounted for in the estimates for LULUCF.

[b] Emissions from international bunker fuels are not included in totals. These values are presented for informational purposes only, in line with the *2006 IPCC Guidelines* and Paris Agreement and UNFCCC reporting obligations.

Note: Totals may not sum due to independent rounding.

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

Gas/Source	1990	2005	2018	2019	2020	2021	2022
CO_2	**4,910,861**	**5,923,075**	**5,190,611**	**5,059,075**	**4,520,249**	**4,840,748**	**4,875,487**
Fossil Fuel Combustion	4,752,232	5,744,134	4,988,198	4,852,631	4,341,710	4,654,265	4,699,403
Non-Energy Use of Fuels	99,104	124,988	118,382	106,474	97,757	111,624	102,808
Natural Gas Systems	32,427	26,312	32,768	38,525	36,719	35,780	36,470
Petroleum Systems	9,585	10,210	34,777	45,498	28,937	24,140	21,967
Incineration of Waste	12,900	13,254	13,339	12,948	12,921	12,476	12,357
Coal Mining	4,606	4,169	3,139	2,992	2,197	2,455	2,474
Abandoned Oil and Gas Wells	7	7	8	8	8	8	8
Biomass-Wood[a]	*215,186*	*206,901*	*220,003*	*217,690*	*190,554*	*192,509*	*195,338*
International Bunker Fuels[b]	*103,634*	*113,328*	*124,279*	*113,632*	*69,638*	*80,180*	*98,241*
Biofuels-Ethanol[a]	*4,227*	*22,943*	*81,917*	*82,578*	*71,848*	*79,064*	*79,593*
Biofuels-Biodiesel[a]	*0*	*856*	*17,936*	*17,080*	*17,678*	*16,112*	*15,622*
Biomass-MSW[a]	*18,534*	*14,722*	*16,115*	*15,709*	*15,614*	*15,329*	*14,864*
CH_4	**14,607**	**12,804**	**12,007**	**11,490**	**10,903**	**10,476**	**10,084**
Natural Gas Systems	7,813	7,505	6,795	6,741	6,439	6,235	6,183
Coal Mining	3,860	2,552	2,110	1,892	1,648	1,595	1,558
Petroleum Systems	1,765	1,723	2,108	1,865	1,904	1,737	1,415
Stationary Combustion	345	313	344	351	285	286	307
Abandoned Oil and Gas Wells	279	294	301	302	303	306	303
Abandoned Underground Coal Mines	288	264	247	237	232	224	225
Mobile Combustion	258	154	101	102	91	92	93
Incineration of Waste	+	+	+	+	+	+	+

Gas/Source	1990	2005	2018	2019	2020	2021	2022
International Bunker Fuels[b]	*7*	*5*	*4*	*4*	*3*	*3*	*3*
N_2O	**231**	**256**	**163**	**157**	**140**	**148**	**158**
Stationary Combustion	84	115	95	84	78	83	93
Mobile Combustion	145	140	67	72	61	63	63
Incineration of Waste	2	1	1	1	1	1	1
Natural Gas Systems	+	+	+	+	+	+	0.6
Petroleum Systems	+	+	+	+	+	+	+
International Bunker Fuels[b]	*3*	*3*	*4*	*3*	*2*	*2*	*3*

+ Does not exceed 0.5 kt.

[a] Emissions from biomass and biofuel consumption are not included specifically in summing Energy sector totals. Net carbon fluxes from changes in biogenic carbon reservoirs are accounted for in the estimates for LULUCF.

[b] Emissions from international bunker fuels are not included in totals. These values are presented for informational purposes only, in line with the *2006 IPCC Guidelines* and UNFCCC reporting obligations.

Note: Totals by gas may not sum due to independent rounding.

Emissions estimates reported in the Energy chapter from fossil fuel combustion and fugitive sources include those from all 50 states, including Hawaii and Alaska, and the District of Columbia. Emissions are also included from U.S. Territories to the extent they are known to occur (e.g., coal mining does not occur in U.S. Territories). For some sources there is a lack of detailed information on U.S. Territories including some non-CO_2 emissions from biomass combustion. As part of continuous improvement efforts, EPA reviews this on an ongoing basis to ensure emission sources are included across all geographic areas including U.S. Territories if they are occurring. See Annex 5 for more information on EPA's assessment of the sources not included in this *Inventory*.

Each year, some emission and sink estimates in the *Inventory* are recalculated and revised with improved methods and/or data. In general, recalculations are made to the U.S. greenhouse gas emission estimates either to incorporate new methodologies or, most commonly, to update recent historical data. These improvements are implemented consistently across the previous *Inventory's* time series (i.e., 1990 to 2021) to ensure that the trend is accurate. Key updates in this year's *Inventory* include, updated methodologies for completion and workover emissions estimates and transmission compressor station activity from both natural gas systems and petroleum systems, a shift of all product supplied of natural gasoline and unfinished oils to crude oil transfers for the time series and changes to the non-energy use of fossil fuel methodology (e.g., updates to some of the data and updated methodology for the amount of NEU HGLs). The impact of these recalculations averaged a decrease of 0.2 MMT CO_2 Eq. (less than 0.1 percent) per year across the time series. For more information on specific methodological updates, please see the Recalculations Discussion section for each category in this chapter.

Box 3-1: Methodological Approach for Estimating and Reporting U.S. Emissions and Removals, including Relationship to EPA's Greenhouse Gas Reporting Program

Consistent with Article 13.7(a) of the Paris Agreement and Article 4.1(a) of the UNFCCC as well as relevant decisions under those agreements, the emissions and removals presented in this report and this chapter are organized by source and sink categories and calculated using internationally accepted methods in the *2006 IPCC Guidelines for National Greenhouse Gas Inventories (2006 IPCC Guidelines)*. Additionally, the calculated emissions and removals in a given year for the United States are presented in a common format in line with the reporting guidelines for the reporting of inventories under the Paris Agreement and the UNFCCC. The Parties' use of consistent methods to calculate emissions and removals for their inventories helps to ensure that these reports are comparable. The presentation of emissions and removals provided in the Energy chapter do not preclude alternative examinations (e.g., economic sectors). Rather, this chapter presents emissions and removals in a common format consistent with how Parties are to report their national inventories under the Paris Agreement and the UNFCCC. The report itself, and this chapter, follows this common format, and provides an explanation of the application of methods used to calculate emissions and removals from energy-related activities.

Energy Data from EPA's Greenhouse Gas Reporting Program

EPA's Greenhouse Gas Reporting Program (GHGRP)[5] dataset and the data presented in this Inventory are complementary. The *Inventory* was used to guide the development of the GHGRP, particularly in terms of scope and coverage of both sources and gases. The GHGRP dataset continues to be an important resource for the Inventory, providing not only annual emissions information, but also other annual information, such as activity data and emission factors that can improve and refine national emission estimates and trends over time. GHGRP data also allow EPA to disaggregate national inventory estimates in new ways that can highlight differences across regions and sub-categories of emissions, along with enhancing application of QA/QC procedures and assessment of uncertainties.

EPA uses annual GHGRP data in a number of Energy sector categories to improve the national estimates presented in this Inventory consistent with IPCC guidelines (see Box 3-3 of this chapter, and Sections 3.3 Incineration of Waste, 3.4 Coal Mining, 3.6 Petroleum Systems, and 3.7 Natural Gas Systems).[6] Methodologies used in EPA's GHGRP are consistent with IPCC guidelines, including higher tier methods. Under EPA's GHGRP, facilities collect detailed information specific to their operations according to detailed measurement standards. 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 Paris Agreement and UNFCCC reporting guidelines. In line with the Paris Agreement and 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.

In addition to using GHGRP data to estimate emissions (Sections 3.3 Incineration of Waste, 3.4 Coal Mining, 3.6 Petroleum Systems, and 3.7 Natural Gas Systems), EPA also uses the GHGRP fuel consumption activity data in the Energy sector to disaggregate industrial end-use sector emissions in the category of CO_2 emissions from fossil fuel combustion, for use in reporting emissions in Common Reporting Tables (CRTs) (see Box 3-3). The industrial end-use sector activity data collected for the *Inventory* (EIA 2024) represent aggregated data for the industrial end-use sector. EPA's GHGRP collects industrial fuel consumption activity data by individual categories within the industrial end-use sector. Therefore, GHGRP data are used to provide a more detailed breakout of total emissions in the industrial end-use sector within that source category.

As indicated in the respective Planned Improvements sections for source categories in this chapter, EPA continues to examine the uses of facility-level GHGRP data to improve the national estimates presented in this *Inventory*. See Annex 9 for more information on use of EPA's GHGRP in the *Inventory*.

3.1 Fossil Fuel Combustion (CRT Source Category 1A)

Emissions from the combustion of fossil fuels for energy include the greenhouse gases CO_2, CH_4, and N_2O. Given that CO_2 is the primary gas emitted from fossil fuel combustion and represents the largest share of U.S. total emissions, CO_2 emissions from fossil fuel combustion are discussed at the beginning of this section. An overview of CH_4 and N_2O emissions from the combustion of fuels in stationary sources is then presented, followed by fossil fuel

[5] On October 30, 2009, the U.S. Environmental Protection Agency (EPA) published a rule requiring annual reporting of greenhouse gas data from large greenhouse gas emission sources in the United States. Implementation of the rule, codified at 40 CFR Part 98, is referred to as EPA's Greenhouse Gas Reporting Program (GHGRP).

[6] See http://www.ipcc-nggip.iges.or.jp/public/tb/TFI_Technical_Bulletin_1.pdf.

combustion emissions for all three gases by sector: electric power, industrial, residential, commercial, U.S. Territories, and transportation.

Methodologies for estimating CO_2 emissions from fossil fuel combustion differ from the estimation of CH_4 and N_2O emissions from stationary combustion and mobile combustion. Thus, three separate descriptions of methodologies, uncertainties, recalculations, and planned improvements are provided at the end of this section. Total CO_2, CH_4, and N_2O emissions from fossil fuel combustion are presented in Table 3-3 and Table 3-4.

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

Gas	1990	2005	2018	2019	2020	2021	2022
CO_2	4,752.2	5,744.1	4,988.2	4,852.6	4,341.7	4,654.3	4,699.4
CH_4	16.9	13.1	12.5	12.7	10.5	10.6	11.2
N_2O	60.8	67.6	42.8	41.2	36.7	38.9	41.4
Total	**4,829.9**	**5,824.8**	**5,043.4**	**4,906.6**	**4,388.9**	**4,703.7**	**4,752.0**

Note: Totals may not sum due to independent rounding.

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

Gas	1990	2005	2018	2019	2020	2021	2022
CO_2	4,752,232	5,744,134	4,988,198	4,852,631	4,341,710	4,654,265	4,699,403
CH_4	602	467	445	453	376	379	401
N_2O	229	255	161	156	138	147	156

CO_2 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. Carbon dioxide emissions from fossil fuel combustion are presented in Table 3-5. In 2022, CO_2 emissions from fossil fuel combustion increased by 1.0 percent relative to the previous year (as shown in Table 3-6). The increase in CO_2 emissions from fossil fuel combustion was a result of a 1.8 percent increase in fossil fuel energy use. This increase in fossil fuel energy use was due primarily to the continued rebound in economic activity after the COVID-19 pandemic. Carbon dioxide emissions from natural gas increased by 84.8 MMT CO_2 Eq., a 5.2 percent increase from 2021. In a shift from last year's trend, CO_2 emissions from coal consumption decreased by 58.6 MMT CO_2 Eq., a 6.1 percent decrease from 2021. Both the increase in natural gas and decrease in coal consumption and emissions in 2022 are observed across all sectors. Emissions from petroleum use also increased 19.0 MMT CO_2 Eq. (0.9 percent) from 2021 to 2022. In 2022, CO_2 emissions from fossil fuel combustion were 4,699,4 MMT CO_2 Eq., or 1.1 percent below emissions in 1990 (see Table 3-5).[7]

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

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

Fuel/Sector	1990	2005	2018	2019	2020	2021	2022
Coal	**1,719.8**	**2,113.7**	**1,211.6**	**1,028.1**	**835.6**	**957.4**	**898.8**
Residential	3.0	0.8	NO	NO	NO	NO	NO
Commercial	12.0	9.3	1.8	1.6	1.4	1.4	1.4
Industrial	157.8	117.8	54.4	49.4	43.0	43.0	43.0
Transportation	NO	NO	NO	NO	NO	NO	NO
Electric Power	1,546.5	1,982.8	1,152.9	973.5	788.2	910.1	851.5
U.S. Territories	0.5	3.0	2.6	3.6	3.1	2.9	2.9
Natural Gas	**998.6**	**1,166.2**	**1,592.0**	**1,649.2**	**1,615.7**	**1,622.1**	**1,706.8**
Residential	237.8	262.2	273.8	275.5	256.4	258.6	272.0
Commercial	142.0	162.9	192.5	192.9	173.5	180.4	192.3
Industrial	407.4	387.8	493.5	501.5	489.7	501.2	510.4
Transportation	36.0	33.1	50.9	58.9	58.7	65.2	70.2
Electric Power	175.4	318.9	577.9	616.6	634.8	612.8	659.3
U.S. Territories	NO	1.3	3.3	3.8	2.6	3.9	2.7
Petroleum	**2,033.3**	**2,463.8**	**2,184.2**	**2,174.9**	**1,890.0**	**2,074.4**	**2,093.4**
Residential	97.8	95.9	65.1	67.4	58.4	59.4	62.1
Commercial	74.3	54.9	52.0	57.2	54.4	55.7	65.1
Industrial	311.2	342.0	262.6	258.9	229.3	236.3	247.6
Transportation	1,432.9	1,825.5	1,762.2	1,757.7	1,514.2	1,688.4	1,681.1
Electric Power	97.5	98.0	22.2	16.2	16.2	17.7	20.5
U.S. Territories	19.5	47.6	20.1	17.5	17.5	17.0	17.0
Geothermal[a]	**0.5**	**0.5**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**
Electric Power	0.5	0.5	0.4	0.4	0.4	0.4	0.4
Total	**4,752.2**	**5,744.1**	**4,988.2**	**4,852.6**	**4,341.7**	**4,654.3**	**4,699.4**

NO (Not Occurring)

[a] Although not technically a fossil fuel, geothermal energy-related CO_2 emissions are included for reporting purposes. The source of CO_2 is non-condensable gases in subterranean heated water.

Note: Totals may not sum due to independent rounding.

Trends in CO_2 emissions from fossil fuel combustion are influenced by many long-term and short-term factors. On a year-to-year basis, the overall demand for fossil fuels in the United States and other countries generally fluctuates in response to changes in general economic conditions, energy prices, weather, and the availability of non-fossil alternatives. For example, in a year with increased consumption of goods and services, low fuel prices, severe summer and winter weather conditions, nuclear plant closures, and lower precipitation feeding hydroelectric dams, there would likely be proportionally greater fossil fuel consumption than a year with poor economic performance, high fuel prices, mild temperatures, and increased output from nuclear and hydroelectric plants. The 2021 to 2022 trends reflect ongoing impacts of the COVID-19 pandemic which generally led to a reduction in demand for fossil fuels in 2020, but an increase in demand as activities continued to rebound in 2022.

Longer-term changes in energy usage patterns, however, tend to be more a function of aggregate societal trends that affect the scale of energy use (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, HVAC systems, 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 intensity. The amount of carbon in fuels varies significantly by fuel type. For example, coal contains the highest amount of carbon per unit of useful energy. Petroleum has roughly 75 percent of the carbon per unit of energy as coal, and natural gas has only about

55 percent.[8] Table 3-6 shows annual changes in emissions during the last five years for coal, petroleum, and natural gas in selected sectors.

Table 3-6: Annual Change in CO_2 Emissions and Total 2022 CO_2 Emissions from Fossil Fuel Combustion for Selected Fuels and Sectors (MMT CO_2 Eq. and Percent)

Sector	Fuel Type	2018 to 2019		2019 to 2020		2020 to 2021		2021 to 2022		Total 2022
Transportation	Petroleum	-4.5	-0.3%	-243.5	-13.9%	174.2	11.5%	-7.2	-0.4%	1,681.1
Electric Power	Coal	-179.3	-15.6%	-185.4	-19.0%	121.9	15.5%	-58.6	-6.4%	851.5
Electric Power	Natural Gas	38.7	6.7%	18.2	3.0%	-22.1	-3.5%	46.5	7.6%	659.3
Industrial	Natural Gas	8.0	1.6%	-11.8	-2.4%	11.4	2.3%	9.2	1.8%	510.4
Residential	Natural Gas	1.7	0.6%	-19.1	-6.9%	2.3	0.9%	13.3	5.2%	272.0
Commercial	Natural Gas	0.4	0.2%	-19.5	-10.1%	6.9	4.0%	11.9	6.6%	192.3
Transportation	**All Fuels[a]**	**3.5**	**0.2%**	**-243.8**	**-13.4%**	**180.7**	**11.5%**	**-2.3**	**-0.1%**	**1,751.3**
Electric Power	**All Fuels[a]**	**-146.7**	**-8.4%**	**-167.2**	**-10.4%**	**101.4**	**7.0%**	**-9.3**	**-0.6%**	**1,531.7**
Industrial	**All Fuels[a]**	**-0.7**	**-0.1%**	**-47.8**	**-5.9%**	**18.5**	**2.4%**	**20.6**	**2.6%**	**801.1**
Residential	**All Fuels[a]**	**4.0**	**1.2%**	**-28.1**	**-8.2%**	**3.2**	**1.0%**	**16.0**	**5.0%**	**334.1**
Commercial	**All Fuels[a]**	**5.5**	**2.2%**	**-22.5**	**-8.9%**	**8.3**	**3.6%**	**21.2**	**8.9%**	**258.7**
All Sectors[a,b]	**All Fuels[a]**	**-135.6**	**-2.7%**	**-510.9**	**-10.5%**	**312.6**	**7.2%**	**45.1**	**1.0%**	**4,699.4**

[a] Includes sector and fuel combinations not shown in this table.
[b] Includes U.S. Territories.
Note: Totals may not sum due to independent rounding.

As shown in Table 3-6, recent trends in CO_2 emissions from fossil fuel combustion show a 2.7 percent decrease from 2018 to 2019, a 10.5 percent decrease from 2019 to 2020, a 7.2 percent increase from 2020 to 2021, and a 1.0 percent increase from 2021 to 2022. These changes contributed to an overall 5.8 percent decrease in CO_2 emissions from fossil fuel combustion from 2018 to 2022.

The overall 2021 to 2022 trends were largely driven by the gradual recovery from the COVID-19 pandemic, which saw reduced economic activity in 2020 and caused changes in energy demand and supply patterns across different sectors. The continued recovery from the COVID-19 pandemic has generally led to increased energy use and emissions across all economic sectors except electric power and transportation from 2021 to 2022. The decrease in emissions from 2021 to 2022 from electric power was due to the reduction in coal consumption for electricity generation, in a return to a pre-pandemic trend in declining coal-fired power generation.

Recent trends in CO_2 emissions from fossil fuel combustion are largely driven by the electric power sector, which until 2017 has accounted for the largest portion of these emissions. The types of fuels consumed to produce electricity have changed in recent years. Electric power sector consumption of natural gas primarily increased due to increased production capacity as natural gas-fired plants replaced coal-fired plants and increased electricity demand related to heating and cooling needs (EIA 2018; EIA 2023a). Total net electric power generation from all fossil and non-fossil sources decreased by 1.3 percent from 2018 to 2019, decreased by 2.9 percent from 2019 to 2020, increased by 2.7 percent from 2020 to 2021, and increased by 3.0 percent from 2021 to 2022 (EIA 2024a). Carbon dioxide emissions from the electric power sector decreased from 2021 to 2022 by 0.6 percent due to increased production and use of natural gas and decreased production and use of coal for electric power generation. Carbon dioxide emissions from coal consumption for electric power generation decreased by 26.1 percent overall since 2018, including a 6.4 percent decrease from 2021 to 2022.

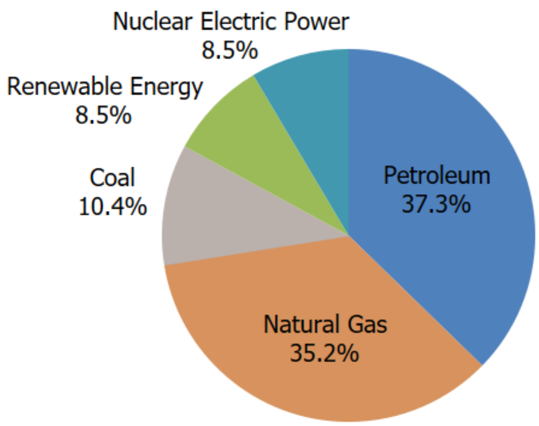
Petroleum use in the transportation sector is another major driver of emissions, representing the largest source of CO_2 emissions from fossil fuel combustion in 2022. Emissions from petroleum consumption for transportation have decreased by 4.6 percent since 2018 and are primarily attributed to a 1.4 percent decrease in VMT over the same

[8] Based on national aggregate carbon content of all coal, natural gas, and petroleum fuels combusted in the United States. See Annex 2.2 for more details on fuel carbon contents.

time period. As of 2017, the transportation sector is the largest source of national CO_2 emissions–whereas in prior years, electric power was the largest source sector.

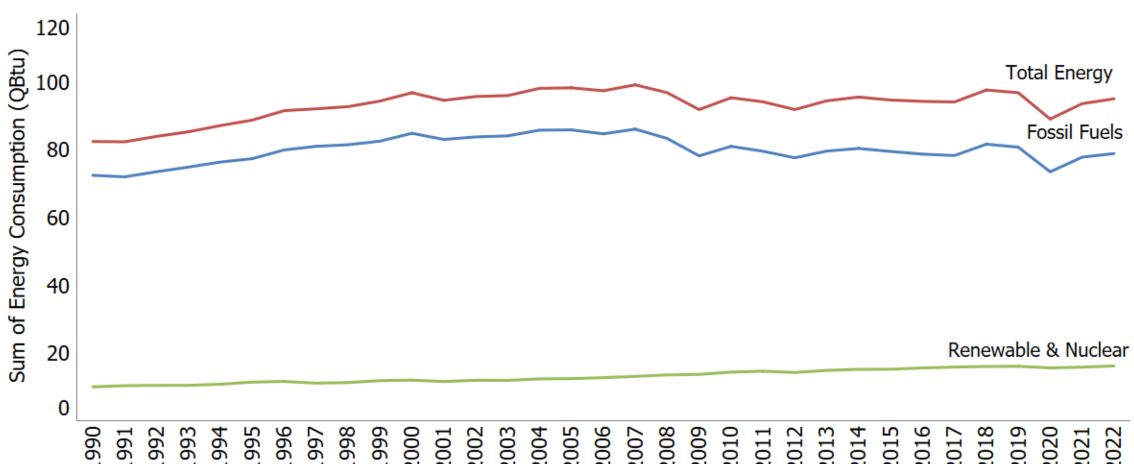
In the United States, 83.0 percent of the energy used in 2022 was produced through the combustion of fossil fuels such as petroleum, natural gas, and coal (see Figure 3-4 and Figure 3-5). Specifically, petroleum supplied the largest share of domestic energy demands, accounting for 37 percent of total U.S. energy used in 2022. Natural gas and coal followed in order of fossil fuel energy demand significance, accounting for approximately 35 percent and 10 percent of total U.S. energy used, respectively. Petroleum was consumed primarily in the transportation end-use sector and the majority of coal was used in the electric power sector. Natural gas was broadly consumed in all end-use sectors except transportation (see Figure 3-6) (EIA 2024a). The remaining portion of energy used in 2022 was supplied by nuclear electric power (8 percent) and by a variety of renewable energy sources (9 percent), primarily wind energy, hydroelectric power, solar, geothermal and biomass (EIA 2024a).[9]

Figure 3-4: 2022 U.S. Energy Use by Energy Source



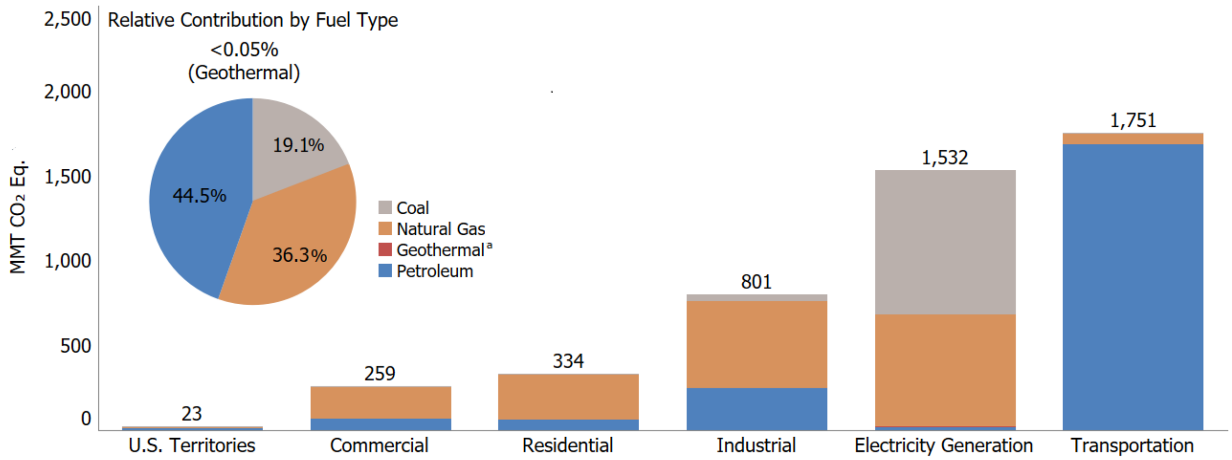
Note: Totals may not sum due to independent rounding.

Figure 3-5: Annual U.S. Energy Use



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

Figure 3-6: 2022 CO_2 Emissions from Fossil Fuel Combustion by Sector and Fuel Type



[a] Although not technically a fossil fuel, geothermal energy-related CO_2 emissions are included for reporting purposes. The source of CO_2 is non-condensable gases in subterranean heated water.

Fossil fuels are generally combusted for the purpose of producing energy for useful heat and work. During the combustion process, the carbon stored in the fuels is oxidized and emitted as CO_2 and smaller amounts of other gases, including CH_4, carbon monoxide (CO), and non-methane volatile organic compounds (NMVOCs).[10] These other C-containing non-CO_2 gases are emitted as a byproduct of incomplete fuel combustion, but are, for the most part, eventually oxidized to CO_2 in the atmosphere. Therefore, as per IPCC guidelines, it is assumed that all of the carbon in fossil fuels used to produce energy is eventually converted to atmospheric CO_2.

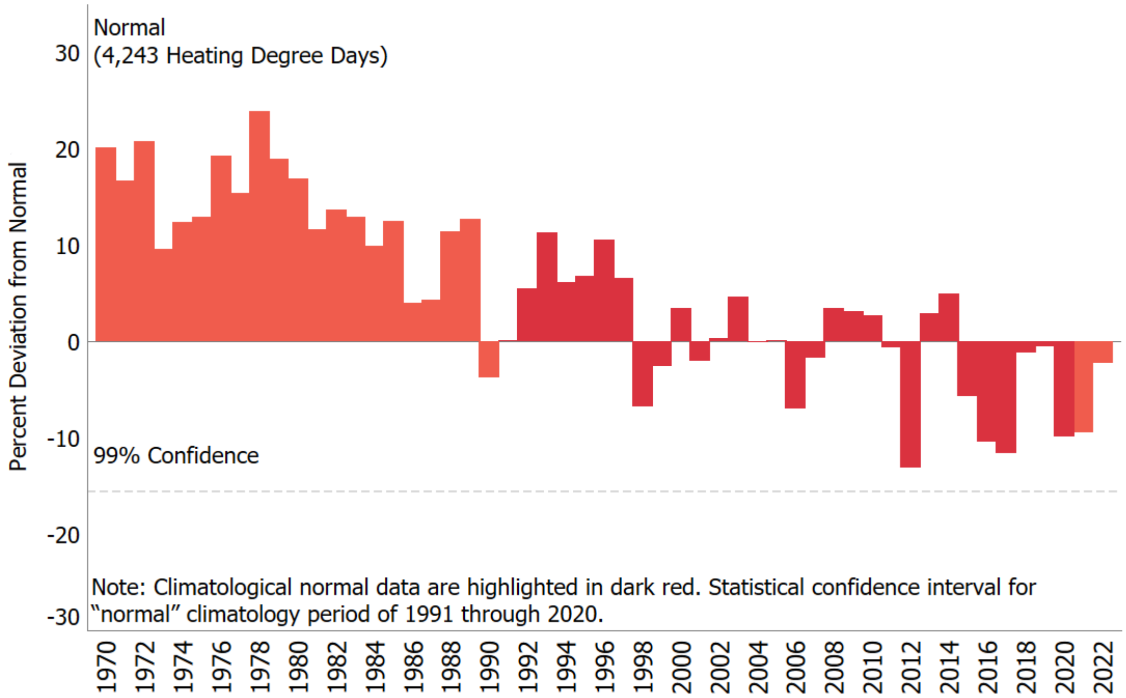
Box 3-2: Weather and Non-Fossil Energy Effects on CO_2 Emissions from Fossil Fuel Combustion Trends

The United States in 2022 experienced a colder winter overall compared to 2021, with a 7.9 percent increase in heating degree days, although 2022 heating degree days were 2.3 percent below normal (see Figure 3-7). Along with a colder winter, 2022 experienced a warmer summer, with cooling degree days 16.9 percent above normal and 4.3 percent higher compared to 2021 (see Figure 3-8) (EIA 2024a).[11] Warmer summers and colder winters can lead to increased energy use to heat and cool building spaces in the residential and commercial sectors. The combination of colder winter and warmer summer conditions in 2022 as compared to 2021 led to an overall increase in direct emissions from fossil fuel combustion in the residential and commercial sectors of 5.0 and 8.9 percent, respectively.

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

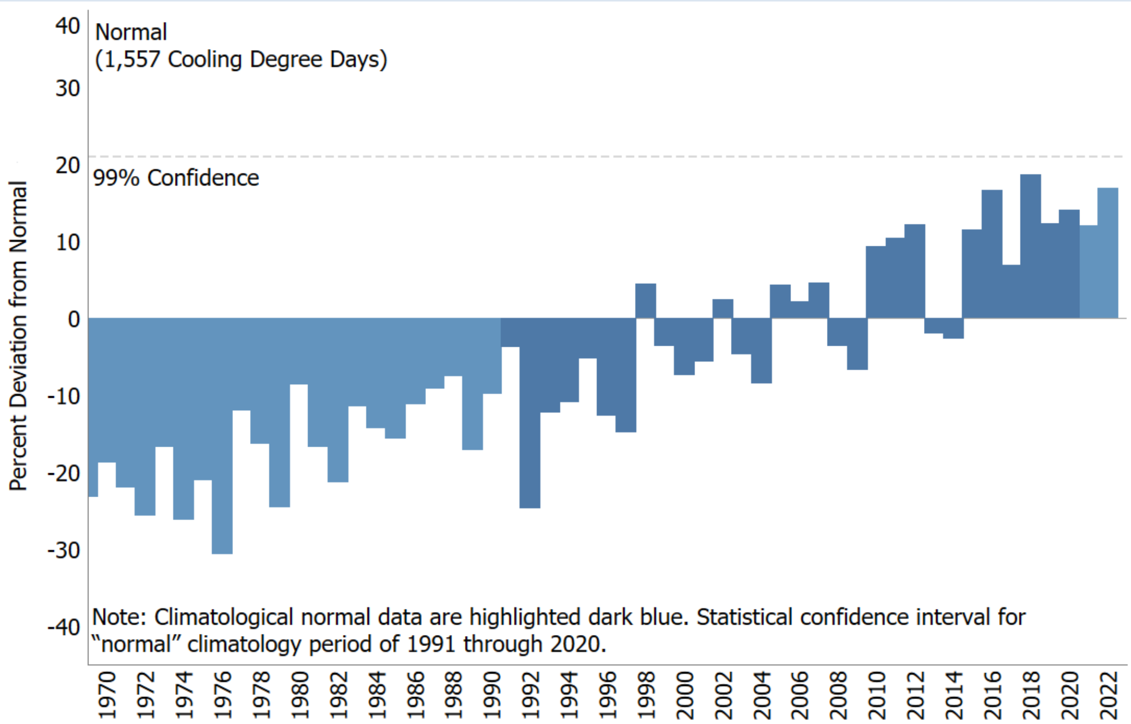
[11] Degree days are relative measurements of outdoor air temperature. Heating degree days are deviations of the mean daily temperature below 65 degrees Fahrenheit, while cooling degree days are deviations of the mean daily temperature above 65 degrees Fahrenheit. Heating degree days have a considerably greater effect on energy demand and related emissions than do cooling degree days. Excludes Alaska and Hawaii. Normals are based on data from 1991 through 2020. The variation in these normals during this time period was ±16 percent and ±27 percent for heating and cooling degree days, respectively (99 percent confidence interval).

Figure 3-7: Annual Deviations from Normal Heating Degree Days for the United States (1970–2022, Index Normal = 100)



Note: Climatological normal data are highlighted in dark red. Statistical confidence interval for "normal" climatology period of 1991 through 2020.

Figure 3-8: Annual Deviations from Normal Cooling Degree Days for the United States (1970–2022, Index Normal = 100)



Note: Climatological normal data are highlighted dark blue. Statistical confidence interval for "normal" climatology period of 1991 through 2020.

The carbon intensity of the electric power sector is impacted by the amount of non-fossil energy sources of electricity. The utilization (i.e., capacity factors)[12] of nuclear power plants in 2022 remained high at 93 percent. In 2022, nuclear power represented 19 percent of total electricity generation. Since 1990, the wind and solar power sectors have shown strong growth and have become relatively important sources of electricity. Between 1990 and 2022, renewable energy generation (in kWh) from solar and wind energy have increased from 0.1 percent in 1990 to 14 percent of total electricity generation in 2022, which helped drive the decrease in the carbon intensity of the electricity supply in the United States.

Stationary Combustion

The direct combustion of fuels by stationary sources in the electric power, industrial, commercial, and residential sectors represent the greatest share of U.S. greenhouse gas emissions. Table 3-7 presents CO_2 emissions from fossil fuel combustion by stationary sources. The CO_2 emitted is closely linked to the type of fuel being combusted in each sector (see the Methodology section of CO_2 from Fossil Fuel Combustion). In addition to CO_2 emissions, CH_4 and N_2O are emitted from fossil fuel combustion as well. Table 3-8 and Table 3-9 present CH_4 and N_2O emissions from the combustion of fuels in stationary sources. The CH_4 and N_2O emissions are linked to the type of fuel being combusted as well as the combustion technology (see the Methodology section for CH_4 and N_2O from Stationary Combustion).

Table 3-7: CO_2 Emissions from Stationary Fossil Fuel Combustion (MMT CO_2 Eq.)

Sector/Fuel Type	1990	2005	2018	2019	2020	2021	2022
Electric Power	**1,820.0**	**2,400.1**	**1,753.4**	**1,606.7**	**1,439.6**	**1,540.9**	**1,531.7**
Coal	1,546.5	1,982.8	1,152.9	973.5	788.2	910.1	851.5
Natural Gas	175.4	318.9	577.9	616.6	634.8	612.8	659.3
Fuel Oil	97.5	98.0	22.2	16.2	16.2	17.7	20.5
Geothermal	0.5	0.5	0.4	0.4	0.4	0.4	0.4
Industrial	**876.5**	**847.6**	**810.5**	**809.8**	**762.0**	**780.5**	**801.1**
Coal	157.8	117.8	54.4	49.4	43.0	43.0	43.0
Natural Gas	407.4	387.8	493.5	501.5	489.7	501.2	510.4
Fuel Oil	311.2	342.0	262.6	258.9	229.3	236.3	247.6
Residential	**338.6**	**358.9**	**338.9**	**342.9**	**314.8**	**318.0**	**334.1**
Coal	3.0	0.8	NO	NO	NO	NO	NO
Natural Gas	237.8	262.2	273.8	275.5	256.4	258.6	272.0
Fuel Oil	97.8	95.9	65.1	67.4	58.4	59.4	62.1
Commercial	**228.3**	**227.1**	**246.3**	**251.7**	**229.3**	**237.5**	**258.7**
Coal	12.0	9.3	1.8	1.6	1.4	1.4	1.4
Natural Gas	142.0	162.9	192.5	192.9	173.5	180.4	192.3
Fuel Oil	74.3	54.9	52.0	57.2	54.4	55.7	65.1
U.S. Territories	**20.0**	**51.9**	**25.9**	**24.8**	**23.3**	**23.8**	**22.6**
Coal	0.5	3.0	2.6	3.6	3.1	2.9	2.9
Natural Gas	NO	1.3	3.3	3.8	2.6	3.9	2.7
Fuel Oil	19.5	47.6	20.1	17.5	17.5	17.0	17.0
Total	**3,283.3**	**3,885.6**	**3,175.1**	**3,036.0**	**2,768.9**	**2,900.7**	**2,948.1**

NO (Not Occurring)

Note: Totals may not sum due to independent rounding.

[12] 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)" (EIA 2020a). Data for both the generation and net summer capacity are from EIA (2024a).

Table 3-8: CH_4 Emissions from Stationary Combustion (MMT CO_2 Eq.)

Sector/Fuel Type	1990	2005	2018	2019	2020	2021	2022
Electric Power	**0.5**	**1.0**	**1.4**	**1.4**	**1.4**	**1.4**	**1.3**
Coal	0.4	0.4	0.3	0.2	0.2	0.2	0.2
Fuel Oil	+	+	+	+	+	+	+
Natural gas	0.1	0.5	1.1	1.2	1.2	1.2	1.0
Wood	+	+	+	+	+	+	+
Industrial	**2.1**	**1.9**	**1.7**	**1.7**	**1.6**	**1.6**	**1.6**
Coal	0.5	0.3	0.2	0.1	0.1	0.1	0.1
Fuel Oil	0.2	0.2	0.2	0.2	0.1	0.1	0.2
Natural gas	0.2	0.2	0.2	0.3	0.2	0.3	0.3
Wood	1.2	1.2	1.1	1.1	1.1	1.1	1.0
Commercial	**1.2**	**1.2**	**1.4**	**1.4**	**1.3**	**1.3**	**1.4**
Coal	+	+	+	+	+	+	+
Fuel Oil	0.3	0.2	0.2	0.2	0.2	0.2	0.3
Natural gas	0.4	0.4	0.5	0.5	0.4	0.5	0.5
Wood	0.5	0.6	0.7	0.7	0.7	0.7	0.7
Residential	**5.9**	**4.5**	**5.1**	**5.3**	**3.6**	**3.6**	**4.3**
Coal	0.3	0.1	NO	NO	NO	NO	NO
Fuel Oil	0.4	0.4	0.3	0.3	0.2	0.2	0.3
Natural Gas	0.6	0.7	0.7	0.7	0.6	0.6	0.7
Wood	4.6	3.4	4.2	4.4	2.8	2.7	3.4
U.S. Territories	**+**	**0.1**	**+**	**+**	**+**	**+**	**+**
Coal	+	+	+	+	+	+	+
Fuel Oil	+	0.1	+	+	+	+	+
Natural Gas	NO	+	+	+	+	+	+
Wood	NE	NE	NE	NE	NE	NE	NE
Total	**9.7**	**8.8**	**9.6**	**9.8**	**8.0**	**8.0**	**8.6**

+ Does not exceed 0.05 MMT CO_2 Eq.
NO (Not Occurring)
NE (Not Estimated)
Note: Totals may not sum due to independent rounding.

Table 3-9: N_2O Emissions from Stationary Combustion (MMT CO_2 Eq.)

Sector/Fuel Type	1990	2005	2018	2019	2020	2021	2022
Electric Power	**18.2**	**26.7**	**21.7**	**18.8**	**17.5**	**19.0**	**21.6**
Coal	17.9	24.9	18.1	14.8	13.5	15.1	18.2
Fuel Oil	0.1	0.1	+	+	+	+	+
Natural Gas	0.3	1.7	3.6	3.9	4.0	3.9	3.4
Wood	+	+	+	+	+	+	+
Industrial	**2.8**	**2.6**	**2.2**	**2.2**	**2.0**	**2.1**	**2.0**
Coal	0.7	0.5	0.2	0.2	0.2	0.2	0.2
Fuel Oil	0.5	0.5	0.3	0.3	0.3	0.3	0.3
Natural Gas	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Wood	1.5	1.5	1.4	1.4	1.4	1.4	1.3
Commercial	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**
Coal	+	+	+	+	+	+	+
Fuel Oil	0.2	0.1	0.1	0.1	0.1	0.1	0.1
Natural Gas	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Wood	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Residential	**0.9**	**0.8**	**0.8**	**0.8**	**0.6**	**0.6**	**0.7**
Coal	+	+	NO	NO	NO	NO	NO
Fuel Oil	0.2	0.2	0.2	0.2	0.1	0.1	0.1

Natural Gas	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Wood	0.6	0.4	0.5	0.5	0.3	0.3	0.4
U.S. Territories	**+**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Coal	+	+	+	+	+	+	+
Fuel Oil	+	0.1	+	+	+	+	+
Natural Gas	NO	+	+	+	+	+	+
Wood	NE	NE	NE	NE	NE	NE	NE
Total	**22.3**	**30.5**	**25.1**	**22.2**	**20.5**	**22.0**	**24.7**

+ Does not exceed 0.05 MMT CO_2 Eq.
NO (Not Occurring)
NE (Not Estimated)
Note: Totals may not sum due to independent rounding.

Fossil Fuel Combustion Emissions by Sector

Table 3-10 provides an overview of the CO_2, CH_4, and N_2O emissions from fossil fuel combustion by sector, including transportation, electric power, industrial, residential, commercial, and U.S. Territories.

Table 3-10: CO_2, CH_4, and N_2O Emissions from Fossil Fuel Combustion by Sector (MMT CO_2 Eq.)

End-Use Sector	1990	2005	2018	2019	2020	2021	2022
Transportation	**1,514.6**	**1,899.9**	**1,833.6**	**1,838.6**	**1,591.5**	**1,772.9**	**1,770.6**
CO_2	1,468.9	1,858.6	1,813.1	1,816.6	1,572.8	1,753.5	1,751.3
CH_4	7.2	4.3	2.8	2.9	2.5	2.6	2.6
N_2O	38.4	37.0	17.7	19.1	16.1	16.8	16.7
Electric Power	**1,838.7**	**2,427.8**	**1,776.5**	**1,626.9**	**1,458.5**	**1,561.3**	**1,554.5**
CO_2	1,820.0	2,400.1	1,753.4	1,606.7	1,439.6	1,540.9	1,531.7
CH_4	0.5	1.0	1.4	1.4	1.4	1.4	1.3
N_2O	18.2	26.7	21.7	18.8	17.5	19.0	21.6
Industrial	**881.3**	**852.2**	**814.4**	**813.7**	**765.6**	**784.1**	**804.7**
CO_2	876.5	847.6	810.5	809.8	762.0	780.5	801.1
CH_4	2.1	1.9	1.7	1.7	1.6	1.6	1.6
N_2O	2.8	2.6	2.2	2.2	2.0	2.1	2.0
Residential	**345.4**	**364.2**	**344.9**	**349.1**	**319.0**	**322.3**	**339.1**
CO_2	338.6	358.9	338.9	342.9	314.8	318.0	334.1
CH_4	5.9	4.5	5.1	5.3	3.6	3.6	4.3
N_2O	0.9	0.8	0.8	0.8	0.6	0.6	0.7
Commercial	**229.8**	**228.6**	**248.0**	**253.5**	**230.9**	**239.2**	**260.5**
CO_2	228.3	227.1	246.3	251.7	229.3	237.5	258.7
CH_4	1.2	1.2	1.4	1.4	1.3	1.3	1.4
N_2O	0.3	0.3	0.3	0.3	0.3	0.3	0.3
U.S. Territories[a]	**20.1**	**52.1**	**26.0**	**24.9**	**23.4**	**23.9**	**22.7**
Total	**4,829.9**	**5,824.8**	**5,043.4**	**4,906.6**	**4,388.9**	**4,703.7**	**4,752.0**

[a] U.S. Territories are not apportioned by sector, and emissions shown in the table are total greenhouse gas emissions from all fuel combustion sources.
Note: Totals may not sum due to independent rounding.

Other than the greenhouse gases CO_2, CH_4, and N_2O, gases emitted from stationary combustion include the greenhouse gas precursors nitrogen oxides (NO_x), CO, NMVOCs, and sulfur dioxide (SO_2). Methane and N_2O emissions from stationary combustion sources depend upon fuel characteristics and the size and vintage of combustion device, 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 CH_4 content of the fuel and combustion efficiency.

Mobile combustion also produces emissions of CH_4, N_2O, and greenhouse gas precursors including NO_x, CO, and NMVOCs. As with stationary combustion, N_2O and NO_x emissions from mobile combustion are closely related to fuel characteristics, air-fuel mixes, combustion temperatures, and the use of pollution control equipment. Nitrous oxide 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 vehicle idle, low speed, and cold start conditions. Methane and NMVOC emissions from motor vehicles are a function of the CH_4 content of the motor fuel, the amount of hydrocarbons passing uncombusted through the engine, and any post-combustion control of hydrocarbon emissions (such as catalytic converters).

An alternative method of presenting combustion emissions is to allocate emissions associated with electric power to the sectors in which it is used. Four end-use sectors are defined: transportation, industrial, residential, and commercial. In Table 3-11 below, electric power emissions have been distributed to each end-use sector based upon the sector's share of national electricity use, with the exception of CH_4 and N_2O from transportation electricity use.[13] Emissions from U.S. Territories are also calculated separately due to a lack of end-use-specific consumption data.[14] This method assumes that emissions from combustion sources are distributed across the four end-use sectors based on the ratio of electricity use in that sector. The results of this alternative method are presented in Table 3-11.

Table 3-11: CO_2, CH_4, and N_2O Emissions from Fossil Fuel Combustion by End-Use Sector with Electricity Emissions Distributed (MMT CO_2 Eq.)

End-Use Sector	1990	2005	2018	2019	2020	2021	2022
Transportation	**1,517.6**	**1,904.6**	**1,838.4**	**1,843.4**	**1,595.6**	**1,778.0**	**1,776.7**
CO_2	1,472.0	1,863.3	1,817.9	1,821.4	1,576.9	1,758.6	1,757.4
CH_4	7.2	4.3	2.8	2.9	2.5	2.6	2.6
N_2O	38.4	37.0	17.7	19.1	16.1	16.8	16.7
Industrial	**1,574.8**	**1,597.0**	**1,322.4**	**1,285.0**	**1,180.8**	**1,235.2**	**1,248.2**
CO_2	1,562.9	1,584.0	1,311.8	1,275.3	1,171.8	1,225.6	1,238.0
CH_4	2.2	2.2	2.1	2.1	2.0	2.0	1.9
N_2O	9.7	10.8	8.5	7.6	7.1	7.6	8.2
Residential	**944.2**	**1,230.1**	**995.7**	**940.2**	**871.6**	**902.1**	**912.9**
CO_2	931.3	1,214.9	981.2	926.7	860.1	890.3	899.4
CH_4	6.0	4.9	5.6	5.8	4.2	4.2	4.8
N_2O	6.9	10.3	8.8	7.7	7.3	7.7	8.7
Commercial	**773.1**	**1,040.9**	**861.0**	**813.1**	**717.6**	**764.6**	**791.6**
CO_2	766.0	1,030.1	851.3	804.4	709.6	756.1	782.0
CH_4	1.3	1.5	1.8	1.9	1.8	1.8	1.8
N_2O	5.7	9.3	7.8	6.8	6.2	6.7	7.7
U.S. Territories[a]	**20.1**	**52.1**	**26.0**	**24.9**	**23.4**	**23.9**	**22.7**
Total	**4,829.9**	**5,824.8**	**5,043.4**	**4,906.6**	**4,388.9**	**4,703.7**	**4,752.0**

[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 electric power are allocated based on aggregate national electricity use by each end-use sector.

[13] Separate calculations are performed for transportation-related CH_4 and N_2O. The methodology used to calculate these emissions is discussed in the Mobile Combustion section.

[14] U.S. Territories (including American Samoa, Guam, Puerto Rico, U.S. Virgin Islands, Wake Island, and other outlying U.S. Pacific Islands) consumption data obtained from EIA are only available at the aggregate level and cannot be broken out by end-use sector. The distribution of emissions to each end-use sector for the 50 states does not apply to territories data.

Electric Power Sector

The process of generating electricity is the largest stationary source of CO_2 emissions in the United States, representing 30.3 percent of total CO_2 emissions from all CO_2 emissions sources across the United States. Methane and N_2O accounted for a small portion of total greenhouse gas emissions from electric power, representing 0.1 percent and 1.4 percent, respectively. Electric power also accounted for 32.6 percent of CO_2 emissions from fossil fuel combustion in 2022. Methane and N_2O from electric power represented 11.4 and 52.2 percent of total CH_4 and N_2O emissions from fossil fuel combustion in 2022, respectively.

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 energy use and emissions associated with the electric power sector are included here. The electric power sector consists of electric utilities and independent power producers whose primary business is the production of electricity. This includes both regulated utilities and non-utilities (e.g., independent power producers, qualifying co-generators, and other small power producers). Energy use and emissions associated with electric generation in the commercial and industrial sectors is reported in those other sectors where the producer of the power indicates that its primary business is something other than the production of electricity.[15]

Total greenhouse gas emissions from the electric power sector have decreased by 15.5 percent since 1990. From 1990 to 2007, electric power sector emissions increased by 33 percent, driven by a significant increase in electricity demand (39 percent) while the carbon intensity of electricity generated showed a modest decline (2.1 percent). From 2008 to 2022, as electricity demand increased by 5.2 percent, electric power sector emissions decreased by 35 percent, driven by a significant drop (25 percent) in the carbon intensity of electricity generated. Overall, the carbon intensity of the electric power sector, in terms of CO_2 Eq. per QBtu, decreased by 28 percent from 1990 to 2022 with additional trends detailed in Box 3-4. This decoupling of electric power generation and the resulting CO_2 emissions is shown in Figure 3-9. This recent decarbonization of the electric power sector is a result of several key drivers.

Coal-fired electric generation (in kilowatt-hours [kWh]) decreased from 54 percent of generation in 1990 to 20 percent in 2022.[16] This corresponded with an increase in natural gas generation and renewable energy generation, largely from wind and solar energy. Natural gas generation (in kWh) represented 11 percent of electric power generation in 1990 and increased over the 33-year period to represent 39 percent of electric power sector generation in 2022 (see Table 3-12). Natural gas has a much lower carbon content than coal and is generated in power plants that are generally more efficient in terms of kWh produced per Btu of fuel combusted, which has led to lower emissions as natural gas replaces coal-powered electricity generation. Natural gas and coal used in the United States in 2022 had an average carbon content of 14.43 MMT C/Qbtu and 26.13 MMT C/Qbtu respectively.

[15] Utilities primarily generate power for the U.S. electric grid for sale to retail customers. Non-utilities typically generate electricity for sale on the wholesale electricity market (e.g., to utilities for distribution and resale to retail customers). Where electricity generation occurs outside the EIA-defined electric power sector, it is typically for the entity's own use.

[16] Values represent electricity *net* generation from the electric power sector (EIA 2024a).

Table 3-12: Electric Power Generation by Fuel Type (Percent)

Fuel Type	1990	2005	2018	2019	2020	2021	2022
Coal	54.1%	51.1%	28.4%	24.2%	19.9%	22.6%	20.3%
Natural Gas	10.7%	17.5%	34.0%	37.3%	39.5%	37.3%	38.8%
Nuclear	19.9%	20.0%	20.1%	20.4%	20.5%	19.7%	18.9%
Renewables	11.3%	8.3%	16.8%	17.6%	19.5%	19.8%	21.4%
Petroleum	4.1%	3.0%	0.6%	0.4%	0.4%	0.5%	0.5%
Other Gases[a]	+	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
Net Electricity Generation (Billion kWh)[b]	2,905	3,902	4,020	3,966	3,851	3,955	4,076

+ Does not exceed 0.05 percent.

[a] Other gases include blast furnace gas, propane gas, and other manufactured and waste gases derived from fossil fuels.

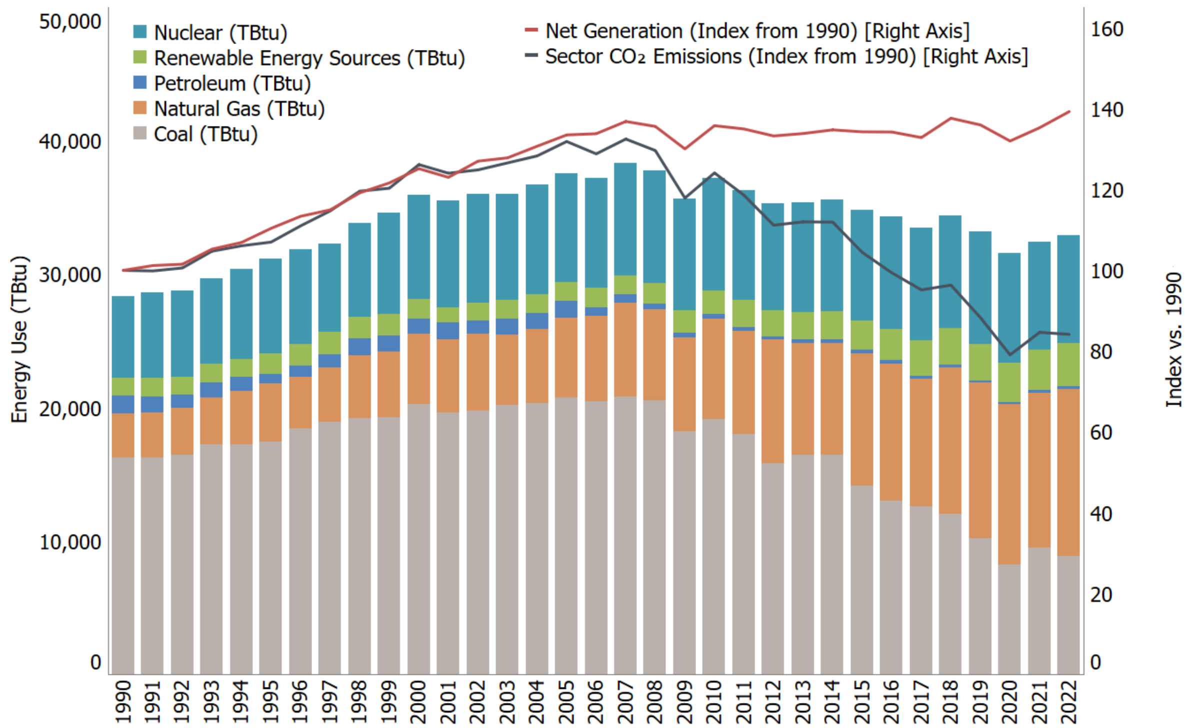
[b] Represents net electricity generation from the electric power sector. Excludes net electricity generation from commercial and industrial combined-heat-and-power and electricity-only plants. Does not include electricity generation from purchased steam as the fuel used to generate the steam cannot be determined.

In 2022, CO_2 emissions from the electric power sector decreased by 0.6 percent relative to 2021. This decrease in CO_2 emissions was primarily driven by a decrease in coal consumed to produce electricity in the electric power sector. Consumption of coal for electric power decreased by 6.4 percent while consumption of natural gas increased 7.6 percent from 2021 to 2022, leading to an overall decrease in emissions. There has also been a rapid increase in renewable energy electricity generation in the electric power sector in recent years. Electricity generation from renewable sources increased by 11 percent from 2021 to 2022 (see Table 3-12). A decrease in coal-fired electricity generation and increases in natural gas and renewable energy sources for electricity generation contributed to a decoupling of emissions trends from electric power generation trends over the recent time series (see Figure 3-9).

Decreases in natural gas prices and the associated increase in natural gas generation, particularly between 2005 and 2019, was a primary driver of the fuel switching from using coal to using natural gas for electricity generation, which led to a significant decrease in CO_2 emissions from electricity generation. During this time period, the cost of natural gas (in $/MMBtu) decreased by 56 percent while the cost of coal (in $/MMBtu) increased by 74 percent (EIA 2024a). However, from 2020 to 2022, natural gas prices increased 200 percent and are now 9 percent higher than 2005 levels due to the COVID-19 pandemic and other factors disrupting the domestic and global natural gas markets. While the increase in natural gas prices led to a temporary trend reversal, with coal consumption increasing and natural gas consumption decreasing from 2020 to 2021, the broader trend of declining coal consumption for electricity generation continues. From 2021 to 2022, coal consumption decreased 6 percent while natural gas consumption increased 8 percent.

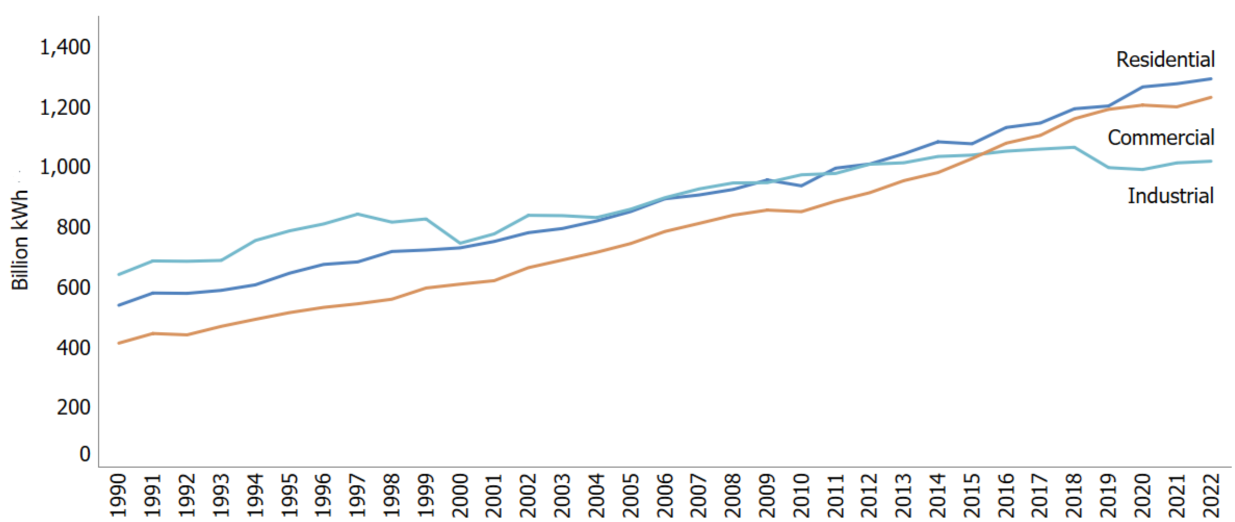
Moving forward, the shift away from coal—and increasingly towards renewable energy sources in addition to natural gas—for electricity generation will further contribute to reductions in power sector emissions. Renewable energy generation (in kWh) from wind and solar energy increased from 0.1 percent of total generation in 1990 to 5 percent in 2015 and increased at a faster pace to 14 percent of total generation in 2022. The decrease in carbon intensity occurred even as total electricity retail sales increased 45 percent, from 2,713 billion kWh in 1990 to 3,927 billion kWh in 2022.

Figure 3-9: Fuels Used in Electric Power Generation and Total Electric Power Sector CO_2 Emissions



Electricity was used primarily in the residential, commercial, and industrial end-use sectors for lighting, heating, electric motors, appliances, electronics, and air conditioning (see Figure 3-10). Note that transportation is an end-use sector as well but is not shown in Figure 3-10 due to the sector's relatively low percentage of electricity use. The Transportation Sector and Mobile Combustion section provides a break-out of CO_2 emissions from electricity use in the transportation end-use sector.

Figure 3-10: Electric Power Retail Sales by End-Use Sector



In 2022, electricity sales to the residential and commercial end-use sectors, as presented in Figure 3-10, increased by 2.6 percent and 4.7 percent relative to 2021, respectively. Electricity sales to the industrial sector in 2022 increased by approximately 2.0 percent relative to 2021. The sections below describe end-use sector energy use in more detail. Overall, in 2022, the amount of electricity retail sales (in kWh) increased by 3.2 percent relative to 2021.

Industrial Sector

Industrial sector CO_2, CH_4, and N_2O emissions accounted for 17, 14, and 5 percent of CO_2, CH_4, and N_2O emissions from fossil fuel combustion, respectively, in 2022. Carbon dioxide, CH_4, and N_2O emissions resulted from the direct consumption of fossil fuels for steam and process heat production.

The industrial end-use sector, per the underlying energy use data from EIA, includes activities such as manufacturing, construction, mining, and agriculture. The largest of these activities in terms of energy use is manufacturing, of which six industries—petroleum refineries, chemicals, paper, primary metals, food, and nonmetallic mineral products—represent the majority of the energy use (EIA 2024a; EIA 2009b).

There are many dynamics that impact emissions from the industrial sector including economic activity, changes in the make-up of the industrial sector, changes in the emissions intensity of industrial processes, and weather-related impacts on heating and cooling of industrial buildings.[17] 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) have had a significant effect on industrial emissions.

From 2021 to 2022, total industrial production and manufacturing output increased by 3.4 percent (FRB 2022). Over this period, output increased slightly across production indices for Food, Nonmetallic Mineral Products, Paper, Petroleum Refineries, and Primary Metals. Production of chemicals declined slightly between 2021 and 2022 (see Figure 3-11). From 2021 to 2022, total energy use in the industrial sector increased by 2.0 percent, driven mainly by a 2.6 percent increase in fossil fuel consumption in the industrial sector. Consumption of renewables decreased 1.6 percent from 2021 to 2022. Due to the relative increases and decreases of individual indices there was an increase in natural gas and an increase in electricity used by this sector (see Figure 3-12). In 2022, CO_2, CH_4, and N_2O emissions from fossil fuel combustion and electricity use within the industrial end-use sector totaled 1,248.2 MMT CO_2 Eq., a 1.1 percent increase from 2021 emissions.

Through EPA's Greenhouse Gas Reporting Program (GHGRP), specific industrial sector trends can be discerned from the overall total EIA industrial fuel consumption data used for these calculations. For example, from 2021 to 2022, the underlying EIA data showed increased consumption of natural gas and petroleum and decreased consumption of coal in the industrial sector. The GHGRP data highlights that several industries contributed to these trends, including chemical manufacturing; pulp, paper and print; food processing, beverages and tobacco; minerals manufacturing; and agriculture-forest-fisheries.[18]

[17] 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.

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

Figure 3-11: Industrial Production Indices (Index 2017=100)

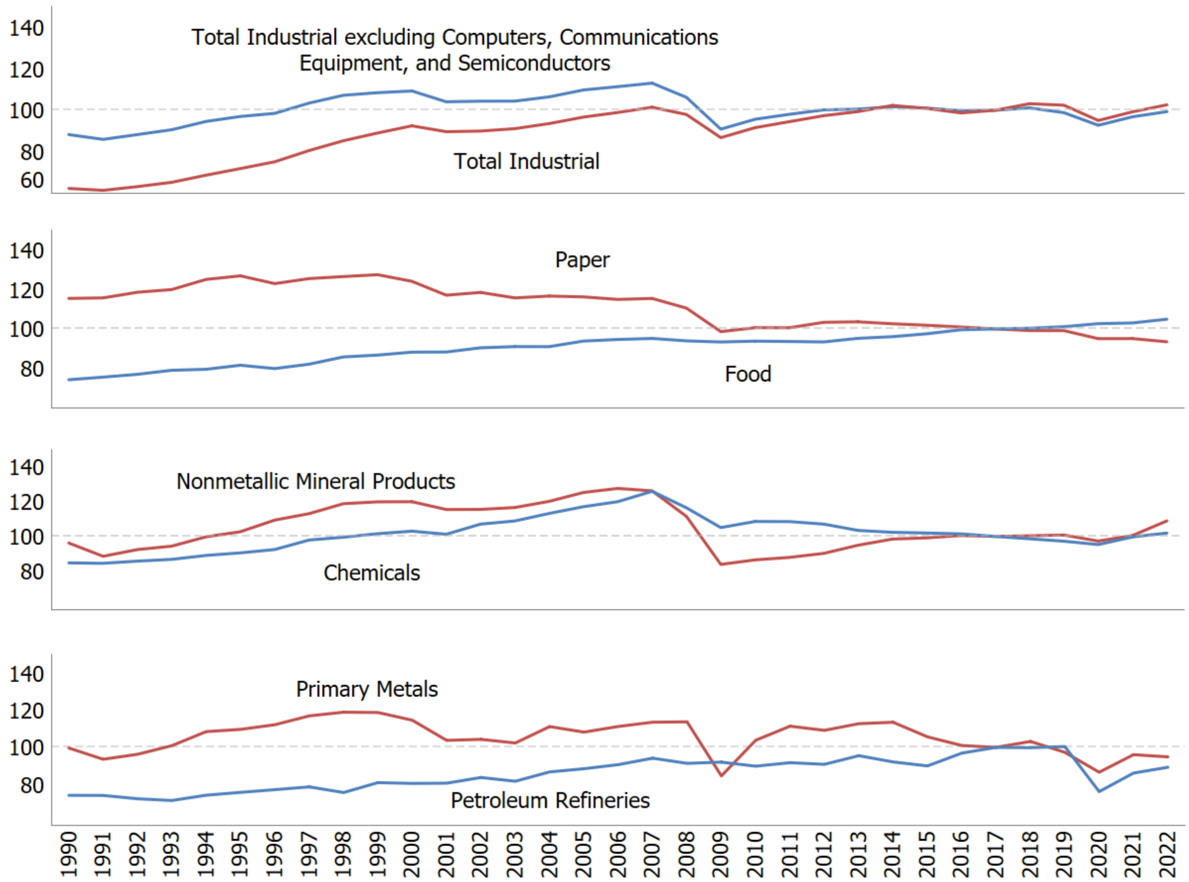
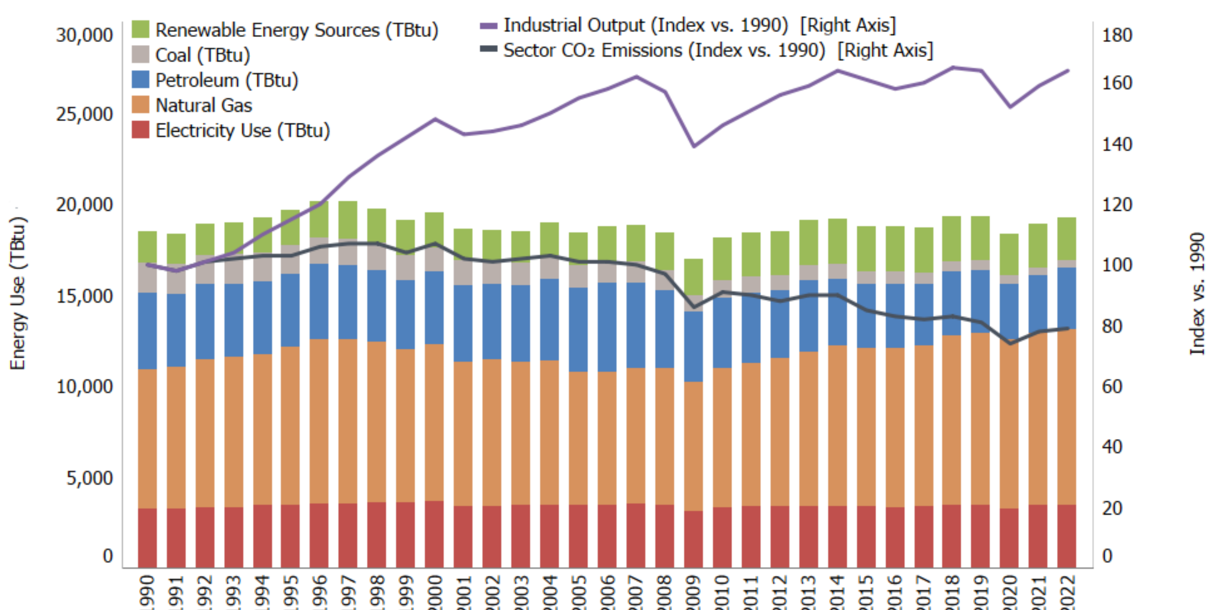


Figure 3-12: Fuels and Electricity Used in Industrial Sector, Industrial Output, and Total Sector CO_2 Emissions (Including Electricity)



Despite the growth in industrial output (65 percent) and the overall U.S. economy (114 percent) from 1990 to 2022, direct CO_2 emissions from fossil fuel combustion in the industrial sector decreased by 8.6 percent over the same time series. A number of factors are assumed to result in decoupling of growth in industrial output from industrial greenhouse gas emissions, for example: (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.

Box 3-3: 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 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 GHGRP 2010 through 2022 reporting years, facility-level fossil fuel combustion emissions reported through EPA's 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 Paris Agreement and 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.[19]

As with previous *Inventory* reports, the current 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 Tables (CRTs) that are submitted to the UNFCCC along with this report.[20] The efforts in reconciling fuels focus on standard, common fuel types (e.g., natural gas, distillate fuel oil) where the fuels in EIA's national statistics aligned well with facility-level GHGRP data. For these reasons, the current information presented in the CRTs 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. The current analysis includes the full time series presented in the CRTs. 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 2022 time period in the CRTs. 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. This includes incorporating the latest MECS data as it becomes available.

Residential and Commercial Sectors

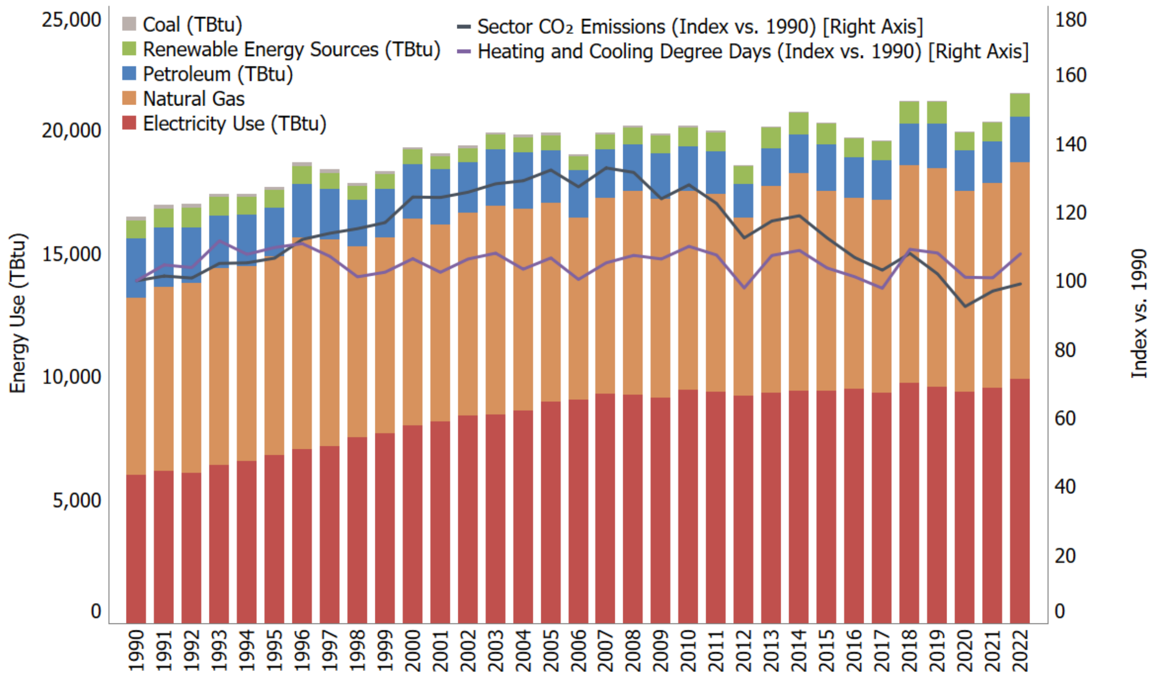
Emissions from the residential and commercial sectors have generally decreased since 2005. Short-term trends are often correlated with seasonal fluctuations in energy use caused by weather conditions, rather than prevailing economic conditions. Population growth and a trend towards larger houses has led to increasing energy use over

[19] 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/public/tb/TFI_Technical_Bulletin_1.pdf.

[20] See https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks.

the time series, while population migration to warmer areas and improved energy efficiency and building insulation have slowed the increase in energy use in recent years. Starting in around 2014, energy use and emissions begin to decouple due to decarbonization of the electric power sector (see Figure 3-13).

Figure 3-13: Fuels and Electricity Used in Residential and Commercial Sectors, Heating and Cooling Degree Days, and Total Sector CO_2 Emissions (Including Electricity)



In 2022, excluding indirect emissions from electricity use, the residential and commercial sectors accounted for 7 and 6 percent of CO_2 emissions from fossil fuel combustion, respectively; 39 and 13 percent of CH_4 emissions from fossil fuel combustion, respectively; and 2 and 1 percent of N_2O emissions from fossil fuel combustion, respectively. Emissions from these sectors are primarily attributable to building -related activities such as 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 the commercial sector and did not contribute to any energy use in the residential sector. Greenhouse gas emissions from commercial and residential buildings also increase substantially when emissions from electricity end-use are included, because the building sector uses 75 percent of the electricity generated in the United States (e.g., for heating, ventilation, and air conditioning; lighting; and appliances) (NREL 2023). In 2022, total emissions (CO_2, CH_4, and N_2O) from fossil fuel combustion and electricity use within the residential and commercial end-use sectors were 912.9 MMT CO_2 Eq. and 791.6 MMT CO_2 Eq., respectively. Total CO_2, CH_4, and N_2O emissions from combined fossil fuel combustion and electricity use within the residential and commercial end-use sectors increased by 1.2 and 3.5 percent from 2021 to 2022, respectively. An increase in heating degree days (7.9 percent) and cooling degree days (4.3 percent) increased energy demand for heating and cooling in the residential and commercial sectors. This resulted in a 2.6 percent increase in residential sector electricity use. From 2021 to 2022 there was a 8.4 percent higher direct energy use in the commercial sector. In addition, a shift toward energy efficient products and more stringent energy efficiency standards for household equipment has contributed to a decrease in energy demand in households (EIA 2022), resulting in a decrease in energy-related emissions in the residential sector since 1990. In the long term, the residential sector is also affected by population growth, migration trends toward warmer areas, and changes in total housing units and building attributes (e.g., larger sizes and improved insulation).

In 2022, combustion emissions from natural gas consumption represented 81 and 74 percent of the direct fossil fuel CO_2 emissions from the residential and commercial sectors, respectively. Carbon dioxide emissions from natural gas combustion in the residential and commercial sectors in 2022 increased by 5.2 percent and 6.6 percent from 2021, 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 outlying U.S. Pacific Islands. As described in the Methodology section of CO_2 from Fossil Fuel Combustion, this data is collected separately from the sectoral-level data available for the general calculations. As sectoral information is not available for U.S. Territories, CO_2, CH_4, and N_2O emissions are not presented for U.S. Territories in the tables above by sector, though the emissions will occur across all sectors and sources including stationary, 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 1-9. Table 1-8 presents direct CO_2, CH_4, and N_2O emissions from all transportation sources (i.e., excluding emissions allocated to electricity consumption in the transportation end-use sector).

The transportation end-use sector and other mobile combustion accounted for 1,776.7 MMT CO_2 Eq. in 2022, which represented 37 percent of CO_2 emissions, 23 percent of CH_4 emissions, and 41 percent of N_2O emissions from fossil fuel combustion, respectively.[21] Fuel purchased in the U.S. for international aircraft and marine travel accounted for an additional 98.9 MMT CO_2 Eq. in 2022; these emissions are recorded as international bunkers and are not included in U.S. totals according to Paris Agreement and UNFCCC reporting protocols.

Transportation End-Use Sector

From 1990 to 2019, transportation emissions from fossil fuel combustion rose by 21 percent, followed by a reduction of 13 percent from 2019 to 2020, followed by an increase of 12 percent from 2020 to 2022. Overall, from 1990 to 2022, transportation emissions from fossil fuel combustion increased by 17 percent. The increase in transportation emissions from fossil fuel combustion from 1990 to 2022 was due, in large part, to increased demand for travel (see Figure 3-14). The number of vehicle miles traveled by light-duty motor vehicles (passenger cars and light-duty trucks) increased 47 percent from 1990 to 2022, as a result of a confluence of factors including population growth, economic growth, urban sprawl, and low fuel prices over much of this period. Between 2019 and 2020, emissions from light-duty vehicles fell by 11 percent, primarily the result of the COVID-19 pandemic and associated restrictions, such as people working from home and traveling less. Light-duty vehicle VMT rebounded in 2022 but is still estimated to be 2 percent below 2019 levels.

Commercial aircraft emissions decreased by 5 percent between 2019 and 2022 but have decreased 7 percent since 2007 (FAA 2024 and DOT 1991 through 2023).[22] Decreases in jet fuel emissions (excluding bunkers) started in 2007 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; however, the sharp decline in commercial aircraft emissions from 2019 to 2020 and their gradual recovery since is primarily due to COVID-19 impacts on scheduled passenger air travel.

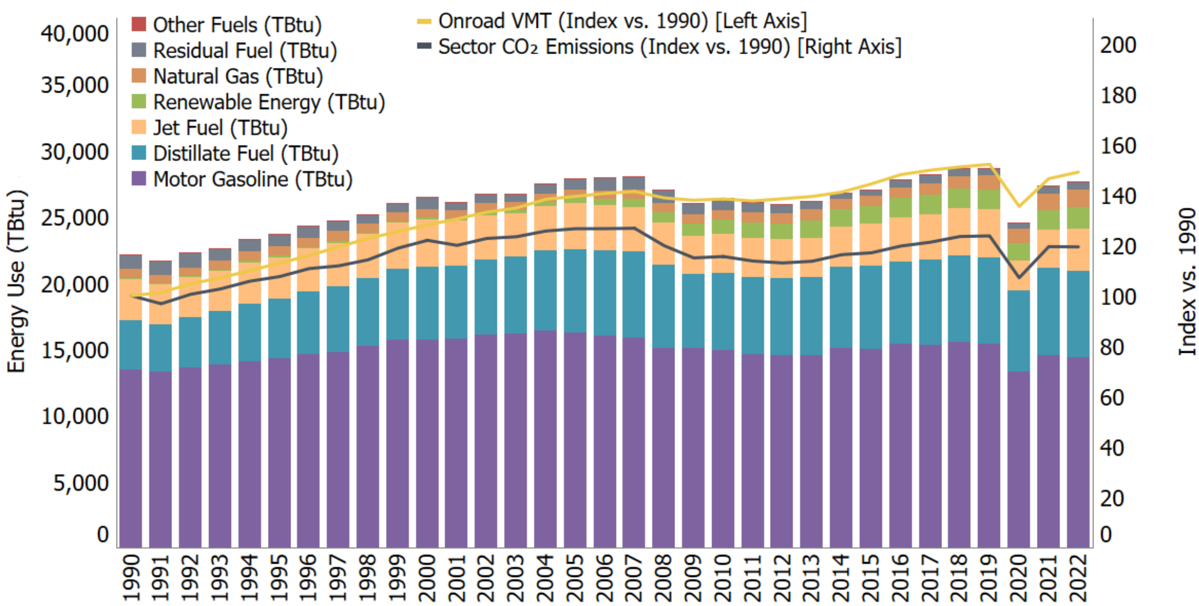
Almost all of the energy consumed for transportation was supplied by petroleum-based products, with more than half being related to gasoline consumption in automobiles and other highway vehicles. Other fuel uses, especially

[21] Note that these totals include CO_2, CH_4 and N_2O emissions from some sources in the U.S. Territories (ships and boats, recreational boats, non-transportation mobile sources) and CH_4 and N_2O emissions from transportation rail electricity.

[22] Commercial aircraft consists of passenger aircraft, cargo, and other chartered flights.

diesel fuel for freight trucks and jet fuel for aircraft, accounted for the remainder. The primary driver of transportation-related emissions was CO_2 from fossil fuel combustion, which increased by 19 percent from 1990 to 2022. Annex 3.2 presents the total emissions from all transportation and mobile sources, including CO_2, N_2O, CH_4, and HFCs.

Figure 3-14: Fuels Used in Transportation Sector, On-road VMT, and Total Sector CO_2 Emissions



Notes: Distillate fuel, residual fuel, and jet fuel include adjustments for international bunker fuels. Distillate fuel and motor gasoline include adjustments for the sectoral allocation of these fuels. Other Fuels includes aviation gasoline and propane.

Source: Information on fuel consumption was obtained from EIA (2022).

Transportation Fossil Fuel Combustion CO_2 Emissions

Domestic transportation CO_2 emissions increased by 19 percent (285.4 MMT CO_2 Eq.) between 1990 and 2022, an annualized increase of 0.6 percent. This includes a 24 percent increase in CO_2 emissions between 1990 and 2019, followed by a 13 percent decrease in 2020. Carbon dioxide emissions then increased by 11 percent between 2020 and 2022. Among domestic transportation sources, light-duty vehicles (including passenger cars and light-duty trucks) represented 57 percent of CO_2 emissions, medium- and heavy-duty trucks and buses 24 percent, commercial aircraft 7 percent, and other sources 11 percent. See Table 3-13 for a detailed breakdown of transportation CO_2 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.[23] Ethanol consumption from the transportation sector has increased from 0.7 billion gallons in 1990 to 12.9 billion gallons in 2022, while biodiesel

[23] 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 Standards website. See https://www.epa.gov/renewable-fuel-standard-program.

consumption has increased from 0.01 billion gallons in 2001 to 1.6 billion gallons in 2022." For additional information, see Section 3.10 on biofuel consumption at the end of this chapter and Table A-74 in Annex 3.2.

Carbon dioxide emissions from passenger cars and light-duty trucks totaled 1,005.5 MMT CO_2 in 2022, an increase of 10 percent (91.2 MMT CO_2) from 1990. The increase in CO_2 emissions from passenger cars and light-duty trucks from 1990 to 2022 was due, in large part, to increased demand for travel as fleet-wide 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 2022). Carbon dioxide emissions from passenger cars and light-duty trucks peaked at 1,145.5 MMT in 2004, and since then have declined about 12 percent. The decline in new light-duty vehicle fuel economy between 1990 and 2004 (see Figure 3-15) reflects 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, average new vehicle fuel economy began to increase while light-duty vehicle VMT grew only modestly for much of the period. Light-duty vehicle VMT grew by less than one percent or declined each year between 2005 and 2013, and again between 2017 and 2019. VMT grew at faster rates of 1.6 percent from 2014 to 2015, and 1.6 percent from 2015-2016. From 2019 to 2020, light-duty vehicle VMT declined by 11.0 percent due to COVID-19 pandemic; from 2020 to 2022 light-duty vehicle VMT rebounded as a part of the ongoing recovery from the pandemic, increasing by 9.8 percent.

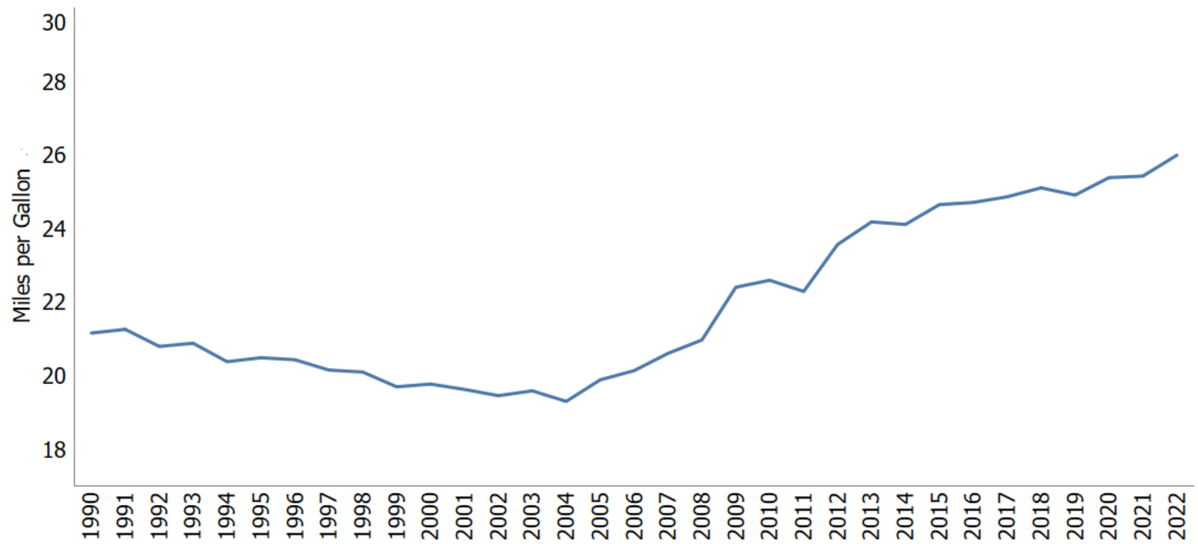
Average new vehicle fuel economy has improved almost every year since 2005 while the light-duty truck share of new vehicle sales decreased to about 33 percent of new vehicles in 2009 and has since varied from year to year between 36 and 63 percent. Since 2014, the light-duty truck share has steadily increased, reaching 62 percent of new vehicle sales in model year 2022. See Annex 3.2 for data by vehicle mode and information on VMT and the share of new vehicles (in VMT).

Medium- and heavy-duty truck CO_2 emissions increased by 73 percent from 1990 to 2022. This increase was largely due to a substantial growth in medium- and heavy-duty truck VMT, which increased by 72 percent between 1990 and 2022.

Carbon dioxide from the domestic operation of commercial aircraft increased by 18 percent (19.8 MMT CO_2) from 1990 to 2022. Across all categories of aviation, excluding international bunkers, CO_2 emissions decreased by 11 percent (20.8 MMT CO_2) between 1990 and 2022.[24] Carbon dioxide emissions from military aircraft decreased 65 percent between 1990 and 2022. Commercial aircraft CO_2 emissions increased 27 percent between 1990 and 2007, dropped 2 percent from 2007 to 2019, dropped another 33 percent from 2019 to 2020, then increased by 30 percent from 2020 to 2022. Overall, this represents a change of approximately 18 percent between 1990 and 2022. Transportation sources also produce CH_4 and N_2O; these emissions are included in Figure 3-14 and Table 3-15 and in the CH_4 and N_2O from Mobile Combustion section. Annex 3.2 presents total emissions from all transportation and mobile sources, including CO_2, CH_4, N_2O, and HFCs.

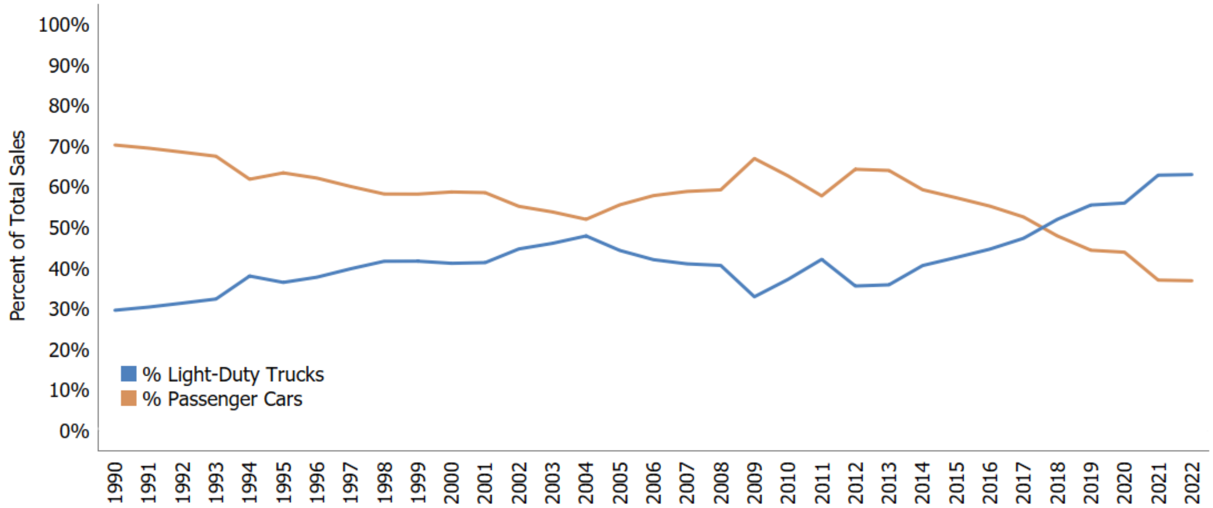
[24] Includes consumption of jet fuel and aviation gasoline. Does not include aircraft bunkers, which are not included in national emission totals, in line with IPCC methodological guidance and UNFCCC reporting obligations.

Figure 3-15: Sales-Weighted Fuel Economy of New Passenger Cars and Light-Duty Trucks, 1990–2022



Source: EPA (2023).

Figure 3-16: Sales of New Passenger Cars and Light-Duty Trucks, 1990–2022



Source: EPA (2023).

Table 3-13: CO_2 Emissions from Fossil Fuel Combustion in Transportation End-Use Sector ($MMT\ CO_2$ Eq.)

Fuel/Vehicle Type	1990	2005	2018	2019	2020	2021	2022
Gasoline[a]	**958.9**	**1,150.1**	**1,097.0**	**1,086.5**	**936.9**	**1,028.7**	**1,014.5**
Passenger Cars	612.8	518.9	382.5	380.0	328.0	360.5	356.0
Light-Duty Trucks	283.6	583.4	667.6	658.6	565.7	619.9	609.5
Medium- and Heavy-Duty Trucks[b]	42.8	28.1	26.2	27.0	24.1	27.4	27.9
Buses	2.1	1.1	2.7	2.8	2.5	2.9	2.9
Motorcycles	3.4	4.9	7.3	7.4	6.6	7.4	7.4
Recreational Boats[c]	14.3	13.7	10.7	10.7	9.9	10.6	10.8

Distillate Fuel Oil (Diesel)[a]	**274.6**	**472.1**	**486.6**	**484.1**	**455.2**	**488.1**	**483.9**
Passenger Cars	9.4	2.2	2.8	2.7	2.5	2.7	2.7
Light-Duty Trucks	8.4	30.4	31.2	31.2	30.2	33.3	33.8
Medium- and Heavy-Duty Trucks[b]	189.0	357.2	371.5	373.0	353.5	380.1	375.6
Buses	11.1	15.5	20.4	20.7	19.8	21.4	21.4
Rail	35.5	46.1	38.5	36.0	31.2	32.5	32.5
Recreational Boats[c]	2.7	2.9	2.8	2.9	2.6	2.8	3.0
Ships and Non-Recreational Boats[d]	6.8	8.4	9.3	7.5	7.6	7.8	7.8
International Bunker Fuels[e]	*11.7*	*9.5*	*10.0*	*10.1*	*7.8*	*7.4*	*7.2*
Jet Fuel	**222.3**	**249.5**	**255.2**	**258.5**	**160.4**	**203.5**	**231.5**
Commercial Aircraft[f]	109.9	132.7	129.6	136.7	91.3	119	129.7
Military Aircraft	35.7	19.8	12.1	12.2	11.7	12.5	12.4
General Aviation Aircraft	38.5	36.8	30.6	31.4	17.6	21.1	22.7
International Bunker Fuels[e]	*38.2*	*60.2*	*83.0*	*78.3*	*39.8*	*50.8*	*66.6*
International Bunker Fuels from Commercial Aviation	*30.0*	*55.6*	*79.8*	*75.1*	*36.7*	*47.6*	*63.5*
Aviation Gasoline	**3.1**	**2.4**	**1.5**	**1.6**	**1.4**	**1.5**	**1.5**
General Aviation Aircraft	3.1	2.4	1.5	1.6	1.4	1.5	1.5
Residual Fuel Oil	**76.3**	**62.9**	**45.4**	**39.7**	**29.4**	**46.2**	**47.3**
Ships and Non-Recreational Boats[e]	22.6	19.3	14.0	14.5	7.3	24.2	22.9
International Bunker Fuels[e]	*53.7*	*43.6*	*31.4*	*25.2*	*22.1*	*21.9*	*24.4*
Natural Gas[i]	**36.0**	**33.1**	**50.9**	**58.9**	**58.7**	**65.2**	**70.2**
Passenger Cars	+	+	+	+	+	+	+
Light-Duty Trucks	+	+	+	+	+	+	+
Medium- and Heavy-Duty Trucks	+	+	0.1	0.1	0.1	0.1	0.1
Buses	+	0.2	0.5	0.5	0.6	0.6	0.7
Pipeline[g]	36.0	32.8	50.3	58.3	58.0	64.4	69.3
LPG[i]	**1.4**	**1.8**	**0.8**	**0.8**	**0.5**	**0.6**	**0.6**
Passenger Cars	+	+	+	+	+	+	+
Light-Duty Trucks	0.1	0.1	+	+	+	+	+
Medium- and Heavy-Duty Trucks[b]	1.3	0.9	0.1	0.1	0.1	+	+
Buses	+	0.7	0.7	0.7	0.5	0.6	0.6
Electricity[k]	**3.0**	**4.7**	**4.8**	**4.8**	**4.1**	**5.0**	**6.1**
Passenger Cars	+	+	1.2	1.4	1.3	1.8	2.4
Light-Duty Trucks	+	+	0.2	0.2	0.3	0.7	1.1
Buses	+	+	+	+	0.1	0.1	0.1
Rail	3.0	4.7	3.4	3.1	2.4	2.5	2.5
Total[e,j]	**1,472.0**	**1,863.3**	**1,817.9**	**1,821.4**	**1,576.9**	**1758.6**	**1,757.4**
International Bunker Fuels	*103.6*	*113.3*	*124.3*	*113.6*	*69.6*	*80.2*	*98.2*
Biofuels-Ethanol[h]	*4.1*	*21.6*	*78.6*	*78.7*	*68.1*	*75.4*	*75.0*
Biofuels-Biodiesel[h]	*0.0*	*0.9*	*17.9*	*17.1*	*17.7*	*16.1*	*15.6*

+ Does not exceed 0.05 MMT CO_2 Eq.

[a] On-road fuel consumption data from FHWA Table MF-21 and MF-27 were used to determine total on-road use of motor gasoline and diesel fuel (FHWA 1996 through 2023). Ratios developed from MOVES3 output are used to apportion FHWA fuel consumption data to vehicle type and fuel type (see Annex 3.2 for information about the MOVES model).

[b] Includes medium- and heavy-duty trucks over 8,500 lbs.

[c] In 2014, EPA incorporated the NONROAD2008 model into the MOVES model framework. The current *Inventory* uses the Nonroad component of MOVES3 for years 1999 through 2022. See Annex 3.2 for information about the MOVES model.

[d] Note that large year over year fluctuations in emission estimates partially reflect nature of data collection for these sources.

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

[f] Commercial aircraft, as modeled in FAA's Aviation Environmental Design Tool (AEDT), consists of passenger aircraft, cargo, and other chartered flights.

[g] Pipelines reflect CO_2 emissions from natural gas-powered pipelines transporting natural gas.
[h] Ethanol and biodiesel 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 Paris Agreement and UNFCCC reporting obligations, for more information on ethanol and biodiesel.
[i] Transportation sector natural gas and LPG consumption are based on data from EIA (2023b). Prior to the 1990 to 2015 *Inventory*, data from DOE TEDB were used to estimate each vehicle class's share of the total natural gas and LPG consumption. Since TEDB does not include estimates for natural gas use by medium and heavy-duty trucks or LPG use by passenger cars, EIA Alternative Fuel Vehicle Data (Browning 2017) is now used to determine each vehicle class's share of the total natural gas and LPG consumption. These changes were first incorporated in the 1990 to 2016 *Inventory* and apply to the 1990 to 2022 time period.
[j] Includes emissions from rail electricity.
[k] Electricity consumption by passenger cars, light-duty trucks (SUVs), and buses is based on plug-in electric vehicle sales and engine efficiency data, as outlined in Browning (2018). In prior *Inventory* years, CO_2 emissions from electric vehicle charging were allocated to the residential and commercial sectors. They are now allocated to the transportation sector. These changes apply to the 2010 through 2022 time period.
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 CO_2 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 CH_4 and N_2O Emissions

Mobile combustion includes emissions of CH_4 and N_2O from all transportation sources identified in the U.S. *Inventory* with the exception of pipelines and electric locomotives;[25] 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.).[26] Annex 3.2 includes a summary of all emissions from both transportation and mobile sources. Table 3-14 and Table 3-15 provide mobile fossil fuel CH_4 and N_2O emission estimates in MMT CO_2 Eq.[27]

Mobile combustion was responsible for a small portion of national CH_4 emissions (0.4 percent) and was the fifth largest source of national N_2O emissions (4.3 percent) in 2022. From 1990 to 2022, mobile source CH_4 emissions declined by 64 percent, to 2.6 MMT CO_2 Eq. (93 kt), due largely to emissions control technologies employed in on-road vehicles since the mid-1990s to reduce CO, NO_x, NMVOC, and CH_4 emissions. Mobile source emissions of N_2O decreased by 57 percent, to 16.7 MMT CO_2 Eq. (63 kt) in 2022. Earlier generation control technologies initially resulted in elevated N_2O emissions, causing a 31 percent increase in N_2O emissions from mobile sources between 1990 and 1997. Improvements in later-generation emission control technologies have reduced N_2O output, resulting in a 67 percent decrease in mobile source N_2O emissions from 1997 to 2022 (see Figure 3-17). Overall, CH_4 and N_2O emissions were predominantly from gasoline-fueled passenger cars, light-duty trucks, and non-highway sources. See Annex 3.2 for data by vehicle mode and information on VMT and the share of new vehicles.

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[25] Emissions of CH_4 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.

[26] See the methodology sub-sections of the CO_2 from Fossil Fuel Combustion and CH_4 and N_2O from Mobile Combustion sections of this chapter. Note that N_2O and CH_4 emissions are reported using different categories than CO_2. CO_2 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. CO_2 emissions from non-transportation mobile sources (e.g., lawn and garden equipment, farm equipment, construction equipment) are allocated to their respective end-use sector (i.e., construction equipment CO_2 emissions are included in the Industrial end-use sector instead of the transportation end-use sector). CH_4 and N_2O emissions are reported using the "mobile combustion" category, which includes non-transportation mobile sources. CH_4 and N_2O emission 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, CO_2 emissions from non-transportation mobile sources are presented separately from their overall end-use sector in Annex 3.2.

[27] See Annex 3.2 for a complete time series of emission estimates for 1990 through 2022.

Figure 3-17: Mobile Source CH_4 and N_2O Emissions

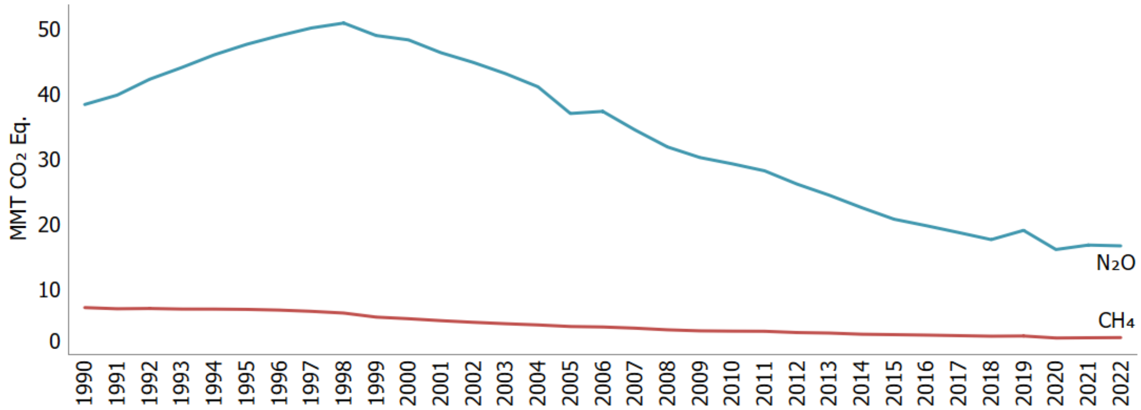

Table 3-14: CH_4 Emissions from Mobile Combustion (MMT CO_2 Eq.)

Fuel Type/Vehicle Type[a]	1990	2005	2018	2019	2020	2021	2022
Gasoline On-Road[b]	**5.8**	**2.4**	**0.9**	**1.0**	**0.8**	**0.8**	**0.7**
Passenger Cars	3.8	1.2	0.3	0.3	0.2	0.2	0.2
Light-Duty Trucks	1.5	1.0	0.5	0.6	0.5	0.5	0.5
Medium- and Heavy-Duty Trucks and Buses	0.5	0.1	+	+	+	+	+
Motorcycles	+	+	+	+	+	+	+
Diesel On-Road[b]	**+**	**+**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Passenger Cars	+	+	+	+	+	+	+
Light-Duty Trucks	+	+	+	+	+	+	+
Medium- and Heavy-Duty Trucks	+	+	0.1	0.1	0.1	0.1	0.1
Medium- and Heavy-Duty Buses	+	+	+	+	+	+	+
Alternative Fuel On-Road	**+**	**+**	**0.1**	**+**	**+**	**+**	**+**
Non-Road[c]	**1.4**	**1.8**	**1.7**	**1.7**	**1.6**	**1.6**	**1.7**
Ships and Boats	0.4	0.5	0.5	0.4	0.4	0.5	0.5
Rail[d]	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Aircraft	0.1	0.1	+	+	+	+	+
Agricultural Equipment[e]	0.2	0.2	0.1	0.1	0.1	0.1	0.1
Construction/Mining Equipment[f]	0.2	0.3	0.2	0.2	0.2	0.2	0.2
Other[g]	0.5	0.7	0.8	0.8	0.8	0.7	0.8
Total	**7.2**	**4.3**	**2.8**	**2.9**	**2.5**	**2.6**	**2.6**

+ Does not exceed 0.05 MMT CO_2 Eq.

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

[b] Gasoline and diesel highway vehicle mileage estimates are based on data from FHWA Highway Statistics Table VM-1. VMT estimates from FHWA are allocated to vehicle type using ratios of VMT per vehicle type to total VMT, derived from EPA's MOVES3 model (see Annex 3.2 for information about the MOVES model).

[c] Nonroad fuel consumption estimates for 2020 are adjusted to account for the COVID-19 pandemic and associated restrictions. For agricultural equipment and airport equipment, sector specific adjustment factors were applied to the 2019 data. For all other sectors, a 7.7 percent reduction factor is used, based on transportation diesel use (EIA 2023b).

[d] Rail emissions do not include emissions from electric powered locomotives. Class II and Class III diesel consumption data for 2014 to 2021 is estimated by applying the historical average fuel usage per carload factor to the annual number of carloads.

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

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

[g] "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.

Table 3-15: N_2O Emissions from Mobile Combustion (MMT CO_2 Eq.)

Fuel Type/Vehicle Type[a]	1990	2005	2018	2019	2020	2021	2022
Gasoline On-Road[b]	**32.0**	**28.5**	**7.0**	**8.1**	**6.3**	**6.0**	**5.3**
Passenger Cars	22.4	13.3	2.5	2.5	2.0	1.9	1.6
Light-Duty Trucks	8.7	14.0	4.3	5.4	4.2	3.9	3.5
Medium- and Heavy-Duty Trucks and Buses	0.8	1.2	0.2	0.2	0.1	0.1	0.1
Motorcycles	+	+	0.1	0.1	0.1	0.1	0.1
Diesel On-Road[b]	**0.2**	**0.4**	**3.0**	**3.2**	**3.0**	**3.3**	**3.5**
Passenger Cars	+	+	+	+	+	+	+
Light-Duty Trucks	+	+	0.3	0.2	0.2	0.3	0.3
Medium- and Heavy-Duty Trucks	0.2	0.3	2.4	2.7	2.5	2.7	2.9
Medium- and Heavy-Duty Buses	+	+	0.3	0.3	0.2	0.3	0.3
Alternative Fuel On-Road	**+**	**+**	**0.2**	**0.1**	**0.1**	**0.1**	**0.1**
Non-Road[c]	**6.2**	**8.1**	**7.5**	**7.6**	**6.7**	**7.4**	**7.8**
Ships and Boats	0.2	0.2	0.2	0.2	0.1	0.3	0.3
Rail[d]	0.2	0.3	0.3	0.2	0.2	0.2	0.2
Aircraft	1.5	1.6	1.4	1.5	1.0	1.3	1.4
Agricultural Equipment[e]	1.2	1.4	1.1	1.1	1.1	1.1	1.1
Construction/Mining Equipment[f]	1.2	1.9	1.6	1.7	1.6	1.7	1.7
Other[g]	1.8	2.8	2.9	2.9	2.7	2.9	3.2
Total	**38.4**	**37.0**	**17.7**	**19.1**	**16.1**	**16.8**	**16.7**

+ Does not exceed 0.05 MMT CO_2 Eq.

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

[b] Gasoline and diesel highway vehicle mileage estimates are based on data from FHWA Highway Statistics Table VM-1. VMT estimates from FHWA are allocated to vehicle type using ratios of VMT per vehicle type to total VMT, derived from EPA's MOVES3 model (see Annex 3.2 for information about the MOVES model).

[c] Nonroad fuel consumption estimates for 2020 are adjusted to account for the COVID-19 pandemic and associated restrictions. For agricultural equipment and airport equipment, sector specific adjustment factors were applied to the 2019 data. For all other sectors, a 7.7 percent reduction factor is used, based on transportation diesel use (EIA 2023a).

[d] Rail emissions do not include emissions from electric powered locomotives. Class II and Class III diesel consumption data for 2014 through 2021 is estimated by applying the historical average fuel usage per carload factor to the annual number of carloads.

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

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

[g] "Other" includes snowmobiles and other recreational equipment, logging equipment, lawn and garden equipment, railroad equipment, airport equipment, commercial equipment, and industrial equipment, as well as fuel consumption from trucks that are used off-road for commercial/industrial purposes.

Note: Totals may not sum due to independent rounding.

CO_2 from Fossil Fuel Combustion

Methodology and Time-Series Consistency

CO_2 emissions from fossil fuel combustion are estimated in line with a Tier 2 method described by the IPCC in the *2006 IPCC Guidelines for National Greenhouse Gas Inventories* (IPCC 2006) Chapter 2, Figure 2.1 decision tree and available data on energy use and country specific fuel carbon contents with some exceptions as discussed below.[28] 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), primary fuel type (e.g., coal, petroleum, gas), and secondary fuel category (e.g., motor gasoline, distillate fuel oil). 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* (EIA 2024a). EIA data include fuel consumption statistics from the 50 U.S. states and the District of Columbia, including tribal lands. 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 2024b).[29]

   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 datasets help inform the annual surveys to arrive at the national total and sectoral breakdowns for that total.[30]

   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).[31]

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 2021), Coffeyville (2012), U.S. Census Bureau (2001 through 2011), EIA (2024a, 2023c, 2023d), USAA (2008 through 2021), USGS (1991 through 2020), (USGS 2019), USGS (2014 through 2021a), USGS (2014 through 2021b), USGS (1995 through 2013), USGS (1995, 1998, 2000, 2001, 2002, 2007), USGS (2021a), USGS (1991 through 2015a), USGS (1991 through 2020), USGS (2014 through 2021a), USGS (1991 through 2015b), USGS (2021b), USGS (1991 through 2020).[32]

3. *Adjust for biofuels and petroleum denaturant*. Fossil fuel consumption estimates are adjusted downward to exclude fuels with biogenic origins and avoid double counting in petroleum data statistics. Carbon

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

29 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 22.6 MMT CO_2 Eq. in 2022.

30 See IPCC Reference Approach for Estimating CO_2 Emissions from Fossil Fuel Combustion in Annex 4 for a comparison of U.S. estimates using top-down and bottom-up approaches.

31 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.

32 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.

dioxide emissions from ethanol added to motor gasoline and biodiesel added to diesel fuel are not included specifically in summing energy sector totals. Net carbon fluxes from changes in biogenic carbon reservoirs are accounted for in the estimates for LULUCF, therefore, fuel consumption estimates are adjusted to remove ethanol and biodiesel.[33] For the years 1993 through 2008, petroleum denaturant is currently included in EIA statistics for both natural gasoline and finished motor gasoline. To avoid double counting, petroleum denaturant is subtracted from finished motor gasoline for these years.[34]

4. *Adjust for exports of CO_2.* Since October 2000, the Dakota Gasification Plant has been exporting CO_2 produced in the coal gasification process to Canada by pipeline. Because this CO_2 is not emitted to the atmosphere in the United States, the associated fossil fuel (lignite coal) that is gasified to create the exported CO_2 is subtracted from EIA (2023d) coal consumption statistics that are used to calculate greenhouse gas emissions from the Energy Sector. The associated fossil fuel is the total fossil fuel burned at the plant with the CO_2 capture system multiplied by the fraction of the plant's total site-generated CO_2 that is recovered by the capture system. To make these adjustments, data for CO_2 exports were collected from Environment and Climate Change Canada (2022). A discussion of the methodology used to estimate the amount of CO_2 captured and exported by pipeline is presented in Annex 2.1.
5. *Adjust sectoral allocation of distillate fuel oil and motor gasoline.* EPA 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 were 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 2022), Benson (2002 through 2004), DOE (1993 through 2020), EIA (2007), EIA (2024a), EPA (2022), and FHWA (1996 through 2023).[35]
6. *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 carbon contained in the fuel for a period of time. As the emission pathways of carbon used for non-energy purposes are vastly different than fuel combustion (since the carbon in these fuels ends up in products instead of being combusted), these emissions are estimated separately in Section3.2. Therefore, the amount of fuels used for non-energy purposes was subtracted from total fuel consumption. Data on non-fuel consumption were provided by EIA (2023c).
7. *Subtract consumption of international bunker fuels.* According to the Paris Agreement and 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 to calculate emissions from consumption of all fossil fuels (i.e., estimation of consumption, and determination of carbon content).[36] 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 2022) supplied data on military jet fuel and marine fuel use.

[33] Natural gas energy statistics from EIA (2023a) are already adjusted downward to account for biogas in natural gas.

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

[35] Bottom-up gasoline and diesel highway vehicle fuel consumption estimates are based on data from FHWA Highway Statistics Table MF-21, MF-27, and VM-1 (FHWA 1996 through 2021).

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

Commercial jet fuel use was estimated based on data from FAA (2024) and DOT (1991 through 2022); residual and distillate fuel use for civilian marine bunkers was obtained from DOC (1991 through 2022) for 1990 through 2001 and 2007 through 2020, and DHS (2008) for 2003 through 2006.[37] Consumption of these fuels was subtracted from the corresponding fuels totals in the transportation end-use sector. Estimates of international bunker fuel emissions for the United States are discussed in detail in Section 3.9.

8. *Determine the total carbon content of fuels consumed.* Total carbon was estimated by multiplying the amount of fuel consumed by the amount of carbon in each fuel. This total carbon estimate defines the maximum amount of carbon that could potentially be released to the atmosphere if all of the carbon in each fuel was converted to CO_2. A discussion of the methodology and sources used to develop the carbon content coefficients are presented in Annexes 2.1 and 2.2.

9. *Estimate CO_2 Emissions.* Total CO_2 emissions are the product of the adjusted energy consumption (from the previous methodology steps 1 through 7), the carbon content of the fuels consumed, and the fraction of carbon 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). Carbon emissions were multiplied by the molecular-to-atomic weight ratio of CO_2 to carbon (44/12) to obtain total CO_2 emitted from fossil fuel combustion in million metric tons (MMT).

10. *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 (2023c) and USAF (1998).[38]

    - For on-road vehicles, annual estimates of combined motor gasoline and diesel fuel consumption by vehicle category were obtained from FHWA (1996 through 2023); for each vehicle category, the percent gasoline, diesel, and other (e.g., CNG, LPG) fuel consumption are estimated using data from EPA's MOVES model and DOE (1993 through 2022).[39,40]

    - For non-road vehicles, activity data were obtained from AAR (2008 through 2022), APTA (2007 through 2022), APTA (2006), BEA (1991 through 2015), Benson (2002 through 2004), BTS (2019 through 2022), DLA Energy (2022), DOC (1991 through 2022), DOE (1993 through 2022), DOT (1991 through 2022), EIA (2009a), EIA (2023a), EIA (2002), EIA (1991 through 2022), EPA (2022),[41] and Gaffney (2007).

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[37] Data for 2002 were interpolated due to inconsistencies in reported fuel consumption data.

[38] For a more detailed description of the data sources used for the analysis of the transportation end use sector see the Mobile Combustion (excluding CO_2) and International Bunker Fuels sections of the Energy chapter, Annex 3.2, and Annex 3.8, respectively.

[39] On-road fuel consumption data from FHWA Table MF-21 and MF-27 were used to determine total on-road use of motor gasoline and diesel fuel (FHWA 1996 through 2020). Data for 2021 is proxied using FHWA Traffic Volume Travel Trends. Ratios developed from MOVES3 output are used to apportion FHWA fuel consumption data to vehicle type and fuel type (see Annex 3.2 for information about the MOVES model).

[40] Transportation sector natural gas and LPG consumption are based on data from EIA (2024a). In previous Inventory years, data from DOE (1993 through 2022) TEDB was used to estimate each vehicle class's share of the total natural gas and LPG consumption. Since TEDB does not include estimates for natural gas use by medium- and heavy-duty trucks or LPG use by passenger cars, EIA Alternative Fuel Vehicle Data (Browning 2017) is now used to determine each vehicle class's share of the total natural gas and LPG consumption. These changes were first incorporated in the 1990 through 2015 Inventory and apply to the time period from 1990 to 2015.

[41] In 2014, EPA incorporated the NONROAD2008 model into the MOVES model framework (EPA 2022b). The current *Inventory* uses the Nonroad component of MOVES3 for years 1999 through 2022.

- For jet fuel used by aircraft, CO_2 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.

Methodological recalculations were applied to the entire time series to ensure time-series consistency from 1990 through 2022. Due to data availability and sources, some adjustments outlined in the methodology above are not applied consistently across the full 1990 to 2022 time series. As described in greater detail in Annex 2.1, to align with EIA's methodology for calculating motor gasoline consumption, petroleum denaturant adjustments are applied to motor gasoline consumption only for the period 1993 through 2008. In addition to ensuring time-series consistency, to ensure consistency in reporting between the *Inventory* and the Canadian National Greenhouse Gas Inventory, the amount of associated fossil fuel (lignite coal) that is gasified to create the exported CO_2 from the Dakota Gasification Plant is adjusted to align with the Canadian National Greenhouse Gas Inventory (Environment and Climate Change Canada 2022). This adjustment is explained in greater detail in Annex 2.1. As discussed in Annex 5, data are unavailable to include estimates of CO_2 emissions from any liquid fuel used in pipeline transport or non-hazardous industrial waste incineration, but those emissions are assumed to be insignificant.

Box 3-4: Carbon Intensity of U.S. Energy Consumption

The amount of carbon emitted from the combustion of fossil fuels is dependent upon the carbon content of the fuel and the fraction of that carbon that is oxidized. Fossil fuels vary in their average carbon content, ranging from about 53 MMT CO_2 Eq./QBtu for natural gas to upwards of 95 MMT CO_2 Eq./QBtu for coal and petroleum coke (see Tables A-42 and A-43 in Annex 2.1 for carbon contents of all fuels). In general, the carbon content per unit of energy of fossil fuels is the highest for coal products, followed by petroleum, and then natural gas. The overall carbon intensity of the U.S. economy is thus dependent upon the quantity and combination of fuels and other energy sources employed to meet demand.

Table 3-16 provides a time series of the carbon intensity of direct emissions for each sector of the U.S. economy. The time series incorporates only the energy from the direct combustion of fossil fuels in each sector. For example, the carbon intensity for the residential sector does not include the energy from or emissions related to the use of electricity for lighting, as it is instead allocated to the electric power sector. For the purposes of maintaining the focus of this section, renewable energy and nuclear energy are not included in the energy totals used in Table 3-16 in order to focus attention on fossil fuel combustion as detailed in this chapter. Looking only at this direct consumption of fossil fuels, the residential sector exhibited the lowest carbon intensity, which is related to the large percentage of its energy derived from natural gas for heating. The carbon intensity of the commercial sector 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 carbon intensities over this period. The carbon intensity of the transportation sector was closely related to the carbon content of petroleum products (e.g., motor gasoline and jet fuel, both around 70 MMT CO_2 Eq./QBtu), which were the primary sources of energy. Lastly, the electric power sector had the highest carbon intensity due to its heavy reliance on coal for generating electricity.

Table 3-16: Carbon Intensity from Direct Fossil Fuel Combustion by Sector (MMT CO_2 Eq./QBtu)

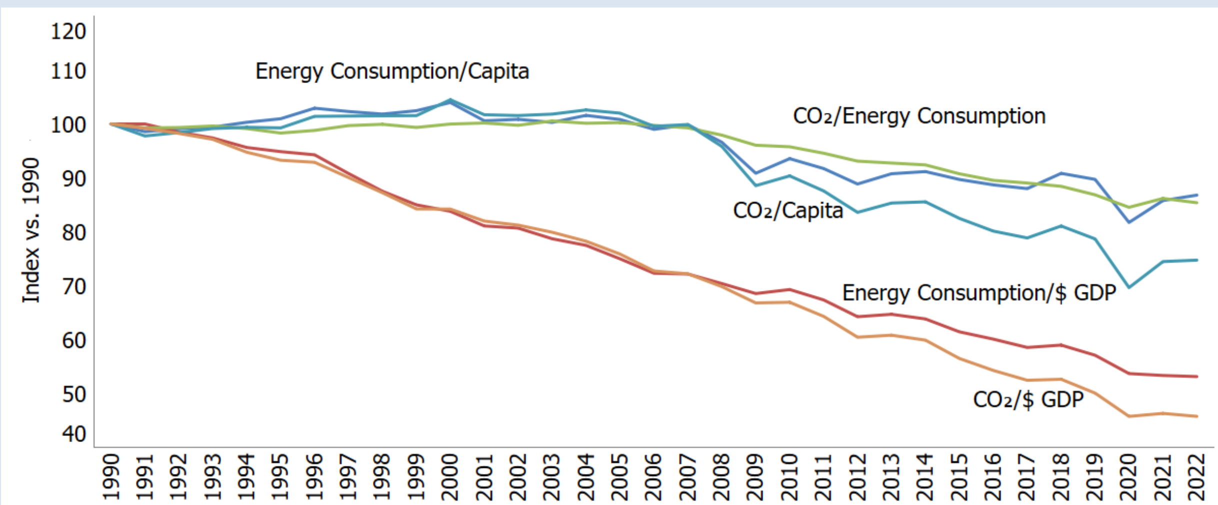
Sector	1990	2005	2018	2019	2020	2021	2022
Residential[a]	57.4	56.8	55.3	55.3	55.1	55.2	55.2
Commercial[a]	59.7	57.8	56.0	56.2	56.3	56.2	56.5
Industrial[a]	64.8	64.6	60.5	60.2	59.6	59.6	59.6
Transportation[a]	71.1	71.5	71.0	70.9	70.8	70.9	70.8
Electric Power[b]	87.3	85.8	75.5	72.9	70.5	72.4	70.9

U.S. Territories[c]	73.1	73.4	70.4	70.8	71.7	70.1	71.3
All Sectors[c]	**73.1**	**73.6**	**68.3**	**67.3**	**66.3**	**67.0**	**66.5**

[a] Does not include electricity or renewable energy consumption.
[b] Does not include electricity produced using nuclear or renewable energy.
[c] Does not include nuclear or renewable energy consumption.
Note: Excludes non-energy fuel use emissions and consumption. Totals may not sum due to independent rounding.

For the time period of 1990 through about 2008, the carbon intensity of U.S. energy consumption was fairly constant, as the proportion of fossil fuels used by the individual sectors did not change significantly over that time. Starting in 2008 the carbon intensity of U.S. energy consumption has decreased, reflecting the shift from coal to natural gas in the electric power sector during that time period. Per capita energy consumption fluctuated little from 1990 to 2007, but then started decreasing after 2007 and, in 2022, was approximately 13.2 percent below levels in 1990 (see Figure 3-18). To differentiate these estimates from those of Table 3-16, the carbon intensity trend shown in Figure 3-18 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 CO_2 emissions per dollar of gross domestic product (GDP) have both declined since 1990 (BEA 2024).

Figure 3-18: U.S. Energy Consumption and Energy-Related CO_2 Emissions Per Capita and Per Dollar GDP



Carbon intensity estimates were developed using nuclear and renewable energy data from EIA (2023c), EPA (2010), and fossil fuel consumption data as discussed above and presented in Annex 2.1.

Uncertainty

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

Nevertheless, there are uncertainties in the consumption data, carbon content of fuels and products, and carbon oxidation efficiencies. For example, given the same primary fuel type (e.g., coal, petroleum, or natural gas), the amount of carbon contained in the fuel per unit of useful energy can vary. For the United States, however, the impact of these uncertainties on overall CO_2 emission estimates is believed to be relatively small. See, for example, Marland and Pippin (1990). See also Annex 2.2 for a discussion of uncertainties associated with fuel carbon contents. Recent updates to carbon factors for natural gas and coal utilized the same approach as previous Inventories with updated recent data, therefore, the uncertainty estimates around carbon contents of the different fuels as outlined in Annex 2.2 were not impacted and the historic uncertainty ranges still apply.

Although national 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 challenges in collecting accurate energy statistics as firms in these industries have undergone significant restructuring.

To calculate the total CO_2 emission estimate from energy-related fossil fuel combustion, the amount of fuel used in non-energy production processes were subtracted from the total fossil fuel consumption. The amount of CO_2 emissions resulting from non-energy related fossil fuel use has been calculated separately and reported in the Carbon Emitted from Non-Energy Uses of Fossil Fuels section of this report (Section 3.2). These factors all contribute to the uncertainty in the CO_2 estimates. Detailed discussions on the uncertainties associated with carbon 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 Section 3.9). Another source of uncertainty is fuel consumption by U.S. Territories. The United States does not collect energy statistics for its territories at the same level of detail as for the fifty states and the District of Columbia. Therefore, estimating both emissions and bunker fuel consumption by these territories is difficult.

Uncertainties in the emission estimates presented above also result from the data used to allocate CO_2 emissions from the transportation end-use sector to individual vehicle types and transport modes. In many cases, bottom-up estimates of fuel consumption by vehicle type do not match aggregate fuel-type estimates from EIA. Further research is planned to improve the allocation into detailed transportation end-use sector emissions.

The uncertainty analysis was performed by primary fuel type for each end-use sector, using the IPCC-recommended Approach 2 uncertainty estimation methodology, Monte Carlo stochastic simulation technique, with @RISK software. For this uncertainty estimation, the inventory estimation model for CO_2 from fossil fuel combustion was integrated with the relevant variables from the inventory estimation model for International Bunker Fuels, to realistically characterize the interaction (or endogenous correlation) between the variables of these two models. About 170 input variables were modeled for CO_2 from energy-related fossil fuel combustion (including about 20 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.[42] 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.[43]

[42] 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.

[43] 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.

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).[44] 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 3-17. Fossil fuel combustion CO_2 emissions in 2022 were estimated to be between 4,603.1 and 4,905.2 MMT CO_2 Eq. at a 95 percent confidence level. This indicates a range of 2 percent below to 4 percent above the 2022 emission estimate of 4,699.4 MMT CO_2 Eq.

Table 3-17: Approach 2 Quantitative Uncertainty Estimates for CO_2 Emissions from Energy-Related Fossil Fuel Combustion by Fuel Type and Sector (MMT CO_2 Eq. and Percent)

Fuel/Sector	2022 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]	**898.8**	**868.6**	**983.9**	**-3%**	**9%**
Residential	NO	NO	NO	NO	NO
Commercial	1.4	1.3	1.6	-5%	15%
Industrial	43.0	41.0	49.9	-5%	16%
Transportation	NO	NO	NO	NO	NO
Electric Power	851.5	818.9	933.8	-4%	10%
U.S. Territories	2.9	2.5	3.4	-12%	19%
Natural Gas[b]	**1,706.8**	**1,687.3**	**1,784.4**	**-1%**	**5%**
Residential	272.0	264.4	291.1	-3%	7%
Commercial	192.3	186.9	205.8	-3%	7%
Industrial	510.4	494.9	548.0	-3%	7%
Transportation	70.2	68.2	75.1	-3%	7%
Electric Power	659.3	640.1	693.0	-3%	5%
U.S. Territories	2.7	2.4	3.2	-12%	17%
Petroleum[b]	**2,093.4**	**1,966.4**	**2,215.9**	**-6%**	**6%**
Residential	62.1	58.6	65.4	-6%	5%
Commercial	65.1	61.5	68.5	-5%	5%
Industrial	247.6	193.3	302.0	-22%	22%
Transportation	1,681.1	1,573.2	1,785.6	-6%	6%
Electric Power	20.5	19.7	22.0	-4%	7%
U.S. Territories	17.0	15.7	18.7	-7%	10%
Geothermal	**0.4**	**0.2**	**1.0**	**-48%**	**173%**
Electric Power	0.4	0.2	1.0	-48%	173%
Total (including Geothermal)[b]	**4,699.4**	**4,603.1**	**4,905.2**	**-2%**	**4%**

NO (Not Occurring)

[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.

Note: Totals may not sum due to independent rounding.

[44] 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.

QA/QC and Verification

In order to ensure the quality of the CO_2 emission estimates from fossil fuel combustion, general (IPCC Tier 1) and category-specific (Tier 2) Quality Assurance/Quality Control (QA/QC) procedures were implemented consistent with the U.S. Inventory QA/QC plan outlined in Annex 8. The Tier 2 procedures that were implemented involved checks specifically focusing on the activity data and methodology used for estimating CO_2 emissions from fossil fuel combustion in the United States. Emission totals for the different sectors and fuels were compared and trends were investigated to determine whether any corrective actions were needed. Minor corrective actions were taken.

One area of QA/QC and verification is to compare the estimates and emission factors used in the *Inventory* with other sources of CO_2 emissions reporting. Two main areas and sources of data were considered. The first is a comparison with the EPA GHGRP combustion data (Subpart C) for stationary combustion sources excluding the electric power sector. This mainly focused on considering carbon factors for natural gas. The second comparison is with the EPA Air Markets Program data for electric power production. This considered carbon factors for coal and natural gas used in electric power production.

The EPA GHGRP collects greenhouse gas emissions data from large emitters including information on fuel combustion. This excludes emissions from mobile sources and smaller residential and commercial sources, those emissions are covered under supplier reporting (Subparts MM and NN) and are areas for further research. Fuel combustion CO_2 data reported in 2022 was 2,082.6 MMT CO_2. Of that, 1,577.7 MMT CO_2 was from electricity production. Therefore, the non-electric power production fuel combustion reporting was a fraction of the total covered by the *Inventory* under fossil fuel combustion. Furthermore, reporters under the GHGRP can use multiple methods of calculating emissions; one method is to use the default emission factors provided in the rule, while another is based on a tier 3 approach using their own defined emission factors. Based on data from reporters on approach used, it was determined that only about 10 percent of natural gas combustion emissions were based on a tier 3 approach. Given the small sample size compared to the overall *Inventory* calculations for natural gas combustion EPA determined it was not reasonable to consider the GHGRP tier 3 natural gas factors at this time. A more detailed analysis was done on upstream oil and gas natural gas combustion emissions using the GHGRP data as discussed in Annex 2.2.

EPA collects detailed sulfur dioxide (SO_2), nitrogen oxides (NO_X), and carbon dioxide (CO_2) emissions data and other information from power plants across the country as part of the Acid Rain Program (ARP), the Cross-State Air Pollution Rule (CSAPR), the CSAPR Update, and the Revised CSAPR Update (RCU). The CO_2 data from these Air Market Programs (AMP) can be compared to the electric power sector emissions calculated from the *Inventory* as shown in Table 3-18 for the three most recent years of data.

Table 3-18: Comparison of Electric Power Sector Emissions (MMT CO_2 Eq. and Percent)

Fuel/Sector	CO_2 Emissions (MMT CO_2 Eq.)			% Change	
	2020	2021	2022	20-21	21-22
Inventory Electric Power Sector	**1,439.6**	**1,540.9**	**1,531.7**	**7.0%**	**-0.6%**
Coal	788.2	910.1	851.5	15.5%	-6.4%
Natural Gas	634.8	612.8	659.3	-3.5%	7.6%
Petroleum	16.2	17.7	20.5	9.6%	15.9%
AMP Electric Power Sector	**1,430.8**	**1,531.7**	**1,520.1**	**7.1%**	**-0.8%**
Coal	792.7	913.4	858.5	15.2%	-6.0%
Natural Gas	629.4	609.6	652.7	-3.1%	7.1%
Petroleum	8.8	8.7	8.9	-0.8%	2.7%

Note: Totals may not sum due to independent rounding.

In general the emissions and trends from the two sources line up well. There are differences expected based on coverage and scope of each source. The *Inventory* covers all emissions from the electric power sector as defined above. The EPA AMP data covers emissions from electricity generating units of a certain size so in some respects it could cover more sources (like electric power units at industrial facilities that would be covered under the industrial sector in the *Inventory*) and not as many sources (since smaller units are excluded). The EPA AMP data also includes heat input for different fuel types. That data can be combined with emissions to calculate implied emission factors.[45] The following Table 3-19 shows the implied emissions factors for coal and natural gas from the EPA AMP data compared to the factors used in the *Inventory* for the three most recent years of data.

Table 3-19: Comparison of Emissions Factors (MMT Carbon/QBtu)

Fuel Type	2020	2021	2022
EPA AMP			
Coal	25.67	25.66	25.53
Natural Gas	14.56	14.60	14.61
EPA Inventory			
Electric Power Coal	26.12	26.13	26.13
Natural Gas	14.43	14.43	14.43

The factors for natural gas line up reasonably well, the EPA factors are roughly 1 percent lower than those calculated from the EPA AMP data. For coal the EPA emissions factors are roughly 2 percent higher than those calculated from the EPA AMP data. One possible reason for the difference is that the EPA *Inventory* factors are based on all coal used in electric power production while the factors from the EPA AMP data are based on units where coal is the source of fuel used. There are units that use coal and other fuel sources but emissions for each fuel type could not be calculated. This is an area of further research but given current data available the approach to develop carbon factors as outlined in Annex 2 is still felt to be the most appropriate to represent total fuel combustion in the United States.

The Paris Agreement and the UNFCCC reporting guidelines also require countries to complete a "top-down" reference approach for estimating CO_2 emissions from fossil fuel combustion in addition to their “bottom-up” sectoral methodology. The reference approach (detailed in Annex 4) uses alternative methodologies and different data sources than those contained in this section of the report. The reference approach estimates fossil fuel consumption by adjusting national aggregate fuel production data for imports, exports, and stock changes rather than relying on end-user consumption surveys. The reference approach assumes that once carbon-based fuels are brought into a national economy, they are either saved in some way (e.g., stored in products, kept in fuel stocks, or left unoxidized in ash) or combusted, and therefore the carbon in them is oxidized and released into the atmosphere. In the reference approach, accounting for actual consumption of fuels at the sectoral or sub-national level is not required. One difference between the two approaches is that emissions from carbon that was not stored during non-energy use of fuels are subtracted from the sectoral approach and reported separately (see Section 3.2). These emissions, however, are not subtracted in the reference approach. As a result, the reference approach emission estimates are comparable to those of the sectoral approach, with the exception that the non-energy use (NEU) source category emissions are included in the reference approach (see Annex 4 for more details).

Recalculations Discussion

EIA (2024a) updated distillate fuel oil consumed by the transportation sector for 2010 and on. This caused transportation petroleum CO_2 emissions to increase by an average annual amount of 0.2 MMT CO_2 Eq. (less than half a percent) for the years 2010 through 2021.

EIA (2024a) updated propane consumed by the industrial sector for 2010 and on, which is used to calculate HGL (Energy Use) annually variable carbon content coefficients. In addition, EIA (2023b) shifted all 2022 product supplied of natural gasoline and unfinished oils to crude oil transfers. This change was made to reflect that natural gasoline and unfinished oils are used as feedstocks in crude oil production instead of directly consumed as an end-use fuel. EPA made the same adjustment across the timeseries. This change impacted industrial energy

[45] These emission factors can be converted from MMT Carbon/QBtu to MMT CO_2 Eq./QBtu by multiplying the emission factor by 44/12, the molecular-to-atomic weight ratio of CO_2 to C. This would assume the fraction oxidized to be 100 percent, which is the guidance in IPCC (2006) (see Annex 2.1).

consumption across the timeseries as well as non-energy use consumption, which impacts industrial energy consumption values. This change also impacted the HGL carbon content coefficient used to calculate emissions.

To better align with EIA methodology, the non-energy use consumption of HGLs is now calculated for the entire timeseries by assuming that 100 percent of ethane, ethylene, and propylene consumption is for non-combustion use and 85 percent of normal butane, butylene, isobutane, and isobutylene is for non-combustion use. Non-energy use consumption of propane is calculated by subtracting the non-energy consumption of all other HGLs from the total non-combustion consumption of HGLs as published by the EIA. Non-energy use consumption is subtracted from energy consumption, therefore this methodology change impacts industrial petroleum consumption values. Additionally, the energy HGL carbon contents are now calculated following the above methodology and have therefore increased across the timeseries, impacting U.S. Territories petroleum and industrial petroleum CO_2 emissions.

Overall, these four updates to EIA (2024a) data and methodology caused U.S. Territories petroleum CO_2 emissions to decrease by an average annual amount of less than 0.1 MMT CO_2 Eq. (less than half a percent) for the timeseries, and industrial petroleum CO_2 emissions to increase by an average annual amount of 5.0 MMT CO_2 Eq. (1.8 percent) for the timeseries.

EPA revised its calculation of change in total energy use in the industrial sector to include renewable energy and electricity. The value previously included only fossil fuel energy consumption. Additionally, EPA revised power sector carbon intensity data to correct for an error and ensure total renewable energy consumed from EIA's *Monthly Energy Review* (EIA 2024a) was being used. There were also very minor updates associated with changes in residential and commercial petroleum use due to MER updates changes in industrial coal use due to updated data on CO_2 exports.

Overall, these changes resulted in an average annual increase of 5.8 MMT CO_2 Eq. (0.1 percent) in CO_2 emissions from fossil fuel combustion for the period 1990 through 2021, relative to the previous *Inventory*.

Planned Improvements

To reduce the uncertainty of CO_2 from fossil fuel combustion estimates for U.S. Territories, further expert elicitation may be conducted to better quantify the total uncertainty associated with emissions from U.S. Territories. Additionally, although not technically a fossil fuel, since geothermal energy-related CO_2 emissions are included for reporting purposes, further expert elicitation may be conducted to better quantify the total uncertainty associated with CO_2 emissions from geothermal energy use.

EPA will continue to examine the availability of facility-level combustion emissions through EPA's GHGRP to help better characterize the industrial sector's energy consumption in the United States and further classify total industrial sector fossil fuel combustion emissions by business establishments according to industrial economic activity type. Most methodologies used in EPA's GHGRP are consistent with IPCC methodologies, although 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 Paris Agreement and UNFCCC reporting guidelines, some facility-level fuel combustion emissions reported under the GHGRP may also include industrial process emissions.[46] In line with the Paris Agreement and 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 CO_2 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. For example, additional work will look at CO_2 emissions from biomass to ensure they are

[46] See https://unfccc.int/resource/docs/2013/cop19/eng/10a03.pdf#page=2.

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.[47]

EPA is also evaluating the methods used to adjust for conversion of fuels and exports of CO_2. EPA is exploring the approach used to account for CO_2 transport, injection, and geologic storage; as part of this there may be changes made to the accounting for CO_2 exports.

Finally, another ongoing planned improvement is to evaluate data availability to update the carbon and heat content of more fuel types accounted for in this *Inventory*. This update will impact consumption and emissions across all sectors and will improve consistency with EIA data as carbon and heat contents of fuels will be accounted for as annually variable and therefore improve accuracy across the time series. Some of the fuels considered in this effort include petroleum coke, residual fuel, and woody biomass.

CH_4 and N_2O from Stationary Combustion

Methodology and Time-Series Consistency

Methane and N_2O emissions from stationary combustion were estimated by multiplying fossil fuel and wood consumption data by emission factors (by sector and fuel type for industrial, residential, commercial, and U.S. Territories; and by fuel and technology type for the electric power sector). The electric power sector utilizes a Tier 2 methodology, whereas all other sectors utilize a Tier 1 methodology in accordance with IPCC methodological decision tree Figure 2.1 in the *2006 IPCC Guidelines for National Greenhouse Gas Inventories* (IPCC 2006) and available data. The activity data and emission factors used are described in the following subsections.

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

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 CH_4 and N_2O emission estimates, consumption data for each fuel were obtained from EIA's *Monthly Energy Review* (EIA 2024a). 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 2024b).[48] Fuel consumption for the industrial sector was adjusted to subtract out mobile source construction and agricultural use, which is reported under mobile sources. Construction and agricultural mobile source fuel use was obtained from EPA (2022) and FHWA (1996 through 2023). Estimates for wood biomass consumption for fuel combustion do not include municipal solid waste, tires, etc., that are reported as biomass by EIA. Non-CO_2 emissions from combustion of the biogenic portion of municipal solid waste and tires is included under waste incineration (Section 3.2). Estimates for natural gas combustion do not include biogas, and therefore non-CO_2 emissions from biogas are not included (see the Planned Improvements section, below). Tier 1 default emission factors for the industrial, commercial, and residential 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 uses a Tier 2 emission estimation methodology as fuel consumption for the electric

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[47] See http://www.ipcc-nggip.iges.or.jp/public/tb/TFI_Technical_Bulletin_1.pdf.

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

power sector by control-technology type is based on EPA's Acid Rain Program Dataset (EPA 2024). Total fuel consumption in the electric power sector from EIA (2024a) was apportioned to each combustion technology type and fuel combination using a ratio of fuel consumption by technology type derived from EPA (2024) data. The combustion technology and fuel use data by facility obtained from EPA (2024) were only available from 1996 to 2022 so the consumption estimates from 1990 to 1995 were estimated by applying the 1996 consumption ratio by combustion technology type from EPA (2024) to the total EIA (2024a) consumption for each year from 1990 to 1995.

Emissions were estimated by multiplying fossil fuel and wood consumption by technology-, fuel-, and country-specific Tier 2 emission factors. The Tier 2 emission factors used are based in part on emission factors published by EPA, and EPA's Compilation of Air Pollutant Emission Factors, AP-42 (EPA 1997) for coal wall-fired boilers, residual fuel oil, diesel oil and wood boilers, natural gas-fired turbines, and combined cycle natural gas units.[49]

Methodological recalculations were applied to the entire time series to ensure time-series consistency from 1990 through 2022 as discussed below. As discussed in Annex 5, data are unavailable to include estimates of CH_4 and N_2O emissions from biomass use in Territories, but those emissions are assumed to be insignificant.

Uncertainty

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 CH_4 and N_2O emissions presented are based on broad indicators of emissions (i.e., fuel use multiplied by an aggregate emission factor for different sectors), rather than specific emission processes (i.e., by combustion technology and type of emission control).

An uncertainty analysis was performed by primary fuel type for each end-use sector, using the IPCC-recommended 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 CH_4 and N_2O stationary source inventory estimation models with the model for CO_2 from fossil fuel combustion to realistically characterize the interaction (or endogenous correlation) between the variables of these three models. About 55 input variables were simulated for the uncertainty analysis of this source category (about 20 from the CO_2 emissions from fossil fuel combustion inventory estimation model and about 35 from the stationary source inventory models).

In developing the uncertainty estimation model, uniform distribution was assumed for all activity-related input variables and N_2O emission factors, based on the SAIC/EIA (2001) report.[50] For these variables, the uncertainty ranges were assigned to the input variables based on the data reported in SAIC/EIA (2001).[51] However, the CH_4 emission factors differ from those used by EIA. These factors and uncertainty ranges are based on IPCC default uncertainty estimates (IPCC 2006).

[49] Several of the U.S. Tier 2 emission factors were used in IPCC (2006) as Tier 1 emission factors. See Table A-67 in Annex 3.1 for emission factors by technology type and fuel type for the electric power sector.

[50] 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.

[51] 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.

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 3-20. Stationary combustion CH_4 emissions in 2022 (including biomass) were estimated to be between 5.9 and 19.1 MMT CO_2 Eq. at a 95 percent confidence level. This indicates a range of 31 percent below to 122 percent above the 2022 emission estimate of 8.6 MMT CO_2 Eq.[52] Stationary combustion N_2O emissions in 2022 (including biomass) were estimated to be between 16.5 and 33.4 MMT CO_2 Eq. at a 95 percent confidence level. This indicates a range of 33 percent below to 35 percent above the 2022 emission estimate of 24.7 MMT CO_2 Eq.

Table 3-20: Approach 2 Quantitative Uncertainty Estimates for CH_4 and N_2O Emissions from Energy-Related Stationary Combustion, Including Biomass (MMT CO_2 Eq. and Percent)

Source	Gas	2022 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	8.6	5.9	19.1	-31%	122%
Stationary Combustion	N_2O	24.7	16.5	33.4	-33%	35%

[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 CH_4 and N_2O are greater than those associated with estimates of CO_2 from fossil fuel combustion, which mainly rely on the carbon content of the fuel combusted. Uncertainties in both CH_4 and N_2O estimates are due to the fact that emissions are estimated based on emission factors representing only a limited subset of combustion conditions. For the indirect greenhouse gases, uncertainties are partly due to assumptions concerning combustion technology types, age of equipment, emission factors used, and activity data projections.

QA/QC and Verification

In order to ensure the quality of the non-CO_2 emission estimates from stationary combustion, general (IPCC Tier 1) and category-specific (Tier 2) Quality Assurance/Quality Control (QA/QC) procedures were implemented consistent with the U.S. Inventory QA/QC plan outlined in Annex 8. The Tier 2 procedures that were implemented involved checks specifically focusing on the activity data and emission factor sources and methodology used for estimating CH_4, N_2O, and the greenhouse gas precursors from stationary combustion in the United States. Emission totals for the different sectors and fuels were compared and trends were investigated.

Recalculations Discussion

EIA (2024a) updated industrial HGL statistics, which caused CH_4 and N_2O emissions from industrial fuel oil to decrease slightly for the years 2010 through 2021.

In addition, EIA (2023b) shifted all 2022 product supplied of natural gasoline and unfinished oils to crude oil transfers. This change was made to reflect the fact that these fuels are used as feedstocks in crude oil production instead of directly consumed as end-use fuels. EPA made the change across the time series. This change impacted energy consumption across the timeseries as well as non-energy use consumption, which impacts energy consumption values.

To better align with EIA methodology, the non-energy use consumption of HGLs is now calculated for the entire timeseries by assuming that 100 percent of ethane, ethylene, and propylene consumption is for non-combustion use and 85 percent of normal butane, butylene, isobutane, and isobutylene is for non-combustion use. Non-energy use consumption of propane is calculated by subtracting the non-energy consumption of all other HGLs from the

[52] 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.

total non-combustion consumption of HGLs as published by the EIA. Non-energy use consumption is subtracted from energy consumption, therefore this methodology change impacts industrial fuel oil consumption values.

Other small updates included changes in residential and commercial/institutional fuel oil are use and changes in industrial coal due to updated CO_2 export data.

Overall, these updates to EIA data and methodology (2024a) caused CH_4 and N_2O emissions from industrial fuel oil to increase by an average annual amount of 0.01 MMT CO_2 Eq. and 0.01 MMT CO_2 Eq. (3 percent and 3 percent), respectively, for the time series. EIA (2024a) updated 2020 and 2021 wood energy consumed by the residential sector due to new underlying data collected by the Residential Energy Consumption Survey (RECS), which collects data about once every 5 years and uses Annual Energy Outlook growth rates to estimate data for other years. This caused CH_4 and N_2O emissions from residential wood consumption to decrease by 0.76 MMT CO_2 Eq. and 0.10 MMT CO_2 Eq. (22 percent and 13 percent) in 2020, respectively, and 0.94 MMT CO_2 Eq. and 0.12 MMT CO_2 Eq. (26 percent and 15 percent) in 2021, respectively.

Planned Improvements

Several items are being evaluated to improve the CH_4 and N_2O emission estimates from stationary combustion and to reduce uncertainty for U.S. Territories. 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 because it was expected that the exclusion of biomass from the 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 combustion estimates from U.S. Territories.

Other forms of biomass-based gas consumption include biogas. As an additional planned improvement, EPA will examine EIA and GHGRP data on biogas collected and burned for energy use and determine if CH_4 and N_2O emissions from biogas can be included in future Inventories. EIA (2024a) natural gas data already deducts biogas used in the natural gas supply, so no adjustments are needed to the natural gas fuel consumption data to account for biogas.

CH_4 and N_2O from Mobile Combustion

Methodology and Time-Series Consistency

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

On-Road Vehicles

Estimates of CH_4 and N_2O emissions from gasoline and diesel on-road vehicles are based on VMT and emission factors (in grams of CH_4 and N_2O per mile) 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 (in grams of CH_4 and N_2O per mile) by vehicle and fuel type.[53]

[53] 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.

CH_4 and N_2O emissions factors by vehicle type and emission tier for newer (starting with model year 2004) on-road gasoline vehicles were calculated by Browning (2019) from annual vehicle certification data compiled by EPA. CH_4 and N_2O emissions factors for older (model year 2003 and earlier) on-road gasoline vehicles were developed by ICF (2004). These earlier emission factors were derived from EPA, California Air Resources Board (CARB) and Environment and Climate Change Canada (ECCC) laboratory test results of different vehicle and control technology types. The EPA, CARB and ECCC tests were designed following the Federal Test Procedure (FTP). The procedure 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 driving segment 2 tests were used to define running emissions. Running emissions were subtracted from the total FTP emissions to determine start emissions. These were then recombined to approximate average driving characteristics, based upon the ratio of start to running emissions for each vehicle class from MOBILE6.2, an EPA emission factor model that predicts grams per mile emissions of CO_2, CO, HC, NO_x, and PM from vehicles under various conditions.[54]

Diesel on-road vehicle emission factors were developed by ICF (2006). CH_4 and N_2O emissions factors for newer (starting with model year 2007) on-road diesel vehicles (those using engine aftertreatment systems) were calculated from annual vehicle certification data compiled by EPA.

CH_4 and N_2O emission factors for AFVs were developed based on the 2022 Greenhouse gases, Regulated Emissions, and Energy use in Transportation (GREET) model (ANL 2022). For light-duty trucks, EPA used travel fractions for LDT1 and LDT2 (MOVES Source Type 31 for LDT1 and MOVES Source Type 32 for LDT2; see Annex 3.2 for information about the MOVES model) to determine emission factors. For medium-duty vehicles, EPA used emission factors for light heavy-duty vocational trucks. For heavy-duty vehicles, EPA used emission factors for long-haul combination trucks. For buses, EPA used emission factors for transit buses. These values represent vehicle operations only (tank-to-wheels); upstream well-to-tank emissions are calculated elsewhere in the Inventory. Biodiesel CH_4 emission factors were corrected from GREET values to be the same as CH_4 emission factors for diesel vehicles. GREET overestimated biodiesel CH_4 emission factors based upon an incorrect CH_4-to-THC ratio for diesel vehicles with aftertreatment technology.

Annual VMT data for 1990 through 2022 were obtained from the Federal Highway Administration's (FHWA) Highway Performance Monitoring System database as reported in Highway Statistics (FHWA 1996 through 2023). VMT estimates were then allocated to vehicle type using ratios of VMT per vehicle type to total VMT, derived from EPA's MOVES3 model (see Annex 3.2 for information about the MOVES model). This corrects time series inconsistencies in FHWA definitions of vehicle types (Browning 2022a). VMT for alternative fuel vehicles (AFVs) were estimated based on Browning (2022b). The age distributions of the U.S. vehicle fleet were obtained from EPA (2004, 2022), and the average annual age-specific vehicle mileage accumulation of U.S. vehicles were obtained from EPA (2022).

Control technology and standards data for on-road vehicles were obtained from EPA's Office of Transportation and Air Quality (EPA 1998, 2022b, and 2023) and Browning (2005). These technologies and standards are defined in Annex 3.2, and were compiled from EPA (1994a, 1994b, 1998, 1999) and IPCC (2006) sources.

Non-Road Mobile Sources

The nonroad mobile category for CH_4 and N_2O includes ships and boats, aircraft, locomotives, and other mobile non-road sources (e.g., construction or agricultural equipment). For locomotives, aircraft, ships, and non-recreational boats, fuel-based emission factors are applied to data on fuel consumption, following the IPCC Tier 1 approach. The Tier 2 approach for these sources would require separate fuel-based emissions factors by

[54] Additional information regarding the MOBILE model can be found at https://www.epa.gov/moves/description-and-history-mobile-highway-vehicle-emission-factor-model.

technology, for which data are not currently available. For other non-road sources, EPA uses the Nonroad component of the MOVES model to estimate fuel use. Emission factors by horsepower bin are estimated from EPA engine certification data. Because separate emission factors are applied to specific engine technologies; these non-road sources utilize a Tier 2 approach.

To estimate CH_4 and N_2O emissions from non-road mobile sources, fuel consumption data were employed as a measure of activity and multiplied by fuel-specific emission factors (in grams of N_2O and CH_4 per kilogram of fuel consumed).[55] Activity data were obtained from AAR (2008 through 2023), APTA (2007 through 2023), Rail Inc (2014 through 2022), APTA (2006), BEA (1991 through 2015), Benson (2002 through 2004), Bureau of Transportation Statistics (BTS; 2023), DLA Energy (2022), DOC (1991 through 2022), DOE (1993 through 2022), DOT (1991 through 2023), EIA (2002, 2007, 2023a, 2023b), EIA (1991 through 2022), EPA (2022), Esser (2003 through 2004), FAA (2024), FHWA (1996 through 2023),[56] Gaffney (2007), FTA (2023), and Whorton (2006 through 2014). Fuel consumption data for boats and vessels in U.S. Territories data and vessel domestic vessel bunkering is proxied from 2021 proxy data. Emission factors for non-road modes were taken from IPCC (2006) and Browning (2020 and 2018).

Uncertainty

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 2022 estimates of CH_4 and N_2O emissions, incorporating probability distribution functions associated with the major input variables. For the purposes of this analysis, the uncertainty was modeled for the following four major sets of input variables: (1) VMT data, by on-road vehicle and fuel type, (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 because 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 3.11. However, a much higher level of uncertainty is associated with CH_4 and N_2O emission factors due to limited emission test data, and because, unlike CO_2 emissions, the emission pathways of CH_4 and N_2O are highly complex.

Based on the uncertainty analysis, mobile combustion CH_4 emissions from all mobile sources in 2022 were estimated to be between 2.5 and 3.4 MMT CO_2 Eq. at a 95 percent confidence level. This indicates a range of 4 percent below to 30 percent above the corresponding 2022 emission estimate of 2.6 MMT CO_2 Eq. Mobile combustion N_2O emissions from mobile sources in 2022 were estimated to be between 15.3 and 20.1MMT CO_2 Eq. at a 95 percent confidence level. This indicates a range of 8 percent below to 20 percent above the corresponding 2022 emission estimate of 16.7 MMT CO_2 Eq.

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

[56] This Inventory uses FHWA's Agriculture, Construction, and Commercial/Industrial MF-24 fuel volumes along with the MOVES model gasoline volumes to estimate non-road mobile source CH_4 and N_2O emissions for these categories. For agriculture, the MF-24 gasoline volume is used directly because it includes both non-road trucks and equipment. For construction and commercial/industrial category gasoline estimates, the 2014 and older MF-24 volumes represented non-road trucks only; therefore, the MOVES gasoline volumes for construction and commercial/industrial categories are added to the respective categories in the Inventory. Beginning in 2015, this addition is no longer necessary since the FHWA updated its methods for estimating on-road and non-road gasoline consumption. Among the method updates, FHWA now incorporates MOVES equipment gasoline volumes in the construction and commercial/industrial categories.

Table 3-21: Approach 2 Quantitative Uncertainty Estimates for CH_4 and N_2O Emissions from Mobile Sources (MMT CO_2 Eq. and Percent)

Source	Gas	2022 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
Mobile Sources	CH_4	2.6	2.5	3.4	-4%	+30%
Mobile Sources	N_2O	16.7	15.3	20.1	-8%	+20%

[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 estimation methodology. As a result, as new information becomes available, uncertainty characterization of input variables may be improved and revised. For additional information regarding uncertainty in emission estimates for CH_4 and N_2O please refer to the Uncertainty Annex. As discussed in Annex 5, data are unavailable to include estimates of CH_4 and N_2O emissions from any liquid fuel used in pipeline transport or some biomass used in transportation sources, but those emissions are assumed to be insignificant.

QA/QC and Verification

In order to ensure the quality of the emission estimates from mobile combustion, general (IPCC Tier 1) and category-specific (Tier 2) Quality Assurance/Quality Control (QA/QC) procedures were implemented consistent with the U.S. Inventory QA/QC plan outlined in Annex 8. The specific plan used for mobile combustion was updated prior to collection and analysis of this current year of data. 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 emission estimates to determine whether they appear consistent with the most recent activity data and emission factors available. A comparison of historical emissions between the current Inventory and the previous Inventory was also conducted to ensure that the changes in estimates were consistent with the changes in activity data and emission factors.

Recalculations Discussion

In previous *Inventories* (1990 through 2020 *Inventory* and before), on-highway greenhouse gas emissions were calculated using FHWA fuel consumption and vehicle miles traveled (VMT) data delineated by FHWA vehicle classes. These fuel consumption estimates were then combined with estimates of fuel shares by vehicle type from Oak Ridge National Laboratory's Transportation Energy Data Book (TEDB), to develop an estimate of fuel consumption for each vehicle type in the Inventory (i.e., passenger cars, light-duty trucks, buses, medium- and heavy-duty trucks, motorcycles). However, in 2011, FHWA changed its methods for estimating 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 in the 1990 through 2008 *Inventory* and applied to the time series beginning in 2007. The FHWA methodology update resulted in large changes in VMT and fuel consumption by vehicle class, leading to a shift in emissions among vehicle classes. For example, FHWA replaced the vehicle category "Passenger Cars" with "Light-duty Vehicles-Short Wheelbase" and the "Other 2 axle-4 Tire Vehicles" category was replaced by "Light-duty Vehicles, Long Wheelbase." FHWA changed the definition of light-duty vehicles to less than 10,000 lbs. GVWR instead of 8,500 lbs. GVWR category updates pushed some single-unit heavy-duty trucks to the light-duty class. This change in vehicle classification also moved some smaller trucks and sport utility vehicles from the light truck category to the passenger cars category in this *Inventory*. These updates resulted in a disconnect in FHWA VMT and fuel consumption data in the 2006 to 2007 timeframe, generating a large drop in the light-duty truck VMT and fuel consumption trend lines between 2006 and 2007, and a corresponding increase in the passenger cars trend lines.

To address this inconsistency in the time series, EPA updated the methodology (starting with the 1990 through 2021 *Inventory*) to divide FHWA VMT data into vehicle classes and fuel type using distributions from EPA's *MOtor Vehicle Emission Simulator*, MOVES. The MOVES model is a nationally recognized model based on vehicle registration, travel activity, and emission rates that are updated with each model release. MOVES uses forecast growth factors which provide EPA's best estimate of likely future activity based on historical data (see Annex 3.2 for more information about the MOVES model). Thus, dividing FHWA total VMT data into vehicle class and fuel type using MOVES ratios provides a more consistent estimate of vehicle activity over the *Inventory* time series. MOVES ratios are also used to reallocate FHWA gasoline and diesel fuel use data (Browning 2022a). For this update, the MOVES3 model was run for calendar years 1990 and 1999 through 2022 for all vehicle types. Calendar years 1991 through 1998 were linearly interpolated from 1990 and 1999 calendar year MOVES3 outputs. Model outputs of VMT and fuel consumption were binned by calendar year, MOVES vehicle type, and fuel type; MOVES vehicle types were then mapped to the vehicle types used in the *Inventory*. Only outputs of gasoline and diesel fuel consumption from MOVES3 were used; alternative fuel VMT and fuel consumption outputs are ignored because they are calculated for the *Inventory* under a separate methodology. Total gasoline and diesel fuel consumption values from FHWA were then allocated to *Inventory* vehicle types using gasoline and diesel fuel consumption ratios by vehicle type from MOVES3. Similarly, VMT by vehicle type and fuel type was calculated by multiplying the total VMT from FHWA by VMT ratios by vehicle and fuel type generated by MOVES3. Overall, because total fuel consumption and VMT values are conserved, the changes in total emissions are small, within 0.1 percent. Observed differences in total emissions are due to changes in CH_4 and N_2O emissions, as the methodology for calculating these non-CO_2 emissions utilizes more detailed activity data and is therefore sensitive to the re-allocation of activity data. While total emissions estimates are not significantly impacted by this methodology update, there are significant changes in the allocation of emissions by vehicle type. The share of emissions allocated to passenger cars now generally decline through the time series while the share of emissions allocated to light-duty trucks increase over time.

In addition, the latest version of Argonne National Laboratory's *Greenhouse Gas, Regulated Emissions, and Energy Use in Transportation Model (*GREET2022*)* provided updated emission factors for all alternative fuel vehicle classes (ANL 2022). Updated emission factors from GREET2022 were implemented in this *Inventory*, across the entire time series.

Additionally, new data from BTS on Amtrak fuel consumption for the time period 2019 through 2022 were included in this *Inventory* (BTS 2023).

Planned Improvements

While the data used for this report represent the most accurate information available, several areas for improvement have been identified.

- Update emission factors for ships and non-recreational boats using residual fuel and distillate fuel. Develop emission factors for locomotives using ultra-low sulfur diesel and emission factors for aircraft using jet fuel. The Inventory currently uses IPCC default values for these emission factors.
- Continue to explore potential improvements to estimates of domestic waterborne fuel consumption for future Inventories. 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. Since 2015, all ships travelling within 200 nautical miles of the U.S. coastlines must use distillate fuels, thereby overestimating the residual fuel used by U.S. vessels and underestimating distillate fuel use in these ships. Additionally, the EIA has stopped publishing the Fuel Oil and Kerosene Sales report, which reported data on distillate marine fuel use in the U.S. and the territories. This affects the volume of fuel and emissions that are allocated to the domestic ships and boats source, although top-down data is still available from the Monthly Energy Review that will be used to estimate total domestic emission from diesel fuel use. New data and methods are being explored to improve the diesel ships and boats emissions estimates going forward.
- Update the analyses to use a forthcoming version of MOVES when it becomes available.

3.2 Carbon Emitted from Non-Energy Uses of Fossil Fuels (CRT 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, hydrocarbon gas liquids (HGL),[57] 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 products such as lubricants, waxes, and asphalt (IPCC 2006). Emissions from non-energy use of lubricants, paraffin waxes, bitumen/asphalt, and solvents are reported in the Energy sector, as opposed to the Industrial Processes and Product Use (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 (see Box 3-5). In addition, estimates of non-energy use emissions included here do not include emissions already reflected in the IPPU sector, e.g., fuels used as reducing agents. To avoid double counting, the "raw" non-energy fuel consumption data reported by EIA are reduced to account for these emissions already included under IPPU.

Carbon dioxide emissions arise from non-energy uses via several pathways. Emissions may occur during the manufacture of a product, as is the case in producing plastics or rubber from fuel-derived feedstocks. Additionally, emissions may occur during the product's lifetime, such as during solvent use. Overall, throughout the time series and across all uses, about 64 percent of the total carbon consumed for non-energy purposes was stored in products (e.g., plastics), and not released to the atmosphere; the remaining 36 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 non-energy use products release CO_2 at the end of their commercial life when they are combusted after disposal; these emissions are reported separately within the Energy chapter in the Incineration of Waste source category. There are also net exports of petrochemical intermediate products 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 carbon in non-energy applications.

As shown in Table 3-22, fossil fuel emissions in 2022 from the non-energy uses of fossil fuels were 102.8 MMT CO_2 Eq., which constituted approximately 2.0 percent of overall fossil fuel emissions. In 2022, the consumption of fuels for non-energy uses (after the adjustments described above) was 5,428.2 TBtu (see Table 3-23). A portion of the carbon in the 5,428.2 TBtu of fuels was stored (236.7 MMT CO_2 Eq.), while the remaining portion was emitted (102.8 MMT CO_2 Eq.). Non-energy use emissions decreased by 7.9 percent from 2021 to 2022, primarily due to decreases in industrial coal, natural gas, and HGL fuel consumption. See Annex 2.3 for more details.

[57] HGL (formerly referred to as liquefied petroleum gas, or LPG) are hydrocarbons that occur as gases at atmospheric pressure and as liquids under higher pressures. HGLs include paraffins, such as ethane, propane, butanes, isobutane, and natural gasoline (formerly referred to as pentanes plus), and HGLs include olefins, such as ethylene, propylene, butylene and isobutylene.

Table 3-22: CO_2 Emissions from Non-Energy Use Fossil Fuel Consumption (MMT CO_2 Eq. and Percent C)

Year	1990	2005	2018	2019	2020	2021	2022
Potential Emissions	292.5	357.7	341.5	334.7	328.6	345.0	339.5
C Stored	193.4	232.7	223.2	228.2	230.8	233.4	236.7
Emissions as a % of Potential	34%	35%	35%	32%	30%	32%	30%
C Emitted	**99.1**	**125.0**	**118.4**	**106.5**	**97.8**	**111.6**	**102.8**

Note: NEU emissions presented in this table differ from the NEU emissions presented in CRT Table 1.A(a)s4 as the CRT NEU emissions do not include NEU of lubricants and other petroleum in U.S. Territories. NEU emissions from U.S. Territories are reported under U.S. Territories in the CRT Table 1.A(a)s4.

Methodology and Time-Series Consistency

As per discussion of methodology for estimating CO_2 emissions from fossil fuel combustion, NEU emissions are estimated in line with a Tier 2 method described by the *IPCC in the 2006 IPCC Guidelines for National Greenhouse Gas Inventories* (IPCC 2006) Chapter 2, Figure 2.1 decision tree and available data on energy use and country specific fuel carbon contents. The first step in estimating carbon stored in products was to determine the aggregate quantity of fossil fuels consumed for non-energy uses. The carbon content of these feedstock fuels is equivalent to potential emissions, or the product of consumption and the fuel-specific carbon content values. Both the non-energy fuel consumption and carbon content data were supplied by the EIA (2023) (see Annex 2.1). Consumption values for industrial coking coal, petroleum coke, other oils, and natural gas in Table 3-23 and Table 3-24 have been adjusted to subtract non-energy uses that are included in the source categories of the Industrial Processes and Product Use chapter.[58] Consumption of natural gas, HGL, naphthas, other oils, and special naphtha were adjusted to subtract out net exports of these products that are not reflected in the raw data from EIA. Consumption values were also adjusted to subtract net exports of HGL components (e.g., propylene, ethane).

For the remaining non-energy uses, the quantity of carbon 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, HGL, naphthas, other oils, still gas, special naphtha, and industrial other coal), asphalt and road oil, lubricants, and waxes—U.S. data on carbon stocks and flows were used to develop carbon storage factors, calculated as the ratio of (a) the carbon stored by the fuel's non-energy products to (b) the total carbon content of the fuel consumed. A lifecycle approach was used in the development of these factors in order to account for losses in the production process 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 Marland and Rotty (1984).
- For the remaining fuel types (petroleum coke, miscellaneous products and other petroleum), IPCC (2006) does not provide guidance on storage factors, and assumptions were made based on the potential fate of carbon in the respective non-energy use products. Carbon dioxide emissions from carbide production are implicitly accounted for in the storage factor calculation for the non-energy use of petroleum coke.

[58] 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.

Table 3-23: Adjusted Consumption of Fossil Fuels for Non-Energy Uses (TBtu)

Year	1990	2005	2018	2019	2020	2021	2022
Industry	**4,110.2**	**4,961.2**	**5,261.0**	**5,143.8**	**5,096.7**	**5,343.1**	**5,301.8**
Industrial Coking Coal	NO	80.4	124.7	112.8	79.9	77.9	46.7
Industrial Other Coal	7.6	11.0	9.5	9.5	9.5	9.5	9.5
Natural Gas to Chemical Plants	280.6	260.7	675.1	663.4	660.5	663.7	654.2
Asphalt & Road Oil	1,170.2	1,323.2	792.8	843.9	832.3	898.1	916.1
HGL[a]	1,135.0	1,554.3	2,427.6	2,372.8	2,469.5	2,639.0	2,758.8
Lubricants	186.3	160.2	122.0	118.3	111.1	113.5	119.5
Natural Gasoline[b]	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Naphtha (<401 °F)	325.4	679.2	420.6	367.7	327.8	329.3	244.2
Other Oil (>401 °F)	660.4	499.2	218.8	211.1	194.7	195.3	111.1
Still Gas	36.7	67.7	166.9	158.7	145.4	152.8	157.1
Petroleum Coke	29.1	104.2	0.0	0.0	0.0	0.0	0.0
Special Naphtha	100.6	60.9	86.9	89.1	80.4	75.7	82.4
Distillate Fuel Oil	7.0	16.0	5.8	5.8	5.8	5.8	5.8
Waxes	33.3	31.4	12.4	10.4	9.2	11.8	13.0
Miscellaneous Products	137.8	112.8	198.0	180.2	170.7	170.8	183.4
Transportation	**176.0**	**151.3**	**137.0**	**131.3**	**115.6**	**119.0**	**125.4**
Lubricants	176.0	151.3	137.0	131.3	115.6	119.0	125.4
U.S. Territories	**50.8**	**114.9**	**3.6**	**3.6**	**1.0**	**1.0**	**1.0**
Lubricants	0.7	4.6	1.0	1.0	1.0	1.0	1.0
Other Petroleum (Misc. Prod.)	50.1	110.3	2.5	2.6	0.0	0.0	0.0
Total	**4,337.1**	**5,227.5**	**5,401.6**	**5,278.8**	**5,213.4**	**5,463.2**	**5,428.2**

NO (Not Occurring)

[a] Excludes natural gasoline.

[b] Formerly referred to as "pentanes plus." This source has been adjusted and is reported separately from HGL to align with historic data and revised EIA terminology.

Table 3-24: 2022 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 (MMT C)	Carbon Stored (MMT C)	Carbon Emissions (MMT C)	Carbon Emissions (MMT CO_2 Eq.)
Industry	**5,301.8**	**NA**	**90.0**	**NA**	**64.3**	**25.7**	**94.3**
Industrial Coking Coal	46.7	25.61	1.2	0.10	0.1	1.1	3.9
Industrial Other Coal	9.5	26.10	0.2	0.67	0.2	0.1	0.3
Natural Gas to Chemical Plants	654.2	14.47	9.4	0.67	6.3	3.1	11.4
Asphalt & Road Oil	916.1	20.55	18.8	1.00	18.7	0.1	0.3
HGL[b]	2,758.8	16.82	46.4	0.67	31.1	15.3	56.2
Lubricants	119.5	20.20	2.4	0.09	0.2	2.2	8.0
Natural Gasoline[c]	0.0	18.24	0.0	0.67	0.0	0.0	0.0
Naphtha (<401° F)	244.2	18.55	4.5	0.67	3.0	1.5	5.5
Other Oil (>401° F)	111.1	20.17	2.2	0.67	1.5	0.7	2.7
Still Gas	157.1	17.51	2.8	0.67	1.8	0.9	3.3
Petroleum Coke	0.0	27.85	0.0	0.30	0.0	0.0	0.0
Special Naphtha	82.4	19.74	1.6	0.67	1.1	0.5	2.0
Distillate Fuel Oil	5.8	20.22	0.1	0.50	0.1	0.1	0.2
Waxes	13.0	19.80	0.3	0.58	0.1	0.1	0.4
Miscellaneous Products	183.4	0.00	0.0	0.00	0.0	0.0	0.0
Transportation	**125.4**	**NA**	**2.5**	**NA**	**0.2**	**2.3**	**8.4**
Lubricants	125.4	20.20	2.5	0.09	0.2	2.3	8.4
U.S. Territories	**1.0**	**NA**	**+**	**NA**	**+**	**+**	**0.1**
Lubricants	1.0	20.20	+	0.09	+	+	0.1

Other Petroleum (Misc. Prod.)	+	20.00	+	0.10	+	+	+
Total	**5,428.2**		**92.6**		**64.6**	**28.0**	**102.8**

+ Does not exceed 0.05 TBtu, MMT C, or MMT CO_2 Eq.
NA (Not Applicable)
NO (Not Occurring)
[a] To avoid double counting, net exports have been deducted.
[b] Excludes natural gasoline.
[c] Formerly referred to as “pentanes plus.” this source has been adjusted and is reported separately from HGL to align with historic data and revised EIA terminology.
Note: Totals may not sum due to independent rounding.

Lastly, emissions were estimated by subtracting the carbon stored from the potential emissions (see Table 3-22). 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 (waste gas from chemicals), 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), EPA’s Emissions Inventory System (EIS) to National Inventory Report (NIR) Mapping file (EPA 2023), *Toxics Release Inventory, 1998* (EPA 2000b), *Biennial Reporting System* (EPA 2000a, 2009), *Resource Conservation and Recovery Act Information System* (EPA 2013b, 2015, 2016b, 2018b, 2021), pesticide sales and use estimates (EPA 1998, 1999, 2002, 2004, 2011, 2017), and the Chemical Data Access Tool (EPA 2014b); the EIA Manufacturer’s Energy Consumption Survey (MECS) (EIA 1994, 1997, 2001, 2005, 2010, 2013, 2017, 2021); the National Petrochemical & Refiners Association (NPRA 2002); the U.S. Census Bureau (1999, 2004, 2009, 2014, 2021); Bank of Canada (2012, 2013, 2014, 2016, 2017, 2018, 2019, 2020, 2021, 2022, 2023); Financial Planning Association (2006); INEGI (2006); the United States International Trade Commission (2023); Gosselin, Smith, and Hodge (1984); EPA’s *Municipal Solid Waste (MSW) Facts and Figures* (EPA 2013, 2014a, 2016a, 2018a, 2019); the U.S. Tire Manufacturers Association (USTMA 2012, 2013, 2014, 2016, 2018, 2020, 2022); the International Institute of Synthetic Rubber Products (IISRP 2000, 2003); the Fiber Economics Bureau (FEB 2001, 2003, 2005, 2007, 2009, 2010, 2011, 2012, 2013); the Independent Chemical Information Service (ICIS 2008, 2016); the EPA Chemical Data Access Tool (CDAT) (EPA 2014b); the American Chemistry Council (ACC 2003 through 2011, 2013, 2014, 2015, 2016, 2017, 2018, 2019, 2020, 2021, 2022, 2023a); the *Guide to the Business of Chemistry* (ACC 2023b); and the Chemistry Industry Association of Canada (CIAC 2023). Specific data sources are listed in full detail in Annex 2.3.

Methodological recalculations were applied to the entire time series to ensure time-series consistency from 1990 through 2022 as discussed below.

Box 3-5: 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 IPPU sector.[59] In this *Inventory*, carbon storage and carbon

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

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 (CRT Source Category 1A5).[60]

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. Although emissions from these non-energy uses are reported in the Energy chapter the methodologies used to determine emissions are compatible with the *2006 IPCC Guidelines*. 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., carbon 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 Table 3-24).

For those inputs, U.S. country-specific data on carbon stocks and flows are used to develop carbon storage factors, which are calculated as the ratio of the carbon stored by the fossil fuel non-energy products to the total carbon content of the fuel consumed, taking into account losses in the production process and during product use.[61] The country-specific methodology to reflect national circumstances starts with the aggregate amount of fossil fuels used for non-energy uses and applies a carbon balance calculation, breaking out the carbon emissions from non-energy use of lubricants, waxes, and asphalt and road oil. The emissions are reported under the Energy chapter to improve transparency, report a more complete carbon balance and to avoid double counting. Due to U.S. national circumstances, reporting these carbon emissions separately under IPPU would involve making artificial adjustments to allocate both the carbon inputs and carbon outputs of the non-energy use carbon balance. For example, only the emissions from the first use of lubricants and waxes are to be reported under the IPPU sector, emissions from use of lubricants in 2-stroke engines and emissions from secondary use of lubricants and waxes in waste incineration with energy recovery are to be reported under the Energy sector. Reporting these non-energy use emissions from only first use of lubricants and waxes under IPPU would involve making artificial adjustments to the non-energy use carbon balance and could potentially result in double counting of emissions. These artificial adjustments would also be required for asphalt and road oil and solvents (which are captured as part of petrochemical feedstock emissions) and could also potentially result in double counting of emissions. To avoid presenting an incomplete carbon balance and a less transparent approach for the Carbon Emitted from Non-Energy Uses of Fossil Fuels source category calculation, the entire calculation of carbon storage and carbon emissions is therefore conducted in the Non-Energy Uses of Fossil Fuels category calculation methodology, and both the carbon storage and carbon emissions for lubricants, waxes, and asphalt and road oil are reported under the Energy sector.

However, emissions from non-energy uses of fossil fuels as feedstocks or reducing agents (e.g., petrochemical production, aluminum production, titanium dioxide, and zinc production) are reported in the IPPU chapter, unless otherwise noted due to specific national circumstances.

Uncertainty

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

[60] 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*.

[61] Data and calculations for lubricants and waxes and asphalt and road oil are in Annex 2.3 – Methodology for Estimating Carbon Emitted from Non-Energy Uses of Fossil Fuels.

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, HGL, natural gasoline, 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 3-23 and Table 3-24) 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 3-25 (emissions) and Table 3-26 (storage factors). Carbon emitted from non-energy uses of fossil fuels in 2022 was estimated to be between 71.0 and 166.6 MMT CO_2 Eq. at a 95 percent confidence level. This indicates a range of 31 percent below to 62 percent above the 2022 emission estimate of 102.8 MMT CO_2 Eq. The uncertainty in the emission estimates is a function of uncertainty in both the quantity of fuel used for non-energy purposes and the storage factor.

Table 3-25: Approach 2 Quantitative Uncertainty Estimates for CO_2 Emissions from Non-Energy Uses of Fossil Fuels (MMT CO_2 Eq. and Percent)

Source	Gas	2022 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	81.4	51.7	146.6	-37%	+80%
Asphalt	CO_2	0.3	0.1	0.7	-58%	+119%
Lubricants	CO_2	16.6	13.7	19.2	-17%	+16%
Waxes	CO_2	0.4	0.3	0.7	-23%	+77%
Other	CO_2	4.2	0.8	4.9	-81%	+17%
Total	**CO_2**	**102.8**	**71.0**	**166.6**	**-31%**	**+62%**

[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 3-26: Approach 2 Quantitative Uncertainty Estimates for Storage Factors of Non-Energy Uses of Fossil Fuels (Percent)

Source	Gas	2022 Storage Factor (%)	Uncertainty Range Relative to Emission Estimate[a] (%)		(%, Relative)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Feedstocks	CO_2	67.0%	52.3%	73.5%	-22%	+10%
Asphalt	CO_2	99.6%	99.1%	99.8%	0.5%	0.3%
Lubricants	CO_2	9.2%	3.9%	17.5%	-57%	+91%
Waxes	CO_2	57.8%	47.4%	67.5%	-18%	+17%
Other	CO_2	13.6%	8.1%	83.0%	-41%	+511%

[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).

As shown in Table 3-26, waxes 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—also appears to have relatively 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 carbon 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.

QA/QC and Verification

In order to ensure the quality of the emission estimates from non-energy uses of fossil fuels, general (IPCC Tier 1) and category-specific (Tier 2) Quality Assurance/Quality Control (QA/QC) procedures were implemented consistent with the U.S. Inventory QA/QC plan outlined in Annex 8. This effort included a general analysis, as well as portions of a category specific 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 carbon (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 with 2021 totals as well as their trends across the time series.

It is important to ensure no double counting of emissions between fuel combustion, non-energy use of fuels and industrial process emissions. For petrochemical feedstock production, our review of the categories suggests this is not a significant issue since the non-energy use industrial release data includes different categories of sources and sectors than those included in the Industrial Processes and Product Use (IPPU) emissions category for petrochemicals. Further data integration is not available at this time because feedstock data from the EIA used to estimate non-energy uses of fuels are aggregated by fuel type, rather than disaggregated by both fuel type and particular industries. Also, GHGRP-reported data on quantities of fuel consumed as feedstocks by petrochemical producers are unable to be used due to the data failing GHGRP CBI aggregation criteria. This country-specific approach taken is better able to reflect the national situation because it is accounting for secondary product imports and exports that are not included directly in the national energy statistics. Furthermore, it is compatible with the *2006 IPCC Guidelines* as discussed in Box 3-5 above, but also as the NEU emissions are here represent different emissions from those covered in the IPPU petrochemical production category.

Recalculations Discussion

Several updates to activity data factors lead to recalculations of previous year results. The major updates are as follows:

- U.S. International Trade Commission (2023) made changes to the classification of certain cleanser types, which doubled the historic emissions data for cleanser imports while exports remained constant.
- ACC (2023b) updated polyester, polyolefin and nylon fiber, ethylene glycol, maleic anhydride, adipic acid, and acetic acid production in 2021 which resulted in a slight decrease in emissions relative to the previous *Inventory*.
- U.S. International Trade Commission (2023) updated historical import and export data from 1996 to 2021, resulting in greater net exports relative to the previous *Inventory*.
- EIA (2024) shifted all 2022 product supplied of natural gasoline and unfinished oils to crude oil transfers, reflecting that, in actuality, nearly the full volume of these fuels is used as a feedstock in crude oil production, instead of directly consumed as an end-use fuel. Under EIA's guidance, EPA shifted all product supplied of natural gasoline to crude oil transfers for the time series. Natural gasoline was entirely

recategorized, which resulted in zero emissions for the time series from 1990 to 2022. Natural gasoline previously made up 1.7 percent of total emissions on average across the time series for non-energy uses of fossil fuels.

- To better align with EIA methodology, the non-energy use consumption of HGLs is now calculated for the entire timeseries by assuming that 100 percent of ethane, ethylene, and propylene consumption is for non-combustion use and 85 percent of normal butane, butylene, isobutane, and isobutylene is for non-combustion use. Non-energy use consumption of propane is calculated by subtracting the non-energy consumption of all other HGLs from the total non-combustion consumption of HGLs as published by the EIA. A further adjustment is made to natural gas, HGL, naphtha, other oil, and special naphtha consumption to account for exports of organic chemicals, cleansers, and pesticides. Because this adjustment is apportioned based on the relative ratios of each fuel, the emissions from these fuels have also changed slightly across the time series. Additionally, to better align with EIA methodology, the non-combustion and energy HGL carbon contents are now calculated for the entire timeseries following the above methodology. Overall, this update caused emissions from the non-energy use of natural gas to decrease an average of 27 MMT CO_2 Eq. annually, or 23 percent.

Overall, these changes resulted in an average annual decrease of 10.1 MMT CO_2 Eq. (8.2 percent) in carbon emissions from non-energy uses of fossil fuels for the period 1990 through 2021, relative to the previous *Inventory*.

Planned Improvements

There are several future improvements planned:

- More accurate accounting of carbon in petrochemical feedstocks. EPA has worked with EIA to determine the cause of input/output discrepancies in the carbon mass balance contained within the NEU model. In the future, two strategies to reduce or eliminate this discrepancy will continue to be pursued as part of quality control procedures. First, accounting of carbon 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, the use of top-down carbon input calculation in estimating emissions will be reconsidered. Alternative approaches that rely more substantially on the bottom-up carbon output calculation will be considered instead.
- 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 carbon. Additional fates may be researched, including the fossil carbon 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. A better understanding of these trends will be pursued to identify any mischaracterized or misreported fuel consumption for non-energy uses.
- Updating the average carbon content of solvents was researched, since the entire time series depends on one year's worth of solvent composition data. The data on carbon emissions from solvents that were readily available do not provide composition data for all categories of solvent emissions and also have conflicting definitions for volatile organic compounds, the source of emissive carbon in solvents. Additional sources of solvents data will be investigated in order to update the carbon content assumptions.
- Updating the average carbon 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 carbon content for this category.

- Revising the methodology for consumption, production, and carbon 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 carbon 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.
- Assess the current method and/or identify new data sources (e.g., EIA) for estimating emissions from ammonia/fertilizer use of natural gas.
- Investigate EIA NEU and MECS data to update, as needed, adjustments made for ammonia production and "natural gas to chemical plants, other uses" and "natural gas to other" non-energy uses, including iron and steel production, in energy uses and IPPU.

3.3 Incineration of Waste (CRT Source Category 1A)

Combustion 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; EPA 2020; 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, combustion of MSW tends to occur at waste-to-energy facilities or industrial facilities where useful energy is recovered, and thus emissions from waste combustion 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. Combustion of waste results in conversion of the organic inputs to CO_2. According to the *2006 IPCC Guidelines*, when the CO_2 emitted is of fossil origin, it is counted as a net anthropogenic emission of CO_2 to the atmosphere. Thus, the emissions from waste combustion are calculated by estimating the quantity of waste combusted and the fraction of the waste that is carbon derived from fossil sources.

Most of the organic materials in MSW are of biogenic origin (e.g., paper, yard trimmings), and have their net carbon flows accounted for under the Land Use, Land-Use Change, and Forestry chapter. However, some components of MSW and scrap tires—plastics, synthetic rubber, synthetic fibers, and carbon black—are of fossil origin. Plastics in the U.S. waste stream are primarily in the form of containers, packaging, and durable goods. Rubber is found in durable goods, such as carpets, and in non-durable goods, such as clothing and footwear. Fibers in MSW 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 combustion estimate, though waste disposal practices for tires differ from MSW. Estimates on emissions from hazardous waste combustion can be found in Annex 2.3 and are accounted for as part of the carbon mass balance for non-energy uses of fossil fuels.

Approximately 26.3 million metric tons of MSW were combusted in 2022 (EPA 2022). Carbon dioxide emissions from combustion of waste decreased 4.2 percent since 1990, to an estimated 12.4 MMT CO_2 (12,357 kt) in 2022. Emissions across the time series are shown in Table 3-27 and Table 3-28.

Waste combustion is also a source of CH_4 and N_2O emissions (De Soete 1993; IPCC 2006). Methane emissions from the combustion of waste were estimated to be less than 0.05 MMT CO_2 Eq. (less than 0.05 kt CH_4) in 2022 and have remained steady since 1990. Nitrous oxide emissions from the combustion of waste were estimated to be 0.3 MMT CO_2 Eq. (1.3 kt N_2O) in 2022 and have decreased by 18 percent since 1990. This decrease is driven by the decrease in total MSW combusted.

Table 3-27: CO_2, CH_4, and N_2O Emissions from the Combustion of Waste (MMT CO_2 Eq.)

Gas	1990	2005	2018	2019	2020	2021	2022
CO_2	12.9	13.3	13.3	12.9	12.9	12.5	12.4
CH_4	+	+	+	+	+	+	+
N_2O	0.4	0.3	0.4	0.4	0.3	0.4	0.3
Total	**13.3**	**13.6**	**13.7**	**13.3**	**13.3**	**12.8**	**12.7**

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

Table 3-28: CO_2, CH_4, and N_2O Emissions from the Combustion of Waste (kt)

Gas	1990	2005	2018	2019	2020	2021	2022
CO_2	12,900	13,254	13,339	12,948	12,921	12,476	12,357
CH_4	+	+	+	+	+	+	+
N_2O	2	1	1	1	1	1	1

+ Does not exceed 0.05 kt.

Methodology and Time-Series Consistency

Municipal Solid Waste Combustion

To determine both CO_2 and non-CO_2 emissions from the combustion of waste, the tonnage of waste combusted and an estimated emissions factor are needed. Emission estimates from the combustion of tires are discussed separately. Data for total waste combusted was derived from *BioCycle* (van Haaren et al. 2010), EPA Facts and Figures Report, Energy Recovery Council (ERC), EPA's Greenhouse Gas Reporting Program (GHGRP), and the U.S. Energy Information Administration (EIA). Multiple sources were used to ensure a complete, quality dataset, as each source encompasses a different timeframe.

EPA determined the MSW tonnages based on data availability and accuracy throughout the time series.

- 1990-2006: MSW combustion tonnages are from Biocycle combustion data. Tire combustion data from the U.S. Tire Manufacturers Association (USTMA) are removed to arrive at MSW combusted without tires.
- 2006-2010: MSW combustion tonnages are an average of Biocycle (with USTMA tire data tonnage removed), U.S. EPA Facts and Figures, EIA, and Energy Recovery Council data (with USTMA tire data tonnage removed).
- 2011-2022: MSW combustion tonnages are from EPA's GHGRP data.

Table 3-29 provides the estimated tons of MSW combusted including and excluding tires.

Table 3-29: Municipal Solid Waste Combusted (Short Tons)

	1990	2005	2018	2019	2020	2021	2022
Waste Combusted *(excluding tires)*	33,344,839	26,486,414	29,162,364	28,174,311	27,586,271	27,867,446	26,338,130
Waste Combusted *(including tires)*	33,766,239	28,631,054	30,853,949	29,821,141	29,106,686	29,261,446	27,732,130

Sources: BioCycle, EPA Facts and Figures, ERC, GHGRP, EIA, USTMA.

CO_2 Emissions from MSW Excluding Scrap Tires

Fossil CO_2 emission factors were calculated from EPA's GHGRP data for non-biogenic sources. Using GHGRP-reported emissions for CH_4 and N_2O and assumed emission factors, the tonnage of waste combusted, excluding tires, was derived. Methane and N_2O emissions and assumed emission factors were used to estimate the amount of MSW combusted in terms of energy content. The energy content of MSW combusted was then converted into tonnage based on assumed MSW heating value. Two estimates were generated (one for CH_4 and one for N_2O) and the two were averaged together. Dividing fossil CO_2 emissions from GHGRP FLIGHT data for MSW combustors by this estimated tonnage yielded an annual CO_2 emission factor. As this data was only available following 2011, all years prior use an average of the emission factors from 2011 through 2015. See Annex 3.7 for more detail on how MSW carbon factors were calculated.

Finally, CO_2 emissions were calculated by multiplying the annual tonnage estimates, excluding tires, by the calculated emissions factor. Calculated fossil CO_2 emission factors are shown in Table 3-30.

Table 3-30: Calculated Fossil CO_2 Content per Ton Waste Combusted (kg CO_2/Short Ton Combusted)

Year	1990	2005	2018	2019	2020	2021	2022
CO_2 Emission Factors	366	366	361	363	377	365	382

CO_2 Emissions from Scrap Tires

Scrap tires contain several types of synthetic rubber, carbon black, and synthetic fibers. Each type of synthetic rubber has a discrete carbon content, and carbon black is 100 percent C. For synthetic rubber and carbon black in scrap tires, information on average weight, disposal percentage, and total tires incinerated for energy was obtained biannually from U.S. Scrap Tire Management Summary for 2005 through 2022 data (USTMA 2022). Information about scrap tire composition was taken from the Rubber Manufacturers' Association internet site (USTMA 2012a). Emissions of CO_2 were calculated based on the amount of scrap tires used for fuel and the synthetic rubber and carbon black content of scrap tires. The mass of combusted material is multiplied by its carbon content to calculate the total amount of carbon stored. 2022 values are proxied from 2021 data. More detail on the methodology for calculating emissions from each of these waste combustion sources is provided in Annex 3.7. Table 3-31 provides CO_2 emissions from combustion of waste tires.

Table 3-31: CO_2 Emissions from Combustion of Tires (MMT CO_2 Eq.)

Year	1990	2005	2018	2019	2020	2021	2022
Synthetic Rubber	0.3	1.6	1.3	1.2	1.1	1.0	1.0
C Black	0.4	2.0	1.5	1.5	1.4	1.3	1.3
Total	**0.7**	**3.6**	**2.8**	**2.7**	**2.5**	**2.3**	**2.3**

Non-CO_2 Emissions

Combustion of waste also results in emissions of CH_4 and N_2O. These emissions were calculated by multiplying the total estimated mass of waste combusted, including tires, by the respective emission factors. The emission factors for CH_4 and N_2O emissions per quantity of MSW combusted are default emission factors for the default continuously-fed stoker unit MSW combustion technology type and were taken from IPCC (2006).

Uncertainty

An Approach 2 Monte Carlo analysis was performed to determine the level of uncertainty surrounding the estimates of CO_2 emissions and N_2O emissions from the incineration of waste (given the very low emissions for CH_4, no uncertainty estimate was derived). IPCC 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. Statistical analyses or expert judgments of uncertainty were not available directly from the information sources for most 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 reported CO_2 emissions; N_2O and CH_4 emissions factors, and tire synthetic rubber and black carbon contents. The highest levels of uncertainty surround the reported emissions from GHGRP; the lowest levels of uncertainty surround variables that were determined by quantitative measurements (e.g., combustion efficiency, carbon content of carbon black).

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 3-32. Waste incineration CO_2 emissions in 2022 were estimated to be between 10.3 and 14.4 MMT CO_2 Eq. at a 95 percent confidence level. This indicates a range of 17 percent below to 16 percent above the 2022 emission estimate of 12.4 MMT CO_2 Eq. Also at a 95 percent confidence level, waste incineration N_2O emissions in 2022 were estimated to be between 0.2 and 0.9 MMT CO_2 Eq. This indicates a range of 54 percent below to 164 percent above the 2022 emission estimate of 0.3 MMT CO_2 Eq.

Table 3-32: Approach 2 Quantitative Uncertainty Estimates for CO_2 and N_2O from the Incineration of Waste (MMT CO_2 Eq. and Percent)

Source	Gas	2022 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	12.4	10.3	14.4	-17%	16%
Incineration of Waste	N_2O	0.3	0.2	0.9	-54%	164%

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

QA/QC and Verification

In order to ensure the quality of the emission estimates from waste combustion, general (IPCC Tier 1) and category-specific (Tier 2) Quality Assurance/Quality Control (QA/QC) procedures were implemented consistent with the U.S. Inventory QA/QC plan outlined in Annex 8. 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 combustion of waste. Trends across the time series were analyzed to determine whether any corrective actions were needed. Corrective actions were taken to rectify minor errors in the use of activity data.

Recalculations Discussion

No recalculations were performed for the current *Inventory*.

Planned Improvements

Research was conducted to review the composition of carbon black abraded and stored in tires. No definitive sources were found that support updating the current factor of 28 percent carbon black for commercial and light duty tires. This factor was not updated, but additional research can be completed in future *Inventory* cycles.

3.4 Coal Mining (CRT Source Category 1B1a)

Three types of coal mining-related activities release CH_4 and CO_2 to the atmosphere: underground mining, surface mining, and post-mining (i.e., coal-handling) activities. While surface coal mines account for the majority of U.S. coal production, underground coal mines contribute the largest share of fugitive CH_4 emissions (see Table 3-34 and Table 3-35) due to the higher CH_4 content of coal in the deeper underground coal seams. In 2022, 185 underground coal mines and 354 surface mines were operating in the United States (EIA 2023). In recent years, the total number of active coal mines in the United States has declined. In 2022, the United States was the fourth largest coal producer in the world, after China, India, and Indonesia (IEA 2022).

Table 3-33: Coal Production (kt)

Year	1990	2005	2018	2019	2020	2021	2022
Underground							
Number of Mines	1,683	586	236	226	196	174	185
Production	384,244	334,399	249,804	242,557	177,380	200,122	201,525
Surface							
Number of Mines	1,656	789	430	432	350	332	354
Production	546,808	691,447	435,521	397,750	307,944	323,142	336,990
Total							
Number of Mines	**3,339**	**1,398**	**666**	**658**	**546**	**506**	**539**
Production	**931,052**	**1,025,846**	**685,325**	**640,307**	**485,324**	**523,264**	**538,515**

Fugitive CH_4 Emissions

Underground coal mines liberate CH_4 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 CH_4 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 CH_4 before, during, or after mining. Some mines recover and use CH_4 generated from ventilation and degasification systems, thereby reducing emissions to the atmosphere.

Surface coal mines liberate CH_4 as the overburden is removed and the coal is exposed to the atmosphere. Methane 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, CH_4 is released during post-mining activities, as the coal is processed, transported, and stored for use.

Total CH_4 emissions in 2022 were estimated to be 1,558 kt (43.6 MMT CO_2 Eq.), a decline of approximately 60 percent since 1990 (see Table 3-34 and Table 3-35). In 2022, underground mines accounted for approximately 72 percent of total emissions, surface mines accounted for 14 percent, and post-mining activities accounted for 14 percent. In 2022, total CH_4 emissions from coal mining decreased by approximately 2 percent relative to the previous year. Total coal production in 2022 increased by 3 percent compared to 2021. This resulted in an increase of 4 percent in CH_4 emissions from surface mining and post-mining activities in 2022. However, surface mining and post-mining activities have a lower impact on total CH_4 compared to underground mining (72 percent of total emissions in 2022). The number of operating underground mines increased in 2022 and the amount of CH_4 recovered and used in 2022 increased by 25 percent compared to 2021. This resulted in a slight decrease in overall CH_4 emissions in 2022 (2 percent), compared to 2021.

Table 3-34: CH_4 Emissions from Coal Mining (MMT CO_2 Eq.)

Activity	1990	2005	2018	2019	2020	2021	2022
Underground (UG) Mining	**83.1**	**46.7**	**43.6**	**38.5**	**35.2**	**32.9**	**31.5**
Liberated	90.6	66.9	66.7	56.6	53.7	52.3	55.7
Recovered & Used	(7.5)	(20.1)	(23.1)	(18.1)	(18.5)	(19.4)	(24.2)
Surface Mining	**12.0**	**13.3**	**7.8**	**7.2**	**5.4**	**5.7**	**6.0**
Post-Mining (UG)	**10.3**	**8.6**	**5.9**	**5.8**	**4.3**	**4.8**	**4.8**
Post-Mining (Surface)	**2.6**	**2.9**	**1.7**	**1.5**	**1.2**	**1.2**	**1.3**
Total	**108.1**	**71.5**	**59.1**	**53.0**	**46.2**	**44.7**	**43.6**

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

Table 3-35: CH_4 Emissions from Coal Mining (kt)

Activity	1990	2005	2018	2019	2020	2021	2022
Underground (UG) Mining	**2,968**	**1,669**	**1,557**	**1,375**	**1,257**	**1,176**	**1,124**
Liberated	3,237	2,388	2,382	2,022	1,917	1,868	1,989
Recovered & Used	(269)	(720)	(825)	(646)	(660)	(692)	(865)
Surface Mining	**430**	**475**	**280**	**255**	**194**	**205**	**215**
Post-Mining (UG)	**368**	**306**	**212**	**206**	**155**	**170**	**173**
Post-Mining (Surface)	**93**	**103**	**61**	**55**	**42**	**44**	**47**
Total	**3,860**	**2,552**	**2,110**	**1,892**	**1,648**	**1,595**	**1,558**

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

Methodology and Time-Series Consistency

EPA uses an IPCC Tier 3 method for estimating CH_4 emissions from underground coal mining and an IPCC Tier 2 method for estimating CH_4 emissions from surface mining and post-mining activities (for coal production from both underground mines and surface mines) in accordance with methodological decisions trees in IPCC guidelines (Volume 2, Chapter 4, Figure 4.1.1 and 4.1.2) and available data (IPCC 2006). The methodology for estimating CH_4 emissions from coal mining consists of two steps:

- Estimate CH_4 emissions from underground mines. These emissions have two sources: ventilation systems and degasification systems. They are estimated using mine-specific data, then summed to determine total CH_4 liberated. The CH_4 recovered and used is then subtracted from this total, resulting in an estimate of net emissions to the atmosphere.
- Estimate CH_4 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 CH_4 Liberated and CH_4 Emitted from Underground Mines

Underground mines generate CH_4 from ventilation systems and degasification systems. Some mines recover and use the liberated CH_4, thereby reducing emissions to the atmosphere. Total CH_4 emitted from underground mines equals the CH_4 liberated from ventilation systems, plus the CH_4 liberated from degasification systems, minus the CH_4 recovered and used.

Step 1.1: Estimate CH_4 Liberated from Ventilation Systems

To estimate CH_4 liberated from ventilation systems, EPA uses data collected through its Greenhouse Gas Reporting Program (GHGRP)[62] (Subpart FF, "Underground Coal Mines"), data provided by the U.S. Mine Safety and Health Administration (MSHA) (MSHA 2023), and occasionally data collected from other sources on a site-specific level (e.g., state gas production databases). Since 2011, the nation's "gassiest" underground coal mines—those that liberate more than 36,500,000 actual cubic feet of CH_4 per year (about 17,525 MT CO_2 Eq.)—have been required to report to EPA's GHGRP (EPA 2023).[63] Mines that report to EPA's GHGRP must report quarterly measurements of CH_4 emissions from ventilation systems; they have the option of recording and reporting 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 CH_4 concentrations.[64]

Since 2013, ventilation CH_4 emission estimates have been calculated based on both quarterly GHGRP data submitted by underground mines and on quarterly measurement data obtained directly from MSHA. Because not all mines report under EPA's GHGRP, the emissions of the mines that do not report must be calculated using MSHA data. The MSHA data also serves as a quality assurance tool for validating GHGRP data. For GHGRP data, reported quarterly ventilation methane emissions (metric tons) are summed for each mine to develop mine-specific annual ventilation emissions. For MSHA data, the average daily CH_4 emission rate for each mine is determined using the CH_4 total for all data measurement events conducted during the calendar year and total duration of all data measurement events (in days). The calculated average daily CH_4 emission rate is then multiplied by 365 days to estimate annual ventilation CH_4 emissions for the MSHA dataset.

Step 1.2: Estimate CH_4 Liberated from Degasification Systems

Particularly gassy underground mines also use degasification systems (e.g., wells or boreholes) to remove CH_4 before, during, or after mining. This CH_4 can then be collected for use or vented to the atmosphere. Nineteen mines used degasification systems in 2022 and all of these mines reported the CH_4 removed through these systems to EPA's GHGRP under Subpart FF (EPA 2023). Based on the weekly measurements reported to EPA's GHGRP, degasification data summaries for each mine are added to estimate the CH_4 liberated from degasification systems. Twelve of the 19 mines with degasification systems had operational CH_4 recovery and use projects, including two mines with two recovery and use projects each (see step 1.3 below).[65]

Degasification data reported to EPA's GHGRP by underground coal mines is the primary source of data used to develop estimates of CH_4 liberated from degasification systems. Data reported to EPA's GHGRP were used exclusively to estimate CH_4 liberated from degasification systems at 13 of the 19 mines that used degasification systems in 2022. Data from state gas well production databases were used to supplement GHGRP degasification data for the remaining six mines (DMME 2023; GSA 2023; WVGES 2023; McElroy OVS 2013).

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[62] In implementing improvements and integrating data from EPA's GHGRP, EPA followed the latest guidance from the IPCC on the use of facility-level data in national inventories (IPCC 2011).

[63] Underground coal mines report to EPA under Subpart FF of the GHGRP (40 CFR Part 98). In 2022, 61 underground coal mines reported to the program.

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

[65] Several of the mines venting CH_4 from degasification systems use a small portion of the gas to fuel gob well blowers in remote locations where electricity is not available. However, this CH_4 use is not considered to be a formal recovery and use project.

For pre-mining wells, cumulative degasification volumes that occur prior to the well being mined through are attributed to the mine in the inventory year in which the well is mined through.[66] EPA's GHGRP does not require gas production from virgin coal seams (coalbed methane) to be reported by coal mines under Subpart FF.[67] Most pre-mining wells drilled from the surface are considered coalbed methane wells prior to mine-through and associated CH_4 emissions are reported under another subpart of the GHGRP (Subpart W, "Petroleum and Natural Gas Systems"). As a result, GHGRP data must be supplemented to estimate cumulative degasification volumes that occurred prior to well mine-through. There were four mines with degasification systems that include pre-mining wells that were mined through in 2022. For all of these mines, GHGRP data were supplemented with historical data from state gas well production databases (ERG 2023; GSA 2023), as well as with mine-specific information regarding the locations and dates on which the pre-mining wells were mined through (JWR 2010; El Paso 2009; ERG 2023).

Step 1.3: Estimate CH_4 Recovered from Ventilation and Degasification Systems, and Utilized or Destroyed (Emissions Avoided)

Twelve mines had a total of fourteen CH_4 recovery and use projects in place in 2022, including two mines that each have two recovery and use projects. Thirteen of these projects involved degasification systems with one mine having a ventilation air methane abatement project (VAM). Eleven of these mines sold the recovered CH_4 to a pipeline, including one that also used CH_4 to fuel a thermal coal dryer. One mine destroyed the recovered CH_4 (VAM) using regenerative thermal oxidation (RTO) without energy recovery and using enclosed flares.

The CH_4 recovered and used (or destroyed) at the twelve mines described above are estimated using the following methods:

- EPA's GHGRP data was exclusively used to estimate the CH_4 recovered and used from six of the 12 mines that deployed degasification systems in 2022. Based on quarterly measurements, the GHGRP degasification destruction data summaries for each mine are added together to estimate the CH_4 recovered and used from degasification systems.
- State sales data were used to supplement GHGRP data to estimate CH_4 recovered and used from five mines that deployed degasification systems in 2022 (DMME 2023, ERG 2023, GSA 2023, and WVGES 2023). Four of these mines intersected pre-mining wells in 2022. Supplemental information is used for these mines because estimating CH_4 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 prior to the well being mined through. The supplemental data is obtained from state gas production databases as well as mine-specific information on the location and timing of mined-through pre-mining wells.
- For the single mine that employed VAM for CH_4 recovery and use, the estimates of CH_4 recovered and used were obtained from the mine's offset verification statement (OVS) submitted to the California Air Resources Board (CARB) (McElroy OVS 2023). This mine also reported CH_4 reductions from flaring. GHGRP data were used to estimate CH_4 recovered and flared in 2022.

Step 2: Estimate CH_4 Emitted from Surface Mines and Post-Mining Activities

Mine-specific data are not available for estimating CH_4 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 2023) is multiplied by basin-specific CH_4 contents (EPA 1996, 2005) and a 150 percent emission factor (to account for CH_4 from over- and under-burden) to estimate CH_4 emissions (King 1994; Saghafi

[66] A well is "mined through" when coal mining development or the working face intersects the borehole or well.

[67] This applies for pre-drainage in years prior to the well being mined through. Beginning with the year the well is mined through, the annual volume of CH_4 liberated from a pre-drainage well is reported under Subpart FF of EPA's GHGRP.

2013). For post-mining activities, basin-specific coal production is multiplied by basin-specific CH_4 contents and a mid-range 32.5 percent emission factor for CH_4 desorption during coal transportation and storage (Creedy 1993). Basin-specific in situ gas content data were compiled from AAPG (1984) and USBM (1986).

Fugitive CO_2 Emissions

Methane and CO_2 are naturally occurring in coal seams and are collectively referred to as coal seam gas. These gases remain trapped in the coal seam until coal is mined (i.e., coal seam is exposed and fractured during mining operations). Fugitive CO_2 emissions occur during underground coal mining, surface coal mining, and post-mining activities. Methods and data to estimate fugitive CO_2 emissions from underground and surface coal mining are presented in the sections below. Fugitive CO_2 emissions from post-mining activities were not estimated due to the lack of an IPCC method and unavailability of data.

Total fugitive CO_2 emissions in 2022 were estimated to be 2,474 kt (2.5 MMT CO_2 Eq.), a decline of approximately 46 percent since 1990. In 2022, underground mines accounted for approximately 89 percent of total fugitive CO_2 emissions. In 2022, total fugitive CO_2 emissions from coal mining increased by approximately 1 percent relative to the previous year. This increase was due to an increase in annual coal production.

Table 3-36: CO_2 Emissions from Coal Mining (MMT CO_2 Eq.)

Activity	1990	2005	2018	2019	2020	2021	2022
Underground (UG) Mining	**4.2**	**3.6**	**2.8**	**2.7**	**1.9**	**2.2**	**2.2**
Liberated	4.2	3.6	2.7	2.6	1.9	2.2	2.2
Recovered & Used	(+)	(+)	(+)	(+)	(+)	(+)	(+)
Flaring	NO	NO	0.1	0.1	+	+	+
Surface Mining	**0.4**	**0.6**	**0.4**	**0.3**	**0.2**	**0.3**	**0.3**
Total	**4.6**	**4.2**	**3.1**	**3.0**	**2.2**	**2.5**	**2.5**

\+ Does not exceed 0.05 MMT CO_2 Eq.
NO (Not Occurring)
Notes: Parentheses indicate negative values. Totals may not sum due to independent rounding.

Table 3-37: CO_2 Emissions from Coal Mining (kt)

Activity	1990	2005	2018	2019	2020	2021	2022
Underground (UG) Mining	**4,164**	**3,610**	**2,787**	**2,670**	**1,948**	**2,193**	**2,201**
Liberated	4,171	3,630	2,712	2,633	1,926	2,173	2,188
Recovered & Used	(8)	(21)	(23)	(18)	(19)	(19)	(24)
Flaring	NO	NO	97	55	41	40	38
Surface Mining	**443**	**560**	**353**	**322**	**249**	**262**	**273**
Total	**4,606**	**4,169**	**3,139**	**2,992**	**2,197**	**2,455**	**2,474**

NO (Not Occurring)
Notes: Parentheses indicate negative values. Totals may not sum due to independent rounding.

Methodology and Time-Series Consistency

EPA uses an IPCC Tier 1 method for estimating fugitive CO_2 emissions from underground coal mining and surface mining in accordance with methodological decisions trees in IPCC guidelines (Volume 2, Chapter 4, Figure 4.1.1a) and available data (IPCC 2019). IPCC methods and data to estimate fugitive CO_2 emissions from post-mining activities (for both underground and surface coal mining) are currently not available.

Step 1: Underground Mining

EPA used the following overarching IPCC equation to estimate fugitive CO_2 emissions from underground coal mines (IPCC 2019):

Equation 3-1: Estimating Fugitive CO_2 Emissions from Underground Mines

$$\begin{aligned} &Total\ CO_2\ from\ Underground\ Mines \\ &\quad = CO_2\ from\ underground\ mining\ - Amount\ of\ CO_2\ in\ gas\ recovered \\ &\quad + CO_2\ from\ methane\ flaring \end{aligned}$$

Step 1.1: Estimate Fugitive CO_2 Emissions from Underground Mining

EPA estimated fugitive CO_2 emissions from underground mining using the IPCC Tier 1 emission factor (5.9 m^3/metric ton) and annual coal production from underground mines (EIA 2023). The underground mining default emission factor accounts for all the fugitive CO_2 likely to be emitted from underground coal mining. Therefore, the amount of CO_2 from coal seam gas recovered and utilized for energy is subtracted from underground mining estimates in Step 2, below. Under IPCC methods, the CO_2 emissions from gas recovered and utilized for energy use (e.g., injected into a natural gas pipeline) are reported under other sectors of the *Inventory* (e.g., stationary combustion of fossil fuel or oil and natural gas systems) and not under the coal mining sector.

Step 1.2: Estimate Amount of CO_2 In Coal Seam Gas Recovered for Energy Purposes

EPA estimated fugitive CO_2 emissions from coal seam gas recovered and utilized for energy purposes by using the IPCC Tier 1 default emission factor (19.57 metric tons CO_2/million cubic meters of coal bed methane (CBM) produced) and quantity of coal seam gas recovered and utilized. Data on annual quantity of coal seam gas recovered and utilized are available from GHGRP and state sales data (GHGRP 2023; DMME 2023; ERG 2023; GSA 2023; WVGES 2023). The quantity of coal seam gas recovered and destroyed without energy recovery (e.g., VAM projects with RTO) is deducted from the total coal seam gas recovered quantity (McElroy OVS 2023).

Step 1.3: Estimate Fugitive CO_2 Emissions from Flaring

The IPCC method includes combustion CO_2 emissions from gas recovered for non-energy uses (i.e., flaring, or catalytic oxidation) under fugitive CO_2 emission estimates for underground coal mining. In effect, these emissions, though occurring through stationary combustion, are categorized as fugitive emissions in the *Inventory*. EPA estimated CO_2 emissions from methane flaring using the following equation:

Equation 3-2: Estimating CO_2 Emissions from Drained Methane Flared or Catalytically Oxidized

$$\begin{aligned} &CO_2\ from\ flaring \\ &\quad = 0.98\ \times Volume\ of\ methane\ flared \times Conversion\ Factor \\ &\quad \times Stoichiometric\ Mass\ Factor \end{aligned}$$

Currently there are three mines that report destruction of recovered methane through flaring without energy use. Annual data for 2022 were obtained from one mine's offset verification statement (OVS) submitted to the California Air Resources Board (CARB) and the GHGRP for the remaining two mines (McElroy OVS 2023; GHGRP 2023).

Step 2: Surface Mining

EPA estimated fugitive CO_2 emissions from surface mining using the IPCC Tier 1 emission factor (0.44 m^3/metric ton) and annual coal production from surface mines (EIA 2023).

Uncertainty

A quantitative uncertainty analysis was conducted for the coal mining source category using the IPCC-recommended Approach 2 uncertainty estimation methodology. Because emission estimates of CH_4 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 annual emission rates. Additionally, the measurement equipment used can be expected to have resulted in an average of 10 percent overestimation of annual CH_4 emissions (Mutmansky & Wang 2000). Equipment measurement uncertainty is applied to GHGRP data.

Estimates of CH_4 liberated and recovered by degasification systems are relatively certain for utilized CH_4 because of the availability of EPA's GHGRP data and state gas sales information. Many of the liberation and 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 liberated CH_4 and avoided emissions, may vary if the drainage area is found to be larger or smaller than estimated.

EPA's GHGRP requires weekly CH_4 monitoring of mines that report degasification systems, and continuous CH_4 monitoring is required for CH_4 utilized on- or off-site. Since 2012, GHGRP data have been used to estimate CH_4 emissions from vented degasification wells, reducing the uncertainty associated with prior MSHA estimates used for this sub-source. Beginning in 2013, GHGRP data were also used for determining CH_4 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 coal mining, as a general matter, results in significantly larger CH_4 emissions due to production of higher-rank coal and greater depth, and estimated emissions from underground mining constitute the majority of estimated total coal mining CH_4 emissions, the uncertainty associated with underground emissions is the primary factor that determines overall uncertainty.

The major sources of uncertainty for estimates of fugitive CO_2 emissions are the Tier 1 IPCC default emission factors used for underground mining (-50 percent to +100 percent) and surface mining (-67 percent to +200 percent) (IPCC 2019). Additional sources of uncertainty for fugitive CO_2 emission estimates include EIA's annual coal production data and data used for gas recovery projects, such as GHGRP data, state gas sales data, and VAM estimates for the single mine that operates an active VAM project. Uncertainty ranges for these additional data sources are already available, as these are the same data sources used for CH_4 emission estimates.

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 3-38. Coal mining CH_4 emissions in 2022 were estimated to be between 34.8 and 47.8 MMT CO_2 Eq. at a 95 percent confidence level. This indicates a range of 20.3 percent below to 9.5 percent above the 2022 emission estimate of 43.6 MMT CO_2 Eq. Coal mining fugitive CO_2 emissions in 2022 were estimated to be between 0.8 and 4.3 MMT CO_2 Eq. at a 95 percent confidence level. This indicates a range of 68.5 percent below to 75.4 percent above the 2022 emission estimate of 2.5 MMT CO_2 Eq.

Table 3-38: Approach 2 Quantitative Uncertainty Estimates for CH_4 and CO_2 Emissions from Coal Mining (MMT CO_2 Eq. and Percent)

Source	Gas	2022 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	43.6	34.8	47.8	-20%	+9%
Coal Mining	CO_2	2.5	0.8	4.3	-69%	+75%

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

QA/QC and Verification

In order to ensure the quality of the emission estimates for coal mining, general (IPCC Tier 1) and category-specific (Tier 2) Quality Assurance/Quality Control (QA/QC) procedures were implemented consistent with the U.S. Inventory QA/QC plan outlined in Annex 8. The Tier 2 procedures that were implemented involved checks specifically focusing on the activity data and reported emissions data used for estimating fugitive emissions from coal mining. Trends across the time series were analyzed to determine whether any corrective actions were needed.

Emission estimates for coal mining rely in large part on data reported by coal mines to EPA's GHGRP. EPA verifies annual facility-level reports through a multi-step process to identify potential errors and ensure that data submitted to EPA are accurate, complete, and consistent. All reports submitted to EPA are evaluated by electronic validation and verification checks. If potential errors are identified, EPA will notify the reporter, who can resolve the issue either by providing an acceptable response describing why the flagged issue is not an error or by correcting the flagged issue and resubmitting their annual report. Additional QA/QC and verification procedures occur for each GHGRP subpart. No QA/QC issues or errors were identified in the 2022 Subpart FF data.

Recalculations Discussion

Time series recalculations were performed due to revised historical data from state natural gas sales databases for five mines, which are used to estimate avoided CH_4 emissions. Additionally, calculation errors were identified and corrected for CH_4 emissions avoided from two mines. As a result of recalculations, CH_4 emissions decreased by an average of 0.03 percent across the time series, compared to the previous *Inventory*. The biggest increase in CH_4 emissions was in 1991 where emissions increased by 0.14 percent, compared to the previous *Inventory*. The biggest decrease in CH_4 emissions was in 2006 (0.6 percent). As a result of recalculations, there was a very minor decrease in CH_4 emissions in 2021 (less than 0.005 percent), compared to the previous *Inventory*.

Planned Improvements

EPA is assessing planned improvements for future reports, but at this time has no specific planned improvements for estimating CH_4 and CO_2 emissions from underground and surface mining and CH_4 emissions from post-mining.

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

- Time since abandonment;
- Gas content and adsorption characteristics of coal;
- CH_4 flow capacity of the mine;
- Mine flooding;
- Presence of vent holes; and
- Mine seals.

Annual gross abandoned mine CH_4 emissions ranged from 8.1 to 12.1 MMT CO_2 Eq. from 1990 to 2022, 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 (12.1 MMT CO_2 Eq.) due to the large number of gassy mine[68] 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. In 2022 there was one gassy mine closure. Gross abandoned mine emissions decreased slightly from 9.2 MMT CO_2 Eq. (330 kt CH_4) in 2021 to 9.1 (324 kt CH_4) MMT CO_2 Eq. in 2022 (see Table 3-39 and Table 3-40). Gross emissions are reduced by CH_4 recovered and used at 51 mines, resulting in net emissions in 2022 of 6.3 MMT CO_2 Eq. (225 kt CH_4).

Table 3-39: CH_4 Emissions from Abandoned Coal Mines (MMT CO_2 Eq.)

Activity	1990	2005	2018	2019	2020	2021	2022
Abandoned Underground Mines	8.1	9.3	9.9	9.6	9.4	9.2	9.1
Recovered & Used	NO	(2.0)	(3.0)	(2.9)	(2.9)	(3.0)	(2.8)
Total	**8.1**	**7.4**	**6.9**	**6.6**	**6.5**	**6.3**	**6.3**

NO (Not Occurring)

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

Table 3-40: CH_4 Emissions from Abandoned Coal Mines (kt)

Activity	1990	2005	2018	2019	2020	2021	2022
Abandoned Underground Mines	288	334	355	341	335	330	324
Recovered & Used	NO	(70)	(107)	(104)	(103)	(106)	(100)
Total	**288**	**264**	**247**	**237**	**232**	**224**	**225**

NO (Not Occurring)

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

Methodology and Time-Series Consistency

Estimating CH_4 emissions from an abandoned coal mine requires predicting the emissions of a mine from the time of abandonment through the inventory year of interest. The flow of CH_4 from the coal to the mine void is primarily dependent on the mine's emissions when active and the extent to which the mine is flooded or sealed. The CH_4 emission rate before abandonment reflects the gas content of the coal, the 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 that 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.

There are sufficient mine level data available to establish decline curves for individual gassy mines abandoned since 1972. For mines abandoned prior to 1972, county level data are available. Mine status information (i.e., whether a mine is sealed, venting, or flooded) is not available for all the abandoned gassy mines. Therefore, a hybrid Tier 2/Tier 3 method was developed to model abandoned gassy mine emissions using Monte Carlo simulations. Tier 3 calculations are used for mines with known status information where decline curves can be used to directly estimate abandoned mine emissions. For mines with unknown status, a Tier 2 approach that estimates basin level emissions is used. This Tier 2 approach relies on data from other mines with known status

[68] A mine is considered a "gassy" mine if it emits more than 100 thousand cubic feet of CH_4 per day (100 Mcfd).

and located within the same basin as the unknown status mines. This approach is consistent with the IPCC 2006 Guidelines as underground mines can be considered point sources and measurement methods are available.

To estimate CH_4 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 CH_4 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 CH_4 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:

Equation 3-3: Decline Function to Estimate Venting Abandoned Mine Methane Emissions

$$q = q_i (1 + bD_i t)^{\left(-\frac{1}{b}\right)}$$

where,

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

This equation is applied to mines of various initial emission rates that have similar initial pressures, permeability, and adsorption isotherms (EPA 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 CH_4 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. For this analysis of flooded abandoned mines, there was not enough data to establish basin-specific equations, as was done with the vented, non-flooding mines (EPA 2004). This decline through time can be empirically expressed as:

Equation 3-4: Decline Function to Estimate Flooded Abandoned Mine Methane Emissions

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

where,

q	=	Gas flow rate at time t in mmcfd
q_i	=	Initial gas flow rate at time zero (t_o), mmcfd
D	=	Decline rate, 1/year
t	=	Elapsed time from t_o (years)

Seals have an inhibiting effect on the rate of flow of CH_4 into the atmosphere compared to the 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 × (1 – [initial emissions from sealed mine / emission rate at abandonment prior to sealing]). Significant differences are seen between 50 percent, 80 percent, and 95 percent closure. These decline curves were therefore used as the high, middle, and low values for emissions from sealed mines (EPA 2004).

For active coal mines, those mines producing over 100 thousand cubic feet per day (Mcfd) of CH_4 account for about 98 percent of all CH_4 emissions. This same relationship is assumed for abandoned mines. It was determined that the 531 abandoned mines closed since 1972 produced CH_4 emissions greater than 100 Mcfd when active. Further, the status of 307 of the 531 mines (or 58 percent) is known to be either: 1) vented to the atmosphere; 2) sealed to some degree (either earthen or concrete seals); or 3) flooded (enough to inhibit CH_4 flow to the atmosphere). The remaining 42 percent of the mines 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 3-41 presents the count of mines by post-abandonment state, based on EPA's probability distribution analysis.

Table 3-41: Number of Gassy Abandoned Mines Present in U.S. Basins in 2022, Grouped by Class According to Post-Abandonment State

Basin	Sealed	Vented	Flooded	Total Known	Unknown	Total Mines
Central Appl.	43	25	50	118	144	262
Illinois	35	3	14	52	31	83
Northern Appl.	49	23	15	87	39	126
Warrior Basin	0	0	16	16	0	16
Western Basins	28	4	2	34	10	44
Total	**155**	**55**	**97**	**307**	**224**	**531**

Note: Totals may not sum due to independent rounding.

Inputs to the decline equation require the average CH_4 emission rate prior to abandonment and the date of abandonment. Generally, these data are 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 CH_4 emissions from coal mining came from seventeen counties in seven states. 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 CH_4 emission rates during the 1970s (EPA 2004).

Abandoned mine emission estimates are based on all closed mines known to have active mine CH_4 ventilation emission rates greater than 100 Mcfd at the time of abandonment. For example, for 1990 the analysis included 145 mines closed before 1972 and 258 mines closed between 1972 and 1990. Initial emission rates based on MSHA reports, time of abandonment, and basin-specific decline curves influenced by a number of factors were used to calculate annual emissions for each mine in the database (MSHA 2023). Coal mine degasification data are not available for years prior to 1990, thus the initial emission rates used reflect only ventilation emissions for pre-1990 closures. Methane degasification amounts were added to the quantity of CH_4 vented to determine the total CH_4 liberation rate for all mines that closed between 1992 and 2022. Since the sample of gassy mines described above 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, respectively, to account for all U.S. abandoned mine emissions.

From 1993 through 2022, emission totals were downwardly adjusted to reflect CH_4 emissions avoided from abandoned mines with CH_4 recovery and use or destruction systems. Currently, there are 51 abandoned mines with recovery projects, including 11 projects at mines abandoned before 1972 (pre-1972 mines) (EPA 2004, CMOP 2022). Because CH_4 recovered by these projects is expected to decline with the age of the mine, CH_4 recovery is assumed to be the total estimated CH_4 liberated based on the mine's decline function except for three recovery projects where additional data are available (COGIS 2018, MSHA 2023).[69]

The *Inventory* totals were not adjusted for abandoned mine CH_4 emissions avoided from 1990 through 1992 due to unavailability of data. Avoided CH_4 emissions from pre-1972 abandoned mines are estimated by multiplying the total estimated emissions from these mines in each decade by the fraction of mines with recovery projects in that decade. For recovery projects at pre-1972 abandoned mines, four projects are at mines abandoned in the 1920s, three in the 1930s, two in the 1950s, and two in the 1960s (EPA 2004).

Reviewing Coalbed Methane Outreach Program data (CMOP 2023) revealed four additional recovery projects starting in 2021. In addition to reviewing CMOP data, the recovery project list was checked against the International Coal Mine Methane Database (GMI 2021). Of the 24 operational recovery projects for U.S. abandoned coal mines currently available in the GMI dataset, 18 are already included in the AMM model. The remaining six projects in the GMI dataset are for mines that are not yet abandoned according to MSHA records (MSHA 2023). Therefore, no new recovery projects were added from the GMI database for the 1990 through 2022 *Inventory*.

Uncertainty

A quantitative uncertainty analysis was conducted for the abandoned coal mine source category using the IPCC-recommended Approach 2 uncertainty estimation methodology. The uncertainty 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 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 to predict its decline curve are: 1) the coal's adsorption isotherm; 2) CH_4 flow capacity as expressed by permeability; and 3) pressure at abandonment. Because these parameters are not available for each mine, a methodological approach to estimating emissions was used that generates a probability distribution of potential outcomes based on the most likely value and the probable range of values for each parameter. The range of values is not meant to capture the extreme values, but 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 3-42. Annual abandoned coal mine CH_4 emissions in 2022 were estimated to be between 5.0 and 7.5 MMT CO_2 Eq. at a 95 percent confidence level. This indicates a range of 21 percent below to 20 percent above the 2022 emission estimate of 6.3 MMT CO_2 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 in 1972 and later years. Emissions from mines closed prior to 1972 have the largest degree of uncertainty because no mine-specific CH_4 liberation rates at the time of abandonment exist.

[69] Data from a state oil and gas database (COGIS) is used for one project and the mine status information from MSHA for two mines (sealed and flooded) indicate zero recovery emissions for these projects.

Table 3-42: Approach 2 Quantitative Uncertainty Estimates for CH_4 Emissions from Abandoned Underground Coal Mines (MMT CO_2 Eq. and Percent)

Source	Gas	2022 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
Abandoned Underground Coal Mines	CH_4	6.3	5.0	7.5	-21%	+20%

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

QA/QC and Verification

In order to ensure the quality of the emission estimates for abandoned coal mines, general (IPCC Tier 1) and category-specific (Tier 2) Quality Assurance/Quality Control (QA/QC) procedures were implemented consistent with the U.S. Inventory QA/QC plan outlined in Annex 8. The Tier 2 procedures that were implemented involved checks specifically focusing on the activity data and reported emissions data used for estimating emissions from abandoned coal mines. Trends across the time series were analyzed to determine whether any corrective actions were needed.

Recalculations Discussion

Four new abandoned mine methane recovery projects were added to the AMM model during the current *Inventory* (CMOP 2023). CMOP data indicate these recovery projects were started in 2021. Time series recalculations were performed for 2021. As a result of recalculations, CH_4 emissions decreased by 2 percent in 2021, compared to the previous *Inventory*.

3.6 Petroleum Systems (CRT Source Category 1B2a)

This category (1B2a) is defined in the IPCC methodological guidance as fugitive emissions from petroleum systems, which per IPCC guidelines include emissions from leaks, venting, and flaring. Methane emissions from petroleum systems are primarily associated with onshore and offshore crude oil exploration, production, transportation, and refining operations. During these activities, CH_4 is released to the atmosphere as emissions from leaks, venting (including emissions from operational upsets), and flaring. Carbon dioxide emissions from petroleum systems are primarily associated with onshore and offshore crude oil production and refining operations. Note, CO_2 emissions in petroleum systems exclude all combustion emissions (e.g., engine combustion) except for flaring CO_2 emissions. All combustion CO_2 emissions (except for flaring) are accounted for in the fossil fuel combustion chapter (see Section 3.1). Emissions of N_2O from petroleum systems are primarily associated with flaring. Total greenhouse gas emissions (CH_4, CO_2, and N_2O) from petroleum systems in 2022 were 61.6 MMT CO_2 Eq., an increase of 4 percent from 1990, primarily due to increases in CO_2 emissions. Total emissions decreased by 6 percent from 2010 levels and have decreased by 15 percent since 2021. Total CO_2 emissions from petroleum systems in 2022 were 21.97 MMT CO_2 (21,967 kt CO_2), 2.3 times higher than in 1990. Total CO_2 emissions in 2022 were 1.6 times higher than in 2010 and 9 percent lower than in 2021. Total CH_4 emissions from petroleum systems in 2022 were 39.6 MMT CO_2 Eq. (1,415 kt CH_4), a decrease of 20 percent from 1990. Since 2010, total CH_4 emissions decreased by 24 percent; and since 2021, CH_4 emissions decreased by 19 percent. Total N_2O emissions from petroleum systems in 2022 were 0.048 MMT CO_2 Eq. (0.179 kt N_2O), 3.8 times higher than in 1990, 2.8 times higher than in 2010, and 142 percent higher than in 2021. Since 1990, U.S. oil production has increased by 56 percent. In 2022, U.S. oil production was 163 percent higher than in 2010 and 7 percent higher than in 2021.

Each year, some estimates in the *Inventory* are recalculated with improved methods and/or data. These improvements are implemented consistently across the entire *Inventory's* time series (i.e., 1990 to 2022) to ensure that the trend is representative of changes in emissions levels. Recalculations in petroleum systems in this year's *Inventory* include:

- Updates to oil and gas production volumes, produced water production volumes, and well counts using the most recent data from Enverus.
- Updates to oil and gas production volumes using the most recent data from the United States Energy Information Administration (EIA)
- Recalculations due to Greenhouse Gas Reporting Program (GHGRP) submission revisions
- Recalculations due to methodological updates to completions and workovers.

The Recalculations Discussion section below provides more details on the updated methods.

Exploration. Exploration includes well drilling, testing, and completions. Exploration accounts for less than 0.5 percent of total CH_4 emissions (including leaks, vents, and flaring) from petroleum systems in 2022. The predominant sources of CH_4 emissions from exploration are hydraulically fractured oil well completions. Other sources include well testing, well drilling, and well completions without hydraulic fracturing. Since 1990, exploration CH_4 emissions have decreased 96 percent, and while the number of hydraulically fractured wells completed increased 64 percent, there were decreases in the fraction of such completions without reduced emissions completions (RECs) or flaring. Emissions of CH_4 from exploration were highest in 2008, over 70 times higher than in 2022; and lowest in 2022. Emissions of CH_4 from exploration decreased 39 percent from 2021 to 2022, due to a decrease in emissions from hydraulically fractured oil well completions with RECs. Exploration accounts for 1 percent of total CO_2 emissions (including leaks, vents, and flaring) from petroleum systems in 2022. Emissions of CO_2 from exploration in 2022 were 25 percent lower than in 1990, and decreased by 50 percent from 2021, largely due to a decrease in emissions from hydraulically fractured oil well completions with REC and flaring (by 58 percent from 2021). Emissions of CO_2 from exploration were highest in 2014, over 13 times higher than in 2022. Exploration accounts for less than 0.5 percent of total N_2O emissions from petroleum systems in 2022. Emissions of N_2O from exploration in 2022 are 29 percent lower than in 1990, and 56 percent lower than in 2021, due to hydraulically fractured oil well completions with flaring.

Production. Production accounts for 97 percent of total CH_4 emissions (including leaks, vents, and flaring) from petroleum systems in 2022. The predominant sources of emissions from production field operations are pneumatic controllers, offshore oil platforms, equipment leaks, produced water, gas engines, chemical injection pumps, and associated gas flaring. In 2022, these seven sources together accounted for 93 percent of the CH_4 emissions from production. Since 1990, CH_4 emissions from production have decreased by 15 percent primarily due to decreases in emissions from offshore production. Overall, production segment CH_4 emissions decreased by 19 percent from 2021 levels due primarily to lower pneumatic controller emissions. Production emissions account for 86 percent of the total CO_2 emissions (including leaks, vents, and flaring) from petroleum systems in 2022. The principal sources of CO_2 emissions are associated gas flaring, miscellaneous production flaring, and oil tanks with flares. In 2022, these three sources together accounted for 96 percent of the CO_2 emissions from production. In 2022, CO_2 emissions from production were 3.1 times higher than in 1990, due to increases in flaring emissions from associated gas flaring, miscellaneous production flaring, and tanks. Overall, in 2022, production segment CO_2 emissions decreased by 8 percent from 2021 levels primarily due to decreases in associated gas flaring in the Williston Basin and oil tanks with flares. Production emissions accounted for 84 percent of the total N_2O emissions from petroleum systems in 2022. The principal sources of N_2O emissions are oil tanks with flares and associated gas flaring, accounting for 90% of N_2O emissions from the production segment in 2022. In 2022, N_2O emissions from production were 8.0 times higher than in 1990 and were 3.5 times higher than in 2021.

Crude Oil Transportation. Emissions from crude oil transportation account for a very small percentage of the total emissions (including leaks, vents, and flaring) from petroleum systems. Crude oil transportation activities account for 0.6 percent of total CH_4 emissions from petroleum systems. Emissions from tanks, marine loading, and truck loading operations accounted for 81 percent of CH_4 emissions from crude oil transportation in 2022. Since 1990,

CH_4 emissions from transportation have increased by 27 percent. In 2022, CH_4 emissions from transportation increased by 6 percent from 2021 levels. Crude oil transportation activities account for less than 0.01 percent of total CO_2 emissions from petroleum systems. Emissions from tanks, marine loading, and truck loading operations account for 81 percent of CO_2 emissions from crude oil transportation.

Crude Oil Refining. Crude oil refining processes and systems account for 2 percent of total fugitive (including leaks, vents, and flaring) CH_4 emissions from petroleum systems in 2022. This low share is because most of the CH_4 in crude oil is removed or escapes before the crude oil is delivered to the refineries. There is a negligible amount of CH_4 in all refined products. Within refineries, flaring accounts for 42 percent of the CH_4 emissions, while delayed cokers, uncontrolled blowdowns, and equipment leaks account for 19, 14 and 11 percent, respectively. Fugitive CH_4 emissions from refining of crude oil have decreased by 4 percent since 1990, and decreased by 3 percent from 2021; however, like the transportation subcategory, this increase has had little effect on the overall emissions of CH_4 from petroleum systems. Crude oil refining processes and systems account for 13 percent of total fugitive (including leaks, vents, and flaring) CO_2 emissions from petroleum systems. Of the total fugitive CO_2 emissions from refining, almost all (about 99 percent) of it comes from flaring.[70] Since 1990, refinery fugitive CO_2 emissions decreased by 10 percent and have decreased by 5 percent from 2021 levels, due to a decrease in flaring. Flaring occurring at crude oil refining processes and systems accounts for 16 percent of total fugitive N_2O emissions from petroleum systems. In 2022, refinery fugitive N_2O emissions increased by 4 percent since 1990 and decreased by 5 percent from 2021 levels.

Table 3-43: Total Greenhouse Gas Emissions (CO_2, CH_4, and N_2O) from Petroleum Systems (MMT CO_2 Eq.)

Activity	1990	2005	2018	2019	2020	2021	2022
Exploration	3.4	5.7	3.2	2.5	1.1	0.8	0.4
Production	51.6	48.1	86.7	90.6	77.3	68.0	57.4
Transportation	0.2	0.1	0.2	0.3	0.2	0.2	0.2
Crude Refining	3.9	4.4	3.7	4.4	3.6	3.7	3.6
Total	**59.0**	**58.5**	**93.8**	**97.8**	**82.3**	**72.8**	**61.6**

Note: Totals may not sum due to independent rounding.

Table 3-44: CH_4 Emissions from Petroleum Systems (MMT CO_2 Eq.)

Activity	1990	2005	2018	2019	2020	2021	2022
Exploration	**3.0**	**5.3**	**0.5**	**0.5**	**0.3**	**0.2**	**0.1**
Production	**45.5**	**42.0**	**57.5**	**50.6**	**52.0**	**47.5**	**38.6**
Pneumatic Controllers	21.3	22.7	34.7	24.7	31.3	28.1	19.4
Offshore Production	9.9	7.2	5.5	5.4	5.1	5.1	5.1
Equipment Leaks	2.3	2.8	3.7	3.9	3.2	3.2	3.1
Gas Engines	2.3	2.0	2.5	2.6	2.5	2.4	2.5
Produced Water	2.6	1.8	2.7	2.8	2.5	2.6	2.7
Chemical Injection Pumps	1.3	2.2	3.0	3.4	2.7	2.4	2.2
Assoc Gas Flaring	0.6	0.4	1.9	2.5	1.3	1.0	0.8
Other Sources	5.3	2.8	3.5	5.3	3.3	2.7	2.7
Crude Oil Transportation	**0.2**	**0.1**	**0.2**	**0.3**	**0.2**	**0.2**	**0.2**
Refining	**0.7**	**0.8**	**0.8**	**0.9**	**0.7**	**0.7**	**0.7**
Total	**49.4**	**48.2**	**59.0**	**52.2**	**53.3**	**48.6**	**39.6**

Note: Totals may not sum due to independent rounding.

[70] Petroleum Systems includes fugitive emissions (leaks, venting, and flaring). In many industries, including petroleum refineries, the largest source of onsite CO_2 emissions is often fossil fuel combustion, which is covered in Section 3.1 of this chapter.

Table 3-45: CH_4 Emissions from Petroleum Systems (kt CH_4)

Activity	1990	2005	2018	2019	2020	2021	2022
Exploration	**106**	**189**	**19**	**16**	**12**	**7**	**4**
Production	**1,626**	**1,500**	**2,052**	**1,809**	**1,858**	**1,696**	**1,377**
Pneumatic Controllers	761	811	1,240	881	1,119	1,003	694
Offshore Production	353	259	197	193	183	182	182
Equipment Leaks	82	101	132	138	115	114	112
Gas Engines	81	70	91	93	89	87	88
Produced Water	92	64	95	99	90	92	95
Chemical Injection Pumps	47	80	108	123	96	85	80
Assoc Gas Flaring	20	14	66	91	47	35	30
Other Sources	189	100	124	190	119	97	98
Crude Oil Transportation	**7**	**5**	**8**	**9**	**8**	**8**	**8**
Refining	**26**	**29**	**28**	**31**	**26**	**25**	**25**
Total	**1,765**	**1,723**	**2,108**	**1,865**	**1,904**	**1,737**	**1,415**

Note: Totals may not sum due to independent rounding.

Table 3-46: CO_2 Emissions from Petroleum Systems (MMT CO_2)

Activity	1990	2005	2018	2019	2020	2021	2022
Exploration	0.4	0.5	2.7	2.0	0.8	0.6	0.3
Production	6.0	6.1	29.2	39.9	25.2	20.5	18.8
Transportation	+	+	+	+	+	+	+
Crude Refining	3.2	3.6	2.9	3.6	2.9	3.0	2.9
Total	**9.6**	**10.2**	**34.8**	**45.5**	**28.9**	**24.1**	**22.0**

+ Does not exceed 0.05 MMT CO_2.

Note: Totals may not sum due to independent rounding.

Table 3-47: CO_2 Emissions from Petroleum Systems (kt CO_2)

Activity	1990	2005	2018	2019	2020	2021	2022
Exploration	398	465	2,684	2,044	798	601	300
Production	6,012	6,143	29,215	39,882	25,244	20,516	18,793
Transportation	0.9	0.7	1.2	1.3	1.2	1.1	1.2
Crude Refining	3,174	3,602	2,877	3,571	2,893	3,021	2,872
Total	**9,585**	**10,210**	**34,777**	**45,498**	**28,937**	**24,140**	**21,967**

Table 3-48: N_2O Emissions from Petroleum Systems (Metric Tons CO_2 Eq.)

Activity	1990	2005	2018	2019	2020	2021	2022
Exploration	180	209	1,161	820	353	290	127
Production	4,996	4,588	30,822	28,047	13,614	11,414	39,859
Transportation	NE	NE	NE	NE	NE	NE	NE
Crude Refining	7,262	8,243	7,405	9,312	7,575	7,920	7,523
Total	**12,438**	**13,040**	**39,387**	**38,180**	**21,542**	**19,624**	**47,510**

NE (Not Estimated)

Note: Totals may not sum due to independent rounding.

Table 3-49: N_2O Emissions from Petroleum Systems (Metric Tons N_2O)

Activity	1990	2005	2018	2019	2020	2021	2022
Exploration	0.7	0.8	4.4	3.1	1.3	1.1	0.5
Production	18.9	17.3	116.3	105.8	51.4	43.1	150.4
Transportation	NE	NE	NE	NE	NE	NE	NE
Crude Refining	27.4	31.1	27.9	35.1	28.6	29.9	28.4
Total	**46.9**	**49.2**	**148.6**	**144.1**	**81.3**	**74.1**	**179.3**

NE (Not Estimated)

Note: Totals may not sum due to independent rounding.

Methodology and Time-Series Consistency

See Annex 3.5 for the full time series of emissions data, activity data, emission factors, and additional information on methods and data sources.

Petroleum systems includes emission estimates for activities occurring in petroleum systems from the oil wellhead through crude oil refining, including activities for crude oil exploration, production field operations, crude oil transportation activities, and refining operations. Generally, emissions are estimated for each activity by multiplying emission factors (e.g., emission rate per equipment or per activity) by corresponding activity data (e.g., equipment count or frequency of activity). Certain sources within petroleum refineries are developed using an IPCC Tier 3 approach (i.e., all refineries in the nation report facility-level emissions data to the GHGRP, which are included directly in the national emissions estimates here). Other estimates are developed with a Tier 2 approach. Tier 1 approaches are not used.

EPA did not receive stakeholder feedback on updates in the *Inventory* through EPA's stakeholder process on oil and gas in the *Inventory*. More information on the stakeholder process can be found online.[71]

Emission Factors. Key references for emission factors include *Methane Emissions from the Natural Gas Industry by the Gas Research Institute and EPA* (GRI/EPA 1996), *Estimates of Methane Emissions from the U.S. Oil Industry* (EPA 1999), *Compilation of Air Pollutant Emission Factors, AP-42* (EPA 1997), *Global Emissions of Methane from Petroleum Sources* (API 1992), consensus of industry peer review panels, Bureau of Ocean Energy Management (BOEM) reports, *Nonpoint Oil and Gas Emission Estimation Tool* (EPA 2017), and analysis of GHGRP data (EPA 2023).

Emission factors for hydraulically fractured (HF) oil well completions and workovers (in four control categories) were developed at the basin level using EPA's GHGRP data; year-specific data were used to calculate basin-specific emission factors from 2016-forward and the year 2016 emission factors were applied to all prior years in the time series. For basins not reporting to the GHGRP, Subpart W average emission factors were used. For more information, please see the 2023 memoranda available online.[72]

The emission factors for well testing and associated gas venting and flaring were developed using year-specific GHGRP data for years 2015 forward; earlier years in the time series use 2015 emission factors. For miscellaneous production flaring, year-specific emission factors were developed for years 2015 forward from GHGRP data, an emission factor of 0 (assumption of no flaring) was assumed for 1990 through 1992, and linear interpolation was applied to develop emission factors for 1993 through 2014. For more information, please see memoranda available online.[73] For offshore oil production, emission factors were calculated using BOEM data for offshore facilities in federal waters of the Gulf of Mexico (and these data were also applied to facilities located in state waters of the Gulf of Mexico) and GHGRP data for offshore facilities off the coasts of California and Alaska. For

[71] See https://www.epa.gov/ghgemissions/natural-gas-and-petroleum-systems.

[72] See https://www.epa.gov/ghgemissions/natural-gas-and-petroleum-systems.

[73] See https://www.epa.gov/ghgemissions/natural-gas-and-petroleum-systems.

many other sources, emission factors were held constant for the period 1990 through 2022, and trends in emissions reflect changes in activity levels. Emission factors from EPA 1999 are used for all other production and transportation activities.

For associated gas venting and flaring and miscellaneous production flaring, emission factors were developed on a production basis (i.e., emissions per unit oil produced). Additionally, for these two sources, basin-specific activity and emission factors were developed for each basin that in any year from 2011 forward contributed at least 10 percent of total source emissions (on a CO_2 Eq. basis) in the GHGRP. For associated gas venting and flaring, basin-specific factors were developed for four basins: Williston, Permian, Gulf Coast, and Anadarko. For miscellaneous production flaring, basin-specific factors were developed for three basins: Williston, Permian, and Gulf Coast. For each source, data from all other basins were combined, and activity and emission factors were developed for the other basins as a single group.

For pneumatic controllers and tanks, basin-specific emission factors were calculated for all the basins reporting to the GHGRP. These emission factors were calculated for all the years with applicable GHGRP data (i.e., 2011 - 2022 or 2015 - 2022). For the remaining basins (i.e., basins not reporting to the GHGRP), Subpart W average emission factors were used. For more information, please see memoranda available online.[3]

For the exploration and production segments, in general, CO_2 emissions for each source were estimated with GHGRP data or by multiplying CO_2 content factors by the corresponding CH_4 data, as the CO_2 content of gas relates to its CH_4 content. Sources with CO_2 emission estimates calculated using GHGRP data include HF completions and workovers, associated gas venting and flaring, tanks, well testing, pneumatic controllers, chemical injection pumps, miscellaneous production flaring, and certain offshore production facilities (those located off the coasts of California and Alaska). For these sources, CO_2 was calculated using the same methods as used for CH_4. Carbon dioxide emission factors for offshore oil production in the Gulf of Mexico were derived using data from BOEM, following the same methods as used for CH_4 estimates. For other sources, the production field operations emission factors for CO_2 are generally estimated by multiplying the CH_4 emission factors by a conversion factor, which is the ratio of CO_2 content and CH_4 content in produced associated gas.

For the exploration and production segments, N_2O emissions were estimated for flaring sources using GHGRP or BOEM OGOR-B data and the same method used for CO_2. Sources with N_2O emissions in the exploration segment include well testing and HF completions with flaring. Sources with N_2O emissions in the production segment include associated gas flaring, tank flaring, miscellaneous production flaring, HF workovers with flaring, and flaring from offshore production sources.

For crude oil transportation, emission factors for CH_4 were largely developed using data from EPA (1997), API (1992), and EPA (1999). Emission factors for CO_2 were estimated by multiplying the CH_4 emission factors by a conversion factor, which is the ratio of CO_2 content and CH_4 content in whole crude post-separator.

For petroleum refining activities, year-specific emissions from 2010 forward were directly obtained from EPA's GHGRP. All U.S. refineries have been required to report CH_4, CO_2, and N_2O emissions for all major activities starting with emissions that occurred in 2010. The reported total CH_4, CO_2, and N_2O emissions for each activity was used for the emissions in each year from 2010 forward. To estimate emissions for 1990 to 2009, the 2010 to 2013 emissions data from GHGRP along with the refinery feed data for 2010 to 2013 were used to derive CH_4 and CO_2 emission factors (i.e., sum of activity emissions/sum of refinery feed) and 2010 to 2017 data were used to derive N_2O emission factors; these emission factors were then applied to the annual refinery feed in years 1990 to 2009. GHGRP delayed coker CH_4 emissions for 2010 through 2017 were increased using the ratio of certain reported emissions for 2018 to 2017, to account for a more accurate GHGRP calculation methodology that was implemented starting in reporting year 2018.

A complete list of references for emission factors and activity data by emission source is provided in Annex 3.5.

Activity Data. References for activity data include Enverus data (Enverus 2023), Energy Information Administration (EIA) reports, *Methane Emissions from the Natural Gas Industry by the Gas Research Institute and EPA* (EPA/GRI 1996), *Estimates of Methane Emissions from the U.S. Oil Industry* (EPA 1999), consensus of industry peer review panels, BOEM reports, the Oil & Gas Journal, the Interstate Oil and Gas Compact Commission, the United States Army Corps of Engineers, and analysis of GHGRP data (EPA 2023).

For HF oil well completions and workovers, pneumatic controllers, equipment leaks, chemical injection pumps, and tanks, basin-specific activity factors were calculated for all the basins reporting to the GHGRP. These factors were calculated for all the years with applicable GHGRP data (i.e., 2011 through 2022, 2016 through 2022, or 2015 through 2022). For the remaining basins (i.e., basins not reporting to the GHGRP), GHGRP average activity factors were used. For more information, please see memoranda available online.[74]

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 to estimate values, consistent with IPCC good practice. Where appropriate, the activity data were calculated from related statistics using ratios developed based on EPA/GRI (1996) and/or GHGRP data. In some cases, activity data are developed by interpolating between recent data points (such as from GHGRP) and earlier data points, such as from EPA/GRI (1996). Lastly, in limited instances the previous year's data were used if current year data were not yet available.

A complete list of references for emission factors and activity data by emission source is provided in Annex 3.5. The United States reports data to the UNFCCC using this *Inventory* report along with Common Reporting Tables (CRTs). This note is provided for those reviewing the CRTs: The notation key "IE" is used for CO_2 and CH_4 emissions from venting and flaring in CRT 1.B.2. Disaggregating flaring and venting estimates across the Inventory would involve the application of assumptions and could result in inconsistent reporting and, potentially, decreased transparency. Data availability varies across segments within oil and gas activities systems, and emission factor data available for activities that include flaring can include emissions from multiple sources (flaring, venting and leaks).

As noted above, EPA's GHGRP data, available starting in 2010 for refineries and in 2011 for other sources, have improved estimates of emissions from petroleum systems. Many of the previously available datasets were collected in the 1990s. To develop a consistent time series for sources with new data, EPA reviewed available information on factors that may have resulted in changes over the time series (e.g., regulations, voluntary actions) and requested stakeholder feedback on trends as well. For most sources, EPA developed annual data for 1993 through 2009 or 2014 by interpolating activity data or emission factors or both between 1992 (when GRI/EPA data are available) and 2010 or 2015 data points. Information on time-series consistency for sources updated in this year's *Inventory* can be found in the Recalculations Discussion below, with additional detail provided in supporting memos (relevant memos are cited in the Recalculations Discussion). For information on other sources, please see the Methodology and Time-Series Consistency discussion above and Annex 3.5.

Methodological recalculations were applied to the entire time series to ensure time-series consistency from 1990 through 2022.

Uncertainty

EPA conducted a quantitative uncertainty analysis using the IPCC Approach 2 methodology (Monte Carlo Simulation technique) to characterize uncertainty for petroleum systems. For more information on the approach, please see the memoranda *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2016: Natural Gas and Petroleum Systems Uncertainty Estimates* (*2018 uncertainty memo)* and *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2019: Update for Natural Gas and Petroleum Systems CO_2 Uncertainty Estimates (2021 uncertainty memo)*.[75]

EPA used Microsoft Excel's @RISK add-in tool to estimate the 95 percent confidence bound around CH_4 and CO_2 emissions from petroleum systems for the current *Inventory*. For the CH_4 uncertainty analysis, EPA focused on the eight highest methane-emitting sources for the year 2022, which together emitted 75 percent of methane from petroleum systems in 2022, and extrapolated the estimated uncertainty for the remaining sources. For the CO_2 uncertainty analysis, EPA focused on the five highest-emitting sources for the year 2022 which together emitted 81 percent of CO_2 from petroleum systems in 2022, and extrapolated the estimated uncertainty for the remaining

[74] See https://www.epa.gov/ghgemissions/natural-gas-and-petroleum-systems.

[75] See https://www.epa.gov/ghgemissions/natural-gas-and-petroleum-systems.

sources. The @RISK add-in provides for the specification of probability density functions (PDFs) for key variables within a computational structure that mirrors the calculation of the inventory estimate. For emission factors that are derived from methane emissions measurement studies, the PDFs are commonly determined to be lognormally distributed (GRI/EPA 1996; EPA 1999). For activity data that are derived from national datasets, the PDFs are set to a uniform distribution (see 2018 and 2021 uncertainty memos). Many emission factors and activity factors are calculated using subpart W data, and for these, the @RISK add-in determines the best fitting PDF (e.g., lognormal, gaussian), based on bootstrapping of the underlying data (see 2018 and 2021 uncertainty memos). The IPCC guidance notes that in using this Approach 2 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 bounds reported below only reflect those uncertainties that EPA has been able to quantify and do not incorporate considerations such as modeling uncertainty, data representativeness, measurement errors, misreporting or misclassification. To estimate uncertainty for N_2O, EPA applied the uncertainty bounds calculated for CO_2. EPA will seek to refine this estimate in future *Inventories*.

The results presented below provide the 95 percent confidence bound within which actual emissions from this source category are likely to fall for the year 2022, using the recommended IPCC methodology. The results of the Approach 2 uncertainty analysis are summarized in Table 3-50. Petroleum systems CH_4 emissions in 2022 were estimated to be between 32.7 and 48.6 MMT CO_2 Eq., while CO_2 emissions were estimated to be between 17.9 and 27.4 MMT CO_2 Eq. at a 95 percent confidence level. Petroleum systems N_2O emissions in 2022 were estimated to be between 0.039 and 0.059 MMT CO_2 Eq. at a 95 percent confidence level.

Uncertainty bounds for other years of the time series have not been calculated, but uncertainty is expected to vary over the time series. For example, years where many emission sources are calculated with interpolated data would likely have higher uncertainty than years with predominantly year-specific data. In addition, the emission sources that contribute the most to CH_4 and CO_2 emissions are different over the time series, particularly when comparing recent years to early years in the time series. For example, associated gas venting emissions were higher and flaring emissions were lower in early years of the time series, compared to recent years. Technologies also changed over the time series (e.g., reduced emissions completions were not used early in the time series).

Table 3-50: Approach 2 Quantitative Uncertainty Estimates for CH_4 and CO_2 Emissions from Petroleum Systems (MMT CO_2 Eq. and Percent)

Source	Gas	2022 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	39.6	32.7	48.6	-18%	+23%
Petroleum Systems	CO_2	22.0	17.9	27.4	-19%	+25%
Petroleum Systems	N_2O	0.048	0.039	0.059	-19%	+25%

[a] Range of emission estimates estimated by applying the 95 percent confidence intervals obtained from the Monte Carlo Simulation analysis conducted for the year 2022 CH_4 and CO_2 emissions.

[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.

QA/QC and Verification Discussion

In order to ensure the quality of the emission estimates for petroleum systems, general (IPCC Tier 1) Quality Assurance/Quality Control (QA/QC) procedures were implemented consistent with the U.S. Inventory QA/QC plan outlined in Annex 8.

The petroleum systems 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 emission 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. EPA has a multi-step data verification process for GHGRP data, including automatic checks during data-entry, statistical analyses on completed reports, and staff review of the reported data. Based on the results of the verification process, EPA follows up with facilities to resolve mistakes that may have occurred.[76]

As in previous years, EPA conducted early engagement and communication with stakeholders on updates prior to public review of the current *Inventory*. EPA held a stakeholder webinar on greenhouse gas data for oil and gas in October of 2023. EPA released memos detailing updates under consideration and requesting stakeholder feedback. EPA did not receive stakeholder feedback for the updates under consideration for the current *Inventory*.

In recent years, several studies have measured emissions at the source level and at the national or regional level and calculated emission estimates that may differ from the *Inventory*. There are a variety of potential uses of data from new studies, including replacing a previous estimate or factor, verifying or QA of an existing estimate or factor, and identifying areas for updates. In general, there are two major types of studies related to oil and gas greenhouse gas data: studies that focus on measurement or quantification of emissions from specific activities, processes, and equipment, and studies that use tools such as inverse modeling to estimate the level of overall emissions needed to account for measured atmospheric concentrations of greenhouse gases at various scales. The first type of study can lead to direct improvements to or verification of *Inventory* estimates. In the past few years, EPA has reviewed, and in many cases, incorporated data from these data sources. The second type of study can provide general indications on potential over- and under-estimates.

A key challenge in using these types of studies to assess *Inventory* results is having a relevant basis for comparison (e.g., the two data sets should have comparable time frames and geographic coverage, and the independent study should assess data from the *Inventory* and not another data set, such as the Emissions Database for Global Atmospheric Research, or "EDGAR"). In an effort to improve the ability to compare the national-level *Inventory* with measurement results that may be at other spatial and temporal scales, EPA has developed a gridded inventory of U.S. anthropogenic methane emissions with 0.1 degree x 0.1 degree spatial resolution, monthly temporal resolution, and detailed scale-dependent error characterization.[77] The most recent version of the gridded methane inventory is designed to be consistent with the U.S. EPA's *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2018* estimates for the years 2012 through 2018. The gridded inventory improves efforts to compare results of this *Inventory* with atmospheric studies.

As discussed above, refinery emissions are quantified by using the total emissions reported to GHGRP for the refinery emission categories included in petroleum systems. Subpart Y has provisions that refineries are not required to report under Subpart Y if their emissions fall below certain thresholds. Each year, a review is conducted to determine whether an adjustment is needed to the Inventory emissions to include emissions from refineries that stopped reporting to the GHGRP. Based on the review of the most recent GHGRP data, EPA did not identify any additional refineries that would require gap filling. There are a total of 7 refineries that EPA previously identified (i.e., during the 1990 through 2021 *Inventory* and prior versions) as not reporting to the GHGRP and continued to gap fill annual emissions for these refineries. EPA used the last reported emissions (by source) for these refineries as proxy to gap fill annual emissions.

[76] See https://www.epa.gov/sites/production/files/2015-07/documents/ghgrp_verification_factsheet.pdf.

[77] See https://www.epa.gov/ghgemissions/us-gridded-methane-emissions.

Recalculations Discussion

EPA received information and data related to the emission estimates through GHGRP reporting and presented information to stakeholders regarding the updates under consideration. In November 2023, EPA released draft memoranda that discussed changes under consideration and requested stakeholder feedback on those changes. EPA then released final memoranda documenting the methodology implemented in the current Inventory.[78] The memorandum cited in the Recalculations Discussion below is: Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2022: Updates for Completion and Workover Emissions (*Completions and Workovers* memo).

EPA evaluated relevant information available and made an updates to the *Inventory* for hydraulically fractured (HF) oil well completions and workovers. General information for these source specific recalculations are presented below and details are available in the *Completions and Workovers* memo.

In addition to the updates to the sources mentioned above, for certain sources, CH_4 and/or CO_2 emissions changed by greater than 0.05 MMT CO_2 Eq., comparing the previous estimate for 2021 to the current (recalculated) estimate for 2021. The emissions changes were mostly due to GHGRP data submission revisions. These sources are discussed below and include associated gas flaring, miscellaneous production flaring, pneumatic controllers, oil tanks, chemical injection pumps, produced water, offshore production (in Gulf of Mexico federal waters), gas engines, and refinery flaring.

The combined impact of revisions to 2021 petroleum systems CH_4 emission estimates on a CO_2-equivalent basis, compared to the previous *Inventory*, is a decrease from 50.2 to 48.6 MMT CO_2 Eq. (1.5 MMT CO_2 Eq., or 3 percent). The recalculations resulted in lower CH_4 emission estimates on average across the 1990 through 2021 time series, compared to the previous *Inventory*, by 2.5 MMT CO_2 Eq., or 5 percent.

The combined impact of revisions to 2021 petroleum systems CO_2 emission estimates, compared to the previous *Inventory*, is a decrease from 24.7 to 24.1 MMT CO_2 (0.5 MMT CO_2, or 2 percent). The recalculations resulted in lower emission estimates on average across the 1990 through 2021 time series, compared to the previous *Inventory*, by 0.1 MMT CO_2 Eq., or 0.2 percent.

The combined impact of revisions to 2021 petroleum systems N_2O emission estimates on a CO_2-equivalent basis, compared to the previous *Inventory*, is a decrease of 0.002 MMT CO_2, Eq. or 10.2 percent. The recalculations resulted in an average decrease in emission estimates across the 1990 through 2021 time series, compared to the previous *Inventory*, of 0.001 MMT CO_2 Eq., or 7.4 percent.

In Table 3-51 and Table 3-52 below are categories in petroleum systems with updated methodologies or with recalculations resulting in a change of greater than 0.05 MMT CO_2 Eq., comparing the previous estimate for 2021 to the current (recalculated) estimate for 2021. For more information, please see the discussion below.

Table 3-51: Recalculations of CO_2 in Petroleum Systems (MMT CO_2)

Segment/Source	*Previous Estimate Year 2021, 2023 Inventory*	Current Estimate Year 2021, 2024 *Inventory*	Current Estimate Year 2022, 2024 *Inventory*
Exploration	***0.5***	**0.6**	**0.3**
HF Completions	*0.5*	0.6	0.3
Production	***20.0***	**20.5**	**18.8**
Tanks	*5.4*	5.6	4.5
HF Workovers	*0.2*	+	+
Pneumatic Controllers	*0.1*	0.1	0.1
Equipment Leaks	*+*	+	+
Chemical Injection Pumps	*+*	+	+

[78] Stakeholder materials including draft and final memoranda for the current (i.e., 1990 to 2022) *Inventory* are available at https://www.epa.gov/ghgemissions/natural-gas-and-petroleum-systems.

Miscellaneous Production Flaring	*4.2*	4.6	5.0
Transportation	***+***	**+**	**+**
Refining	***4.2***	**3.0**	**2.9**
Flares	*4.2*	3.0	2.8
Petroleum Systems Total	***24.7***	**24.1**	**22.0**

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

Table 3-52: Recalculations of CH_4 in Petroleum Systems (MMT CO_2 Eq.)

Segment/Source	*Previous Estimate Year 2021, 2023 Inventory*	Current Estimate Year 2021, 2024 *Inventory*	Current Estimate Year 2022, 2024 *Inventory*
Exploration	***0.2***	**0.2**	**0.1**
HF Completions	*0.1*	0.2	0.1
Production	***48.9***	**47.5**	**38.6**
Pneumatic Controllers	*28.4*	28.1	19.4
Chemical Injection Pumps	*3.2*	2.4	2.2
Produced Water	*2.5*	2.6	2.7
Offshore Production from GOM Federal Waters (vented and leaks)	*4.7*	4.4	4.3
HF Workovers	*0.1*	+	+
Gas Engines	*2.5*	2.4	2.5
Associated Gas Flaring	*0.8*	1.0	0.8
Transportation	***0.2***	**0.2**	**0.2**
Refining	***0.8***	**0.7**	**0.7**
Petroleum Systems Total	***50.2***	**48.6**	**39.6**

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

Exploration

HF Completions (Methodological Update)

EPA updated the calculation methodology for HF completions to use basin-level HF completion counts from Enverus and basin-specific activity factors and emission factors calculated from Subpart W data for each control category (i.e., non-reduced emission completion (REC) with venting, non-REC with flaring, REC with venting, REC with flaring). Previously, national annual average activity and emission factors calculated using Subpart W data were applied to national activity data counts to estimate HF gas well completion emissions. In this update, EPA developed national emission estimates by summing calculated basin-level total emission estimates. The *Completions and Workovers* memo presents additional information and considerations for this update.

EPA calculated basin-specific activity factors and CH_4 and CO_2 emission factors for all basins that reported Subpart W data. The factors were year-specific for reporting year (RY) 2011 (first year of GHGRP data for this source) through RY2022. For basin-level HF completion event counts, EPA used Enverus data for 1990 to 2010 and Subpart W for 2011 forward. For the fraction of completions in each control subcategory, EPA retained the previous *Inventory's* assumption that all HF gas well completions were non-REC for 1990 to 2000. The previous *Inventory* also assumed that 10 percent of HF completions were non-REC with flaring from 1990 to 2010 (based on national Subpart W data for RY2011 and RY2012); EPA updated this value using basin-specific Subpart W data for RY2011 and RY2012. For 2011 to 2022, EPA determined the percent contribution of each control category directly from Subpart W data and used linear interpolation between 2000 and 2011 to determine the percent of gas wells with RECs. EPA developed year- and basin-specific Subpart W EFs for 2011 forward. Year 2011 emission factors were applied to all prior years for each basin. For basins without Subpart W data available, EPA applied national average activity and emission factors (unweighted average of all Subpart W reported data).

Comparing the final completion emissions and those presented at the October 2023 webinar and in the November 2023 *Completions and Workovers* memo, the final estimates are higher for certain completion categories. These emissions increases are due not to the basin-level methodology changes discussed here but rather to changes in the Enverus dataset. EPA applied the same data processing steps to Enverus data in the fall of 2023 as it did for the previous Enverus data analysis (conducted in 2021) and data changes led to many more completions being classified as HF completions.

As a result of this methodological update, CH_4 emissions estimates are on average 10 percent lower across the time series than in the previous *Inventory*. The 2021 CH_4 emissions estimate is 41 percent higher than in the previous *Inventory*. The largest increase in the CH_4 emissions estimates compared to the previous *Inventory* is 42 percent in 2016, and the largest decrease is 35 percent in 1999. The decrease in CH_4 emissions is predominantly due to HF completions that were non-REC with venting. Basins such as the Permian basin (basin 430), Williston basin (basin 395), and Denver basin (basin 540) had a high number of HF oil well completion events over the time series. However, they had low EFs for non-REC with venting, decreasing the overall CH_4 emissions. The update resulted in CO_2 emissions estimates that are on average 33 percent higher across the time series than in the previous *Inventory*. The 2021 CO_2 emissions estimate is 29 percent higher than in the previous *Inventory*. The largest increase in CO_2 emissions estimates compared to the previous *Inventory* is 80 percent in 2000, and the largest decrease is 17 percent in 2018. The increase in CO_2 emissions is due to HF completions that were non-REC with flaring and REC with flaring. The Permian basin (basin 430) had the highest emissions across the time series for completions that were non-REC with flaring and REC with flaring. The Permian basin had the highest number of HF oil well completions and high EFs for both control categories.

Table 3-53: HF Completions National CH_4 Emissions (Metric Tons CH_4)

Source	1990	2005	2018	2019	2020	2021	2022
HF Completions – Non-REC with Venting	95,717	179,290	380	1,126	845	244	509
HF Completions – Non-REC with Flaring	898	1,190	2,797	2,801	1,989	1,272	1,269
HF Completions - REC with Venting	NO	NO	5,478	5,466	6,212	1,114	912
HF Completions - REC with Flaring	NO	NO	9,637	6,188	1,945	3,620	685
Total Emissions	**96,615**	**180,480**	**18,292**	**15,581**	**10,992**	**6,250**	**3,375**
Previous Estimate	*143,304*	*202,773*	*18,090*	*14,864*	*10,568*	*4,430*	*NA*

NO (Not Occurring)
NA (Not Applicable)
Note: Totals may not sum due to independent rounding.

Table 3-54: HF Completions National CO_2 Emissions (kt CO_2)

Source	1990	2005	2018	2019	2020	2021	2022
HF Completions – Non-REC with Venting	3	4	+	+	+	+	+
HF Completions – Non-REC with Flaring	155	240	485	762	355	262	131
HF Completions - REC with Venting	NO	NO	+	+	+	+	+
HF Completions - REC with Flaring	NO	NO	2,165	1,278	441	338	141
Total Emissions	**157**	**244**	**2,651**	**2,041**	**797**	**601**	**272**
Previous Estimate	*119*	*168*	*3,174*	*2,431*	*836*	*466*	*NA*

+ Does not exceed 0.5 kt.
NO (Not Occurring)
NA (Not Applicable)
Note: Totals may not sum due to independent rounding.

Production

HF Workovers (Methodological Update)

EPA updated the activity data source and calculation methodology for HF workovers to use basin-specific activity factors and emission factors, calculated from Subpart W data for each control category (i.e., non-reduced emission completion (REC) with venting, non-REC with flaring, REC with venting, REC with flaring). Previously, national HF workover counts calculated using analyses for NSPS OOOO (i.e., 1 percent of HF oil wells were worked over annually) and national annual average emission factors calculated using Subpart W data were applied to estimate HF oil well workover emissions. In this update, EPA developed national emission estimates by summing calculated basin-level total emission estimates. The *Completions and Workovers* memo presents additional information and considerations for this update.

EPA calculated basin-specific activity factors (AFs) and CH_4 and CO_2 emission factors for all basins that reported Subpart W data. For basin-level workover counts, instead of applying a 1 percent workover rate to HF oil wells, EPA developed year- and basin-specific Subpart W AFs for 2016 (the first year of GHGRP data for this source) forward that represent the number of HF workovers per oil well. Year 2016 Subpart W AFs were applied to all prior years for each basin. For the fraction of workovers in each control subcategory, EPA retained the previous *Inventory's* assumption that all HF oil well workovers were non-REC for 1990 to 2007 and 10 percent flaring from 1990 to 2007. For 2016 to 2022, EPA determined the percent contribution of each control category directly from Subpart W data at the basin level and used linear interpolation between 2008 and 2015 to determine the percent of oil wells with RECs and the percent flaring. EPA developed year- and basin-specific Subpart W EFs for 2016 forward. Year 2016 emission factors were applied to all prior years for each basin. For basins without Subpart W data available, EPA applied national average activity and emission factors (unweighted average of all Subpart W reported data).

As a result of this methodological update, CH_4 emissions estimates are on average 62 percent lower across the time series than in the previous *Inventory*. The largest decrease in CH_4 emissions estimates compared to the previous *Inventory* is 97 percent in 2021 and the smallest decrease is 39 percent in 2018. The 2021 CH_4 emissions estimate is 97 percent lower than in the previous *Inventory*. The update resulted in CO_2 emissions estimates that are on average 51 percent lower than in the previous *Inventory*. The 2021 CO_2 emissions estimate is 97 percent lower than in the previous *Inventory*. The largest decrease in CO_2 emissions estimates compared to the previous *Inventory* is 97 percent in 2021 and the smallest decrease is 26 percent in 1990. The decrease in emissions for both CH_4 and CO_2 was primarily due to the change in calculation method for workover counts. HF oil well workover counts decreased by an average of 52 percent across the 1990 to 2021 time series compared to the previous *Inventory*.

Table 3-55: HF Workovers National CH_4 Emissions (Metric Tons CH_4)

Source	1990	2005	2018	2019	2020	2021	2022
HF Workovers – Non-REC with Venting	17,639	16,244	87	1,339	5	16	35
HF Workovers – Non-REC with Flaring	104	96	11	7	11	20	NO
HF Workovers - REC with Venting	NO	NO	1,304	331	130	5	63
HF Workovers - REC with Flaring	NO	NO	222	75	14	19	33
Total Emissions	**17,744**	**16,340**	**1,623**	**1,753**	**160**	**60**	**130**
Previous Estimate	*37,696*	*41,993*	*2,670*	*3,679*	*3,873*	*2,151*	*NA*

NO (Not Occurring)
NA (Not Applicable)
Note: Totals may not sum due to independent rounding.

Table 3-56: HF Workovers National CO_2 Emissions (Metric Tons CO_2)

Source	1990	2005	2018	2019	2020	2021	2022
HF Workovers – Non-REC with Venting	431	408	5	63	+	1	6
HF Workovers – Non-REC with Flaring	22,654	21,076	2,544	2,093	1,947	2,532	NO

HF Workovers - REC with Venting	NO	NO	17	14	4	+	3
HF Workovers - REC with Flaring	NO	NO	51,135	18,285	5,987	2,768	6,095
Total Emissions	**23,085**	**21,484**	**53,701**	**20,456**	**7,939**	**5,301**	**6,105**
Previous Estimate	*31,219*	*34,778*	*89,049*	*97,515*	*97,766*	*205,160*	*NA*

+ Does not exceed 0.5 MT.
NO (Not Occurring)
NA (Not Applicable)
Note: Totals may not sum due to independent rounding.

Pneumatic Controllers (Methodological Update)

In the previous *Inventory*, EPA updated the CH_4 emissions calculation methodology for pneumatic controllers to use basin-specific activity factors and emission factors by bleed type (i.e., low, high, intermittent bleed) from GHGRP data. However, the CO_2 emissions calculation methodology was not updated and instead the previous *Inventory* still relied on a national-level methodology to estimate CO_2 emissions. For this year's *Inventory*, EPA calculated pneumatic controller CO_2 emissions using basin-specific emissions data such that the CO_2 emissions reflect the unique CO_2 composition of the gas in a basin.

The update for pneumatic controller CO_2 emission estimates resulted in an average increase of 61 percent across the time series and an increase of 57 percent in 2021, compared to the previous *Inventory*.

In addition, methane emissions for pneumatic controllers were impacted due to recalculations with updated data. Methane emissions from onshore production pneumatic controllers are an average of 2 percent lower across the time series and 1 percent lower in 2021, compared to the previous *Inventory*. The emission changes were due to GHGRP data submission revisions.

Table 3-57: Pneumatic Controllers National CO_2 Emissions (Metric Tons CO_2)

Source	1990	2005	2018	2019	2020	2021	2022
High Bleed Controllers	94,495	39,873	5,056	5,369	5,778	4,260	2,403
Low Bleed Controllers	7,109	4,132	3,740	4,819	3,704	4,561	3,992
Intermittent Bleed Controllers	NO	26,370	75,579	80,855	82,493	80,063	70,328
Total Emissions	**101,604**	**70,374**	**84,374**	**91,044**	**91,975**	**88,884**	**76,723**
Previous Estimate	*42,406*	*46,477*	*70,322*	*49,460*	*63,104*	*56,641*	*NA*

NO (Not Occurring)
NA (Not Applicable)
Note: Totals may not sum due to independent rounding.

Table 3-58: Pneumatic Controllers National CH_4 Emissions (Metric Tons CH_4)

Source	1990	2005	2018	2019	2020	2021	2022
High Bleed Controllers	709,796	481,760	71,824	72,432	86,363	44,611	23,712
Low Bleed Controllers	51,129	62,162	32,106	50,770	36,740	46,060	35,439
Intermittent Bleed Controllers	NO	267,220	1,135,995	758,001	996,250	912,391	634,400
Total Emissions	**760,925**	**811,142**	**1,239,924**	**881,203**	**1,119,352**	**1,003,063**	**693,551**
Previous Estimate	*759,970*	*832,929*	*1,260,259*	*886,382*	*1,130,899*	*1,015,080*	*NA*

NO (Not Occurring)
NA (Not Applicable)
Note: Totals may not sum due to independent rounding.

Equipment Leaks (Methodological Update)

In the previous *Inventory*, EPA updated the CH_4 emissions calculation methodology for onshore production equipment leaks to use basin-specific equipment-level activity factors (e.g., separators per well) from GHGRP data. However, the CO_2 emissions calculation methodology was not updated and instead the previous *Inventory* still relied on a national-level methodology to estimate CO_2 emissions. For this year's *Inventory*, EPA calculated equipment leak CO_2 emissions in the same manner as CH_4 emissions. EPA calculated CO_2 estimates using the basin-specific equipment-level activity factors for RY2015 through RY2022 from GHGRP, consistent with the methodology used to calculate the CH_4 activity factors, and the CO_2 emissions factors for onshore production segment equipment leaks. Note, this methodological update applies only for activity factors. The previous *Inventory's* CO_2 emission factors for onshore production segment equipment leaks (by equipment type) were retained and used to develop CO_2 estimates.

The update for CO_2 emission estimates resulted in an average increase of 7 percent across the time series and an increase of 18 percent in 2021, compared to the previous *Inventory*. Years 2015 to 2021 were impacted more by the update, with an average increase of 28 percent compared to the previous *Inventory*.

Table 3-59: Equipment Leaks National CO_2 Emissions (Metric Tons CO_2)

Source	1990	2005	2018	2019	2020	2021	2022
Oil Wellheads (heavy crude)	2	2	2	1	1	1	1
Oil Wellheads (light crude)	3,159	2,857	3,330	3,416	3,280	3,272	3,195
Separators (heavy crude)	1	1	1	1	+	+	+
Separators (light crude)	613	868	2,280	2,114	1,601	1,443	1,411
Heater/Treaters (light crude)	508	474	786	1,028	846	951	905
Headers (heavy crude)	+	+	+	+	+	+	+
Headers (light crude)	185	458	712	843	432	430	485
Total Emissions	**4,468**	**4,660**	**7,111**	**7,403**	**6,161**	**6,098**	**5,997**
Previous Estimate	*4,453*	*4,681*	*5,396*	*5,351*	*5,159*	*5,159*	*NA*

+ Does not exceed 0.05 MT CO_2.
NA (Not Applicable)

Chemical Injection Pumps (Methodological Update)

In the previous *Inventory*, EPA updated the CH_4 emissions calculation methodology for chemical injection pumps to use basin-specific equipment-level activity factors (e.g., pumps per well) from GHGRP data. However, the CO_2 emissions calculation methodology was not updated and instead the previous *Inventory* still relied on a national-level methodology to estimate CO_2 emissions. For this year's *Inventory*, EPA calculated chemical injection pump CO_2 emissions in the same manner as CH_4 emissions. EPA calculated CO_2 estimates using the basin-specific equipment-level activity factors for RY2015 through RY2022 from GHGRP, consistent with the methodology used to calculate the CH_4 activity factors, and the CO_2 emission factor. Note, this methodological update applies only for activity factors. The previous *Inventory's* chemical injection pumps CO_2 emission factor was retained and used to develop CO_2 estimates. The update for CO_2 emission estimates resulted in an average decrease of 29 percent across the time series and a decrease of 35 percent in 2021, compared to the previous *Inventory*.

Table 3-60: Chemical Injection Pump National CO_2 Emissions (Metric Tons CO_2)

Source	1990	2005	2018	2019	2020	2021	2022
Chemical Injection Pumps	2,646	4,464	5,955	6,784	5,338	4,749	4,449
Previous Estimate	*4,506*	*6,522*	*7,689*	*7,625*	*7,351*	*7,351*	*NA*

NA (Not Applicable)

Storage Tanks (Recalculation with Updated Data)

Carbon dioxide emissions from production storage tanks are on average 0.9 percent higher across the time series compared to the previous *Inventory*. Emissions estimates for 2021 are 4 percent higher than in the previous *Inventory*, which is primarily due to large tanks with flares. The emission changes were due to GHGRP data submission revisions.

Table 3-61: Storage Tanks National CO_2 Emissions (kt CO_2)

Source	1990	2005	2018	2019	2020	2021	2022
Large Tanks w/Flares	NO	716	5,336	6,251	5,829	5,594	4,513
Large Tanks w/VRU	NO	3	3	9	2	1	1
Large Tanks w/o Control	24	8	4	9	5	4	2
Small Tanks w/Flares	NO	3	7	9	11	10	11
Small Tanks w/o Flares	12	5	5	4	4	5	5
Malfunctioning Separator Dump Valves	12	13	30	26	21	34	8
Total Emissions	**48**	**748**	**5,386**	**6,309**	**5,871**	**5,649**	**4,539**
Previous Estimate	*47*	*748*	*5,398*	*6,024*	*5,255*	*5439*	*NA*

NO (Not Occurring)
NA (Not Applicable)

Chemical injection Pumps (Recalculation with Updated Data)

Chemical injection pump CH_4 estimates decreased by an average of 19 percent across the time series and decreased by 26 percent in 2021, compared to the previous *Inventory*. The emission changes were due to GHGRP data submission revisions.

Table 3-62: Chemical Injection Pumps National CH_4 Emissions (Metric Tons CH_4)

Source	1990	2005	2018	2019	2020	2021	2022
Chemical Injection Pumps	47,425	79,968	108,147	122,967	96,186	85,494	79,712
Previous Estimate	*47,401*	*105,458*	*138,866*	*387,416*	*116,080*	*115,678*	*NA*

NA (Not Applicable)

Produced Water (Recalculation with Updated Data)

Methane estimates from produced water increased by an average of 2 percent across the time series and increased by 4 percent in 2021, compared to the previous *Inventory*. The emission changes were due to Enverus data updates.

Table 3-63: Produced Water National CH_4 Emissions (Metric Tons CH_4)

Source	1990	2005	2018	2019	2020	2021	2022
Produced Water - Regular Pressure Wells	71,854	49,840	73,727	77,370	70,374	71,749	73,665
Produced Water - Low Pressure Wells	20,482	14,207	21,016	22,055	20,061	20,452	20,998
Total Emissions	**92,336**	**64,047**	**94,743**	**99,425**	**90,435**	**92,201**	**94,663**
Previous Estimate	*91,391*	*62,458*	*92,863*	*97,735*	*88,622*	*88,622*	*NA*

NA (Not Applicable)

Associated Gas Flaring (Recalculation with Updated Data)

Associated gas flaring CH_4 emission estimates increased by an average of 2 percent across the time series and increased by 23 percent in 2021, compared to the previous *Inventory*. The emission changes were due to GHGRP data submission revisions.

Table 3-64: Associated Gas Flaring National CH_4 Emissions (Metric Tons CH_4)

Source	1990	2005	2018	2019	2020	2021	2022
220 - Gulf Coast Basin (LA, TX)	901	480	2,379	2,907	3,643	2,136	1,900
360 - Anadarko Basin	452	274	350	90	21	35	30
395 - Williston Basin	2,666	3,405	36,108	58,138	28,176	21,676	18,341

430 - Permian Basin	11,662	7,992	25,286	26,063	12,695	8,178	7,546
"Other" Basins	4,314	2,335	2,089	3,760	2,353	2,790	2,072
Total Emissions	**19,995**	**14,486**	**66,211**	**90,958**	**46,888**	**34,814**	**29,889**
220 - Gulf Coast Basin (LA, TX)	*886*	*490*	*2,440*	*2,991*	*3,692*	*1,864*	*NA*
360 - Anadarko Basin	*447*	*274*	*348*	*88*	*21*	*41*	*NA*
395 - Williston Basin	*2,665*	*3,419*	*36,120*	*48,019*	*23,556*	*18,734*	*NA*
430 - Permian Basin	*11,263*	*7,805*	*25,198*	*27,484*	*13,086*	*5,852*	*NA*
"Other" Basins	*4,369*	*2,347*	*1,992*	*3,563*	*2,295*	*1,802*	*NA*
Previous Estimate	*19,630*	*14,335*	*66,096*	*82,146*	*42,649*	*28,293*	*NA*

NA (Not Applicable)

Gas Engines (Recalculation with Updated Data)

Methane estimates from gas engines decreased by an average of 2 percent across the time series and decreased by 2 percent in 2021, compared to the previous *Inventory*. The emission changes were due to Enverus data updates.

Table 3-65: Gas Engines National CH_4 Emissions (Metric Tons CH_4)

Source	1990	2005	2018	2019	2020	2021	2022
Gas Engines	81,271	69,973	90,773	92,909	88,619	87,040	87,546
Previous Estimate	*81,916*	*71,348*	*91,719*	*93,608*	*89,497*	*89,233*	*NA*

NA (Not Applicable)

Miscellaneous Production Flaring (Recalculation with Updated Data)

Miscellaneous production flaring CO_2 emission estimates are on average 1 percent higher across the time series compared to the previous *Inventory*. Carbon dioxide emissions estimates for 2021 increased by 12 percent compared to the previous *Inventory*. The emission changes were due to GHGRP data submission revisions.

Table 3-66: Miscellaneous Production Flaring National CO_2 Emissions (kt CH_4)

Source	1990	2005	2018	2019	2020	2021	2022
220 - Gulf Coast Basin (LA, TX)	0	103	567	609	654	802	649
395 - Williston Basin	0	71	1,701	3,049	1,307	1,312	1,241
430 - Permian Basin	0	214	1,463	4,312	2,723	2,156	2,709
"Other" Basins	0	398	639	707	427	368	429
Total Emissions	**0**	**786**	**4,370**	**8,678**	**5,110**	**4,638**	**5,028**
Previous Estimate	*0*	*3,008*	*4,307*	*8,225*	*4,679*	*4,154*	*NA*

NA (Not Applicable)

Offshore Production – GOM Federal Waters (Recalculation with Updated Data)

Vented and leak CH_4 emission estimates from offshore production in GOM federal waters decreased by an average of 0.4 percent across the time series and decreased by 8 percent in 2021, compared to the previous *Inventory*. The emission changes were due to updated offshore complex counts from BOEM.

Table 3-67: Offshore Production National CH_4 Emissions (Metric Tons CH_4)

Source	1990	2005	2018	2019	2020	2021	2022
GOM Federal Waters – Vented	196,769	101,585	112,786	110,263	103,116	102,365	101,546
GOM Federal Waters - Leaks	96,575	103,712	58,938	57,577	53,860	53,395	52,961
Total Emissions	**293,344**	**205,298**	**171,724**	**167,840**	**156,976**	**155,760**	**154,507**
Previous Estimate	*293,204*	*205,207*	*171,910*	*170,190*	*162,543*	*168,798*	*NA*

NA (Not Applicable)

Transportation

Recalculations for the transportation segment have resulted in calculated CH_4 and CO_2 emissions over the time series from this segment that are lower (by less than 0.05 percent) than in the previous *Inventory*.

Refining

Recalculations due to resubmitted GHGRP data in the refining segment have resulted in a decrease in calculated CH_4 emissions by an average of 4.5 percent across the time series and a decrease of 14 percent in 2021, compared to the previous *Inventory*.

Refining CO_2 emission estimates decreased by an average of 8 percent across the time series and decreased by 28 percent in 2021, compared to the previous *Inventory*. This change in emissions is due to GHGRP resubmissions and was largely due to a change in reported flaring CO_2 emissions.

Table 3-68: Refining National CH_4 Emissions (Metric Tons CH_4)

Source	1990	2005	2018	2019	2020	2021	2022
Refining	25,742	29,218	27,804	30,814	25,861	25,366	24,685
Previous Estimate	*26,398*	*29,963*	*30,313*	*35,516*	*31,023*	*29,551*	*NA*

NA (Not Applicable)

Table 3-69: Refining National CO_2 Emissions (kt CO_2)

Source	1990	2005	2018	2019	2020	2021	2022
Flares	3,023	3,431	2,814	3,523	2,859	2,989	2,836
Total Refining	**3,174**	**3,602**	**2,877**	**3,571**	**2,893**	**3,021**	**2,872**
Previous Estimate	*3,284*	*3,728*	*3,706*	*5,009*	*4,242*	*4,216*	*NA*

NA (Not Applicable)

Planned Improvements

Planned Improvements for 2025 *Inventory*

EPA updated the Enverus data and there were notable increases in the number of wells and completions identified as being hydraulically fractured compared with previous versions of the database. EPA will assess the underlying Enverus data to determine the cause of these changes.

Upcoming Data, and Additional Data that Could Inform the *Inventory*

EPA will assess new data received by the Greenhouse Gas Reporting Program, the Methane Challenge Program, and other relevant programs on an ongoing basis, which may be used to confirm or improve existing estimates and assumptions.

EPA continues to track studies that contain data that may be used to update the *Inventory*. EPA will also continue to assess studies that include and compare both top-down and bottom-up estimates, and which could lead to improved understanding of unassigned high emitters (e.g., identification of emission sources and information on frequency of high emitters) as recommended in previous stakeholder comments.

Box 3-6: 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, or is stored geologically. This CO_2 is produced from both naturally-occurring CO_2 reservoirs and from industrial sources such as natural gas processing plants and ammonia plants. In the *Inventory*, emissions of CO_2 from naturally-occurring CO_2 reservoirs are estimated based on the specific application.

In the *Inventory*, CO_2 that is used in non-EOR industrial and commercial applications (e.g., food processing, chemical production) is assumed to be emitted to the atmosphere during its industrial use. These emissions are discussed in the Carbon Dioxide Consumption section, 4.15.

For EOR CO_2, as noted in the *2006 IPCC Guidelines*, "At the Tier 1 or 2 methodology levels [EOR CO_2 is] indistinguishable from fugitive greenhouse gas emissions by the associated oil and gas activities." In the U.S. estimates for oil and gas fugitive emissions, the Tier 2 emission factors for CO_2 include CO_2 that was originally injected and is emitted along with other gas from leak, venting, and flaring pathways, as measurement data used to develop those factors would not be able to distinguish between CO_2 from EOR and CO_2 occurring in the produced natural gas. Therefore, EOR CO_2 emitted through those pathways is included in CO_2 estimates in 1B2.

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

In the United States, facilities that produce CO_2 for various end-use applications (including capture facilities such as acid gas removal plants and ammonia plants), importers of CO_2, exporters of CO_2, facilities that conduct geologic sequestration of CO_2, and facilities that inject CO_2 underground, are required to report greenhouse gas data annually to EPA through its GHGRP. Facilities reporting geologic sequestration of CO_2 to the GHGRP develop and implement an EPA-approved site-specific monitoring, reporting and verification plan, and report the amount of CO_2 sequestered using a mass balance approach.

GHGRP data relevant for this *Inventory* estimate consists of national-level annual quantities of CO_2 captured and extracted for EOR applications for 2010 to 2022 and data reported for geologic sequestration from 2016 to 2022.

The amount of CO_2 captured and extracted from natural and industrial sites for EOR applications in 2022 is 36,680 kt (36.7 MMT CO_2 Eq.) 6. The quantity of CO_2 captured and extracted is noted here for information purposes only; CO_2 captured and extracted from industrial and commercial processes is generally assumed to be emitted and included in emissions totals from those processes.

Table 3-70: Quantity of CO_2 Captured and Extracted for EOR Operations (kt CO_2)

Stage	2018	2019	2020	2021	2022
Quantity of CO_2 Captured and Extracted for EOR Operations	48,400	52,100	35,210	35,090	36,680

Several facilities are reporting under GHGRP Subpart RR (Geologic Sequestration of Carbon Dioxide). See Table 3-71 for the number of facilities reporting under Subpart RR, the reported CO_2 sequestered in subsurface geologic formations in each year, and of the quantity of CO_2 emitted from equipment leaks in each year. The quantity of CO_2 sequestered and emitted is noted here for information purposes only; EPA is considering updates to its approach for this source and is seeking feedback as part of this public review draft on potential updates that could be incorporated in future *Inventories*.

Table 3-71: Geologic Sequestration Information Reported Under GHGRP Subpart RR

Stage	2018	2019	2020	2021	2022
Number of Reporting Facilities	5	5	6	9	13
Reported Annual CO_2 Sequestered (kt)	7,662	8,332	6,802	6,947	7,953

Reported Annual CO_2 Emissions from Equipment Leaks (kt)	11	16	13	37	27

3.7 Natural Gas Systems (CRT 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. This category (1B2b) as defined in the IPCC methodological guidance is for fugitive emissions from natural gas systems, which per IPCC guidelines include emissions from leaks, venting, and flaring. Total greenhouse gas emissions (CH_4, CO_2, and N_2O) from natural gas systems in 2022 were 209.7 MMT CO_2 Eq., a decrease of 17 percent from 1990 and a decrease of 0.3 percent from 2021, both primarily due to decreases in CH_4 emissions. From 2011, emissions decreased by 5 percent, primarily due to decreases in CH_4 emissions. National total dry gas production in the United States increased by 104 percent from 1990 to 2022, increased by 5 percent from 2021 to 2022, and increased by 59 percent from 2011 to 2022. Of the overall greenhouse gas emissions (209.7 MMT CO_2 Eq.), 83 percent are CH_4 emissions (173.1 MMT CO_2 Eq.), 17 percent are CO_2 emissions (36.5 MMT), and less than 0.1 percent are N_2O emissions (0.15 MMT CO_2 Eq.).

Overall, natural gas systems emitted 173.1 MMT CO_2 Eq. (6,183 kt CH_4) of CH_4 in 2022, a 21 percent decrease compared to 1990 emissions, and 1 percent decrease compared to 2021 emissions (see Table 3-72 and Table 3-73). For non-combustion CO_2, a total of 36.5 MMT CO_2 Eq. (36,470 kt) was emitted in 2022, a 12 percent increase compared to 1990 emissions, and a 2 percent increase compared to 2021 levels. The 2022 N_2O emissions were estimated to be 0.15 MMT CO_2 Eq. (0.57 kt N_2O), a 3205 percent increase compared to 1990 emissions, and a 1104 percent increase compared to 2021 levels.

The 1990 to 2022 emissions trend is not consistent across segments or gases. Overall, the 1990 to 2022 decrease in CH_4 emissions is due primarily to the decrease in emissions from the following segments: distribution (70 percent decrease), transmission and storage (38 percent decrease), processing (37 percent decrease), and exploration (97 percent decrease). Over the same time period, the production segment saw increased CH_4 emissions of 38 percent (with onshore production emissions increasing 16 percent, offshore production emissions decreasing 86 percent, and gathering and boosting [G&B] emissions increasing 108 percent), and post-meter emissions increasing by 65 percent. The 1990 to 2022 increase in CO_2 emissions is primarily due to an increase in CO_2 emissions in the production segment, where emissions from flaring have increased over time.

Methane and CO_2 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, flaring, and leak 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. Emissions of N_2O from flaring activities are included in the *Inventory*, with most of the emissions occurring in the processing and production segments. Note, CO_2 emissions exclude all combustion emissions (e.g., engine combustion) except for flaring CO_2 emissions. All combustion CO_2 emissions (except for flaring) are accounted for in Section 3.1.

Each year, some estimates in the *Inventory* are recalculated with improved methods and/or data. These improvements are implemented consistently across the previous *Inventory's* time series (i.e., 1990 to 2022) to ensure that the trend is representative of changes in emissions. Recalculations in natural gas systems in this year's *Inventory* include:

- Methodological updates to transmission compressor station activity data, completions and workovers, and underground natural gas storage well events.
- Recalculations due to Greenhouse Gas Reporting Program (GHGRP) submission revisions.
- Recalculations due to updated well counts and production data from Enverus.

The Recalculations Discussion section below provides more details on the updated methods.

Below is a characterization of the six emission subcategories of natural gas systems: exploration, production (including gathering and boosting), processing, transmission and storage, distribution, and post-meter. Each of the segments is described and the different factors affecting CH_4, CO_2, and N_2O emissions are discussed.

Exploration. Exploration includes well drilling, testing, and completion. Emissions from exploration accounted for 0.1 percent of CH_4 emissions and 0.1% of CO_2 emissions from natural gas systems in 2022. Well completions accounted for approximately 90 percent of CH_4 emissions from the exploration segment in 2022, with the rest resulting from well testing and drilling. Well completion flaring emissions account for most of the CO_2 emissions. Methane emissions from exploration decreased by 97 percent from 1990 to 2022, with the largest decreases coming from hydraulically fractured gas well completions without reduced emissions completions (RECs). Methane emissions from exploration increased 58 percent from 2021 to 2022 due to increases in emissions from hydraulically fractured well completions (both non-REC with flaring and REC with venting). Methane emissions from exploration were highest from 2006 to 2008. Carbon dioxide emissions from exploration decreased by 94 percent from 1990 to 2022 primarily due to decreases in hydraulically fractured gas well completions. Carbon dioxide emissions from exploration increased by 14 percent from 2020 to 2021 due to increases in emissions from hydraulically fractured gas well completions (REC with flaring). Carbon dioxide emissions from exploration were highest from 2006 to 2008. Nitrous oxide emissions from exploration decreased 95 percent from 1990 to 2022 and increased 74 percent from 2021 to 2022.

Production (including gathering and boosting). In the production segment, wells are used to withdraw raw gas from underground formations. Emissions arise from the wells themselves, and from well-site equipment and activities such as pneumatic controllers, tanks and separators, and liquids unloading. Gathering and boosting emission sources are included within the production sector. The gathering and boosting sources include 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). Boosting processes include compression, dehydration, and transport of gas to a processing facility or pipeline. Emissions from production (including gathering and boosting) accounted for 52 percent of CH_4 emissions and 23 percent of CO_2 emissions from natural gas systems in 2022. Emissions from gathering and boosting and pneumatic controllers in onshore production accounted for most of the production segment CH_4 emissions in 2022. Within gathering and boosting, the largest sources of CH_4 are compressor exhaust slip, compressor venting and leaks, and tanks. Flaring emissions account for most of the CO_2 emissions from production, with the highest emissions coming from flare stacks at gathering stations, miscellaneous onshore production flaring, and tank flaring. Methane emissions from production increased by 38 percent from 1990 to 2022, due primarily to increases in emissions from pneumatic controllers (due to an increase in the number of controllers, particularly in the number of intermittent bleed controllers) and increases in emissions from compressor exhaust slip in gathering and boosting. Methane emissions from production decreased 3 percent from 2021 to 2022 due to decreases in emissions from pneumatic controllers and liquids unloading. Carbon dioxide emissions from production increased by approximately a factor of 2.6 from 1990 to 2022 due to increases in emissions at flare stacks in gathering and boosting and miscellaneous onshore production flaring and decreased 8 percent from 2021 to 2022 due primarily to decreases in emissions at flare stacks in miscellaneous onshore production flaring and tank venting. Nitrous oxide emissions from production were 36.9 times higher in 2022 than in 1990 and 17.5 times higher in 2022 than in 2021. The increase in N_2O emissions from 1990 to 2022 and from 2021 to 2022 is primarily due to increases in emissions from condensate tank flaring.

Processing. In the processing segment, 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. Methane emissions from compressors, including compressor seals, are the primary emission source from this stage. Most of the CO_2 emissions come from acid gas removal (AGR) units, which are designed to remove CO_2 from natural gas. Processing plants accounted for 9 percent of CH_4 emissions and 73 percent of CO_2 emissions from natural gas systems. Methane emissions from processing decreased by 37 percent from 1990 to 2022 as emissions from compressors (leaks and venting) and equipment leaks decreased; and increased 7 percent from 2021 to 2022 due to increased emissions from gas engines. Carbon dioxide emissions from processing decreased by 6 percent from 1990 to 2022, due to a decrease in AGR, and increased 4 percent from 2021 to 2022 due to increased emissions from flaring emissions at processing plants. Nitrous oxide emissions increased 116 percent from 2021 to 2022.

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 are used to move the gas throughout the U.S. transmission system. Leak CH_4 emissions from these compressor stations and venting from pneumatic controllers account for most of the emissions from this stage. Uncombusted compressor engine exhaust and pipeline venting are also sources of CH_4 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). Leak and venting emissions from compressors are the primary contributors to CH_4 emissions from storage. Emissions from liquefied natural gas (LNG) stations and terminals are also calculated under the transmission and storage segment. Methane emissions from the transmission and storage segment accounted for approximately 23 percent of methane emissions from natural gas systems, while CO_2 emissions from transmission and storage accounted for 3 percent of the CO_2 emissions from natural gas systems. CH_4 emissions from this source decreased by 38 percent from 1990 to 2022 due to reduced pneumatic device and compressor station emissions (including emissions from compressors and leaks) and decreased 1 percent from 2021 to 2022 due to decreased emissions from pipeline venting transmission compressors. CO_2 emissions from transmission and storage were 6.6 times higher in 2022 than in 1990, due to increased emissions from LNG export terminals, and increased by 36 percent from 2021 to 2022, also due to LNG export terminals and flaring (both transmission and storage). The quantity of LNG exported from the United States increased by a factor of 74 from 1990 to 2022, and by 9 percent from 2021 to 2022. LNG emissions are about 1 percent of CH_4 and 86 percent of CO_2 emissions from transmission and storage in year 2022. Nitrous oxide emissions from transmission and storage increased by 405 percent from 1990 to 2022 and increased by 177 percent from 2021 to 2022.

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 1,352,384 miles of distribution mains in 2022, an increase of 408,227 miles since 1990 (PHMSA 2022). Distribution system emissions, which accounted for 9 percent of CH_4 emissions from natural gas systems and less than 0.1 percent of CO_2 emissions from natural gas systems, result mainly from leak emissions from pipelines and stations. An increased use of plastic piping, which has lower emissions than other pipe materials, has reduced both CH_4 and CO_2 emissions from this stage, as have station upgrades at metering and regulating (M&R) stations. Distribution system CH_4 emissions in 2022 were 70 percent lower than 1990 levels and 1 percent lower than 2021 emissions. Distribution system CO_2 emissions in 2022 were 70 percent lower than 1990 levels and 1 percent lower than 2021 emissions. Annual CO_2 emissions from this segment are less than 0.1 MMT CO_2 Eq. across the time series.

Post-Meter. Post-meter includes leak emissions from residential and commercial appliances, industrial facilities and power plants, and natural gas fueled vehicles. Leak emissions from residential appliances and industrial facilities and power plants account for the majority of post-meter CH_4 emissions. Methane emissions from the post-meter segment accounted for approximately 8 percent of emissions from natural gas systems in 2022. Post-meter CH_4 emissions increased by 65 percent from 1990 to 2022 and increased by 3 percent from 2021 to 2022, due to increases in the number of residential houses using natural gas and increased natural gas consumption at industrial facilities and power plants. CO_2 emissions from post-meter account for less than 0.01 percent of total CO_2 emissions from natural gas systems.

Total greenhouse gas emissions from the six subcategories within natural gas systems are shown in MMT CO_2 Eq. in Table 3-72. Total CH_4 emissions for these same segments of natural gas systems are shown in MMT CO_2 Eq. (Table 3-73) and kt (Table 3-74). Most emission estimates are calculated using a net emission approach. However, a few sources are still calculated with a potential emission approach. Reductions data are applied to those sources. In 2022, 2.6 MMT CO_2 Eq. CH_4 is subtracted from production segment emissions, 4.3 MMT CO_2 Eq. CH_4 is subtracted from the transmission and storage segment, and 0.1 MMT CO_2 Eq. CH_4 is subtracted from the distribution segment to calculate net emissions. More disaggregated information on potential emissions, net emissions, and reductions data is available in Annex 3.6, Methodology for Estimating CH_4 and CO_2 Emissions from Natural Gas Systems.

Table 3-72: Total Greenhouse Gas Emissions (CH_4, CO_2, and N_2O) from Natural Gas Systems (MMT CO_2 Eq.)

Segment	1990	2005	2018	2019	2020	2021	2022
Exploration	7.3	22.3	2.9	2.3	0.3	0.1	0.2
Production	68.4	97.9	114.1	114.5	105.8	101.5	98.3
Processing	52.2	31.8	36.3	40.4	39.3	39.7	41.8
Transmission and Storage	64.2	46.2	41.7	41.8	43.1	40.7	40.7
Distribution	51.0	28.5	15.6	15.5	15.5	15.3	15.3
Post-Meter	8.1	9.6	12.5	12.8	13.0	13.0	13.4
Total	**251.2**	**236.5**	**223.0**	**227.3**	**217.0**	**210.4**	**209.7**

Note: Totals may not sum due to independent rounding.

Table 3-73: CH_4 Emissions from Natural Gas Systems (MMT CO_2 Eq.)

Segment	1990	2005	2018	2019	2020	2021	2022
Exploration	6.7	19.6	2.6	2.1	0.2	0.1	0.2
Production	65.2	93.4	104.9	103.6	96.7	92.2	89.7
Onshore Production	*39.9*	*64.4*	*60.5*	*58.0*	*53.1*	*48.3*	*46.2*
Gathering and Boosting	*20.5*	*27.0*	*43.6*	*44.8*	*42.7*	*43.3*	*42.8*
Offshore Production	*4.8*	*2.0*	*0.9*	*0.8*	*0.9*	*0.6*	*0.6*
Processing	23.9	13.0	13.5	14.2	13.8	14.2	15.1
Transmission and Storage	64.0	46.0	41.2	40.5	41.1	39.8	39.6
Distribution	50.9	28.5	15.6	15.5	15.5	15.3	15.2
Post-Meter	8.1	9.6	12.5	12.8	13.0	13.0	13.4
Total	**218.8**	**210.1**	**190.3**	**188.7**	**180.3**	**174.6**	**173.1**

Note: Totals may not sum due to independent rounding.

Table 3-74: CH_4 Emissions from Natural Gas Systems (kt)

Segment	1990	2005	2018	2019	2020	2021	2022
Exploration	238	700	93	75	7	4	6
Production	2,328	3,335	3,748	3,701	3,453	3,293	3,202
Onshore Production	*1,424*	*2,299*	*2,162*	*2,073*	*1,895*	*1,726*	*1,650*
Gathering and Boosting	*733*	*963*	*1,556*	*1,601*	*1,527*	*1,545*	*1,528*
Offshore Production	*170*	*73*	*31*	*28*	*32*	*22*	*23*
Processing	853	463	483	507	495	507	541
Transmission and Storage	2,285	1,645	1,470	1,448	1,468	1,421	1,413
Distribution	1,819	1,018	556	554	553	547	544
Post-Meter	290	344	445	457	463	464	477
Total	**7,813**	**7,505**	**6,795**	**6,741**	**6,439**	**6,235**	**6,183**

Note: Totals may not sum due to independent rounding.

Table 3-75: CO_2 Emissions from Natural Gas Systems (MMT)

Segment	1990	2005	2018	2019	2020	2021	2022
Exploration	0.6	2.7	0.3	0.2	0.1	+	+
Production	3.2	4.6	9.1	10.8	9.1	9.3	8.6
Processing	28.3	18.8	22.8	26.2	25.5	25.5	26.7
Transmission and Storage	0.2	0.2	0.5	1.2	2.0	0.9	1.2
Distribution	0.1	+	+	+	+	+	+
Post-Meter	+	+	+	+	+	+	+
Total	**32.4**	**26.3**	**32.8**	**38.5**	**36.7**	**35.8**	**36.5**

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

Table 3-76: CO_2 Emissions from Natural Gas Systems (kt)

Segment	1990	2005	2018	2019	2020	2021	2022
Exploration	619	2,710	325	249	97	32	37
Production	3,236	4,554	9,118	10,844	9,102	9,331	8,558
Processing	28,338	18,836	22,769	26,189	25,471	25,525	26,672
Transmission and Storage	179	181	537	1,224	2,030	874	1,185
Distribution	54	30	17	16	16	16	16
Post-Meter	1	1	2	2	2	2	2
Total	**32,427**	**26,312**	**32,768**	**38,525**	**36,719**	**35,780**	**36,470**

Note: Totals may not sum due to independent rounding.

Table 3-77: N_2O Emissions from Natural Gas Systems (Metric Tons CO_2 Eq.)

Segment	1990	2005	2018	2019	2020	2021	2022
Exploration	518	1,708	148	114	46	15	27
Production	3,853	5,467	5,768	6,157	3,687	8,115	142,002
Processing	NO	2,977	3,002	5,082	4,353	4,083	8,808
Transmission and Storage	228	276	205	553	943	415	1,149
Distribution	NO	NO	NO	NO	NO	NO	NO
Post-Meter	NO	NO	NO	NO	NO	NO	NO
Total	**4,599**	**10,428**	**9,123**	**11,906**	**9,029**	**12,628**	**151,986**

NO (Not Occurring)
Note: Totals may not sum due to independent rounding.

Table 3-78: N_2O Emissions from Natural Gas Systems (Metric Tons N_2O)

Segment	1990	2005	2018	2019	2020	2021	2022
Exploration	2.0	6.4	0.6	0.4	0.2	0.1	0.1
Production	14.5	20.6	21.8	23.2	13.9	30.6	535.9
Processing	NO	11.2	11.3	19.2	16.4	15.4	33.2
Transmission and Storage	0.9	1.0	0.8	2.1	3.6	1.6	4.3
Distribution	NO	NO	NO	NO	NO	NO	NO
Post-Meter	NO	NO	NO	NO	NO	NO	NO
Total	**17.4**	**39.3**	**34.4**	**44.9**	**34.1**	**47.7**	**573.5**

NO (Not Occurring)
Note: Totals may not sum due to independent rounding.

Methodology and Time-Series Consistency

See Annex 3.6 for the full time series of emissions data, activity data, and emission factors, and additional information on methods and data sources—for example, the specific years of reporting data from EPA's GHGRP that are used to develop certain factors.

This section provides a general overview of the methodology for natural gas system emission estimates in the *Inventory*, which involves the calculation of CH_4, CO_2, and N_2O emissions for over 100 emissions sources (i.e., equipment types or processes), 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 most sources, the approach uses technology-specific emission factors or emission factors that vary over time and take into account changes to technologies and practices, which are used to calculate net emissions directly. For others, the approach uses what are considered “potential methane factors” and emission reduction data to calculate net emissions. The estimates are developed with an IPCC Tier 2 approach. Tier 1 approaches are not used.

Emission Factors. Key references for emission factors for CH_4 and CO_2 emissions from the U.S. natural gas industry include a 1996 study published by the Gas Research Institute (GRI) and EPA (GRI/EPA 1996), EPA's GHGRP (EPA 2023b), and others.

The 1996 GRI/EPA study developed over 80 CH_4 emission factors to characterize emissions from the various components within the operating segments of the U.S. natural gas system. The GRI/EPA study was based on a combination of process engineering studies, collection of activity data, and measurements at representative natural gas facilities conducted in the early 1990s. Year-specific natural gas CH_4 compositions are calculated using U.S. Department of Energy’s Energy Information Administration (EIA) annual gross production data for National Energy Modeling System (NEMS) oil and gas supply module regions in conjunction with data from the Gas Technology Institute (GTI, formerly GRI) Unconventional Natural Gas and Gas Composition Databases (GTI 2001). These year-specific CH_4 compositions are applied to emission factors, which therefore may vary from year to year due to slight changes in the CH_4 composition of natural gas for each NEMS region.

GHGRP Subpart W data were used to develop CH_4, CO_2, and N_2O emission factors for many sources in the *Inventory*. In the exploration and production segments, GHGRP data were used to develop emission factors used for all years of the time series for well testing, gas well completions and workovers with and without hydraulic fracturing, pneumatic controllers and chemical injection pumps, condensate tanks, liquids unloading, miscellaneous flaring, gathering and boosting pipelines, and certain sources at gathering and boosting stations. In the processing segment, for recent years of the time series, GHGRP data were used to develop emission factors for leaks, compressors, flares, dehydrators, and blowdowns/venting. In the transmission and storage segment, GHGRP data were used to develop factors for all years of the time series for LNG stations and terminals and transmission pipeline blowdowns, and for pneumatic controllers for recent years of the time series.

Other data sources used for CH_4 emission factors include Zimmerle et al. (2015) for transmission and storage station leaks and compressors, GTI (2009 and 2019) for commercial and industrial meters, Lamb et al. (2015) for recent years for distribution pipelines and meter/regulator stations, Zimmerle et al. (2019) for gathering and boosting stations, Bureau of Ocean Energy Management (BOEM) reports, and Fischer et al. (2019) and IPCC (2019) for post-meter emissions.

For CO_2 emissions from sources in the exploration, production, and processing segments that use emission factors not directly calculated from GHGRP data, data from the 1996 GRI/EPA study and a 2001 GTI publication were used to adapt the CH_4 emission factors into related CO_2 emission factors. For sources in the transmission and storage segment that use emission factors not directly calculated from GHGRP data, and for sources in the distribution segment, data from the 1996 GRI/EPA study and a 1993 GTI publication were used to adapt the CH_4 emission factors into non-combustion related CO_2 emission factors. CO_2 emissions from post-meter sources (commercial, industrial and vehicles) were estimated using default emission factors from IPCC (2019). Carbon dioxide emissions from post-meter residential sources are included in fossil fuel combustion data.

Flaring N_2O emissions were estimated for flaring sources using GHGRP data.

See Annex 3.6 for more detailed information on the methodology and data used to calculate CH_4, CO_2, and N_2O emissions from natural gas systems.

Activity Data. Activity data were taken from various published data sets, as detailed in Annex 3.6. Key activity data sources include data sets developed and maintained by EPA's GHGRP (EPA 2023b); Enverus (Enverus 2023); BOEM; Federal Energy Regulatory Commission (FERC); EIA; the Natural Gas STAR and Methane Challenge Programs annual data; Oil and Gas Journal; and PHMSA.

For a few sources, recent direct activity data are not available. For these sources, either 2021 data were used as a proxy for 2022 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.

A complete list of references for emission factors and activity data by emission source is provided in Annex 3.6.

Calculating Net Emissions. For most sources, net emissions are calculated directly by applying emission factors to activity data. Emission factors used in net emission approaches reflect technology-specific information and take into account regulatory and voluntary reductions. However, for production, transmission and storage, and distribution, some sources are calculated using potential emission factors, and CH_4 that is not emitted is deducted from the total CH_4 potential estimates. To account for use of such technologies and practices that result in lower emissions but are not reflected in "potential" emission factors, data are collected on both regulatory and voluntary reductions. Regulatory actions addressed using this method include EPA National Emission Standards for Hazardous Air Pollutants (NESHAP) regulations for dehydrator vents. Voluntary reductions included in the *Inventory* are those reported to Natural Gas STAR and Methane Challenge for certain sources.

Methodological recalculations were applied to the entire time series to ensure time-series consistency from 1990 through 2022. GHGRP data available (starting in 2011) and other recent data sources have improved estimates of emissions from natural gas systems. To develop a consistent time series, for sources with new data, EPA reviewed available information on factors that may have resulted in changes over the time series (e.g., regulations, voluntary actions) and requested stakeholder feedback on trends as well. For most sources, EPA developed annual data for 1993 through 2010 by interpolating activity data or emission factors or both between 1992 and 2011 data points. Information on time-series consistency for sources updated in this year's *Inventory* can be found in the Recalculations Discussion below, with additional detail provided in supporting memos (relevant memos are cited in the Recalculations Discussion). For detailed documentation of methodologies, please see Annex 3.5.

The United States reports data to the UNFCCC using this *Inventory* report along with Common Reporting Tables (CRTs). This note is provided for those reviewing the CRTs: The notation key "IE" is used for CO_2 and CH_4 emissions from venting and flaring in CRT 1.B.2. Disaggregating flaring and venting estimates across the *Inventory* would involve the application of assumptions and could result in inconsistent reporting and, potentially, decreased transparency. Data availability varies across segments within oil and gas activities systems, and emission factor data available for activities that include flaring can include emissions from multiple sources (flaring, venting and leaks).

Uncertainty

EPA has conducted a quantitative uncertainty analysis using the IPCC Approach 2 methodology (Monte Carlo Simulation technique) to characterize the uncertainty for natural gas systems. For more information on the approach, please see the memoranda *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2016: Natural Gas and Petroleum Systems Uncertainty Estimates* (*2018 uncertainty memo*) and *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2019: Update for Natural Gas and Petroleum Systems CO_2 Uncertainty Estimates* (*2021* *uncertainty memo*).[79]

EPA used Microsoft Excel's @RISK add-in tool to estimate the 95 percent confidence bound around CH_4 and CO_2 emissions from natural gas systems for the current *Inventory*. For the CH_4 uncertainty analysis, EPA focused on the 17 highest-emitting sources for the year 2022, which together emitted 75 percent of methane from natural gas systems in 2022, and extrapolated the estimated uncertainty for the remaining sources. For the CO_2 uncertainty analysis, EPA focused on the three highest-emitting sources for the year 2022, which together emitted 81 percent of CO_2 from natural gas systems in 2022, and extrapolated the estimated uncertainty for the remaining sources. To estimate uncertainty for N_2O, EPA applied the uncertainty bounds calculated for CO_2. EPA will seek to refine this estimate in future Inventories. The @RISK add-in provides for the specification of probability density functions (PDFs) for key variables within a computational structure that mirrors the calculation of the inventory estimate. For emission factors that are derived from methane emissions measurement studies, the PDFs are commonly determined to be lognormally distributed (GRI/EPA 1996; GTI 2001; GTI 2009; Lamb et al. 2015; Zimmerle et al. 2015; Fischer et al. 2018; GTI 2019). For activity data that are derived from national datasets, the PDFs are set to a uniform distribution (see 2018 and 2021 uncertainty memos). Many emission factors and activity factors are calculated using Subpart W data, and for these, the @RISK add-in determines the best fitting PDF (e.g., lognormal, gaussian), based on bootstrapping of the underlying data (see 2018 and 2021 uncertainty memos). The IPCC guidance notes that in using this Approach 2 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." The uncertainty bounds reported below only reflect those uncertainties that EPA has been able to quantify and do not incorporate considerations such as modeling uncertainty, data representativeness, measurement errors, misreporting or misclassification. The understanding of the uncertainty of emission estimates for this category evolves and improves as the underlying methodologies and datasets improve.

The results presented below provide the 95 percent confidence bound within which actual emissions from this source category are likely to fall for the year 2022, using the IPCC methodology. The results of the Approach 2 uncertainty analysis are summarized in Table 3-79. Natural gas systems CH_4 emissions in 2022 were estimated to be between 141.2 and 203.0 MMT CO_2 Eq. at a 95 percent confidence level. Natural gas systems CO_2 emissions in 2022 were estimated to be between 31.9 and 42.1 MMT CO_2 Eq. at a 95 percent confidence level. Natural gas systems N_2O emissions in 2022 were estimated to be between 0.13 and 0.18 MMT CO_2 Eq. at a 95 percent confidence level.

Uncertainty bounds for other years of the time series have not been calculated, but uncertainty is expected to vary over the time series. For example, years where many emission sources are calculated with interpolated data would likely have higher uncertainty than years with predominantly year-specific data. In addition, the emission sources that contribute the most to CH_4 and CO_2 emissions are different over the time series, particularly when comparing recent years to early years in the time series. For example, venting emissions were higher and flaring emissions were lower in early years of the time series, compared to recent years. Technologies also changed over the time series (e.g., liquids unloading with plunger lifts and reduced emissions completions were not used early in the time series and cast iron distribution mains were more prevalent than plastic mains in early years). Transmission and gas processing compressor leak and vent emissions were also higher in the early years of the time series.

Table 3-79: Approach 2 Quantitative Uncertainty Estimates for CH_4 and Non-combustion CO_2 Emissions from Natural Gas Systems (MMT CO_2 Eq. and Percent)

Source	Gas	2022 Emission Estimate (MMT CO_2 Eq.)[b]	Uncertainty Range Relative to Emission Estimate[a] (MMT CO_2 Eq.)		(%)	
			Lower Bound[b]	Upper Bound[b]	Lower Bound[b]	Upper Bound[b]
Natural Gas Systems	CH_4	173.1	141.2	203.0	-18%	+17%

[79] See https://www.epa.gov/ghgemissions/natural-gas-and-petroleum-systems.

Natural Gas Systems	CO_2	36.5	31.9	42.1	-12%	+15%
Natural Gas Systems	N_2O	0.15	0.13	0.18	-12%	+15%

[a] Range of emission estimates estimated by applying the 95 percent confidence intervals obtained from the Monte Carlo simulation analysis conducted for the year 2022 CH_4 and CO_2 emissions.

[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 3-73 and Table 3-74.

QA/QC and Verification Discussion

In order to ensure the quality of the emission estimates for natural gas systems, general (IPCC Tier 1) Quality Assurance/Quality Control (QA/QC) procedures were implemented consistent with the U.S. Inventory QA/QC plan outlined in Annex 8.

The natural gas systems 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. The EPA has a multi-step data verification process for GHGRP data, including automatic checks during data-entry, statistical analyses on completed reports, and staff review of the reported data. Based on the results of the verification process, the EPA follows up with facilities to resolve mistakes that may have occurred.[80]

As in previous years, EPA conducted early engagement and communication with stakeholders on updates prior to public review of the current *Inventory*. EPA held a stakeholder webinar in October of 2023. EPA released memos detailing updates under consideration and requesting stakeholder feedback.

In recent years, several studies have measured emissions at the source level and at the national or regional level and calculated emission estimates that may differ from the *Inventory*. There are a variety of potential uses of data from new studies, including replacing a previous estimate or factor, verifying or QA of an existing estimate or factor, and identifying areas for updates. In general, there are two major types of studies related to oil and gas greenhouse gas data: studies that focus on measurement or quantification of emissions from specific activities, processes and equipment, and studies that use tools such as inverse modeling to estimate the level of overall emissions needed to account for measured atmospheric concentrations of greenhouse gases at various scales. The first type of study can lead to direct improvements to or verification of *Inventory* estimates. In the past few years, EPA has reviewed and, in many cases, incorporated data from these data sources. The second type of study can provide general indications of potential over- and under-estimates. In addition, in recent years information from top-down studies has been directly incorporated to quantify emissions from well blowouts.

A key challenge in using these types of studies to assess *Inventory* results is having a relevant basis for comparison (e.g., the two data sets should have comparable time frames and geographic coverage, and the independent study should assess data from the *Inventory* and not another data set, such as the Emissions Database for Global Atmospheric Research, or "EDGAR"). In an effort to improve the ability to compare the national-level *Inventory* with measurement results that may be at other spatial and temporal scales, EPA has developed a gridded inventory of U.S. anthropogenic methane emissions with 0.1 degree x 0.1 degree spatial resolution, monthly temporal resolution, and detailed scale-dependent error characterization.[81] The most recent version of the gridded methane inventory is designed to be consistent with the U.S. EPA's *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2018* estimates for the years 2012 to 2018. The gridded inventory improves efforts to compare results of this *Inventory* with atmospheric studies.

[80] See https://www.epa.gov/sites/production/files/2015-07/documents/ghgrp_verification_factsheet.pdf.

[81] See https://www.epa.gov/ghgemissions/us-gridded-methane-emissions.

Recalculations Discussion

EPA received information and data related to the emission estimates through GHGRP reporting and presented information to stakeholders regarding the updates under consideration. In November 2023, EPA released draft memoranda that discussed changes under consideration and requested stakeholder feedback on those changes. EPA then released final memoranda documenting the methodology implemented in the current Inventory.[82] Memoranda cited in the Recalculations Discussion below are: Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2022: Updates for Transmission Compressor Station Activity (*Transmission Station Activity* memo), Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2022: Updates for Completion and Workover Emissions (*Completions and Workovers* memo), and Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2022: Updates for Underground Natural Gas Storage Well Emission Events (*Storage Well Events* memo).

EPA evaluated relevant information available and made several updates to the *Inventory*, including for transmission compressor stations, completions and workovers, and underground natural gas storage wells. General information for these source specific recalculations are presented below and details are available in the *Transmission Station Activity*, *Completions and Workovers*, and *Storage Well Events* memos, including additional considerations for the updates.

In addition to the updates to the sources mentioned above, for certain sources, CH_4 and/or CO_2 emissions changed by greater than 0.05 MMT CO_2 Eq., comparing the previous estimate for 2021 to the current (recalculated) estimate for 2021. The emissions changes were mostly due to GHGRP data submission revisions. These sources are discussed below and include pneumatic controllers, well pad equipment leaks, condensate tanks, liquids unloading, gas engines (in production segment), miscellaneous production flaring, gathering and boosting (G&B) station blowdowns, G&B pneumatic controllers, G&B yard piping, G&B acid gas removal units (AGRU), natural gas processing flares, and transmission pipeline venting.

The combined impact of revisions to 2021 natural gas systems CH_4 emissions, compared to the previous *Inventory*, is a decrease from 181.4 to 174.6 MMT CO_2 Eq. (6.8 MMT CO_2 Eq., or 4 percent). The recalculations resulted in an average increase in the annual CH_4 emission estimates across the 1990 through 2021 time series, compared to the previous *Inventory*, of 1.9 MMT CO_2 Eq., or 0.8 percent.

The combined impact of revisions to 2021 natural gas systems CO_2 emissions, compared to the previous *Inventory*, is a decrease from 36.2 MMT to 35.8 MMT, or 1.1 percent. The recalculations resulted in an average increase in emission estimates across the 1990 through 2021 time series, compared to the previous *Inventory*, of 0.4 MMT CO_2 Eq., or 1.5 percent.

The combined impact of revisions to 2021 natural gas systems N_2O emissions, compared to the previous *Inventory*, is an increase from 7.6 kt CO_2 Eq. to 12.6 kt CO_2 Eq., or 65 percent. The recalculations resulted in an average increase in emission estimates across the 1990 through 2021 time series, compared to the previous *Inventory*, of 10.4 percent.

In Table 3-80 and Table 3-81 below are categories in natural gas systems with recalculations resulting in a change of greater than 0.05 MMT CO_2 Eq., comparing the previous estimate for 2021 to the current (recalculated) estimate for 2021. No changes made to N_2O estimates resulted in a change greater than 0.05 MMT CO_2 Eq. For more information, please see the Recalculations Discussion below.

[82] Stakeholder materials including draft and final memoranda for the current (i.e., 1990 to 2022) *Inventory* are available at https://www.epa.gov/ghgemissions/natural-gas-and-petroleum-systems.

Table 3-80: Recalculations of CO_2 in Natural Gas Systems (MMT CO_2)

Segment and Emission Sources with Changes of Greater than 0.05 MMT CO_2 due to Recalculations	*Previous Estimate Year 2021, 2023 Inventory*	Current Estimate Year 2021, 2024 *Inventory*	Current Estimate Year 2022, 2024 *Inventory*
Exploration	***+***	**+**	**+**
Gas Well Completions	*+*	+	+
Production	***9.1***	**9.3**	**8.6**
Gas Well Workovers	*+*	+	+
Pneumatic Controllers	*0.1*	+	+
Well Pad Equipment Leaks	*+*	0.1	0.1
Chemical Injection Pumps	*+*	+	+
Misc. Onshore Production Flaring	*1.0*	1.1	0.7
Condensate Tanks	*0.9*	1.1	0.6
G&B Station - AGRU	*2.3*	2.2	2.0
Processing	***26.1***	**25.5**	**26.7**
Flares	*7.4*	6.9	8.5
Transmission and Storage	***0.9***	**0.9**	**1.2**
Transmission Compressor Station Leaks and Venting	*0.1*	0.1	0.1
Storage Wells	*+*	+	+
Distribution	***+***	**+**	**+**
Post-Meter	***+***	**+**	**+**
Total	**36.2**	**35.8**	**36.5**

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

Table 3-81: Recalculations of CH_4 in Natural Gas Systems (MMT CO_2 Eq.)

Segment and Emission Sources with Changes of Greater than 0.05 MMT CO_2 due to Recalculations	*Previous Estimate Year 2021, 2023 Inventory*	Current Estimate Year 2021, 2024 *Inventory*	Current Estimate Year 2022, 2024 *Inventory*
Exploration	***0.2***	**0.1**	**0.2**
Gas Well Completions	*0.2*	0.1	0.2
Production	***94.1***	**92.2**	**89.7**
Gas Well Workovers	*0.2*	0.04	0.05
Well Pad Equipment Leaks	*9.6*	9.4	10.8
Pneumatic Controllers	*21.3*	20.9	18.0
Condensate Tanks	*1.2*	1.2	1.1
Liquids Unloading	*3.4*	2.8	2.4
Gas Engines	*5.5*	5.3	5.3
G&B Stations – Station Blowdowns	*1.2*	1.0	0.9
G&B Stations – Pneumatic Controllers	*0.7*	0.6	0.5
G&B Station – Yard Piping	*2.6*	2.7	2.8
Processing	***14.3***	**14.2**	**15.1**
Flares	*0.8*	0.8	0.9
Transmission and Storage	***44.5***	**39.8**	**39.6**
Transmission Compressor Station Leaks and Venting	*25.9*	21.3	21.5
Storage Wells	*0.3*	0.3	0.3
Pipeline Venting	*4.8*	4.6	3.7
Distribution	***15.3***	**15.3**	**15.2**
Post-Meter	***13.0***	**13.0**	**13.4**
Total	***181.4***	**174.6**	**173.1**

Note: Totals may not sum due to independent rounding.

Exploration

HF Completions (Methodological Update)

EPA updated the calculation methodology for HF completions to use basin-level HF completion counts from Enverus and basin-specific activity factors and emission factors calculated from Subpart W data for each control category (i.e., non-reduced emission completion (REC) with venting, non-REC with flaring, REC with venting, REC with flaring). Previously, national annual average activity and emission factors calculated using Subpart W data were applied to national completion counts to estimate HF gas well completion emissions. In this update, EPA developed national emission estimates by summing calculated basin-level total emission estimates. The *Completions and Workovers* memo presents additional information and considerations for this update.

EPA calculated basin-specific activity factors and CH_4 and CO_2 emission factors for all basins that reported Subpart W data. The factors were year-specific for reporting year (RY) 2011 through RY2022. For basin-level HF completion event counts, EPA used Enverus data for 1990 to 2010 and Subpart W for 2011 forward. For the fraction of completions in each control subcategory, EPA retained the previous *Inventory's* assumption that all HF gas well completions were non-REC for 1990 to 2000. The previous *Inventory* also assumed that 10 percent of HF completions were non-REC with flaring from 1990 to 2010 (based on national Subpart W data for RY2011 and RY2012); EPA updated this value using basin-specific Subpart W data for RY2011 and RY2012. For 2011 to 2022, EPA determined the percent contribution of each control category directly from Subpart W data and used linear interpolation between 2000 and 2011 to determine the percent of gas wells with RECs. EPA developed year- and basin-specific Subpart W EFs for 2011 forward. Year 2011 emission factors were applied to all prior years for each basin. For basins without Subpart W data available, EPA applied national average activity and emission factors (unweighted average of all Subpart W reported data).

Comparing the final completion emissions and those presented at the October 2023 webinar and in the November 2023 *Completions and Workovers* memo, the final estimates are higher for certain completion categories. These emissions increases are due not to the basin-level methodology changes discussed here but rather to changes in the Enverus dataset. EPA applied the same data processing steps to Enverus data in the fall of 2023 as it did for the previous Enverus data analysis (conducted in 2021) and data changes led to many more completions being classified as HF completions.

As a result of this methodological update, CH_4 emissions estimates for HF completions are on average 55 percent higher across the time series than in the previous *Inventory*. The 2021 CH_4 emissions estimate is 54 percent lower than in the previous *Inventory*. The largest increase between the updates and the previous *Inventory* for CH_4 emissions is 134 percent in 1998 with an average increase of 92 percent over the 1990 through 2010 time period. CH_4 emissions decreased or were similar for 2011 forward and the largest decrease between the updates and the previous *Inventory* is 54 percent in 2021. CH_4 emissions increased on average across the time series, but particularly in earlier years due to gas well HF completions that were non-REC with venting, particularly in the Appalachian basin (Eastern Overthrust) [basin 160a]. The Appalachian basin (Eastern Overthrust) had a large number of gas well HF completion events that were non-REC with venting and the highest EF of any basin. The update resulted in CO_2 emissions estimates that are on average 54 percent higher across the time series than in the previous *Inventory*. The 2021 CO_2 emissions estimate is 3 percent lower than in the previous *Inventory*. The largest increase between the updates and the previous *Inventory* for CO_2 emissions is 141 percent in 1996, and the largest decrease between the updates and the previous *Inventory* is 44 percent in 2013. CO_2 emissions increased predominantly due to non-REC with flaring events in the Appalachian basin (basin 160A) and the East Texas basin (basin 260); these two basins had the highest EFs of any basin.

Table 3-82: HF Completions National CH_4 Emissions (Metric Tons CH_4)

Source	1990	2005	2018	2019	2020	2021	2022
HF Completions – Non-REC with Venting	187,841	590,423	1,210	678	75	166	83
HF Completions – Non-REC with Flaring	3,112	11,791	652	399	154	31	1,605
HF Completions - REC with Venting	NO	6,710	28,946	18,150	4,594	2,487	3,376

HF Completions - REC with Flaring	NO	2,238	1,345	1,148	634	127	190
Total Emissions	**190,954**	**611,162**	**32,154**	**20,375**	**5,458**	**2,811**	**5,253**
Previous Estimate	*111,265*	*345,098*	*32,147*	*20,002*	*5,220*	*6,111*	*NA*

NO (Not Occurring)
NA (Not Applicable)

Table 3-83: HF Completions National CO_2 Emissions (kt CO_2)

Source	1990	2005	2018	2019	2020	2021	2022
HF Completions – Non-REC with Venting	15	50	+	+	+	+	+
HF Completions – Non-REC with Flaring	472	2,023	57	43	10	2	5
HF Completions - REC with Venting	NO	4	3	+	+	+	+
HF Completions - REC with Flaring	NO	496	233	199	87	13	31
Total Emissions	**487**	**2,573**	**293**	**243**	**97**	**15**	**36**
Previous Estimate	*289*	*1,418*	*290*	*214*	*96*	*15*	*NA*

+ Does not exceed 0.5 kt.
NO (Not Occurring)
NA (Not Applicable)

Non-HF Completions (Methodological Update)

EPA updated the activity data sources and calculation methodology for non-HF completions to use basin-level non-HF completion counts from Enverus and basin-specific activity factors and emission factors, calculated from Subpart W data for each control category (i.e., vented, flared). Previously, national non-HF completion counts and national annual average activity and emission factors calculated using historical data analyses, and Subpart W data were applied to estimate non-HF gas well completion emissions. In this update, EPA developed national emission estimates by summing calculated basin-level total emission estimates. The *Completions and Workovers* memo presents additional information and considerations for this update.

EPA calculated basin-specific activity factors and CH_4 and CO_2 emission factors for all basins that reported Subpart W data. The factors were year-specific for reporting year (RY) 2011 through RY2022. For basin-level non-HF gas well completion event counts, EPA used Enverus data across the time series. For the fraction of completions in each control category, EPA implemented at the basin level the previous *Inventory's* approach and the percent of non-HF gas well completions that are vented in 2011 is applied to all prior years. For 2011 to 2022, EPA determined the percent contribution of each control category directly from Subpart W data for each basin. EPA developed year- and basin-specific Subpart W EFs for 2011 forward. Year 2011 emission factors were applied to all prior years for each basin. For basins without Subpart W data available, EPA applied national average activity and emission factors (unweighted average of all Subpart W reported data).

As a result of this methodological update, CH_4 emissions estimates for non-HF completions are on average 419 percent higher across the time series than in the previous *Inventory*. The 2021 CH_4 estimate is 43 percent higher than in the previous *Inventory*. The largest increase between the updates and the previous *Inventory* for CH_4 emissions is 1,533 percent in 1991, and the largest decrease between the updates and the previous *Inventory* is 63 percent in 2018. Methane emissions increased primarily due to gas well non-HF completions that were vented. The Appalachian basin (Eastern Overthrust) [basin 160a] and the Appalachian basin (basin 160) had many non-HF completion events that were vented and average EFs more than 2 times higher than the national average across the 1990-2022 time series. The update resulted in CO_2 emissions estimates that are on average 1,312 percent higher across the time series than in the previous *Inventory*. The 2021 CO_2 emissions estimate is 7,331 percent higher than in the previous *Inventory*. The largest increase between the updates and the previous *Inventory* for CO_2 emissions is 7,331 percent in 2021, and the largest decrease between the updates and the previous *Inventory* is 47 percent in 2018. The increase in CO_2 emissions is due to non-HF completions that were flared, primarily in the Gulf Coast basin (basin 220). The Gulf Coast basin had the highest fraction of non-HF completions that were flared of any basin.

Table 3-84: Non-HF Completions National CH_4 Emissions (Metric Tons CH_4)

Source	1990	2005	2018	2019	2020	2021	2022
Non-HF Completions - vented	44,362	84,955	79	319	1,548	284	159
Non-HF Completions - flared	547	545	113	+	NO	98	NO
Total Emissions	**44,909**	**85,500**	**192**	**320**	**1,548**	**381**	**159**
Previous Estimate	*5,736*	*10,363*	*513*	*796*	*2,659*	*267*	*NA*

+ Does not exceed 0.5 MT.
NO (Not Occurring)
NA (Not Applicable)

Table 3-85: Non-HF Completions National CO_2 Emissions (Metric Tons CO_2)

Source	1990	2005	2018	2019	2020	2021	2022
Non-HF Completions - vented	1,398	3,531	1	8	197	8	549
Non-HF Completions - flared	127,316	126,743	15,699	42	NO	16,449	NO
Total Emissions	**128,714**	**130,274**	**15,700**	**50**	**197**	**16,457**	**549**
Previous Estimate	*4,862*	*8,784*	*29,834*	*81*	*364*	*221*	*NA*

NO (Not Occurring)
NA (Not Applicable)

Production

HF Workovers (Methodological Update)

EPA updated the activity data source and calculation methodology for HF workovers to use basin-specific activity factors and emission factors, calculated from Subpart W data for each control category (i.e., non-reduced emission completion (REC) with venting, non-REC with flaring, REC with venting, REC with flaring). Previously, national HF workover counts calculated using analyses for NSPS OOOO (i.e., 1 percent of HF gas wells were worked over annually) and national annual average emission factors calculated using Subpart W data were applied to estimate HF gas well workover emissions. In this update, EPA developed national emission estimates by summing calculated basin-level total emission estimates. The *Completions and Workovers* memo presents additional information and considerations for this update.

EPA calculated basin-specific activity factors and CH_4 and CO_2 emission factors for all basins that reported Subpart W data. For basin-level workover counts, instead of applying a 1 percent workover rate to HF gas wells, EPA developed year- and basin-specific Subpart W AFs for 2015 forward that represent the number of HF workovers per gas well. Year 2015 Subpart W AFs were applied to all prior years for each basin. For the fraction of workovers in each control subcategory, EPA retained the previous *Inventory's* assumption that all HF gas well workovers were non-REC for 1990 to 2000. The previous Inventory also assumed that 10 percent of HF workovers were non-REC with flaring from 1990 to 2010; EPA updated this value using basin-specific data from Subpart W. For 2011 forward, EPA determined the percent contribution of each control category directly from Subpart W data at the basin-level. EPA used linear interpolation for interpolation between 2000 and 2011 to determine the percent of gas wells with RECs. EPA developed year-and basin-specific Subpart W EFs for 2011 forward. Year 2011 emission factors were applied to all prior years for each basin. For basins without Subpart W data available, EPA applied national average activity and emission factors (unweighted average of all Subpart W reported data).

As a result of this methodological update, CH_4 emissions estimates for HF workovers are on average 43 percent lower across the time series than in the previous *Inventory*. The 2021 CH_4 emissions estimate is 94 percent lower than in the previous *Inventory*. The largest increase between the updates and the previous *Inventory* for CH_4 emissions is 5 percent in 1990, and the largest decrease between the updates and the previous *Inventory* is 99 percent in 2019. The update resulted in CO_2 emissions estimates that are on average 60 percent lower than in the previous *Inventory*. The 2021 CO_2 emissions estimate is 67 percent lower than in the previous *Inventory*. The largest increase between the updates and the previous *Inventory* for CO_2 emissions is 53 percent in 2013, and the largest decrease between the updates and the previous *Inventory* is 99 percent in 2019. The decrease in emissions for both CH_4 and CO_2 was primarily due to the change in calculation method for workover counts. HF gas well workover counts decreased by an average of 73 percent across the 1990 through 2021 time series compared to the previous *Inventory*.

Table 3-86: HF Workovers National CH_4 Emissions (Metric Tons CH_4)

Source	1990	2005	2018	2019	2020	2021	2022
HF Workovers – Non-REC with Venting	22,198	37,917	114	96	4	17	35
HF Workovers – Non-REC with Flaring	242	483	29	2	1	+	19
HF Workovers - REC with Venting	NO	231	1,667	73	229	457	113
HF Workovers - REC with Flaring	NO	+	6	4	1	2	17
Total Emissions	**22,440**	**38,632**	**1,816**	**174**	**234**	**476**	**185**
Previous Estimate	*21,427*	*57,972*	*19,594*	*13,612*	*6,771*	*8,144*	*NA*

+ Does not exceed 0.5 mt.
NO (Not Occurring)
NA (Not Applicable)

Table 3-87: HF Workovers National CO_2Emissions (kt CO_2)

Source	1990	2005	2018	2019	2020	2021	2022
HF Workovers – Non-REC with Venting	1	2	+	+	+	+	+
HF Workovers – Non-REC with Flaring	32	67	2	+	+	+	+
HF Workovers - REC with Venting	NO	+	+	+	+	+	+
HF Workovers - REC with Flaring	NO	+	1	+	+	+	3
Total Emissions	**33**	**69**	**4**	**1**	**+**	**+**	**3**
Previous Estimate	*56*	*165*	*99*	*86*	*8*	*1*	*NA*

+ Does not exceed 0.5 kt.
NO (Not Occurring)
NA (Not Applicable)

Non-HF Workovers (Methodological Update)

EPA updated the activity data source and calculation methodology for non-HF workovers to use basin-specific activity factors and emission factors, calculated from Subpart W data for each control category (i.e., vented, flared). Previously, national annual average activity and emission factors calculated using historical data analyses and Subpart W data were applied along with national gas well counts to estimate non-HF gas well workover emissions. In this update, EPA developed national emission estimates by summing calculated basin-level total emission estimates. The *Completions and Workovers* memo presents additional information and considerations for this update.

EPA calculated basin-specific activity factors and CH_4 and CO_2 emission factors for all basins that reported Subpart W data. For basin-level workover counts, EPA developed year-specific Subpart W AFs for 2015 forward. Year 2015 Subpart W data was applied to prior years for each basin. For the fraction of workovers in each control subcategory, EPA applied year- and basin-specific AFs for 2011 forward, retained the previous *Inventory's* assumption that all non-HF workovers were vented in 1990 to 1992, and used linear interpolation between the 1992 and 2011 activity factors at the basin-level. EPA developed year- and basin-specific Subpart W EFs for 2011 forward. Year 2011 emission factors were applied to all prior years for each basin. For basins without Subpart W data available, EPA applied national average activity and emission factors (unweighted average of all Subpart W reported data).

As a result of this methodological update, CH_4 emissions estimates for non-HF workovers are on average 277 percent higher than in the previous *Inventory*. The 2021 estimate is 180 percent higher than in the previous *Inventory*. The largest increase between the estimates and the previous *Inventory* for CH_4 emissions is 698 percent in 2017, and the smallest increase is 78 percent in 2018. The increase in CH_4 emissions is due to non-HF workovers that were vented. In the Chautauqua Platform basin (basin 355), all non-HF workovers were vented, and it had the highest CH_4 EF in 2017. The update resulted in CO_2 emissions estimates for non-HF workovers that are higher across the entire time series than the previous *Inventory* (on average 3,067 percent higher). The 2021 CO_2 emissions estimate is 116 percent higher than in the previous *Inventory*. The largest increase between estimates and the previous *Inventory* for CO_2 emissions is 7,432 percent in 1994, and the smallest increase is 78 percent in 2018. The increase in CO_2 emissions is due to non-HF workovers that were flared, particularly in the Bend Arch basin (basin 425). The Bend Arch basin has a high non-HF completion per total gas well AF and a high fraction of non-HF workovers that were flared compared to other basins over the time series.

Table 3-88: Non-HF Workovers National CH_4 Emissions (Metric Tons CH_4)

Source	1990	2005	2018	2019	2020	2021	2022
Non-HF Workovers - vented	1,415	2,083	1,139	866	959	1,068	1,594
Non-HF Workovers - flared	NO	1,077	1	5	+	43	3
Total Emissions	**1,415**	**3,159**	**1,140**	**870**	**959**	**1,111**	**1,597**
Previous Estimate	*532*	*752*	*415*	*436*	*259*	*396*	*NA*

+ Does not exceed 0.5 MT.
NO (Not Occurring)
NA (Not Applicable)

Table 3-89: Non-HF Workovers National CO_2 Emissions (Metric Tons CO_2)

Source	1990	2005	2018	2019	2020	2021	2022
Non-HF Workovers - vented	87	180	61	51	2,163	199	460
Non-HF Workovers - flared	NO	174,881	269	665	34	9,591	424
Total Emissions	**87**	**175,062**	**329**	**716**	**2,197**	**9,790**	**885**
Previous Estimate	*32*	*3,701*	*185*	*294*	*476*	*4,539*	*NA*

NO (Not Occurring)
NA (Not Applicable)

Equipment Leaks (Methodological Update)

In the previous *Inventory*, EPA updated the CH_4 emissions calculation methodology for onshore production equipment leaks to use basin-specific equipment-level activity factors (e.g., separators per well) from GHGRP data. However, the CO_2 emissions calculation methodology was not updated and instead the previous *Inventory* still relied on a national-level methodology to estimate CO_2 emissions. For this year's *Inventory*, EPA calculated equipment leak CO_2 emissions in the same manner as CH_4 emissions. EPA calculated CO_2 estimates using the basin-specific equipment-level activity factors for RY2015 through RY2022 from GHGRP, consistent with the methodology used to calculate the CH_4 activity factors, and the CO_2 emissions factors for onshore production segment equipment leaks. Note, this methodological update applies only for activity factors. The previous *Inventory's* CO_2 emission factors for onshore production segment equipment leaks (by equipment type) were retained and used to develop CO_2 estimates.

The update for CO_2 emission estimates for equipment leaks resulted in an average increase of 12 percent across the time series compared to the previous *Inventory*. Years 1990 through 2002 were minimally impacted by the updates, with an increase of 2 percent for CO_2 emissions. Years 2020 and 2021 showed larger increases of 69 and 48 percent for 2020 and 2021, respectively, which is mostly due to much higher emissions from meters and piping in the Powder River Basin.

Methane emissions for equipment leaks were impacted due to recalculations with updated data. CH_4 emission estimates were an average of 5 percent lower across the time series compared to the previous *Inventory*. The 2021 CH_4 estimate is 2 percent lower in 2021 compared to the previous *Inventory*. These CH_4 emissions changes were due to GHGRP submission revisions.

Table 3-90: Production Equipment Leaks National CO_2 Emissions (Metric Tons CO_2)

Source	1990	2005	2018	2019	2020	2021	2022
Heaters	1,639	3,642	10,485	3,412	4,261	4,014	4,359
Separators	5,372	14,404	19,114	19,689	21,306	17,239	15,518
Dehydrators	1,261	1,690	794	677	589	893	683
Meters/Piping	5,400	10,527	11,199	11,775	30,564	24,424	11,022
Compressors	2,673	7,178	7,818	7,236	6,966	9,079	20,310
Total Emissions	**16,344**	**37,441**	**49,410**	**42,789**	**63,686**	**55,649**	**51,893**
Previous Estimate	*18,497*	*33,300*	*38,458*	*37,974*	*37,608*	*37,608*	*NA*

NA (Not Applicable)

Table 3-91: Production Equipment Leaks National CH_4 Emissions (Metric Tons CH_4)

Source	1990	2005	2018	2019	2020	2021	2022
Heaters	12,305	18,436	79,890	16,158	18,568	17,581	18,476
Separators	41,579	80,745	121,349	126,037	129,133	109,610	94,591
Dehydrators	12,904	11,381	5,449	3,656	3,070	4,078	3,105
Meters/Piping	43,055	63,764	79,864	84,730	153,917	130,390	75,719
Compressors	30,307	61,753	71,705	64,771	60,637	73,636	193,389
Total Emissions	**140,150**	**236,079**	**358,256**	**295,352**	**365,325**	**335,295**	**385,280**
Previous Estimate	*137,647*	*262,188*	*363,367*	*298,930*	*369,466*	*343,686*	*NA*

NA (Not Applicable)

Chemical Injection Pumps (Methodological Update)

In the previous *Inventory*, EPA updated the CH_4 emissions calculation methodology for chemical injection pumps to use basin-specific equipment-level activity factors (e.g., pumps per well) from GHGRP data. However, the CO_2 emissions calculation methodology was not updated and instead the previous *Inventory* still relied on a national-level methodology to estimate CO_2 emissions. For the current *Inventory*, EPA calculated chemical injection pump CO_2 emissions in the same manner as CH_4 emissions. EPA calculated CO_2 estimates using the basin-specific equipment-level activity factors for RY2015 through RY2022 from GHGRP, consistent with the methodology used to calculate the CH_4 activity factors, and the CO_2 emission factor. Note, this methodological update applies only for activity factors. The previous *Inventory's* chemical injection pumps CO_2 emission factor was retained and used to develop CO_2 estimates.

The update for CO_2 emission estimates resulted in an average decrease of 9 percent across the time series compared to the previous *Inventory*. There were larger decreases of 31 and 39 percent for 2020 and 2021, respectively. The recent years of the time series used basin-specific activity factors and certain basins had lower activity factors compared to the national average factors (e.g., Permian Basin, Denver Basin, San Juan, Paradox, AK Cook Inlet).

Table 3-92: Chemical Injection Pumps National CO_2 Emissions (Metric Tons CO_2)

Source	1990	2005	2018	2019	2020	2021	2022
Chemical Injection Pumps	2,153	6,749	10,254	9,392	7,339	6,469	6,428
Previous Estimate	*2,275*	*7,760*	*11,053*	*10,899*	*10,635*	*10,635*	*NA*

NA (Not Applicable)

Pneumatic Controllers (Methodological Update)

In the previous *Inventory*, EPA updated the CH_4 emissions calculation methodology for pneumatic controllers to use basin-specific activity factors and emission factors by bleed type (i.e., low, high, intermittent bleed) from GHGRP data. However, the CO_2 emissions calculation methodology was not updated and instead the previous

Inventory still relied on a national-level methodology to estimate CO_2 emissions. For the current *Inventory*, EPA calculated pneumatic controller CO_2 emissions using basin-specific emissions data such that the CO_2 emissions reflect the unique CO_2 composition of the gas in a basin.

The update for pneumatic controller CO_2 emission estimates resulted in an average decrease of 44 percent across the time series compared to the previous *Inventory*. This average decrease is generally consistent for all years.

Methane emissions for pneumatic controllers were impacted due to recalculations with updated data. Methane emissions estimates are on average 0.3 percent lower across the time-series than in the previous *Inventory*. The estimate for 2021 is 2 percent lower than in the previous *Inventory*. These changes were due to GHGRP submission revisions.

Table 3-93: Pneumatic Controllers National CO_2 Emissions (Metric Tons CO_2)

Source	1990	2005	2018	2019	2020	2021	2022
Low Bleed Controllers	NO	1,318	2,325	2,283	2,047	1,773	2,180
High Bleed Controllers	23,058	32,794	4,378	2,898	2,373	2,418	1,726
Intermittent Bleed Controllers	15,076	41,267	56,974	57,147	48,052	44,964	37,897
Total Emissions	**38,135**	**75,378**	**63,677**	**62,328**	**52,472**	**49,155**	**41,803**
Previous Estimate	*70,028*	*129,648*	*115,235*	*115,591*	*98,144*	*91,662*	*NA*

NO (Not Occurring)
NA (Not Applicable)

Table 3-94: Pneumatic Controllers National CH_4 Emissions (Metric Tons CH_4)

Source	1990	2005	2018	2019	2020	2021	2022
Low Bleed Controllers	NO	22,656	33,220	31,099	27,238	25,247	29,877
High Bleed Controllers	355,671	480,272	86,764	52,676	42,269	41,435	30,700
Intermittent Bleed Controllers	233,661	565,070	830,140	875,168	748,219	680,708	583,144
Total Emissions	**589,332**	**1,067,997**	**950,124**	**958,943**	**817,727**	**747,391**	**643,721**
Previous Estimate	*581,039*	*1,075,712*	*956,125*	*959,080*	*814,318*	*760,534*	*NA*

NO (Not Occurring)
NA (Not Applicable)

Storage Tanks (Recalculation with Updated Data)

Methane emissions for production condensate storage tanks are on average lower than the previous *Inventory* by less than 0.1 percent across the 1990 to 2021 time series. The 2021 estimate is 6 percent lower than in the previous *Inventory*. The production storage tanks CO_2 emissions estimates are on average 3 percent higher across the 1990 to 2021 time series than in the previous Inventory. The 2021 estimate is 25 percent higher than in the previous *Inventory*. These changes were due to GHGRP submission revisions.

Table 3-95: Storage Tanks National CH_4 Emissions (Metric Tons CH_4)

Source	1990	2005	2018	2019	2020	2021	2022
Large Tanks w/Flares	520	337	1,284	819	765	715	467
Large Tanks w/VRU	NO	27	141	464	743	597	94
Large Tanks w/o Control	16,743	6,828	15,179	3,149	5,323	4,205	3,319
Small Tanks w/Flares	NO	51	235	207	200	161	166
Small Tanks w/o Flares	92,334	31,003	43,050	61,331	47,423	35,460	33,455
Malfunctioning Separator Dump Valves	7	4	40	79	255	212	67
Total Emissions	109,605	38,250	59,929	66,049	54,708	41,351	37,567
Previous Estimate	*106,429*	*38,461*	*60,556*	*67,595*	*53,613*	*44,217*	*NA*

NO (Not Occurring)
NA (Not Applicable)

Table 3-96: Storage Tanks National CO_2 Emissions (kt CO_2)

Source	1990	2005	2018	2019	2020	2021	2022
Large Tanks w/Flares	587	421	1,476	974	1,108	1,049	575
Large Tanks w/VRU	NO	2	+	+	1	1	+
Large Tanks w/o Control	2	1	36	1	1	1	+
Small Tanks w/Flares	NO	13	86	82	41	27	20
Small Tanks w/o Flares	48	17	26	32	23	17	18
Malfunctioning Separator Dump Valves	+	+	+	+	1	+	+
Total Emissions	**637**	**455**	**1,625**	**1,089**	**1,175**	**1,094**	**613**
Previous Estimate	*628*	*456*	*1,507*	*956*	*862*	*873*	*NA*

+ Does not exceed 0.5 kt.
NO (Not Occurring)
NA (Not Applicable)

Liquids Unloading (Recalculation with Updated Data)

Liquids unloading CH_4 emissions estimates decreased by an average of 9 percent across the 1990 to 2021 time series compared with the previous *Inventory*. The 2021 estimate decreased by 17 percent compared with the previous *Inventory*. These changes were due to GHGRP submission revisions.

Table 3-97: Liquids Unloading National CH_4 Emissions (Metric Tons CH_4)

Source	1990	2005	2018	2019	2020	2021	2022
Liquids Unloading With Plunger Lifts	0	128,295	82,501	75,081	51,457	33,916	30,384
Liquids Unloading Without Plunger Lifts	77,767	198,728	132,866	104,484	84,251	65,655	54,227
Total Emissions	**77,767**	**327,023**	**215,367**	**179,565**	**135,707**	**99,572**	**84,611**
Previous Estimate	*76,815*	*358,925*	*265,173*	*209,964*	*158,968*	*120,145*	*NA*

NA (Not Applicable)

Gas Engines (Recalculation with Updated Data)

Gas engines CH_4 emissions estimates are on average 2 percent lower across the 1990 to 2021 time series compared with the previous *Inventory*. The 2021 estimate is 4 percent lower than in the previous *Inventory*. These changes were due to revisions to Enverus data.

Table 3-98: Production Gas Engines National CH_4 Emissions (Metric Tons CH_4)

Source	1990	2005	2018	2019	2020	2021	2022
Gas Engines	116,587	194,140	201,660	196,996	192,854	188,374	188,611
Previous Estimate	*115,689*	*198,005*	*207,052*	*202,060*	*197,027*	*197,027*	*NA*

NA (Not Applicable)

Miscellaneous Production Flaring (Recalculation with Updated Data)

Miscellaneous production flaring CO_2 emissions estimates are on average 1 percent higher across the 1993 to 2021 time series compared with the previous *Inventory*, and the 2021 estimate is 12 percent higher compared to the previous *Inventory*. These changes were due to GHGRP submission revisions.

Table 3-99: Miscellaneous Production Flaring National Emissions (kt CO_2)

Source	1990	2005	2018	2019	2020	2021	2022
Miscellaneous Flaring-Gulf Coast Basin	NO	164	135	395	251	316	206
Miscellaneous Flaring-Williston Basin	NO	+	6	3	4	7	+
Miscellaneous Flaring-Permian Basin	NO	263	690	926	808	578	231

Miscellaneous Flaring-Other Basins	NO	117	476	334	237	211	238
Total Emissions	**NO**	**544**	**1,308**	**1,659**	**1,301**	**1,112**	**676**
Previous Estimate	*NO*	*543*	*1,326*	*1,595*	*1,298*	*991*	*NA*

+ Does not exceed 0.5 kt.
NO (Not Occurring)
NA (Not Applicable)

Gathering and Boosting – Station Blowdowns (Recalculation with Updated Data)

Methane emissions estimates for gathering and boosting station blowdowns are on average 0.7 percent lower across the 1990 to 2021 time series than in the previous *Inventory*. The 2021 estimate is 17 percent lower than in the previous *Inventory*. These changes were due to GHGRP submission revisions.

Table 3-100: Station Blowdowns National Emissions (Metric Tons CH_4)

Source	1990	2005	2018	2019	2020	2021	2022
Station Blowdowns	20,218	26,155	79,313	39,059	40,519	35,161	32,036
Previous Estimate	*20,517*	*26,113*	*78,548*	*38,412*	*40,468*	*42,231*	*NA*

NA (Not Applicable)

Gathering and Boosting – Pneumatic Controllers (Recalculation with Updated Data)

Gathering and boosting pneumatic controllers CH_4 emissions estimates are on average 0.1 percent higher across the 1990 to 2021 time series compared with the previous *Inventory*. The emissions estimate for 2021 is 2 percent lower than in the previous *Inventory*, largely because of a decrease in emissions from high-bleed pneumatic devices. These changes were due to GHGRP submission revisions.

Table 3-101: Pneumatic Controllers National Emissions (Metric Tons CH_4)

Source	1990	2005	2018	2019	2020	2021	2022
High-Bleed Pneumatic Devices	17,092	22,111	25,030	24,187	22,981	20,709	18,854
Intermittent Bleed Pneumatic Devices	78,424	101,451	173,929	184,542	171,679	156,842	145,574
Low-Bleed Pneumatic Devices	2,713	3,509	5,799	6,996	6,965	6,564	6,572
Total Emissions	**98,229**	**127,072**	**204,758**	**215,725**	**201,625**	**184,116**	**171,000**
Previous Estimate	*99,843*	*127,073*	*204,748*	*215,339*	*201,415*	*187,290*	*NA*

NA (Not Applicable)

Gathering and Boosting – Acid Gas Removal Units (Recalculation with Updated Data)

Carbon dioxide emissions estimates for acid gas removal units (AGRU) are on average 0.3 percent lower across the 1990 to 2021 time series compared with the previous *Inventory*. The emissions estimate for 2021 decreased by 4 percent compared to the previous *Inventory*. These changes were due to GHGRP submission revisions.

Table 3-102: Acid Gas Removal Units National Emissions (kt CO_2)

Source	1990	2005	2018	2019	2020	2021	2022
AGRU	241	311	707	1,191	1,629	2,222	2,044
Previous Estimate	*245*	*311*	*707*	*1,288*	*1,655*	*2,304*	*NA*

NA (Not Applicable)

Gathering and Boosting – Yard Piping (Recalculation with Updated Data)

Methane emissions estimates for yard piping are on average 0.6 percent higher across the 1990 to 2021 time series compared with the previous *Inventory*. The emissions estimate for 2021 is 4 percent higher than in the previous *Inventory*. These changes were due to GHGRP submission revisions.

Table 3-103: Yard Piping National Emissions (Metric Tons CH_4)

Source	1990	2005	2018	2019	2020	2021	2022
Yard Piping	36,319	46,984	86,270	94,306	94,463	96,785	101,777
Previous Estimate	*36,773*	*46,802*	*85,996*	*94,191*	*93,253*	*93,253*	*NA*

NA (Not Applicable)

Processing

Flares (Recalculation with Updated Data)

Processing segment flare CH_4 emission estimates are on average 0.5 percent lower across the 1993 to 2021 time series than in the previous *Inventory*. The CH_4 estimate for 2021 is 7 percent lower than in the previous Inventory. The processing segment flare CO_2 emission estimates decreased by an average of 0.4 percent over the 1993 to 2021 time series, while the CO_2 estimate for 2021 decreased by 6 percent compared to the previous *Inventory*. These changes were due to GHGRP submission revisions.

Table 3-104: Processing Segment Flares National CH_4 Emissions (Metric Tons CH_4)

Source	1990	2005	2018	2019	2020	2021	2022
Flares	NO	NA	24,173	43,887	36,985	26,807	33,586
Previous Estimate	*NO*	*NA*	*24,148*	*43,613*	*36,928*	*28,784*	*NA*

NA (Not Applicable)
NO (Not Occurring)

Table 3-105: Processing Segment Flares National CO_2 Emissions (kt CO_2)

Source	1990	2005	2018	2019	2020	2021	2022
Flares	NO	3,517	5,948	9,776	8,121	6,941	8,533
Previous Estimate	*NO*	*3,517*	*5,945*	*9,859*	*8,120*	*7,381*	*NA*

NA (Not Applicable)
NO (Not Occurring)

Transmission and Storage

Transmission Compressor Station Leaks and Venting (Methodological Update)

EPA updated the methodology to estimate national level activity data for transmission compressor stations (i.e., station and compressor counts). EPA used annual data for 1996 to 2022 from FERC and PHMSA to estimate national transmission station counts and total transmission compressor counts. FERC requires major interstate transmission compression facilities to report annual data on station counts, total compressor counts, and total transmission pipeline miles. EPA compiled annual FERC data and scaled it up to the national level using PHMSA national transmission pipeline miles for 1996 to 2022. EPA retained existing *Inventory* activity data for 1990 to 1992 and used linear interpolation to estimate national station and total compressor counts for 1993 to 1995.

Total compressor counts were apportioned to reciprocating and centrifugal compressor types using data from GHGRP's Subpart W. EPA retained existing *Inventory* activity data for 1990 to 1992 and used linear interpolation for intermediate time series years. For more details on this update, refer to the *Transmission Station Activity* memo.

This update impacts CH_4 and CO_2 emissions from leaks (including compressor leaks), dehydrator vents, pneumatic devices, flaring, and venting at transmission compression stations. As a result of this update, CH_4 emissions estimates increased by an average of 2.6 percent across the time series and decreased by 18 percent in 2021, compared to the previous *Inventory*. Emissions estimates of CO_2 increased by an average of 2.5 percent across the time series and decreased by 16 percent in 2021, compared to the previous *Inventory*.

Table 3-106: Transmission Compressor Station National CH_4 Emissions (Metric Tons CH_4)

Source	1990	2005	2018	2019	2020	2021	2022
Station Total Emissions	1,096,527	704,651	581,117	585,617	580,273	585,666	588,497
Station + Compressor Fugitive Emissions	NE	NE	118,592	120,704	120,256	125,440	128,128
Reciprocating Compressor	NE	NE	347,685	342,485	333,385	325,130	322,725
Centrifugal Compressor (wet seals)	NE	NE	50,116	51,544	52,360	53,652	50,524
Centrifugal Compressor (dry seals)	NE	NE	64,724	70,884	74,272	81,444	87,120
Dehydrator vents	1,991	1,931	2,132	2,170	2,162	2,255	2,304
Flaring	305	296	606	432	522	364	492
Pneumatic Devices	213,081	87,701	31,749	31,640	30,120	30,585	31,170
High Bleed	NE	NE	9,781	9,797	9,119	8,951	8,350
Intermittent Bleed	NE	NE	21,132	21,074	20,222	20,882	22,157
Low Bleed	NE	NE	836	769	779	753	663
Station Venting	145,241	138,843	127,165	136,920	136,332	143,132	146,659
Total Emissions	**1,457,144**	**933,422**	**742,770**	**756,779**	**749,409**	**762,002**	**769,121**
Previous Estimate	*1,459,223*	*871,649*	*809,418*	*891,620*	*911,471*	*923,868*	*NA*

NE (Not Estimated at individual source level due to lack of data)
NA (Not Applicable)

Table 3-107: Transmission Compressor Station National CO_2 Emissions (Metric Tons CO_2)

Source	1990	2005	2018	2019	2020	2021	2022
Station Total Emissions	32,285	20,747	17,110	17,242	17,085	17,244	17,327
Station + Compressor Fugitive Emissions	NE	NE	3,492	3,554	3,541	3,693	3,773
Reciprocating Compressor	NE	NE	10,237	10,084	9,816	9,573	9,502
Centrifugal Compressor (wet seals)	NE	NE	1,476	1,518	1,542	1,580	1,488
Centrifugal Compressor (dry seals)	NE	NE	1,906	2,087	2,187	2,398	2,565
Dehydrator vents	59	57	63	64	64	66	68
Flaring	78,386	76,030	70,366	78,424	93,510	62,974	82,004
Pneumatic Devices Transmission	6,274	4,526	945	915	863	841	876
High Bleed	NE	NE	290	280	256	226	221
Intermittent Bleed	NE	NE	631	614	587	598	639
Low Bleed	NE	NE	23	21	20	17	16
Station Venting	4,276	4,148	4,580	4,662	4,645	4,845	4,949
Total Emissions	**121,281**	**105,508**	**93,065**	**101,307**	**116,166**	**85,970**	**105,224**
Previous Estimate	*121,473*	*98,281*	*101,654*	*118,915*	*140,933*	*102,280*	*NA*

NE (Not Estimated at individual source level due to lack of data)
NA (Not Applicable)

Underground Natural Gas Storage Well Events (Methodological Update)

EPA updated the *Inventory* with CO_2 and CH_4 estimates resulting from underground natural gas storage well events that occurred in several years across the inventory time series. Previously, EPA included emissions only from the Aliso Canyon event (occurring 2015 to 2016). This update incorporates emissions from 9 events identified as occurring at storage wells. For the update, emissions from individual events were added to the year in which they occurred.

EPA calculated CH_4 emissions using the reported leak size and applying inventory assumptions for CH_4 content. The CH_4 emissions estimates were then adjusted using a 60 percent combustion efficiency if there was evidence of combustion or ignition during the event. EPA calculated CO_2 emissions only for the events where combustion or ignition occurred, using the 60 percent combustion efficiency. The *Storage Well Events* memo presents additional information and considerations for this update.

One commenter provided feedback and it focused on the 60 percent combustion efficiency. The commenter suggested using 30 percent as the combustion efficiency instead of 60 percent based on research from Gvakharia et al., 2017, which lists 30 percent as the lowest flare efficiency.[83] The commenter noted the study used to justify the 60 percent combustion efficiency evaluated engineered flares which may not be representative of combustion during emergency events.

The newly incorporated events occurred in years 1992, 1998, 2001, 2002, 2003, 2004, 2006, 2010, and 2011. They emitted on average 7,085 metric tons of CH_4 and 27,056 metric tons CO_2.

Methane emissions estimates for underground natural gas storage wells increased 15 percent across the time series compared to previous estimates. The largest increase between the updates and the previous estimates occurs in 2004, which incorporates CH_4 emissions from the Moss Bluff event.

Updates to CO_2 emissions resulted in an increase of 1,693 percent across the time series compared to previous estimates. This increase is mostly due to additions for 2001 and 2004 estimates, resulting from Yaggy and Moss Bluff events, respectively. Combustion occurred at both of these events, resulting in the application of the 60 percent combustion efficiency.

Pipeline Venting (Recalculation with Updated Data)

Transmission pipeline venting CH_4 emission estimates are on average 0.1 percent lower across the 1990 to 2021 time series than in the previous *Inventory*. The CH_4 emissions estimate for 2021 is 4 percent lower than in the previous *Inventory*. These changes were due to GHGRP submission revisions.

Table 3-108: Pipeline Venting National CH_4 Emissions (Metric Tons CH_4)

Source	1990	2005	2018	2019	2020	2021	2022
Pipeline Venting	177,951	183,159	208,438	187,266	220,544	165,703	133,761
Previous Estimate	*177,951*	*183,159*	*208,438*	*187,266*	*220,560*	*172,287*	*NA*

NA (Not Applicable)

Distribution

There were no methodological updates to the distribution segment and recalculations resulted in an average decrease in CH_4 emissions across the 1990 to 2021 time series of less than 0.1 percent and an average decrease in calculated CO_2 emissions across the 1990 to 2021 time series of less than 0.1 percent, compared to the previous *Inventory*.

[83] Gvakharia et al, 2017. Methane, Black Carbon, and Ethane Emissions from Natural Gas Flares in the Bakken Shale, North Dakota. *Environmental Science & Technology*. 51: 5317-5325. https://doi.org/10.1021/acs.est.6b05183.

Post-Meter

There were no methodological updates to estimate post-meter emissions and recalculations resulted in an average decrease in CH_4 emissions across the 1990 to 2021 time series of less than 0.1 percent and an average decrease in calculated CO_2 emissions across the 1990 to 2021 time series of less than 0.1 percent, compared to the previous *Inventory*.

Planned Improvements

Planned Improvements for 2025 *Inventory*

EPA updated the Enverus data and there were notable increases in the number of wells and completions identified as being hydraulically fractured compared with previous versions of the database. EPA will assess the underlying Enverus data to determine the cause of these changes.

Upcoming Data, and Additional Data that Could Inform the *Inventory*

EPA will assess new data received by EPA's Greenhouse Gas Reporting Program and Methane Challenge Program on an ongoing basis, which may be used to validate or improve existing estimates and assumptions.

EPA continues to track studies that contain data that may be used to update the *Inventory*. EPA will also continue to assess studies that include and compare both top-down and bottom-up emission estimates, which could lead to improved understanding of unassigned high emitters (e.g., identification of emission sources and information on frequency of high emitters) as recommended in previous stakeholder comments.

3.8 Abandoned Oil and Gas Wells (CRT Source Categories 1B2a and 1B2b)

The term "abandoned wells", as used in the *Inventory*, encompasses various types of oil and gas wells, including orphaned wells and other non-producing wells:

- Wells with no recent production, and not plugged. Common terms (such as those used in state databases) might include: inactive, temporarily abandoned, shut-in, dormant, and idle.
- Wells with no recent production and no responsible operator. Common terms might include: orphaned, deserted, long-term idle, and abandoned.
- Wells that have been plugged to prevent migration of gas or fluids.

The U.S. population of abandoned oil and gas wells (including orphaned wells and other non-producing wells) is around 3.9 million (with around 3.0 million abandoned oil wells and 0.9 million abandoned gas wells). The methods to calculate emissions from abandoned wells involve calculating the total populations of plugged and unplugged abandoned oil and gas wells in the United States and the application of emission factors. An estimate of the number of orphaned wells within this population is not developed as part of the methodology. Wells that are plugged have much lower average emissions than wells that are unplugged (less than 1 kg CH_4 per well per year, versus over 100 kg CH_4 per well per year). Around 43 percent of the abandoned well population in the United States is plugged. This fraction has increased over the *Inventory* time series (from around 22 percent in 1990) as more wells fall under regulations and programs requiring or promoting plugging of abandoned wells.

Abandoned oil wells. Abandoned oil wells emitted 235 kt CH_4 and 5 kt CO_2 in 2022. Emissions of both gases increased by 3 percent from 1990, while the total population of abandoned oil wells increased 40 percent.

Abandoned gas wells. Abandoned gas wells emitted 68 kt CH_4 and 3 kt CO_2 in 2022. Emissions of both gases increased by 33 percent from 1990, while the total population of abandoned gas wells increased 83 percent.

Table 3-109: CH_4 Emissions from Abandoned Oil and Gas Wells (MMT CO_2 Eq.)

Activity	1990	2005	2018	2019	2020	2021	2022
Abandoned Oil Wells	6.4	6.6	6.6	6.6	6.6	6.6	6.6
Abandoned Gas Wells	1.4	1.6	1.8	1.8	1.9	1.9	1.9
Total	**7.8**	**8.2**	**8.4**	**8.5**	**8.5**	**8.6**	**8.5**

Note: Totals may not sum due to independent rounding.

Table 3-110: CH_4 Emissions from Abandoned Oil and Gas Wells (kt)

Activity	1990	2005	2018	2019	2020	2021	2022
Abandoned Oil Wells	228	236	237	237	237	237	235
Abandoned Gas Wells	51	58	64	65	66	69	68
Total	**279**	**294**	**301**	**302**	**303**	**306**	**303**

Note: Totals may not sum due to independent rounding.

Table 3-111: CO_2 Emissions from Abandoned Oil and Gas Wells (MMT CO_2)

Activity	1990	2005	2018	2019	2020	2021	2022
Abandoned Oil Wells	+	+	+	+	+	+	+
Abandoned Gas Wells	+	+	+	+	+	+	+
Total	**+**	**+**	**+**	**+**	**+**	**+**	**+**

+ Does not exceed 0.05 MMT CO_2 Eq.

Note: Totals may not sum due to independent rounding.

Table 3-112: CO_2 Emissions from Abandoned Oil and Gas Wells (kt)

Activity	1990	2005	2018	2019	2020	2021	2022
Abandoned Oil Wells	5	5	5	5	5	5	5
Abandoned Gas Wells	2	3	3	3	3	3	3
Total	**7**	**7**	**8**	**8**	**8**	**8**	**8**

Note: Totals may not sum due to independent rounding.

Methodology and Time-Series Consistency

EPA uses a Tier 2 method from IPCC (2019) to quantify emissions from abandoned oil and gas wells. EPA's approach is based on the number of plugged and unplugged abandoned wells in the Appalachian region and in the rest of the U.S., and emission factors for plugged and unplugged abandoned wells in Appalachia and the rest of the U.S. Methods for abandoned wells are unavailable in IPCC (2006). The details of this approach and of the data sources used are described in the memorandum *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2016: Abandoned Wells in Natural Gas and Petroleum Systems (2018 Abandoned Wells Memo).*

EPA developed abandoned well CH_4 emission factors using data from Kang et al. (2016) and Townsend-Small et al. (2016). Plugged and unplugged abandoned well CH_4 emission factors were developed at the national-level (using emission data from Townsend-Small et al.) and for the Appalachia region (using emission data from measurements in Pennsylvania and Ohio conducted by Kang et al. and Townsend-Small et al., respectively). The Appalachia region emissions factors were applied to abandoned wells in states in the Appalachian basin region, and the national-level emission factors were applied to abandoned wells in all other states. EPA developed abandoned well CO_2 emission factors using the CH_4 emission factors and an assumed ratio of CO_2-to-CH_4 gas content, similar to the approach used to calculate CO_2 emissions for many sources in Petroleum Systems and Natural Gas Systems. For abandoned oil wells, EPA used the Petroleum Systems default production segment associated gas ratio of 0.020 MT CO_2/MT CH_4, which was derived through API TankCalc modeling runs. For abandoned gas wells, EPA used the Natural Gas Systems default production segment CH_4 and CO_2 gas content values (GRI/EPA 1996, GTI 2001) to develop a ratio of 0.044 MT CO_2/MT CH_4. The same respective emission factors are applied for each year of the time series.

EPA developed state-level annual counts of abandoned wells for 1990 through 2022 by summing together an annual estimate of abandoned wells in the Enverus data set (Enverus 2023), and an estimate of total abandoned wells not included the Enverus dataset (see 2018 Abandoned Wells Memo for additional information on how the value was calculated) for each state. References reviewed to develop the number of abandoned wells not included in the Enverus dataset include historical records collected by state agencies and by USGS.

The state-level abandoned well population was then split into plugged and unplugged wells by applying an assumption that all abandoned wells were unplugged in 1950 and using Enverus data to calculate the fraction of plugged abandoned wells in 2022. Linear interpolation was applied between the 1950 value and 2022 value to calculate the plugged fraction for intermediate years. See the memorandum *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2016: Abandoned Wells in Natural Gas and Petroleum Systems (2018 Abandoned Wells Memo)* for details.[84]

Abandoned Oil Wells

Table 3-113: Abandoned Oil Wells Activity Data, CH_4 and CO_2 Emissions (kt)

Source	1990	2005	2018	2019	2020	2021	2022
Plugged abandoned oil wells	475,939	810,564	1,156,633	1,192,282	1,227,566	1,263,583	1,281,380
Unplugged abandoned oil wells	1,697,730	1,787,095	1,781,964	1,783,807	1,784,834	1,785,340	1,767,543
Total Abandoned Oil Wells	2,173,669	2,597,659	2,938,597	2,976,089	3,012,400	3,048,923	3,048,923
Abandoned oil wells in Appalachia	22%	20%	19%	19%	18%	18%	18%
Abandoned oil wells outside of Appalachia	78%	80%	81%	81%	82%	82%	82%
CH_4 from plugged abandoned oil wells (kt)	0.17	0.25	0.34	0.35	0.36	0.36	0.37
CH_4 from unplugged abandoned oil wells(kt)	227.6	236.1	236.5	236.9	237.0	236.8	235.0
Total CH_4 from abandoned oil wells (kt)	**227.7**	**236.4**	**236.8**	**237.2**	**237.3**	**237.2**	**235.4**
Total CO_2 from abandoned oil wells (kt)	**4.6**	**4.8**	**4.8**	**4.8**	**4.8**	**4.8**	**4.8**

Abandoned Gas Wells

Table 3-114: Abandoned Gas Wells Activity Data, CH_4 and CO_2 Emissions (kt)

Source	1990	2005	2018	2019	2020	2021	2022
Plugged abandoned gas wells	110,089	210,902	348,625	359,018	372,605	389,745	395,236
Unplugged abandoned gas wells	355,620	404,960	447,374	448,504	453,988	463,119	457,628
Total Abandoned Gas Wells	465,709	615,862	795,999	807,522	826,593	852,864	852,864
Abandoned gas wells in Appalachia	28%	25%	24%	24%	24%	26%	26%

[84] See https://www.epa.gov/ghgemissions/natural-gas-and-petroleum-systems.

Abandoned gas wells outside of Appalachia	72%	75%	76%	76%	76%	74%	74%
CH_4 from plugged abandoned gas wells (kt)	0.06	0.11	0.17	0.17	0.19	0.21	0.21
CH_4 from unplugged abandoned gas wells (kt)	51.1	57.5	64.1	64.5	65.9	68.5	67.8
Total CH_4 from abandoned gas wells (kt)	**51.1**	**57.6**	**64.3**	**64.7**	**66.1**	**68.7**	**68.0**
Total CO_2 from abandoned gas wells (kt)	**2.2**	**2.5**	**2.8**	**2.8**	**2.9**	**3.0**	**3.0**

Uncertainty

To characterize uncertainty surrounding estimates of abandoned well emissions, EPA conducted a quantitative uncertainty analysis using the IPCC Approach 2 methodology (Monte Carlo simulation technique). See the 2018 Abandoned Wells Memo for details of the uncertainty analysis methods. EPA used Microsoft Excel's @RISK add-in tool to estimate the 95 percent confidence bound around total methane emissions from abandoned oil and gas wells in year 2022, then applied the calculated bounds to both CH_4 and CO_2 emissions estimates for each population. The @RISK add-in provides for the specification of probability density functions (PDFs) for key variables within a computational structure that mirrors the calculation of the inventory estimate. EPA used measurement data from the Kang et al. (2016) and Townsend-Small et al. (2016) studies to characterize the CH_4 emission factor PDFs. For activity data inputs (e.g., total count of abandoned wells, split between plugged and unplugged), EPA assigned default uncertainty bounds of ± 10 percent based on expert judgment.

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 bounds reported below only reflect those uncertainties that EPA has been able to quantify and do not incorporate considerations such as modeling uncertainty, data representativeness, measurement errors, misreporting or misclassification.

The results presented below in Table 3-115 provide the 95 percent confidence bound within which actual emissions from abandoned oil and gas wells are likely to fall for the year 2022, using the recommended IPCC methodology. Abandoned oil well CH_4 emissions in 2022 were estimated to be between 1.1 and 19.7 MMT CO_2 Eq., while abandoned gas well CH_4 emissions were estimated to be between 0.3 and 5.4 MMT CO_2 Eq. at a 95 percent confidence level. Uncertainty bounds for other years of the time series have not been calculated, but uncertainty is expected to vary over the time series.

Table 3-115: Approach 2 Quantitative Uncertainty Estimates for CH_4 and CO_2 Emissions from Petroleum and Natural Gas Systems (MMT CO_2 Eq. and Percent)

Source	Gas	2022 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
Abandoned Oil Wells	CH_4	6.6	1.1	19.7	-83%	+204%
Abandoned Gas Wells	CH_4	1.9	0.3	5.4	-83%	+204%
Abandoned Oil Wells	CO_2	0.005	0.001	0.014	-83%	+204%
Abandoned Gas Wells	CO_2	0.003	0.0005	0.008	-83%	+204%

[a] Range of emission estimates estimated by applying the 95 percent confidence intervals obtained from the Monte Carlo simulation analysis conducted for total abandoned oil and gas well CH_4 emissions in year 2022.

[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 the table.

QA/QC and Verification Discussion

The emission estimates in the *Inventory* are continually reviewed and assessed to determine whether emission factors and activity factors accurately reflect current industry practices. In order to ensure the quality of emission estimates for abandoned wells, general (IPCC Tier 1) quality assurance/quality control (QA/QC) procedures were implemented consistent with the U.S. Inventory QA/QC plan outlined in Annex 8. Additionally, EPA reviewed the current Enverus dataset and compared it with results from the previous dataset to identify outliers and instances of significant changes to abandoned oil and gas well counts.

EPA performs a thorough review of information associated with new studies to assess whether the assumptions in the *Inventory* are consistent with industry practices and whether new data is available that could be considered for updates to the estimates. As in previous years, EPA conducted early engagement and communication with stakeholders on updates prior to public review. EPA held a stakeholder webinar on greenhouse gas data for oil and gas in October of 2023.

Recalculations Discussion

EPA updated the *Inventory* with revised abandoned oil and gas well counts developed from Enverus data (Enverus 2023). Compared to the previous *Inventory*, annual abandoned oil well counts increased by an average of 2 percent across the time series and increased by 4 percent in 2021. Annual abandoned gas well counts increased by 2 percent across the time series and 7 percent in 2021. Similarly, both plugged wells and unplugged wells increased by 2 percent across the time series. As a result of this update, calculated abandoned oil well CH_4 and CO_2 emissions increased by an average of 2 percent each year across the time series and increased by 3 percent in 2021, compared to the previous *Inventory*. Abandoned gas well CH_4 and CO_2 emissions increased by an average of 1 percent across the time series and increased by 8 percent in 2021, compared to the previous *Inventory*.

Planned Improvements

EPA will continue to assess new data and stakeholder feedback on considerations (such as potential use of emission factor data from regions not included in the measurement studies on which current emission factors are based) to improve the abandoned well count estimates and emission factors. In future Inventories, EPA will assess data that become available from Department of Interior and Department of Energy orphan well plugging programs.

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

Emissions resulting from the combustion of fuels used for international transport activities, termed international bunker fuels under the Paris Agreement and 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.[85] 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).[86]

Two transport modes are addressed under the IPCC definition of international bunker fuels: aviation and marine.[87] Greenhouse gases emitted from the combustion of international bunker fuels, like other fossil fuels, include CO_2, CH_4 and N_2O for marine transport modes, and CO_2 and N_2O 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 *2006 IPCC Guidelines* distinguish between three different modes of air traffic: civil aviation, military aviation, and general aviation. 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 *2006 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 *2006 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 and military aviation is kerosene-type jet fuel, while the typical fuel used for general aviation is aviation gasoline.[88]

Emissions of CO_2 from aircraft are essentially a function of fuel consumption. 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 CH_4 is emitted by modern engines (Anderson et al. 2011), and as a result, CH_4 emissions from this category are reported as zero. In jet engines, N_2O is primarily produced by the oxidation of atmospheric nitrogen, and the majority of emissions occur during the cruise phase.

International marine bunkers comprise emissions from fuels burned by ocean-going ships of all flags that are engaged in international transport. Ocean-going ships are generally classified as cargo and passenger carrying, military (i.e., U.S. Navy), fishing, and miscellaneous support ships (e.g., tugboats). For the purpose of estimating greenhouse gas emissions, international bunker fuels are solely related to cargo and passenger carrying vessels, which is the largest of the four categories, and military vessels. Two main types of fuels are used on sea-going vessels: distillate diesel fuel and residual fuel oil. Carbon dioxide is the primary greenhouse gas emitted from marine shipping.

Overall, aggregate greenhouse gas emissions in 2022 from the combustion of international bunker fuels from both aviation and marine activities were 99.1 MMT CO_2 Eq., or 5.2 percent below emissions in 1990 (see Table 3-116 and Table 3-117). Emissions from international flights and international shipping voyages departing from the United States have increased by 74.4 percent and decreased by 51.7 percent, respectively, since 1990. The majority of these emissions were in the form of CO_2; however, small amounts of CH_4 (from marine transport modes) and N_2O were also emitted.

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[85] 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).

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

[87] 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).

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

Table 3-116: CO_2, CH_4, and N_2O Emissions from International Bunker Fuels (MMT CO_2 Eq.)

Gas/Mode	1990	2005	2018	2019	2020	2021	2022
CO_2	**103.6**	**113.3**	**124.3**	**113.6**	**69.6**	**80.2**	**98.2**
Aviation	38.2	60.2	83.0	78.3	39.8	50.8	66.6
Commercial	*30.0*	*55.6*	*79.8*	*75.1*	*36.7*	*47.6*	*63.5*
Military	*8.2*	*4.6*	*3.2*	*3.2*	*3.1*	*3.2*	*3.1*
Marine	65.4	53.1	41.3	35.4	29.9	29.4	31.6
CH_4	**0.2**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Aviation	NO	NO	NO	NO	NO	NO	NO
Marine	0.2	0.1	0.1	0.1	0.1	0.1	0.1
N_2O	**0.8**	**0.9**	**1.0**	**0.9**	**0.5**	**0.6**	**0.8**
Aviation	0.3	0.5	0.7	0.7	0.3	0.4	0.6
Marine	0.4	0.4	0.3	0.2	0.2	0.2	0.2
Total	**104.6**	**114.3**	**125.3**	**114.6**	**70.3**	**80.9**	**99.1**

NO (Not Occurring)

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

Table 3-117: CO_2, CH_4, and N_2O Emissions from International Bunker Fuels (kt)

Gas/Mode	1990	2005	2018	2019	2020	2021	2022
CO_2	**103,634**	**113,328**	**124,279**	**113,632**	**69,638**	**80,180**	**98,241**
Aviation	38,205	60,221	82,953	78,280	39,781	50,812	66,646
Marine	65,429	53,107	41,325	35,351	29,857	29,369	31,595
CH_4	**7**	**5**	**4**	**4**	**3**	**3**	**3**
Aviation	NO	NO	NO	NO	NO	NO	NO
Marine	7	5	4	4	3	3	3
N_2O	**3**	**3**	**4**	**3**	**2**	**2**	**3**
Aviation	1	2	3	2	1	2	2
Marine	2	1	1	1	1	1	1

NO (Not Occurring)

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

Methodology and Time-Series Consistency

Emissions of CO_2 were for the most part estimated by applying carbon content and fraction oxidized factors to fuel consumption activity data. This approach is analogous to that described under Section 3.1. Carbon content and fraction oxidized factors for jet fuel (except for commercial aviation as per below), distillate fuel oil, and residual fuel oil are the same as used for CO_2 from Fossil Fuel Combustion and are presented in Annex 2.1, Annex 2.2, and Annex 3.8 of this *Inventory*. Density conversions were taken from ASTM (1989) and USAF (1998). Heat content for distillate fuel oil and residual fuel oil were taken from EIA (2024) and USAF (1998), and heat content for jet fuel was taken from EIA (2024). See below for details on how emission estimates for commercial aviation were determined.

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 CH_4 and N_2O were calculated by multiplying emission factors by measures of fuel consumption by fuel type and mode. Emission factors used in the calculations of CH_4 and N_2O emissions were obtained from the *Revised 1996 IPCC Guidelines* (IPCC/UNEP/OECD/IEA 1997), which is also referenced in the *2006 IPCC Guidelines* (IPCC 2006). For aircraft emissions, the following value, in units of grams of pollutant per kilogram of fuel consumed (g/kg), was employed: 0.1 for N_2O (IPCC 2006). For marine vessels consuming either distillate diesel or residual fuel oil the following values (g/MJ), were employed: 0.315 for CH_4 and 0.08 for N_2O. Activity data for aviation included solely jet fuel consumption statistics, while the marine mode included both distillate diesel and residual fuel oil.

Activity data on 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 and 2000 through 2022 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 CO_2 estimates for 1990 and 2000 through 2022 were obtained directly from FAA's AEDT model (FAA 2024). The radar-informed method that was used to estimate CO_2 emissions for commercial aircraft for 1990 and 2000 through 2022 was not possible for 1991 through 1999 because the radar dataset was not available for years prior to 2000. FAA developed Official Airline Guide (OAG) schedule-informed inventories modeled with AEDT and great circle trajectories for 1990, 2000, and 2010. Because fuel consumption and CO_2 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. See Annex 3.3 for more information on the methodology for estimating emissions from commercial aircraft jet fuel consumption.

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 2023). 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 3-118. See Annex 3.8 for additional discussion of military data.

Table 3-118: Aviation Jet Fuel Consumption for International Transport (TBtu)

Nationality	1990	2005	2018	2019	2020	2021	2022
U.S. and Foreign Carriers	426	791	1,104	1,068	521	677	902
U.S. Military	116	64	44	44	43	44	44
Total	**542**	**854**	**1,148**	**1,112**	**564**	**721**	**946**

Note: Totals may not sum due to independent rounding.

In order to quantify the civilian international component of marine bunker fuels, activity data on distillate diesel and residual fuel oil consumption by cargo or passenger carrying marine vessels departing from U.S. ports were collected for individual shipping agents on a monthly basis by the U.S. Customs and Border Protection. This information was then reported in unpublished data collected by the Foreign Trade Division of the U.S. Department of Commerce's Bureau of the Census (DOC 1991 through 2022) for 1990 through 2001, 2007 through 2022, 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 (2023). 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 3-119.

Table 3-119: Marine Fuel Consumption for International Transport (Million Gallons)

Fuel Type	1990	2005	2018	2019	2020	2021	2022
Residual Fuel Oil	4,781	3,881	2,790	2,246	1,964	1,953	2,172
Distillate Diesel Fuel & Other	617	444	684	702	461	437	435
U.S. Military Naval Fuels	522	471	285	281	296	285	263
Total	**5,920**	**4,796**	**3,759**	**3,229**	**2,721**	**2,674**	**2,870**

Note: Totals may not sum due to independent rounding.

Methodological recalculations were applied to the entire time series to ensure time-series consistency from 1990 through 2022.

Uncertainty

Emission estimates related to the consumption of international bunker fuels are subject to the same uncertainties as those from domestic aviation and marine mobile combustion emissions; however, additional uncertainties result from the difficulty in collecting accurate fuel consumption activity data for international transport activities separate from domestic transport activities.[89] 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. Total aircraft and ship fuel use estimates were developed from DoD records, which document fuel sold to the DoD Components (e.g., Army, Department of Navy and Air Force) from the Defense Logistics Agency Energy. These data may not include fuel used in aircraft and ships as a result of a Service procuring fuel from, selling fuel to, trading fuel with, or giving fuel to other ships, aircraft, governments, or other entities.

Additionally, there are uncertainties in historical 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 2022, including estimates for the quantity of jet fuel allocated to ground transportation. 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, DoD 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 revalidation of assumptions based on data regarding current equipment and operational tempo, however, it is doubtful data with more fidelity exist at this time.

[89] See uncertainty discussions under section 3.1 CO_2 from Fossil Fuel Combustion.

Although aggregate fuel consumption data have been used to estimate emissions from aviation, the recommended method for estimating emissions of gases other than CO_2 in the *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 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 CO_2.[90]

There is also concern regarding the reliability of the existing DOC (1991 through 2022) data on marine vessel fuel consumption reported at U.S. customs stations due to the significant degree of inter-annual variation.

QA/QC and Verification

In order to ensure the quality of the emission estimates from international bunker fuels, General (IPCC Tier 1) and category-specific (Tier 2) Quality Assurance/Quality Control (QA/QC) procedures were implemented consistent with the U.S. Inventory QA/QC plan outlined in Annex 8 The Tier 2 procedures that were implemented involved checks specifically focusing on the activity data and emission factor sources and methodology used for estimating CO_2, CH_4, and N_2O emissions from international bunker fuels in the United States. Emission totals for the different sectors and fuels were compared and trends were investigated. No corrective actions were necessary.

Recalculations Discussion

No recalculations were performed for the current *Inventory*.

Planned Improvements

EPA will evaluate data availability to update the sources for densities, energy contents, and emission factors applied to estimate emissions from aviation and marine fuels. Many are from sources from the late 1990s, such as IPCC/UNEP/OECD/IEA (1997). Potential sources with more recent data include the International Maritime Organization (IMO) greenhouse gas emission inventory, International Air Transport Association (IATA)/ICAO greenhouse gas reporting system (CORSIA), and the EPA Greenhouse Gas Reporting Program (GHGRP) Technical Support Document for Petroleum Products. Specifically, EPA will evaluate data availability to support updating the heat contents and carbon contents of jet fuel with input from EIA.

A longer-term effort is underway to consider the feasibility of including data from a broader range of domestic and international sources for bunker fuels. Potential sources include the IMO greenhouse gas emission inventory, data from the U.S. Coast Guard on vehicle operation currently used in criteria pollutant modeling, data from the International Energy Agency (IEA), relevant updated FAA models to improve aviation bunker fuel estimates, and researching newly available marine bunker data.

[90] U.S. aviation emission estimates for CO, NO_x, and NMVOCs are reported by EPA's National Emission Inventory (NEI) Air Pollutant Emission Trends website, 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.

3.10 Biomass and Biofuels Consumption (CRT Source Category 1A)

The combustion of biomass—such as wood, charcoal, the biogenic portions of MSW, and wood waste and biofuels such as ethanol, biogas, and biodiesel—generates CO_2 in addition to CH_4 and N_2O already covered in this chapter. In line with the reporting requirements for inventories submitted under the Paris Agreement and the UNFCCC, CO_2 emissions from biomass and biofuel combustion have been estimated separately from fossil fuel CO_2 emissions and are not directly included in the energy sector contributions to U.S. totals. In accordance with IPCC methodological guidelines, any such emissions are calculated by accounting for net carbon fluxes from changes in biogenic carbon 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 CO_2 emissions to U.S. totals within the Land Use, Land-Use Change, and Forestry sector's approach.

Therefore, CO_2 emissions from biomass and biofuel consumption are not included specifically in summing energy sector totals. However, they are presented here for informational purposes and to provide detail on biomass and biofuels consumption.

In 2022, total CO_2 emissions from the burning of woody biomass in the industrial, residential, commercial, and electric power sectors were approximately 195.3 MMT CO_2 Eq. (195,338 kt) (see Table 3-120 and Table 3-121). As the largest consumer of woody biomass, the industrial sector was responsible for 62.9 percent of the CO_2 emissions from this source. The residential sector was the second largest emitter, constituting 22.3 percent of the total, while the electric power and commercial sectors accounted for the remainder.

Table 3-120: CO_2 Emissions from Wood Consumption by End-Use Sector (MMT CO_2 Eq.)

End-Use Sector	1990	2005	2018	2019	2020	2021	2022
Industrial	135.3	136.3	134.4	132.1	127.3	128.2	122.8
Residential	59.8	44.3	54.1	56.3	35.6	35.5	43.6
Commercial	6.8	7.2	8.7	8.7	8.6	8.5	8.6
Electric Power	13.3	19.1	22.8	20.7	19.1	20.3	20.4
Total	**215.2**	**206.9**	**220.0**	**217.7**	**190.6**	**192.5**	**195.3**

Note: Totals may not sum due to independent rounding.

Table 3-121: CO_2 Emissions from Wood Consumption by End-Use Sector (kt)

End-Use Sector	1990	2005	2018	2019	2020	2021	2022
Industrial	135,348	136,269	134,417	132,069	127,301	128,209	122,824
Residential	59,808	44,340	54,122	56,251	35,585	35,484	43,565
Commercial	6,779	7,218	8,669	8,693	8,554	8,528	8,563
Electric Power	13,252	19,074	22,795	20,677	19,115	20,288	20,385
Total	**215,186**	**206,901**	**220,003**	**217,690**	**190,554**	**192,509**	**195,338**

Note: Totals may not sum due to independent rounding.

Carbon dioxide emissions from combustion of the biogenic components of MSW by the electric power sector were an estimated 14.9 MMT CO_2 (14,864 kt) in 2022. Emissions across the time series are shown in Table 3-122 and Table 3-123. As discussed in Section 3.3, MSW is combusted to produce electricity and the CO_2 emissions from the fossil portion of the MSW (e.g., plastics, textiles, etc.) are included in the energy sector FFC estimates. The MSW also includes biogenic components (e.g., food waste, yard trimmings, natural fibers) and the CO_2 emissions associated with that biogenic portion is included here.

Table 3-122: CO_2 Emissions from Biogenic Components of MSW (MMT CO_2 Eq.)

End-Use Sector	1990	2005	2018	2019	2020	2021	2022
Electric Power	18.5	14.7	16.1	15.7	15.6	15.3	14.9

Table 3-123: CO_2 Emissions from Biogenic Components of MSW (kt)

End-Use Sector	1990	2005	2018	2019	2020	2021	2022
Electric Power	18,534	14,722	16,115	15,709	15,614	15,329	14,864

The transportation sector is responsible for most of the fuel ethanol consumption in the United States. Ethanol used for fuel 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 2022, the United States transportation sector consumed an estimated 1,094.9 trillion Btu of ethanol (94 percent of total), and as a result, produced approximately 75.0 MMT CO_2 Eq. (74,953 kt) (see Table 3-124 and Table 3-125) of CO_2 emissions. Smaller quantities of ethanol were also used in the industrial and commercial sectors. Ethanol fuel 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 3-124: CO_2 Emissions from Ethanol Consumption (MMT CO_2 Eq.)

End-Use Sector	1990	2005	2018	2019	2020	2021	2022
Transportation[a]	4.1	21.6	78.6	78.7	68.1	75.4	75.0
Industrial	0.1	1.2	1.4	1.6	1.6	1.5	1.9
Commercial	0.1	0.2	1.9	2.2	2.2	2.1	2.7
Total	**4.2**	**22.9**	**81.9**	**82.6**	**71.8**	**79.1**	**79.6**

[a] See Annex 3.2, Table A-74 for additional information on transportation consumption of these fuels.
Note: Totals may not sum due to independent rounding.

Table 3-125: CO_2 Emissions from Ethanol Consumption (kt)

End-Use Sector	1990	2005	2018	2019	2020	2021	2022
Transportation[a]	4,059	21,616	78,603	78,739	68,085	75,417	74,953
Industrial	105	1,176	1,404	1,610	1,582	1,509	1,919
Commercial	63	151	1,910	2,229	2,182	2,139	2,721
Total	**4,227**	**22,943**	**81,917**	**82,578**	**71,848**	**79,064**	**79,593**

[a] See Annex 3.2, Table A-74 for additional information on transportation consumption of these fuels.
Note: Totals may not sum due to independent rounding.

The transportation sector is assumed to be responsible for all of the biodiesel consumption in the United States (EIA 2024a). Biodiesel is currently produced primarily from soybean oil, but it can be produced from a variety of biomass feedstocks including waste oils, fats, and greases. Biodiesel for transportation use appears in low-level blends (less than 5 percent) with diesel fuel, high-level blends (between 6 and 20 percent) with diesel fuel, and 100 percent biodiesel (EIA 2024b).

In 2022, the United States consumed an estimated 211.6 trillion Btu of biodiesel, and as a result, produced approximately 15.6 MMT CO_2 Eq. (15,622 kt) (see Table 3-126 and Table 3-127) of CO_2 emissions. Biodiesel production and consumption has grown significantly since 2001 due to the favorable economics of blending biodiesel into diesel and federal policies that have encouraged use of renewable fuels (EIA 2024b). There was no measured biodiesel consumption prior to 2001 EIA (2024a).

Table 3-126: CO_2 Emissions from Biodiesel Consumption (MMT CO_2 Eq.)

End-Use Sector	1990	2005	2018	2019	2020	2021	2022
Transportation[a]	NO	0.9	17.9	17.1	17.7	16.1	15.6

NO (Not Occurring)
[a] See Annex 3.2, Table A-74 for additional information on transportation consumption of these fuels.

Table 3-127: CO_2 Emissions from Biodiesel Consumption (kt)

End-Use Sector	1990	2005	2018	2019	2020	2021	2022
Transportation[a]	NO	856	17,936	17,080	17,678	16,112	15,622

NO (Not Occurring)
[a] See Annex 3.2, Table A-74 for additional information on transportation consumption of these fuels.

Methodology and Time-Series Consistency

Woody biomass emissions were estimated by applying two gross heat contents from EIA (Lindstrom 2006) to U.S. consumption data (EIA 2024a) (see Table 3-129), provided in energy units for the industrial, residential, commercial, and electric power sectors. One heat content (16.95 MMBtu/MT wood and wood waste) was applied to the industrial sector's consumption, while the other heat content (15.43 MMBtu/MT wood and wood waste) was applied to the consumption data for the other sectors. An EIA emission factor of 0.434 MT C/MT wood (Lindstrom 2006) was then applied to the resulting quantities of woody biomass to obtain CO_2 emission estimates. The woody biomass is assumed to contain black liquor and other wood wastes, have a moisture content of 12 percent, and undergo complete combustion to be converted into CO_2.

Data for total waste incinerated, excluding tires, from 1990 to 2022 was derived following the methodology described in Section 3.3. Biogenic CO_2 emissions associated with MSW combustion were obtained from EPA's GHGRP FLIGHT data for MSW combustion sources (EPA 2023). Dividing biogenic CO_2 emissions from GHGRP FLIGHT data for MSW combustors by estimated MSW tonnage combusted yielded an annual biogenic CO_2 emission factor. This approach follows the same approach used to develop the fossil CO_2 emissions from MSW combustion as discussed in Section 3.3. As this data was only available following 2011, all years prior use an average of the emission factors from 2011 through 2015.

Biogenic CO_2 emissions from MSW combustion were calculated by multiplying the annual tonnage estimates, excluding tires, by the calculated emissions factor. Calculated biogenic CO_2 emission factors are shown in Table 3-128.

Table 3-128: Calculated Biogenic CO_2 Content per Ton Waste (kg CO_2/Short Ton Combusted)

End-Use Sector	1990	2005	2018	2019	2020	2021	2022
CO_2 Emission Factors	556	556	553	558	566	550	564

The amount of ethanol allocated across the transportation, industrial, and commercial sectors was based on the sector allocations of ethanol-blended motor gasoline. The sector allocations of ethanol-blended motor gasoline were determined using a bottom-up analysis conducted by EPA, as described in the Methodology section of Fossil Fuel Combustion. Total U.S. ethanol consumption from EIA (2024a) was allocated to individual sectors using the same sector allocations as ethanol-blended motor gasoline. The emissions from ethanol consumption were calculated by applying an emission factor of 18.67 MMT C/Qbtu (EPA 2010) to adjusted ethanol consumption estimates (see Table 3-130). The emissions from biodiesel consumption were calculated by applying an emission factor of 20.1 MMT C/Qbtu (EPA 2010) to U.S. biodiesel consumption estimates that were provided in energy units (EIA 2024a) (see Table 3-131).[91]

Table 3-129: Woody Biomass Consumption by Sector (Trillion Btu)

End-Use Sector	1990	2005	2018	2019	2020	2021	2022
Industrial	1,441.9	1,451.7	1,432.0	1,407.0	1,356.2	1,365.9	1,308.5
Residential	580.0	430.0	524.9	545.5	345.1	344.1	422.5
Commercial	65.7	70.0	84.1	84.3	83.0	82.7	83.0
Electric Power	128.5	185.0	221.1	200.5	185.4	196.7	197.7
Total	**2,216.2**	**2,136.7**	**2,262.0**	**2,237.3**	**1,969.6**	**1,989.4**	**2,011.7**

Note: Totals may not sum due to independent rounding.

Table 3-130: Ethanol Consumption by Sector (Trillion Btu)

End-Use Sector	1990	2005	2018	2019	2020	2021	2022
Transportation	59.3	315.8	1,148.2	1,150.2	994.6	1,101.7	1,094.9
Industrial	1.5	17.2	20.5	23.5	23.1	22.0	28.0
Commercial	0.9	2.2	27.9	32.6	31.9	31.2	39.7
Total	**61.7**	**335.1**	**1,196.6**	**1,206.3**	**1,049.5**	**1,155.0**	**1,162.7**

Note: Totals may not sum due to independent rounding.

Table 3-131: Biodiesel Consumption by Sector (Trillion Btu)

End-Use Sector	1990	2005	2018	2019	2020	2021	2022
Transportation	NO	11.6	242.9	231.3	239.4	218.2	211.6

NO (Not Occurring)

Methodological recalculations were applied to the entire time series to ensure time-series consistency from 1990 through 2022.

Uncertainty

It is assumed that the combustion efficiency for biomass is 100 percent, which is believed to be an overestimate of the efficiency of biomass combustion processes in the United States. Decreasing the combustion efficiency would decrease emission estimates for CO_2. 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 and biodiesel production are more certain than estimates from woody biomass consumption due to better activity data collection methods and uniform combustion techniques.

Recalculations Discussion

EIA (2024a) updated 2020 and 2021 wood energy consumed by the residential sector due to new underlying data collected by the Residential Energy Consumption Survey (RECS), which collects data about once every 5 years and uses Annual Energy Outlook growth rates to estimate data for other years. This caused CO_2 emissions from residential wood consumption to decrease by 9.9 MMT CO_2 Eq. (4.9 percent) in 2020 and 12.3 MMT CO_2 Eq. (6.0 percent) in 2021 compared to estimates in the previous *Inventory* for these years.

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[91] CO_2 emissions from biodiesel do not include emissions associated with the carbon in the fuel that is from the methanol used in the process. Emissions from methanol use and combustion are assumed to be accounted for under Non-Energy Use of Fuels. See Annex 2.3 – Methodology for Estimating Carbon Emitted from Non-Energy Uses of Fossil Fuels.

Planned Improvements

Future research will investigate the availability of data on woody biomass heat contents and carbon emission factors to see if there are newer, improved data sources available for these factors.

Currently, emission estimates from biomass and biomass-based fuels included in this *Inventory* are limited to woody biomass, biogenic components of MSW, ethanol, and biodiesel. Additional forms of biomass-based fuel consumption include biogas, and other renewable diesel fuels. EPA will investigate additional forms of biomass-based fuel consumption, research the availability of relevant emissions factors, and integrate these into the *Inventory* as feasible. EPA will examine EIA data on biogas and other renewable diesel fuels to see if these fuel types can be included in future Inventories. EIA (2024a) natural gas data already deducts biogas used in the natural gas supply, so no adjustments are needed to the natural gas fuel consumption data to account for biogas. Distillate fuel statistics are adjusted in this *Inventory* to remove other renewable diesel fuels as well as biodiesel. Additionally, options for including "Other Renewable Fuels," as defined by EIA, will be evaluated.

The availability of facility-level combustion emissions through EPA's GHGRP will be examined to help better characterize the industrial sector's energy consumption in the United States and further classify woody biomass consumption by business establishments according to industrial economic activity type. Most methodologies used in EPA's GHGRP are consistent with IPCC, although 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 Paris Agreement and UNFCCC reporting guidelines, some facility-level fuel combustion emissions reported under EPA's GHGRP may also include industrial process emissions.[92]

In line with the Paris Agreement and 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 CO_2 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 CO_2 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.[93]

3.11 Energy Sources of Precursor Greenhouse Gases

In addition to the main greenhouse gases addressed above, energy-related activities are also sources of greenhouse gas precursors. The reporting requirements of the Paris Agreement and the UNFCCC[94] request that information should be provided on precursor emissions, which include carbon monoxide (CO), nitrogen oxides (NO_x), non-methane volatile organic compounds (NMVOCs), and sulfur dioxide (SO_2). These gases are not direct greenhouse gases, but indirectly impact Earth's radiative balance by altering the concentrations of greenhouse

[92] See https://unfccc.int/resource/docs/2013/cop19/eng/10a03.pdf#page=2.

[93] See http://www.ipcc-nggip.iges.or.jp/public/tb/TFI_Technical_Bulletin_1.pdf.

[94] See paragraph 51 of Annex to 18/CMA.1 available online at: https://unfccc.int/sites/default/files/resource/CMA2018_03a02E.pdf.

gases (e.g., tropospheric ozone) and atmospheric aerosol (e.g., particulate sulfate). Total emissions of NO_x, CO, NMVOCs, and SO_2 from energy-related activities from 1990 to 2022 are reported in Table 3-132.

Table 3-132: NO_x, CO, NMVOC, and SO_2 Emissions from Energy-Related Activities (kt)

Gas/Activity	1990	2005	2018	2019	2020	2021	2022
NO_x	**21,804**	**18,196**	**6,812**	**6,503**	**5,630**	**5,570**	**5,225**
Fossil Fuel Combustion	21,678	18,188	6,804	6,496	5,624	5,563	5,218
Transportation[a]	*12,132*	*12,628*	*4,486*	*4,322*	*3,618*	*3,546*	*3,228*
Industrial	*2,475*	*1,486*	*820*	*800*	*751*	*721*	*721*
Electric Power Sector	*6,045*	*3,440*	*1,025*	*898*	*762*	*807*	*781*
Commercial	*451*	*288*	*186*	*187*	*193*	*189*	*188*
Residential	*575*	*346*	*288*	*290*	*300*	*300*	*300*
Petroleum and Natural Gas Systems	127	8	7	7	7	6	6
International Bunker Fuels	1,953	1,699	1,456	1,280	977	1,008	1,132
CO	**124,584**	**63,891**	**30,237**	**29,854**	**27,897**	**28,283**	**27,607**
Fossil Fuel Combustion	124,353	63,686	30,050	29,660	27,703	28,098	27,426
Transportation[a]	*119,478*	*59,540*	*26,024*	*25,621*	*23,546*	*23,912*	*23,235*
Residential	*3,620*	*2,393*	*2,751*	*2,860*	*2,968*	*2,950*	*2,950*
Industrial	*705*	*976*	*620*	*600*	*670*	*658*	*655*
Electric Power Sector	*329*	*582*	*505*	*428*	*362*	*423*	*428*
Commercial	*220*	*195*	*151*	*151*	*157*	*154*	*158*
Petroleum and Natural Gas Systems	232	205	186	194	194	185	181
International Bunker Fuels	102	131	158	150	83	101	128
NMVOCs	**12,269**	**8,081**	**5,050**	**4,987**	**4,822**	**5,167**	**5,045**
Fossil Fuel Combustion	11,793	6,079	2,632	2,593	2,391	2,454	2,329
Transportation[a]	*10,932*	*5,608*	*2,127*	*2,072*	*1,846*	*1,912*	*1,786*
Residential	*693*	*322*	*382*	*397*	*431*	*429*	*429*
Commercial	*9*	*18*	*14*	*14*	*14*	*14*	*14*
Industrial	*117*	*87*	*80*	*81*	*74*	*73*	*74*
Electric Power Sector	*43*	*44*	*30*	*29*	*26*	*27*	*27*
Petroleum and Natural Gas Systems	476	2,002	2,418	2,394	2,431	2,713	2,716
International Bunker Fuels	57	54	50	45	32	34	40
SO_2	**22,638**	**13,331**	**1,827**	**1,509**	**1,288**	**1,423**	**1,327**
Fossil Fuel Combustion	21,482	13,235	1,770	1,447	1,138	1,272	1,176
Electric Power Sector	*14,432*	*9,436*	*1,189*	*921*	*758*	*898*	*819*
Industrial	*2,886*	*1,378*	*259*	*234*	*172*	*168*	*159*
Transportation[a]	*793*	*724*	*45*	*40*	*23*	*24*	*25*
Commercial	*485*	*318*	*18*	*19*	*13*	*14*	*13*
Residential	*2,886*	*1,378*	*259*	*234*	*172*	*168*	*159*
Petroleum and Natural Gas Systems	156	96	56	61	150	151	151
International Bunker Fuels	*NA*	*NA*	*NA*	*NA*	*NA*	*NA*	*NA*

NA (Not Applicable)

[a] The scope of the NEI for aircraft related precursor emissions included under the transportation is different from the Paris Agreement and UNFCCC reporting scope. The NEI precursor estimate methodology does not exclude emissions that could be considered international bunkers given local impacts from these emissions. The precursor estimates are based on modeled using FAA- and state-supplied landing and take-off data for all aircraft types (including ground support equipment and auxiliary engines) used for public, private, and military purposes.

Note: Totals may not sum due to independent rounding.

Source: (EPA 2023a). Emission categories from EPA (2023a) are aggregated into sectors and categories reported under the Paris Agreement and the UNFCCC as shown in Table ES-3.

Methodology and Time-Series Consistency

Emission estimates for 1990 through 2022 were obtained from data published on the National Emissions Inventory (NEI) Air Pollutant Emissions Trends Data website (EPA 2023a). For Table 3-132, NEI reported emissions of CO, NO_x, NMVOCs, and SO_2 were recategorized from NEI Emissions Inventory System (EIS) sectors to source categories more closely aligned with reporting sectors and categories under the Paris Agreement and the UNFCCC, based on discussions between the EPA *Inventory* and NEI staff (see crosswalk documented in Annex 6.3).[95] EIS sectors mapped to the energy sector categories in this report include: fuel combustion for electric utilities, industrial, and other; petroleum and related industries; highway vehicles; off-highway; and other mobile sources (e.g., commercial marine vessels and rail). As described in the NEI Technical Support Documentation (TSD) (EPA 2023b), NEI emissions are estimated through a combination of emissions data submitted directly to the EPA by state, local, and tribal air agencies, as well as additional information added by the Agency from EPA emissions programs, such as the emission trading program, Toxics Release Inventory (TRI), and data collected during rule development or compliance testing.

Methodological approaches were applied to the entire time series to ensure time-series consistency from 1990 through 2022, which are described in detail in the NEI's TSD and on EPA's Air Pollutant Emission Trends website (EPA 2023a; EPA 2023b). No quantitative estimates of uncertainty were calculated for this source category.

[95] The NEI estimates and reports emissions from six criteria air pollutants (CAPs) and 187 hazardous air pollutants (HAPs) in support of National Ambient Air Quality Standards. EPA reported CAP emission trends are grouped into 60 sectors and 15 Tier 1 source categories, which broadly cover similar source categories to those presented in this chapter. For reporting precursor emissions in the common reporting tables (CRTs), EPA has mapped and regrouped emissions of greenhouse gas precursors (CO, NO_x, SO_2, and NMVOCs) from NEI's EIS sectors to better align with NIR source categories, and to ensure consistency and completeness to the extent possible. See Annex 6.3 for more information on this mapping.