EPA 430-R-16-002

DRAFT Inventory of U.S. Greenhouse Gas Emissions and Sinks:

1990 – 2014

FEBRUARY 22, 2016

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All data tables of this document are available for the full time series 1990 through 2014, inclusive, at the internet site mentioned above.

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For more information regarding climate change and greenhouse gas emissions, see the EPA web site at <http://www.epa.gov/climatechange>.

Released for printing: April 15, 2016

Acknowledgments

The Environmental Protection Agency would like to acknowledge the many individual and organizational contributors to this document, without whose efforts this report would not be complete. Although the complete list of researchers, government employees, and consultants who have provided technical and editorial support is too long to list here, EPA's Office of Atmospheric Programs would like to thank some key contributors and reviewers whose work has significantly improved this year's report.

Work on emissions from fuel combustion was led by Leif Hockstad. Susan Burke and Amy Bunker directed the work on mobile combustion and transportation. Work on industrial processes and product use emissions was led by Mausami Desai. Work on fugitive methane emissions from the energy sector was directed by Melissa Weitz and Cate Hight. Calculations for the waste sector were led by Rachel Schmeltz. Tom Wirth directed work on the Agriculture and the Land Use, Land-Use Change, and Forestry chapters. Work on emissions of HFCs, PFCs, SF_6, and NF_3 was directed by Deborah Ottinger and Dave Godwin.

Within the EPA, other Offices also contributed data, analysis, and technical review for this report. The Office of Transportation and Air Quality and the Office of Air Quality Planning and Standards provided analysis and review for several of the source categories addressed in this report. The Office of Solid Waste and the Office of Research and Development also contributed analysis and research.

The Energy Information Administration and the Department of Energy contributed invaluable data and analysis on numerous energy-related topics. The U.S. Forest Service prepared the forest carbon inventory, and the Department of Agriculture's Agricultural Research Service and the Natural Resource Ecology Laboratory at Colorado State University contributed leading research on nitrous oxide and carbon fluxes from soils.

Other government agencies have contributed data as well, including the U.S. Geological Survey, the Federal Highway Administration, the Department of Transportation, the Bureau of Transportation Statistics, the Department of Commerce, the National Agricultural Statistics Service, the Federal Aviation Administration, and the Department of Defense.

We would also like to thank Marian Martin Van Pelt and the full Inventory team at ICF International including Leslie Chinery, Randy Freed, Diana Pape, Robert Lanza, Lauren Marti, Mollie Averyt, Mark Flugge, Larry O'Rourke, Deborah Harris, Dean Gouveia, Jonathan Cohen, Alexander Lataille, Andrew Pettit, Sabrina Andrews, Marybeth Riley-Gilbert, Sarah Kolansky, David Towle, Bikash Acharya, Bobby Renz, Rebecca Ferenchiak, Kasey Knoell, Cory Jemison, Kevin Kurkul, Matt Lichtash, Krisztina Pjeczka, Cecilia Bremner, and Gabrielle Jette for synthesizing this report and preparing many of the individual analyses. Eastern Research Group, RTI International, Raven Ridge Resources, and Ruby Canyon Engineering Inc. also provided significant analytical support.

Preface

The United States Environmental Protection Agency (EPA) prepares the official U.S. Inventory of Greenhouse Gas Emissions and Sinks to comply with existing commitments under the United Nations Framework Convention on Climate Change (UNFCCC). Under decision 3/CP.5 of the UNFCCC Conference of the Parties, national inventories for UNFCCC Annex I parties should be provided to the UNFCCC Secretariat each year by April 15.

In an effort to engage the public and researchers across the country, the EPA has instituted an annual public review and comment process for this document. The availability of the draft document is announced via Federal Register Notice and is posted on the EPA web site. Copies are also mailed upon request. The public comment period is generally limited to 30 days; however, comments received after the closure of the public comment period are accepted and considered for the next edition of this annual report.

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Executive Summary

An emissions inventory that identifies and quantifies a country's primary anthropogenic[1] sources and sinks of greenhouse gases is essential for addressing climate change. This inventory adheres to both (1) a comprehensive and detailed set of methodologies for estimating sources and sinks of anthropogenic greenhouse gases, and (2) a common and consistent mechanism that enables Parties to the United Nations Framework Convention on Climate Change (UNFCCC) to compare the relative contribution of different emission sources and greenhouse gases to climate change.

In 1992, the United States signed and ratified the UNFCCC. As stated in Article 2 of the UNFCCC, "The ultimate objective of this Convention and any related legal instruments that the Conference of the Parties may adopt is to achieve, in accordance with the relevant provisions of the Convention, stabilization of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system. Such a level should be achieved within a time-frame sufficient to allow ecosystems to adapt naturally to climate change, to ensure that food production is not threatened and to enable economic development to proceed in a sustainable manner."[2]

Parties to the Convention, by ratifying, "shall develop, periodically update, publish and make available…national inventories of anthropogenic emissions by sources and removals by sinks of all greenhouse gases not controlled by the Montreal Protocol, using comparable methodologies…"[3] The United States views this report as an opportunity to fulfill these commitments.

This chapter summarizes the latest information on U.S. anthropogenic greenhouse gas emission trends from 1990 through 2014. To ensure that the U.S. emissions inventory is comparable to those of other UNFCCC Parties, the estimates presented here were calculated using methodologies consistent with those recommended in the *2006 Intergovernmental Panel on Climate Change (IPCC) Guidelines for National Greenhouse Gas Inventories* (IPCC 2006). The structure of this report is consistent with the UNFCCC guidelines for inventory reporting.[4]

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

In following the UNFCCC requirement under Article 4.1 to develop and submit national greenhouse gas emissions inventories, the emissions and sinks presented in this report are organized by source and sink categories and calculated using internationally-accepted methods provided by the IPCC.[5] Additionally, the calculated emissions

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[1] The term "anthropogenic," in this context, refers to greenhouse gas emissions and removals that are a direct result of human activities or are the result of natural processes that have been affected by human activities (IPCC 2006).

[2] Article 2 of the Framework Convention on Climate Change published by the UNEP/WMO Information Unit on Climate Change. See <http://unfccc.int>.

[3] Article 4(1)(a) of the United Nations Framework Convention on Climate Change (also identified in Article 12). Subsequent decisions by the Conference of the Parties elaborated the role of Annex I Parties in preparing national inventories. See <http://unfccc.int>.

[4] See < http://unfccc.int/resource/docs/2013/cop19/eng/10a03.pdf >.

[5] See < http://www.ipcc-nggip.iges.or.jp/public/index.html>.

and sinks in a given year for the United States are presented in a common manner in line with the UNFCCC reporting guidelines for the reporting of inventories under this international agreement.[6] The use of consistent methods to calculate emissions and sinks by all nations providing their inventories to the UNFCCC ensures that these reports are comparable. In this regard, U.S. emissions and sinks reported in this Inventory report are comparable to emissions and sinks reported by other countries. The manner that emissions and sinks are provided in this Inventory is one of many ways U.S. emissions and sinks could be examined; this Inventory report presents emissions and sinks in a common format consistent with how countries are to report inventories under the UNFCCC. The report itself follows this standardized format, and provides an explanation of the IPCC methods used to calculate emissions and sinks, and the manner in which those calculations are conducted.

On October 30, 2009, the U.S. Environmental Protection Agency (EPA) published a rule for the mandatory reporting of greenhouse gases from large greenhouse gas emissions sources in the United States. Implementation of 40 CFR Part 98 is referred to as the Greenhouse Gas Reporting Program (GHGRP). 40 CFR part 98 applies to direct greenhouse gas emitters, fossil fuel suppliers, industrial gas suppliers, and facilities that inject CO_2 underground for sequestration or other reasons.[7] Reporting is at the facility level, except for certain suppliers of fossil fuels and industrial greenhouse gases. The GHGRP dataset and the data presented in this Inventory report are complementary and, as indicated in the respective methodological and planned improvements sections in this report's chapters, EPA is using the data, as applicable, to improve the national estimates presented in this Inventory.

ES.1. Background Information

Greenhouse gases trap heat and make the planet warmer. The most important greenhouse gases directly emitted by humans include CO_2, CH_4, N_2O, and several other fluorine-containing halogenated substances. Although the direct greenhouse gases CO_2, CH_4, and N_2O occur naturally in the atmosphere, human activities have changed their atmospheric concentrations. From the pre-industrial era (i.e., ending about 1750) to 2014, concentrations of these greenhouse gases have increased globally by 43, 152, and 20 percent, respectively (IPCC 2013 and NOAA/ESRL 2016). This annual report estimates the total national greenhouse gas emissions and removals associated with human activities across the United States.

Global Warming Potentials

Gases in the atmosphere can contribute to climate change both directly and indirectly. Direct effects occur when the gas itself absorbs radiation. Indirect radiative forcing occurs when chemical transformations of the substance produce other greenhouse gases, when a gas influences the atmospheric lifetimes of other gases, and/or when a gas affects atmospheric processes that alter the radiative balance of the earth (e.g., affect cloud formation or albedo).[8] The IPCC developed the Global Warming Potential (GWP) concept to compare the ability of each greenhouse gas to trap heat in the atmosphere relative to another gas.

The GWP of a greenhouse gas is defined as the ratio of the time-integrated radiative forcing from the instantaneous release of 1 kilogram (kg) of a trace substance relative to that of 1 kg of a reference gas (IPCC 2013). Direct radiative effects occur when the gas itself is a greenhouse gas. The reference gas used is CO_2, and therefore GWP-weighted emissions are measured in million metric tons of CO_2 equivalent (MMT CO_2 Eq.).[9,10] All gases in this

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[6] See <http://unfccc.int/resource/docs/2013/cop19/eng/10a03.pdf#page=2 >

[7] See < http://www.epa.gov/ghgreporting > and <http://ghgdata.epa.gov/ghgp/main.do>.

[8] Albedo is a measure of the Earth's reflectivity, and is defined as the fraction of the total solar radiation incident on a body that is reflected by it.

[9] Carbon comprises 12/44$^{\text{ths}}$ of carbon dioxide by weight.

[10] One teragram is equal to 10^{12} grams or one million metric tons.

Executive Summary are presented in units of MMT CO_2 Eq. Emissions by gas in unweighted mass tons are provided in the Trends chapter of this report.

UNFCCC reporting guidelines for national inventories require the use of GWP values from the *IPCC Fourth Assessment Report* (AR4) (IPCC 2007).[11] To comply with international reporting standards under the UNFCCC, official emission estimates are reported by the United States using AR4 GWP values, which have replaced the previously required use of SAR GWP values in the U.S. Inventory. All estimates are provided throughout the report in both CO_2 equivalents and unweighted units. A comparison of emission values using the AR4 GWP values versus the *IPCC Second Assessment Report* (SAR) (IPCC 1996), *IPCC Third Assessment Report (TAR)* (IPCC 2001), and the *IPCC Fifth Assessment Report* (AR5) (IPCC 2013) GWP values can be found in Chapter 1 and, in more detail, in Annex 6.1 of this report. The GWP values used in this report are listed below in Table ES-1.

Table ES-1: Global Warming Potentials (100-Year Time Horizon) Used in this Report

Gas	GWP
CO_2	1
CH_4[a]	25
N_2O	298
HFC-23	14,800
HFC-32	675
HFC-125	3,500
HFC-134a	1,430
HFC-143a	4,470
HFC-152a	124
HFC-227ea	3,220
HFC-236fa	9,810
HFC-4310mee	1,640
CF_4	7,390
C_2F_6	12,200
C_4F_{10}	8,860
C_6F_{14}	9,300
SF_6	22,800
NF_3	17,200

Source: IPCC (2007)

[a] The CH_4 GWP includes the direct effects and those indirect effects due to the production of tropospheric ozone and stratospheric water vapor. The indirect effect due to production of CO_2 is not included.

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[11] See < http://unfccc.int/resource/docs/2013/cop19/eng/10a03.pdf >.

ES.2. Recent Trends in U.S. Greenhouse Gas Emissions and Sinks

In 2014, total U.S. greenhouse gas emissions were 6,872.6 MMT, or million metric tons, CO_2 Eq. Total U.S. emissions have increased by 7.7 percent from 1990 to 2014, and emissions increased from 2013 to 2014 by 0.9 percent (61.5 MMT CO_2 Eq.). Additionally, relatively cool winter conditions led to an increase in fuels for the residential and commercial sectors for heating. In 2014 there also was an increase in industrial production across multiple sectors resulting in slight increases in industrial sector emissions. Lastly, transportation emissions increased as a result of a small increase in vehicle miles traveled (VMT) and fuel use across on-road transportation modes. Since 1990, U.S. emissions have increased at an average annual rate of 0.3 percent. Figure ES-1 through Figure ES-3 illustrate the overall trends in total U.S. emissions by gas, annual changes, and absolute change since 1990.

Table ES-2 provides a detailed summary of U.S. greenhouse gas emissions and sinks for 1990 through 2014.

Figure ES-1: U.S. Greenhouse Gas Emissions by Gas (MMT CO_2 Eq.)

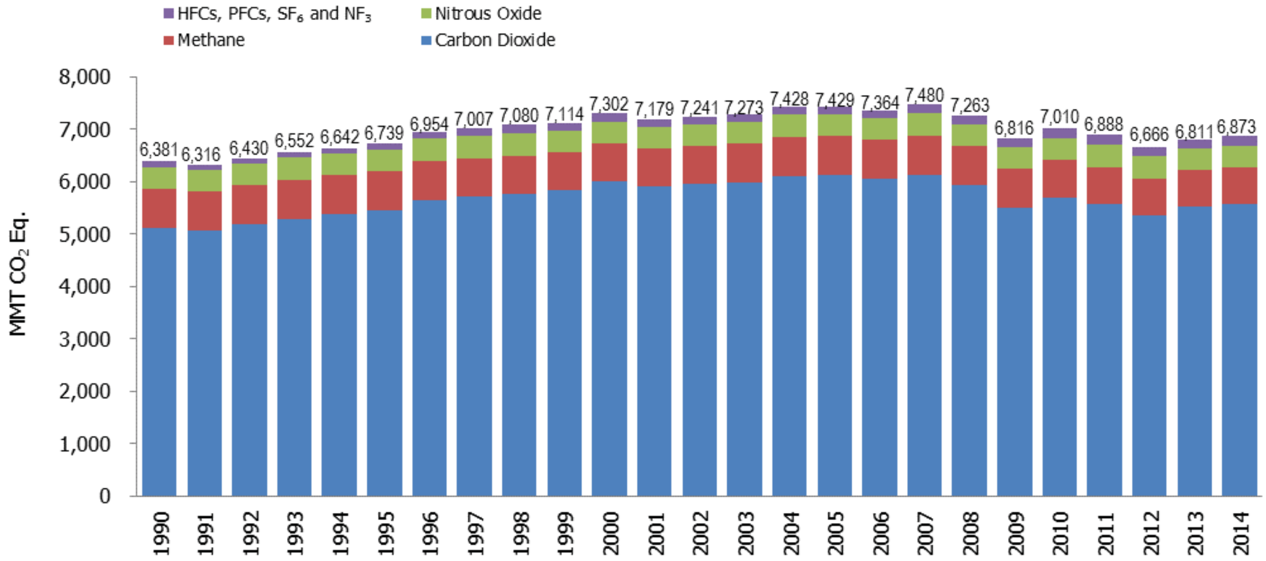


Figure ES-2: Annual Percent Change in U.S. Greenhouse Gas Emissions

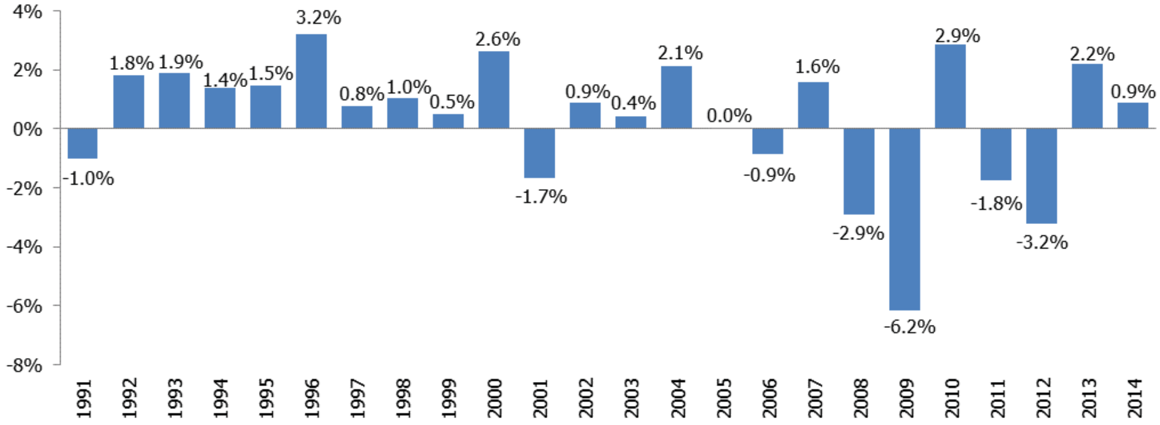


Figure ES-3: Annual Greenhouse Gas Emissions Relative to 1990 (1990=0)

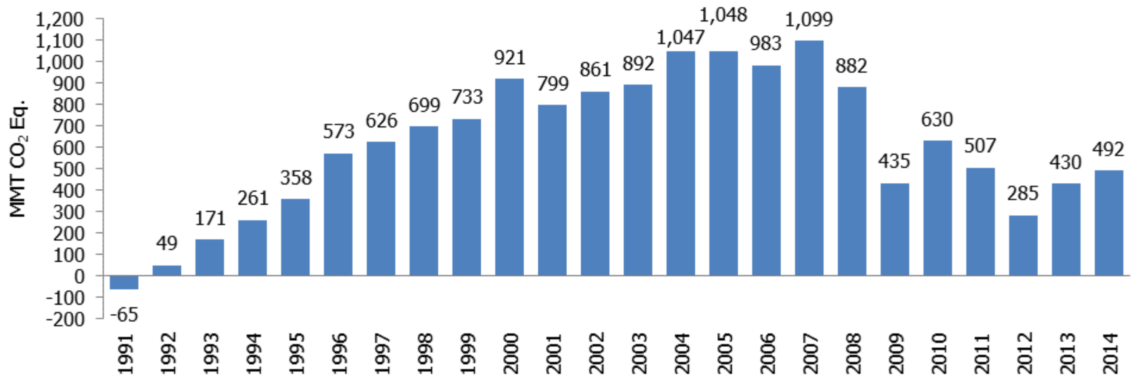


Table ES-2: Recent Trends in U.S. Greenhouse Gas Emissions and Sinks (MMT CO_2 Eq.)

Gas/Source	1990	2005	2010	2011	2012	2013	2014
CO_2	**5,124.0**	**6,132.6**	**5,698.2**	**5,568.6**	**5,361.0**	**5,513.2**	**5,564.3**
Fossil Fuel Combustion	4,740.7	5,747.1	5,358.3	5,227.7	5,024.7	5,157.6	5,208.7
Electricity Generation	*1,820.8*	*2,400.9*	*2,258.4*	*2,157.7*	*2,022.2*	*2,038.1*	*2,039.3*
Transportation	*1,493.8*	*1,887.0*	*1,728.3*	*1,707.6*	*1,696.8*	*1,713.0*	*1,737.4*
Industrial	*842.5*	*828.0*	*775.5*	*773.3*	*782.9*	*812.2*	*814.2*
Residential	*338.3*	*357.8*	*334.6*	*326.8*	*282.5*	*329.7*	*345.1*
Commercial	*217.4*	*223.5*	*220.1*	*220.7*	*196.7*	*221.0*	*231.6*
U.S. Territories	*27.9*	*49.9*	*41.4*	*41.5*	*43.6*	*43.5*	*41.0*
Non-Energy Use of Fuels	118.1	138.9	114.1	108.5	105.6	121.7	114.3
Iron and Steel Production & Metallurgical Coke Production	99.7	66.5	55.7	59.9	54.2	52.2	55.4
Cement Production	33.3	45.9	31.3	32.0	35.1	36.1	38.8
Natural Gas Systems[a]	37.6	30.0	32.3	35.6	34.8	37.8	37.8
Petrochemical Production	21.6	27.4	27.2	26.3	26.5	26.4	26.5
Lime Production	11.7	14.6	13.4	14.0	13.7	14.0	14.1
Other Process Uses of Carbonates	4.9	6.3	9.6	9.3	8.0	10.4	12.1
Ammonia Production	13.0	9.2	9.2	9.3	9.4	10.0	9.4
Incineration of Waste	8.0	12.5	11.0	10.5	10.4	9.4	9.4
Petroleum Systems[b]	4.4	4.9	4.2	4.5	5.1	6.0	6.0

Urea Fertilization	2.4	3.5	3.8	4.1	4.2	4.3	4.5
Carbon Dioxide Consumption	1.5	1.4	4.4	4.1	4.0	4.2	4.5
Liming	4.7	4.3	4.8	3.9	6.0	3.9	4.1
Urea Consumption for Non-Agricultural Purposes	3.8	3.7	4.7	4.0	4.4	4.2	4.0
Aluminum Production	6.8	4.1	2.7	3.3	3.4	3.3	3.3
Soda Ash Production and Consumption	2.8	3.0	2.7	2.7	2.8	2.8	2.8
Ferroalloy Production	2.2	1.4	1.7	1.7	1.9	1.8	1.9
Titanium Dioxide Production	1.2	1.8	1.8	1.7	1.5	1.7	1.8
Glass Production	1.5	1.9	1.5	1.3	1.2	1.3	1.3
Phosphoric Acid Production	1.5	1.3	1.1	1.2	1.1	1.1	1.1
Zinc Production	0.6	1.0	1.2	1.3	1.5	1.4	1.0
Peatlands Remaining Peatlands	1.1	1.1	1.0	0.9	0.8	0.8	0.8
Lead Production	0.5	0.6	0.5	0.5	0.5	0.5	0.5
Silicon Carbide Production and Consumption	0.4	0.2	0.2	0.2	0.2	0.2	0.2
Magnesium Production and Processing	+	+	+	+	+	+	+
LULUCF Total Net Flux[c]	*(704.2)*	*(636.1)*	*(683.2)*	*(683.6)*	*(680.8)*	*(682.4)*	*(685.8)*
Wood Biomass and Ethanol Consumption[d]	*219.4*	*229.8*	*265.1*	*268.1*	*267.7*	*286.3*	*293.7*
International Bunker Fuels[e]	*103.5*	*113.1*	*117.0*	*111.7*	*105.8*	*99.8*	*103.2*
CH_4	**745.3**	**735.4**	**720.8**	**711.8**	**703.8**	**704.0**	**707.9**
Landfills	184.4	187.3	176.3	176.9	173.5	176.7	181.8
Enteric Fermentation	164.2	168.9	171.3	168.9	166.7	165.5	164.3
Natural Gas Systems[a]	179.1	176.3	159.6	159.3	154.4	157.4	157.4
Coal Mining	96.5	64.1	82.3	71.2	66.5	64.6	64.6
Manure Management	37.2	56.3	60.9	61.5	63.7	61.4	61.2
Petroleum Systems[b]	31.5	23.5	21.3	22.0	23.3	25.2	25.2
Wastewater Treatment	15.7	15.9	15.5	15.3	15.2	15.0	15.0
Rice Cultivation	11.3	14.2	12.2	12.2	12.2	12.2	12.2
Stationary Combustion	8.5	7.4	7.1	7.1	6.6	8.0	8.1
Forest Fires	3.3	9.9	3.3	6.6	11.1	7.3	7.3
Abandoned Underground Coal Mines	7.2	6.6	6.6	6.4	6.2	6.2	6.2
Composting	0.4	1.9	1.8	1.9	1.9	2.0	2.1
Mobile Combustion	5.6	2.7	2.3	2.2	2.2	2.1	2.0
Field Burning of Agricultural Residues	0.2	0.2	0.3	0.3	0.3	0.3	0.3
Petrochemical Production	0.2	0.1	+	+	0.1	0.1	0.1
Ferroalloy Production	+	+	+	+	+	+	+
Silicon Carbide Production and Consumption	+	+	+	+	+	+	+
Iron and Steel Production & Metallurgical Coke Production	+	+	+	+	+	+	+
Peatlands Remaining Peatlands	+	+	+	+	+	+	+
Incineration of Waste	+	+	+	+	+	+	+
International Bunker Fuels[e]	*0.2*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*
N_2O	**409.5**	**406.4**	**415.2**	**423.8**	**419.4**	**411.0**	**411.4**
Agricultural Soil Management	302.9	296.7	320.4	322.9	322.9	318.4	318.5
Stationary Combustion	11.9	20.2	22.2	21.3	21.4	22.9	23.4
Manure Management	14.0	16.5	17.2	17.4	17.5	17.5	17.5
Mobile Combustion	41.2	34.4	23.6	22.4	20.0	18.2	16.3
Nitric Acid Production	12.1	11.3	11.5	10.9	10.5	10.7	10.9
Adipic Acid Production	15.2	7.1	4.2	10.2	5.5	4.0	5.4
Wastewater Treatment	3.4	4.3	4.7	4.8	4.9	4.9	4.9
Forest Fires	2.2	6.5	2.2	4.4	7.3	4.8	4.8

N_2O from Product Uses	4.2	4.2	4.2	4.2	4.2	4.2	4.2
Settlement Soils	1.4	2.3	2.4	2.5	2.5	2.4	2.4
Composting	0.3	1.7	1.6	1.7	1.7	1.8	1.8
Forest Soils	0.1	0.5	0.5	0.5	0.5	0.5	0.5
Incineration of Waste	0.5	0.4	0.3	0.3	0.3	0.3	0.3
Semiconductor Manufacture	+	0.1	0.1	0.2	0.2	0.2	0.2
Field Burning of Agricultural Residues	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Peatlands Remaining Peatlands	+	+	+	+	+	+	+
International Bunker Fuels[e]	*0.9*	*1.0*	*1.0*	*1.0*	*0.9*	*0.9*	*0.9*
HFCs, PFCs, SF_6 and NF_3	**102.0**	**154.4**	**176.2**	**183.6**	**181.4**	**182.9**	**189.1**
HFCs	**46.6**	**133.3**	**161.7**	**166.1**	**167.1**	**169.6**	**175.8**
Substitution of Ozone Depleting Substances[f]	0.3	113.0	153.5	157.1	161.4	165.3	171.4
HCFC-22 Production	46.1	20.0	8.0	8.8	5.5	4.1	4.1
Semiconductor Manufacture	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Magnesium Production and Processing	0.0	0.0	+	+	+	0.1	0.1
PFCs	**24.3**	**6.6**	**4.4**	**6.9**	**6.0**	**5.8**	**5.8**
Aluminum Production	21.5	3.4	1.9	3.5	2.9	3.0	3.0
Semiconductor Manufacture	2.8	3.2	2.6	3.4	3.0	2.9	2.9
SF_6	**31.1**	**14.0**	**9.5**	**10.0**	**7.7**	**6.9**	**6.9**
Electrical Transmission and Distribution	25.4	10.6	7.0	6.8	5.7	5.1	5.1
Magnesium Production and Processing	5.2	2.7	2.1	2.8	1.6	1.4	1.4
Semiconductor Manufacture	0.5	0.7	0.4	0.4	0.4	0.4	0.4
NF_3	**+**	**0.5**	**0.5**	**0.7**	**0.6**	**0.6**	**0.6**
Semiconductor Manufacture	+	0.5	0.5	0.7	0.6	0.6	0.6
Total Emissions	**6,380.8**	**7,428.8**	**7,010.5**	**6,887.8**	**6,665.7**	**6,811.2**	**6,872.6**
LULUCF Emissions[g]	**15.0**	**28.2**	**17.8**	**22.9**	**32.3**	**24.1**	**24.6**
LULUCF Total Net Flux[c]	**(704.2)**	**(636.1)**	**(683.2)**	**(683.6)**	**(680.8)**	**(682.4)**	**(685.8)**
LULUCF Sector Total[h]	**(689.1)**	**(607.9)**	**(665.3)**	**(660.7)**	**(648.5)**	**(658.3)**	**(661.3)**
Net Emissions (Sources and Sinks)	**5,676.6**	**6,792.6**	**6,327.3**	**6,204.2**	**5,984.9**	**6,128.8**	**6,186.8**

+ Does not exceed 0.05 MMT CO_2 Eq.

[a] The values in this table for Natural Gas Systems are presented from the previous Inventory and do not reflect updates to emission estimates for this category. See Section 3.7, Natural Gas Systems of the Energy chapter for more information. Gray highlighting was added on 2/24 for clarification.

[b] The values in this table for Petroleum Systems are presented from the previous Inventory and do not reflect updates to emission estimates for this category. See Section 3.6, Petroleum Systems of the Energy chapter for more information. Gray highlighting was added on 2/24 for clarification.

[c] Total net flux from LULUCF is only included in the Net Emissions total. Net flux from LULUCF includes the positive C sequestration reported for *Forest Land Remaining Forest Land, Land Converted to Forest Land, Cropland Remaining Cropland, Land Converted to Grassland, Settlements Remaining Settlements,* and *Other Land* plus the loss in C sequestration reported for *Land Converted to Cropland and Grassland Remaining Grassland.* Refer to Table ES-5 for a breakout of emissions and removals for Land Use, Land-Use Change, and Forestry by gas and source category.

[d] Emissions from Wood Biomass and Ethanol 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 Land Use, Land-Use Change, and Forestry.

[e] Emissions from International Bunker Fuels are not included in totals.

[f] Small amounts of PFC emissions also result from this source.

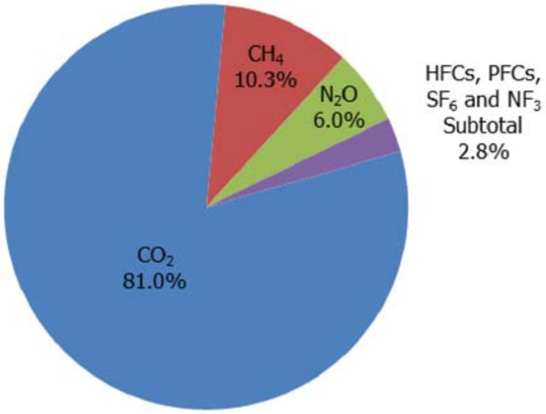
[g] LULUCF emissions include the CO_2, CH_4, and N_2O emissions reported for *Forest Fires, Forest Soils, Liming, Urea Fertilization, Settlement Soils,* and *Peatlands Remaining Peatlands*.

[h] The LULUCF Sector Total is the sum of positive emissions (i.e., sources) of greenhouse gases to the atmosphere plus removals of CO_2 (i.e., sinks or negative emissions) from the atmosphere.

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

Figure ES-4 illustrates the relative contribution of the direct greenhouse gases to total U.S. emissions in 2014. The primary greenhouse gas emitted by human activities in the United States was CO_2, representing approximately 81.0 percent of total greenhouse gas emissions. The largest source of CO_2, and of overall greenhouse gas emissions, was fossil fuel combustion. CH_4 emissions, which have decreased by 5.0 percent since 1990, resulted primarily from decomposition of wastes in landfills, enteric fermentation associated with domestic livestock, and natural gas systems. Agricultural soil management, manure management, mobile source fuel combustion and stationary fuel combustion were the major sources of N_2O emissions. Ozone depleting substance substitute emissions and emissions of HFC-23 during the production of HCFC-22 were the primary contributors to aggregate hydrofluorocarbon (HFC) emissions. Perfluorocarbon (PFC) emissions resulted as a byproduct of primary aluminum production and from semiconductor manufacturing, electrical transmission and distribution systems accounted for most sulfur hexafluoride (SF_6) emissions, and semiconductor manufacturing is the only source of NF_3 emissions.

Figure ES-4: 2014 Greenhouse Gas Emissions by Gas (Percentages based on MMT CO_2 Eq.)



Overall, from 1990 to 2014, total emissions of CO_2 increased by 440.2 MMT CO_2 Eq. (8.6 percent), while total emissions of CH_4 decreased by 37.4 MMT CO_2 Eq. (5.0 percent), and N_2O increased by 1.9 MMT CO_2 Eq. (0.5 percent). During the same period, aggregate weighted emissions of HFCs, PFCs, SF_6 and NF_3 rose by 87.1 MMT CO_2 Eq. (85.4 percent). From 1990 to 2014, HFCs increased by 129.2 MMT CO_2 Eq. (277.3 percent), PFCs decreased by 18.4 MMT CO_2 Eq. (76.0 percent), SF_6 decreased by 24.1 MMT CO_2 Eq. (77.7 percent), and NF_3 increased by 0.5 MMT CO_2 Eq. (1,070.1 percent). Despite being emitted in smaller quantities relative to the other principal greenhouse gases, emissions of HFCs, PFCs, SF_6 and NF_3 are significant because many of these gases have extremely high global warming potentials and, in the cases of PFCs and SF_6, long atmospheric lifetimes. Conversely, U.S. greenhouse gas emissions were partly offset by carbon sequestration in forests, trees in urban areas, agricultural soils, and landfilled yard trimmings and food scraps, which, in aggregate, offset 10.0 percent of total emissions in 2014. The following sections describe each gas's contribution to total U.S. greenhouse gas emissions in more detail.

Carbon Dioxide Emissions

The global carbon cycle is made up of large carbon flows and reservoirs. Billions of tons of carbon in the form of CO_2 are absorbed by oceans and living biomass (i.e., sinks) and are emitted to the atmosphere annually through natural processes (i.e., sources). When in equilibrium, carbon fluxes among these various reservoirs are roughly balanced.[12] Since the Industrial Revolution (i.e., about 1750), global atmospheric concentrations of CO_2 have risen approximately 43 percent (IPCC 2013 and NOAA/ESRL 2016), principally due to the combustion of fossil fuels. Within the United States, fossil fuel combustion accounted for 93.6 percent of CO_2 emissions in 2014. Globally, approximately 32,310 MMT of CO_2 were added to the atmosphere through the combustion of fossil fuels in 2012, of

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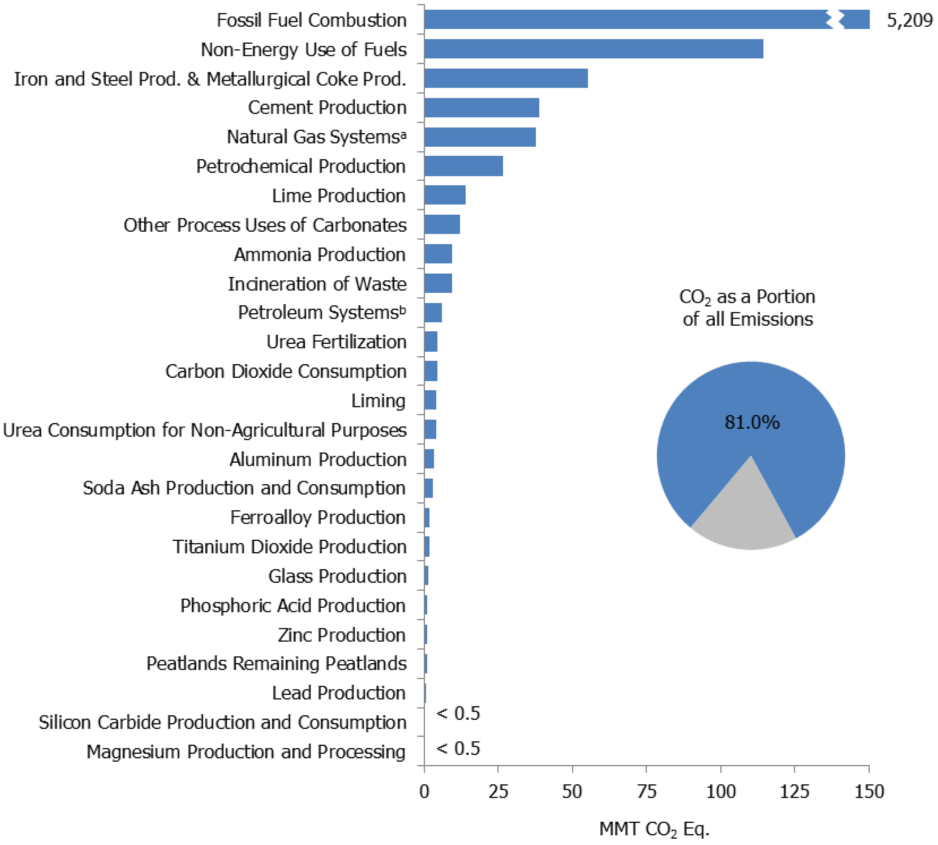
[12] The term "flux" is used to describe the net emissions of greenhouse gases to the atmosphere accounting for both the emissions of CO_2 to and the removals of CO_2 from the atmosphere. Removal of CO_2 from the atmosphere is also referred to as "carbon sequestration."

which the United States accounted for about 16 percent.[13] Changes in land use and forestry practices can also emit CO_2 (e.g., through conversion of forest land to agricultural or urban use) or can act as a sink for CO_2 (e.g., through net additions to forest biomass). Although fossil fuel combustion is the greatest source of CO_2 emissions, there are 25 additional sources of CO_2 emissions (Figure ES-5).

Figure ES-5: 2014 Sources of CO_2 Emissions



Note: Fossil Fuel Combustion includes electricity generation, which also includes emissions of less than 0.05 MMT CO_2 Eq. from geothermal-based generation.

[a] The value in this figure for Natural Gas Systems is presented from the previous Inventory and does not reflect updates to emission estimates for this category. See Section 3.7, Natural Gas Systems of the Energy chapter for more information.
[b] The value in this figure for Petroleum Systems is presented from the previous Inventory and does not reflect updates to emission estimates for this category. See Section 3.6, Petroleum Systems of the Energy chapter for more information.

As the largest source of U.S. greenhouse gas emissions, CO_2 from fossil fuel combustion has accounted for approximately 76 percent of GWP-weighted emissions since 1990, and is approximately 76 percent of total GWP-weighted emissions in 2014. Emissions of CO_2 from fossil fuel combustion increased at an average annual rate of 0.4 percent from 1990 to 2014. The fundamental factors influencing this trend include (1) a generally growing domestic economy over the last 25 years, (2) an overall growth in emissions from electricity generation and transportation activities, along with (3) a general decline in the carbon intensity of fuels combusted for energy in recent years by most sectors of the economy. Between 1990 and 2014, CO_2 emissions from fossil fuel combustion increased from 4,740.7 MMT CO_2 Eq. to 5,208.7 MMT CO_2 Eq., a 9.9 percent total increase over the twenty-five-year period. From 2013 to 2014, these emissions increased by 51.1 MMT CO_2 Eq. (1.0 percent).

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[13] Global CO_2 emissions from fossil fuel combustion were taken from Energy Information Administration *International Energy Statistics 2013* < http://tonto.eia.doe.gov/cfapps/ipdbproject/IEDIndex3.cfm> (EIA 2013).

Historically, changes in emissions from fossil fuel combustion have been the dominant factor affecting U.S. emission trends. Changes in CO_2 emissions from fossil fuel combustion are influenced by many long-term and short-term factors, including population and economic growth, energy price fluctuations, technological changes, energy fuel choices, and seasonal temperatures. In the short term, the overall consumption of fossil fuels in the United States fluctuates primarily 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. In the long term, energy consumption patterns respond to changes that affect the scale of consumption (e.g., population, number of cars, and size of houses), the efficiency with which energy is used in equipment (e.g., cars, power plants, steel mills, and light bulbs) and behavioral choices (e.g., walking, bicycling, or telecommuting to work instead of driving).

Figure ES-6: 2014 CO_2 Emissions from Fossil Fuel Combustion by Sector and Fuel Type (MMT CO_2 Eq.)

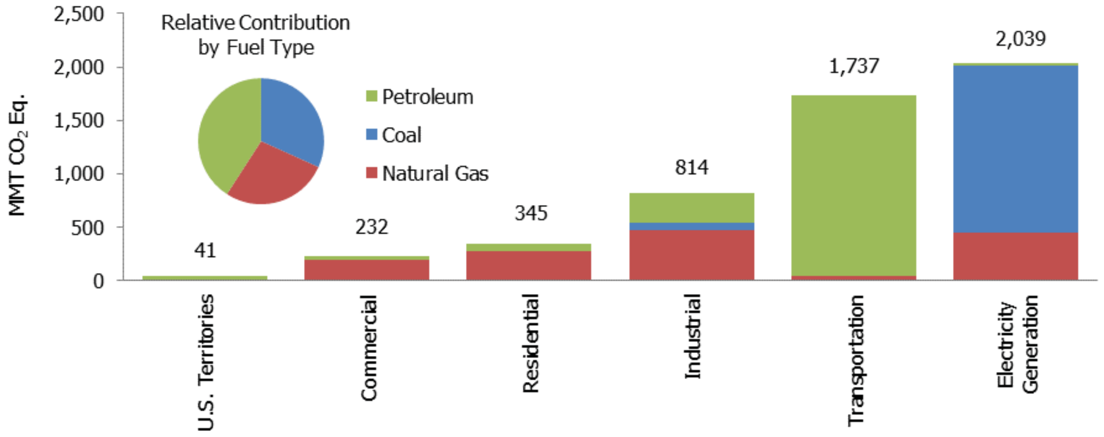
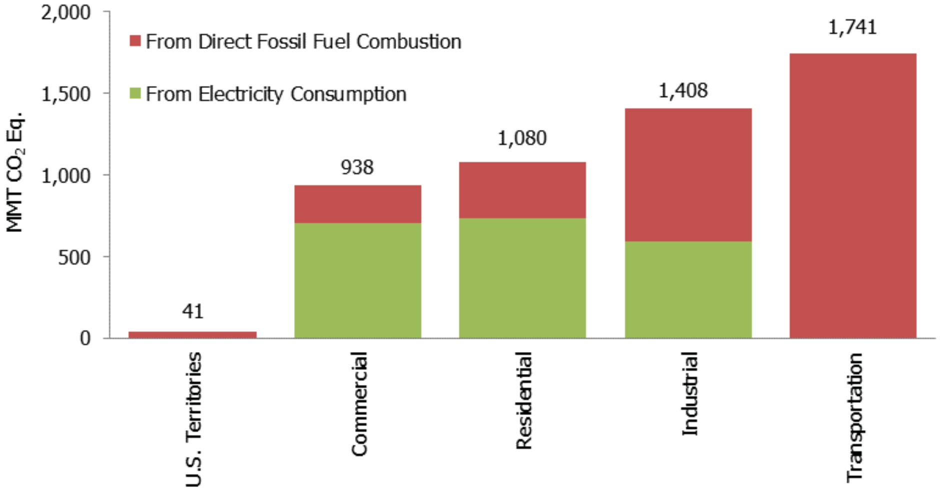


Figure ES-7: 2014 End-Use Sector Emissions of CO_2 from Fossil Fuel Combustion (MMT CO_2 Eq.)



The five major fuel consuming sectors contributing to CO_2 emissions from fossil fuel combustion are electricity generation, transportation, industrial, residential, and commercial. CO_2 emissions are produced by the electricity generation sector as they consume fossil fuel to provide electricity to one of the other four sectors, or "end-use" sectors. For the discussion below, electricity generation emissions have been distributed to each end-use sector on the basis of each sector's share of aggregate electricity consumption. This method of distributing emissions assumes that each end-use sector consumes electricity that is generated from the national average mix of fuels according to their carbon intensity. Emissions from electricity generation are also addressed separately after the end-use sectors have been discussed.

Note that emissions from U.S. Territories are calculated separately due to a lack of specific consumption data for the individual end-use sectors. Figure ES-6, Figure ES-7, and Table ES-3 summarize CO_2 emissions from fossil fuel combustion by end-use sector.

Table ES-3: CO_2 Emissions from Fossil Fuel Combustion by Fuel Consuming End-Use Sector (MMT CO_2 Eq.)

End-Use Sector	1990	2005	2010	2011	2012	2013	2014
Transportation	**1,496.8**	**1,891.8**	**1,732.7**	**1,711.9**	**1,700.6**	**1,717.0**	**1,741.5**
Combustion	1,493.8	1,887.0	1,728.3	1,707.6	1,696.8	1,713.0	1,737.4
Electricity	3.0	4.7	4.5	4.3	3.9	4.0	4.1
Industrial	**1,529.2**	**1,564.6**	**1,416.5**	**1,398.0**	**1,375.7**	**1,407.0**	**1,407.8**
Combustion	842.5	828.0	775.5	773.3	782.9	812.2	814.2
Electricity	686.7	736.6	641.0	624.7	592.8	594.7	593.6
Residential	**931.4**	**1,214.1**	**1,174.6**	**1,117.5**	**1,007.8**	**1,064.6**	**1,080.4**
Combustion	338.3	357.8	334.6	326.8	282.5	329.7	345.1
Electricity	593.0	856.3	840.0	790.7	725.3	734.9	735.2
Commercial	**755.4**	**1,026.8**	**993.0**	**958.8**	**897.0**	**925.5**	**938.1**
Combustion	217.4	223.5	220.1	220.7	196.7	221.0	231.6
Electricity	538.0	803.3	772.9	738.0	700.3	704.5	706.5
U.S. Territories[a]	**27.9**	**49.9**	**41.4**	**41.5**	**43.6**	**43.5**	**41.0**
Total	**4,740.7**	**5,747.1**	**5,358.3**	**5,227.7**	**5,024.7**	**5,157.6**	**5,208.7**
Electricity Generation	**1,820.8**	**2,400.9**	**2,258.4**	**2,157.7**	**2,022.2**	**2,038.1**	**2,039.3**

Note: Totals may not sum due to independent rounding. Combustion-related emissions from electricity generation are allocated based on aggregate national electricity consumption by each end-use sector.

[a] 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.

Transportation End-Use Sector. When electricity-related emissions are distributed to economic end-use sectors, transportation activities accounted for 33.4 percent of U.S. CO_2 emissions from fossil fuel combustion in 2014. The largest sources of transportation CO_2 emissions in 2014 were passenger cars (42.5 percent), medium- and heavy-duty trucks (23.1 percent), light-duty trucks, which include sport utility vehicles, pickup trucks, and minivans (17.8 percent), commercial aircraft (6.6 percent), pipelines (2.7 percent), rail (2.6 percent), and ships and boats (1.6 percent). Annex 3.2 presents the total emissions from all transportation and mobile sources, including CO_2, CH_4, N_2O, and HFCs.

In terms of the overall trend, from 1990 to 2014, total transportation CO_2 emissions rose by 16 percent 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 2014). The number of vehicle miles traveled by light-duty motor vehicles (passenger cars and light-duty trucks) increased 37 percent from 1990 to 2014, as a result of a confluence of factors including population growth, economic growth, urban sprawl, and low fuel prices during the beginning of this period. Almost all of the energy consumed for transportation was supplied by petroleum-based products, with more than half being related to gasoline consumption in automobiles and other highway vehicles. Other fuel uses, especially diesel fuel for freight trucks and jet fuel for aircraft, accounted for the remainder.

Industrial End-Use Sector. Industrial CO_2 emissions, resulting both directly from the combustion of fossil fuels and indirectly from the generation of electricity that is consumed by industry, accounted for 27 percent of CO_2 from fossil fuel combustion in 2014. Approximately 58 percent of these emissions resulted from direct fossil fuel combustion to produce steam and/or heat for industrial processes. The remaining emissions resulted from consuming electricity for motors, electric furnaces, ovens, lighting, and other applications. In contrast to the other end-use sectors, emissions from industry have steadily declined since 1990. This decline is due to structural changes in the U.S. economy (i.e., shifts from a manufacturing-based to a service-based economy), fuel switching, and efficiency improvements.

Residential and Commercial End-Use Sectors. The residential and commercial end-use sectors accounted for 21 and 18 percent, respectively, of CO_2 emissions from fossil fuel combustion in 2014. Both sectors relied heavily on electricity for meeting energy demands, with 68 and 75 percent, respectively, of their emissions attributable to electricity consumption for lighting, heating, cooling, and operating appliances. The remaining emissions were due to the consumption of natural gas and petroleum for heating and cooking. Emissions from the residential and commercial end-use sectors have increased by 16 percent and 24 percent since 1990, respectively, due to increasing electricity consumption for lighting, heating, air conditioning, and operating appliances.

Electricity Generation. The United States relies on electricity to meet a significant portion of its energy demands. Electricity generators consumed 34 percent of total U.S. energy uses from fossil fuels and emitted 39 percent of the CO_2 from fossil fuel combustion in 2014. The type of fuel combusted by electricity generators has a significant effect on their emissions. For example, some electricity is generated through non-fossil fuel options such as nuclear, hydroelectric, or geothermal energy. Including all electricity generation modes, generators relied on coal for approximately 39 percent of their total energy requirements in 2014.[14] In addition, the coal used by electricity generators accounted for 93 percent of all coal consumed for energy in the United States in 2014.[15] Recently a decrease in the carbon intensity of fuels consumed to generate electricity has occurred due to a decrease in coal consumption, and increased natural gas consumption and other generation sources. Including all electricity generation modes, electricity generators used natural gas for approximately 27 percent of their total energy requirements in 2014.[16] Across the time series, changes in electricity demand and the carbon intensity of fuels used for electricity generation have a significant impact on CO_2 emissions.

Other significant CO_2 trends included the following:

- Carbon dioxide emissions from non-energy use of fossil fuels have decreased by 3.8 MMT CO_2 Eq. (3.2 percent) from 1990 through 2014. Emissions from non-energy uses of fossil fuels were 114.3 MMT CO_2 Eq. in 2014, which constituted 2.1 percent of total national CO_2 emissions, approximately the same proportion as in 1990.

- Carbon dioxide emissions from iron and steel production and metallurgical coke production have declined by 44.3 MMT CO_2 Eq. (44.5 percent) from 1990 through 2014, due to restructuring of the industry, technological improvements, and increased scrap steel utilization.

- Carbon dioxide emissions from ammonia production (9.4 MMT CO_2 Eq. in 2014) decreased by 3.6 MMT CO_2 Eq. (27.7 percent) since 1990. Ammonia production relies on natural gas as both a feedstock and a fuel, and as such, market fluctuations and volatility in natural gas prices affect the production of ammonia.

- Carbon sequestration from Land Use, Land-Use Change, and Forestry decreased by 18.4 MMT CO_2 Eq. (2.6 percent) from 1990 through 2014. This increase was primarily due to a decrease in the rate of net C accumulation in agricultural soil carbon stocks. Annual carbon accumulation in landfilled yard trimmings and food scraps slowed over this period, while the rate of carbon accumulation in urban trees increased.

Box ES- 2: Use of Ambient Measurements Systems for Validation of Emission Inventories

In following the UNFCCC requirement under Article 4.1 to develop and submit national greenhouse gas emission inventories, the emissions and sinks presented in this report are organized by source and sink categories and calculated using internationally-accepted methods provided by the IPCC.[17] Several recent studies have measured emissions at the national or regional level (e.g., Petron 2012, Miller et al. 2013) with results that differ from EPA's

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[14] See < http://www.eia.gov/energyexplained/index.cfm?page=electricity_in_the_united_states >.

[15] See Table 6.2 Coal Consumption by Sector of EIA 2015a.

[16] See < http://www.eia.gov/energyexplained/index.cfm?page=electricity_in_the_united_states >.

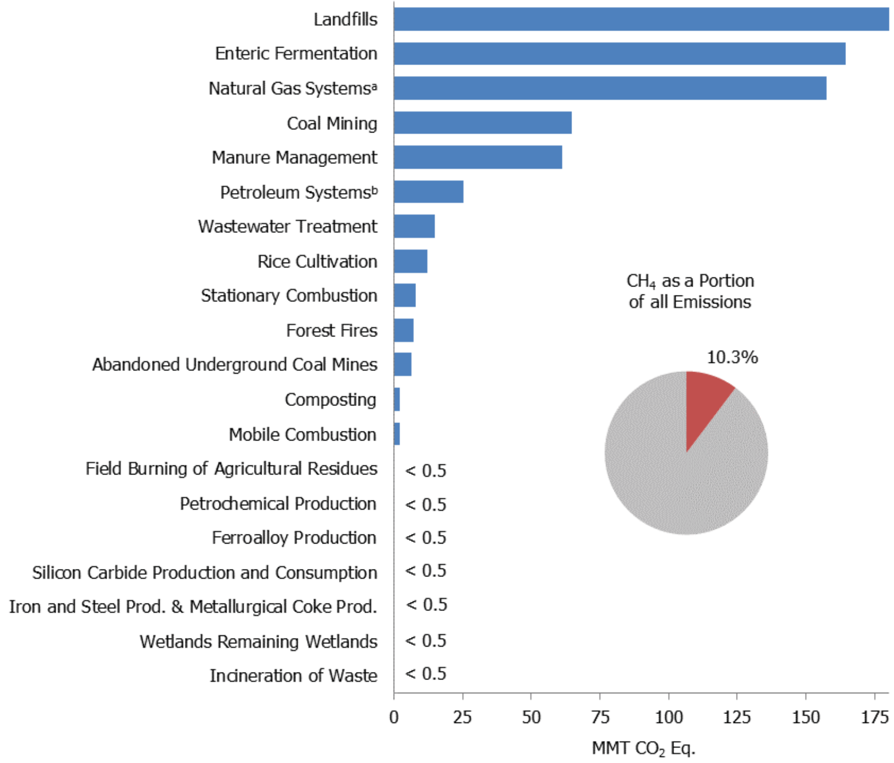
[17] See < http://www.ipcc-nggip.iges.or.jp/public/index.html>.

estimate of emissions. A recent study (Brandt et al. 2014) reviewed technical literature on methane emissions and estimated methane emissions from all anthropogenic sources (e.g., livestock, oil and gas, waste emissions) to be greater than EPA's estimate. EPA has engaged with researchers on how remote sensing, ambient measurement, and inverse modeling techniques for greenhouse gas emissions could assist in improving the understanding of inventory estimates. An area of particular interest in EPA's outreach efforts is how these data can be used in a manner consistent with this Inventory report's transparency on its calculation methodologies, and the ability of these techniques to attribute emissions and removals from remote sensing to anthropogenic sources, as defined by the IPCC for this report, versus natural sources and sinks. In working with the research community on ambient measurement and remote sensing techniques to improve national greenhouse gas inventories, EPA relies upon guidance from the IPCC on the use of measurements and modeling to validate emission inventories.[18]

Methane Emissions

Methane (CH_4) is 25 times as effective as CO_2 at trapping heat in the atmosphere (IPCC 2007). Over the last two hundred and fifty years, the concentration of CH_4 in the atmosphere increased by 152 percent (IPCC 2013 and CDIAC 2014). Anthropogenic sources of CH_4 include natural gas and petroleum systems, agricultural activities, landfills, coal mining, wastewater treatment, stationary and mobile combustion, and certain industrial processes (see Figure ES-8).

Figure ES-8: 2014 Sources of CH_4 Emissions (MMT CO_2 Eq.)



[a] The value in this figure for Natural Gas Systems is presented from the previous Inventory and does not reflect updates to emission estimates for this category. See Section 3.7, Natural Gas Systems of the Energy chapter for more information.

[b] The value in this figure for Petroleum Systems is presented from the previous Inventory and does not reflect updates to emission estimates for this category. See Section 3.6, Petroleum Systems of the Energy chapter for more information.

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[18] See < http://www.ipcc-nggip.iges.or.jp/meeting/pdffiles/1003_Uncertainty%20meeting_report.pdf >.

Some significant trends in U.S. emissions of CH_4 include the following:

- Landfills are the largest anthropogenic source of CH_4 emissions in the United States (181.8 MMT CO_2 Eq.), accounting for 25.7 percent of total CH_4 emissions in 2014. From 1990 to 2014, CH_4 emissions from landfills decreased by 2.6 MMT CO_2 Eq. (1.4 percent), with small increases occurring in some interim years. This downward trend in overall emissions can be attributed to a 21 percent reduction in the amount of decomposable materials (i.e., paper and paperboard, food scraps, and yard trimmings) discarded in MSW landfills over the time series (EPA 2015b) and an increase in the amount of landfill gas collected and combusted (i.e., used for energy or flared),[19] which has more than offset the additional CH_4 emissions resulting from an increase in the amount of municipal solid waste landfilled.

- Enteric fermentation is the second largest anthropogenic source of CH_4 emissions in the United States. In 2014, enteric fermentation CH_4 emissions were 164.3 MMT CO_2 Eq. (23.2 percent of total CH_4 emissions), which represents an increase of 0.1 MMT CO_2 Eq. (0.1 percent) since 1990. This increase in emissions from 1990 to 2014 in enteric generally follows the increasing trends in cattle populations. From 1990 to 1995 emissions increased and then generally decreased from 1996 to 2004, mainly due to fluctuations in beef cattle populations and increased digestibility of feed for feedlot cattle. Emissions increased from 2005 to 2007, as both dairy and beef populations underwent increases and the literature for dairy cow diets indicated a trend toward a decrease in feed digestibility for those years. Emissions decreased again from 2008 to 2014 as beef cattle populations again decreased.

- Substantial new data are available on natural gas and petroleum systems from EPA's Greenhouse Gas Reporting Program (GHGRP) and a number of new studies. EPA is evaluating approaches for incorporating this new data into its emission estimates. In Section 3.7 and Section 3.6 of the Energy chapter, updated draft estimates of CH_4 emissions for the year 2013 are presented for Natural Gas Systems and Petroleum Systems, respectively, to provide reviewers of the public review draft an indication of the sector-wide emission estimates resulting from the combined changes under consideration. EPA is continuing to evaluate stakeholder feedback on the updates under consideration. For the final Inventory, the 2013 estimates presented in this section will be refined, and a full time series of emission estimates will be developed based on feedback received through the earlier stakeholder reviews of the memos and through this public review period. The details of the revisions under consideration for this year's Inventory, and key questions for stakeholder feedback are available in segment-level memoranda at http://www3.epa.gov/climatechange/ghgemissions/usinventoryreport/natural-gas-systems.html.

- Methane emissions from manure management increased by 64.7 percent since 1990, from 37.2 MMT CO_2 Eq. in 1990 to 61.2 MMT CO_2 Eq. in 2014. The majority of this increase was from swine and dairy cow manure, since the general trend in manure management is one of increasing use of liquid systems, which tends to produce greater CH_4 emissions. The increase in liquid systems is the combined result of a shift to larger facilities, and to facilities in the West and Southwest, all of which tend to use liquid systems. Also, new regulations limiting the application of manure nutrients have shifted manure management practices at smaller dairies from daily spread to manure managed and stored on site.

Nitrous Oxide Emissions

Nitrous oxide is produced by biological processes that occur in soil and water and by a variety of anthropogenic activities in the agricultural, energy-related, industrial, and waste management fields. While total N_2O emissions are much lower than CO_2 emissions, N_2O is approximately 300 times more powerful than CO_2 at trapping heat in the atmosphere (IPCC 2007). Since 1750, the global atmospheric concentration of N_2O has risen by approximately 20 percent (IPCC 2013 and CDIAC 2014). The main anthropogenic activities producing N_2O in the United States are agricultural soil management, stationary fuel combustion, fuel combustion in motor vehicles, manure management and nitric acid production (see Figure ES-9).

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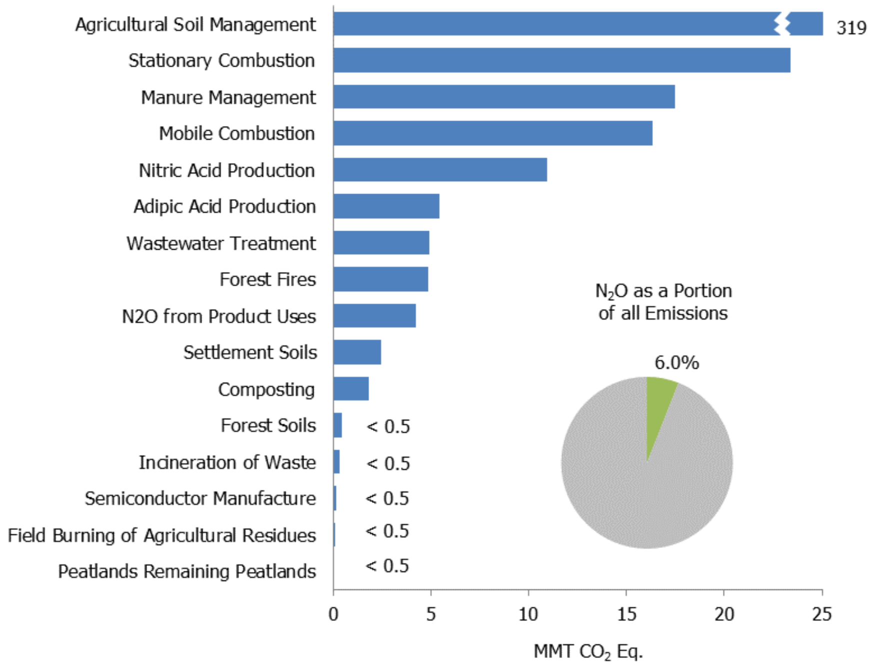
[19] Carbon dioxide emissions from landfills are not included specifically in summing waste sector totals. Net carbon fluxes from changes in biogenic carbon reservoirs are accounted for in the estimates for Land Use, Land-Use Change, and Forestry.

Figure ES-9: 2014 Sources of N_2O Emissions (MMT CO_2 Eq.)



Some significant trends in U.S. emissions of N_2O include the following:

- Agricultural soils accounted for approximately 77.4 percent of N_2O emissions and 4.6 percent of total emissions in the United States in 2014. Estimated emissions from this source in 2014 were 318.5 MMT CO_2 Eq. Annual N_2O emissions from agricultural soils fluctuated between 1990 and 2014, although overall emissions were 5.1 percent higher in 2014 than in 1990. Year-to-year fluctuations are largely a reflection of annual variation in weather patterns, synthetic fertilizer use, and crop production.
- Nitrous oxide emissions from stationary combustion increased 11.5 MMT CO_2 Eq. (96.4 percent) from 1990 through 2014. Nitrous oxide emissions from this source increased primarily as a result of an increase in the number of coal fluidized bed boilers in the electric power sector.
- In 2014, total N_2O emissions from manure management were estimated to be 17.5 MMT CO_2 Eq.; emissions were 14.0 MMT CO_2 Eq. in 1990. These values include both direct and indirect N_2O emissions from manure management. Nitrous oxide emissions have remained fairly steady since 1990. Small changes in N_2O emissions from individual animal groups exhibit the same trends as the animal group populations, with the overall net effect that N_2O emissions showed a 24.9 percent increase from 1990 to 2014 and a 0.1 percent decrease from 2013 through 2014. Overall shifts toward liquid systems have driven down the emissions per unit of nitrogen excreted.
- Nitrous oxide emissions from mobile combustion decreased 24.9 MMT CO_2 Eq. (60.4 percent) from 1990 through 2014. Nitrous oxide emissions from this source decreased primarily as a result of N_2O national emissions control standards and emissions control technologies for on-road vehicles.
- Nitrous oxide emissions from adipic acid production were 5.4 MMT CO_2 Eq. in 2014, and have decreased significantly since 1990 due to both the widespread installation of pollution control measures in the late 1990s and plant idling in the late 2000s. Emissions from adipic acid production have decreased by 64.2 percent since 1990 and by 67.8 percent since a peak in 1995.

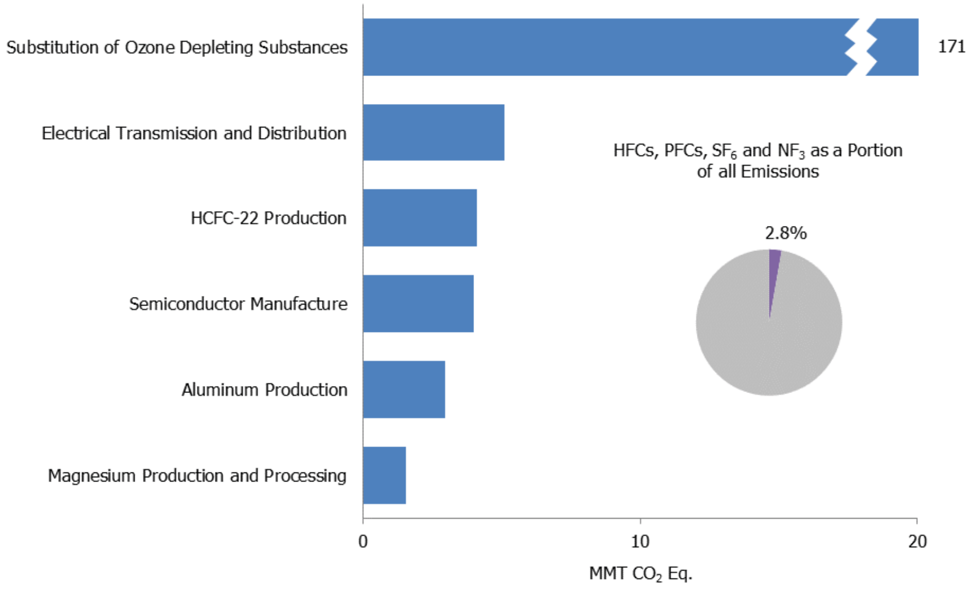
HFC, PFC, SF_6, and NF_3 Emissions

HFCs and PFCs are families of synthetic chemicals that are used as alternatives to Ozone Depleting Substances, which are being phased out under the Montreal Protocol and Clean Air Act Amendments of 1990. HFCs and PFCs do not deplete the stratospheric ozone layer, and are therefore acceptable alternatives under the Montreal Protocol.

These compounds, however, along with SF_6 and NF_3, are potent greenhouse gases. In addition to having high global warming potentials, SF_6 and PFCs have extremely long atmospheric lifetimes, resulting in their essentially irreversible accumulation in the atmosphere once emitted. Sulfur hexafluoride is the most potent greenhouse gas the IPCC has evaluated (IPCC 2013).

Other emissive sources of these gases include HCFC-22 production, electrical transmission and distribution systems, semiconductor manufacturing, aluminum production, and magnesium production and processing (see Figure ES-10).

Figure ES-10: 2014 Sources of HFCs, PFCs, SF_6, and NF_3 Emissions (MMT CO_2 Eq.)



Some significant trends in U.S. HFC, PFC, SF_6, and NF_3 emissions include the following:

- Emissions resulting from the substitution of ozone depleting substances (ODS) (e.g., CFCs) have been consistently increasing, from small amounts in 1990 to 171.4 MMT CO_2 Eq. in 2014. This increase was in large part the result of efforts to phase out CFCs and other ODSs in the United States. In the short term, this trend is expected to continue, and will likely continue over the next decade as HCFCs, which are interim substitutes in many applications, are themselves phased-out under the provisions of the Copenhagen Amendments to the *Montreal Protocol*.
- GWP-weighted PFC, HFC, SF_6, and NF_3 emissions from semiconductor manufacture have increased by 12 percent from 1990 to 2014, due to industrial growth and the adoption of emissions reduction technologies. Within that time span, emissions peaked in 1999, the initial year of EPA's PFC Reduction / Climate Partnership for the Semiconductor Industry, but have since declined to 4.0 MMT CO_2 Eq. in 2014 (a 56 percent decrease relative to 1999).
- SF_6 emissions from electric power transmission and distribution systems decreased by 79.9 percent (20.3 MMT CO_2 Eq.) from 1990 to 2014. There are two potential causes for this decrease: (1) a sharp increase in the price of SF_6 during the 1990s and (2) a growing awareness of the environmental impact of SF_6 emissions through programs such as EPA's SF_6 Emission Reduction Partnership for Electric Power Systems.

- PFC emissions from aluminum production decreased by 86.2 percent (18.5 MMT CO_2 Eq.) from 1990 to 2014. This decline is due both to reductions in domestic aluminum production and to actions taken by aluminum smelting companies to reduce the frequency and duration of anode effects.

ES.3. Overview of Sector Emissions and Trends

In accordance with the UNFCCC decision to set the *2006 IPCC Guidelines for National Greenhouse Gas Inventories* (IPCC 2006) as the standard for Annex I countries at the Nineteenth Conference of the Parties (UNFCCC 2014), Figure ES-11 and Table ES-4 aggregate emissions and sinks by these chapters. Emissions of all gases can be summed from each source category from IPCC guidance. Over the twenty-five-year period of 1990 to 2014, total emissions in the Energy, Industrial Processes and Product Use, Agriculture, and Waste sectors grew by 388.9 MMT CO_2 Eq. (7.3 percent), 47.7 MMT CO_2 Eq. (14.0 percent), 44.2 MMT CO_2 Eq. (8.3 percent), and 1.5 MMT CO_2 Eq. (0.7 percent), respectively. Over the same period, estimates of net C sequestration in the Land Use, Land-Use Change, and Forestry (LULUCF) sector (magnitude of emissions plus CO_2 removals from all LULUCF source categories) decreased by 27.9 MMT CO_2 Eq. (4.0 percent).

Figure ES-11: U.S. Greenhouse Gas Emissions and Sinks by Chapter/IPCC Sector (MMT CO_2 Eq.)

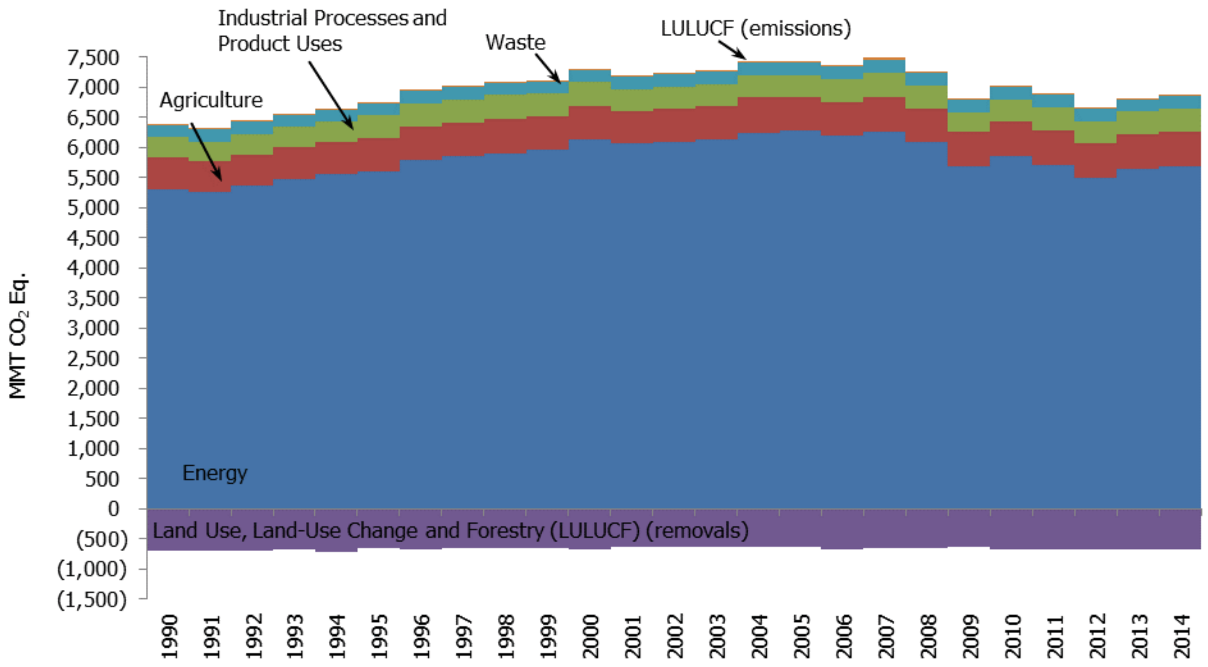


Table ES-4: Recent Trends in U.S. Greenhouse Gas Emissions and Sinks by Chapter/IPCC Sector (MMT CO_2 Eq.)

Chapter/IPCC Sector	1990	2005	2010	2011	2012	2013	2014
Energy	**5,290.9**	**6,269.0**	**5,845.2**	**5,699.0**	**5,481.3**	**5,637.4**	**5,679.8**
Fossil Fuel Combustion	4,740.7	5,747.1	5,358.3	5,227.7	5,024.7	5,157.6	5,208.7
Natural Gas Systems[a]	216.8	206.3	191.9	194.8	189.2	195.2	195.2
Non-Energy Use of Fuels	118.1	138.9	114.1	108.5	105.6	121.7	114.3
Coal Mining	96.5	64.1	82.3	71.2	66.5	64.6	64.6
Stationary Combustion	20.4	27.6	29.2	28.4	28.0	30.9	31.5

Petroleum Systems[b]	36.0	28.4	25.5	26.4	28.3	31.2	31.2
Mobile Combustion	46.9	37.1	25.9	24.7	22.2	20.3	18.4
Incineration of Waste	8.4	12.8	11.4	10.9	10.7	9.7	9.7
Abandoned Underground Coal Mines	7.2	6.6	6.6	6.4	6.2	6.2	6.2
Industrial Processes and Product Use	**340.9**	**367.6**	**365.2**	**382.2**	**371.4**	**373.8**	**388.6**
Substitution of Ozone Depleting Substances	0.3	113.0	153.5	157.1	161.4	165.3	171.4
Iron and Steel Production & Metallurgical Coke Production	99.7	66.6	55.7	59.9	54.2	52.2	55.4
Cement Production	33.3	45.9	31.3	32.0	35.1	36.1	38.8
Petrochemical Production	21.8	27.5	27.3	26.4	26.5	26.5	26.6
Lime Production	11.7	14.6	13.4	14.0	13.7	14.0	14.1
Other Process Uses of Carbonates	4.9	6.3	9.6	9.3	8.0	10.4	12.1
Nitric Acid Production	12.1	11.3	11.5	10.9	10.5	10.7	10.9
Ammonia Production	13.0	9.2	9.2	9.3	9.4	10.0	9.4
Aluminum Production	28.3	7.6	4.6	6.8	6.4	6.2	6.2
Adipic Acid Production	15.2	7.1	4.2	10.2	5.5	4.0	5.4
Electrical Transmission and Distribution	25.4	10.6	7.0	6.8	5.7	5.1	5.1
Carbon Dioxide Consumption	1.5	1.4	4.4	4.1	4.0	4.2	4.5
N_2O from Product Uses	4.2	4.2	4.2	4.2	4.2	4.2	4.2
Semiconductor Manufacture	3.6	4.7	3.8	4.9	4.5	4.2	4.2
HCFC-22 Production	46.1	20.0	8.0	8.8	5.5	4.1	4.1
Urea Consumption for Non-Agricultural Purposes	3.8	3.7	4.7	4.0	4.4	4.2	4.0
Soda Ash Production and Consumption	2.8	3.0	2.7	2.7	2.8	2.8	2.8
Ferroalloy Production	2.2	1.4	1.7	1.7	1.9	1.8	1.9
Titanium Dioxide Production	1.2	1.8	1.8	1.7	1.5	1.7	1.8
Magnesium Production and Processing	5.2	2.7	2.1	2.8	1.7	1.5	1.5
Glass Production	1.5	1.9	1.5	1.3	1.2	1.3	1.3
Phosphoric Acid Production	1.5	1.3	1.1	1.2	1.1	1.1	1.1
Zinc Production	0.6	1.0	1.2	1.3	1.5	1.4	1.0
Lead Production	0.5	0.6	0.5	0.5	0.5	0.5	0.5
Silicon Carbide Production and Consumption	0.4	0.2	0.2	0.2	0.2	0.2	0.2
Agriculture	**529.8**	**552.9**	**582.3**	**583.3**	**583.4**	**575.4**	**574.1**
Agricultural Soil Management	302.9	296.7	320.4	322.9	322.9	318.4	318.5
Enteric Fermentation	164.2	168.9	171.3	168.9	166.7	165.5	164.3
Manure Management	51.1	72.9	78.1	78.9	81.2	78.9	78.7
Rice Cultivation	11.3	14.2	12.2	12.2	12.2	12.2	12.2
Field Burning of Agricultural Residues	0.3	0.3	0.4	0.4	0.4	0.4	0.4
Land Use, Land-Use Change, and Forestry (Emissions)	**15.0**	**28.2**	**17.8**	**22.9**	**32.3**	**24.1**	**24.6**
Forest Fires	5.4	16.5	5.4	11.0	18.3	12.2	12.2
Urea Fertilization	2.4	3.5	3.8	4.1	4.2	4.3	4.5
Liming	4.7	4.3	4.8	3.9	6.0	3.9	4.1
Settlement Soils	1.4	2.3	2.4	2.5	2.5	2.4	2.4
Peatlands Remaining Peatlands	1.1	1.1	1.0	0.9	0.8	0.8	0.8
Forest Soils	0.1	0.5	0.5	0.5	0.5	0.5	0.5
Waste	**204.1**	**211.1**	**200.0**	**200.5**	**197.2**	**200.5**	**205.6**
Landfills	184.4	187.3	176.3	176.9	173.5	176.7	181.8
Wastewater Treatment	19.0	20.2	20.2	20.1	20.0	20.0	20.0
Composting	0.7	3.5	3.5	3.5	3.7	3.9	3.9
Total Emissions	**6,380.8**	**7,428.8**	**7,010.5**	**6,887.8**	**6,665.7**	**6,811.2**	**6,872.6**
LULUCF Total Net Flux[c]	**(704.2)**	**(636.1)**	**(683.2)**	**(683.6)**	**(680.8)**	**(682.4)**	**(685.8)**
Forest Land Remaining Forest Land[d]	(576.0)	(532.4)	(585.0)	(578.1)	(576.7)	(580.1)	(583.4)
Cropland Remaining Cropland	(43.2)	(16.5)	(4.7)	(20.0)	(18.7)	(16.8)	(16.0)
Land Converted to Cropland[c]	22.8	14.6	15.6	14.2	14.5	14.8	14.7
Grassland Remaining Grassland[c]	(12.9)	2.9	2.6	11.3	11.7	11.9	11.9

Land Converted to Grassland	(8.5)	(12.8)	(12.3)	(11.0)	(10.9)	(10.9)	(10.9)
Settlements Remaining Settlements	(60.4)	(80.5)	(86.1)	(87.3)	(88.4)	(89.5)	(90.6)
Other: Landfilled Yard Trimmings and Food Scraps	(26.0)	(11.4)	(13.2)	(12.7)	(12.2)	(11.7)	(11.6)
Net Emissions (Sources and Sinks)	**5,676.6**	**6,792.6**	**6,327.3**	**6,204.2**	**5,984.9**	**6,128.8**	**6,186.8**

[a] The values in this table for Natural Gas Systems are presented from the previous Inventory and do not reflect updates to emission estimates for this category. See Section 3.7, Natural Gas Systems of the Energy chapter for more information. Gray highlighting was added on 2/24 for clarification.

[b] The values in this table for Petroleum Systems are presented from the previous Inventory and do not reflect updates to emission estimates for this category. See Section 3.6, Petroleum Systems of the Energy chapter for more information. Gray highlighting was added on 2/24 for clarification.

[c] Total net flux from LULUCF is only included in the Net Emissions total. Net flux from LULUCF includes the positive C sequestration reported for *Forest Land Remaining Forest Land, Land Converted to Forest Land, Cropland Remaining Cropland, Land Converted to Grassland, Settlements Remaining Settlements,* and *Other Land* plus the loss in C sequestration reported for *Land Converted to Cropland and Grassland Remaining Grassland.* Refer to Table ES-5 for a breakout of emissions and removals for Land Use, Land-Use Change, and Forestry by gas and source category.

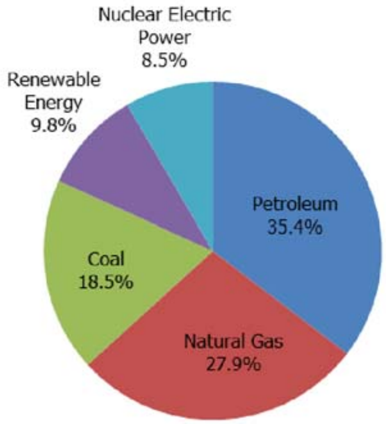
[d] Includes the effects of net additions to stocks of carbon stored in forest ecosystem pools and harvested wood products.

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

Energy

The Energy chapter contains emissions of all greenhouse gases resulting from stationary and mobile energy activities including fuel combustion and fugitive fuel emissions. Energy-related activities, primarily fossil fuel combustion, accounted for the vast majority of U.S. CO_2 emissions for the period of 1990 through 2014. In 2014, approximately 82 percent of the energy consumed in the United States (on a Btu basis) was produced through the combustion of fossil fuels. The remaining 18 percent came from other energy sources such as hydropower, biomass, nuclear, wind, and solar energy (see Figure ES-12). Energy-related activities are also responsible for CH_4 and N_2O emissions (37 percent and 10 percent of total U.S. emissions of each gas, respectively). Overall, emission sources in the Energy chapter account for a combined 82.6 percent of total U.S. greenhouse gas emissions in 2014.

Figure ES-12: 2014 U.S. Energy Consumption by Energy Source



Industrial Processes and Product Use

The Industrial Processes and Product Use (IPPU) chapter includes greenhouse gas emissions occurring from industrial processes and from the use of greenhouse gases in products.

Greenhouse gas emissions are produced as the by-products of many non-energy-related industrial activities. For example, industrial processes can chemically transform raw materials, which often release waste gases such as CO_2, CH_4, and N_2O. These processes include iron and steel production and metallurgical coke production, cement production, ammonia production, urea consumption, lime production, other process uses of carbonates (e.g., flux stone, flue gas desulfurization, and glass manufacturing), soda ash production and consumption, titanium dioxide production, phosphoric acid production, ferroalloy production, CO_2 consumption, silicon carbide production and consumption, aluminum production, petrochemical production, nitric acid production, adipic acid production, lead production, zinc production, and N_2O from product uses. Industrial processes also release HFCs, PFCs, SF_6, and NF_3. In addition to their use as ODS substitutes, HFCs, PFCs, SF_6, NF_3, and other fluorinated compounds are employed and emitted by a number of other industrial sources in the United States. These industries include aluminum production, HCFC-22 production, semiconductor manufacture, electric power transmission and distribution, and magnesium metal production and processing. Overall, emission sources in the Industrial Process and Product Use chapter account for 5.7 percent of U.S. greenhouse gas emissions in 2014.

Agriculture

The Agriculture chapter contains anthropogenic emissions from agricultural activities (except fuel combustion, which is addressed in the Energy chapter, and agricultural CO_2 fluxes, which are addressed in the Land Use, Land-Use Change, and Forestry chapter). Agricultural activities contribute directly to emissions of greenhouse gases through a variety of processes, including the following source categories: enteric fermentation in domestic livestock, livestock manure management, rice cultivation, agricultural soil management, and field burning of agricultural residues. CH_4 and N_2O were the primary greenhouse gases emitted by agricultural activities. CH_4 emissions from enteric fermentation and manure management represented 23.2 percent and 8.6 percent of total CH_4 emissions from anthropogenic activities, respectively, in 2014. Agricultural soil management activities such as fertilizer application and other cropping practices were the largest source of U.S. N_2O emissions in 2014, accounting for 77.4 percent. In 2014, emission sources accounted for in the Agricultural chapters were responsible for 8.4 percent of total U.S. greenhouse gas emissions.

Land Use, Land-Use Change, and Forestry

The Land Use, Land-Use Change, and Forestry chapter contains emissions of CH_4 and N_2O, and emissions and removals of CO_2 from forest management, other land-use activities, and land-use change. Forest management practices, tree planting in urban areas, the management of agricultural soils, and the landfilling of yard trimmings and food scraps resulted in a net removal of CO_2 (sequestration of C) in the United States. Forests (including vegetation, soils, and harvested wood) accounted for 85 percent of total 2014 CO_2 removals, urban trees accounted for 13 percent, mineral and organic soil carbon stock changes accounted for less than 0.5 percent, and landfilled yard trimmings and food scraps accounted for 1.7 percent of the total CO_2 removals in 2014. The net forest sequestration is a result of net forest growth and increasing forest area, as well as a net accumulation of carbon stocks in harvested wood pools. The net sequestration in urban forests is a result of net tree growth in these areas. In agricultural soils, mineral and organic soils sequester approximately 1.8 times as much C as is emitted from these soils through liming and urea fertilization. The mineral soil C sequestration is largely due to the conversion of cropland to permanent pastures and hay production, a reduction in summer fallow areas in semi-arid areas, an increase in the adoption of conservation tillage practices, and an increase in the amounts of organic fertilizers (i.e., manure and sewage sludge) applied to agriculture lands. The landfilled yard trimmings and food scraps net sequestration is due to the long-term accumulation of yard trimming carbon and food scraps in landfills.

Land use, land-use change, and forestry activities in 2014 resulted in a C sequestration (i.e., net CO_2 removals) of 685.8 MMT CO_2 Eq. (Table ES-5).[20] This represents an offset of 10.0 percent of total (i.e., gross) greenhouse gas emissions in 2014. Emissions from land use, land-use change, and forestry activities in 2014 represent 0.4 percent of total greenhouse gas emissions.[21] Between 1990 and 2014, total land use, land-use change, and forestry C sequestration decreased by 2.6 percent, primarily due to a decrease in the rate of net C accumulation in agricultural

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[20] Net flux from LULUCF includes the positive C sequestration reported for *Forest Land Remaining Forest Land, Land Converted to Forest Land, Cropland Remaining Cropland, Land Converted to Grassland, Settlements Remaining Settlements,* and *Other Land* plus the loss in C sequestration reported for *Land Converted to Cropland* and *Grassland Remaining Grassland*.

[21] LULUCF emissions include the CO_2, CH_4, and N_2O emissions reported for *Forest Fires, Forest Soils, Liming, Urea Fertilization, Settlement Soils,* and *Peatlands Remaining Peatlands.*

soil carbon stocks. Annual C accumulation in landfilled yard trimmings and food scraps slowed over this period, while the rate of annual C accumulation increased in urban trees.

CO_2 removals are presented in Table ES-5 along with CO_2, CH_4, and N_2O emissions for Land Use, Land-Use Change, and Forestry source categories.[22] Liming and urea fertilization in 2014 resulted in CO_2 emissions of 8.7 MMT CO_2 Eq. (8,653 kt). Lands undergoing peat extraction (i.e., *Peatlands Remaining Peatlands*) resulted in CO_2 emissions of 0.8 MMT CO_2 Eq. (842 kt) and CH_4 and N_2O emissions of less than 0.05 MMT CO_2 Eq. each. The application of synthetic fertilizers to forest soils in 2014 resulted in N_2O emissions of 0.5 MMT CO_2 Eq. (2 kt). N_2O emissions from fertilizer application to forest soils have increased by 455 percent since 1990, but still account for a relatively small portion of overall emissions. Additionally, N_2O emissions from fertilizer application to settlement soils in 2014 accounted for 2.4 MMT CO_2 Eq. (8 kt). This represents an increase of 78 percent since 1990. Forest fires in 2014 resulted in CH_4 emissions of 7.3 MMT CO_2 Eq. (294 kt), and in N_2O emissions of 4.8 MMT CO_2 Eq. (16 kt).

Table ES-5: Emissions and Removals (Flux) from Land Use, Land-Use Change, and Forestry (MMT CO_2 Eq.)

Gas/Land-Use Category	1990	2005	2010	2011	2012	2013	2014
Net CO_2 Flux[a]	**(704.2)**	**(636.1)**	**(683.2)**	**(683.6)**	**(680.8)**	**(682.4)**	**(685.8)**
Forest Land Remaining Forest Land[b]	(576.0)	(532.4)	(585.0)	(578.1)	(576.7)	(580.1)	(583.4)
Land Converted to Forest Land							
Cropland Remaining Cropland	(43.2)	(16.5)	(4.7)	(20.0)	(18.7)	(16.8)	(16.0)
Land Converted to Cropland[a]	22.8	14.6	15.6	14.2	14.5	14.8	14.7
Grassland Remaining Grassland[a]	(12.9)	2.9	2.6	11.3	11.7	11.9	11.9
Land Converted to Grassland	(8.5)	(12.8)	(12.3)	(11.0)	(10.9)	(10.9)	(10.9)
Settlements Remaining Settlements[c]	(60.4)	(80.5)	(86.1)	(87.3)	(88.4)	(89.5)	(90.6)
Other: Landfilled Yard Trimmings and Food Scraps	(26.0)	(11.4)	(13.2)	(12.7)	(12.2)	(11.7)	(11.6)
CO_2	**8.1**	**9.0**	**9.6**	**8.9**	**11.0**	**9.0**	**9.5**
Cropland Remaining Cropland: Liming	4.7	4.3	4.8	3.9	6.0	3.9	4.1
Cropland Remaining Cropland: Urea Fertilization	2.4	3.5	3.8	4.1	4.2	4.3	4.5
Wetlands Remaining Wetlands: Peatlands Remaining Peatlands	1.1	1.1	1.0	0.9	0.8	0.8	0.8
CH_4	**3.3**	**9.9**	**3.3**	**6.6**	**11.1**	**7.3**	**7.4**
Forest Land Remaining Forest Land: Forest Fires	3.3	9.9	3.3	6.6	11.1	7.3	7.3
Wetlands Remaining Wetlands: Peatlands Remaining Peatlands	+	+	+	+	+	+	+
N_2O	**3.6**	**9.3**	**5.0**	**7.3**	**10.3**	**7.7**	**7.7**
Forest Land Remaining Forest Land: Forest Fires	2.2	6.5	2.2	4.4	7.3	4.8	4.8
Forest Land Remaining Forest Land: Forest Soils[d]	0.1	0.5	0.5	0.5	0.5	0.5	0.5
Settlements Remaining Settlements: Settlement Soils[e]	1.4	2.3	2.4	2.5	2.5	2.4	2.4
Wetlands Remaining Wetlands: Peatlands Remaining Peatlands	+	+	+	+	+	+	+
LULUCF Emissions[f]	**15.0**	**28.2**	**17.8**	**22.9**	**32.3**	**24.1**	**24.6**
LULUCF Total Net Flux[a]	**(704.2)**	**(636.1)**	**(683.2)**	**(683.6)**	**(680.8)**	**(682.4)**	**(685.8)**
LULUCF Sector Total[g]	**(689.1)**	**(607.9)**	**(665.3)**	**(660.7)**	**(648.5)**	**(658.3)**	**(661.3)**

Note: Totals may not sum due to independent rounding. Parentheses indicate net sequestration.

\+ Does not exceed 0.05 MMT CO_2 Eq.

[a] Total net flux from LULUCF is only included in the Net Emissions total. Net flux from LULUCF includes the positive C sequestration reported for *Forest Land Remaining Forest Land, Land Converted to Forest Land, Cropland Remaining Cropland, Land Converted to Grassland, Settlements Remaining Settlements,* and *Other Land* plus the loss in C sequestration reported for *Land Converted to Cropland* and *Grassland Remaining Grassland*.

[b] Includes the effects of net additions to stocks of carbon stored in forest ecosystem pools and harvested wood products.

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[22] Estimates from *Land Converted to Forest Land* are currently under development.

[c] Estimates include C stock changes on both *Settlements Remaining Settlements* and *Land Converted to Settlements*.
[d] Estimates include emissions from N fertilizer additions on both *Forest Land Remaining Forest Land*, and *Land Converted to Forest Land*, but not from land-use conversion.
[e] Estimates include emissions from N fertilizer additions on both *Settlements Remaining Settlements*, and *Land Converted to Settlements*, but not from land-use conversion.
[f] LULUCF emissions include the CO_2, CH_4, and N_2O emissions reported for *Forest Fires, Forest Soils, Liming, Urea Fertilization, Settlement Soils,* and *Peatlands Remaining Peatlands.*
[g] The LULUCF Sector Total is the sum of positive emissions (i.e., sources) of greenhouse gases to the atmosphere plus removals of CO_2 (i.e., sinks or negative emissions) from the atmosphere.

Waste

The Waste chapter contains emissions from waste management activities (except incineration of waste, which is addressed in the Energy chapter). Landfills were the largest source of anthropogenic greenhouse gas emissions in the Waste chapter, accounting for 88.4 percent of this chapter's emissions, and 25.7 percent of total U.S. CH_4 emissions.[23] Additionally, wastewater treatment accounts for 9.7 percent of Waste emissions, 2.1 percent of U.S. CH_4 emissions, and 1.2 percent of U.S. N_2O emissions. Emissions of CH_4 and N_2O from composting are also accounted for in this chapter, generating emissions of 2.1 MMT CO_2 Eq. and 1.8 MMT CO_2 Eq., respectively. Overall, emission sources accounted for in the Waste chapter generated 3.0 percent of total U.S. greenhouse gas emissions in 2014.

ES.4. Other Information

Emissions by Economic Sector

Throughout the *Inventory of U.S. Greenhouse Gas Emissions and Sinks* report, emission estimates are grouped into five sectors (i.e., chapters) defined by the IPCC: Energy; Industrial Processes and Product Use; Agriculture; Land Use, Land-Use Change, and Forestry; and Waste. While it is important to use this characterization for consistency with UNFCCC reporting guidelines, it is also useful to allocate emissions into more commonly used sectoral categories. This section reports emissions by the following economic sectors: Residential, Commercial, Industry, Transportation, Electricity Generation, Agriculture, and U.S. Territories.

Table ES-6 summarizes emissions from each of these economic sectors, and Figure ES-13 shows the trend in emissions by sector from 1990 to 2014.

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[23] Landfills also store carbon, due to incomplete degradation of organic materials such as harvest wood products, yard trimmings, and food scraps, as described in the Land-Use, Land-Use Change, and Forestry chapter of the Inventory report.

Figure ES-13: Emissions Allocated to Economic Sectors (MMT CO_2 Eq.)

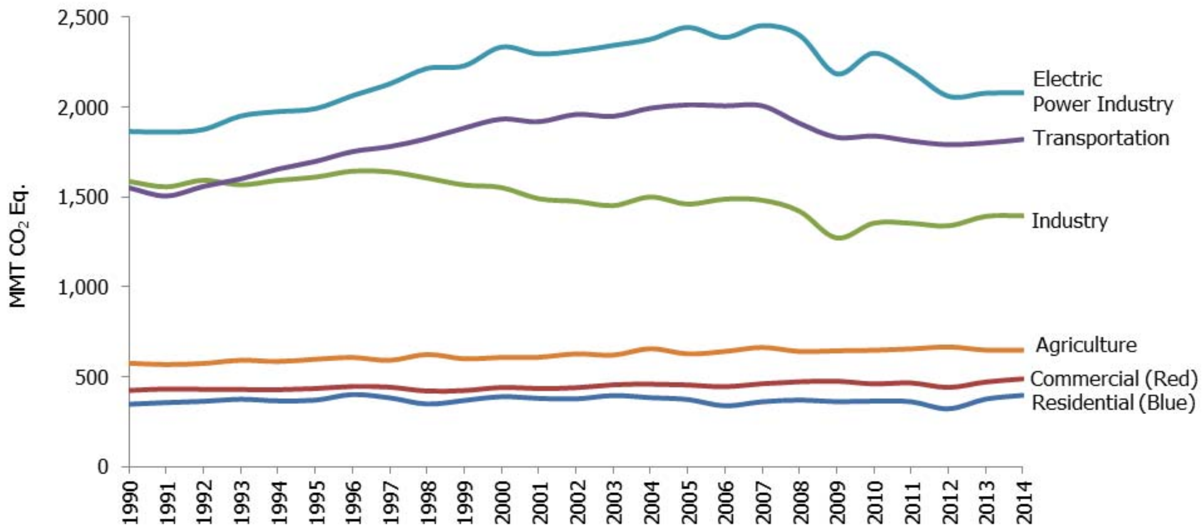

Table ES-6: U.S. Greenhouse Gas Emissions Allocated to Economic Sectors (MMT CO_2 Eq.)

Implied Sectors	**1990**	**2005**	**2010**	**2011**	**2012**	**2013**	**2014**
Electric Power Industry	1,864.8	2,443.9	2,300.5	2,198.1	2,060.8	2,077.7	2,080.2
Transportation	1,551.3	2,012.9	1,839.7	1,811.3	1,791.6	1,800.5	1,820.3
Industry	1,586.9	1,460.6	1,354.9	1,353.9	1,339.5	1,392.1	1,395.5
Agriculture	574.9	626.8	646.6	654.2	665.3	648.0	648.0
Commercial	422.9	453.6	459.9	464.7	440.0	470.2	487.8
Residential	346.3	372.8	363.6	360.1	320.9	375.1	396.1
U.S. Territories	33.7	58.2	45.3	45.4	47.6	47.5	44.7
Total Emissions	**6,380.8**	**7,428.8**	**7,010.5**	**6,887.8**	**6,665.7**	**6,811.2**	**6,872.6**
LULUCF Emissions[a]	15.0	28.2	17.8	22.9	32.3	24.1	24.6
LULUCF Total Net Flux[b]	(704.2)	(636.1)	(683.2)	(683.6)	(680.8)	(682.4)	(685.8)
LULUCF Sector Total[c]	(689.1)	(607.9)	(665.3)	(660.7)	(648.5)	(658.3)	(661.3)
Net Emissions (Sources and Sinks)	**5,676.6**	**6,792.6**	**6,327.3**	**6,204.2**	**5,984.9**	**6,128.8**	**6,186.8**

[a] LULUCF emissions include the CO_2, CH_4, and N_2O emissions reported for *Forest Fires, Forest Soils, Liming, Urea Fertilization, Settlement Soils*, and *Peatlands Remaining Peatlands*.

[b] Total net flux from LULUCF is only included in the Net Emissions total. Net flux from LULUCF includes the positive C sequestration reported for *Forest Land Remaining Forest Land, Land Converted to Forest Land, Cropland Remaining Cropland, Land Converted to Grassland, Settlements Remaining Settlements*, and *Other Land* plus the loss in C sequestration reported for *Land Converted to Cropland* and *Grassland Remaining Grassland*. Refer to Table ES-5 for a breakout of emissions and removals for Land Use, Land-Use Change, and Forestry by gas and source category.

[c] The LULUCF Sector Total is the sum of positive emissions (i.e., sources) of greenhouse gases to the atmosphere plus removals of CO_2 (i.e., sinks or negative emissions) from the atmosphere.

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

Using this categorization, emissions from electricity generation accounted for the largest portion (30 percent) of U.S. greenhouse gas emissions in 2014. Transportation activities, in aggregate, accounted for the second largest portion (26 percent), while emissions from industry accounted for the third largest portion (20 percent) of U.S. greenhouse gas emissions in 2014. In contrast to electricity generation and transportation, emissions from industry have in general declined over the past decade. The long-term decline in these emissions has been due to structural changes in the U.S. economy (i.e., shifts from a manufacturing-based to a service-based economy), fuel switching, and energy efficiency improvements. The remaining 23 percent of U.S. greenhouse gas emissions were contributed by, in order of magnitude, the agriculture, commercial, and residential sectors, plus emissions from U.S. Territories. Activities related to agriculture accounted for 9 percent of U.S. emissions; unlike other economic sectors, agricultural sector emissions were dominated by N_2O emissions from agricultural soil management and CH_4 emissions from enteric fermentation. The commercial and residential sectors accounted for 7 percent and 6 percent of emissions, respectively, and U.S. Territories accounted for 1 percent of emissions; emissions from these sectors primarily consisted of CO_2 emissions from fossil fuel combustion. CO_2 was also emitted and sequestered by a variety of activities related to forest management practices, tree planting in urban areas, the management of agricultural soils, and landfilling of yard trimmings.

Electricity is ultimately consumed in the economic sectors described above. Table ES-7 presents greenhouse gas emissions from economic sectors with emissions related to electricity generation distributed into end-use categories (i.e., emissions from electricity generation are allocated to the economic sectors in which the electricity is consumed). To distribute electricity emissions among end-use sectors, emissions from the source categories assigned to electricity generation were allocated to the residential, commercial, industry, transportation, and agriculture economic sectors according to retail sales of electricity.[24] These source categories include CO_2 from fossil fuel combustion and the use of limestone and dolomite for flue gas desulfurization, CO_2 and N_2O from incineration of waste, CH_4 and N_2O from stationary sources, and SF_6 from electrical transmission and distribution systems.

When emissions from electricity are distributed among these sectors, industrial activities and transportation account for the largest shares of U.S. greenhouse gas emissions (28 percent and 27 percent, respectively) in 2014. The residential and commercial sectors contributed the next largest shares of total U.S. greenhouse gas emissions in 2014. Emissions from these sectors increase substantially when emissions from electricity are included, due to their relatively large share of electricity consumption (e.g., lighting, appliances, etc.). In all sectors except agriculture, CO_2 accounts for more than 78 percent of greenhouse gas emissions, primarily from the combustion of fossil fuels. Figure ES-14 shows the trend in these emissions by sector from 1990 to 2014.

Table ES-7: U.S Greenhouse Gas Emissions by Economic Sector with Electricity-Related Emissions Distributed (MMT CO_2 Eq.)

Implied Sectors	1990	2005	2010	2011	2012	2013	2014
Industry	2,228.9	2,146.3	1,939.4	1,924.9	1,881.4	1,936.4	1,939.4
Transportation	1,554.4	2,017.7	1,844.3	1,815.7	1,795.5	1,804.6	1,824.4
Commercial	973.9	1,271.2	1,247.2	1,216.6	1,153.7	1,188.4	1,208.5
Residential	953.6	1,244.4	1,219.3	1,165.6	1,060.1	1,124.2	1,146.1
Agriculture	636.3	690.9	715.0	719.6	727.4	710.1	709.5
U.S. Territories	33.7	58.2	45.3	45.4	47.6	47.5	44.7
Total Emissions	**6,380.8**	**7,428.8**	**7,010.5**	**6,887.8**	**6,665.7**	**6,811.2**	**6,872.6**
LULUCF Emissions[a]	15.0	28.2	17.8	22.9	32.3	24.1	24.6
LULUCF Total Net Flux[b]	(704.2)	(636.1)	(683.2)	(683.6)	(680.8)	(682.4)	(685.8)
LULUCF Sector Total[c]	(689.1)	(607.9)	(665.3)	(660.7)	(648.5)	(658.3)	(661.3)
Net Emissions (Sources and Sinks)	**5,676.6**	**6,792.6**	**6,327.3**	**6,204.2**	**5,984.9**	**6,128.8**	**6,186.8**

Note: Emissions from electricity generation are allocated based on aggregate electricity consumption in each end-use sector.

[a] LULUCF emissions include the CO_2, CH_4, and N_2O emissions reported for *Forest Fires, Forest Soils, Liming, Urea Fertilization, Settlement Soils,* and *Peatlands Remaining Peatlands.*

[b] Total net flux from LULUCF is only included in the Net Emissions total. Net flux from LULUCF includes the positive C sequestration reported for *Forest Land Remaining Forest Land, Land Converted to Forest Land, Cropland Remaining Cropland, Land Converted to Grassland, Settlements Remaining Settlements,* and *Other Land* plus the loss in C sequestration reported for *Land Converted to Cropland and Grassland Remaining Grassland.* Refer to Table ES-5 for a breakout of emissions and removals for Land Use, Land-Use Change, and Forestry by gas and source category.

[c] The LULUCF Sector Total is the sum of positive emissions (i.e., sources) of greenhouse gases to the atmosphere plus removals of CO_2 (i.e., sinks or negative emissions) from the atmosphere.

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

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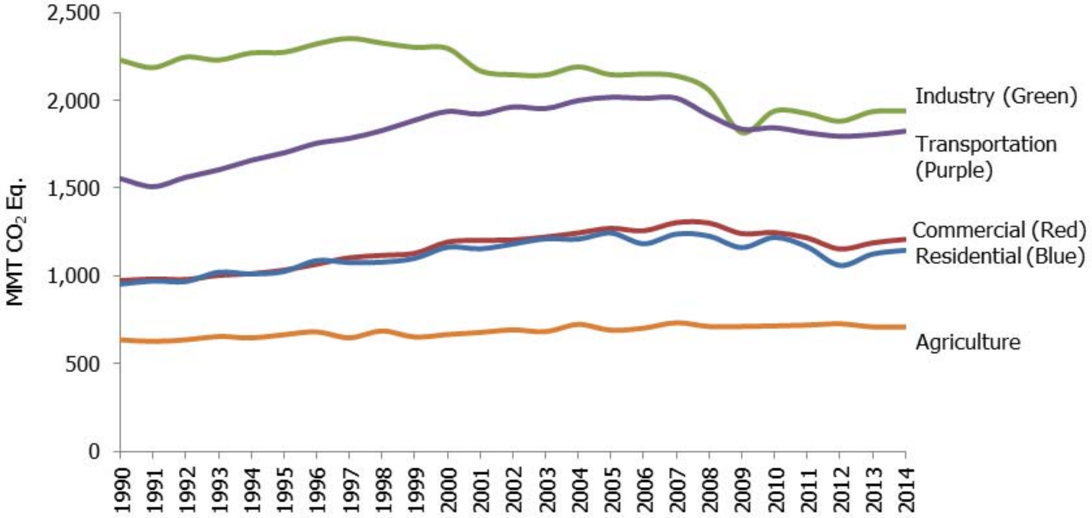
[24] Emissions were not distributed to U.S. territories, since the electricity generation sector only includes emissions related to the generation of electricity in the 50 states and the District of Columbia.

Figure ES-14: Emissions with Electricity Distributed to Economic Sectors (MMT CO_2 Eq.)



Box ES- 2: Recent Trends in Various U.S. Greenhouse Gas Emissions-Related Data

Total emissions can be compared to other economic and social indices to highlight changes over time. These comparisons include: (1) emissions per unit of aggregate energy consumption, because energy-related activities are the largest sources of emissions; (2) emissions per unit of fossil fuel consumption, because almost all energy-related emissions involve the combustion of fossil fuels; (3) emissions per unit of electricity consumption, because the electric power industry—utilities and non-utilities combined—was the largest source of U.S. greenhouse gas emissions in 2014; (4) emissions per unit of total gross domestic product as a measure of national economic activity; and (5) emissions per capita.

Table ES-8 provides data on various statistics related to U.S. greenhouse gas emissions normalized to 1990 as a baseline year. Greenhouse gas emissions in the United States have grown at an average annual rate of 0.3 percent since 1990. Since 1990, this rate is slightly slower than that for total energy and for fossil fuel consumption, and much slower than that for electricity consumption, overall gross domestic product and national population (see Figure ES-15).

Table ES-8: Recent Trends in Various U.S. Data (Index 1990 = 100)

Variable	1990	2005	2010	2011	2012	2013	2014	Avg. Annual Growth Rate
Greenhouse Gas Emissions[a]	100	116	110	108	104	107	108	0.3%
Energy Consumption[b]	100	118	116	115	112	116	117	0.7%
Fossil Fuel Consumption[b]	100	119	112	110	107	110	111	0.5%
Electricity Consumption[b]	100	134	137	137	135	136	138	1.4%
GDP[c]	100	159	165	168	171	174	178	2.5%
Population[d]	100	118	124	125	126	126	127	1.0%

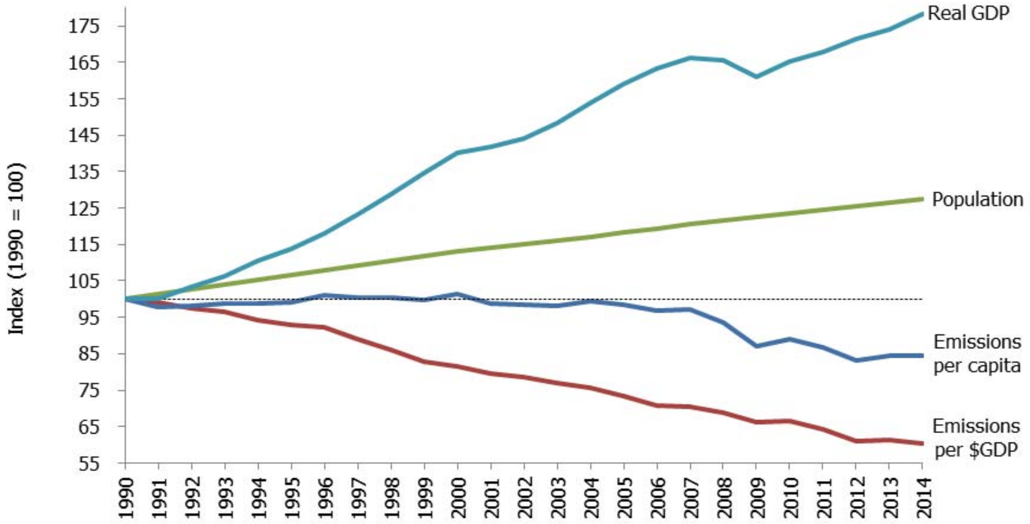
[a] GWP-weighted values

[b] Energy content-weighted values (EIA 2015a)

[c] Gross Domestic Product in chained 2009 dollars (BEA 2015)

[d] U.S. Census Bureau (2015)

Figure ES-15: U.S. Greenhouse Gas Emissions Per Capita and Per Dollar of Gross Domestic Product



Source: BEA (2015), U.S. Census Bureau (2015), and emission estimates in this report.

Key Categories

The *2006 IPCC Guidelines* (IPCC 2006) defines a key category as a "[category] that is prioritized within the national inventory system because its estimate has a significant influence on a country's total inventory of greenhouse gases in terms of the absolute level, the trend, or the uncertainty in emissions and removals."[25] By definition, key categories are sources or sinks that have the greatest contribution to the absolute overall level of national emissions in any of the years covered by the time series. In addition, when an entire time series of emission estimates is prepared, a thorough investigation of key categories must also account for the influence of trends of individual source and sink categories. Finally, a qualitative evaluation of key categories should be performed, in order to capture any key categories that were not identified in either of the quantitative analyses.

Figure ES-16 presents 2014 emission estimates for the key categories as defined by a level analysis (i.e., the contribution of each source or sink category to the total inventory level). The UNFCCC reporting guidelines request that key category analyses be reported at an appropriate level of disaggregation, which may lead to source and sink category names which differ from those used elsewhere in the Inventory report. For more information regarding key categories, see Section 1.6 – Key Categories and Annex 1.

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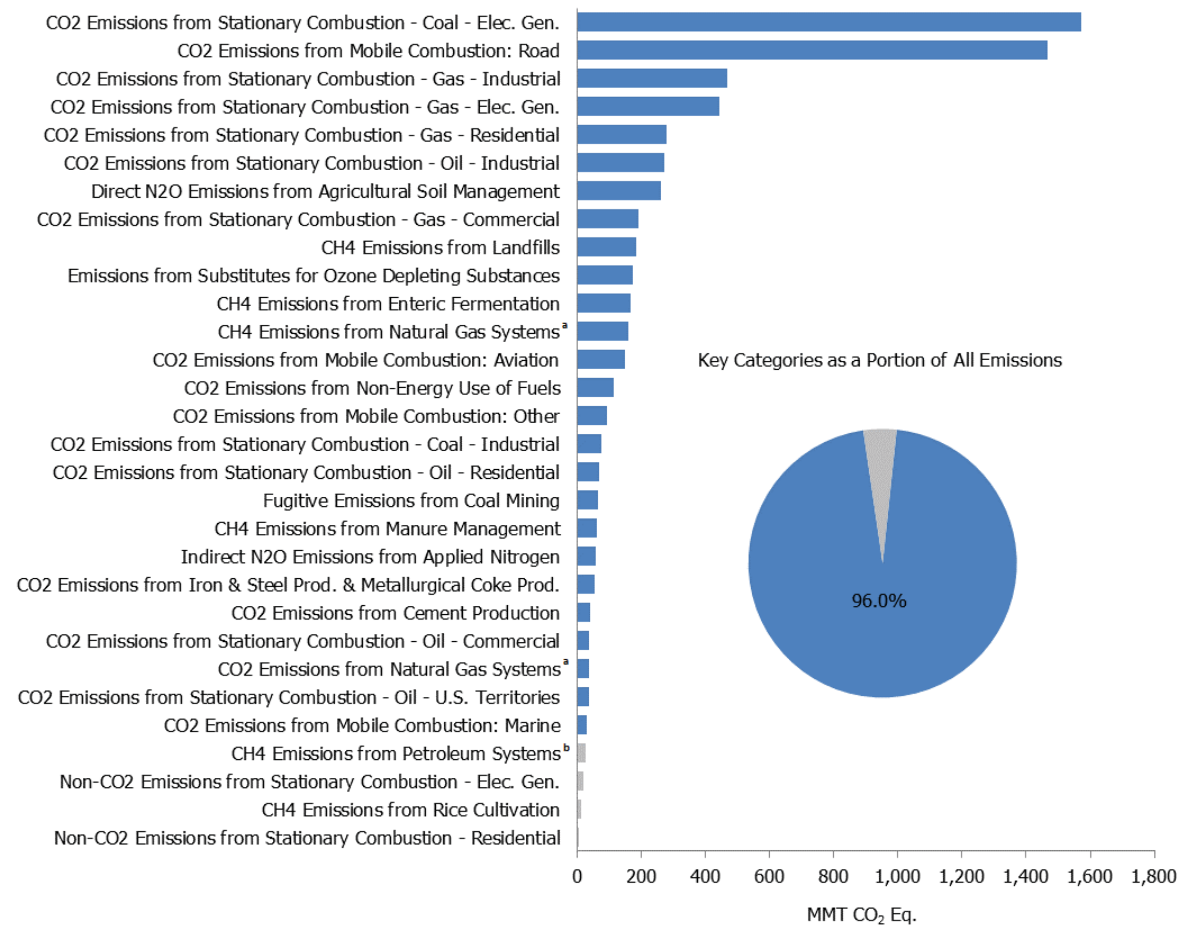
[25] See Chapter 4 "Methodological Choice and Identification of Key Categories" in IPCC (2006). <http://www.ipcc-nggip.iges.or.jp/public/2006gl/vol1.html>

Figure ES-16: 2014 Key Categories (MMT CO_2 Eq.) TO BE UPDATED



Note: For a complete discussion of the key category analysis, see Annex 1. Blue bars indicate either an Approach 1, or Approach 1 *and* Approach 2 level assessment key category. Gray bars indicate solely an Approach 2 level assessment key category.

[a] The value in this figure for Natural Gas Systems is presented from the previous Inventory and does not reflect updates to emission estimates for this category. See Section 3.7, Natural Gas Systems of the Energy chapter for more information.

[b] The value in this figure for Petroleum Systems is presented from the previous Inventory and does not reflect updates to emission estimates for this category. See Section 3.6, Petroleum Systems of the Energy chapter for more information.

Quality Assurance and Quality Control (QA/QC)

The United States seeks to continually improve the quality, transparency, and credibility of the Inventory of U.S. Greenhouse Gas Emissions and Sinks. To assist in these efforts, the United States implemented a systematic approach to QA/QC. While QA/QC has always been an integral part of the U.S. national system for inventory development, the procedures followed for the current inventory have been formalized in accordance with the QA/QC plan and the UNFCCC reporting guidelines.

Uncertainty Analysis of Emission Estimates

Uncertainty estimates are an essential element of a complete inventory of greenhouse gas emissions and removals. Some of the current estimates, such as those for CO_2 emissions from energy-related activities and cement processing, are considered to have low uncertainties. For some other categories of emissions, however, a lack of data or an incomplete understanding of how emissions are generated increases the uncertainty associated with the estimates presented. Acquiring a better understanding of the uncertainty associated with inventory estimates is an important step in helping to prioritize future work and improve the overall quality of the Inventory. Recognizing the benefit of conducting an uncertainty analysis, the UNFCCC reporting guidelines follow the recommendations of the *2006 IPCC Guidelines* (IPCC 2006) and require that countries provide single estimates of uncertainty for source and sink categories.

Currently, a qualitative discussion of uncertainty is presented for all source and sink categories. Within the discussion of each emission source, specific factors affecting the uncertainty surrounding the estimates are discussed. Most sources also contain a quantitative uncertainty assessment, in accordance with UNFCCC reporting guidelines.

Box ES- 3: Recalculations of Inventory Estimates

Each year, emission and sink estimates are recalculated and revised for all years in the *Inventory of U.S. Greenhouse Gas Emissions and Sinks*, as attempts are made to improve both the analyses themselves, through the use of better methods or data, and the overall usefulness of the report. In this effort, the United States follows the *2006 IPCC Guidelines* (IPCC 2006), which states, "Both methodological changes and refinements over time are an essential part of improving inventory quality. It is good practice to change or refine methods" when: available data have changed; the previously used method is not consistent with the IPCC guidelines for that category; a category has become key; the previously used method is insufficient to reflect mitigation activities in a transparent manner; the capacity for inventory preparation has increased; new inventory methods become available; and for correction of errors." 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.

In each Inventory report, the results of all methodology changes and historical data updates are presented in the "Recalculations and Improvements" chapter; detailed descriptions of each recalculation are contained within each source's description contained in the report, if applicable. In general, when methodological changes have been implemented, the entire time series (in the case of the most recent Inventory report, 1990 through 2013) has been recalculated to reflect the change, per the *2006 IPCC Guidelines* (IPCC 2006). Changes in historical data are generally the result of changes in statistical data supplied by other agencies. References for the data are provided for additional information.

1. Introduction

This report presents estimates by the United States government of U.S. anthropogenic greenhouse gas emissions and sinks for the years 1990 through 2014. A summary of these estimates is provided in Table 2-1 and Table 2-2 by gas and source category in the Trends in Greenhouse Gas Emissions chapter. The emission estimates in these tables are presented on both a full molecular mass basis and on a Global Warming Potential (GWP) weighted basis[1] in order to show the relative contribution of each gas to global average radiative forcing. This report also discusses the methods and data used to calculate these emission estimates.

In 1992, the United States signed and ratified the United Nations Framework Convention on Climate Change (UNFCCC). As stated in Article 2 of the UNFCCC, "The ultimate objective of this Convention and any related legal instruments that the Conference of the Parties may adopt is to achieve, in accordance with the relevant provisions of the Convention, stabilization of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system. Such a level should be achieved within a time-frame sufficient to allow ecosystems to adapt naturally to climate change, to ensure that food production is not threatened and to enable economic development to proceed in a sustainable manner."[2,3]

Parties to the Convention, by ratifying, "shall develop, periodically update, publish and make available…national inventories of anthropogenic emissions by sources and removals by sinks of all greenhouse gases not controlled by the Montreal Protocol, using comparable methodologies…"[4] The United States views this report as an opportunity to fulfill these commitments under the UNFCCC.

In 1988, preceding the creation of the UNFCCC, the World Meteorological Organization (WMO) and the United Nations Environment Programme (UNEP) jointly established the Intergovernmental Panel on Climate Change (IPCC). The role of the IPCC is to assess on a comprehensive, objective, open and transparent basis the scientific, technical and socio-economic information relevant to understanding the scientific basis of risk of human-induced climate change, its potential impacts and options for adaptation and mitigation (IPCC 2003). Under Working Group 1 of the IPCC, nearly 140 scientists and national experts from more than thirty countries collaborated in the creation of the *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories* (IPCC/UNEP/OECD/IEA 1997) to ensure that the emission inventories submitted to the UNFCCC are consistent and comparable between nations. The *IPCC Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories* and the *IPCC Good Practice Guidance for Land Use, Land-Use Change, and Forestry* further expanded upon the methodologies in the *Revised 1996 IPCC Guidelines*. In 2006, the IPCC accepted the *2006 Guidelines for National Greenhouse Gas Inventories* at its Twenty-Fifth Session (Mauritius, April 2006). The *2006 IPCC Guidelines* built

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[1] More information provided in "Global Warming Potentials" section of this chapter on the use of *IPCC Fourth Assessment Report* (AR4) GWP values.

[2] The term "anthropogenic," in this context, refers to greenhouse gas emissions and removals that are a direct result of human activities or are the result of natural processes that have been affected by human activities (IPCC 2006).

[3] Article 2 of the Framework Convention on Climate Change published by the UNEP/WMO Information Unit on Climate Change. See <http://unfccc.int>. (UNEP/WMO 2000)

[4] Article 4(1)(a) of the United Nations Framework Convention on Climate Change (also identified in Article 12). Subsequent decisions by the Conference of the Parties elaborated the role of Annex I Parties in preparing national inventories. See <http://unfccc.int>.

upon the previous bodies of work and include new sources and gases "…as well as updates to the previously published methods whenever scientific and technical knowledge have improved since the previous guidelines were issued. The UNFCCC adopted the *2006 IPCC Guidelines* as the standard methodological approach for Annex I countries at the Nineteenth Conference of the Parties (Warsaw, November 11-23, 2013). This report presents information in accordance with these guidelines.

Overall, this Inventory of anthropogenic greenhouse gas emissions and sinks provides a common and consistent mechanism through which Parties to the UNFCCC can estimate emissions and compare the relative contribution of individual sources, gases, and nations to climate change. The Inventory provides a national estimate of sources and sinks for the United States, including all states and U.S. Territories.[5] The structure of this report is consistent with the current UNFCCC Guidelines on Annual Inventories (UNFCCC 2014).

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

In following the UNFCCC requirement under Article 4.1 to develop and submit national greenhouse gas emission inventories, the emissions and sinks presented in this report are organized by source and sink categories and calculated using internationally-accepted methods provided by the IPCC.[6] Additionally, the calculated emissions and sinks in a given year for the United States are presented in a common manner in line with the UNFCCC reporting guidelines for the reporting of inventories under this international agreement.[7] The use of consistent methods to calculate emissions and sinks by all nations providing their inventories to the UNFCCC ensures that these reports are comparable. In this regard, U.S. emissions and sinks reported in this Inventory report are comparable to emissions and sinks reported by other countries. The manner that emissions and sinks are provided in this Inventory is one of many ways U.S. emissions and sinks could be examined; this Inventory report presents emissions and sinks in a common format consistent with how countries are to report inventories under the UNFCCC. Emissions and sinks provided in this inventory do not preclude alternative examinations, but rather this inventory report presents emissions and sinks in a common format consistent with how countries are to report inventories under the UNFCCC. The report itself follows this standardized format, and provides an explanation of the IPCC methods used to calculate emissions and sinks, and the manner in which those calculations are conducted.

On October 30, 2009, the U.S. Environmental Protection Agency (EPA) published a rule for the mandatory reporting of greenhouse gases from large greenhouse gas emissions sources in the United States. Implementation of 40 CFR Part 98 is referred to as the Greenhouse Gas Reporting Program (GHGRP). 40 CFR Part 98 applies to direct greenhouse gas emitters, fossil fuel suppliers, industrial gas suppliers, and facilities that inject CO_2 underground for sequestration or other reasons.[8] Reporting is at the facility level, except for certain suppliers of fossil fuels and industrial greenhouse gases. The GHGRP dataset and the data presented in this Inventory report are complementary and, as indicated in the respective planned improvements sections in this report's chapters, EPA is analyzing the data for use, as applicable, to improve the national estimates presented in this Inventory.

1.1 Background Information

Science

For over the past 200 years, the burning of fossil fuels such as coal and oil, deforestation, land-use changes, and other sources have caused the concentrations of heat-trapping "greenhouse gases" to increase significantly in our

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[5] U.S. Territories include American Samoa, Guam, Puerto Rico, U.S. Virgin Islands, Wake Island, and other U.S. Pacific Islands.

[6] See <http://www.ipcc-nggip.iges.or.jp/public/index.html>.

[7] See <http://unfccc.int/resource/docs/2013/cop19/eng/10a03.pdf#page=2 >.

[8] See <http://www.epa.gov/climatechange/emissions/ghgrulemaking.html> and <http://ghgdata.epa.gov/ghgp/main.do>.

atmosphere (NOAA 2014). These gases in the atmosphere absorb some of the energy being radiated from the surface of the Earth and then re-radiate this energy with some returning to the Earth's surface, essentially acting like a blanket that makes the Earth's surface warmer than it would be otherwise.

Greenhouse gases are necessary to life as we know it. Without greenhouse gases in the atmosphere, the planet's surface would be about 60ºF cooler than present (EPA 2009). Carbon dioxide is also necessary for plant growth. With emissions from biological and geological sources, there is a natural level of greenhouse gases that is maintained in the atmosphere. But, as the concentrations of these gases continue to increase in from man-made sources, the Earth's temperature is climbing above past levels. The Earth's averaged land and ocean surface temperature has increased by about 1.2 to 1.9ºF since 1880. The last three decades have each been the warmest decade successively at the Earth's surface since 1850 (IPCC 2013). Most of the warming in recent decades is very likely the result of human activities. Other aspects of the climate are also changing such as rainfall patterns, snow and ice cover, and sea level.

If greenhouse gases continue to increase, climate models predict that the average temperature at the Earth's surface is likely to increase from 0.5 to 8.6ºF above 1986 through 2005 levels by the end of this century, depending on future emissions (IPCC 2013). Scientists are certain that human activities are changing the composition of the atmosphere, and that increasing the concentration of greenhouse gases will change the planet's climate. However, they are not sure by how much it will change, at what rate it will change, or what the exact effects will be.[9]

Greenhouse Gases

Although the Earth's atmosphere consists mainly of oxygen and nitrogen, neither plays a significant role in enhancing the greenhouse effect because both are essentially transparent to terrestrial radiation. The greenhouse effect is primarily a function of the concentration of water vapor, carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), and other trace gases in the atmosphere that absorb the terrestrial radiation leaving the surface of the Earth (IPCC 2013). Changes in the atmospheric concentrations of these greenhouse gases can alter the balance of energy transfers between the space and the earth system.[10] A gauge of these changes is called radiative forcing, which is a measure of the influence a perturbation has in altering the balance of incoming and outgoing energy in the Earth-atmosphere system (IPCC 2013). Holding everything else constant, increases in greenhouse gas concentrations in the atmosphere will produce positive radiative forcing (i.e., a net increase in the absorption of energy by the Earth).

> *Human activities are continuing to affect the Earth's energy budget by changing the emissions and resulting atmospheric concentrations of radiatively important gases and aerosols and by changing land surface properties (IPCC 2013).*

Naturally occurring greenhouse gases include water vapor, CO_2, CH_4, N_2O, and ozone (O_3). Several classes of halogenated substances that contain fluorine, chlorine, or bromine are also greenhouse gases, but they are, for the most part, solely a product of industrial activities. Chlorofluorocarbons (CFCs) and hydrochlorofluorocarbons (HCFCs) are halocarbons that contain chlorine, while halocarbons that contain bromine are referred to as bromofluorocarbons (i.e., halons). As stratospheric ozone depleting substances, CFCs, HCFCs, and halons are covered under the Montreal Protocol on Substances that Deplete the Ozone Layer. The UNFCCC defers to this earlier international treaty. Consequently, Parties to the UNFCCC are not required to include these gases in national greenhouse gas inventories.[11] Some other fluorine-containing halogenated substances—hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), sulfur hexafluoride (SF_6), and nitrogen trifluoride (NF_3)—do not deplete stratospheric ozone but are potent greenhouse gases. These latter substances are addressed by the UNFCCC and accounted for in national greenhouse gas inventories.

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[9] For more information see <http://www.epa.gov/climatechange/science>.

[10] For more on the science of climate change, see NRC (2012).

[11] Emissions estimates of CFCs, HCFCs, halons and other ozone-depleting substances are included in this document for informational purposes.

There are also several other substances that influence the global radiation budget but are short-lived and therefore not well-mixed. These substances include carbon monoxide (CO), nitrogen dioxide (NO_2), sulfur dioxide (SO_2), and tropospheric (ground level) ozone (O_3). Tropospheric ozone is formed by two precursor pollutants, volatile organic compounds (VOCs) and nitrogen oxides (NO_x) in the presence of ultraviolet light (sunlight).

Aerosols are extremely small particles or liquid droplets suspended in the Earth's atmosphere that are often composed of sulfur compounds, carbonaceous combustion products (e.g., black carbon), crustal materials (e.g., dust) and other human induced pollutants. They can affect the absorptive characteristics of the atmosphere (e.g., scattering incoming sunlight away from the Earth's surface, or, in the case of black carbon, absorb sunlight) and can play a role in affecting cloud formation and lifetime affecting the radiative forcing of clouds and precipitation patterns. Comparatively, however, while the understanding of aerosols has increased in recent years, they still account for the largest contribution to uncertainty estimates in global energy budgets (IPCC 2013).

Carbon dioxide, methane, and nitrous oxide are continuously emitted to and removed from the atmosphere by natural processes on Earth. Anthropogenic activities, however, can cause additional quantities of these and other greenhouse gases to be emitted or sequestered, thereby changing their global average atmospheric concentrations. Natural activities such as respiration by plants or animals and seasonal cycles of plant growth and decay are examples of processes that only cycle carbon or nitrogen between the atmosphere and organic biomass. Such processes, except when directly or indirectly perturbed out of equilibrium by anthropogenic activities, generally do not alter average atmospheric greenhouse gas concentrations over decadal timeframes. Climatic changes resulting from anthropogenic activities, however, could have positive or negative feedback effects on these natural systems. Atmospheric concentrations of these gases, along with their rates of growth and atmospheric lifetimes, are presented in Table 1-1.

Table 1-1: Global Atmospheric Concentration, Rate of Concentration Change, and Atmospheric Lifetime of Selected Greenhouse Gases

Atmospheric Variable	CO_2	CH_4	N_2O	SF_6	CF_4
Pre-industrial atmospheric concentration	280 ppm	0.700 ppm	0.270 ppm	0 ppt	40 ppt
Atmospheric concentration	401 ppm[g]	1.823 ppm[a]	0.327 ppm[a]	7.9 ppt[a]	79 ppt[f]
Rate of concentration change	2.3 ppm/yr	0.005 ppm/yr[b]	0.26%/yr	Linear[c]	Linear[c]
Atmospheric lifetime (years)	See footnote[d]	12.4[e]	121[e]	3,200	50,000

Source: Pre-industrial atmospheric concentrations, atmospheric lifetime, and rate of concentration changes for CH_4, N_2O, SF_6, and CF_4 are from IPCC (2013). The rate of concentration change for CO_2 is an average of the rates from 2011 through 2015 has fluctuated between 1.7 to 3.0 ppm per year over this period (NOAA/ESRL 2016).

[a] The values presented are global annual average mole fractions (CDIAC 2015).

[b] The growth rate for atmospheric CH_4 decreased from over 10 ppb/yr in the 1980s to nearly zero in the early 2000s; recently, the growth rate has been about 5 ppb/year.

[c] IPCC (2007) identifies the rate of concentration change for SF_6 and CF_4 as linear.

[d] For a given amount of carbon dioxide emitted, some fraction of the atmospheric increase in concentration is quickly absorbed by the oceans and terrestrial vegetation, some fraction of the atmospheric increase will only slowly decrease over a number of years, and a small portion of the increase will remain for many centuries or more.

[e] This lifetime has been defined as an "adjustment time" that takes into account the indirect effect of the gas on its own residence time.

[f] The 2011 CF_4 global mean atmospheric concentration is from the Advanced Global Atmospheric Gases Experiment (IPCC 2013).

[g] The atmospheric CO_2 concentration is the 2015 annual average at the Mauna Loa, HI station (NOAA/ESRL 2016).

A brief description of each greenhouse gas, its sources, and its role in the atmosphere is given below. The following section then explains the concept of GWPs, which are assigned to individual gases as a measure of their relative average global radiative forcing effect.

Water Vapor (H_2O). Water vapor is the largest contributor to the natural greenhouse effect. Water vapor is fundamentally different from other greenhouse gases in that it can condense and rain out when it reaches high concentrations, and the total amount of water vapor in the atmosphere is in part a function of the Earth's temperature. While some human activities such as evaporation from irrigated crops or power plant cooling release water vapor into the air, this has been determined to have a negligible effect on climate (IPCC 2013). The lifetime of water vapor in the troposphere is on the order of 10 days. Water vapor can also contribute to cloud formation, and clouds can have both warming and cooling effects by either trapping or reflecting heat. Because of the relationship between water vapor levels and temperature, water vapor and clouds serve as a feedback to climate change, such that for any given increase in other greenhouse gases, the total warming is greater than would happen in the absence of water vapor. Aircraft contrails, which consist of water vapor and other substances, are aviation-induced clouds with the same radiative forcing effects as high-altitude cirrus clouds (IPCC 1999).

Carbon Dioxide (CO_2). In nature, carbon is cycled between various atmospheric, oceanic, land biotic, marine biotic, and mineral reservoirs. The largest fluxes occur between the atmosphere and terrestrial biota, and between the atmosphere and surface water of the oceans. In the atmosphere, carbon predominantly exists in its oxidized form as CO_2. Atmospheric CO_2 is part of this global carbon cycle, and therefore its fate is a complex function of geochemical and biological processes. Carbon dioxide concentrations in the atmosphere increased from approximately 280 parts per million by volume (ppmv) in pre-industrial times to 401 ppmv in 2015, a 43 percent increase (IPCC 2013 and NOAA/ESRL 2016).[12,13] The IPCC definitively states that "the increase of CO_2 … is caused by anthropogenic emissions from the use of fossil fuel as a source of energy and from land use and land use changes, in particular agriculture" (IPCC 2013). The predominant source of anthropogenic CO_2 emissions is the combustion of fossil fuels. Forest clearing, other biomass burning, and some non-energy production processes (e.g., cement production) also emit notable quantities of CO_2. In its Fifth Assessment Report, the IPCC stated "it is extremely likely that more than half of the observed increase in global average surface temperature from 1951 to 2010 was caused by the anthropogenic increase in greenhouse gas concentrations and other anthropogenic forcings together," of which CO_2 is the most important (IPCC 2013).

Methane (CH_4). Methane is primarily produced through anaerobic decomposition of organic matter in biological systems. Agricultural processes such as wetland rice cultivation, enteric fermentation in animals, and the decomposition of animal wastes emit CH_4, as does the decomposition of municipal solid wastes. Methane is also emitted during the production and distribution of natural gas and petroleum, and is released as a by-product of coal mining and incomplete fossil fuel combustion. Atmospheric concentrations of CH_4 have increased by about 152 percent since 1750, from a pre-industrial value of about 700 ppb to 1,762 – 1,893 ppb in 2012,[14] although the rate of increase decreased to near zero in the early 2000s, and has recently increased again to about 5 ppb/year. The IPCC has estimated that slightly more than half of the current CH_4 flux to the atmosphere is anthropogenic, from human activities such as agriculture, fossil fuel use, and waste disposal (IPCC 2007).

Methane is primarily removed from the atmosphere through a reaction with the hydroxyl radical (OH) and is ultimately converted to CO_2. Minor removal processes also include reaction with chlorine in the marine boundary layer, a soil sink, and stratospheric reactions. Increasing emissions of CH_4 reduce the concentration of OH, a feedback that increases the atmospheric lifetime of CH_4 (IPCC 2013). Methane's reactions in the atmosphere also lead to production of tropospheric ozone and stratospheric water vapor, both of which also contribute to climate change.

Nitrous Oxide (N_2O). Anthropogenic sources of N_2O emissions include agricultural soils, especially production of nitrogen-fixing crops and forages, the use of synthetic and manure fertilizers, and manure deposition by livestock; fossil fuel combustion, especially from mobile combustion; adipic (nylon) and nitric acid production; wastewater treatment and waste incineration; and biomass burning. The atmospheric concentration of N_2O has increased by 20 percent since 1750, from a pre-industrial value of about 270 ppb to 324-326 ppb in 2012,[15] a concentration that has not been exceeded during the last thousand years. Nitrous oxide is primarily removed from the atmosphere by the photolytic action of sunlight in the stratosphere (IPCC 2007).

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[12] The pre-industrial period is considered as the time preceding the year 1750 (IPCC 2013).

[13] Carbon dioxide concentrations during the last 1,000 years of the pre-industrial period (i.e., 750-1750), a time of relative climate stability, fluctuated by about ±10 ppmv around 280 ppmv (IPCC 2013).

[14] The range is the annual arithmetic averages from a mid-latitude Northern-Hemisphere site and a mid-latitude Southern-Hemisphere site for October 2012 through September 2013 (CDIAC 2014).

[15] The range is the annual arithmetic averages from a mid-latitude Northern-Hemisphere site and a mid-latitude Southern-Hemisphere site for October 2012 through September 2013 (CDIAC 2014).

Ozone (O_3). Ozone is present in both the upper stratosphere,[16] where it shields the Earth from harmful levels of ultraviolet radiation, and at lower concentrations in the troposphere,[17] where it is the main component of anthropogenic photochemical "smog." During the last two decades, emissions of anthropogenic chlorine and bromine-containing halocarbons, such as CFCs, have depleted stratospheric ozone concentrations. This loss of ozone in the stratosphere has resulted in negative radiative forcing, representing an indirect effect of anthropogenic emissions of chlorine and bromine compounds (IPCC 2013). The depletion of stratospheric ozone and its radiative forcing was expected to reach a maximum in about 2000 before starting to recover.

The past increase in tropospheric ozone, which is also a greenhouse gas, is estimated to provide the fourth largest increase in direct radiative forcing since the pre-industrial era, behind CO_2, black carbon, and CH_4. Tropospheric ozone is produced from complex chemical reactions of volatile organic compounds (including methane) mixing with NO_x in the presence of sunlight. The tropospheric concentrations of ozone and these other pollutants are short-lived and, therefore, spatially variable (IPCC 2013).

Halocarbons, Perfluorocarbons, Sulfur Hexafluoride, and Nitrogen Triflouride. Halocarbons are, for the most part, man-made chemicals that have both direct and indirect radiative forcing effects. Halocarbons that contain chlorine (CFCs, HCFCs, methyl chloroform, and carbon tetrachloride) and bromine (halons, methyl bromide, and hydrobromofluorocarbons HFCs) result in stratospheric ozone depletion and are therefore controlled under the Montreal Protocol on Substances that Deplete the Ozone Layer. Although CFCs and HCFCs include potent global warming gases, their net radiative forcing effect on the atmosphere is reduced because they cause stratospheric ozone depletion, which itself is an important greenhouse gas in addition to shielding the Earth from harmful levels of ultraviolet radiation. Under the Montreal Protocol, the United States phased out the production and importation of halons by 1994 and of CFCs by 1996. Under the Copenhagen Amendments to the Protocol, a cap was placed on the production and importation of HCFCs by non-Article 5[18] countries beginning in 1996, and then followed by a complete phase-out by the year 2030. While ozone depleting gases covered under the Montreal Protocol and its Amendments are not covered by the UNFCCC, they are reported in this inventory under Annex 6.2 of this report for informational purposes.

HFCs, PFCs, SF_6, and NF_3 are not ozone depleting substances, and therefore are not covered under the Montreal Protocol. They are, however, powerful greenhouse gases. HFCs are primarily used as replacements for ozone depleting substances but also emitted as a by-product of the HCFC-22 manufacturing process. Currently, they have a small aggregate radiative forcing impact, but it is anticipated that their contribution to overall radiative forcing will increase (IPCC 2013). PFCs, SF_6, and NF_3 are predominantly emitted from various industrial processes including aluminum smelting, semiconductor manufacturing, electric power transmission and distribution, and magnesium casting. Currently, the radiative forcing impact of PFCs, SF_6, and NF_3 is also small, but they have a significant growth rate, extremely long atmospheric lifetimes, and are strong absorbers of infrared radiation, and therefore have the potential to influence climate far into the future (IPCC 2013).

Carbon Monoxide. Carbon monoxide has an indirect radiative forcing effect by elevating concentrations of CH_4 and tropospheric ozone through chemical reactions with other atmospheric constituents (e.g., the hydroxyl radical, OH) that would otherwise assist in destroying CH_4 and tropospheric ozone. Carbon monoxide is created when carbon-containing fuels are burned incompletely. Through natural processes in the atmosphere, it is eventually oxidized to CO_2. Carbon monoxide concentrations are both short-lived in the atmosphere and spatially variable.

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[16] The stratosphere is the layer from the troposphere up to roughly 50 kilometers. In the lower regions the temperature is nearly constant but in the upper layer the temperature increases rapidly because of sunlight absorption by the ozone layer. The ozone-layer is the part of the stratosphere from 19 kilometers up to 48 kilometers where the concentration of ozone reaches up to 10 parts per million.

[17] The troposphere is the layer from the ground up to 11 kilometers near the poles and up to 16 kilometers in equatorial regions (i.e., the lowest layer of the atmosphere where people live). It contains roughly 80 percent of the mass of all gases in the atmosphere and is the site for most weather processes, including most of the water vapor and clouds.

[18] Article 5 of the Montreal Protocol covers several groups of countries, especially developing countries, with low consumption rates of ozone depleting substances. Developing countries with per capita consumption of less than 0.3 kg of certain ozone depleting substances (weighted by their ozone depleting potential) receive financial assistance and a grace period of ten additional years in the phase-out of ozone depleting substances.

Nitrogen Oxides (NO_x). The primary climate change effects of nitrogen oxides (i.e., NO and NO_2) are indirect and result from their role in promoting the formation of ozone in the troposphere, are a precursor to nitrate particles (i.e., aerosols) and, to a lesser degree, lower stratosphere, where they have positive radiative forcing effects.[19] Additionally, NO_x emissions are also likely to decrease CH_4 concentrations, thus having a negative radiative forcing effect (IPCC 2013). Nitrogen oxides are created from lightning, soil microbial activity, biomass burning (both natural and anthropogenic fires) fuel combustion, and, in the stratosphere, from the photo-degradation of N_2O. Concentrations of NO_x are both relatively short-lived in the atmosphere and spatially variable.

Nonmethane Volatile Organic Compounds (NMVOCs). Non-CH_4 volatile organic compounds include substances such as propane, butane, and ethane. These compounds participate, along with NO_x, in the formation of tropospheric ozone and other photochemical oxidants. NMVOCs are emitted primarily from transportation and industrial processes, as well as biomass burning and non-industrial consumption of organic solvents. Concentrations of NMVOCs tend to be both short-lived in the atmosphere and spatially variable.

Aerosols. Aerosols are extremely small particles or liquid droplets found in the atmosphere that are either directly emitted into or are created through chemical reactions in the Earth's atmosphere. Aerosols or their chemical precursors can be emitted by natural events such as dust storms and volcanic activity, or by anthropogenic processes such as fuel combustion and biomass burning. Various categories of aerosols exist, including naturally produced aerosols such as soil dust, sea salt, biogenic aerosols, sulfates, nitrates, and volcanic aerosols, and anthropogenically manufactured aerosols such as industrial dust and carbonaceous[20] aerosols (e.g., black carbon, organic carbon) from transportation, coal combustion, cement manufacturing, waste incineration, and biomass burning. Aerosols can be removed from the atmosphere relatively rapidly by precipitation or through more complex processes under dry conditions.

Aerosols affect radiative forcing differently than greenhouse gases. Their radiative effects occur through direct and indirect mechanisms: directly by scattering and absorbing solar radiation (and to a lesser extent scattering, absorption, and emission of terrestrial radiation); and indirectly by increasing cloud droplets and ice crystals that modify the formation, precipitation efficiency, and radiative properties of clouds (IPCC 2013). Despite advances in understanding of cloud-aerosol interactions, the contribution of aerosols to radiative forcing are difficult to quantify because aerosols generally have short atmospheric lifetimes, and have number concentrations, size distributions, and compositions that vary regionally, spatially, and temporally (IPCC 2013).

The net effect of aerosols on the Earth's radiative forcing is believed to be negative (i.e., net cooling effect on the climate). In fact, "despite the large uncertainty ranges on aerosol forcing, there is high confidence that aerosols have offset a substantial portion of GHG forcing" (IPCC 2013).[21] Although because they remain in the atmosphere for only days to weeks, their concentrations respond rapidly to changes in emissions.[22] Not all aerosols have a cooling effect. Current research suggests that another constituent of aerosols, black carbon, has a positive radiative forcing by heating the Earth's atmosphere and causing surface warming when deposited on ice and snow (IPCC 2013). Black carbon also influences cloud development, but the direction and magnitude of this forcing is an area of active research.

Global Warming Potentials

A global warming potential is a quantified measure of the globally averaged relative radiative forcing impacts of a particular greenhouse gas (see Table 1-2). It is defined as the ratio of the time-integrated radiative forcing from the instantaneous release of 1 kilogram (kg) of a trace substance relative to that of 1 kg of a reference gas (IPCC 2007). Direct radiative effects occur when the gas itself absorbs radiation. Indirect radiative forcing occurs when chemical

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[19] NO_x emissions injected higher in the stratosphere, primarily from fuel combustion emissions from high altitude supersonic aircraft, can lead to stratospheric ozone depletion.

[20] Carbonaceous aerosols are aerosols that are comprised mainly of organic substances and forms of black carbon (or soot) (IPCC 2013).

[21] The IPCC (2013) defines high confidence as an indication of strong scientific evidence and agreement in this statement.

[22] Volcanic activity can inject significant quantities of aerosol producing sulfur dioxide and other sulfur compounds into the stratosphere, which can result in a longer negative forcing effect (i.e., a few years) (IPCC 2013).

transformations involving the original gas produce a gas or gases that are greenhouse gases, or when a gas influences other radiatively important processes such as the atmospheric lifetimes of other gases. The reference gas used is CO_2, and therefore GWP-weighted emissions are measured in million metric tons of CO_2 equivalent (MMT CO_2 Eq.).[23] The relationship between kilotons (kt) of a gas and MMT CO_2 Eq. can be expressed as follows:

$$MMT\ CO_2\ Eq. = (kt\ of\ gas) \times (GWP) \times \left(\frac{MMT}{1{,}000\ kt}\right)$$

where,

MMT CO_2 Eq. = Million metric tons of CO_2 equivalent

kt = Kilotons (equivalent to a thousand metric tons)

GWP = Global warming potential

MMT = Million metric tons

GWP values allow for a comparison of the impacts of emissions and reductions of different gases. According to the IPCC, GWPs typically have an uncertainty of ±35 percent. Parties to the UNFCCC have also agreed to use GWPs based upon a 100-year time horizon, although other time horizon values are available.

> *…the global warming potential values used by Parties included in Annex I to the Convention (Annex I Parties) to calculate the carbon dioxide equivalence of anthropogenic emissions by sources and removals by sinks of greenhouse gases shall be those listed in the column entitled "Global warming potential for given time horizon" in table 2.14 of the errata to the contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change, based on the effects of greenhouse gases over a 100-year time horizon...*[24]

Greenhouse gases with relatively long atmospheric lifetimes (e.g., CO_2, CH_4, N_2O, HFCs, PFCs, SF_6, NF_3) tend to be evenly distributed throughout the atmosphere, and consequently global average concentrations can be determined. The short-lived gases such as water vapor, carbon monoxide, tropospheric ozone, ozone precursors (e.g., NO_x, and NMVOCs), and tropospheric aerosols (e.g., SO_2 products and carbonaceous particles), however, vary regionally, and consequently it is difficult to quantify their global radiative forcing impacts. Parties to the UNFCCC have not agreed upon GWP values for these gases that are short-lived and spatially inhomogeneous in the atmosphere.

Table 1-2: Global Warming Potentials and Atmospheric Lifetimes (Years) Used in this Report

Gas	Atmospheric Lifetime	GWP[c]
CO_2	[b]	1
CH_4[a]	12	25
N_2O	114	298
HFC-23	270	14,800
HFC-32	4.9	675
HFC-125	29	3,500
HFC-134a	14	1,430
HFC-143a	52	4,470
HFC-152a	1.4	124
HFC-227ea	34.2	3,220
HFC-236fa	240	9,810
HFC-4310mee	15.9	1,640

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[23] Carbon comprises 12/44ths of carbon dioxide by weight.

[24] Framework Convention on Climate Change; < http://unfccc.int/resource/docs/2013/cop19/eng/10a03.pdf >; 31 January 2014; Report of the Conference of the Parties at its nineteenth session; held in Warsaw from 11 to 23 November 2013; Addendum; Part two: Action taken by the Conference of the Parties at its nineteenth session; Decision 24/CP.19; Revision of the UNFCCC reporting guidelines on annual inventories for Parties included in Annex I to the Convention; p. 2. (UNFCCC 2014)

CF_4	50,000	7,390
C_2F_6	10,000	12,200
C_4F_{10}	2,600	8,860
C_6F_{14}	3,200	9,300
SF_6	3,200	22,800
NF_3	740	17,200

Source: (IPCC 2007)

[a] The GWP of CH_4 includes the direct effects and those indirect effects due to the production of tropospheric ozone and stratospheric water vapor. The indirect effect due to the production of CO_2 is not included.

[b] For a given amount of carbon dioxide emitted, some fraction of the atmospheric increase in concentration is quickly absorbed by the oceans and terrestrial vegetation, some fraction of the atmospheric increase will only slowly decrease over a number of years, and a small portion of the increase will remain for many centuries or more.

[c] 100-year time horizon.

Box 1-2: The IPCC *Fifth Assessment Report* and Global Warming Potentials

In 2014, the IPCC published its *Fifth Assessment Report* (AR5), which provided an updated and more comprehensive scientific assessment of climate change. Within the AR5 report, the GWP values of several gases were revised relative to previous IPCC reports, namely the *IPCC Second Assessment Report* (SAR) (IPCC 1996), the *IPCC Third Assessment Report* (TAR) (IPCC 2001), and the *IPCC Fourth Assessment Report* (AR4) (IPCC 2007). Although the AR4 GWP values are used throughout this report, consistent with UNFCCC reporting requirements, it is interesting to review the changes to the GWP values and the impact improved understanding has on the total GWP-weighted emissions of the United States. In the AR5, the IPCC has applied an improved calculation of CO_2 radiative forcing and an improved CO_2 response function in presenting updated GWP values. Additionally, the atmospheric lifetimes of some gases have been recalculated, and updated background concentrations were used. In addition, the values for radiative forcing and lifetimes have been recalculated for a variety of halocarbons, and the indirect effects of methane on ozone have been adjusted to match more recent science. Table 1-3 presents the new GWP values, relative to those presented in the AR4 and using the 100-year time horizon common to UNFCCC reporting.

Table 1-3: Comparison of 100-Year GWP values

Gas	SAR	TAR	AR4	AR5[b]	Comparison to AR4		
					SAR	TAR	AR5
CO_2	1	1	1	1	NC	NC	NC
CH_4[a]	21	23	25	28	(4)	(2)	3
N_2O	310	296	298	265	12	(2)	(33)
HFC-23	11,700	12,000	14,800	12,400	(3,100)	(2,800)	(2,400)
HFC-32	650	550	675	677	(25)	(125)	2
HFC-125	2,800	3,400	3,500	3,170	(700)	(100)	(330)
HFC-134a	1,300	1,300	1,430	1,300	(130)	(130)	(130)
HFC-143a	3,800	4,300	4,470	4,800	(670)	(170)	330
HFC-152a	140	120	124	138	16	(4)	14
HFC-227ea	2,900	3,500	3,220	3,350	(320)	280	130
HFC-236fa	6,300	9,400	9,810	8,060	(3,510)	(410)	(1,750)
HFC-4310mee	1,300	1,500	1,640	1,650	(340)	(140)	10
CF_4	6,500	5,700	7,390	6,630	(890)	(1,690)	(760)
C_2F_6	9,200	11,900	12,200	11,100	(3,000)	(300)	(1,100)
C_4F_{10}	7,000	8,600	8,860	9,200	(1,860)	(260)	340
C_6F_{14}	7,400	9,000	9,300	7,910	(1,900)	(300)	(1,390)
SF_6	23,900	22,200	22,800	23,500	1,100	(600)	700
NF_3	NA	10,800	17,200	16,100	NA	(6,400)	700

Source: (IPCC 2013, IPCC 2007, IPCC 2001, IPCC 1996)
NC (No Change)
NA (Not Applicable)
Note: Parentheses indicate negative values.

[a] The GWP of CH_4 includes the direct effects and those indirect effects due to the production of tropospheric ozone and stratospheric water vapor. The indirect effect due to the production of CO_2 is not included.

[b] The GWPs presented here are the ones most consistent with the methodology used in the AR4 report. The AR5 report has also calculated GWPs (not shown here) where climate-carbon feedbacks have been included for the non-CO_2 gases in order to be consistent with the approach used in calculating the CO_2 lifetime. Additionally, the AR5 reported separate values for fossil versus biogenic methane in order to account for the CO_2 oxidation product.

To comply with international reporting standards under the UNFCCC, official emission estimates are reported by the United States using AR4 GWP values, as required by the 2013 revision to the UNFCCC reporting guidelines for national inventories.[25] All estimates provided throughout this report are also presented in unweighted units. For informational purposes, emission estimates that use GWPs from other IPCC Assessment Reports are presented in detail in Annex 6.1 of this report.

1.2 National Inventory Arrangements

The U.S. Environmental Protection Agency (EPA), in cooperation with other U.S. government agencies, prepares the Inventory of U.S. Greenhouse Gas Emissions and Sinks. A wide range of agencies and individuals are involved in supplying data to, planning methodological approaches and improvements, reviewing, or preparing portions of the U.S. Inventory—including federal and state government authorities, research and academic institutions, industry associations, and private consultants.

Within EPA, the Office of Atmospheric Programs (OAP) is the lead office responsible for the emission calculations provided in the Inventory, as well as the completion of the National Inventory Report and the Common Reporting Format tables. EPA's Office of Transportation and Air Quality (OTAQ) is also involved in calculating emissions for the Inventory. While the U.S. Department of State officially submits the annual Inventory to the UNFCCC, EPA's OAP serves as the Inventory focal point for technical questions and comments on the U.S. Inventory. The staff of OAP and OTAQ coordinates the annual methodological choice, activity data collection, and emission calculations at the individual source category level. Within OAP, an inventory coordinator compiles the entire Inventory into the proper reporting format for submission to the UNFCCC, and is responsible for the collection and consistency of cross-cutting issues in the Inventory.

Several other government agencies contribute to the collection and analysis of the underlying activity data used in the Inventory calculations. Formal relationships exist between EPA and other U.S. agencies that provide official data for use in the Inventory. The U.S. Department of Energy's Energy Information Administration provides national fuel consumption data and the U.S. Department of Defense provides military fuel consumption and bunker fuels. Informal relationships also exist with other U.S. agencies to provide activity data for use in EPA's emission calculations. These include: the U.S. Department of Agriculture, the U.S. Geological Survey, the Federal Highway Administration, the Department of Transportation, the Bureau of Transportation Statistics, the Department of Commerce, the National Agricultural Statistics Service, and the Federal Aviation Administration. Academic and research centers also provide activity data and calculations to EPA, as well as individual companies participating in voluntary outreach efforts with EPA. Finally, the U.S. Department of State officially submits the Inventory to the UNFCCC each April. Figure 1-1 diagrams the National Inventory Arrangements.

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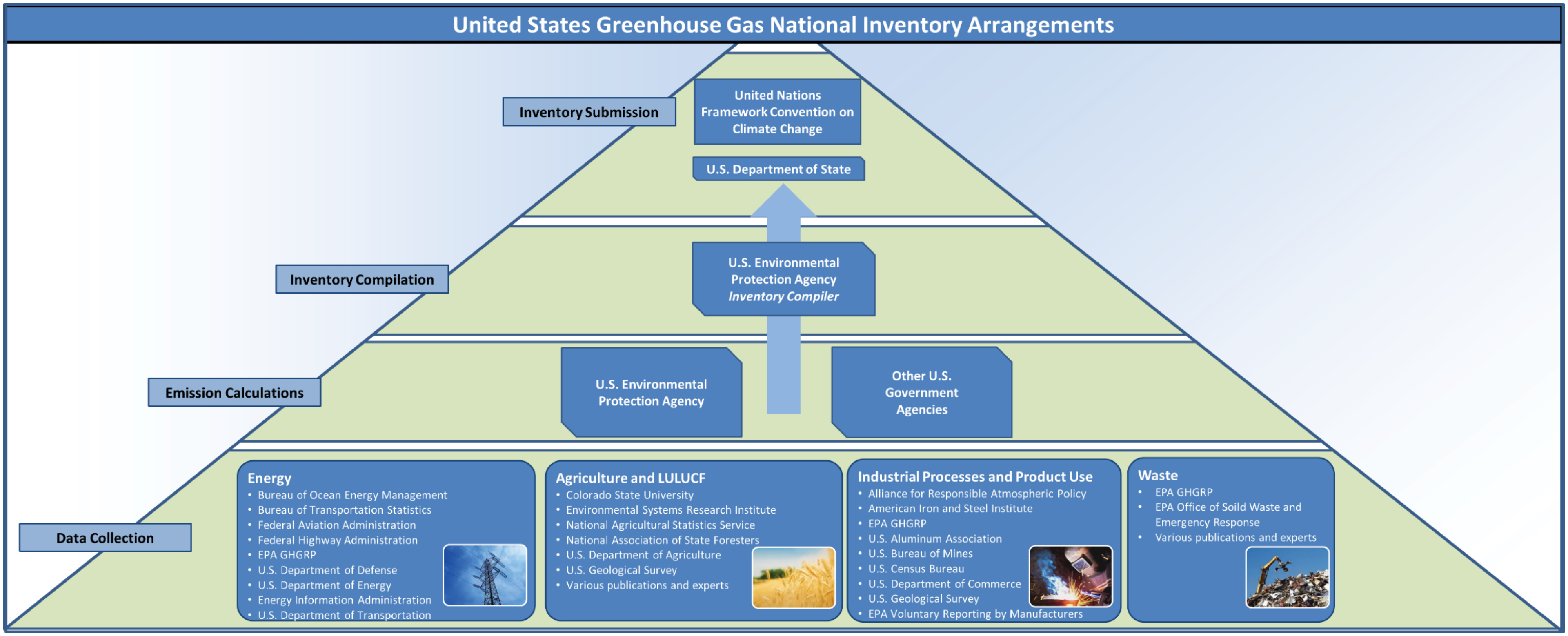
[25] See < http://unfccc.int/resource/docs/2013/cop19/eng/10a03.pdf >.

Figure 1-1: National Inventory Arrangements Diagram



1.3 Inventory Process

EPA has a decentralized approach to preparing the annual U.S. Inventory, which consists of a National Inventory Report (NIR) and Common Reporting Format (CRF) tables. The inventory coordinator at EPA is responsible for compiling all emission estimates and ensuring consistency and quality throughout the NIR and CRF tables. Emission calculations for individual sources are the responsibility of individual source leads, who are most familiar with each source category and the unique characteristics of its emissions profile. The individual source leads determine the most appropriate methodology and collect the best activity data to use in the emission calculations, based upon their expertise in the source category, as well as coordinating with researchers and contractors familiar with the sources. A multi-stage process for collecting information from the individual source leads and producing the Inventory is undertaken annually to compile all information and data.

Methodology Development, Data Collection, and Emissions and Sink Estimation

Source leads at EPA collect input data and, as necessary, evaluate or develop the estimation methodology for the individual source categories. For most source categories, the methodology for the previous year is applied to the new "current" year of the Inventory, and inventory analysts collect any new data or update data that have changed from the previous year. If estimates for a new source category are being developed for the first time, or if the methodology is changing for an existing source category (e.g., the United States is implementing a higher Tiered approach for that source category), then the source category lead will develop a new methodology, gather the most appropriate activity data and emission factors (or in some cases direct emission measurements) for the entire time series, and conduct a special source-specific peer review process involving relevant experts from industry, government, and universities.

Once the methodology is in place and the data are collected, the individual source leads calculate emissions and sink estimates. The source leads then update or create the relevant text and accompanying annexes for the Inventory. Source leads are also responsible for completing the relevant sectoral background tables of the Common Reporting Format, conducting quality assurance and quality control (QA/QC) checks, and uncertainty analyses.

Summary Spreadsheet Compilation and Data Storage

The inventory coordinator at EPA collects the source categories' descriptive text and Annexes, and also aggregates the emission estimates into a summary spreadsheet that links the individual source category spreadsheets together. This summary sheet contains all of the essential data in one central location, in formats commonly used in the Inventory document. In addition to the data from each source category, national trend and related data are also gathered in the summary sheet for use in the Executive Summary, Introduction, and Recent Trends sections of the Inventory report. Electronic copies of each year's summary spreadsheet, which contains all the emission and sink estimates for the United States, are kept on a central server at EPA under the jurisdiction of the inventory coordinator.

National Inventory Report Preparation

The NIR is compiled from the sections developed by each individual source lead. In addition, the inventory coordinator prepares a brief overview of each chapter that summarizes the emissions from all sources discussed in the chapters. The inventory coordinator then carries out a key category analysis for the Inventory, consistent with the *2006 IPCC Guidelines for National Greenhouse Gas Inventories*, and in accordance with the reporting requirements of the UNFCCC. Also at this time, the Introduction, Executive Summary, and Recent Trends sections are drafted, to reflect the trends for the most recent year of the current Inventory. The analysis of trends necessitates gathering supplemental data, including weather and temperature conditions, economic activity and gross domestic product, population, atmospheric conditions, and the annual consumption of electricity, energy, and fossil fuels.

Changes in these data are used to explain the trends observed in greenhouse gas emissions in the United States. Furthermore, specific factors that affect individual sectors are researched and discussed. Many of the factors that affect emissions are included in the Inventory document as separate analyses or side discussions in boxes within the text. Text boxes are also created to examine the data aggregated in different ways than in the remainder of the document, such as a focus on transportation activities or emissions from electricity generation. The document is prepared to match the specification of the UNFCCC reporting guidelines for National Inventory Reports.

Common Reporting Format Table Compilation

The CRF tables are compiled from individual tables completed by each individual source lead, which contain source emissions and activity data. The inventory coordinator integrates the source data into the UNFCCC’s “CRF Reporter” for the United States, assuring consistency across all sectoral tables. The summary reports for emissions, methods, and emission factors used, the overview tables for completeness and quality of estimates, the recalculation tables, the notation key completion tables, and the emission trends tables are then completed by the inventory coordinator. Internal automated quality checks on the CRF Reporter, as well as reviews by the source leads, are completed for the entire time series of CRF tables before submission.

QA/QC and Uncertainty

QA/QC and uncertainty analyses are supervised by the QA/QC and Uncertainty coordinators, who have general oversight over the implementation of the QA/QC plan and the overall uncertainty analysis for the Inventory (see sections on QA/QC and Uncertainty, below). These coordinators work closely with the source leads to ensure that a consistent QA/QC plan and uncertainty analysis is implemented across all inventory sources. The inventory QA/QC plan, detailed in a following section, is consistent with the quality assurance procedures outlined by EPA and IPCC.

Expert and Public Review Periods

During the Expert Review period, a first draft of the document is sent to a select list of technical experts outside of EPA. The purpose of the Expert Review is to encourage feedback on the methodological and data sources used in the current Inventory, especially for sources which have experienced any changes since the previous Inventory.

Once comments are received and addressed, a second draft of the document is released for public review by publishing a notice in the U.S. Federal Register and posting the document on the EPA Web site. The Public Review period allows for a 30 day comment period and is open to the entire U.S. public.

Final Submittal to UNFCCC and Document Printing

After the final revisions to incorporate any comments from the Expert Review and Public Review periods, EPA prepares the final National Inventory Report and the accompanying Common Reporting Format Reporter database. The U.S. Department of State sends the official submission of the U.S. Inventory to the UNFCCC. The document is then formatted and posted online, available for the public.[1]

1.4 Methodology and Data Sources

Emissions of greenhouse gases from various source and sink categories have been estimated using methodologies that are consistent with the *2006 IPCC Guidelines for National Greenhouse Gas Inventories* (IPCC 2006). To the extent possible, the present report relies on published activity and emission factor data. Depending on the emission

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[1] See <http://epa.gov/climatechange/ghgemissions/usinventoryreport.html.>

source category, activity data can include fuel consumption or deliveries, vehicle-miles traveled, raw material processed, etc. Emission factors are factors that relate quantities of emissions to an activity.

The IPCC methodologies provided in the *2006 IPCC Guidelines* represent baseline methodologies for a variety of source categories, and many of these methodologies continue to be improved and refined as new research and data become available. This report uses the IPCC methodologies when applicable, and supplements them with other available country-specific methodologies and data where possible. Choices made regarding the methodologies and data sources used are provided in conjunction with the discussion of each source category in the main body of the report. Complete documentation is provided in the annexes on the detailed methodologies and data sources utilized in the calculation of each source category.

Box 1-3: IPCC Reference Approach

The UNFCCC reporting guidelines 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. This estimation method uses alternative methodologies and different data sources than those contained in that section of the Energy chapter. 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 (see Annex 4 of this report). 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. Accounting for actual consumption of fuels at the sectoral or sub-national level is not required.

1.5 Key Categories

The *2006 IPCC Guidelines* (IPCC 2006) defines a key category as a “[category] that is prioritized within the national inventory system because its estimate has a significant influence on a country’s total inventory of greenhouse gases in terms of the absolute level, the trend, or the uncertainty in emissions and removals.”[2] By definition, key categories include those categories that have the greatest contribution to the absolute level of national emissions. In addition, when an entire time series of emission and removal estimates is prepared, a thorough investigation of key categories must also account for the influence of trends and uncertainties of individual source and sink categories. This analysis culls out source and sink categories that diverge from the overall trend in national emissions. Finally, a qualitative evaluation of key categories is performed to capture any categories that were not identified in any of the quantitative analyses.

Approach 1, as defined in the *2006 IPCC Guidelines* (IPCC 2006), was implemented to identify the key categories for the United States. This analysis was performed twice; one analysis included sources and sinks from the Land Use, Land-Use Change, and Forestry (LULUCF) sector, the other analysis did not include the LULUCF categories. Following Approach 1, Approach 2, as defined in the *2006 IPCC Guidelines* (IPCC 2006), was then implemented to identify any additional key categories not already identified in Approach 1 assessment. This analysis, which includes each source category’s uncertainty assessments (or proxies) in its calculations, was also performed twice to include or exclude LULUCF categories.

In addition to conducting Approach 1 and 2 level and trend assessments, a qualitative assessment of the source categories, as described in the *2006 IPCC Guidelines* (IPCC 2006), was conducted to capture any key categories that were not identified by either quantitative method. One additional key category, international bunker fuels, was identified using this qualitative assessment. International bunker fuels are fuels consumed for aviation or marine international transport activities, and emissions from these fuels are reported separately from totals in accordance

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[2] See Chapter 4 “Methodological Choice and Identification of Key Categories” in IPCC (2006). See < http://www.ipcc-nggip.iges.or.jp/public/2006gl/index.html>.

with IPCC guidelines. If these emissions were included in the totals, bunker fuels would qualify as a key category according to Approach 1. The amount of uncertainty associated with estimation of emissions from international bunker fuels also supports the qualification of this source category as key, because it would qualify bunker fuels as a key category according to Approach 2. Table 1-4 presents the key categories for the United States (including and excluding LULUCF categories) using emissions and uncertainty data in this report, and ranked according to their sector and global warming potential-weighted emissions in 2014. The table also indicates the criteria used in identifying these categories (i.e., level, trend, Approach 1, Approach 2, and/or qualitative assessments). Annex 1 of this report provides additional information regarding the key categories in the United States and the methodologies used to identify them.

Table 1-4: Key Categories for the United States (1990-2014)

IPCC Source Categories	Gas	Approach 1				Approach 2				Qual[a]	2014 Emissions (MMT CO_2 Eq.)
		Level Without LULUCF	Trend Without LULUCF	Level With LULUCF	Trend With LULUCF	Level Without LULUCF	Trend Without LULUCF	Level With LULUCF	Trend With LULUCF		
Energy											
CO_2 Emissions from Stationary Combustion - Coal - Electricity Generation	CO_2	•	•	•	•	•	•	•	•		1,570.4
CO_2 Emissions from Mobile Combustion: Road	CO_2	•	•	•	•	•	•	•	•		1,467.7
CO_2 Emissions from Stationary Combustion - Gas - Industrial	CO_2	•	•	•	•	•	•	•			466.0
CO_2 Emissions from Stationary Combustion - Gas - Electricity Generation	CO_2	•	•	•	•	•	•	•	•		443.2
CO_2 Emissions from Stationary Combustion - Gas - Residential	CO_2	•	•	•	•	•		•			277.6
CO_2 Emissions from Stationary Combustion - Oil - Industrial	CO_2	•	•	•	•	•	•	•	•		272.9
CO_2 Emissions from Stationary Combustion - Gas - Commercial	CO_2	•	•	•	•	•	•	•	•		189.2
CO_2 Emissions from Mobile Combustion: Aviation	CO_2	•	•	•	•	•	•	•	•		150.1
CO_2 Emissions from Non-Energy Use of Fuels	CO_2	•	•	•	•	•	•	•	•		114.3
CO_2 Emissions from Mobile Combustion: Other	CO_2	•	•	•	•						92.0
CO_2 Emissions from Stationary Combustion - Coal - Industrial	CO_2	•	•	•	•	•	•	•	•		75.3

CO_2 Emissions from Stationary Combustion - Oil - Residential	CO_2	•	•	•	•		•				67.6
CO_2 Emissions from Stationary Combustion - Oil - Commercial	CO_2	•	•	•	•						37.9
CO_2 Emissions from Natural Gas Systems	CO_2	•		•		•		•			37.8
CO_2 Emissions from Stationary Combustion - Oil - U.S. Territories	CO_2	•		•	•						34.6
CO_2 Emissions from Mobile Combustion: Marine	CO_2	•	•	•	•						27.7
CO_2 Emissions from Stationary Combustion - Oil - Electricity Generation	CO_2	•	•	•	•		•		•		25.3
CO_2 Emissions from Stationary Combustion - Coal - Commercial	CO_2		•		•						4.5
CO_2 Emissions from Stationary Combustion - Gas - U.S. Territories	CO_2						•				3.0
CO_2 Emissions from Stationary Combustion - Coal - Residential	CO_2						•		•		0.0
CH_4 Emissions from Natural Gas Systems	CH_4	•	•	•	•	•	•	•	•		157.4
Fugitive Emissions from Coal Mining	CH_4	•	•	•	•	•	•	•	•		64.6
CH_4 Emissions from Petroleum Systems	CH_4	•	•	•	•	•	•	•	•		25.2
Non-CO_2 Emissions from Stationary Combustion - Residential	CH_4					•		•			5.0
Non-CO_2 Emissions from Stationary Combustion - Electricity Generation	N_2O		•		•	•	•	•	•		19.6
N_2O Emissions from Mobile Combustion: Road	N_2O	•	•	•	•	•	•		•		12.5
Non-CO_2 Emissions from Stationary Combustion - Industrial	N_2O						•				2.4
International Bunker Fuels[b]	Several									•	104.2
Industrial Processes and Product Use											
CO_2 Emissions from Iron and Steel Production & Metallurgical Coke Production	CO_2	•	•	•	•	•	•	•	•		55.4

CO_2 Emissions from Cement Production	CO_2	•		•							38.8
CO_2 Emissions from Petrochemical Production	CO_2			•							26.5
CO_2 Emissions from Other Process Uses of Carbonates	CO_2		•		•						12.1
N_2O Emissions from Adipic Acid Production	N_2O		•		•						5.4
Emissions from Substitutes for Ozone Depleting Substances	HiGWP	•	•	•	•	•	•	•	•		171.4
SF_6 Emissions from Electrical Transmission and Distribution	HiGWP		•		•		•		•		5.1
HFC-23 Emissions from HCFC-22 Production	HiGWP	•	•	•	•		•		•		4.1
PFC Emissions from Aluminum Production	HiGWP		•		•						3.0
Agriculture											
CH_4 Emissions from Enteric Fermentation	CH_4	•	•	•	•	•	•	•			164.3
CH_4 Emissions from Manure Management	CH_4	•	•	•	•	•	•	•	•		61.2
CH_4 Emissions from Rice Cultivation	CH_4					•		•			12.2
Direct N_2O Emissions from Agricultural Soil Management	N_2O	•		•		•		•			261.3
Indirect N_2O Emissions from Applied Nitrogen	N_2O	•		•		•	•	•	•		57.2
Waste											
CH_4 Emissions from Landfills	CH_4	•	•	•	•	•	•	•	•		181.8
Land Use, Land-Use Change, and Forestry											
CO_2 Emissions from Land Converted to Cropland	CO_2				•			•	•		14.7
CO_2 Emissions from Grassland Remaining Grassland	CO_2							•	•		11.9
CO_2 Emissions from Landfilled Yard Trimmings and Food Scraps	CO_2			•	•			•	•		(11.6)
CO_2 Emissions from Cropland Remaining Cropland	CO_2			•	•			•	•		(16.0)
CO_2 Emissions from Urban Trees	CO_2			•	•			•	•		(90.6)
CO_2 Emissions from Forest Land Remaining Forest Land	CO_2			•	•			•	•		(583.4)
CH_4 Emissions from Forest Fires	CH_4							•	•		7.3

N_2O Emissions from Settlement Soils	N_2O			•		2.4
N_2O Emissions from Forest Fires	N_2O			•		4.8
Subtotal Without LULUCF						**6,676.8**
Total Emissions Without LULUCF						**6,848.1**
Percent of Total Without LULUCF						**97%**
Subtotal With LULUCF						**6,037.6**
Total Emissions With LULUCF						**6,186.8**
Percent of Total With LULUCF						**98%**

[a] Qualitative criteria.
[b] Emissions from this source not included in totals.
Note: Parentheses indicate negative values (or sequestration).

1.6 Quality Assurance and Quality Control (QA/QC)

As part of efforts to achieve its stated goals for inventory quality, transparency, and credibility, the United States has developed a quality assurance and quality control plan designed to check, document and improve the quality of its inventory over time. QA/QC activities on the Inventory are undertaken within the framework of the U.S. QA/QC plan, Quality Assurance/Quality Control and Uncertainty Management Plan for the U.S. Greenhouse Gas Inventory: Procedures Manual for QA/QC and Uncertainty Analysis.

Key attributes of the QA/QC plan are summarized in Figure 1-2. These attributes include:

- *Procedures and Forms:* detailed and specific systems that serve to standardize the process of documenting and archiving information, as well as to guide the implementation of QA/QC and the analysis of uncertainty
- *Implementation of Procedures:* application of QA/QC procedures throughout the whole inventory development process from initial data collection, through preparation of the emission estimates, to publication of the Inventory
- *Quality Assurance:* expert and public reviews for both the inventory estimates and the Inventory report (which is the primary vehicle for disseminating the results of the inventory development process)
- *Quality Control*: consideration of secondary data and source-specific checks (Tier 2 QC) in parallel and coordination with the uncertainty assessment; the development of protocols and templates, which provides for more structured communication and integration with the suppliers of secondary information
- *Tier 1 (general) and Tier 2 (source-specific) Checks:* quality controls and checks, as recommended by IPCC Good Practice Guidance
- *Record Keeping:* provisions to track which procedures have been followed, the results of the QA/QC, uncertainty analysis, and feedback mechanisms for corrective action based on the results of the investigations which provide for continual data quality improvement and guided research efforts
- *Multi-Year Implementation*: a schedule for coordinating the application of QA/QC procedures across multiple years
- *Interaction and Coordination:* promoting communication within the EPA, across Federal agencies and departments, state government programs, and research institutions and consulting firms involved in supplying data or preparing estimates for the Inventory. The QA/QC Management Plan itself is intended to

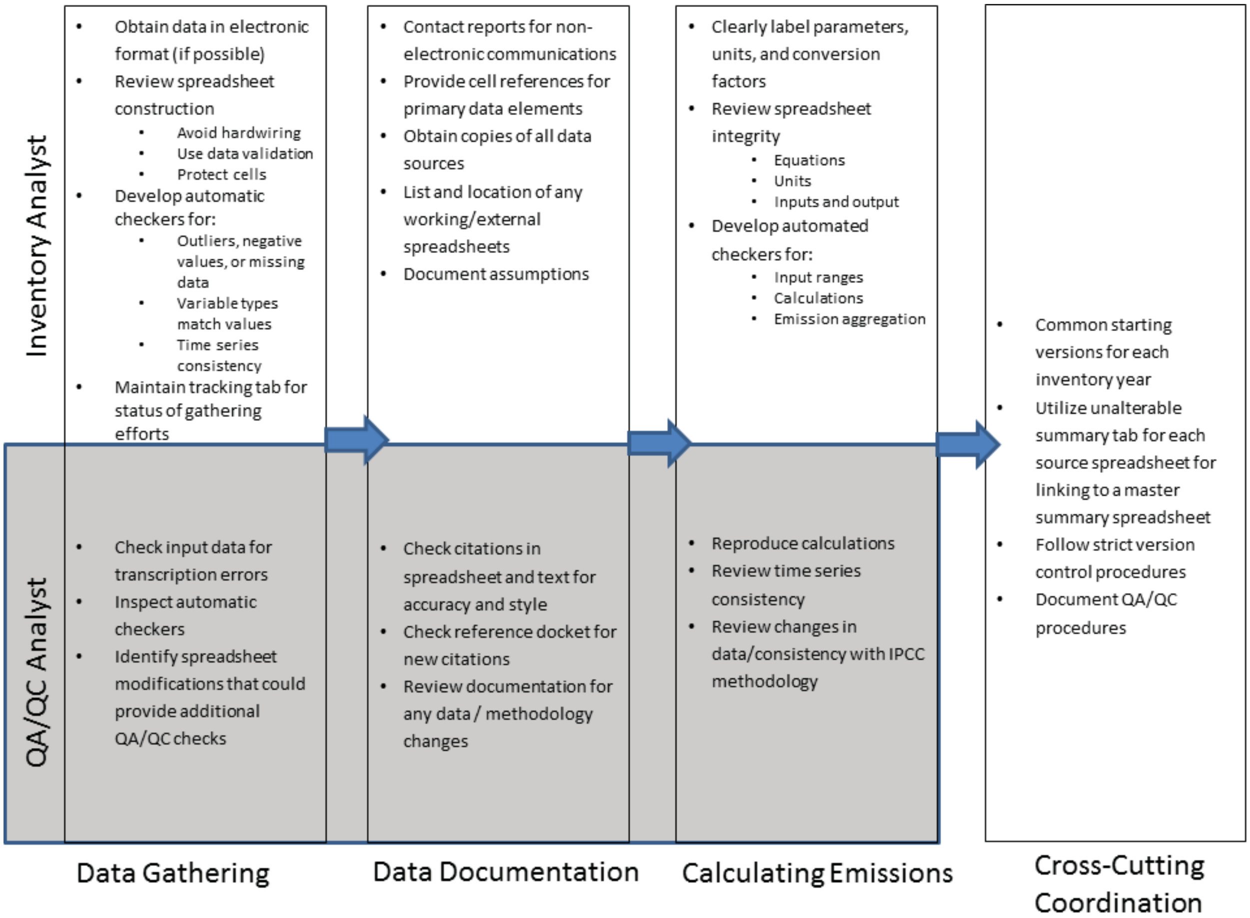
be revised and reflect new information that becomes available as the program develops, methods are improved, or additional supporting documents become necessary.

In addition, based on the national QA/QC plan for the Inventory, source-specific QA/QC plans have been developed for a number of sources. These plans follow the procedures outlined in the national QA/QC plan, tailoring the procedures to the specific text and spreadsheets of the individual sources. For each greenhouse gas emissions source or sink included in this Inventory, a minimum of a Tier 1 QA/QC analysis has been undertaken. Where QA/QC activities for a particular source go beyond the minimum Tier 1 level, further explanation is provided within the respective source category text.

The quality control activities described in the U.S. QA/QC plan occur throughout the inventory process; QA/QC is not separate from, but is an integral part of, preparing the Inventory. Quality control—in the form of both good practices (such as documentation procedures) and checks on whether good practices and procedures are being followed—is applied at every stage of inventory development and document preparation. In addition, quality assurance occurs at two stages—an expert review and a public review. While both phases can significantly contribute to inventory quality, the public review phase is also essential for promoting the openness of the inventory development process and the transparency of the inventory data and methods.

The QA/QC plan guides the process of ensuring inventory quality by describing data and methodology checks, developing processes governing peer review and public comments, and developing guidance on conducting an analysis of the uncertainty surrounding the emission estimates. The QA/QC procedures also include feedback loops and provide for corrective actions that are designed to improve the inventory estimates over time.

Figure 1-2: U.S. QA/QC Plan Summary



1.7 Uncertainty Analysis of Emission Estimates

Uncertainty estimates are an essential element of a complete and transparent emissions inventory. Uncertainty information is not intended to dispute the validity of the inventory estimates, but to help prioritize efforts to improve the accuracy of future inventories and guide future decisions on methodological choice. While the U.S. Inventory calculates its emission estimates with the highest possible accuracy, uncertainties are associated to a varying degree with the development of emission estimates for any inventory. Some of the current estimates, such as those for CO_2 emissions from energy-related activities, are considered to have minimal uncertainty associated with them. For some other categories of emissions, however, a lack of data or an incomplete understanding of how emissions are generated increases the uncertainty surrounding the estimates presented. The UNFCCC reporting guidelines follow the recommendation in the *2006 IPCC Guidelines* (IPCC 2006) and require that countries provide single point estimates for each gas and emission or removal source category. Within the discussion of each emission source, specific factors affecting the uncertainty associated with the estimates are discussed.

Additional research in the following areas could help reduce uncertainty in the U.S. Inventory:

- *Incorporating excluded emission sources*. Quantitative estimates for some of the sources and sinks of greenhouse gas emissions are not available at this time. In particular, emissions from some land-use activities and industrial processes are not included in the inventory either because data are incomplete or because methodologies do not exist for estimating emissions from these source categories. See Annex 5 of this report for a discussion of the sources of greenhouse gas emissions and sinks excluded from this report.
- *Improving the accuracy of emission factors*. Further research is needed in some cases to improve the accuracy of emission factors used to calculate emissions from a variety of sources. For example, the accuracy of current emission factors applied to CH_4 and N_2O emissions from stationary and mobile combustion is highly uncertain.
- *Collecting detailed activity data*. Although methodologies exist for estimating emissions for some sources, problems arise in obtaining activity data at a level of detail in which aggregate emission factors can be applied. For example, the ability to estimate emissions of SF_6 from electrical transmission and distribution is limited due to a lack of activity data regarding national SF_6 consumption or average equipment leak rates.

The overall uncertainty estimate for total U.S. greenhouse gas emissions was developed using the IPCC Approach 2 uncertainty estimation methodology. Estimates of quantitative uncertainty for the total U.S. greenhouse gas emissions are shown below, in Table 1-5.

The IPCC provides good practice guidance on two approaches—Approach 1 and Approach 2—to estimating uncertainty for individual source categories. Approach 2 uncertainty analysis, employing the Monte Carlo Stochastic Simulation technique, was applied wherever data and resources permitted; further explanation is provided within the respective source category text and in Annex 7. Consistent with the *2006 IPCC Guidelines* (IPCC 2006), over a multi-year timeframe, the United States expects to continue to improve the uncertainty estimates presented in this report.

Table 1-5: Estimated Overall Inventory Quantitative Uncertainty (MMT CO_2 Eq. and Percent) (TO BE UPDATED)

Gas	2013 Emission Estimate[a]	Uncertainty Range Relative to Emission Estimate[b]				Mean[c]	Standard Deviation[c]
	(MMT CO_2 Eq.)	(MMT CO_2 Eq.)		(%)		(MMT CO_2 Eq.)	
		Lower Bound[d]	Upper Bound[d]	Lower Bound	Upper Bound		
CO_2	5,505	5,400	5,766	-2%	5%	5,584	95
CH_4[e]	636	573	751	-10%	18%	656	45
N_2O[e]	355	320	445	-10%	25%	376	32
PFC, HFC, SF_6, and NF_3[e]	171	170	190	-1%	11%	180	5

Total	**6,667**	**6,584**	**7,008**	**-1%**	**5%**	**6,795**	**110**
Net Emissions (Sources and Sinks)	**5,785.5**	**5,613**	**6,220**	**-3%**	**8%**	**5,916**	**154**

Notes:

[a] Emission estimates reported in this table correspond to emissions from only those source categories for which quantitative uncertainty was performed this year. Thus the totals reported in this table exclude approximately 5.7 MMT CO_2 Eq. of emissions for which quantitative uncertainty was not assessed. Hence, these emission estimates do not match the final total U.S. greenhouse gas emission estimates presented in this Inventory.

[b] The lower and upper bounds for emission estimates correspond to a 95 percent confidence interval, with the lower bound corresponding to 2.5th percentile and the upper bound corresponding to 97.5th percentile.

[c] Mean value indicates the arithmetic average of the simulated emission estimates; standard deviation indicates the extent of deviation of the simulated values from the mean.

[d] The lower and upper bound emission estimates for the sub-source categories do not sum to total emissions because the low and high estimates for total emissions were calculated separately through simulations.

[e] The overall uncertainty estimates did not take into account the uncertainty in the GWP values for CH_4, N_2O and high GWP gases used in the inventory emission calculations for 2013.

Emissions calculated for the U.S. Inventory reflect current best estimates; in some cases, however, estimates are based on approximate methodologies, assumptions, and incomplete data. As new information becomes available in the future, the United States will continue to improve and revise its emission estimates. See Annex 7 of this report for further details on the U.S. process for estimating uncertainty associated with the emission estimates and for a more detailed discussion of the limitations of the current analysis and plans for improvement. Annex 7 also includes details on the uncertainty analysis performed for selected source categories.

1.8 Completeness

This report, along with its accompanying CRF tables, serves as a thorough assessment of the anthropogenic sources and sinks of greenhouse gas emissions for the United States for the time series 1990 through 2014. Although this report is intended to be comprehensive, certain sources have been identified which were excluded from the estimates presented for various reasons. Generally speaking, sources not accounted for in this inventory are excluded due to data limitations or a lack of thorough understanding of the emission process. The United States is continually working to improve upon the understanding of such sources and seeking to find the data required to estimate related emissions. As such improvements are implemented, new emission sources are quantified and included in the Inventory. For a complete list of sources not included, see Annex 5 of this report.

1.9 Organization of Report

In accordance with the revision of the UNFCCC reporting guidelines agreed to at the nineteenth Conference of the Parties (UNFCCC 2014), this Inventory of U.S. Greenhouse Gas Emissions and Sinks is segregated into five sector-specific chapters, listed below in Table 1-6. In addition, chapters on Trends in Greenhouse Gas Emissions and Other information to be considered as part of the U.S. Inventory submission are included.

Table 1-6: IPCC Sector Descriptions

Chapter/IPCC Sector	Activities Included
Energy	Emissions of all greenhouse gases resulting from stationary and mobile energy activities including fuel combustion and fugitive fuel emissions, and non-energy use of fossil fuels.
Industrial Processes and Product Use	Emissions resulting from industrial processes and product use of greenhouse gases.

Agriculture	Anthropogenic emissions from agricultural activities except fuel combustion, which is addressed under Energy.
Land Use, Land-Use Change, and Forestry	Emissions and removals of CO_2, CH_4, and N_2O from forest management, other land-use activities, and land-use change.
Waste	Emissions from waste management activities.

Within each chapter, emissions are identified by the anthropogenic activity that is the source or sink of the greenhouse gas emissions being estimated (e.g., coal mining). Overall, the following organizational structure is consistently applied throughout this report:

Chapter/IPCC Sector: Overview of emission trends for each IPCC defined sector

Source category: Description of source pathway and emission trends.

Methodology: Description of analytical methods employed to produce emission estimates and identification of data references, primarily for activity data and emission factors.

Uncertainty and Timeseries Consistency: A discussion and quantification of the uncertainty in emission estimates and a discussion of time-series consistency.

QA/QC and Verification: A discussion on steps taken to QA/QC and verify the emission estimates, where beyond the overall U.S. QA/QC plan, and any key findings.

Recalculations: A discussion of any data or methodological changes that necessitate a recalculation of previous years' emission estimates, and the impact of the recalculation on the emission estimates, if applicable.

Planned Improvements: A discussion on any source-specific planned improvements, if applicable.

Special attention is given to CO_2 from fossil fuel combustion relative to other sources because of its share of emissions and its dominant influence on emission trends. For example, each energy consuming end-use sector (i.e., residential, commercial, industrial, and transportation), as well as the electricity generation sector, is described individually. Additional information for certain source categories and other topics is also provided in several Annexes listed in Table 1-7.

Table 1-7: List of Annexes

ANNEX 1 Key Category Analysis
ANNEX 2 Methodology and Data for Estimating CO_2 Emissions from Fossil Fuel Combustion
2.1. Methodology for Estimating Emissions of CO_2 from Fossil Fuel Combustion
2.2. Methodology for Estimating the Carbon Content of Fossil Fuels
2.3. Methodology for Estimating Carbon Emitted from Non-Energy Uses of Fossil Fuels
ANNEX 3 Methodological Descriptions for Additional Source or Sink Categories
3.1. Methodology for Estimating Emissions of CH_4, N_2O, and Indirect Greenhouse Gases from Stationary Combustion
3.2. Methodology for Estimating Emissions of CH_4, N_2O, and Indirect Greenhouse Gases from Mobile Combustion and Methodology for and Supplemental Information on Transportation-Related Greenhouse Gas Emissions
3.3. Methodology for Estimating Emissions from Commercial Aircraft Jet Fuel Consumption
3.4. Methodology for Estimating CH_4 Emissions from Coal Mining (TO BE UPDATED)
3.5. Methodology for Estimating CH_4 and CO_2 Emissions from Petroleum Systems (TO BE UPDATED)
3.6. Methodology for Estimating CH_4 Emissions from Natural Gas Systems (TO BE UPDATED)
3.7. Methodology for Estimating CO_2 and N_2O Emissions from Incineration of Waste
3.8. Methodology for Estimating Emissions from International Bunker Fuels used by the U.S. Military
3.9. Methodology for Estimating HFC and PFC Emissions from Substitution of Ozone Depleting Substances
3.10. Methodology for Estimating CH_4 Emissions from Enteric Fermentation
3.11. Methodology for Estimating CH_4 and N_2O Emissions from Manure Management
3.12. Methodology for Estimating N_2O Emissions and Soil Organic C Stock Changes from Agricultural Soil Management (Cropland and Grassland) (TO BE UPDATED)
3.13. Methodology for Estimating Net Carbon Stock Changes in Forest Lands Remaining Forest Lands (TO BE UPDATED)
3.14. Methodology for Estimating CH_4 Emissions from Landfills
ANNEX 4 IPCC Reference Approach for Estimating CO_2 Emissions from Fossil Fuel Combustion
ANNEX 5 Assessment of the Sources and Sinks of Greenhouse Gas Emissions Not Included (TO BE UPDATED)
ANNEX 6 Additional Information
6.1. Global Warming Potential Values
6.2. Ozone Depleting Substance Emissions
6.3. Sulfur Dioxide Emissions
6.4. Complete List of Source Categories
6.5. Constants, Units, and Conversions
6.6. Abbreviations
6.7. Chemical Formulas
ANNEX 7 Uncertainty
7.1. Overview
7.2. Methodology and Results
7.3. Planned Improvements
ANNEX 8 QA/QC Procedures
8.1. Background
8.2. Purpose
8.3. Assessment Factors

2. Trends in Greenhouse Gas Emissions

2.1 Recent Trends in U.S. Greenhouse Gas Emissions and Sinks

In 2014, total U.S. greenhouse gas emissions were 6,872.6 MMT or million metric tons CO_2 Eq. Total U.S. emissions have increased by 7.7 percent from 1990 to 2014, and emissions increased from 2013 to 2014 by 0.9 percent (61.5 MMT CO_2 Eq.). The increase in CO_2 emissions from fossil fuel combustion was a result of multiple factors, including: (1) colder winter conditions in the first quarter of 2014 resulting in an increased demand for heating fuel in the residential and commercial sectors; (2) an increase in transportation emissions resulting from an increase in vehicle miles traveled (VMT) and fuel use across on-road transportation modes; and (3) an increase in industrial production across multiple sectors resulting in slight increases in industrial sector emissions. Since 1990, U.S. emissions have increased at an average annual rate of 0.3 percent. Figure 2-1 through Figure 2-3 illustrate the overall trend in total U.S. emissions by gas, annual changes, and absolute changes since 1990.

Figure 2-1: U.S. Greenhouse Gas Emissions by Gas (MMT CO_2 Eq.)

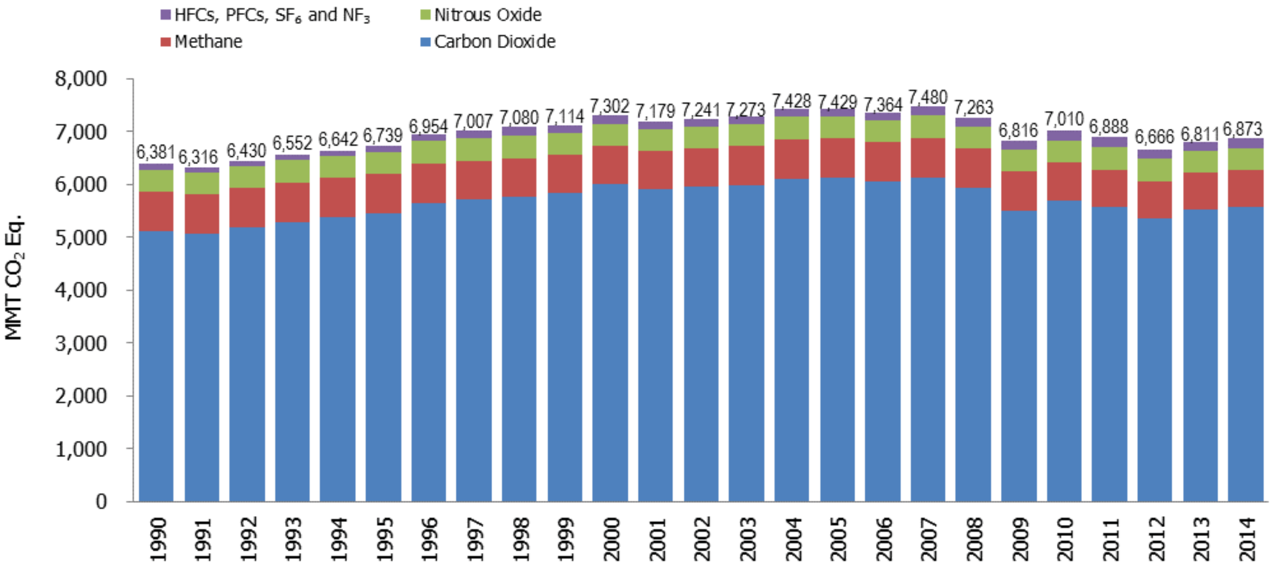


Figure 2-2: Annual Percent Change in U.S. Greenhouse Gas Emissions

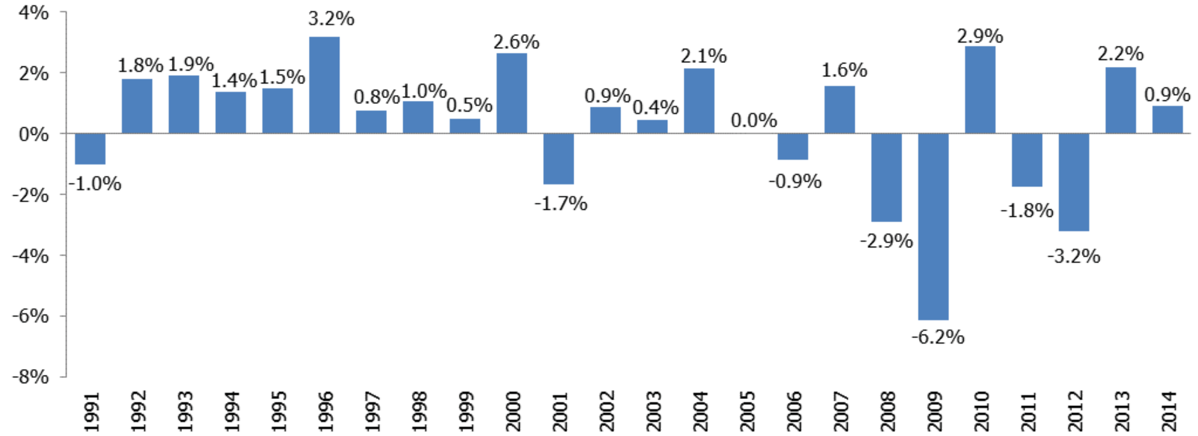
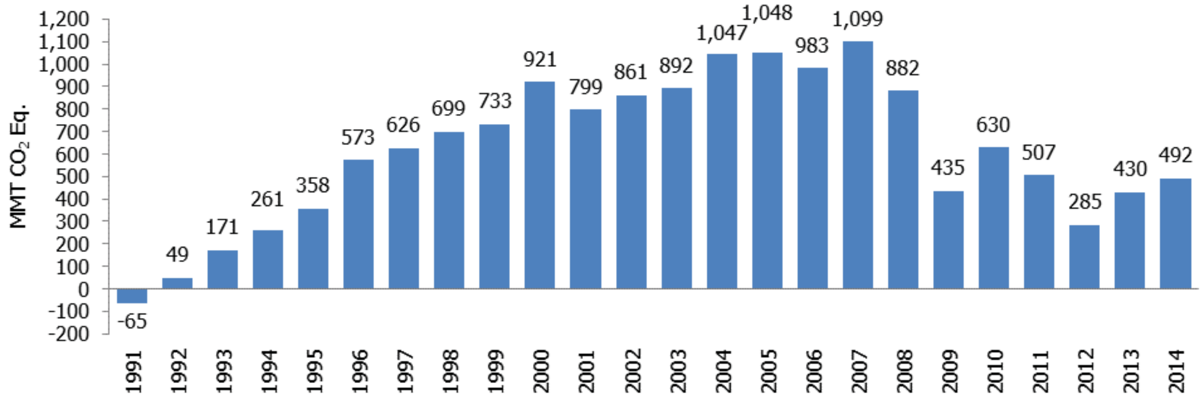


Figure 2-3: Cumulative Change in Annual U.S. Greenhouse Gas Emissions Relative to 1990 (MMT CO_2 Eq.)



Overall, from 1990 to 2014, total emissions of CO_2 increased by 440.2 MMT CO_2 Eq. (8.6 percent), while total emissions of CH_4 decreased by 37.4 MMT CO_2 Eq. (5.0 percent), and total emissions of N_2O increased by 1.9 MMT CO_2 Eq. (0.5 percent). During the same period, aggregate weighted emissions of HFCs, PFCs, SF_6, and NF_3 rose by 87.1 MMT CO_2 Eq. (85.4 percent). Despite being emitted in smaller quantities relative to the other principal greenhouse gases, emissions of HFCs, PFCs, SF_6, and NF_3 are significant because many of them have extremely high GWPs and, in the cases of PFCs SF_6, and NF_3, long atmospheric lifetimes. Conversely, U.S. greenhouse gas emissions were partly offset by C sequestration in managed forests, trees in urban areas, agricultural soils, and landfilled yard trimmings. These were estimated to offset 10.0 percent of total emissions in 2014.

As the largest contributor to U.S. greenhouse gas emissions, carbon dioxide (CO_2) from fossil fuel combustion has accounted for approximately 76 percent of global warming potential (GWP) weighted emissions for the entire time series since 1990, from 74 percent of total GWP-weighted emissions in 1990 to 76 percent in 2014. Emissions from this source category grew by 9.9 percent (468.0 MMT CO_2 Eq.) from 1990 to 2014 and were responsible for most of the increase in national emissions during this period. From 2013 to 2014, these emissions increased by 1.0 percent (51.1 MMT CO_2 Eq.). Historically, changes in emissions from fossil fuel combustion have been the dominant factor affecting U.S. emission trends.

Changes in CO_2 emissions from fossil fuel combustion are influenced by many long-term and short-term factors, including population and economic growth, energy price fluctuations, technological changes, energy fuel choices, and seasonal temperatures. On an annual basis, the overall consumption of fossil fuels in the United States fluctuates primarily 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 in a year with poor economic performance, high fuel prices, mild temperatures, and increased output from nuclear and hydroelectric plants.

In the longer-term, energy consumption patterns respond to changes that affect the scale of consumption (e.g., population, number of cars, and size of houses), the efficiency with which energy is used in equipment (e.g., cars, power plants, steel mills, and light bulbs) and behavioral choices (e.g., walking, bicycling, or telecommuting to work instead of driving).

Energy-related CO_2 emissions also depend on the type of fuel or energy consumed and its carbon (C) intensity. Producing a unit of heat or electricity using natural gas instead of coal, for example, can reduce the CO_2 emissions because of the lower C content of natural gas.

A brief discussion of the year to year variability in fuel combustion emissions is provided below, beginning with 2010.

From 2010 to 2011, CO_2 emissions from fossil fuel combustion decreased by 2.4 percent. This decrease is a result of multiple factors including: (1) a decrease in the carbon intensity of fuels consumed to generate electricity due to a decrease in coal consumption, with increased natural gas consumption and a significant increase in hydropower used; (2) a decrease in transportation-related energy consumption due to higher fuel costs, improvements in fuel efficiency, and a reduction in miles traveled; and (3) relatively mild winter conditions resulting in an overall decrease in energy demand in most sectors. Changing fuel prices played a role in the decreasing emissions. A significant increase in the price of motor gasoline in the transportation sector was a major factor leading to a decrease in energy consumption by 1.2 percent. In addition, an increase in the price of coal and a concurrent decrease in natural gas prices led to a 5.7 percent decrease and a 2.5 percent increase in fuel consumption of these fuels by electric generators. This change in fuel prices also reduced the carbon intensity of fuels used to produce electricity in 2011, further contributing to the decrease in fossil fuel combustion emissions.

From 2011 to 2012, CO_2 emissions from fossil fuel combustion decreased by 3.9 percent, with emissions from fossil fuel combustion at their lowest level since 1994. This decrease from 2011 to 2012 is primarily a result of the decrease in the carbon intensity of fuels used to generate electricity due to a slight increase in the price of coal, and a significant decrease in the price of natural gas. The consumption of coal used to generate electricity decreased by 12.3 percent, while consumption of natural gas for electricity generation increased by 20.4 percent. Also, emissions declined in the transportation sector largely due to a small increase in fuel efficiency across different transportation modes and limited new demand for passenger transportation. In 2012, weather conditions remained fairly constant in the summer and were much warmer in the winter compared to 2011, as cooling degree days increased by 1.7 percent while heating degree days decreased 12.6 percent. This decrease in heating degree days resulted in a decreased demand for heating fuel in the residential and commercial sector, which had a decrease in natural gas consumption of 11.7 and 8.0 percent, respectively.

From 2012 to 2013, CO_2 emissions from fossil fuel combustion increased by 2.6 percent. This increase is primarily a result of the increased energy consumption in the residential and commercial sectors, as heating degree days increased 18.5 percent in 2013 as compared to 2012. The cooler weather led to an increase of 17.1 and 12.9 percent direct use of fuels in the residential and commercial sectors, respectively. In addition, there was an increase of 1.5 and 0.8 percent in electricity consumption in the residential and commercial sectors, respectively, due to regions that heat their homes with electricity. The consumption of natural gas used to generate electricity decreased by 9.8 percent due to an increase in the price of natural gas. Electric power plants shifted some consumption from natural gas to coal, and as a result increased coal consumption to generate electricity by 4.0 percent. Lastly, industrial production increased 1.9 percent from 2012 to 2013, resulting in an increase in the in CO_2 emissions from fossil fuel combustion from the industrial sector by 3.7 percent.

From 2013 to 2014, CO_2 emissions from fossil fuel combustion increased by 1.0 percent. This increase is primarily a result of the increased energy consumption in the transportation, residential, and commercial sectors. In the transportation sector, vehicle miles traveled increased by 1.3 percent resulting in increased fuel consumption across on-road transportation modes. In the residential and commercial sectors, heating degree days increased 1.9 percent in 2014 as compared to 2013, resulting in an increased demand in heating fuels for these sectors. The cooler weather led to an increase of 4.5 and 4.9 percent in direct use of fuels in the residential and commercial sectors, respectively.

In addition, there was an increase of 0.9 and 1.1 percent in electricity consumption in the residential and commercial sectors, respectively, due to regions that heat their homes with electricity. There was also an increase in transportation emissions resulting from an increase in vehicle miles traveled (VMT) and fuel use across on-road transportation modes in 2014. Lastly, industrial production increased 3.7 percent from 2013 to 2014, resulting in a slight increase in CO_2 emissions from fossil fuel combustion from the industrial sector by 0.2 percent.

Table 2-1 summarizes emissions and sinks from all U.S. anthropogenic sources in weighted units of MMT CO_2 Eq., while unweighted gas emissions and sinks in kilotons (kt) are provided in Table 2-2.

Table 2-1: Recent Trends in U.S. Greenhouse Gas Emissions and Sinks (MMT CO_2 Eq.)

Gas/Source	1990	2005	2010	2011	2012	2013	2014
CO_2	**5,124.0**	**6,132.6**	**5,698.2**	**5,568.6**	**5,361.0**	**5,513.2**	**5,564.3**
Fossil Fuel Combustion	4,740.7	5,747.1	5,358.3	5,227.7	5,024.7	5,157.6	5,208.7
Electricity Generation	*1,820.8*	*2,400.9*	*2,258.4*	*2,157.7*	*2,022.2*	*2,038.1*	*2,039.3*
Transportation	*1,493.8*	*1,887.0*	*1,728.3*	*1,707.6*	*1,696.8*	*1,713.0*	*1,737.4*
Industrial	*842.5*	*828.0*	*775.5*	*773.3*	*782.9*	*812.2*	*814.2*
Residential	*338.3*	*357.8*	*334.6*	*326.8*	*282.5*	*329.7*	*345.1*
Commercial	*217.4*	*223.5*	*220.1*	*220.7*	*196.7*	*221.0*	*231.6*
U.S. Territories	*27.9*	*49.9*	*41.4*	*41.5*	*43.6*	*43.5*	*41.0*
Non-Energy Use of Fuels	118.1	138.9	114.1	108.5	105.6	121.7	114.3
Iron and Steel Production & Metallurgical Coke Production	99.7	66.5	55.7	59.9	54.2	52.2	55.4
Cement Production	33.3	45.9	31.3	32.0	35.1	36.1	38.8
Natural Gas Systems[a]	37.6	30.0	32.3	35.6	34.8	37.8	37.8
Petrochemical Production	21.6	27.4	27.2	26.3	26.5	26.4	26.5
Lime Production	11.7	14.6	13.4	14.0	13.7	14.0	14.1
Other Process Uses of Carbonates	4.9	6.3	9.6	9.3	8.0	10.4	12.1
Ammonia Production	13.0	9.2	9.2	9.3	9.4	10.0	9.4
Incineration of Waste	8.0	12.5	11.0	10.5	10.4	9.4	9.4
Petroleum Systems[b]	4.4	4.9	4.2	4.5	5.1	6.0	6.0
Urea Fertilization	2.4	3.5	3.8	4.1	4.2	4.3	4.5
Carbon Dioxide Consumption	1.5	1.4	4.4	4.1	4.0	4.2	4.5
Liming	4.7	4.3	4.8	3.9	6.0	3.9	4.1
Urea Consumption for Non-Agricultural Purposes	3.8	3.7	4.7	4.0	4.4	4.2	4.0
Aluminum Production	6.8	4.1	2.7	3.3	3.4	3.3	3.3
Soda Ash Production and Consumption	2.8	3.0	2.7	2.7	2.8	2.8	2.8
Ferroalloy Production	2.2	1.4	1.7	1.7	1.9	1.8	1.9
Titanium Dioxide Production	1.2	1.8	1.8	1.7	1.5	1.7	1.8
Glass Production	1.5	1.9	1.5	1.3	1.2	1.3	1.3
Phosphoric Acid Production	1.5	1.3	1.1	1.2	1.1	1.1	1.1
Zinc Production	0.6	1.0	1.2	1.3	1.5	1.4	1.0
Peatlands Remaining Peatlands	1.1	1.1	1.0	0.9	0.8	0.8	0.8
Lead Production	0.5	0.6	0.5	0.5	0.5	0.5	0.5
Silicon Carbide Production and Consumption	0.4	0.2	0.2	0.2	0.2	0.2	0.2
Magnesium Production and Processing	+	+	+	+	+	+	+
LULUCF Total Net Flux[c]	*(704.2)*	*(636.1)*	*(683.2)*	*(683.6)*	*(680.8)*	*(682.4)*	*(685.8)*
Wood Biomass and Ethanol Consumption[d]	*219.4*	*229.8*	*265.1*	*268.1*	*267.7*	*286.3*	*293.7*
International Bunker Fuels[e]	*103.5*	*113.1*	*117.0*	*111.7*	*105.8*	*99.8*	*103.2*
CH_4	**745.3**	**735.4**	**720.8**	**711.8**	**703.8**	**704.0**	**707.9**
Landfills	184.4	187.3	176.3	176.9	173.5	176.7	181.8
Enteric Fermentation	164.2	168.9	171.3	168.9	166.7	165.5	164.3
Natural Gas Systems[a]	179.1	176.3	159.6	159.3	154.4	157.4	157.4
Coal Mining	96.5	64.1	82.3	71.2	66.5	64.6	64.6

Manure Management	37.2	56.3	60.9	61.5	63.7	61.4	61.2
Petroleum Systems[b]	31.5	23.5	21.3	22.0	23.3	25.2	25.2
Wastewater Treatment	15.7	15.9	15.5	15.3	15.2	15.0	15.0
Rice Cultivation	11.3	14.2	12.2	12.2	12.2	12.2	12.2
Stationary Combustion	8.5	7.4	7.1	7.1	6.6	8.0	8.1
Forest Fires	3.3	9.9	3.3	6.6	11.1	7.3	7.3
Abandoned Underground Coal Mines	7.2	6.6	6.6	6.4	6.2	6.2	6.2
Composting	0.4	1.9	1.8	1.9	1.9	2.0	2.1
Mobile Combustion	5.6	2.7	2.3	2.2	2.2	2.1	2.0
Field Burning of Agricultural Residues	0.2	0.2	0.3	0.3	0.3	0.3	0.3
Petrochemical Production	0.2	0.1	+	+	0.1	0.1	0.1
Ferroalloy Production	+	+	+	+	+	+	+
Silicon Carbide Production and Consumption	+	+	+	+	+	+	+
Iron and Steel Production & Metallurgical Coke Production	+	+	+	+	+	+	+
Peatlands Remaining Peatlands	+	+	+	+	+	+	+
Incineration of Waste	+	+	+	+	+	+	+
International Bunker Fuels[e]	*0.2*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*
N_2O	**409.5**	**406.4**	**415.2**	**423.8**	**419.4**	**411.0**	**411.4**
Agricultural Soil Management	302.9	296.7	320.4	322.9	322.9	318.4	318.5
Stationary Combustion	11.9	20.2	22.2	21.3	21.4	22.9	23.4
Manure Management	14.0	16.5	17.2	17.4	17.5	17.5	17.5
Mobile Combustion	41.2	34.4	23.6	22.4	20.0	18.2	16.3
Nitric Acid Production	12.1	11.3	11.5	10.9	10.5	10.7	10.9
Adipic Acid Production	15.2	7.1	4.2	10.2	5.5	4.0	5.4
Wastewater Treatment	3.4	4.3	4.7	4.8	4.9	4.9	4.9
Forest Fires	2.2	6.5	2.2	4.4	7.3	4.8	4.8
N_2O from Product Uses	4.2	4.2	4.2	4.2	4.2	4.2	4.2
Settlement Soils	1.4	2.3	2.4	2.5	2.5	2.4	2.4
Composting	0.3	1.7	1.6	1.7	1.7	1.8	1.8
Forest Soils	0.1	0.5	0.5	0.5	0.5	0.5	0.5
Incineration of Waste	0.5	0.4	0.3	0.3	0.3	0.3	0.3
Semiconductor Manufacture	+	0.1	0.1	0.2	0.2	0.2	0.2
Field Burning of Agricultural Residues	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Peatlands Remaining Peatlands	+	+	+	+	+	+	+
International Bunker Fuels[e]	*0.9*	*1.0*	*1.0*	*1.0*	*0.9*	*0.9*	*0.9*
HFCs, PFCs, SF_6 and NF_3	**102.0**	**154.4**	**176.2**	**183.6**	**181.4**	**182.9**	**189.1**
HFCs	**46.6**	**133.3**	**161.7**	**166.1**	**167.1**	**169.6**	**175.8**
Substitution of Ozone Depleting Substances[f]	0.3	113.0	153.5	157.1	161.4	165.3	171.4
HCFC-22 Production	46.1	20.0	8.0	8.8	5.5	4.1	4.1
Semiconductor Manufacture	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Magnesium Production and Processing	0.0	0.0	+	+	+	0.1	0.1
PFCs	**24.3**	**6.6**	**4.4**	**6.9**	**6.0**	**5.8**	**5.8**
Aluminum Production	21.5	3.4	1.9	3.5	2.9	3.0	3.0
Semiconductor Manufacture	2.8	3.2	2.6	3.4	3.0	2.9	2.9
SF_6	**31.1**	**14.0**	**9.5**	**10.0**	**7.7**	**6.9**	**6.9**
Electrical Transmission and Distribution	25.4	10.6	7.0	6.8	5.7	5.1	5.1
Magnesium Production and Processing	5.2	2.7	2.1	2.8	1.6	1.4	1.4
Semiconductor Manufacture	0.5	0.7	0.4	0.4	0.4	0.4	0.4
NF_3	**+**	**0.5**	**0.5**	**0.7**	**0.6**	**0.6**	**0.6**
Semiconductor Manufacture	+	0.5	0.5	0.7	0.6	0.6	0.6

Total Emissions	**6,380.8**	**7,428.8**	**7,010.5**	**6,887.8**	**6,665.7**	**6,811.2**	**6,872.6**
LULUCF Emissions[g]	**15.0**	**28.2**	**17.8**	**22.9**	**32.3**	**24.1**	**24.6**
LULUCF Total Net Flux[c]	**(704.2)**	**(636.1)**	**(683.2)**	**(683.6)**	**(680.8)**	**(682.4)**	**(685.8)**
LULUCF Sector Total[h]	**(689.1)**	**(607.9)**	**(665.3)**	**(660.7)**	**(648.5)**	**(658.3)**	**(661.3)**
Net Emissions (Sources and Sinks)	**5,676.6**	**6,792.6**	**6,327.3**	**6,204.2**	**5,984.9**	**6,128.8**	**6,186.8**

+ Does not exceed 0.05 MMT CO_2 Eq.

[a] The values in this table for Natural Gas Systems are presented from the previous Inventory and do not reflect updates to emission estimates for this category. See Section 3.7, Natural Gas Systems of the Energy chapter for more information. Gray highlighting was added on 2/24 for clarification.

[b] The values in this table for Petroleum Systems are presented from the previous Inventory and do not reflect updates to emission estimates for this category. See Section 3.6, Petroleum Systems of the Energy chapter for more information. Gray highlighting was added on 2/24 for clarification.

[c] Total net flux from LULUCF is only included in the Net Emissions total. Net flux from LULUCF includes the positive C sequestration reported for *Forest Land Remaining Forest Land, Land Converted to Forest Land, Cropland Remaining Cropland, Land Converted to Grassland, Settlements Remaining Settlements,* and *Other Land* plus the loss in C sequestration reported for *Land Converted to Cropland and Grassland Remaining Grassland.* Refer to Table 2-8 for a breakout of emissions and removals for Land Use, Land-Use Change, and Forestry by gas and source category.

[d] Emissions from Wood Biomass and Ethanol 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 Land Use, Land-Use Change, and Forestry.

[e] Emissions from International Bunker Fuels are not included in totals.

[f] Small amounts of PFC emissions also result from this source.

[g] LULUCF emissions include the CO_2, CH_4, and N_2O emissions reported for *Forest Fires, Forest Soils, Liming, Urea Fertilization, Settlement Soils,* and *Peatlands Remaining Peatlands*.

[h] The LULUCF Sector Total is the sum of positive emissions (i.e., sources) of greenhouse gases to the atmosphere plus removals of CO_2 (i.e., sinks or negative emissions) from the atmosphere.

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

Table 2-2: Recent Trends in U.S. Greenhouse Gas Emissions and Sinks (kt)

Gas/Source	1990	2005	2010	2011	2012	2013	2014
CO_2	**5,124,039**	**6,132,598**	**5,698,233**	**5,568,569**	**5,360,975**	**5,513,230**	**5,564,285**
Fossil Fuel Combustion	4,740,671	5,747,142	5,358,292	5,227,690	5,024,685	5,157,583	5,208,654
Electricity Generation	*1,820,818*	*2,400,874*	*2,258,399*	*2,157,688*	*2,022,181*	*2,038,122*	*2,039,321*
Transportation	*1,493,758*	*1,887,033*	*1,728,267*	*1,707,631*	*1,696,752*	*1,713,013*	*1,737,410*
Industrial	*842,473*	*827,999*	*775,535*	*773,312*	*782,929*	*812,217*	*814,197*
Residential	*338,347*	*357,834*	*334,587*	*326,808*	*282,540*	*329,674*	*345,145*
Commercial	*217,393*	*223,480*	*220,125*	*220,749*	*196,714*	*221,030*	*231,590*
U.S. Territories	*27,882*	*49,923*	*41,379*	*41,503*	*43,569*	*43,528*	*40,991*
Non-Energy Use of Fuels	118,114	138,876	114,063	108,515	105,617	121,682	114,333
Iron and Steel Production & Metallurgical Coke Production	99,669	66,543	55,671	59,928	54,229	52,201	55,355
Cement Production	33,278	45,910	31,256	32,010	35,051	36,146	38,755
Natural Gas Systems[a]	37,645	29,995	32,334	35,551	34,764	37,808	37,808
Petrochemical Production	21,609	27,380	27,246	26,326	26,464	26,437	26,509
Lime Production	11,700	14,552	13,381	13,981	13,715	14,045	14,125
Other Process Uses of Carbonates	4,907	6,339	9,560	9,335	8,022	10,414	12,077
Ammonia Production	13,047	9,196	9,188	9,292	9,377	9,962	9,436
Incineration of Waste	7,972	12,454	11,026	10,550	10,362	9,421	9,421
Petroleum Systems[b]	4,445	4,904	4,153	4,467	5,060	6,001	6,001
Urea Fertilization	2,417	3,504	3,778	4,099	4,225	4,342	4,514
Carbon Dioxide Consumption	1,472	1,375	4,425	4,083	4,019	4,188	4,471
Liming	4,667	4,349	4,784	3,873	5,978	3,909	4,139
Urea Consumption for Non-Agricultural Purposes	3,784	3,653	4,730	4,029	4,449	4,179	4,007
Aluminum Production	6,831	4,142	2,722	3,292	3,439	3,255	3,255
Soda Ash Production and Consumption	2,822	2,960	2,697	2,712	2,763	2,804	2,827
Ferroalloy Production	2,152	1,392	1,663	1,735	1,903	1,785	1,914
Titanium Dioxide Production	1,195	1,755	1,769	1,729	1,528	1,715	1,755
Glass Production	1,535	1,928	1,481	1,299	1,248	1,317	1,341
Phosphoric Acid Production	1,529	1,342	1,087	1,151	1,093	1,119	1,095
Zinc Production	632	1,030	1,182	1,286	1,486	1,429	956
Peatlands Remaining Peatlands	1,055	1,101	1,022	926	812	770	842
Lead Production	516	553	542	538	527	546	518
Silicon Carbide Production and Consumption	375	219	181	170	158	169	173
Magnesium Production and Processing	1	3	1	3	2	2	2
LULUCF Total Net Flux[c]	*(704,191)*	*(636,143)*	*(683,157)*	*(683,557)*	*(680,812)*	*(682,365)*	*(685,827)*
Wood Biomass and Ethanol Consumption[d]	*219,413*	*229,844*	*265,110*	*268,064*	*267,730*	*286,323*	*293,729*
International Bunker Fuels[e]	*103,463*	*113,139*	*116,992*	*111,660*	*105,805*	*99,763*	*103,201*
CH_4	**29,813**	**29,414**	**28,832**	**28,470**	**28,153**	**28,161**	**28,315**
Landfills	7,376	7,493	7,052	7,074	6,942	7,066	7,271
Enteric Fermentation	6,566	6,755	6,853	6,757	6,670	6,619	6,572
Natural Gas Systems[a]	7,165	7,053	6,382	6,371	6,176	6,295	6,295
Coal Mining	3,860	2,565	3,293	2,849	2,658	2,584	2,584
Manure Management	1,486	2,254	2,437	2,460	2,548	2,455	2,447
Petroleum Systems[b]	1,261	939	854	878	931	1,009	1,009
Wastewater Treatment	626	635	619	610	606	601	601
Rice Cultivation	451	567	486	487	488	488	488
Stationary Combustion	339	295	282	283	264	320	323
Forest Fires	131	397	131	265	443	294	294

Abandoned Underground Coal Mines	288	264	263	257	249	249	249
Composting	15	75	73	75	77	81	82
Mobile Combustion	226	110	91	90	86	84	82
Field Burning of Agricultural Residues	10	8	11	11	11	11	11
Petrochemical Production	9	3	2	2	3	3	5
Ferroalloy Production	1	+	+	+	1	+	1
Silicon Carbide Production and Consumption	1	+	+	+	+	+	+
Iron and Steel Production & Metallurgical Coke Production	1	1	+	+	+	+	+
Peatlands Remaining Peatlands	+	+	+	+	+	+	+
Incineration of Waste	+	+	+	+	+	+	+
International Bunker Fuels[e]	*7*	*5*	*6*	*5*	*4*	*3*	*3*
N_2O	**1,374**	**1,364**	**1,393**	**1,422**	**1,408**	**1,379**	**1,381**
Agricultural Soil Management	1,017	996	1,075	1,084	1,083	1,069	1,069
Stationary Combustion	40	68	74	71	72	77	79
Manure Management	47	55	58	58	59	59	59
Mobile Combustion	138	115	79	75	67	61	55
Nitric Acid Production	41	38	39	37	35	36	37
Adipic Acid Production	51	24	14	34	19	13	18
Wastewater Treatment	11	15	16	16	16	17	17
Forest Fires	7	22	7	15	24	16	16
N_2O from Product Uses	14	14	14	14	14	14	14
Settlement Soils	5	8	8	8	9	8	8
Composting	1	6	5	6	6	6	6
Forest Soils	+	2	2	2	2	2	2
Incineration of Waste	2	1	1	1	1	1	1
Semiconductor Manufacture	+	+	+	1	1	1	1
Field Burning of Agricultural Residues	+	+	+	+	+	+	+
Peatlands Remaining Peatlands	+	+	+	+	+	+	+
International Bunker Fuels[e]	*3*	*3*	*3*	*3*	*3*	*3*	*3*
HFCs, PFCs, SF_6 and NF_3	**M**	**M**	**M**	**M**	**M**	**M**	**M**
HFCs	**M**	**M**	**M**	**M**	**M**	**M**	**M**
Substitution of Ozone Depleting Substances[f]	M	M	M	M	M	M	M
HCFC-22 Production	3	1	1	1	+	+	+
Semiconductor Manufacture	+	+	+	+	+	+	+
Magnesium Production and Processing	0	0	+	+	+	+	+
PFCs	**M**	**M**	**M**	**M**	**M**	**M**	**M**
Aluminum Production	M	M	M	M	M	M	M
Semiconductor Manufacture	M	M	M	M	M	M	M
SF_6	**1**	**1**	**+**	**+**	**+**	**+**	**+**
Electrical Transmission and Distribution	1	+	+	+	+	+	+
Magnesium Production and Processing	+	+	+	+	+	+	+
Semiconductor Manufacture	+	+	+	+	+	+	+
NF_3	**+**	**+**	**+**	**+**	**+**	**+**	**+**
Semiconductor Manufacture	+	+	+	+	+	+	+

+ Does not exceed 0.5 kt.

M Mixture of multiple gases

[a] The values in this table for Natural Gas Systems are presented from the previous Inventory and do not reflect updates to emission estimates for this category. See Section 3.7, Natural Gas Systems of the Energy chapter for more information. Gray highlighting was added on 2/24 for clarification.

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[b] The values in this table for Petroleum Systems are presented from the previous Inventory and do not reflect updates to emission estimates for this category. See Section 3.6, Petroleum Systems of the Energy chapter for more information. Gray highlighting was added on 2/24 for clarification.

[c] Total net flux from LULUCF is only included in the Net Emissions total. Net flux from LULUCF includes the positive C sequestration reported for *Forest Land Remaining Forest Land, Land Converted to Forest Land, Cropland Remaining Cropland, Land Converted to Grassland, Settlements Remaining Settlements,* and *Other Land* plus the loss in C sequestration reported for *Land Converted to Cropland and Grassland Remaining Grassland.* Refer to Table 2-8 for a breakout of emissions and removals for Land Use, Land-Use Change, and Forestry by gas and source category.

[d] Emissions from Wood Biomass and Ethanol 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 Land Use, Land-Use Change, and Forestry.

[e] Emissions from International Bunker Fuels are not included in totals.

[f] Small amounts of PFC emissions also result from this source.

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

Emissions of all gases can be summed from each source category into a set of five sectors defined by the Intergovernmental Panel on Climate Change (IPCC). Over the twenty five-year period of 1990 to 2014, total emissions in the Energy, Industrial Processes and Product Use, Agriculture, and Waste sectors grew by 388.9 MMT CO_2 Eq. (7.3 percent), 47.7 MMT CO_2 Eq. (14.0 percent), 44.2 MMT CO_2 Eq. (8.3 percent), and 1.5 MMT CO_2 Eq. (0.7 percent), respectively. Over the same period, estimates of net C sequestration for the Land Use, Land-Use Change, and Forestry sector (magnitude of emissions plus CO_2 removals from all LULUCF source categories) decreased by 27.9 MMT CO_2 Eq. (4.0 percent).

Figure 2-4: U.S. Greenhouse Gas Emissions and Sinks by Chapter/IPCC Sector (MMT CO_2 Eq.)

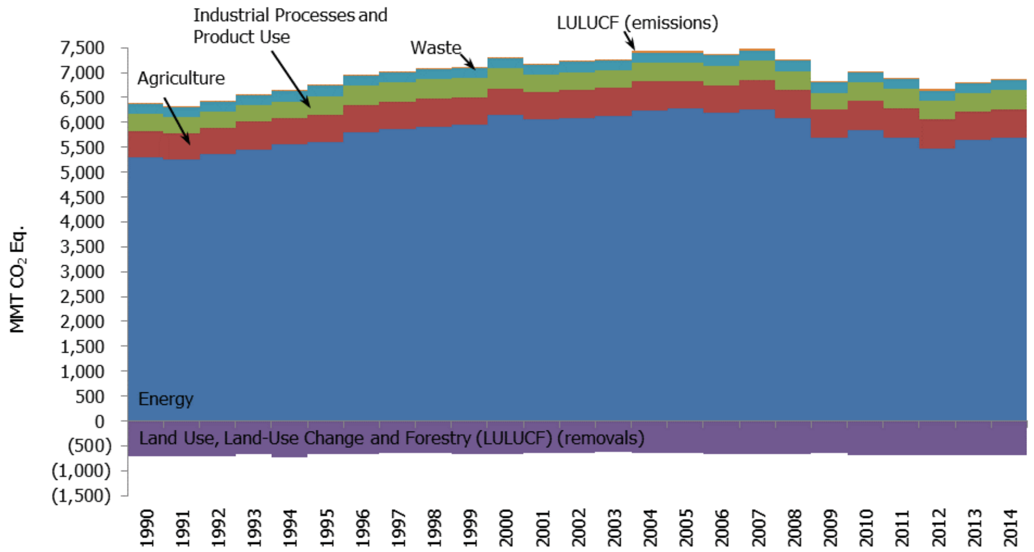


Table 2-3: Recent Trends in U.S. Greenhouse Gas Emissions and Sinks by Chapter/IPCC Sector (MMT CO_2 Eq.)

Chapter/IPCC Sector	1990	2005	2010	2011	2012	2013	2014
Energy	**5,290.9**	**6,269.0**	**5,845.2**	**5,699.0**	**5,481.3**	**5,637.4**	**5,679.8**
Fossil Fuel Combustion	4,740.7	5,747.1	5,358.3	5,227.7	5,024.7	5,157.6	5,208.7
Natural Gas Systems[a]	216.8	206.3	191.9	194.8	189.2	195.2	195.2
Non-Energy Use of Fuels	118.1	138.9	114.1	108.5	105.6	121.7	114.3
Coal Mining	96.5	64.1	82.3	71.2	66.5	64.6	64.6
Stationary Combustion	20.4	27.6	29.2	28.4	28.0	30.9	31.5
Petroleum Systems[b]	36.0	28.4	25.5	26.4	28.3	31.2	31.2

Mobile Combustion	46.9	37.1	25.9	24.7	22.2	20.3	18.4
Incineration of Waste	8.4	12.8	11.4	10.9	10.7	9.7	9.7
Abandoned Underground Coal Mines	7.2	6.6	6.6	6.4	6.2	6.2	6.2
Industrial Processes and Product Use	**340.9**	**367.6**	**365.2**	**382.2**	**371.4**	**373.8**	**388.6**
Substitution of Ozone Depleting Substances	0.3	113.0	153.5	157.1	161.4	165.3	171.4
Iron and Steel Production & Metallurgical Coke Production	99.7	66.6	55.7	59.9	54.2	52.2	55.4
Cement Production	33.3	45.9	31.3	32.0	35.1	36.1	38.8
Petrochemical Production	21.8	27.5	27.3	26.4	26.5	26.5	26.6
Lime Production	11.7	14.6	13.4	14.0	13.7	14.0	14.1
Other Process Uses of Carbonates	4.9	6.3	9.6	9.3	8.0	10.4	12.1
Nitric Acid Production	12.1	11.3	11.5	10.9	10.5	10.7	10.9
Ammonia Production	13.0	9.2	9.2	9.3	9.4	10.0	9.4
Aluminum Production	28.3	7.6	4.6	6.8	6.4	6.2	6.2
Adipic Acid Production	15.2	7.1	4.2	10.2	5.5	4.0	5.4
Electrical Transmission and Distribution	25.4	10.6	7.0	6.8	5.7	5.1	5.1
Carbon Dioxide Consumption	1.5	1.4	4.4	4.1	4.0	4.2	4.5
N_2O from Product Uses	4.2	4.2	4.2	4.2	4.2	4.2	4.2
Semiconductor Manufacture	3.6	4.7	3.8	4.9	4.5	4.2	4.2
HCFC-22 Production	46.1	20.0	8.0	8.8	5.5	4.1	4.1
Urea Consumption for Non-Agricultural Purposes	3.8	3.7	4.7	4.0	4.4	4.2	4.0
Soda Ash Production and Consumption	2.8	3.0	2.7	2.7	2.8	2.8	2.8
Ferroalloy Production	2.2	1.4	1.7	1.7	1.9	1.8	1.9
Titanium Dioxide Production	1.2	1.8	1.8	1.7	1.5	1.7	1.8
Magnesium Production and Processing	5.2	2.7	2.1	2.8	1.7	1.5	1.5
Glass Production	1.5	1.9	1.5	1.3	1.2	1.3	1.3
Phosphoric Acid Production	1.5	1.3	1.1	1.2	1.1	1.1	1.1
Zinc Production	0.6	1.0	1.2	1.3	1.5	1.4	1.0
Lead Production	0.5	0.6	0.5	0.5	0.5	0.5	0.5
Silicon Carbide Production and Consumption	0.4	0.2	0.2	0.2	0.2	0.2	0.2
Agriculture	**529.8**	**552.9**	**582.3**	**583.3**	**583.4**	**575.4**	**574.1**
Agricultural Soil Management	302.9	296.7	320.4	322.9	322.9	318.4	318.5
Enteric Fermentation	164.2	168.9	171.3	168.9	166.7	165.5	164.3
Manure Management	51.1	72.9	78.1	78.9	81.2	78.9	78.7
Rice Cultivation	11.3	14.2	12.2	12.2	12.2	12.2	12.2
Field Burning of Agricultural Residues	0.3	0.3	0.4	0.4	0.4	0.4	0.4
Land Use, Land-Use Change, and Forestry (Emissions)	**15.0**	**28.2**	**17.8**	**22.9**	**32.3**	**24.1**	**24.6**
Forest Fires	5.4	16.5	5.4	11.0	18.3	12.2	12.2
Urea Fertilization	2.4	3.5	3.8	4.1	4.2	4.3	4.5
Liming	4.7	4.3	4.8	3.9	6.0	3.9	4.1
Settlement Soils	1.4	2.3	2.4	2.5	2.5	2.4	2.4
Peatlands Remaining Peatlands	1.1	1.1	1.0	0.9	0.8	0.8	0.8
Forest Soils	0.1	0.5	0.5	0.5	0.5	0.5	0.5
Waste	**204.1**	**211.1**	**200.0**	**200.5**	**197.2**	**200.5**	**205.6**
Landfills	184.4	187.3	176.3	176.9	173.5	176.7	181.8
Wastewater Treatment	19.0	20.2	20.2	20.1	20.0	20.0	20.0
Composting	0.7	3.5	3.5	3.5	3.7	3.9	3.9
Total Emissions	**6,380.8**	**7,428.8**	**7,010.5**	**6,887.8**	**6,665.7**	**6,811.2**	**6,872.6**
LULUCF Total Net Flux[c]	**(704.2)**	**(636.1)**	**(683.2)**	**(683.6)**	**(680.8)**	**(682.4)**	**(685.8)**
Forest Land Remaining Forest Land[d]	(576.0)	(532.4)	(585.0)	(578.1)	(576.7)	(580.1)	(583.4)

Cropland Remaining Cropland	(43.2)	(16.5)	(4.7)	(20.0)	(18.7)	(16.8)	(16.0)
Land Converted to Cropland[c]	22.8	14.6	15.6	14.2	14.5	14.8	14.7
Grassland Remaining Grassland[c]	(12.9)	2.9	2.6	11.3	11.7	11.9	11.9
Land Converted to Grassland	(8.5)	(12.8)	(12.3)	(11.0)	(10.9)	(10.9)	(10.9)
Settlements Remaining Settlements	(60.4)	(80.5)	(86.1)	(87.3)	(88.4)	(89.5)	(90.6)
Other: Landfilled Yard Trimmings and Food Scraps	(26.0)	(11.4)	(13.2)	(12.7)	(12.2)	(11.7)	(11.6)
Net Emissions (Sources and Sinks)	**5,676.6**	**6,792.6**	**6,327.3**	**6,204.2**	**5,984.9**	**6,128.8**	**6,186.8**

[a] The values in this table for Natural Gas Systems are presented from the previous Inventory and do not reflect updates to emission estimates for this category. See Section 3.7, Natural Gas Systems of the Energy chapter for more information. Gray highlighting was added on 2/24 for clarification.

[b] The values in this table for Petroleum Systems are presented from the previous Inventory and do not reflect updates to emission estimates for this category. See Section 3.6, Petroleum Systems of the Energy chapter for more information. Gray highlighting was added on 2/24 for clarification.

[c] Total net flux from LULUCF is only included in the Net Emissions total. Net flux from LULUCF includes the positive C sequestration reported for *Forest Land Remaining Forest Land, Land Converted to Forest Land, Cropland Remaining Cropland, Land Converted to Grassland, Settlements Remaining Settlements,* and *Other Land* plus the loss in C sequestration reported for *Land Converted to Cropland and Grassland Remaining Grassland.* Refer to Table 2-8 for a breakout of emissions and removals for Land Use, Land-Use Change, and Forestry by gas and source category.

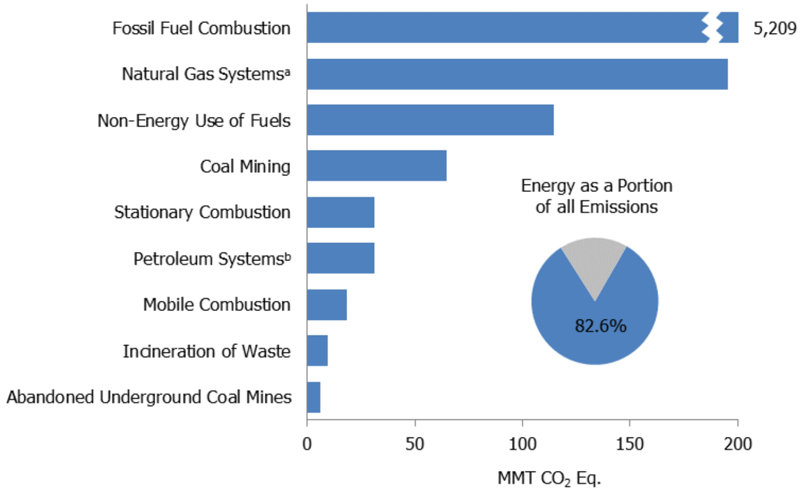
[d] Includes the effects of net additions to stocks of carbon stored in forest ecosystem pools and harvested wood products.

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

Energy

Energy-related activities, primarily fossil fuel combustion, accounted for the vast majority of U.S. CO_2 emissions for the period of 1990 through 2014. In 2014, approximately 82 percent of the energy consumed in the United States (on a Btu basis) was produced through the combustion of fossil fuels. The remaining 18 percent came from other energy sources such as hydropower, biomass, nuclear, wind, and solar energy (see Figure 2-5 and Figure 2-6). A discussion of specific trends related to CO_2 as well as other greenhouse gas emissions from energy consumption is presented in the Energy chapter. Energy-related activities are also responsible for CH_4 and N_2O emissions (37 percent and 10 percent of total U.S. emissions of each gas, respectively). Table 2-4 presents greenhouse gas emissions from the Energy chapter, by source and gas.

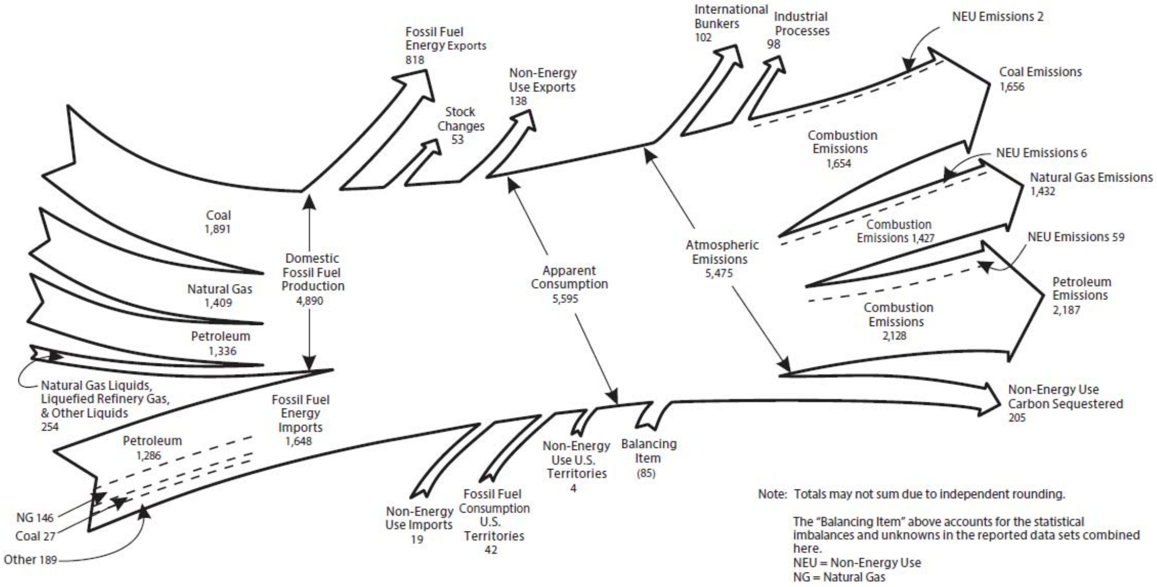
Figure 2-5: 2014 Energy Chapter Greenhouse Gas Sources (MMT CO_2 Eq.)



[a] The value in this figure for Natural Gas Systems is presented from the previous Inventory and does not reflect updates to emission estimates for this category. See Section 3.7, Natural Gas Systems of the Energy chapter for more information.

[b] The value in this figure for Petroleum Systems is presented from the previous Inventory and does not reflect updates to emission estimates for this category. See Section 3.6, Petroleum Systems of the Energy chapter for more information.

Figure 2-6: 2014 U.S. Fossil Carbon Flows (MMT CO_2 Eq.)



Note: Totals may not sum due to independent rounding.

The "Balancing Item" above accounts for the statistical imbalances and unknowns in the reported data sets combined here.
NEU = Non-Energy Use
NG = Natural Gas

Table 2-4: Emissions from Energy (MMT CO_2 Eq.)

Gas/Source	1990	2005	2010	2011	2012	2013	2014
CO_2	**4,908.8**	**5,933.4**	**5,519.9**	**5,386.8**	**5,180.5**	**5,332.5**	**5,376.2**
Fossil Fuel Combustion	4,740.7	5,747.1	5,358.3	5,227.7	5,024.7	5,157.6	5,208.7
Electricity Generation	*1,820.8*	*2,400.9*	*2,258.4*	*2,157.7*	*2,022.2*	*2,038.1*	*2,039.3*
Transportation	*1,493.8*	*1,887.0*	*1,728.3*	*1,707.6*	*1,696.8*	*1,713.0*	*1,737.4*
Industrial	*842.5*	*828.0*	*775.5*	*773.3*	*782.9*	*812.2*	*814.2*
Residential	*338.3*	*357.8*	*334.6*	*326.8*	*282.5*	*329.7*	*345.1*
Commercial	*217.4*	*223.5*	*220.1*	*220.7*	*196.7*	*221.0*	*231.6*
U.S. Territories	*27.9*	*49.9*	*41.4*	*41.5*	*43.6*	*43.5*	*41.0*
Non-Energy Use of Fuels	118.1	138.9	114.1	108.5	105.6	121.7	114.3
Natural Gas Systems[a]	37.6	30.0	32.3	35.6	34.8	37.8	37.8
Incineration of Waste	8.0	12.5	11.0	10.5	10.4	9.4	9.4
Petroleum Systems[b]	4.4	4.9	4.2	4.5	5.1	6.0	6.0
Biomass-Wood[c]	*215.2*	*206.9*	*192.5*	*195.2*	*194.9*	*211.6*	*217.7*
International Bunker Fuels[d]	*103.5*	*113.1*	*117.0*	*111.7*	*105.8*	*99.8*	*103.2*
Biomass-Ethanol[c]	*4.2*	*22.9*	*72.6*	*72.9*	*72.8*	*74.7*	*76.1*
CH_4	**328.5**	**280.7**	**279.2**	**268.2**	**259.1**	**263.5**	**263.5**
Natural Gas Systems[a]	179.1	176.3	159.6	159.3	154.4	157.4	157.4
Coal Mining	96.5	64.1	82.3	71.2	66.5	64.6	64.6
Petroleum Systems[b]	31.5	23.5	21.3	22.0	23.3	25.2	25.2
Stationary Combustion	8.5	7.4	7.1	7.1	6.6	8.0	8.1
Abandoned Underground Coal Mines	7.2	6.6	6.6	6.4	6.2	6.2	6.2
Mobile Combustion	5.6	2.7	2.3	2.2	2.2	2.1	2.0
Incineration of Waste	+	+	+	+	+	+	+
International Bunker Fuels[d]	*0.2*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*
N_2O	**53.6**	**55.0**	**46.1**	**44.0**	**41.7**	**41.4**	**40.0**
Stationary Combustion	11.9	20.2	22.2	21.3	21.4	22.9	23.4
Mobile Combustion	41.2	34.4	23.6	22.4	20.0	18.2	16.3
Incineration of Waste	0.5	0.4	0.3	0.3	0.3	0.3	0.3
International Bunker Fuels[d]	*0.9*	*1.0*	*1.0*	*1.0*	*0.9*	*0.9*	*0.9*
Total	**5,290.9**	**6,269.0**	**5,845.2**	**5,699.0**	**5,481.3**	**5,637.4**	**5,679.8**

Note: Totals may not sum due to independent rounding.
+ Does not exceed 0.05 MMT CO_2 Eq.
[a] The values in this table for Natural Gas Systems are presented from the previous Inventory and do not reflect updates to emission estimates for this category. See Section 3.7, Natural Gas Systems of the Energy chapter for more information. Gray highlighting was added on 2/24 for clarification.
[b] The values in this table for Petroleum Systems are presented from the previous Inventory and do not reflect updates to emission estimates for this category. See Section 3.6, Petroleum Systems of the Energy chapter for more information. Gray highlighting was added on 2/24 for clarification.
[c] Emissions from Wood Biomass and Ethanol 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 Land Use, Land-Use Change, and Forestry.
[d] Emissions from International Bunker Fuels are not included in totals.

Carbon dioxide emissions from fossil fuel combustion are presented in Table 2-5 based on the underlying U.S. energy consumer data collected by EIA. Estimates of CO_2 emissions from fossil fuel combustion are calculated from these EIA “end-use sectors” based on total consumption and appropriate fuel properties (any additional analysis and refinement of the EIA data is further explained in the Energy chapter of this report). EIA’s fuel consumption data for the electric power sector comprises electricity-only and combined-heat-and-power (CHP) plants within the NAICS 22 category whose primary business is to sell electricity, or electricity and heat, to the public (nonutility power producers can be included in this sector as long as they meet they electric power sector definition). EIA statistics for the industrial sector include fossil fuel consumption that occurs in the fields of manufacturing, agriculture, mining, and construction. EIA’s fuel consumption data for the transportation sector consists of all vehicles whose primary purpose is transporting people and/or goods from one physical location to another. EIA’s fuel consumption data for the industrial sector consists of all facilities and equipment used for producing, processing, or assembling goods (EIA includes generators that produce electricity and/or useful thermal output primarily to support on-site industrial activities in this sector). EIA’s fuel consumption data for the residential sector consists of living quarters for private households. EIA’s fuel consumption data for the commercial sector consists of service-providing facilities and equipment from private and public organizations and businesses (EIA includes generators that produce electricity and/or useful thermal output primarily to support the activities at commercial establishments in this sector). Table 2-5 and Figure 2-7 summarize CO_2 emissions from fossil fuel combustion by end-use sector. Figure 2-8 further describes the total emissions from fossil fuel combustion, separated by end-use sector, including CH_4 and N_2O in addition to CO_2.

Table 2-5: CO_2 Emissions from Fossil Fuel Combustion by End-Use Sector (MMT CO_2 Eq.)

End-Use Sector	1990	2005	2010	2011	2012	2013	2014
Transportation	**1,496.8**	**1,891.8**	**1,732.7**	**1,711.9**	**1,700.6**	**1,717.0**	**1,741.5**
Combustion	1,493.8	1,887.0	1,728.3	1,707.6	1,696.8	1,713.0	1,737.4
Electricity	3.0	4.7	4.5	4.3	3.9	4.0	4.1
Industrial	**1,529.2**	**1,564.6**	**1,416.5**	**1,398.0**	**1,375.7**	**1,407.0**	**1,407.8**
Combustion	842.5	828.0	775.5	773.3	782.9	812.2	814.2
Electricity	686.7	736.6	641.0	624.7	592.8	594.7	593.6
Residential	**931.4**	**1,214.1**	**1,174.6**	**1,117.5**	**1,007.8**	**1,064.6**	**1,080.4**
Combustion	338.3	357.8	334.6	326.8	282.5	329.7	345.1
Electricity	593.0	856.3	840.0	790.7	725.3	734.9	735.2
Commercial	**755.4**	**1,026.8**	**993.0**	**958.8**	**897.0**	**925.5**	**938.1**
Combustion	217.4	223.5	220.1	220.7	196.7	221.0	231.6
Electricity	538.0	803.3	772.9	738.0	700.3	704.5	706.5
U.S. Territories[a]	**27.9**	**49.9**	**41.4**	**41.5**	**43.6**	**43.5**	**41.0**
Total	**4,740.7**	**5,747.1**	**5,358.3**	**5,227.7**	**5,024.7**	**5,157.6**	**5,208.7**
Electricity Generation	**1,820.8**	**2,400.9**	**2,258.4**	**2,157.7**	**2,022.2**	**2,038.1**	**2,039.3**

Note: Totals may not sum due to independent rounding. Combustion-related emissions from electricity generation are allocated based on aggregate national electricity consumption by each end-use sector.
[a] 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.

Figure 2-7: 2014 CO_2 Emissions from Fossil Fuel Combustion by Sector and Fuel Type (MMT CO_2 Eq.)

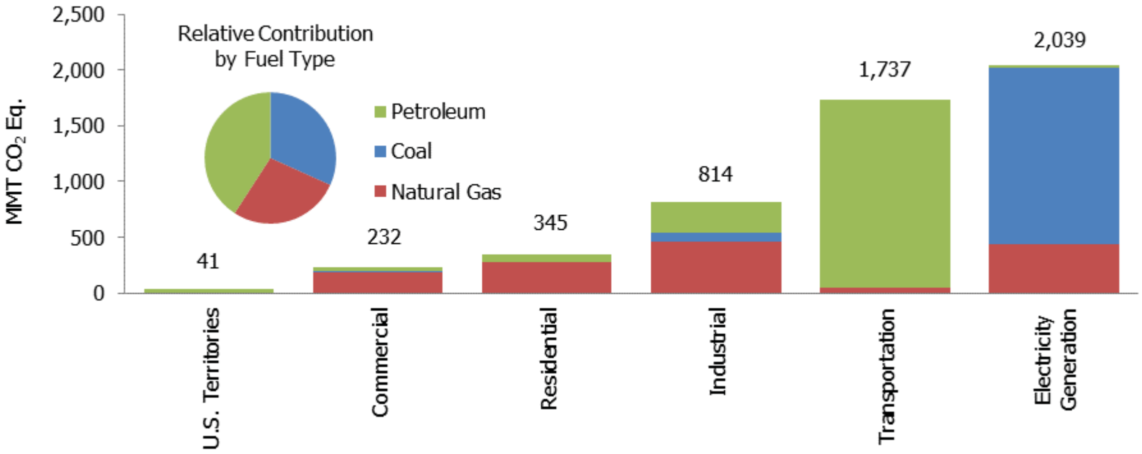
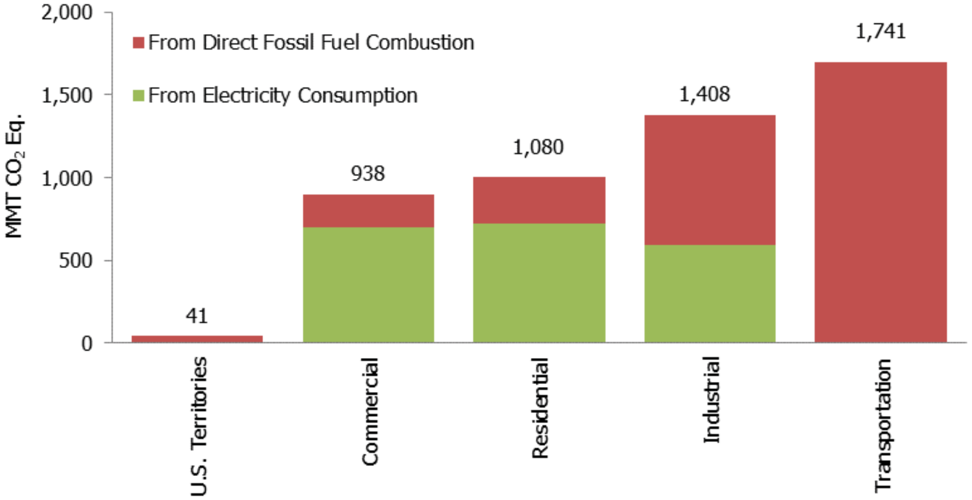


Figure 2-8: 2014 End-Use Sector Emissions of CO_2 from Fossil Fuel Combustion (MMT CO_2 Eq.)



The main driver of emissions in the Energy sector is CO_2 from fossil fuel combustion. Electricity generation is the largest emitter of CO_2, and electricity generators consumed 34 percent of U.S. energy from fossil fuels and emitted 39 percent of the CO_2 from fossil fuel combustion in 2014. Electricity generation emissions can also be allocated to the end-use sectors that are consuming that electricity, as presented in Table 2-5. The transportation end-use sector accounted for 1,741.5 MMT CO_2 Eq. in 2014 or approximately 33 percent of total CO_2 emissions from fossil fuel combustion. The industrial end-use sector accounted for 27 percent of CO_2 emissions from fossil fuel combustion. The residential and commercial end-use sectors accounted for 21 and 18 percent, respectively, of CO_2 emissions from fossil fuel combustion. Both of these end-use sectors were heavily reliant on electricity for meeting energy needs, with electricity consumption for lighting, heating, air conditioning, and operating appliances contributing 68 and 75 percent of emissions from the residential and commercial end-use sectors, respectively. Significant trends in emissions from energy source categories over the twenty five-year period from 1990 through 2014 included the following:

- Total CO_2 emissions from fossil fuel combustion increased from 4,740.7 MMT CO_2 Eq. in 1990 to 5,208.7 MMT CO_2 Eq. in 2014 – a 9.9 percent total increase over the twenty five-year period. From 2013 to 2014, these emissions increased by 51.1 MMT CO_2 Eq. (1.0 percent).

- Substantial new data are available on natural gas and petroleum systems from subpart W of the EPA's greenhouse gas reporting program (GHGRP) and a number of new studies. The EPA is evaluating approaches for incorporating this new data into its emission estimates. In the Energy chapter, sections 3.7 and 3.6, updated draft estimates of CH_4 emissions for the year 2013 are presented for Natural Gas Systems and Petroleum Systems, respectively, to provide reviewers of the public review draft an indication of the sector-wide emission estimates resulting from the combined changes under consideration. The EPA is continuing to evaluate stakeholder feedback on the updates under consideration. For the final Inventory, the 2013 estimates presented in this section will be refined, and a full time series of emissions estimates will be developed based on feedback received through the earlier stakeholder reviews of the memos and through this public review period..

- Carbon dioxide emissions from non-energy use of fossil fuels decreased by 3.8 MMT CO_2 Eq. (3.2 percent) from 1990 through 2014. Emissions from non-energy uses of fossil fuels were 114.3 MMT CO_2 Eq. in 2014, which constituted 2.1 percent of total national CO_2 emissions, approximately the same proportion as in 1990.

- Nitrous oxide emissions from stationary combustion increased by 11.5 MMT CO_2 Eq. (96.4 percent) from 1990 through 2014. Nitrous oxide emissions from this source increased primarily as a result of an increase in the number of coal fluidized bed boilers in the electric power sector.

- Nitrous oxide emissions from mobile combustion decreased 24.9 MMT CO_2 Eq. (60.4 percent) from 1990 through 2014. Nitrous oxide emissions from this source decreased primarily as a result of N_2O national emissions control standards and emissions control technologies for on-road vehicles.

- Carbon dioxide emissions from incineration of waste (9.4 MMT CO_2 Eq. in 2014) increased by 1.4 MMT CO_2 Eq. (18.2 percent) from 1990 through 2014, as the volume of plastics and other fossil carbon-containing materials in municipal solid waste grew.

The increase in CO_2 emissions from fossil fuel combustion in 2014 was a result of multiple factors including: (1) colder winter conditions in the first quarter of 2014 resulting in an increased demand for heating fuel in the residential and commercial sectors; (2) an increase in industrial production across multiple sectors resulting in slight increases in industrial sector emissions;[1] and (3) an increase in transportation emissions resulting from an increase in vehicle miles traveled (VMT) and fuel use across on-road transportation modes.

Industrial Processes and Product Use

The Industrial Processes and Product Use (IPPU) chapter includes greenhouse gas emissions occurring from industrial processes and from the use of greenhouse gases in products.

Greenhouse gas emissions are produced as the by-products of many non-energy-related industrial activities. For example, industrial processes can chemically transform raw materials, which often release waste gases such as CO_2, CH_4, and N_2O. These processes include iron and steel production and metallurgical coke production, cement production, ammonia production, urea consumption, lime production, other process uses of carbonates (e.g., flux stone, flue gas desulfurization, and glass manufacturing), soda ash production and consumption, titanium dioxide production, phosphoric acid production, ferroalloy production, CO_2 consumption, silicon carbide production and consumption, aluminum production, petrochemical production, nitric acid production, adipic acid production, lead production, zinc production, and N_2O from product uses (see Figure 2-9). Industrial processes also release HFCs, PFCs, SF_6, and NF_3. In addition to their use as ODS substitutes, HFCs, PFCs, SF_6, NF_3, and other fluorinated compounds are employed and emitted by a number of other industrial sources in the United States. These industries include aluminum production, HCFC-22 production, semiconductor manufacture, electric power transmission and

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

distribution, and magnesium metal production and processing. Table 2-6 presents greenhouse gas emissions from industrial processes by source category.

Figure 2-9: 2014 Industrial Processes and Product Use Chapter Greenhouse Gas Sources (MMT CO_2 Eq.)

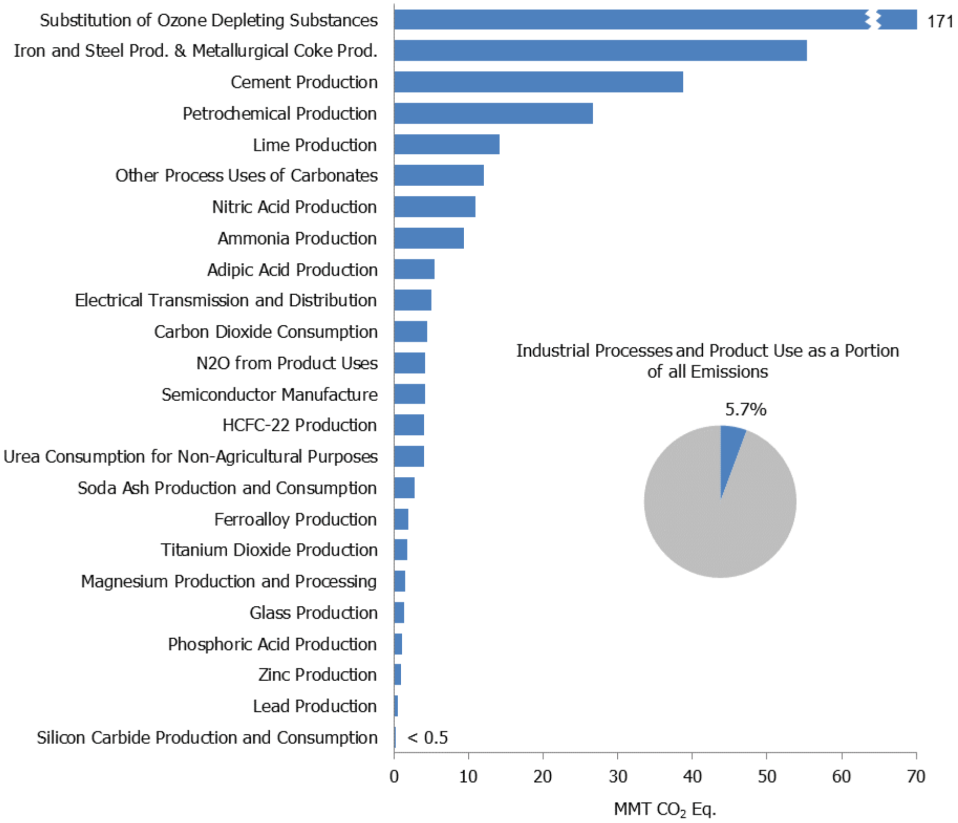

Table 2-6: Emissions from Industrial Processes and Product Use (MMT CO_2 Eq.)

Gas/Source	1990	2005	2010	2011	2012	2013	2014
CO_2	**207.1**	**190.3**	**168.8**	**172.9**	**169.5**	**171.7**	**178.6**
Iron and Steel Production & Metallurgical Coke Production	99.7	66.5	55.7	59.9	54.2	52.2	55.4
Iron and Steel Production	*97.2*	*64.5*	*53.6*	*58.5*	*53.7*	*50.4*	*53.4*
Metallurgical Coke Production	*2.5*	*2.0*	*2.1*	*1.4*	*0.5*	*1.8*	*1.9*
Cement Production	33.3	45.9	31.3	32.0	35.1	36.1	38.8
Petrochemical Production	21.6	27.4	27.2	26.3	26.5	26.4	26.5
Lime Production	11.7	14.6	13.4	14.0	13.7	14.0	14.1
Other Process Uses of Carbonates	4.9	6.3	9.6	9.3	8.0	10.4	12.1
Ammonia Production	13.0	9.2	9.2	9.3	9.4	10.0	9.4
Carbon Dioxide Consumption	1.5	1.4	4.4	4.1	4.0	4.2	4.5
Urea Consumption for Non-Agricultural Purposes	3.8	3.7	4.7	4.0	4.4	4.2	4.0
Aluminum Production	6.8	4.1	2.7	3.3	3.4	3.3	3.3
Soda Ash Production and Consumption	2.8	3.0	2.7	2.7	2.8	2.8	2.8
Ferroalloy Production	2.2	1.4	1.7	1.7	1.9	1.8	1.9
Titanium Dioxide Production	1.2	1.8	1.8	1.7	1.5	1.7	1.8
Glass Production	1.5	1.9	1.5	1.3	1.2	1.3	1.3
Phosphoric Acid Production	1.5	1.3	1.1	1.2	1.1	1.1	1.1
Zinc Production	0.6	1.0	1.2	1.3	1.5	1.4	1.0

Lead Production	0.5	0.6	0.5	0.5	0.5	0.5	0.5
Silicon Carbide Production and Consumption	0.4	0.2	0.2	0.2	0.2	0.2	0.2
Magnesium Production and Processing	+	+	+	+	+	+	+
CH_4	**0.3**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.2**
Petrochemical Production	0.2	0.1	+	+	0.1	0.1	0.1
Ferroalloy Production	+	+	+	+	+	+	+
Silicon Carbide Production and Consumption	+	+	+	+	+	+	+
Iron and Steel Production & Metallurgical Coke Production	+	+	+	+	+	+	+
Iron and Steel Production	+	+	+	+	+	+	+
Metallurgical Coke Production	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
N_2O	**31.6**	**22.8**	**20.1**	**25.5**	**20.4**	**19.1**	**20.8**
Nitric Acid Production	12.1	11.3	11.5	10.9	10.5	10.7	10.9
Adipic Acid Production	15.2	7.1	4.2	10.2	5.5	4.0	5.4
N_2O from Product Uses	4.2	4.2	4.2	4.2	4.2	4.2	4.2
Semiconductor Manufacturing	+	0.1	0.1	0.2	0.2	0.2	0.2
HFCs	**46.6**	**133.3**	**161.7**	**166.1**	**167.1**	**169.6**	**175.8**
Substitution of Ozone Depleting Substances[a]	0.3	113.0	153.5	157.1	161.4	165.3	171.4
HCFC-22 Production	46.1	20.0	8.0	8.8	5.5	4.1	4.1
Semiconductor Manufacturing	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Magnesium Production and Processing	0.0	0.0	+	+	+	0.1	0.1
PFCs	**24.3**	**6.6**	**4.4**	**6.9**	**6.0**	**5.8**	**5.8**
Aluminum Production	21.5	3.4	1.9	3.5	2.9	3.0	3.0
Semiconductor Manufacturing	2.8	3.2	2.6	3.4	3.0	2.9	2.9
SF_6	**31.1**	**14.0**	**9.5**	**10.0**	**7.7**	**6.9**	**6.9**
Electrical Transmission and Distribution	25.4	10.6	7.0	6.8	5.7	5.1	5.1
Magnesium Production and Processing	5.2	2.7	2.1	2.8	1.6	1.4	1.4
Semiconductor Manufacturing	0.5	0.7	0.4	0.4	0.4	0.4	0.4
NF_3	**+**	**0.5**	**0.5**	**0.7**	**0.6**	**0.6**	**0.6**
Semiconductor Manufacturing	+	0.5	0.5	0.7	0.6	0.6	0.6
Total	**340.9**	**367.6**	**365.2**	**382.2**	**371.4**	**373.8**	**388.6**

+ Does not exceed 0.05 MMT CO_2 Eq.

[a] Small amounts of PFC emissions also result from this source.

Note: Totals may not sum due to independent rounding.

Overall, emissions from the IPPU sector increased by 14.0 percent from 1990 to 2014. Significant trends in emissions from IPPU source categories over the twenty five-year period from 1990 through 2014 included the following:

- HFC emissions from ODS substitutes have been increasing from small amounts in 1990 to 171.4 MMT CO_2 Eq. in 2014. This increase was in large part the result of efforts to phase out CFCs and other ODSs in the United States. In the short term, this trend is expected to continue, and will likely continue over the next decade as HCFCs, which are interim substitutes in many applications, are themselves phased-out under the provisions of the Copenhagen Amendments to the *Montreal Protocol*.
- Combined CO_2 and CH_4 emissions from iron and steel production and metallurgical coke production decreased by 6.0 percent to 55.4 MMT CO_2 Eq. from 2013 to 2014, and have declined overall by 44.3 MMT CO_2 Eq. (44.5 percent) from 1990 through 2014, due to restructuring of the industry, technological improvements, and increased scrap steel utilization.
- Carbon dioxide emissions from ammonia production (9.4 MMT CO_2 Eq. in 2014) decreased by 3.6 MMT CO_2 Eq. (27.7 percent) since 1990. Ammonia production relies on natural gas as both a feedstock and a fuel, and as such, market fluctuations and volatility in natural gas prices affect the production of ammonia.
- Urea consumption for non-agricultural purposes (4.0 MMT CO_2 Eq. in 2014) increased by 0.2 MMT CO_2 Eq. (5.9 percent) since 1990. From 1990 to 2007, emissions increased by 30 percent to a peak of 4.9 MMT CO_2 Eq., before decreasing by 19 percent to 2014 levels.

- In 2014, N_2O emissions from product uses constituted 1.0 percent of U.S. N_2O emissions. From 1990 to 2014, emissions from this source category decreased by 0.4 percent, though slight increases occurred in intermediate years.

- Nitrous oxide emissions from adipic acid production were 5.4 MMT CO_2 Eq. in 2014, and have decreased significantly since 1990 due to both the widespread installation of pollution control measures in the late 1990s and plant idling in the late 2000s. Emissions from adipic acid production have decreased by 64.2 percent since 1990 and by 67.8 percent since a peak in 1995.

- PFC emissions from aluminum production decreased by 86.2 percent (18.5 MMT CO_2 Eq.) from 1990 to 2014, due to both industry emission reduction efforts and lower domestic aluminum production.

Agriculture

Agricultural activities contribute directly to emissions of greenhouse gases through a variety of processes, including the following source categories: enteric fermentation in domestic livestock, livestock manure management, rice cultivation, agricultural soil management, and field burning of agricultural residues.

In 2014, agricultural activities were responsible for emissions of 574.1 MMT CO_2 Eq., or 8.4 percent of total U.S. greenhouse gas emissions. Methane and nitrous oxide were the primary greenhouse gases emitted by agricultural activities. Methane emissions from enteric fermentation and manure management represented about 23.2 percent and 8.6 percent of total CH_4 emissions from anthropogenic activities, respectively, in 2014. Agricultural soil management activities, such as fertilizer use and other cropping practices, were the largest source of U.S. N_2O emissions in 2014, accounting for 77.4 percent.

Figure 2-10: 2014 Agriculture Chapter Greenhouse Gas Sources (MMT CO_2 Eq.)

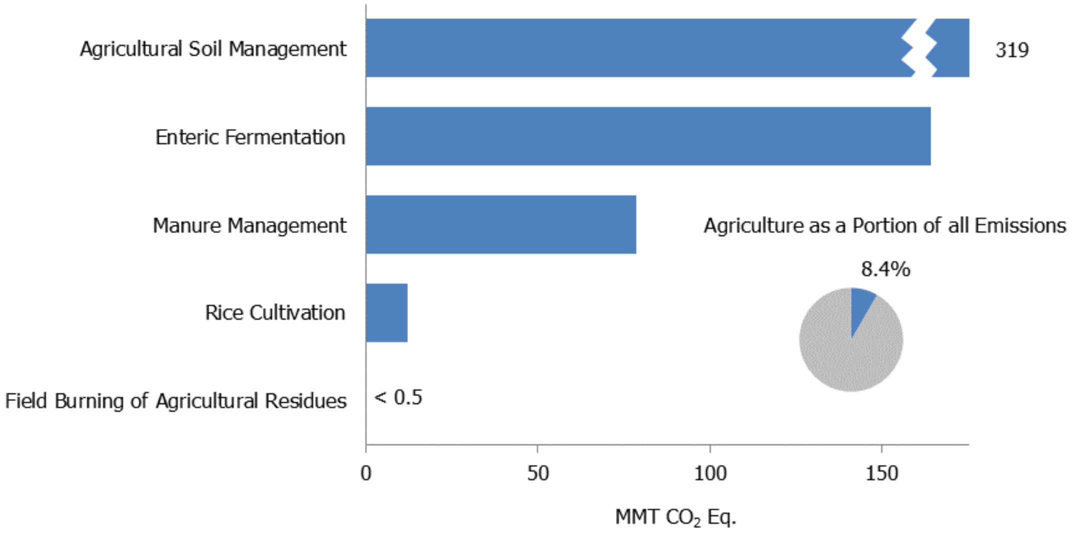

Table 2-7: Emissions from Agriculture (MMT CO_2 Eq.)

Gas/Source	1990	2005	2010	2011	2012	2013	2014
CH_4	**212.8**	**239.6**	**244.7**	**242.9**	**242.9**	**239.3**	**238.0**
Enteric Fermentation	164.2	168.9	171.3	168.9	166.7	165.5	164.3
Manure Management	37.2	56.3	60.9	61.5	63.7	61.4	61.2
Rice Cultivation	11.3	14.2	12.2	12.2	12.2	12.2	12.2
Field Burning of Agricultural Residues	0.2	0.2	0.3	0.3	0.3	0.3	0.3
N_2O	**317.0**	**313.3**	**337.7**	**340.4**	**340.5**	**336.0**	**336.1**
Agricultural Soil Management	302.9	296.7	320.4	322.9	322.9	318.4	318.5
Manure Management	14.0	16.5	17.2	17.4	17.5	17.5	17.5
Field Burning of Agricultural Residues	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	**529.8**	**552.9**	**582.3**	**583.3**	**583.4**	**575.4**	**574.1**

Note: Totals may not sum due to independent rounding.

Some significant trends in U.S. emissions from Agriculture source categories include the following:

- Agricultural soils produced approximately 77.4 percent of N_2O emissions in the United States in 2014. Estimated emissions from this source in 2014 were 318.5 MMT CO_2 Eq. Annual N_2O emissions from agricultural soils fluctuated between 1990 and 2014, although overall emissions were 5.1 percent higher in 2014 than in 1990. Year-to-year fluctuations are largely a reflection of annual variation in weather patterns, synthetic fertilizer use, and crop production.

- Enteric fermentation is the second largest anthropogenic source of CH_4 emissions in the United States. In 2014, enteric fermentation CH_4 emissions were 164.3 MMT CO_2 Eq. (23.2 percent of total CH_4 emissions), which represents an increase of 0.1 MMT CO_2 Eq. (0.1 percent) since 1990. This increase in emissions from 1990 to 2014 in enteric generally follows the increasing trends in cattle populations. From 1990 to 1995 emissions increased and then generally decreased from 1996 to 2004, mainly due to fluctuations in beef cattle populations and increased digestibility of feed for feedlot cattle. Emissions increased from 2005 to 2007, as both dairy and beef populations underwent increases and the literature for dairy cow diets indicated a trend toward a decrease in feed digestibility for those years. Emissions decreased again from 2008 to 2014 as beef cattle populations again decreased.

- Overall, emissions from manure management increased 53.8 percent between 1990 and 2014. This encompassed an increase of 64.7 percent for CH_4, from 37.2 MMT CO_2 Eq. in 1990 to 61.2 MMT CO_2 Eq. in 2014; and an increase of 24.9 percent for N_2O, from 14.0 MMT CO_2 Eq. in 1990 to 17.5 MMT CO_2 Eq. in 2014. The majority of the increase observed in CH_4 resulted from swine and dairy cow manure, where emissions increased 44 and 118 percent, respectively, from 1990 to 2014. From 2013 to 2014, there was a 0.3 percent decrease in total CH_4 emissions from manure management, mainly due to minor shifts in the animal populations and the resultant effects on manure management system allocations.

Land Use, Land-Use Change, and Forestry

When humans alter the terrestrial biosphere through land use, changes in land use, and land management practices, they also alter the background carbon fluxes between biomass, soils, and the atmosphere. Forest management practices, tree planting in urban areas, the management of agricultural soils, and the landfilling of yard trimmings and food scraps have resulted in a net removal of CO_2 (sequestration of C) in the United States. Forests (including vegetation, soils, and harvested wood) accounted for approximately 85 percent of total 2014 CO_2 removals, urban trees accounted for 13 percent, mineral and organic soil carbon stock changes accounted for less than 0.5 percent, and landfilled yard trimmings and food scraps accounted for 1.7 percent of total CO_2 removals in 2014. The net forest sequestration is a result of net forest growth, increasing forest area, and a net accumulation of carbon stocks in harvested wood pools. The net sequestration in urban forests is a result of net tree growth and increased urban forest size. In agricultural soils, mineral and organic soils sequester approximately 1.8 times as much C as is emitted from these soils through liming and urea fertilization. The mineral soil C sequestration is largely due to the conversion of cropland to hay production fields, the limited use of bare-summer fallow areas in semi-arid areas, and an increase in the adoption of conservation tillage practices. The landfilled yard trimmings and food scraps net sequestration is due to the long-term accumulation of yard trimming and food scraps carbon in landfills.

Land use, land-use change, and forestry activities in 2014 resulted in a C sequestration (i.e., net CO_2 removals) of 685.8 MMT CO_2 Eq. (Table 2-3).[2] This represents an offset of approximately 10.0 percent of total (i.e., gross) greenhouse gas emissions in 2014. Emissions from land use, land-use change, and forestry activities in 2014 represent 0.4 percent of total greenhouse gas emissions.[3] Between 1990 and 2014, total land use, land-use change, and forestry C sequestration decreased by 2.6 percent, primarily due to a decrease in the rate of net C accumulation in agricultural soil carbon stocks.

Carbon dioxide removals are presented in Table 2-8 along with CO_2, CH_4, and N_2O emissions for Land Use, Land-Use Change, and Forestry source categories.[4] Liming and urea fertilization resulted in CO_2 emissions of 8.7 MMT CO_2 Eq. in 2014, an increase of about 22.2 percent relative to 1990. Lands undergoing peat extraction (i.e., *Peatlands Remaining Peatlands*) resulted in CO_2 emissions of 0.8 MMT CO_2 Eq. and CH_4 and N_2O emissions of less than 0.05 MMT CO_2 Eq. each. N_2O emissions from the application of synthetic fertilizers to forest soils have increased from 0.1 MMT CO_2 Eq. in 1990 to 0.5 MMT CO_2 Eq. in 2014. Settlement soils in 2014 resulted in N_2O emissions of 2.4 MMT CO_2 Eq., a 78.4 percent increase relative to 1990. Emissions from forest fires in 2014 resulted in CH_4 emissions of 7.3 MMT CO_2 and in N_2O emissions of 4.8 MMT CO_2 (see Table 2-8).

Table 2-8: Emissions and Removals (Flux) from Land Use, Land-Use Change, and Forestry (MMT CO_2 Eq.)

Gas/Land-Use Category	1990	2005	2010	2011	2012	2013	2014
Net CO_2 Flux[a]	**(704.2)**	**(636.1)**	**(683.2)**	**(683.6)**	**(680.8)**	**(682.4)**	**(685.8)**
Forest Land Remaining Forest Land[b]	(576.0)	(532.4)	(585.0)	(578.1)	(576.7)	(580.1)	(583.4)
Cropland Remaining Cropland	(43.2)	(16.5)	(4.7)	(20.0)	(18.7)	(16.8)	(16.0)
Land Converted to Cropland[a]	22.8	14.6	15.6	14.2	14.5	14.8	14.7
Grassland Remaining Grassland[a]	(12.9)	2.9	2.6	11.3	11.7	11.9	11.9
Land Converted to Grassland	(8.5)	(12.8)	(12.3)	(11.0)	(10.9)	(10.9)	(10.9)
Settlements Remaining Settlements[c]	(60.4)	(80.5)	(86.1)	(87.3)	(88.4)	(89.5)	(90.6)
Other: Landfilled Yard Trimmings and Food Scraps	(26.0)	(11.4)	(13.2)	(12.7)	(12.2)	(11.7)	(11.6)
CO_2	**8.1**	**9.0**	**9.6**	**8.9**	**11.0**	**9.0**	**9.5**
Cropland Remaining Cropland: Liming	4.7	4.3	4.8	3.9	6.0	3.9	4.1
Cropland Remaining Cropland: Urea Fertilization	2.4	3.5	3.8	4.1	4.2	4.3	4.5
Wetlands Remaining Wetlands: Peatlands Remaining Peatlands	1.1	1.1	1.0	0.9	0.8	0.8	0.8
CH_4	**3.3**	**9.9**	**3.3**	**6.6**	**11.1**	**7.3**	**7.4**
Forest Land Remaining Forest Land: Forest Fires	3.3	9.9	3.3	6.6	11.1	7.3	7.3
Wetlands Remaining Wetlands: Peatlands Remaining Peatlands	+	+	+	+	+	+	+
N_2O	**3.6**	**9.3**	**5.0**	**7.3**	**10.3**	**7.7**	**7.7**
Forest Land Remaining Forest Land: Forest Fires	2.2	6.5	2.2	4.4	7.3	4.8	4.8
Forest Land Remaining Forest Land: Forest Soils[d]	0.1	0.5	0.5	0.5	0.5	0.5	0.5
Settlements Remaining Settlements: Settlement Soils[e]	1.4	2.3	2.4	2.5	2.5	2.4	2.4
Wetlands Remaining Wetlands:	+	+	+	+	+	+	+

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[2] Net flux from LULUCF includes the positive C sequestration reported for *Forest Land Remaining Forest Land, Land Converted to Forest Land, Cropland Remaining Cropland, Land Converted to Grassland, Settlements Remaining Settlements,* and *Other Land* plus the loss in C sequestration reported for *Land Converted to Cropland* and *Grassland Remaining Grassland*.

[3] LULUCF emissions include the CO_2, CH_4, and N_2O emissions reported for *Forest Fires, Forest Soils, Liming, Urea Fertilization, Settlement Soils,* and *Peatlands Remaining Peatlands.*

[4] Estimates from *Land Converted to Forest Land* are currently under development.

Peatlands Remaining Peatlands							
LULUCF Emissions[f]	**15.0**	**28.2**	**17.8**	**22.9**	**32.3**	**24.1**	**24.6**
LULUCF Total Net Flux[a]	**(704.2)**	**(636.1)**	**(683.2)**	**(683.6)**	**(680.8)**	**(682.4)**	**(685.8)**
LULUCF Sector Total[g]	**(689.1)**	**(607.9)**	**(665.3)**	**(660.7)**	**(648.5)**	**(658.3)**	**(661.3)**

Note: Totals may not sum due to independent rounding. Parentheses indicate net sequestration.

+ Does not exceed 0.05 MMT CO_2 Eq.

[a] Total net flux from LULUCF is only included in the Net Emissions total. Net flux from LULUCF includes the positive C sequestration reported for *Forest Land Remaining Forest Land*, *Land Converted to Forest Land*, *Cropland Remaining Cropland*, *Land Converted to Grassland*, *Settlements Remaining Settlements,* and *Other Land* plus the loss in C sequestration reported for *Land Converted to Cropland* and *Grassland Remaining Grassland*.

[b] Includes the effects of net additions to stocks of carbon stored in forest ecosystem pools and harvested wood products.

[c] Estimates include C stock changes on both *Settlements Remaining Settlements* and *Land Converted to Settlements*.

[d] Estimates include emissions from N fertilizer additions on both *Forest Land Remaining Forest Land*, and *Land Converted to Forest Land*, but not from land-use conversion.

[e] Estimates include emissions from N fertilizer additions on both *Settlements Remaining Settlements*, and *Land Converted to Settlements*, but not from land-use conversion.

[f] LULUCF emissions include the CO_2, CH_4, and N_2O emissions reported for *Forest Fires, Forest Soils, Liming, Urea Fertilization, Settlement Soils*, and *Peatlands Remaining Peatlands.*

[g] The LULUCF Sector Total is the sum of positive emissions (i.e., sources) of greenhouse gases to the atmosphere plus removals of CO_2 (i.e., sinks or negative emissions) from the atmosphere.

Other significant trends from 1990 to 2014 in emissions from land use, land-use change, and forestry source categories include:

- Annual C sequestration by forest land (i.e., annual carbon stock accumulation in the five carbon pools) has increased by approximately 1 percent. This is primarily due to increased forest management and the effects of previous reforestation. The increase in intensive forest management resulted in higher growth rates and higher biomass density. The tree planting and conservation efforts of the 1970s and 1980s continue to have a significant impact on sequestration rates. Finally, the forested area in the United States increased over the past twenty five years, although only at an average rate of 0.2 percent per year.
- Annual C sequestration by urban trees has increased by 50.0 percent over the period from 1990 to 2014. This is primarily due to an increase in urbanized land area in the United States.
- Annual C sequestration in landfilled yard trimmings and food scraps has decreased by 55.4 percent since 1990. Food scrap generation has grown by 55 percent since 1990, and though the proportion of food scraps discarded in landfills has decreased slightly from 82 percent in 1990 to 76 percent in 2014, the tonnage disposed in landfills has increased considerably (by 45 percent). Overall, the decrease in the landfill disposal rate of yard trimmings has more than compensated for the increase in food scrap disposal in landfills.

Waste

Waste management and treatment activities are sources of greenhouse gas emissions (see Figure 2-11). In 2014, landfills were the largest source of U.S. anthropogenic CH_4 emissions, accounting for 25.7 percent of total U.S. CH_4 emissions.[5] Additionally, wastewater treatment accounts for 9.7 percent of Waste emissions, 2.1 percent of U.S. CH_4 emissions, and 1.2 percent of N_2O emissions. Emissions of CH_4 and N_2O from composting grew from 1990 to 2014, and resulted in emissions of 3.9 MMT CO_2 Eq. in 2014. A summary of greenhouse gas emissions from the Waste chapter is presented in Table 2-9.

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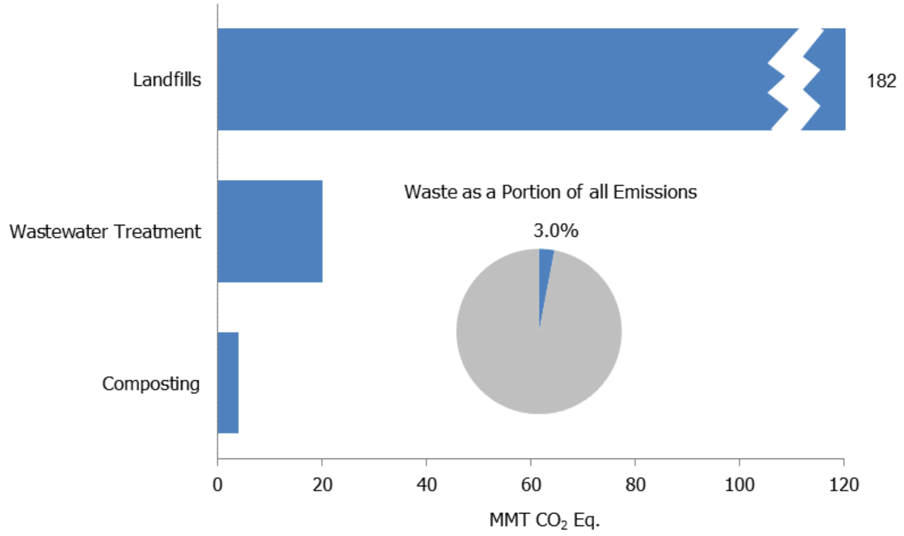
[5] Landfills also store carbon, due to incomplete degradation of organic materials such as wood products and yard trimmings, as described in the Land Use, Land-Use Change, and Forestry chapter.

Figure 2-11: 2014 Waste Chapter Greenhouse Gas Sources (MMT CO_2 Eq.)



Overall, in 2014, waste activities generated emissions of 205.6 MMT CO_2 Eq., or 3.0 percent of total U.S. greenhouse gas emissions.

Table 2-9: Emissions from Waste (MMT CO_2 Eq.)

Gas/Source	1990	2005	2010	2011	2012	2013	2014
CH_4	**200.4**	**205.1**	**193.6**	**194.0**	**190.6**	**193.7**	**198.9**
Landfills	184.4	187.3	176.3	176.9	173.5	176.7	181.8
Wastewater Treatment	15.7	15.9	15.5	15.3	15.2	15.0	15.0
Composting	0.4	1.9	1.8	1.9	1.9	2.0	2.1
N_2O	**3.7**	**6.0**	**6.4**	**6.5**	**6.6**	**6.7**	**6.8**
Wastewater Treatment	3.4	4.3	4.7	4.8	4.9	4.9	4.9
Composting	0.3	1.7	1.6	1.7	1.7	1.8	1.8
Total	**204.1**	**211.1**	**200.0**	**200.5**	**197.2**	**200.5**	**205.6**

Note: Totals may not sum due to independent rounding.

Some significant trends in U.S. emissions from waste source categories include the following:

- From 1990 to 2014, net CH_4 emissions from landfills decreased by 2.6 MMT CO_2 Eq. (1.4 percent), with small increases occurring in interim years. This slight downward trend in overall emissions is the result of increases in the amount of landfill gas collected and combusted as well as reductions in the amount of decomposable materials (i.e., paper and paperboard, food scraps, and yard trimmings) discarded in MSW landfills over the time series,[6] which has more than offset the additional CH_4 emissions resulting from an increase in the amount of municipal solid waste landfilled.
- Combined CH_4 and N_2O emissions from composting have generally increased since 1990, from 0.7 MMT CO_2 Eq. to 3.9 MMT CO_2 Eq. in 2014, which represents slightly more than a five-fold increase over the time series. The growth in composting since the 1990s is attributable to primarily two factors: (1) steady growth in population and residential housing, and (2) the enactment of legislation by state and local governments that discouraged the disposal of yard trimmings in landfills.
- From 1990 to 2014, CH_4 and N_2O emissions from wastewater treatment decreased by 0.6 MMT CO_2 Eq. (4.0 percent) and increased by 1.6 MMT CO_2 Eq. (46.5 percent), respectively. Methane emissions from

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[6] The CO_2 produced from combusted landfill CH_4 at landfills is not counted in national inventories as it is considered part of the natural C cycle of decomposition.

domestic wastewater treatment have decreased since 1999 due to decreasing percentages of wastewater being treated in anaerobic systems, including reduced use of on-site septic systems and central anaerobic treatment systems. Nitrous oxide emissions from wastewater treatment processes gradually increased across the time series as a result of increasing U.S. population and protein consumption.

2.2 Emissions by Economic Sector

Throughout this report, emission estimates are grouped into five sectors (i.e., chapters) defined by the IPCC and detailed above: Energy; Industrial Processes and Product Use; Agriculture; Land Use, Land-Use Change, and Forestry; and Waste. While it is important to use this characterization for consistency with UNFCCC reporting guidelines, it is also useful to allocate emissions into more commonly used sectoral categories. This section reports emissions by the following U.S. economic sectors: residential, commercial, industry, transportation, electricity generation, and agriculture, as well as U.S. Territories.

Using this categorization, emissions from electricity generation accounted for the largest portion (30 percent) of U.S. greenhouse gas emissions in 2014. Transportation activities, in aggregate, accounted for the second largest portion (26 percent). Emissions from industry accounted for about 20 percent of U.S. greenhouse gas emissions in 2014. In contrast to electricity generation and transportation, emissions from industry have in general declined over the past decade. The long-term decline in these emissions has been due to structural changes in the U.S. economy (i.e., shifts from a manufacturing-based to a service-based economy), fuel switching, and efficiency improvements. The remaining 23 percent of U.S. greenhouse gas emissions were contributed by the residential, agriculture, and commercial sectors, plus emissions from U.S. Territories. The residential sector accounted for 6 percent, and primarily consisted of CO_2 emissions from fossil fuel combustion. Activities related to agriculture accounted for roughly 9 percent of U.S. emissions; unlike other economic sectors, agricultural sector emissions were dominated by N_2O emissions from agricultural soil management and CH_4 emissions from enteric fermentation, rather than CO_2 from fossil fuel combustion. The commercial sector accounted for roughly 7 percent of emissions, while U.S. Territories accounted for less than 1 percent. Carbon dioxide was also emitted and sequestered (in the form of C) by a variety of activities related to forest management practices, tree planting in urban areas, the management of agricultural soils, and landfilling of yard trimmings.

Table 2-10 presents a detailed breakdown of emissions from each of these economic sectors by source category, as they are defined in this report. Figure 2-12 shows the trend in emissions by sector from 1990 to 2014.

Figure 2-12: Emissions Allocated to Economic Sectors (MMT CO_2 Eq.)

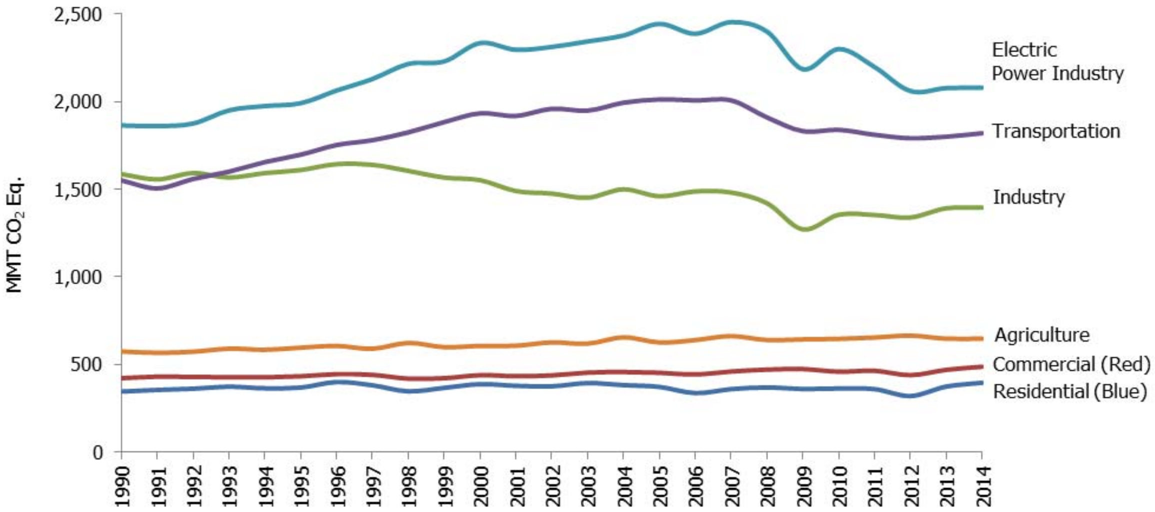


Table 2-10: U.S. Greenhouse Gas Emissions Allocated to Economic Sectors (MMT CO_2 Eq. and Percent of Total in 2014)

Sector/Source	1990	2005	2010	2011	2012	2013	2014	Percent[a]
Electric Power Industry	**1,864.8**	**2,443.9**	**2,300.5**	**2,198.1**	**2,060.8**	**2,077.7**	**2,080.2**	**30.3%**
CO_2 from Fossil Fuel Combustion	1,820.8	2,400.9	2,258.4	2,157.7	2,022.2	2,038.1	2,039.3	29.7%
Stationary Combustion	7.7	16.5	18.9	18.0	18.2	19.5	20.0	0.3%
Incineration of Waste	8.4	12.8	11.4	10.9	10.7	9.7	9.7	0.1%
Other Process Uses of Carbonates	2.5	3.2	4.8	4.7	4.0	5.2	6.0	0.1%
Electrical Transmission and Distribution	25.4	10.6	7.0	6.8	5.7	5.1	5.1	0.1%
Transportation	**1,551.3**	**2,012.9**	**1,839.7**	**1,811.3**	**1,791.6**	**1,800.5**	**1,820.3**	**26.5%**
CO_2 from Fossil Fuel Combustion	1,493.8	1,887.0	1,728.3	1,707.6	1,696.8	1,713.0	1,737.4	25.3%
Substitution of Ozone Depleting Substances	+	80.4	77.9	72.0	66.3	60.5	57.4	0.8%
Mobile Combustion	45.7	35.3	24.0	22.7	20.2	18.3	16.3	0.2%
Non-Energy Use of Fuels	11.8	10.2	9.5	9.0	8.3	8.8	9.1	0.1%
Industry	**1,586.9**	**1,460.6**	**1,354.9**	**1,353.9**	**1,339.5**	**1,392.1**	**1,395.5**	**20.3%**
CO_2 from Fossil Fuel Combustion	811.4	780.6	727.4	723.4	731.5	761.8	763.0	11.1%
Natural Gas Systems[b]	216.8	206.3	191.9	194.8	189.2	195.2	195.2	2.8%
Non-Energy Use of Fuels	100.6	120.6	100.8	95.8	93.5	109.1	101.6	1.5%
Coal Mining	96.5	64.1	82.3	71.2	66.5	64.6	64.6	0.9%
Iron and Steel Production	99.7	66.6	55.7	59.9	54.2	52.2	55.4	0.8%
Cement Production	33.3	45.9	31.3	32.0	35.1	36.1	38.8	0.6%
Petroleum Systems[c]	36.0	28.4	25.5	26.4	28.3	31.2	31.2	0.5%
Petrochemical Production	21.8	27.5	27.3	26.4	26.5	26.5	26.6	0.4%
Substitution of Ozone Depleting Substances	+	7.3	15.3	17.0	18.7	20.4	22.2	0.3%
Lime Production	11.7	14.6	13.4	14.0	13.7	14.0	14.1	0.2%
Nitric Acid Production	12.1	11.3	11.5	10.9	10.5	10.7	10.9	0.2%
Ammonia Production	13.0	9.2	9.2	9.3	9.4	10.0	9.4	0.1%
Abandoned Underground Coal Mines	7.2	6.6	6.6	6.4	6.2	6.2	6.2	0.1%
Aluminum Production	28.3	7.6	4.6	6.8	6.4	6.2	6.2	0.1%
Other Process Uses of Carbonates	2.5	3.2	4.8	4.7	4.0	5.2	6.0	0.1%
Adipic Acid Production	15.2	7.1	4.2	10.2	5.5	4.0	5.4	0.1%
Carbon Dioxide Consumption	1.5	1.4	4.4	4.1	4.0	4.2	4.5	0.1%

N_2O from Product Uses	4.2	4.2	4.2	4.2	4.2	4.2	4.2	0.1%
Semiconductor Manufacture	3.6	4.7	3.8	4.9	4.5	4.2	4.2	0.1%
HCFC-22 Production	46.1	20.0	8.0	8.8	5.5	4.1	4.1	0.1%
Urea Consumption for Non-Agricultural Purposes	3.8	3.7	4.7	4.0	4.4	4.2	4.0	0.1%
Stationary Combustion	4.9	4.6	3.9	3.9	3.9	3.9	3.9	0.1%
Soda Ash Production and Consumption	2.8	3.0	2.7	2.7	2.8	2.8	2.8	+
Ferroalloy Production	2.2	1.4	1.7	1.7	1.9	1.8	1.9	+
Titanium Dioxide Production	1.2	1.8	1.8	1.7	1.5	1.7	1.8	+
Magnesium Production and Processing	5.2	2.7	2.1	2.8	1.7	1.5	1.5	+
Mobile Combustion	0.9	1.3	1.4	1.4	1.4	1.5	1.5	+
Glass Production	1.5	1.9	1.5	1.3	1.2	1.3	1.3	+
Phosphoric Acid Production	1.5	1.3	1.1	1.2	1.1	1.1	1.1	+
Zinc Production	0.6	1.0	1.2	1.3	1.5	1.4	1.0	+
Lead Production	0.5	0.6	0.5	0.5	0.5	0.5	0.5	+
Silicon Carbide Production and Consumption	0.4	0.2	0.2	0.2	0.2	0.2	0.2	+
Agriculture	**574.9**	**626.8**	**646.6**	**654.2**	**665.3**	**648.0**	**648.0**	**9.4%**
N_2O from Agricultural Soil Management	302.9	296.7	320.4	322.9	322.9	318.4	318.5	4.6%
Enteric Fermentation	164.2	168.9	171.3	168.9	166.7	165.5	164.3	2.4%
Manure Management	51.1	72.9	78.1	78.9	81.2	78.9	78.7	1.1%
CO_2 from Fossil Fuel Combustion	31.0	47.4	48.2	49.9	51.4	50.4	51.2	0.7%
Rice Cultivation	11.3	14.2	12.2	12.2	12.2	12.2	12.2	0.2%
CH_4 and N_2O from Forest Fires	5.4	16.5	5.4	11.0	18.3	12.2	12.2	0.2%
Urea Fertilization	2.4	3.5	3.8	4.1	4.2	4.3	4.5	0.1%
Liming	4.7	4.3	4.8	3.9	6.0	3.9	4.1	0.1%
CO_2, CH_4 and N_2O from Managed Peatlands	1.1	1.1	1.0	0.9	0.8	0.8	0.8	+
Mobile Combustion	0.3	0.5	0.5	0.5	0.6	0.6	0.6	+
N_2O from Forest Soils	0.1	0.5	0.5	0.5	0.5	0.5	0.5	+
Field Burning of Agricultural Residues	0.3	0.3	0.4	0.4	0.4	0.4	0.4	+
Stationary Combustion	+	+	+	+	+	+	+	+
Commercial	**422.9**	**453.6**	**459.9**	**464.7**	**440.0**	**470.2**	**487.8**	**7.1%**
CO_2 from Fossil Fuel Combustion	217.4	223.5	220.1	220.7	196.7	221.0	231.6	3.4%
Landfills	184.4	187.3	176.3	176.9	173.5	176.7	181.8	2.6%
Substitution of Ozone Depleting Substances	+	17.6	38.5	42.1	44.9	47.4	49.2	0.7%
Wastewater Treatment	15.7	15.9	15.5	15.3	15.2	15.0	15.0	0.2%
Human Sewage	3.4	4.3	4.7	4.8	4.9	4.9	4.9	0.1%
Composting	0.7	3.5	3.5	3.5	3.7	3.9	3.9	0.1%
Stationary Combustion	1.4	1.4	1.4	1.4	1.2	1.3	1.4	+
Residential	**346.3**	**372.8**	**363.6**	**360.1**	**320.9**	**375.1**	**396.1**	**5.8%**
CO_2 from Fossil Fuel Combustion	338.3	357.8	334.6	326.8	282.5	329.7	345.1	5.0%
Substitution of Ozone Depleting Substances	0.3	7.7	21.8	25.9	31.4	37.0	42.6	0.6%
Stationary Combustion	6.3	4.9	4.8	4.9	4.5	5.9	6.0	0.1%
Settlement Soil Fertilization	1.4	2.3	2.4	2.5	2.5	2.4	2.4	+
U.S. Territories	**33.7**	**58.2**	**45.3**	**45.4**	**47.6**	**47.5**	**44.7**	**0.7%**
CO_2 from Fossil Fuel Combustion	27.9	49.9	41.4	41.5	43.6	43.5	41.0	0.6%
Non-Energy Use of Fuels	5.7	8.1	3.7	3.7	3.8	3.8	3.5	0.1%
Stationary Combustion	0.1	0.2	0.2	0.2	0.2	0.2	0.2	+
Total Emissions	**6,380.8**	**7,428.8**	**7,010.5**	**6,887.8**	**6,665.7**	**6,811.2**	**6,872.6**	**100.0%**
LULUCF Total Net Flux[d]	**(704.2)**	**(636.1)**	**(683.2)**	**(683.6)**	**(680.8)**	**(682.4)**	**(685.8)**	**(10.0%)**
Forest Land Remaining Forest Land[e]	(576.0)	(532.4)	(585.0)	(578.1)	(576.7)	(580.1)	(583.4)	(8.5%)
Land Converted to Forest Land								
Cropland Remaining Cropland	(43.2)	(16.5)	(4.7)	(20.0)	(18.7)	(16.8)	(16.0)	(0.2%)
Land Converted to Cropland[d]	22.8	14.6	15.6	14.2	14.5	14.8	14.7	0.2%
Grassland Remaining Grassland[d]	(12.9)	2.9	2.6	11.3	11.7	11.9	11.9	0.2%

Land Converted to Grassland	(8.5)	(12.8)	(12.3)	(11.0)	(10.9)	(10.9)	(10.9)	(0.2%)
Settlements Remaining Settlements	(60.4)	(80.5)	(86.1)	(87.3)	(88.4)	(89.5)	(90.6)	(1.3%)
Other: Landfilled Yard Trimmings and Food Scraps	(26.0)	(11.4)	(13.2)	(12.7)	(12.2)	(11.7)	(11.6)	(0.2%)
Net Emissions (Sources and Sinks)	**5,676.6**	**6,792.6**	**6,327.3**	**6,204.2**	**5,984.9**	**6,128.8**	**6,186.8**	**90.0%**

Note: Includes all emissions of CO_2, CH_4, N_2O, HFCs, PFCs, SF_6, and NF_3. Parentheses indicate negative values or sequestration. Totals may not sum due to independent rounding.

+ Does not exceed 0.05 MMT CO_2 Eq. or 0.05 percent.

[a] Percent of total emissions for year 2014.

[b] The values in this table for Natural Gas Systems are presented from the previous Inventory and do not reflect updates to emission estimates for this category. See Section 3.7, Natural Gas Systems of the Energy chapter for more information. Gray highlighting was added on 2/24 for clarification.

[c] The values in this table for Petroleum Systems are presented from the previous Inventory and do not reflect updates to emission estimates for this category. See Section 3.6, Petroleum Systems of the Energy chapter for more information. Gray highlighting was added on 2/24 for clarification.

[d] Total net flux from LULUCF is only included in the Net Emissions total. Net flux from LULUCF includes the positive C sequestration reported for *Forest Land Remaining Forest Land, Land Converted to Forest Land, Cropland Remaining Cropland, Land Converted to Grassland, Settlements Remaining Settlements,* and *Other Land* plus the loss in C sequestration reported for *Land Converted to Cropland and Grassland Remaining Grassland.* Refer to Table 2-8 for a breakout of emissions and removals for Land Use, Land-Use Change, and Forestry by gas and source category.

[e] Includes the effects of net additions to stocks of carbon stored in forest ecosystem pools and harvested wood products.

Emissions with Electricity Distributed to Economic Sectors

It can also be useful to view greenhouse gas emissions from economic sectors with emissions related to electricity generation distributed into end-use categories (i.e., emissions from electricity generation are allocated to the economic sectors in which the electricity is consumed). The generation, transmission, and distribution of electricity, which is the largest economic sector in the United States, accounted for 30 percent of total U.S. greenhouse gas emissions in 2014. Emissions increased by 12 percent since 1990, as electricity demand grew and fossil fuels remained the dominant energy source for generation. Electricity generation-related emissions increased from 2013 to 2014 by 0.1 percent, primarily due to increased CO_2 emissions from fossil fuel combustion. Electricity sales to the residential and commercial end-use sectors in 2014 increased approximately 0.9 percent and 1.1 percent, respectively. The trend in the residential and commercial sectors can largely be attributed to colder more energy-intensive winter conditions compared to 2013. Electricity sales to the industrial sector in 2014 increased by approximately 1.2 percent. Overall, in 2014, the amount of electricity generated (in kWh) increased by 1.1 percent from the previous year. Despite this increase in generation, CO_2 emissions from the electric power sector increased by 0.1 percent as the consumption petroleum for electricity generation increased by 15.8 percent in 2014 and the consumption of CO_2-intensive coal and natural gas for electricity generation decreased by 0.1 and 0.2 percent, respectively. Table 2-11 provides a detailed summary of emissions from electricity generation-related activities.

Table 2-11: Electricity Generation-Related Greenhouse Gas Emissions (MMT CO_2 Eq.)

Gas/Fuel Type or Source	1990	2005	2010	2011	2012	2013	2014
CO_2	**1,831.2**	**2,416.5**	**2,274.2**	**2,172.9**	**2,036.6**	**2,052.8**	**2,054.8**
Fossil fuel combustion	1,820.8	2,400.9	2,258.4	2,157.7	2,022.2	2,038.1	2,039.3
Coal	*1,547.6*	*1,983.8*	*1,827.6*	*1,722.7*	*1,511.2*	*1,571.3*	*1,570.4*
Natural Gas	*175.3*	*318.8*	*399.0*	*408.8*	*492.2*	*444.0*	*443.2*
Petroleum	*97.5*	*97.9*	*31.4*	*25.8*	*18.3*	*22.4*	*25.3*
Geothermal	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*
Incineration of Waste	8.0	12.5	11.0	10.5	10.4	9.4	9.4
Other Process Uses of Carbonates	2.5	3.2	4.8	4.7	4.0	5.2	6.0
CH_4	**0.3**	**0.5**	**0.5**	**0.4**	**0.4**	**0.4**	**0.4**
Stationary Sources (Elec Gen)	0.3	0.5	0.5	0.4	0.4	0.4	0.4
Incineration of Waste	+	+	+	+	+	+	+
N_2O	**7.8**	**16.4**	**18.8**	**17.9**	**18.1**	**19.4**	**19.9**

Stationary Sources (Elec Gen)	7.4		16.0		18.5	17.6	17.8	19.1	19.6
Incineration of Waste	0.5		0.4		0.3	0.3	0.3	0.3	0.3
SF_6	**25.4**		**10.6**		**7.0**	**6.8**	**5.7**	**5.1**	**5.1**
Electrical Transmission and Distribution	25.4		10.6		7.0	6.8	5.7	5.1	5.1
Total	**1,864.8**		**2,443.9**		**2,300.5**	**2,198.1**	**2,060.8**	**2,077.7**	**2,080.2**

Note: Totals may not sum due to independent rounding.

[a] Includes only stationary combustion emissions related to the generation of electricity.

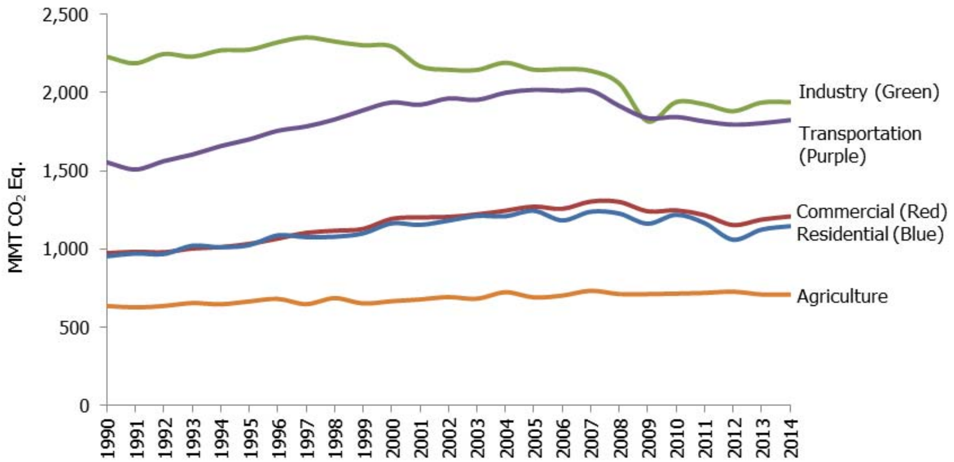
+ Does not exceed 0.05 MMT CO_2 Eq.

To distribute electricity emissions among economic end-use sectors, emissions from the source categories assigned to the electricity generation sector were allocated to the residential, commercial, industry, transportation, and agriculture economic sectors according to each economic sector's share of retail sales of electricity consumption (EIA 2015, Duffield 2006). These source categories include CO_2 from Fossil Fuel Combustion, CH_4 and N_2O from Stationary Combustion, Incineration of Waste, Other Process Uses of Carbonates, and SF_6 from Electrical Transmission and Distribution Systems. Note that only 50 percent of the Other Process Uses of Carbonates emissions were associated with electricity generation and distributed as described; the remainder of Other Process Uses of Carbonates emissions were attributed to the industrial processes economic end-use sector.[7]

When emissions from electricity are distributed among these sectors, industrial activities account for the largest share of total U.S. greenhouse gas emissions (28.2 percent), followed closely by emissions from transportation (26.5 percent). Emissions from the residential and commercial sectors also increase substantially when emissions from electricity are included. In all sectors except agriculture, CO_2 accounts for more than 78 percent of greenhouse gas emissions, primarily from the combustion of fossil fuels.

Table 2-12 presents a detailed breakdown of emissions from each of these economic sectors, with emissions from electricity generation distributed to them. Figure 2-13 shows the trend in these emissions by sector from 1990 to 2014.

Figure 2-13: Emissions with Electricity Distributed to Economic Sectors (MMT CO_2 Eq.)



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[7] Emissions were not distributed to U.S. Territories, since the electricity generation sector only includes emissions related to the generation of electricity in the 50 states and the District of Columbia.

Table 2-12: U.S. Greenhouse Gas Emissions by Economic Sector and Gas with Electricity-Related Emissions Distributed (MMT CO_2 Eq.) and Percent of Total in 2014

Sector/Gas	1990	2005	2010	2011	2012	2013	2014	Percent[a]
Industry	**2,228.9**	**2,146.3**	**1,939.4**	**1,924.9**	**1,881.4**	**1,936.4**	**1,939.4**	**28.2%**
Direct Emissions	**1,586.9**	**1,460.6**	**1,354.9**	**1,353.9**	**1,339.5**	**1,392.1**	**1,395.5**	**20.3%**
CO_2	1,158.7	1,123.2	1,028.7	1,027.4	1,030.3	1,081.2	1,081.0	15.7%
CH_4	316.6	272.5	271.6	260.6	252.1	255.2	255.3	3.7%
N_2O	35.4	26.7	23.7	29.1	24.0	22.7	24.4	0.4%
HFCs, PFCs, SF_6, and NF_3	76.3	38.1	30.9	36.8	33.1	32.9	34.8	0.5%
Electricity-Related	**642.0**	**685.7**	**584.5**	**571.0**	**542.0**	**544.2**	**543.9**	**7.9%**
CO_2	638.3	680.1	578.4	565.0	536.0	537.7	537.0	7.8%
CH_4	0.1	0.1	0.1	0.1	0.1	0.1	0.1	+
N_2O	2.7	4.6	4.8	4.7	4.8	5.1	5.2	0.1%
SF_6	0.8	0.9	1.2	1.2	1.1	1.4	1.6	+
Transportation	**1,554.4**	**2,017.7**	**1,844.3**	**1,815.7**	**1,795.5**	**1,804.6**	**1,824.4**	**26.5%**
Direct Emissions	**1,551.3**	**2,012.9**	**1,839.7**	**1,811.3**	**1,791.6**	**1,800.5**	**1,820.3**	**26.5%**
CO_2	1,505.6	1,897.2	1,737.8	1,716.6	1,705.0	1,721.8	1,746.6	25.4%
CH_4	5.4	2.4	1.9	1.8	1.8	1.7	1.6	+
N_2O	40.3	32.9	22.1	20.9	18.5	16.6	14.7	0.2%
HFCs[b]	+	80.4	77.9	72.0	66.3	60.5	57.4	0.8%
Electricity-Related	**3.1**	**4.8**	**4.6**	**4.3**	**3.9**	**4.1**	**4.1**	**0.1%**
CO_2	3.1	4.8	4.5	4.3	3.9	4.0	4.1	0.1%
CH_4	+	+	+	+	+	+	+	+
N_2O	+	+	+	+	+	+	+	+
SF_6	+	+	+	+	+	+	+	+
Commercial	**973.9**	**1,271.2**	**1,247.2**	**1,216.6**	**1,153.7**	**1,188.4**	**1,208.5**	**17.6%**
Direct Emissions	**422.9**	**453.6**	**459.9**	**464.7**	**440.0**	**470.2**	**487.8**	**7.1%**
CO_2	217.4	223.5	220.1	220.7	196.7	221.0	231.6	3.4%
CH_4	201.5	206.1	194.7	195.0	191.5	194.8	200.0	2.9%
N_2O	4.1	6.3	6.7	6.8	6.8	7.0	7.1	0.1%
HFCs	+	17.6	38.5	42.1	44.9	47.4	49.2	0.7%
Electricity-Related	**551.0**	**817.7**	**787.3**	**751.9**	**713.6**	**718.1**	**720.6**	**10.5%**
CO_2	547.8	811.0	779.1	744.0	705.8	709.5	711.5	10.4%
CH_4	0.1	0.2	0.2	0.1	0.1	0.1	0.1	+
N_2O	2.3	5.5	6.4	6.1	6.3	6.7	6.9	0.1%
SF_6	0.7	1.1	1.6	1.6	1.4	1.8	2.1	+
Residential	**953.6**	**1,244.4**	**1,219.3**	**1,165.6**	**1,060.1**	**1,124.2**	**1,146.1**	**16.7%**
Direct Emissions	**346.3**	**372.8**	**363.6**	**360.1**	**320.9**	**375.1**	**396.1**	**5.8%**
CO_2	338.3	357.8	334.6	326.8	282.5	329.7	345.1	5.0%
CH_4	5.2	4.1	4.0	4.0	3.7	5.0	5.0	0.1%
N_2O	2.4	3.2	3.2	3.3	3.3	3.4	3.4	+
HFCs	0.3	7.7	21.8	25.9	31.4	37.0	42.6	0.6%
Electricity-Related	**607.3**	**871.6**	**855.7**	**805.5**	**739.1**	**749.2**	**750.0**	**10.9%**
CO_2	603.9	864.5	846.8	797.1	731.0	740.1	740.5	10.8%
CH_4	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.0%
N_2O	2.5	5.8	7.0	6.6	6.5	7.0	7.2	0.1%
SF_6	0.8	1.1	1.8	1.7	1.4	1.9	2.2	+
Agriculture	**636.3**	**690.9**	**715.0**	**719.6**	**727.4**	**710.1**	**709.5**	**10.3%**
Direct Emissions	**574.9**	**626.8**	**646.6**	**654.2**	**665.3**	**648.0**	**648.0**	**9.4%**
CO_2	39.2	56.4	57.8	58.8	62.5	59.4	60.7	0.9%
CH_4	216.2	249.7	248.2	249.7	254.2	246.9	245.5	3.6%
N_2O	319.5	320.7	340.6	345.6	348.6	341.7	341.8	5.0%
Electricity-Related	**61.3**	**64.1**	**68.4**	**65.4**	**62.1**	**62.1**	**61.6**	**0.9%**
CO_2	61.0	63.5	67.7	64.7	61.4	61.3	60.8	0.9%
CH_4	+	+	+	+	+	+	+	+
N_2O	0.3	0.4	0.6	0.5	0.5	0.6	0.6	+
SF_6	0.1	0.1	0.1	0.1	0.1	0.2	0.2	+

U.S. Territories	**33.7**	**58.2**	**45.3**	**45.4**	**47.6**	**47.5**	**44.7**	**0.7%**
Total	**6,380.8**	**7,428.8**	**7,010.5**	**6,887.8**	**6,665.7**	**6,811.2**	**6,872.6**	**100.0%**

Note: Emissions from electricity generation are allocated based on aggregate electricity consumption in each end-use sector.

Totals may not sum due to independent rounding.

+ Does not exceed 0.05 MMT CO_2 Eq. or 0.05 percent.

[a] Percent of total emissions for year 2014.

[b] Includes primarily HFC-134a.

Industry

The industry end-use sector includes CO_2 emissions from fossil fuel combustion from all manufacturing facilities, in aggregate. This end-use sector also includes emissions that are produced as a byproduct of the non-energy-related industrial process activities. The variety of activities producing these non-energy-related emissions includes methane emissions from petroleum and natural gas systems, fugitive CH_4 emissions from coal mining, by-product CO_2 emissions from cement manufacture, and HFC, PFC, SF_6, and NF_3 byproduct emissions from semiconductor manufacture, to name a few. Since 1990, industrial sector emissions have declined. The decline has occurred both in direct emissions and indirect emissions associated with electricity use. In theory, emissions from the industrial end-use sector should be highly correlated with economic growth and industrial output, but heating of industrial buildings and agricultural energy consumption are also affected by weather conditions. In addition, structural changes within the U.S. economy that lead to shifts in industrial output away from energy-intensive manufacturing products to less energy-intensive products (e.g., from steel to computer equipment) also have a significant effect on industrial emissions.

Transportation

When electricity-related emissions are distributed to economic end-use sectors, transportation activities accounted for 27 percent of U.S. greenhouse gas emissions in 2014. The largest sources of transportation greenhouse gases in 2014 were passenger cars (41.8 percent), freight trucks (22.8 percent), light-duty trucks, which include sport utility vehicles, pickup trucks, and minivans (18.5 percent), commercial aircraft (6.4 percent), rail (2.7 percent), pipelines (2.6 percent), and ships and boats (1.5 percent). These figures include direct CO_2, CH_4, and N_2O emissions from fossil fuel combustion used in transportation and emissions from non-energy use (i.e., lubricants) used in transportation, as well as HFC emissions from mobile air conditioners and refrigerated transport allocated to these vehicle types.

In terms of the overall trend, from 1990 to 2014, total transportation emissions rose by 17 percent due, in large part, to increased demand for travel as fleetwide light-duty vehicle fuel economy was relatively stable (average new vehicle fuel economy declined slowly from 1990 through 2004 and then increased more rapidly from 2005 through 2014). The number of vehicle miles traveled by light-duty motor vehicles (passenger cars and light-duty trucks) increased 37 percent from 1990 to 2014, as a result of a confluence of factors including population growth, economic growth, urban sprawl, and periods of low fuel prices. The decline in new light-duty vehicle fuel economy between 1990 and 2004 reflected the increasing market share of light-duty trucks, which grew from about 30 percent of new vehicle sales in 1990 to 48 percent in 2004. Starting in 2005, the rate of VMT growth slowed while average new vehicle fuel economy began to increase. Average new vehicle fuel economy has improved almost every year since 2005, and the truck share has decreased to about 41 percent of new vehicles in MY 2014 (EPA 2015a). Between 2013 and 2014, VMT increased by only 1.3 percent. Table 2-13 provides a detailed summary of greenhouse gas emissions from transportation-related activities with electricity-related emissions included in the totals.

From 2008 to 2009, CO_2 emissions from the transportation end-use sector declined 4.2 percent. The decrease in emissions could largely be attributed to decreased economic activity in 2009 and an associated decline in the demand for transportation. Modes such as medium- and heavy-duty trucks were significantly impacted by the decline in freight transport. After reaching a decadal low in 2012, CO_2 emissions from the transportation end-use sector stabilized and grew slowly in 2013 and 2014 as the economic recovery gained strength.

Almost all of the energy consumed for transportation was supplied by petroleum-based products, with more than half being related to gasoline consumption in automobiles and other highway vehicles. Other fuel uses, especially diesel fuel for freight trucks and jet fuel for aircraft, accounted for the remainder. The primary driver of transportation-related emissions was CO_2 from fossil fuel combustion, which increased by 16 percent from 1990 to 2014. This rise in CO_2 emissions, combined with an increase in HFCs from close to zero emissions in 1990 to 57.4 MMT CO_2 Eq. in 2014, led to an increase in overall emissions from transportation activities of 17 percent.

Table 2-13: Transportation-Related Greenhouse Gas Emissions (MMT CO_2 Eq.)

Gas/Vehicle	1990	2005	2010	2011	2012	2013	2014
Passenger Cars	**656.7**	**708.9**	**783.6**	**774.3**	**767.9**	**763.2**	**762.6**
CO_2	629.3	660.1	742.0	736.9	735.5	735.5	737.7
CH_4	3.2	1.2	1.2	1.2	1.1	1.0	1.0
N_2O	24.1	15.9	12.9	12.3	10.7	9.4	8.0
HFCs	+	31.7	27.5	23.9	20.6	17.3	16.0
Light-Duty Trucks	**335.6**	**551.5**	**348.9**	**332.0**	**326.0**	**323.4**	**338.2**
CO_2	321.1	504.3	308.8	294.8	291.9	292.5	309.3
CH_4	1.7	0.8	0.4	0.4	0.3	0.3	0.3
N_2O	12.8	13.2	5.5	5.0	4.4	3.9	3.6
HFCs	0.0	33.3	34.2	31.7	29.3	26.7	25.0
Medium- and Heavy-Duty Trucks	**231.1**	**409.3**	**400.0**	**398.2**	**398.1**	**404.6**	**415.1**
CO_2	230.1	395.4	385.6	383.9	383.7	390.3	402.0
CH_4	0.3	0.1	0.1	0.1	0.1	0.1	0.1
N_2O	0.7	1.1	1.1	1.0	0.9	0.9	0.9
HFCs	0.0	12.7	13.2	13.3	13.3	13.3	12.1
Buses	**8.4**	**12.1**	**15.8**	**16.8**	**17.8**	**18.0**	**19.1**
CO_2	8.4	11.8	15.3	16.2	17.3	17.5	18.6
CH_4	+	+	+	+	+	+	+
N_2O	+	+	0.1	0.1	0.1	0.1	0.1
HFCs	0.0	0.3	0.4	0.4	0.4	0.4	0.4
Motorcycles	**1.8**	**1.7**	**3.7**	**3.6**	4.2	4.0	3.9
CO_2	1.7	1.6	3.6	3.6	4.1	3.9	3.8
CH_4	+	+	+	+	+	+	+
N_2O	+	+	+	+	+	+	+
Commercial Aircraft[a]	**110.9**	**134.0**	**114.4**	**115.7**	**114.3**	**115.4**	**116.3**
CO_2	109.9	132.7	113.3	114.6	113.3	114.3	115.2
CH_4	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N_2O	1.0	1.2	1.0	1.1	1.0	1.1	1.1
Other Aircraft[b]	**78.3**	**59.7**	**40.4**	**34.2**	**32.1**	**34.7**	**35.2**
CO_2	77.5	59.1	40.1	33.9	31.8	34.4	34.9
CH_4	0.1	0.1	+	+	+	+	+
N_2O	0.7	0.5	0.4	0.3	0.3	0.3	0.3
Ships and Boats[c]	**44.9**	**44.9**	**44.8**	**46.4**	**40.1**	**39.4**	**28.3**
CO_2	44.3	44.3	44.0	45.5	39.3	38.7	27.7
CH_4	+	+	+	+	+	+	+
N_2O	0.6	0.6	0.8	0.8	0.7	0.7	0.5
HFCs	0.0	+	+	+	+	+	0.1
Rail	**39.0**	**53.2**	**46.2**	**47.8**	**46.4**	**47.2**	**50.0**
CO_2	38.5	50.3	43.1	44.7	43.4	44.2	45.7
CH_4	0.1	0.1	0.1	0.1	0.1	0.1	0.1
N_2O	0.3	0.4	0.3	0.3	0.3	0.3	0.4
HFCs	0.0	2.5	2.6	2.6	2.6	2.6	3.8
Other Emissions from Electricity Generation[d]	0.1	0.1	+	+	+	+	0.0
Pipelines[e]	**36.0**	**32.2**	**37.1**	**37.8**	**40.3**	**45.9**	**46.5**
CO_2	36.0	32.2	37.1	37.8	40.3	45.9	46.5
Lubricants	**11.8**	**10.2**	**9.5**	**9.0**	**8.3**	**8.8**	**9.1**

CO_2	11.8	10.2	9.5	9.0	8.3	8.8	9.1
Total Transportation	**1,554.4**	**2,017.7**	**1,844.3**	**1,815.7**	**1,795.5**	**1,804.6**	**1,824.4**
International Bunker Fuels[f]	*104.5*	*114.2*	*118.1*	*112.8*	*106.8*	*100.7*	*104.2*

Note: Totals may not sum due to independent rounding. Passenger cars and light-duty trucks include vehicles typically used for personal travel and less than 8,500 lbs; medium- and heavy-duty trucks include vehicles larger than 8,500 lbs. HFC emissions primarily reflect HFC-134a.

+ Does not exceed 0.05 MMT CO_2 Eq.

[a] Consists of emissions from jet fuel consumed by domestic operations of commercial aircraft (no bunkers).

[b] Consists of emissions from jet fuel and aviation gasoline consumption by general aviation and military aircraft.

[c] Fluctuations in emission estimates are associated with fluctuations in reported fuel consumption, and may reflect issues with data sources.

[d] Other emissions from electricity generation are a result of waste incineration (as the majority of municipal solid waste is combusted in “trash-to-steam” electricity generation plants), electrical transmission and distribution, and a portion of Other Process Uses of Carbonates (from pollution control equipment installed in electricity generation plants).

[e] CO_2 estimates reflect natural gas used to power pipelines, but not electricity. While the operation of pipelines produces CH_4 and N_2O, these emissions are not directly attributed to pipelines in the U.S. Inventory.

[f] Emissions from International Bunker Fuels include emissions from both civilian and military activities; these emissions are not included in the transportation totals.

Commercial

The commercial sector is heavily reliant on electricity for meeting energy needs, with electricity consumption for lighting, heating, air conditioning, and operating appliances. The remaining emissions were largely due to the direct consumption of natural gas and petroleum products, primarily for heating and cooking needs. Energy-related emissions from the residential and commercial sectors have generally been increasing since 1990, and are often correlated with short-term fluctuations in energy consumption caused by weather conditions, rather than prevailing economic conditions. Landfills and wastewater treatment are included in this sector, with landfill emissions decreasing since 1990 and wastewater treatment emissions decreasing slightly.

Residential

The residential sector is heavily reliant on electricity for meeting energy needs, with electricity consumption for lighting, heating, air conditioning, and operating appliances. The remaining emissions were largely due to the direct consumption of natural gas and petroleum products, primarily for heating and cooking needs. Emissions from the residential sectors have generally been increasing since 1990, and are often correlated with short-term fluctuations in energy consumption caused by weather conditions, rather than prevailing economic conditions. In the long-term, this sector is also affected by population growth, regional migration trends, and changes in housing and building attributes (e.g., size and insulation).

Agriculture

The agriculture end-use sector includes a variety of processes, including enteric fermentation in domestic livestock, livestock manure management, and agricultural soil management. In 2014, agricultural soil management was the largest source of N_2O emissions, and enteric fermentation was the second largest source of CH_4 emissions in the United States. This sector also includes small amounts of CO_2 emissions from fossil fuel combustion by motorized farm equipment like tractors. The agriculture sector is less reliant on electricity than the other sectors.

Box 2-1: Methodology for Aggregating Emissions by Economic Sector

In presenting the Economic Sectors in the annual Inventory of U.S. Greenhouse Gas Emissions and Sinks, the Inventory expands upon the standard IPCC sectors common for UNFCCC reporting. Discussing greenhouse gas emissions relevant to U.S.-specific sectors improves communication of the report’s findings.

In the Electricity Generation economic sector, CO_2 emissions from the combustion of fossil fuels included in the EIA electric utility fuel consuming sector are apportioned to this economic sector. Stationary combustion emissions of CH_4 and N_2O are also based on the EIA electric utility sector. Additional sources include CO_2, CH_4, and N_2O from waste incineration, as the majority of municipal solid waste is combusted in "trash-to-steam" electricity generation plants. The Electricity Generation economic sector also includes SF_6 from Electrical Transmission and Distribution, and a portion of CO_2 from Other Process Uses of Carbonates (from pollution control equipment installed in electricity generation plants).

In the Transportation economic sector, the CO_2 emissions from the combustion of fossil fuels included in the EIA transportation fuel consuming sector are apportioned to this economic sector (additional analyses and refinement of the EIA data is further explained in the Energy chapter of this report). Additional emissions are apportioned from the CH_4 and N_2O from Mobile Combustion, based on the EIA transportation sector. Substitutes of Ozone Depleting Substances are apportioned based on their specific end-uses within the source category, with emissions from transportation refrigeration/air-conditioning systems to this economic sector. Finally, CO_2 emissions from Non-Energy Uses of Fossil Fuels identified as lubricants for transportation vehicles are included in the Transportation economic sector.

For the Industry economic sector, the CO_2 emissions from the combustion of fossil fuels included in the EIA industrial fuel consuming sector, minus the agricultural use of fuel explained below, are apportioned to this economic sector. Stationary and mobile combustion emissions of CH_4 and N_2O are also based on the EIA industrial sector, minus emissions apportioned to the Agriculture economic sector described below. Substitutes of Ozone Depleting Substances are apportioned based on their specific end-uses within the source category, with most emissions falling within the Industry economic sector (minus emissions from the other economic sectors). Additionally, all process-related emissions from sources with methods considered within the IPCC Industrial Process guidance have been apportioned to this economic sector. This includes the process-related emissions (i.e., emissions from the actual process to make the material, not from fuels to power the plant) from such activities as Cement Production, Iron and Steel Production and Metallurgical Coke Production, and Ammonia Production. Additionally, fugitive emissions from energy production sources, such as Natural Gas Systems, Coal Mining, and Petroleum Systems are included in the Industry economic sector. A portion of CO_2 from Other Process Uses of Carbonates (from pollution control equipment installed in large industrial facilities) are also included in the Industry economic sector. Finally, all remaining CO_2 emissions from Non-Energy Uses of Fossil Fuels are assumed to be industrial in nature (besides the lubricants for transportation vehicles specified above), and are attributed to the Industry economic sector.

As agriculture equipment is included in EIA's industrial fuel consuming sector surveys, additional data is used to extract the fuel used by agricultural equipment, to allow for accurate reporting in the Agriculture economic sector from all sources of emissions, such as motorized farming equipment. Energy consumption estimates are obtained from Department of Agriculture survey data, in combination with separate EIA fuel sales reports. This supplementary data is used to apportion CO_2 emissions from fossil fuel combustion, and CH_4 and N_2O emissions from stationary and mobile combustion (all data is removed from the Industrial economic sector, to avoid double-counting). The other emission sources included in this economic sector are intuitive for the agriculture sectors, such as N_2O emissions from Agricultural Soils, CH_4 from Enteric Fermentation (i.e., exhalation from the digestive tracts of domesticated animals), CH_4 and N_2O from Manure Management, CH_4 from Rice Cultivation, CO_2 emissions from Liming and Urea Application, and CH_4 and N_2O from Forest Fires. N_2O emissions from the Application of Fertilizers to tree plantations (termed "forest land" by the IPCC) are also included in the Agriculture economic sector.

The Residential economic sector includes the CO_2 emissions from the combustion of fossil fuels reported for the EIA residential sector. Stationary combustion emissions of CH_4 and N_2O are also based on the EIA residential fuel consuming sector. Substitutes of Ozone Depleting Substances are apportioned based on their specific end-uses within the source category, with emissions from residential air-conditioning systems to this economic sector. N_2O emissions from the Application of Fertilizers to developed land (termed "settlements" by the IPCC) are also included in the Residential economic sector.

The Commercial economic sector includes the CO_2 emissions from the combustion of fossil fuels reported in the EIA commercial fuel consuming sector data. Stationary combustion emissions of CH_4 and N_2O are also based on the EIA commercial sector. Substitutes of Ozone Depleting Substances are apportioned based on their specific end-uses within the source category, with emissions from commercial refrigeration/air-conditioning systems to this economic sector. Public works sources including direct CH_4 from Landfills and CH_4 and N_2O from Wastewater Treatment and Composting are included in this economic sector.

Box 2-2: Recent Trends in Various U.S. Greenhouse Gas Emissions-Related Data

Total emissions can be compared to other economic and social indices to highlight changes over time. These comparisons include: (1) emissions per unit of aggregate energy consumption, because energy-related activities are the largest sources of emissions; (2) emissions per unit of fossil fuel consumption, because almost all energy-related emissions involve the combustion of fossil fuels; (3) emissions per unit of electricity consumption, because the electric power industry—utilities and non-utilities combined—was the largest source of U.S. greenhouse gas emissions in 2014; (4) emissions per unit of total gross domestic product as a measure of national economic activity; or (5) emissions per capita.

Table 2-14 provides data on various statistics related to U.S. greenhouse gas emissions normalized to 1990 as a baseline year. Greenhouse gas emissions in the United States have grown at an average annual rate of 0.3 percent since 1990. Since 1990, this rate is slightly slower than that for total energy and for fossil fuel consumption, and much slower than that for electricity consumption, overall gross domestic product and national population (see Table 2-14).

Table 2-14: Recent Trends in Various U.S. Data (Index 1990 = 100)

Chapter/IPCC Sector	1990	2005	2010	2011	2012	2013	2014	Growth[a]
Greenhouse Gas Emissions[b]	100	116	110	108	104	107	108	0.3%
Energy Consumption[c]	100	118	116	115	112	116	117	0.7%
Fossil Fuel Consumption[c]	100	119	112	110	107	110	111	0.5%
Electricity Consumption[c]	100	134	137	137	135	136	138	1.4%
GDP[d]	100	159	165	168	171	174	178	2.5%
Population[e]	100	118	124	125	126	126	127	1.0%

[a] Average annual growth rate

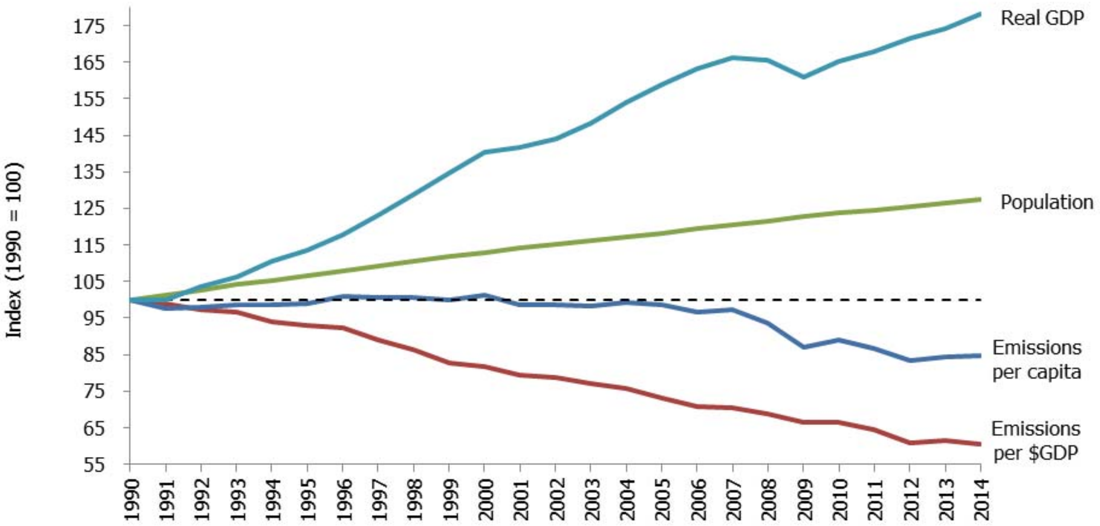
[b] GWP-weighted values

[c] Energy-content-weighted values (EIA 2015)

[d] Gross Domestic Product in chained 2009 dollars (BEA 2015)

[e] U.S. Census Bureau (2015)

Figure 2-14: U.S. Greenhouse Gas Emissions Per Capita and Per Dollar of Gross Domestic Product



Source: BEA (2015), U.S. Census Bureau (2015), and emission estimates in this report.

2.3 Indirect Greenhouse Gas Emissions (CO, NO_x, NMVOCs, and SO_2)

The reporting requirements of the UNFCCC[8] request that information be provided on indirect greenhouse gases, which include CO, NO_x, NMVOCs, and SO_2. These gases do not have a direct global warming effect, but indirectly affect terrestrial radiation absorption by influencing the formation and destruction of tropospheric and stratospheric ozone, or, in the case of SO_2, by affecting the absorptive characteristics of the atmosphere. Additionally, some of these gases may react with other chemical compounds in the atmosphere to form compounds that are greenhouse gases. Carbon monoxide is produced when carbon-containing fuels are combusted incompletely. Nitrogen oxides (i.e., NO and NO_2) are created by lightning, fires, fossil fuel combustion, and in the stratosphere from N_2O. Non-CH_4 volatile organic compounds—which include hundreds of organic compounds that participate in atmospheric chemical reactions (i.e., propane, butane, xylene, toluene, ethane, and many others)—are emitted primarily from transportation, industrial processes, and non-industrial consumption of organic solvents. In the United States, SO_2 is primarily emitted from coal combustion for electric power generation and the metals industry. Sulfur-containing compounds emitted into the atmosphere tend to exert a negative radiative forcing (i.e., cooling) and therefore are discussed separately.

One important indirect climate change effect of NMVOCs and NO_x is their role as precursors for tropospheric ozone formation. They can also alter the atmospheric lifetimes of other greenhouse gases. Another example of indirect greenhouse gas formation into greenhouse gases is CO's interaction with the hydroxyl radical—the major atmospheric sink for CH_4 emissions—to form CO_2. Therefore, increased atmospheric concentrations of CO limit the number of hydroxyl molecules (OH) available to destroy CH_4.

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[8] See < http://unfccc.int/resource/docs/2013/cop19/eng/10a03.pdf#page=2>.

Since 1970, the United States has published estimates of emissions of CO, NO_x, NMVOCs, and SO_2 (EPA 2015),[9] which are regulated under the Clean Air Act. Table 2-15 shows that fuel combustion accounts for the majority of emissions of these indirect greenhouse gases. Industrial processes—such as the manufacture of chemical and allied products, metals processing, and industrial uses of solvents—are also significant sources of CO, NO_x, and NMVOCs.

Table 2-15: Emissions of NO_x, CO, NMVOCs, and SO_2 (kt)

Gas/Activity	1990	2005	2010	2011	2012	2013	2014
NO_x	**21,770**	**17,394**	**12,607**	**12,629**	**11,912**	**11,167**	**10,605**
Mobile Fossil Fuel Combustion	10,862	10,295	7,290	7,294	6,788	6,283	5,777
Stationary Fossil Fuel Combustion	10,023	5,858	4,092	3,807	3,567	3,579	3,522
Oil and Gas Activities	139	321	545	622	622	622	622
Industrial Processes and Product Use	592	572	472	452	452	452	452
Forest Fires	64	212	121	373	400	149	149
Waste Combustion	82	128	77	73	73	73	73
Agricultural Burning	6	6	7	7	8	8	8
Waste	+	2	1	1	1	1	1
CO	**132,271**	**74,276**	**50,984**	**58,845**	**58,002**	**47,240**	**45,424**
Mobile Fossil Fuel Combustion	119,360	58,615	39,475	38,305	36,491	34,676	32,861
Forest Fires	2,300	7,550	4,323	13,291	14,262	5,310	5,310
Stationary Fossil Fuel Combustion	5,000	4,648	4,103	4,170	4,170	4,170	4,169
Industrial Processes and Product Use	4,129	1,557	1,280	1,229	1,229	1,229	1,229
Waste Combustion	978	1,403	1,084	1,003	1,003	1,003	1,003
Oil and Gas Activities	302	318	487	610	610	610	610
Agricultural Burning	201	177	229	232	233	237	238
Waste	1	7	5	5	5	5	5
NMVOCs	**20,930**	**13,154**	**11,641**	**11,726**	**11,416**	**11,107**	**10,796**
Industrial Processes and Product Use	7,638	5,849	4,133	3,929	3,929	3,929	3,928
Mobile Fossil Fuel Combustion	10,932	5,724	4,591	4,562	4,252	3,942	3,632
Oil and Gas Activities	554	510	2,205	2,517	2,517	2,517	2,517
Stationary Fossil Fuel Combustion	912	716	576	599	599	599	599
Waste Combustion	222	241	92	81	81	81	81
Waste	673	114	44	38	38	38	39
Agricultural Burning	NA	NA	NA	NA	NA	NA	NA
SO_2	**20,935**	**13,196**	**7,014**	**5,877**	**4,711**	**4,625**	**4,528**
Stationary Fossil Fuel Combustion	18,407	11,541	6,120	5,008	3,859	3,790	3,710
Industrial Processes and Product Use	1,307	831	617	604	604	604	604
Mobile Fossil Fuel Combustion	390	180	117	108	108	108	108
Oil and Gas Activities	793	619	144	142	125	108	90
Waste Combustion	38	25	16	15	15	15	15
Waste	+	1	+	+	+	+	+
Agricultural Burning	NA	NA	NA	NA	NA	NA	NA

Source: (EPA 2015) except for estimates from Field Burning of Agricultural Residues.
NA (Not Available)
Note: Totals may not sum due to independent rounding.
+ Does not exceed 0.5 kt.

Box 2-3: Sources and Effects of Sulfur Dioxide

Sulfur dioxide (SO_2) emitted into the atmosphere through natural and anthropogenic processes affects the earth's radiative budget through its photochemical transformation into sulfate aerosols that can (1) scatter radiation from the sun back to space, thereby reducing the radiation reaching the earth's surface; (2) affect cloud formation; and (3)

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[9] NO_x and CO emission estimates from Field Burning of Agricultural Residues were estimated separately, and therefore not taken from EPA (2015).

affect atmospheric chemical composition (e.g., by providing surfaces for heterogeneous chemical reactions). The indirect effect of sulfur-derived aerosols on radiative forcing can be considered in two parts. The first indirect effect is the aerosols’ tendency to decrease water droplet size and increase water droplet concentration in the atmosphere. The second indirect effect is the tendency of the reduction in cloud droplet size to affect precipitation by increasing cloud lifetime and thickness. Although still highly uncertain, the radiative forcing estimates from both the first and the second indirect effect are believed to be negative, as is the combined radiative forcing of the two (IPCC 2001). However, because SO_2 is short-lived and unevenly distributed in the atmosphere, its radiative forcing impacts are highly uncertain.

Sulfur dioxide is also a major contributor to the formation of regional haze, which can cause significant increases in acute and chronic respiratory diseases. Once SO_2 is emitted, it is chemically transformed in the atmosphere and returns to the earth as the primary source of acid rain. Because of these harmful effects, the United States has regulated SO_2 emissions in the Clean Air Act.

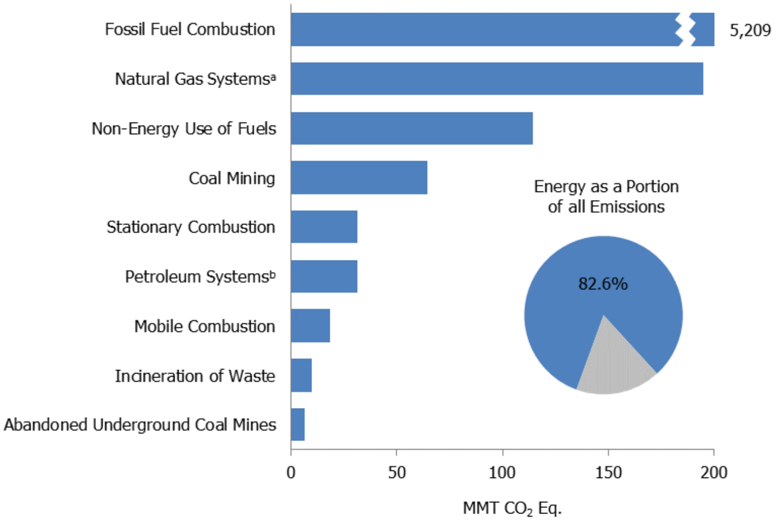
Electricity generation is the largest anthropogenic source of SO_2 emissions in the United States, accounting for 64.0 percent in 2014. Coal combustion contributes nearly all of those emissions (approximately 92 percent). Sulfur dioxide emissions have decreased in recent years, primarily as a result of electric power generators switching from high-sulfur to low-sulfur coal and installing flue gas desulfurization equipment.

3. Energy

Energy-related activities were the primary sources of U.S. anthropogenic greenhouse gas emissions, accounting for 82.6 percent of total greenhouse gas emissions on a carbon dioxide (CO_2) equivalent basis in 2014.[1] This included 97, 37, and 10 percent of the nation's CO_2, methane (CH_4), and nitrous oxide (N_2O) emissions, respectively. Energy-related CO_2 emissions alone constituted 78.2 percent of national emissions from all sources on a CO_2 equivalent basis, while the non-CO_2 emissions from energy-related activities represented a much smaller portion of total national emissions (4.4 percent collectively).

Emissions from fossil fuel combustion comprise the vast majority of energy-related emissions, with CO_2 being the primary gas emitted (see Figure 3-1). Globally, approximately 32,310 MMT of CO_2 were added to the atmosphere through the combustion of fossil fuels in 2012, of which the United States accounted for approximately 16 percent.[2] Due to their relative importance, fossil fuel combustion-related CO_2 emissions are considered separately, and in more detail than other energy-related emissions (see Figure 3-2). Fossil fuel combustion also emits CH_4 and N_2O. 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 fourth-largest source.

Figure 3-1: 2014 Energy Chapter Greenhouse Gas Sources (MMT CO_2 Eq.)



[a] The value in this figure for Natural Gas Systems is presented from the previous Inventory and does not reflect updates to emission estimates for this category. See Section 3.7 Natural Gas Systems in this chapter for more information.

[b] The value in this figure for Petroleum Systems is presented from the previous Inventory and does not reflect updates to emission estimates for this category. See Section 3.6 Petroleum Systems in this chapter for more information.

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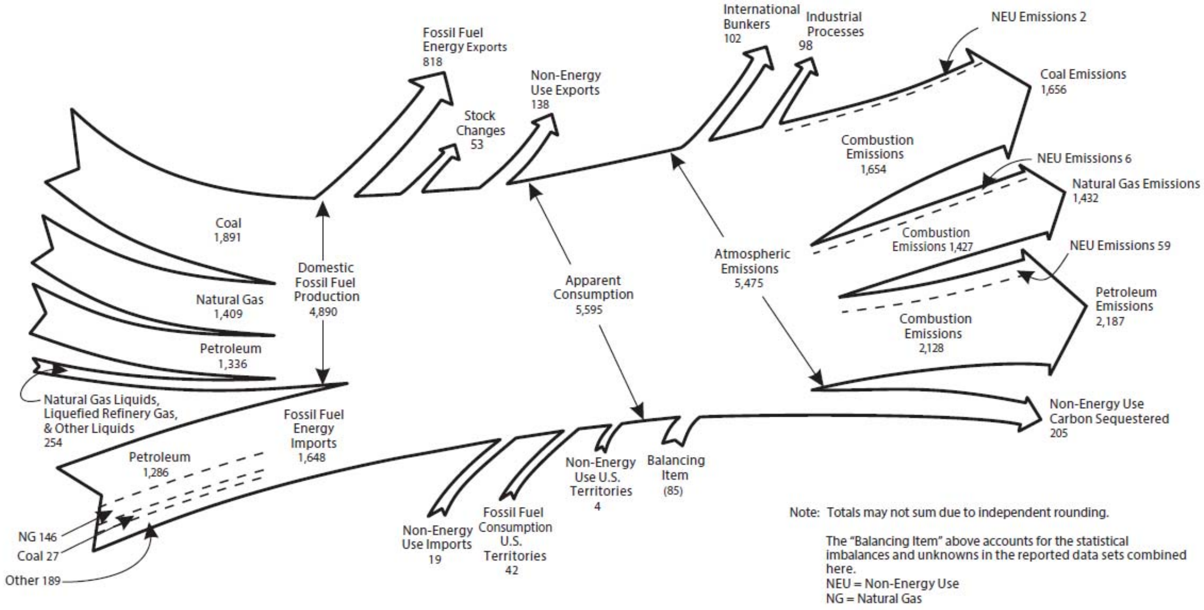
[1] Estimates are presented in units of million metric tons of carbon dioxide equivalent (MMT CO_2 Eq.), which weight each gas by its global warming potential, or GWP, value. See section on global warming potentials in the Executive Summary.

[2] Global CO_2 emissions from fossil fuel combustion were taken from Energy Information Administration *International Energy Statistics 2013* <http://tonto.eia.doe.gov/cfapps/ipdbproject/IEDIndex3.cfm> EIA (2013).

Figure 3-2: 2014 U.S. Fossil Carbon Flows (MMT CO_2 Eq.)



Note: Totals may not sum due to independent rounding.

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

NEU = Non-Energy Use

NG = Natural Gas

Energy-related activities other than fuel combustion, such as the production, transmission, storage, and distribution of fossil fuels, also emit greenhouse gases. These emissions consist primarily of fugitive CH_4 from natural gas systems, petroleum systems, and coal mining. Table 3-1 summarizes emissions from the Energy sector in units of million metric tons of CO_2 equivalents (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 5,679.8 MMT CO_2 Eq. in 2014,[3] an increase of 7.3 percent since 1990.

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

Gas/Source	1990	2005	2010	2011	2012	2013	2014
CO_2	**4,908.8**	**5,933.4**	**5,519.9**	**5,386.8**	**5,180.5**	**5,332.5**	**5,376.2**
Fossil Fuel Combustion	4,740.7	5,747.1	5,358.3	5,227.7	5,024.7	5,157.6	5,208.7
Electricity Generation	*1,820.8*	*2,400.9*	*2,258.4*	*2,157.7*	*2,022.2*	*2,038.1*	*2,039.3*
Transportation	*1,493.8*	*1,887.0*	*1,728.3*	*1,707.6*	*1,696.8*	*1,713.0*	*1,737.4*
Industrial	*842.5*	*828.0*	*775.5*	*773.3*	*782.9*	*812.2*	*814.2*
Residential	*338.3*	*357.8*	*334.6*	*326.8*	*282.5*	*329.7*	*345.1*
Commercial	*217.4*	*223.5*	*220.1*	*220.7*	*196.7*	*221.0*	*231.6*
U.S. Territories	*27.9*	*49.9*	*41.4*	*41.5*	*43.6*	*43.5*	*41.0*
Non-Energy Use of Fuels	118.1	138.9	114.1	108.5	105.6	121.7	114.3
Natural Gas Systems[b]	37.6	30.0	32.3	35.6	34.8	37.8	37.8
Incineration of Waste	8.0	12.5	11.0	10.5	10.4	9.4	9.4
Petroleum Systems[c]	4.4	4.9	4.2	4.5	5.1	6.0	6.0
Biomass-Wood[a]	*215.2*	*206.9*	*192.5*	*195.2*	*194.9*	*211.6*	*217.7*
International Bunker Fuels[a]	*103.5*	*113.1*	*117.0*	*111.7*	*105.8*	*99.8*	*103.2*
Biomass-Ethanol[a]	*4.2*	*22.9*	*72.6*	*72.9*	*72.8*	*74.7*	*76.1*
CH_4	**328.5**	**280.7**	**279.2**	**268.2**	**259.1**	**263.5**	**263.5**
Natural Gas Systems[b]	179.1	176.3	159.6	159.3	154.4	157.4	157.4
Coal Mining	96.5	64.1	82.3	71.2	66.5	64.6	64.6
Petroleum Systems[c]	31.5	23.5	21.3	22.0	23.3	25.2	25.2
Stationary Combustion	8.5	7.4	7.1	7.1	6.6	8.0	8.1

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[3] Following the revised reporting requirements under the UNFCCC, this Inventory report presents CO_2 equivalent values based on the *IPCC Fourth Assessment Report* (AR4) GWP values. See the Introduction chapter for more information.

Abandoned Underground Coal Mines	7.2	6.6	6.6	6.4	6.2	6.2	6.2
Mobile Combustion	5.6	2.7	2.3	2.2	2.2	2.1	2.0
Incineration of Waste	+	+	+	+	+	+	+
International Bunker Fuels[a]	*0.2*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*
N_2O	**53.6**	**55.0**	**46.1**	**44.0**	**41.7**	**41.4**	**40.0**
Stationary Combustion	11.9	20.2	22.2	21.3	21.4	22.9	23.4
Mobile Combustion	41.2	34.4	23.6	22.4	20.0	18.2	16.3
Incineration of Waste	0.5	0.4	0.3	0.3	0.3	0.3	0.3
International Bunker Fuels[a]	*0.9*	*1.0*	*1.0*	*1.0*	*0.9*	*0.9*	*0.9*
Total	**5,290.9**	**6,269.0**	**5,845.2**	**5,699.0**	**5,481.3**	**5,637.4**	**5,679.8**

+ Does not exceed 0.05 MMT CO_2 Eq.

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

[b] The values in this table for Natural Gas Systems are presented from the previous Inventory and do not reflect updates to emission estimates for this category. See Section 3.7 Natural Gas Systems in this chapter for more information. Gray highlighting was added on 2/24 for clarification.

[c] The values in this table for Petroleum Systems are presented from the previous Inventory and do not reflect updates to emission estimates for this category. See Section 3.6 Petroleum Systems in this chapter for more information. Gray highlighting was added on 2/24 for clarification.

Note: Totals may not sum due to independent rounding. Gray highlight added 2/24 for clarification.

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

Gas/Source	1990	2005	2010	2011	2012	2013	2014
CO_2	**4,908,847**	**5,933,371**	**5,519,868**	**5,386,773**	**5,180,488**	**5,332,495**	**5,376,218**
Fossil Fuel Combustion	4,740,671	5,747,142	5,358,292	5,227,690	5,024,685	5,157,583	5,208,654
Non-Energy Use of Fuels	118,114	138,876	114,063	108,515	105,617	121,682	114,333
Natural Gas Systems[b]	37,645	29,995	32,334	35,551	34,764	37,808	37,808
Incineration of Waste	7,972	12,454	11,026	10,550	10,362	9,421	9,421
Petroleum Systems[c]	4,445	4,904	4,153	4,467	5,060	6,001	6,001
Biomass –Wood[a]	*215,186*	*206,901*	*192,462*	*195,182*	*194,903*	*211,581*	*217,654*
International Bunker Fuels[a]	*103,463*	*113,139*	*116,992*	*111,660*	*105,805*	*99,763*	*103,201*
Biomass – Ethanol[a]	*4,227*	*22,943*	*72,647*	*72,881*	*72,827*	*74,743*	*76,075*
CH_4	**13,139**	**11,226**	**11,166**	**10,728**	**10,365**	**10,541**	**10,542**
Natural Gas Systems[b]	7,165	7,053	6,382	6,371	6,176	6,295	6,295
Coal Mining	3,860	2,565	3,293	2,849	2,658	2,584	2,584
Petroleum Systems[c]	1,261	939	854	878	931	1,009	1,009
Stationary Combustion	339	295	282	283	264	320	323
Abandoned Underground Coal Mines	288	264	263	257	249	249	249
Mobile Combustion	226	110	91	90	86	84	82
Incineration of Waste	+	+	+	+	+	+	+
International Bunker Fuels[a]	*7*	*5*	*6*	*5*	*4*	*3*	*3*
N_2O	**180**	**185**	**155**	**148**	**140**	**139**	**134**
Mobile Combustion	40	68	74	71	72	77	79
Stationary Combustion	138	115	79	75	67	61	55
Incineration of Waste	2	1	1	1	1	1	1
International Bunker Fuels[a]	*3*	*3*	*3*	*3*	*3*	*3*	*3*

+ Does not exceed 0.5 kt

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

[b] The values in this table for Natural Gas Systems are presented from the previous Inventory and do not reflect updates to emission estimates for this category. See Section 3.7, Natural Gas Systems in this chapter for more information. Gray highlighting was added on 2/24 for clarification.

[c] The values in this table for Petroleum Systems are presented from the previous Inventory and do not reflect updates to emission estimates for this category. See Section 3.6, Petroleum Systems in this chapter for more information. Gray highlighting was added on 2/24 for clarification.

Note: Totals may not sum due to independent rounding.

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

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

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

On October 30, 2009, the U.S. Environmental Protection Agency (EPA) published a rule for the mandatory reporting of greenhouse gases (GHG) from large GHG emissions sources in the United States. Implementation of 40 CFR Part 98 is referred to as the Greenhouse Gas Reporting Program (GHGRP). 40 CFR Part 98 applies to direct greenhouse gas emitters, fossil fuel suppliers, industrial gas suppliers, and facilities that inject CO_2 underground for sequestration or other reasons. Reporting is at the facility level, except for certain suppliers of fossil fuels and industrial greenhouse gases. 40 CFR part 98 requires reporting by 41 industrial categories. Data reporting by affected facilities included the reporting of emissions from fuel combustion at that affected facility. In general, the threshold for reporting is 25,000 metric tons or more of CO_2 Eq. per year.

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

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

3.1 Fossil Fuel Combustion (IPCC Source Category 1A)

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

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

Gas	1990	2005	2010	2011	2012	2013	2014
CO_2	4,740.7	5,747.1	5,358.3	5,227.7	5,024.7	5,157.6	5,208.7
CH_4	14.1	10.1	9.3	9.3	8.8	10.1	10.1
N_2O	53.1	54.6	45.8	43.8	41.4	41.2	39.8
Total	**4,807.9**	**5,811.9**	**5,413.5**	**5,280.8**	**5,074.9**	**5,208.8**	**5,258.5**

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

Gas	1990	2005	2010	2011	2012	2013	2014
CO_2	4,740,671	5,747,142	5,358,292	5,227,690	5,024,685	5,157,583	5,208,654
CH_4	565	405	374	373	351	403	405
N_2O	178	183	154	147	139	138	133

Note: Totals may not sum due to independent rounding

CO_2 from Fossil Fuel Combustion

CO_2 is the primary gas emitted from fossil fuel combustion and represents the largest share of U.S. total greenhouse gas emissions. CO_2 emissions from fossil fuel combustion are presented in Table 3-5. In 2014, CO_2 emissions from fossil fuel combustion increased by 1.0 percent relative to the previous year. The increase in CO_2 emissions from fossil fuel combustion was a result of multiple factors, including: (1) colder winter conditions in the first quarter of 2014 resulting in an increased demand for heating fuel in the residential and commercial sectors; (2) an increase in transportation emissions resulting from an increase in vehicle miles traveled (VMT) and fuel use across on-road transportation modes; and (3) an increase in industrial production across multiple sectors resulting in slight increases in industrial sector emissions.[4] In 2014, CO_2 emissions from fossil fuel combustion were 5,208.7 MMT CO_2 Eq., or 9.9 percent above emissions in 1990 (see Table 3-5).[5]

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

Fuel/Sector	1990	2005	2010	2011	2012	2013	2014
Coal	**1,718.4**	**2,112.3**	**1,927.7**	**1,813.9**	**1,592.8**	**1,654.4**	**1,653.7**
Residential	3.0	0.8	0.0	0.0	0.0	0.0	0.0
Commercial	12.0	9.3	6.6	5.8	4.1	3.9	4.5
Industrial	155.3	115.3	90.1	82.0	74.1	75.7	75.3
Transportation	NE	NE	NE	NE	NE	NE	NE
Electricity Generation	1,547.6	1,983.8	1,827.6	1,722.7	1,511.2	1,571.3	1,570.4
U.S. Territories	0.6	3.0	3.4	3.4	3.4	3.4	3.4
Natural Gas	**1,000.3**	**1,166.7**	**1,272.1**	**1,291.5**	**1,352.6**	**1,391.2**	**1,426.6**
Residential	238.0	262.2	258.6	254.7	224.8	266.2	277.6
Commercial	142.1	162.9	167.7	170.5	156.9	179.1	189.2
Industrial	408.9	388.5	407.2	417.3	434.8	451.9	466.0
Transportation	36.0	33.1	38.1	38.9	41.3	47.0	47.6
Electricity Generation	175.3	318.8	399.0	408.8	492.2	444.0	443.2
U.S. Territories	NO	1.3	1.5	1.4	2.6	3.0	3.0
Petroleum	**2,021.5**	**2,467.8**	**2,158.2**	**2,121.9**	**2,078.9**	**2,111.6**	**2,128.0**
Residential	97.4	94.9	76.0	72.2	57.7	63.4	67.6

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

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

Commercial	63.3	51.3	45.8	44.5	35.7	38.0	37.9
Industrial	278.3	324.2	278.2	274.0	274.1	284.6	272.9
Transportation	1,457.7	1,854.0	1,690.2	1,668.8	1,655.4	1,666.0	1,689.8
Electricity Generation	97.5	97.9	31.4	25.8	18.3	22.4	25.3
U.S. Territories	27.2	45.6	36.5	36.7	37.6	37.1	34.6
Geothermal[a]	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**
Total	**4,740.7**	**5,747.1**	**5,358.3**	**5,227.7**	**5,024.7**	**5,157.6**	**5,208.7**

+ Does not exceed 0.05 MMT CO_2 Eq.

NE (Not estimated)

NO (Not occurring)

[a] Although not technically a fossil fuel, geothermal energy-related CO_2 emissions are included for reporting purposes.

Note: Totals may not sum due to independent rounding.

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

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

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

Table 3-6: Annual Change in CO_2 Emissions and Total 2014 Emissions from Fossil Fuel Combustion for Selected Fuels and Sectors (MMT CO_2 Eq. and Percent)

Sector	Fuel Type	2010 to 2011		2011 to 2012		2012 to 2013		2013 to 2014		Total 2014
Electricity Generation	Coal	-104.9	-5.7%	-211.5	-12.3%	60.1	4.0%	-0.9	-0.1%	1,570.4
Electricity Generation	Natural Gas	9.8	2.5%	83.5	20.4%	-48.3	-9.8%	-0.8	-0.2%	443.2
Electricity Generation	Petroleum	-5.6	-17.8%	-7.5	-29.0%	4.1	22.3%	2.9	12.8%	25.3
Transportation[a]	Petroleum	-21.4	-1.3%	-13.3	-0.8%	10.6	0.6%	23.8	1.4%	1,689.8
Residential	Natural Gas	-3.9	-1.5%	-29.8	-11.7%	41.4	18.4%	11.4	4.3%	277.6
Commercial	Natural Gas	2.7	1.6%	-13.6	-8.0%	22.3	14.2%	10.0	5.6%	189.2
Industrial	Coal	-8.1	-9.0%	-7.9	-9.7%	1.7	2.3%	-0.4	-0.6%	75.3
Industrial	Natural Gas	10.1	2.5%	17.5	4.2%	17.1	3.9%	14.2	3.1%	466.0
All Sectors[b]	**All Fuels[b]**	**-130.6**	**-2.4%**	**-203.0**	**-3.9%**	**132.9**	**2.6%**	**51.1**	**1.0%**	**5,208.7**

[a] Excludes emissions from International Bunker Fuels.

[b] Includes fuels and sectors not shown in table.

In the United States, 82 percent of the energy consumed in 2014 was produced through the combustion of fossil fuels such as coal, natural gas, and petroleum (see Figure 3-3 and Figure 3-4). The remaining portion was supplied by nuclear electric power (8 percent) and by a variety of renewable energy sources (10 percent), primarily

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

hydroelectric power, wind energy and biofuels (EIA 2015a).[7] Specifically, petroleum supplied the largest share of domestic energy demands, accounting for 35 percent of total U.S. energy consumption in 2014. Natural gas and coal followed in order of energy demand importance, accounting for approximately 28 percent and 19 percent of total U.S. energy consumption, respectively. Petroleum was consumed primarily in the transportation end-use sector and the vast majority of coal was used in electricity generation. Natural gas was broadly consumed in all end-use sectors except transportation (see Figure 3-5) (EIA 2015a).

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

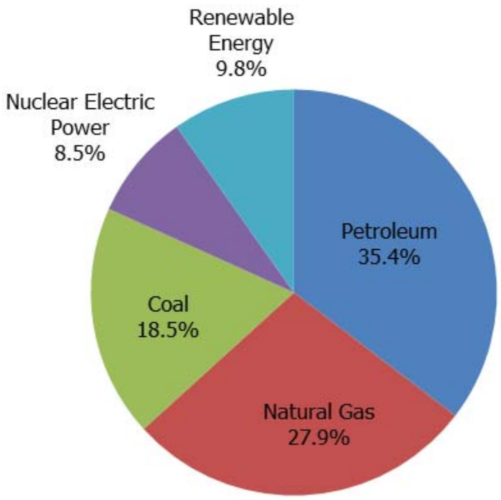
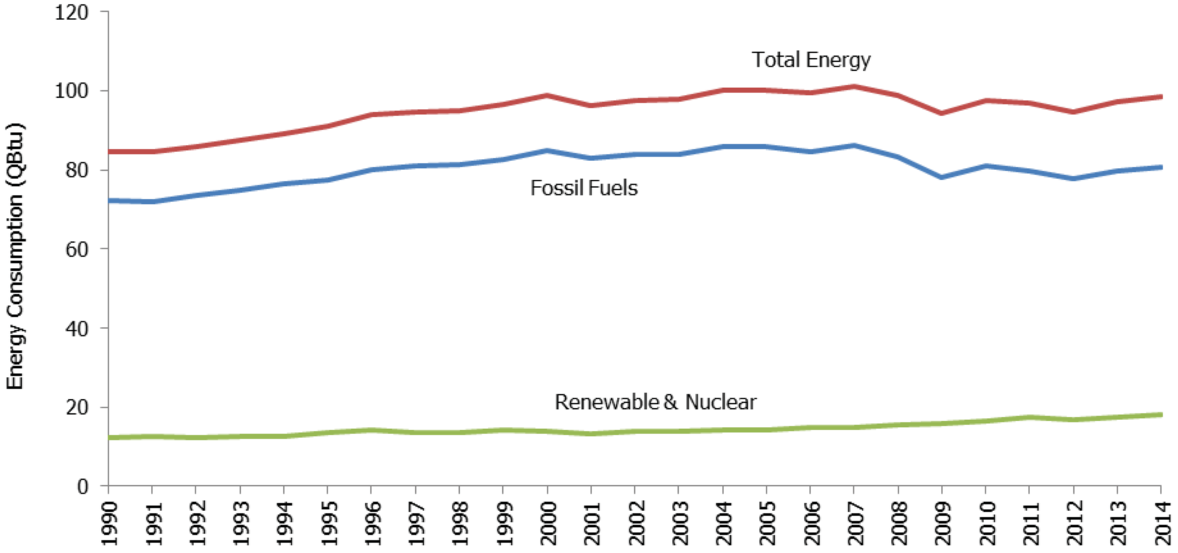


Figure 3-4: U.S. Energy Consumption (Quadrillion Btu)



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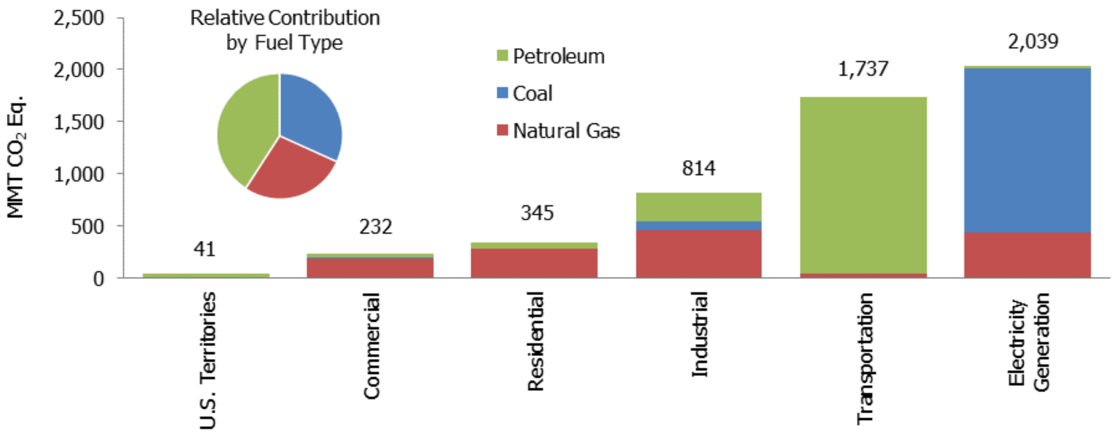
[7] Renewable energy, as defined in EIA's energy statistics, includes the following energy sources: hydroelectric power, geothermal energy, biofuels, solar energy, and wind energy.

Figure 3-5: 2014 CO_2 Emissions from Fossil Fuel Combustion by Sector and Fuel Type (MMT CO_2 Eq.)



Fossil fuels are generally combusted for the purpose of producing energy for useful heat and work. During the combustion process, the C stored in the fuels is oxidized and emitted as CO_2 and smaller amounts of other gases, including CH_4, CO, and NMVOCs.[8] 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, it is assumed all of the C in fossil fuels used to produce energy is eventually converted to atmospheric CO_2.

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

In 2014, weather conditions, and a very cold first quarter of the year in particular, caused a significant increase in energy demand for heating fuels and is reflected in the increased residential emissions during the early part of the year (EIA 2015a). The United States in 2014 also experienced a cooler winter overall compared to 2013, as heating degree days increased (1.9 percent). Cooling degree days decreased by 0.6 percent and despite this decrease in cooling degree days, electricity demand to cool homes still increased slightly. Colder winter conditions compared to 2013 resulted in a significant increase in the amount of energy required for heating, and heating degree days in the United States were 0.6 percent above normal for the first time since 2003 (see Figure 3-6). Summer conditions were slightly cooler in 2014 compared to 2013, and summer temperatures were warmer than normal, with cooling degree days 6.7 percent above normal (see Figure 3-7) (EIA 2015a).[9]

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

[9] Degree days are relative measurements of outdoor air temperature. Heating degree days are deviations of the mean daily temperature below 65° F, while cooling degree days are deviations of the mean daily temperature above 65° F. Heating degree days have a considerably greater effect on energy demand and related emissions than do cooling degree days. Excludes Alaska and Hawaii. Normals are based on data from 1971 through 2000. The variation in these normals during this time period was ±10 percent and ±14 percent for heating and cooling degree days, respectively (99 percent confidence interval).

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

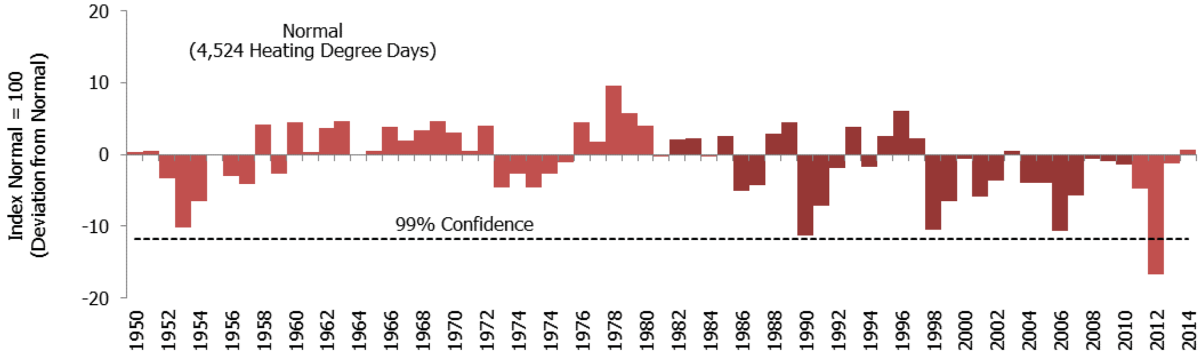
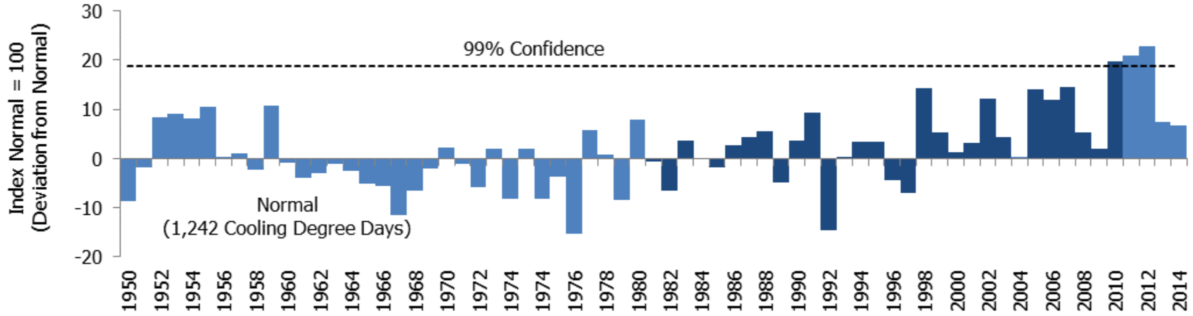


Figure 3-7: Annual Deviations from Normal Cooling Degree Days for the United States (1950–2014)



Although no new U.S. nuclear power plants have been constructed in recent years, the utilization (i.e., capacity factors)[10] of existing plants in 2014 remained high at 92 percent. Electricity output by hydroelectric power plants decreased in 2014 by approximately 3 percent. In recent years, the wind power sector has been showing strong growth, such that, on the margin, it is becoming a relatively important electricity source. Electricity generated by nuclear plants in 2014 provided more than 3 times as much of the energy generated in the United States from hydroelectric plants (EIA 2015a). Nuclear, hydroelectric, and wind power capacity factors since 1990 are shown in Figure 3-8.

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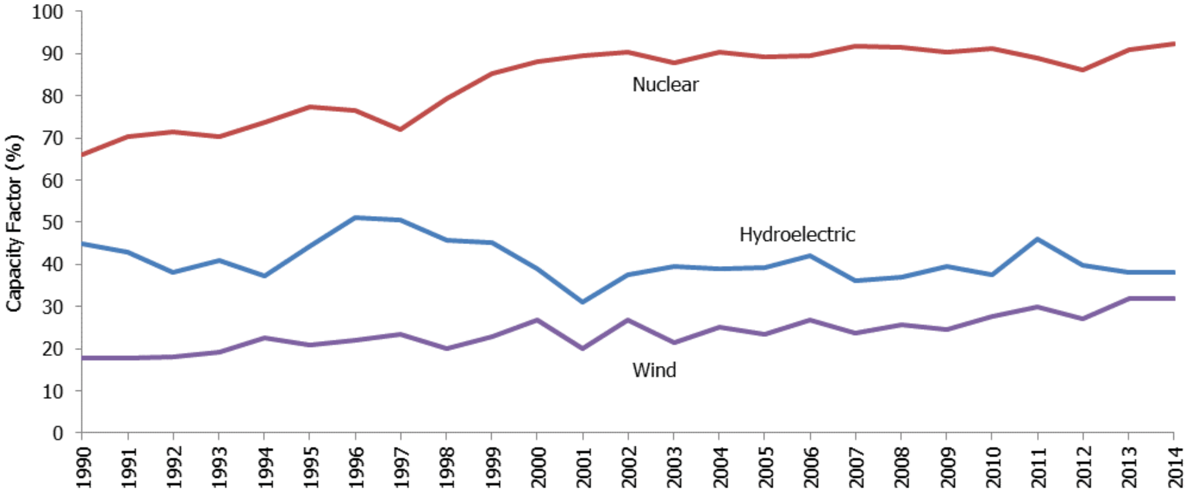
[10] The capacity factor equals generation divided by net summer capacity. Summer capacity is defined as "The maximum output that generating equipment can supply to system load, as demonstrated by a multi-hour test, at the time of summer peak demand (period of June 1 through September 30)." Data for both the generation and net summer capacity are from EIA (2015).

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



Fossil Fuel Combustion Emissions by Sector

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

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

End-Use Sector	1990	2005	2010	2011	2012	2013	2014
Electricity Generation	**1,828.5**	**2,417.4**	**2,277.4**	**2,175.8**	**2,040.4**	**2,057.7**	**2,059.4**
CO_2	1,820.8	2,400.9	2,258.4	2,157.7	2,022.2	2,038.1	2,039.3
CH_4	0.3	0.5	0.5	0.4	0.4	0.4	0.4
N_2O	7.4	16.0	18.5	17.6	17.8	19.1	19.6
Transportation	**1,540.6**	**1,924.1**	**1,754.2**	**1,732.3**	**1,718.9**	**1,733.3**	**1,755.8**
CO_2	1,493.8	1,887.0	1,728.3	1,707.6	1,696.8	1,713.0	1,737.4
CH_4	5.6	2.7	2.3	2.2	2.2	2.1	2.0
N_2O	41.2	34.4	23.6	22.4	20.0	18.2	16.3
Industrial	**847.4**	**832.6**	**779.5**	**777.2**	**786.9**	**816.2**	**818.1**
CO_2	842.5	828.0	775.5	773.3	782.9	812.2	814.2
CH_4	1.8	1.7	1.5	1.5	1.5	1.5	1.5
N_2O	3.1	2.9	2.5	2.4	2.4	2.4	2.4
Residential	**344.6**	**362.8**	**339.4**	**331.7**	**287.0**	**335.6**	**351.1**
CO_2	338.3	357.8	334.6	326.8	282.5	329.7	345.1
CH_4	5.2	4.1	4.0	4.0	3.7	5.0	5.0
N_2O	1.0	0.9	0.8	0.8	0.7	1.0	1.0
Commercial	**218.8**	**224.9**	**221.5**	**222.1**	**197.9**	**222.4**	**233.0**
CO_2	217.4	223.5	220.1	220.7	196.7	221.0	231.6
CH_4	1.0	1.1	1.1	1.0	0.9	1.0	1.1
N_2O	0.4	0.3	0.3	0.3	0.3	0.3	0.3
U.S. Territories[a]	**28.0**	**50.1**	**41.6**	**41.7**	**43.7**	**43.7**	**41.2**

Total	**4,807.9**		**5,811.9**		**5,413.5**	**5,280.8**	**5,074.9**	**5,208.8**	**5,258.5**

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

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

Other than CO_2, gases emitted from stationary combustion include the greenhouse gases CH_4 and N_2O and the indirect greenhouse gases NO_x, CO, and NMVOCs.[11] Methane and N_2O emissions from stationary combustion sources depend upon fuel characteristics, size and vintage, along with combustion technology, pollution control equipment, ambient environmental conditions, and operation and maintenance practices. N_2O emissions from stationary combustion are closely related to air-fuel mixes and combustion temperatures, as well as the characteristics of any pollution control equipment that is employed. Methane emissions from stationary combustion are primarily a function of the CH_4 content of the fuel and combustion efficiency.

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

An alternative method of presenting combustion emissions is to allocate emissions associated with electricity generation to the sectors in which it is used. Four end-use sectors were defined: industrial, transportation, residential, and commercial. In the table below, electricity generation emissions have been distributed to each end-use sector based upon the sector's share of national electricity consumption, with the exception of CH_4 and N_2O from transportation.[12] Emissions from U.S. Territories are also calculated separately due to a lack of end-use-specific consumption data. This method assumes that emissions from combustion sources are distributed across the four end-use sectors based on the ratio of electricity consumption in that sector. The results of this alternative method are presented in Table 3-8.

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

End-Use Sector	1990		2005		2010	2011	2012	2013	2014
Transportation	**1,543.7**		**1,928.9**		**1,758.7**	**1,736.6**	**1,722.8**	**1,737.4**	**1,759.9**
CO_2	1,496.8		1,891.8		1,732.7	1,711.9	1,700.6	1,717.0	1,741.5
CH_4	5.6		2.7		2.3	2.2	2.2	2.1	2.0
N_2O	41.2		34.4		23.7	22.5	20.1	18.2	16.4
Industrial	**1,537.0**		**1,574.2**		**1,425.8**	**1,407.1**	**1,385.0**	**1,416.6**	**1,417.5**
CO_2	1,529.2		1,564.6		1,416.5	1,398.0	1,375.7	1,407.0	1,407.8
CH_4	2.0		1.9		1.6	1.6	1.6	1.6	1.6
N_2O	5.9		7.8		7.7	7.5	7.7	8.0	8.1
Residential	**940.2**		**1,224.9**		**1,186.5**	**1,129.0**	**1,018.8**	**1,077.5**	**1,093.6**
CO_2	931.4		1,214.1		1,174.6	1,117.5	1,007.8	1,064.6	1,080.4
CH_4	5.4		4.2		4.2	4.2	3.9	5.1	5.2
N_2O	3.4		6.6		7.7	7.3	7.1	7.9	8.1

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

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

Commercial	**759.1**	**1,033.7**	**1,000.9**	**966.3**	**904.5**	**933.6**	**946.4**
CO_2	755.4	1,026.8	993.0	958.8	897.0	925.5	938.1
CH_4	1.1	1.2	1.2	1.2	1.1	1.2	1.2
N_2O	2.5	5.7	6.6	6.3	6.4	6.9	7.1
U.S. Territories[a]	**28.0**	**50.1**	**41.6**	**41.7**	**43.7**	**43.7**	**41.2**
Total	**4,807.9**	**5,811.9**	**5,413.5**	**5,280.8**	**5,074.9**	**5,208.8**	**5,258.5**

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

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

Stationary Combustion

The direct combustion of fuels by stationary sources in the electricity generation, industrial, commercial, and residential sectors represent the greatest share of U.S. greenhouse gas emissions. Table 3-9 presents CO_2 emissions from fossil fuel combustion by stationary sources. The CO_2 emitted is closely linked to the type of fuel being combusted in each sector (see Methodology section of CO_2 from Fossil Fuel Combustion). Other than CO_2, gases emitted from stationary combustion include the greenhouse gases CH_4 and N_2O. Table 3-10 and Table 3-11 present CH_4 and N_2O emissions from the combustion of fuels in stationary sources.[13] Methane and N_2O emissions from stationary combustion sources depend upon fuel characteristics, combustion technology, pollution control equipment, ambient environmental conditions, and operation and maintenance practices. N_2O emissions from stationary combustion are closely related to air-fuel mixes and combustion temperatures, as well as the characteristics of any pollution control equipment that is employed. Methane emissions from stationary combustion are primarily a function of the CH_4 content of the fuel and combustion efficiency. The CH_4 and N_2O emission estimation methodology was revised in 2010 to utilize the facility-specific technology and fuel use data reported to EPA's Acid Rain Program (see Methodology section for CH_4 and N_2O from stationary combustion). Please refer to Table 3-7 for the corresponding presentation of all direct emission sources of fuel combustion.

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

Sector/Fuel Type	1990	2005	2010	2011	2012	2013	2014
Electricity Generation	**1,820.8**	**2,400.9**	**2,258.4**	**2,157.7**	**2,022.2**	**2,038.1**	**2,039.3**
Coal	1,547.6	1,983.8	1,827.6	1,722.7	1,511.2	1,571.3	1,570.4
Natural Gas	175.3	318.8	399.0	408.8	492.2	444.0	443.2
Fuel Oil	97.5	97.9	31.4	25.8	18.3	22.4	25.3
Geothermal	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Industrial	**842.5**	**828.0**	**775.5**	**773.3**	**782.9**	**812.2**	**814.2**
Coal	155.3	115.3	90.1	82.0	74.1	75.7	75.3
Natural Gas	408.9	388.5	407.2	417.3	434.8	451.9	466.0
Fuel Oil	278.3	324.2	278.2	274.0	274.1	284.6	272.9
Commercial	**217.4**	**223.5**	**220.1**	**220.7**	**196.7**	**221.0**	**231.6**
Coal	12.0	9.3	6.6	5.8	4.1	3.9	4.5
Natural Gas	142.1	162.9	167.7	170.5	156.9	179.1	189.2
Fuel Oil	63.3	51.3	45.8	44.5	35.7	38.0	37.9
Residential	**338.3**	**357.8**	**334.6**	**326.8**	**282.5**	**329.7**	**345.1**
Coal	3.0	0.8	0.0	0.0	0.0	0.0	0.0
Natural Gas	238.0	262.2	258.6	254.7	224.8	266.2	277.6
Fuel Oil	97.4	94.9	76.0	72.2	57.7	63.4	67.6
U.S. Territories	**27.9**	**49.9**	**41.4**	**41.5**	**43.6**	**43.5**	**41.0**

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[13] Since emission estimates for U.S. Territories cannot be disaggregated by gas in Table 3-10 and Table 3-11, the values for CH_4 and N_2O exclude U.S. territory emissions.

Coal	0.6	3.0	3.4	3.4	3.4	3.4	3.4
Natural Gas	NO	1.3	1.5	1.4	2.6	3.0	3.0
Fuel Oil	27.2	45.6	36.5	36.7	37.6	37.1	34.6
Total	**3,246.9**	**3,860.1**	**3,630.0**	**3,520.1**	**3,327.9**	**3,444.6**	**3,471.2**

+ Does not exceed 0.05 MMT CO_2 Eq.
NO: Not occurring

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

Sector/Fuel Type	1990	2005	2010	2011	2012	2013	2014
Electric Power	**0.3**	**0.5**	**0.5**	**0.4**	**0.4**	**0.4**	**0.4**
Coal	0.3	0.3	0.3	0.3	0.2	0.2	0.2
Fuel Oil	+	+	+	+	+	+	+
Natural gas	0.1	0.1	0.2	0.2	0.2	0.2	0.2
Wood	+	+	+	+	+	+	+
Industrial	**1.8**	**1.7**	**1.5**	**1.5**	**1.5**	**1.5**	**1.5**
Coal	0.4	0.3	0.2	0.2	0.2	0.2	0.2
Fuel Oil	0.2	0.2	0.2	0.1	0.1	0.2	0.1
Natural gas	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Wood	1.0	1.0	0.9	0.9	1.0	0.9	0.9
Commercial/Institutional	**1.0**	**1.1**	**1.1**	**1.0**	**0.9**	**1.0**	**1.1**
Coal	+	+	+	+	+	+	+
Fuel Oil	0.2	0.2	0.2	0.2	0.1	0.1	0.1
Natural gas	0.3	0.4	0.4	0.4	0.4	0.4	0.4
Wood	0.5	0.5	0.5	0.5	0.4	0.5	0.5
Residential	**5.2**	**4.1**	**4.0**	**4.0**	**3.7**	**5.0**	**5.0**
Coal	0.2	0.1	0.0	0.0	0.0	0.0	0.0
Fuel Oil	0.3	0.3	0.3	0.3	0.2	0.2	0.2
Natural Gas	0.5	0.6	0.6	0.6	0.5	0.6	0.6
Wood	4.1	3.1	3.1	3.2	3.0	4.1	4.1
U.S. Territories	**+**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Coal	+	+	+	+	+	+	+
Fuel Oil	+	0.1	0.1	0.1	0.1	0.1	0.1
Natural Gas	0.0	+	+	+	+	+	+
Wood	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**8.5**	**7.4**	**7.1**	**7.1**	**6.6**	**8.0**	**8.1**

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

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

Sector/Fuel Type	1990	2005	2010	2011	2012	2013	2014
Electricity Generation	**7.4**	**16.0**	**18.5**	**17.6**	**17.8**	**19.1**	**19.6**
Coal	6.3	11.6	12.5	11.5	10.2	12.1	12.4
Fuel Oil	0.1	0.1	+	+	+	+	+
Natural Gas	1.0	4.3	5.9	6.1	7.5	7.0	7.2
Wood	+	+	+	+	+	+	+
Industrial	**3.1**	**2.9**	**2.5**	**2.4**	**2.4**	**2.4**	**2.4**
Coal	0.7	0.5	0.4	0.4	0.4	0.4	0.4
Fuel Oil	0.5	0.5	0.4	0.3	0.3	0.4	0.3
Natural Gas	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Wood	1.6	1.6	1.4	1.5	1.5	1.5	1.5
Commercial/Institutional	**0.4**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**
Coal	0.1	+	0.0	0.0	0.0	0.0	0.0
Fuel Oil	0.2	0.1	0.1	0.1	0.1	0.1	0.1
Natural Gas	0.1	0.1	0.1	0.1	0.1	0.1	0.1

Wood	0.1		0.1		0.1	0.1	0.1	0.1	0.1
Residential	**1.0**		**0.9**		**0.8**	**0.8**	**0.7**	**1.0**	**1.0**
Coal	+		+		0.0	0.0	0.0	0.0	0.0
Fuel Oil	0.2		0.2		0.2	0.2	0.2	0.2	0.2
Natural Gas	0.1		0.1		0.1	0.1	0.1	0.1	0.1
Wood	0.7		0.5		0.5	0.5	0.5	0.7	0.7
U.S. Territories	**0.1**		**0.1**		**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Coal	+		+		+	+	+	+	+
Fuel Oil	0.1		0.1		0.1	0.1	0.1	0.1	0.1
Natural Gas	0.0		+		+	+	+	+	+
Wood	0.0		0.0		0.0	0.0	0.0	0.0	0.0
Total	**11.9**		**20.2**		**22.2**	**21.3**	**21.4**	**22.9**	**23.4**

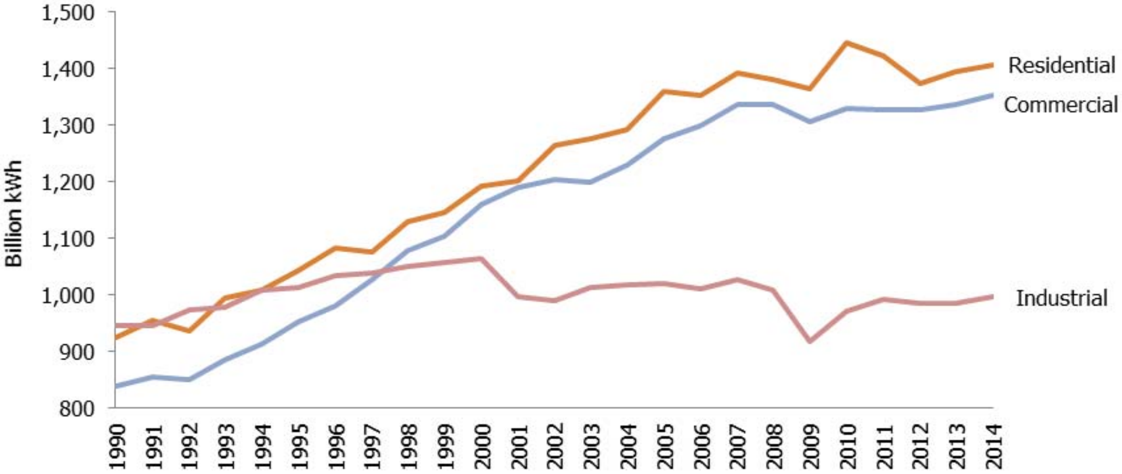
+ Does not exceed 0.05 MMT CO_2 Eq.

Note: Totals may not sum due to independent rounding.

Electricity Generation

The process of generating electricity is the single largest source of CO_2 emissions in the United States, representing 37 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 emissions from electricity generation, representing less than 0.1 percent and 1.0 percent, respectively. Electricity generation also accounted for the largest share of CO_2 emissions from fossil fuel combustion, approximately 39.2 percent in 2014. Methane and N_2O from electricity generation represented 4.2 and 49.3 percent of total methane and N_2O emissions from fossil fuel combustion in 2014, respectively. Electricity was consumed primarily in the residential, commercial, and industrial end-use sectors for lighting, heating, electric motors, appliances, electronics, and air conditioning (see Figure 3-9). Electricity generators, including those using low-CO_2 emitting technologies, relied on coal for approximately 39 percent of their total energy requirements in 2014. Recently an increase in the carbon intensity of fuels consumed to generate electricity has occurred due to an increase in coal consumption, and decreased natural gas consumption and other generation sources. Total U.S. electricity generators used natural gas for approximately 27 percent of their total energy requirements in 2014 (EIA 2015b).

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



The electric power industry includes all power producers, consisting of both regulated utilities and non-utilities (e.g. independent power producers, qualifying co-generators, and other small power producers). For the underlying energy data used in this chapter, the Energy Information Administration (EIA) places electric power generation into three functional categories: the electric power sector, the commercial sector, and the industrial sector. The electric power sector consists of electric utilities and independent power producers whose primary business is the production of electricity, while the other sectors consist of those producers that indicate their primary business is something other than the production of electricity.[14]

The industrial, residential, and commercial end-use sectors, as presented in Table 3-8, were reliant on electricity for meeting energy needs. The residential and commercial end-use sectors were especially reliant on electricity consumption for lighting, heating, air conditioning, and operating appliances. Electricity sales to the residential and commercial end-use sectors in 2014 increased approximately 0.9 percent and 1.1 percent, respectively. The trend in the residential and commercial sectors can largely be attributed to colder, more energy-intensive winter conditions compared to 2013. Electricity sales to the industrial sector in 2014 increased approximately 1.2 percent. Overall, in 2014, the amount of electricity generated (in kWh) increased approximately 1.1 percent relative to the previous year, while CO_2 emissions from the electric power sector increased by 0.1 percent. The increase in CO_2 emissions, despite the relatively larger increase in electricity generation was a result of a slight decrease in the consumption of coal and natural gas for electricity generation by 0.1 percent and 0.2 percent, respectively, in 2014, and an increase in the consumption of petroleum for electricity generation by 15.8 percent.

Industrial Sector

Industrial sector CO_2, CH_4, and N_2O, emissions accounted for 16, 15, and 6 percent of CO_2, CH_4, and N_2O, emissions from fossil fuel combustion, respectively. CO_2, CH_4, and N_2O emissions resulted from the direct consumption of fossil fuels for steam and process heat production.

The industrial sector, per the underlying energy consumption data from EIA, includes activities such as manufacturing, construction, mining, and agriculture. The largest of these activities in terms of energy consumption is manufacturing, of which six industries—Petroleum Refineries, Chemicals, Paper, Primary Metals, Food, and Nonmetallic Mineral Products—represent the vast majority of the energy use (EIA 2015a and EIA 2009b).

In theory, emissions from the industrial sector should be highly correlated with economic growth and industrial output, but heating of industrial buildings and agricultural energy consumption are also affected by weather conditions.[15] In addition, structural changes within the U.S. economy that lead to shifts in industrial output away from energy-intensive manufacturing products to less energy-intensive products (e.g., from steel to computer equipment) also have a significant effect on industrial emissions.

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

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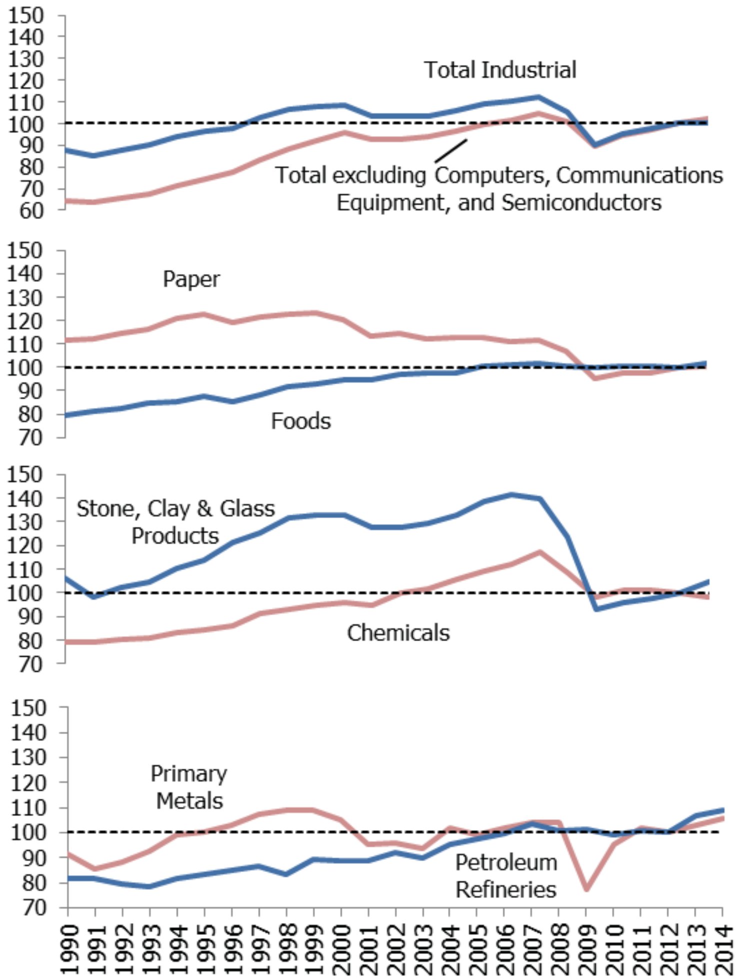
[14] Utilities primarily generate power for the U.S. electric grid for sale to retail customers. Nonutilities produce electricity for their own use, to sell to large consumers, or to sell on the wholesale electricity market (e.g., to utilities for distribution and resale to customers).

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

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

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



Despite the growth in industrial output (64 percent) and the overall U.S. economy (78 percent) from 1990 to 2014, CO_2 emissions from fossil fuel combustion in the industrial sector decreased by 3.4 percent over the same time series. A number of factors are believed to have caused this disparity between growth in industrial output and decrease in industrial emissions, including: (1) more rapid growth in output from less energy-intensive industries relative to traditional manufacturing industries, and (2) energy-intensive industries such as steel are employing new methods, such as electric arc furnaces, that are less carbon intensive than the older methods. In 2014, CO_2, CH_4, and N_2O emissions from fossil fuel combustion and electricity use within the industrial end-use sector totaled 1,417.5 MMT CO_2 Eq., or approximately 0.1 percent above 2013 emissions.

Residential and Commercial Sectors

Residential and commercial sector CO_2 emissions accounted for 7 and 4 percent of CO_2 emissions from fossil fuel combustion, CH_4 emissions accounted for 49 and 11 percent of CH_4 emissions from fossil fuel combustion, and N_2O emissions accounted for 2 and 1 percent of N_2O emissions from fossil fuel combustion, respectively. Emissions from these sectors were largely due to the direct consumption of natural gas and petroleum products, primarily for heating and cooking needs. Coal consumption was a minor component of energy use in both of these end-use sectors. In 2014, CO_2, CH_4, and N_2O emissions from fossil fuel combustion and electricity use within the residential and commercial end-use sectors were 1,093.6 MMT CO_2 Eq. and 946.4 MMT CO_2 Eq., respectively. Total CO_2, CH_4, and N_2O emissions from fossil fuel combustion and electricity use within the residential and commercial end-use sectors increased by 1.5 and 1.4 percent from 2013 to 2014, respectively.

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

In 2014, combustion emissions from natural gas consumption represent 80 and 82 percent of the direct fossil fuel CO_2 emissions from the residential and commercial sectors, respectively. Natural gas combustion CO_2 emissions from the residential and commercial sectors in 2014 increased by 4.3 percent and 5.6 percent from 2013 levels, respectively.

U.S. Territories

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

Transportation Sector and Mobile Combustion

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

Transportation End-Use Sector

The transportation end-use sector accounted for 1,759.9 MMT CO_2 Eq. in 2014, which represented 33 percent of CO_2 emissions, 20 percent of CH_4 emissions, and 41 percent of N_2O emissions from fossil fuel combustion, respectively.[17] Fuel purchased in the United States for international aircraft and marine travel accounted for an additional 104.2 MMT CO_2 Eq. in 2014; these emissions are recorded as international bunkers and are not included in U.S. totals according to UNFCCC reporting protocols.

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

From 2013 to 2014, CO_2 emissions from the transportation end-use sector increased by 1.4 percent.[18] The increase in emissions can largely be attributed to small increases in VMT and fuel use across many on-road transportation modes. Commercial aircraft emissions have decreased 18 percent since 2007.[19] Decreases in jet fuel emissions (excluding bunkers) since 2007 are due in part to improved operational efficiency that results in more direct flight routing, improvements in aircraft and engine technologies to reduce fuel burn and emissions, and the accelerated retirement of older, less fuel efficient aircraft.

Almost all of the energy consumed for transportation was supplied by petroleum-based products, with more than half being related to gasoline consumption in automobiles and other highway vehicles. Other fuel uses, especially diesel fuel for freight trucks and jet fuel for aircraft, accounted for the remainder. The primary driver of transportation-related emissions was CO_2 from fossil fuel combustion, which increased by 16 percent from 1990 to

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[17] 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.

[18] Note that this value does not include lubricants.

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

2014. Annex 3.2 presents the total emissions from all transportation and mobile sources, including CO_2, N_2O, CH_4, and HFCs.

Transportation Fossil Fuel Combustion CO_2 Emissions

Domestic transportation CO_2 emissions increased by 16 percent (244.7 MMT CO_2) between 1990 and 2014, an annualized increase of 0.7 percent. Among domestic transportation sources, light-duty vehicles (including passenger cars and light-duty trucks) represented 60 percent of CO_2 emissions from fossil fuel combustion, medium- and heavy-duty trucks and buses 24 percent, commercial aircraft 7 percent, and other sources 9 percent. See Table 3-12 for a detailed breakdown of transportation 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.[20] Ethanol consumption from the transportation sector has increased from 0.7 billion gallons in 1990 to 12.9 billion gallons in 2014, while biodiesel consumption has increased from 0.01 billion gallons in 2001 to 1.4 billion gallons in 2014. For further information, see the section on biofuel consumption at the end of this chapter and Table A-93 in Annex 3.2.

Carbon dioxide emissions from passenger cars and light-duty trucks totaled 1,047.0 MMT CO_2 in 2014, an increase of 10 percent (96.6 MMT CO_2) from 1990 due, in large part, to increased demand for travel as fleetwide light-duty vehicle fuel economy was relatively stable (average new vehicle fuel economy declined slowly from 1990 through 2004 and then increased more rapidly from 2005 through 2014). Carbon dioxide emissions from passenger cars and light-duty trucks peaked at 1,181.1 MMT CO_2 in 2004, and since then have declined about 11 percent. The decline in new light-duty vehicle fuel economy between 1990 and 2004 (Figure 3-11) reflected the increasing market share of light-duty trucks, which grew from about 30 percent of new vehicle sales in 1990 to 48 percent in 2004. Starting in 2005, the rate of VMT growth slowed while average new vehicle fuel economy began to increase. Average new vehicle fuel economy has improved almost every year since 2005, and the truck share has decreased to about 41 percent of new vehicles in model year 2014 (EPA 2015a).

Medium- and heavy-duty truck CO_2 emissions increased by 75 percent from 1990 to 2014. This increase was largely due to a substantial growth in medium- and heavy-duty truck VMT, which increased by 94 percent between 1990 and 2014.[21] Carbon dioxide from the domestic operation of commercial aircraft increased by 5 percent (5.3 MMT CO_2) from 1990 to 2014.[22] Across all categories of aviation, excluding international bunkers, CO_2 emissions decreased by 20 percent (37.3 MMT CO_2) between 1990 and 2014.[23] This includes a 56 percent (19.6 MMT CO_2) decrease in CO_2 emissions from domestic military operations.

Transportation sources also produce CH_4 and N_2O; these emissions are included in Table 3-13 and Table 3-14 and in the "Mobile Combustion" Section. Annex 3.2 presents total emissions from all transportation and mobile sources, including CO_2, CH_4, N_2O, and HFCs.

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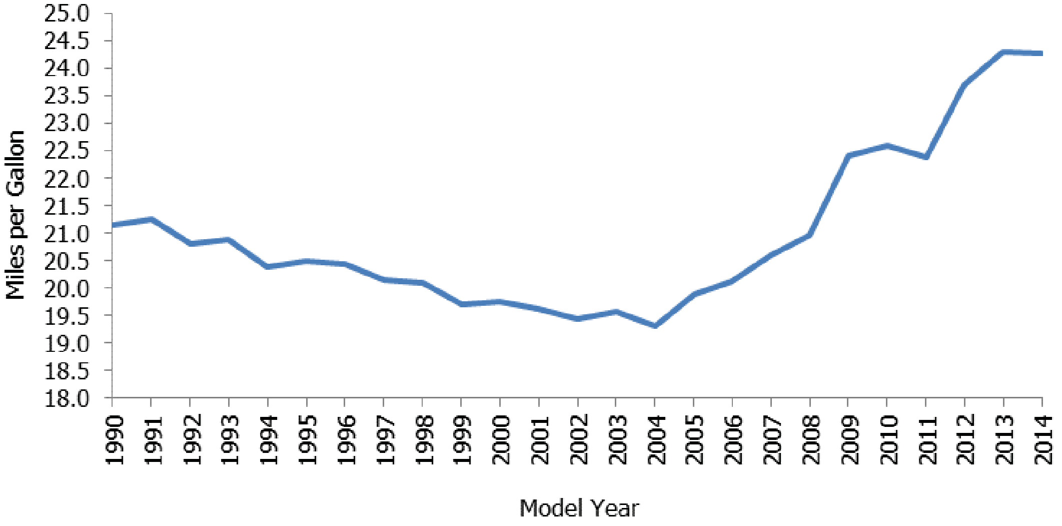
[20] Biofuel estimates are presented in the Energy chapter for informational purposes only, in line with IPCC methodological guidance and UNFCCC reporting obligations. Net carbon fluxes from changes in biogenic carbon reservoirs in croplands are accounted for in the estimates for Land Use, Land-Use Change,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

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

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

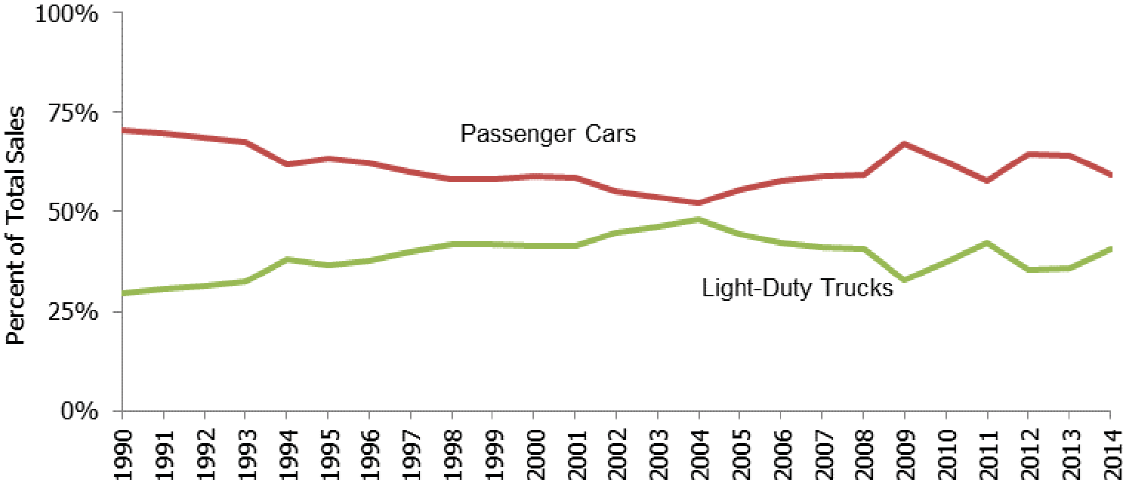
[23] Includes consumption of jet fuel and aviation gasoline. Does not include aircraft bunkers, which are not included in national emission totals, in line with IPCC methodological guidance and UNFCCC reporting obligations.

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



Source: EPA (2015)

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



Source: EPA (2015)

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

Fuel/Vehicle Type	1990	2005	2010[a]	2011	2012	2013	2014
Gasoline[c]	**983.5**	**1,183.7**	**1,092.5**	**1,068.8**	**1,064.7**	**1,065.6**	**1,083.9**
Passenger Cars	621.4	655.9	738.2	732.8	731.4	731.4	733.6
Light-Duty Trucks	309.1	477.2	295.0	280.4	277.4	277.7	293.5

Medium- and Heavy-Duty Trucks[b]	38.7	34.8	42.3	38.9	38.7	39.5	40.0
Buses	0.3	0.4	0.7	0.7	0.8	0.8	0.9
Motorcycles	1.7	1.6	3.6	3.6	4.1	3.9	3.8
Recreational Boats[h]	12.2	13.9	12.6	12.4	12.3	12.3	12.2
Distillate Fuel Oil (Diesel)[c,i]	**262.9**	**457.5**	**422.0**	**430.0**	**427.5**	**433.9**	**447.6**
Passenger Cars	7.9	4.2	3.7	4.1	4.1	4.1	4.1
Light-Duty Trucks	11.5	25.8	12.5	13.0	12.9	12.9	13.9
Medium- and Heavy-Duty Trucks[b]	190.5	360.2	342.7	344.4	344.4	350.0	361.3
Buses	8.0	10.6	13.5	14.4	15.4	15.5	16.6
Rail	35.5	45.5	38.6	40.4	39.5	40.1	41.7
Recreational Boats	2.0	3.2	3.6	3.6	3.7	3.7	3.8
Ships and Other Boats[j]	7.5	8.0	7.4	10.1	7.5	7.5	6.2
International Bunker Fuels[d]	*11.7*	*9.4*	*9.5*	*7.9*	*6.8*	*5.6*	*6.1*
Jet Fuel	**184.2**	**189.3**	**151.5**	**146.6**	**143.4**	**147.1**	**148.6**
Commercial Aircraft[e]	109.9	132.7	113.3	114.6	113.3	114.3	115.2
Military Aircraft	35.0	19.4	13.6	11.6	12.1	11.0	15.4
General Aviation Aircraft	39.4	37.3	24.6	20.4	18.0	21.8	18.0
International Bunker Fuels[d]	*38.0*	*60.1*	*61.0*	*64.8*	*64.5*	*65.7*	*69.4*
International Bunker Fuels from Commercial Aviation	*30.0*	*55.6*	*57.4*	*61.7*	*61.4*	*62.8*	*66.3*
Aviation Gasoline	**3.1**	**2.4**	**1.9**	**1.9**	**1.7**	**1.5**	**1.5**
General Aviation Aircraft	3.1	2.4	1.9	1.9	1.7	1.5	1.5
Residual Fuel Oil	**22.6**	**19.3**	**20.4**	**19.4**	**15.8**	**15.1**	**5.5**
Ships and Other Boats[j]	22.6	19.3	20.4	19.4	15.8	15.1	5.5
International Bunker Fuels[d]	*53.7*	*43.6*	*46.5*	*38.9*	*34.5*	*28.5*	*27.7*
Natural Gas	**36.0**	**33.1**	**38.1**	**38.9**	**41.3**	**47.0**	**47.6**
Passenger Cars	+	+	+	+	+	+	+
Light-Duty Trucks	+	+	+	+	+	+	+
Buses	+	0.8	1.1	1.1	1.0	1.1	1.1
Pipeline[f]	36.0	32.2	37.1	37.8	40.3	45.9	46.5
LPG	**1.4**	**1.7**	**1.8**	**2.1**	**2.3**	**2.7**	**2.7**
Light-Duty Trucks	0.6	1.3	1.3	1.5	1.6	1.9	1.9
Medium- and Heavy-Duty Trucks[b]	0.8	0.4	0.6	0.6	0.7	0.8	0.8
Buses	+	+	+	+	+	+	+
Electricity	**3.0**	**4.7**	**4.5**	**4.3**	**3.9**	**4.0**	**4.1**
Rail	3.0	4.7	4.5	4.3	3.9	4.0	4.1
Ethanol[g]	***4.1***	***22.4***	***71.3***	***71.5***	***71.5***	***73.4***	***74.7***
Total	**1,496.8**	**1,891.8**	**1,732.7**	**1,711.9**	**1,700.6**	**1,717.0**	**1,741.5**
Total (Including Bunkers)[d]	**1,600.3**	**2,004.9**	**1,849.7**	**1,823.6**	**1,806.4**	**1,816.8**	**1,844.7**

Note: 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.

Note: Totals may not sum due to independent rounding.

[a] In 2011 FHWA changed its methods for estimating vehicle miles traveled (VMT) and related data. These methodological changes included how vehicles are classified, moving from a system based on body-type to one that is based on wheelbase. These changes were first incorporated for the 2010 Inventory and apply to the 2007-14 time period. This resulted in large changes in VMT and fuel consumption data by vehicle class, thus leading to a shift in emissions among on-road vehicle classes.

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

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

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

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

[f] Pipelines reflect CO_2 emissions from natural gas powered pipelines transporting natural gas.

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

[h] In 2015, EPA incorporated the NONROAD2008 model into MOVES2014. This year's inventory uses the NONROAD component of MOVES2014a for years 1999 through 2014. This update resulted in small changes (<2%) to the 1999-2013 time series for NONROAD fuel consumption due to differences in the gasoline and diesel default fuel densities used within the model iterations.

[i] Note that updates to the distillate fuel oil heat content data from EIA for years 1993 through present resulted in changes to the time series for energy consumption and emissions compared to the previous Inventory.

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

+ Less than 0.05 MMT CO_2 Eq.

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;[24] mobile sources also include non-transportation sources such as construction/mining equipment, agricultural equipment, vehicles used off-road, and other sources (e.g., snowmobiles, lawnmowers, etc.).[25] Annex 3.2 includes a summary of all emissions from both transportation and mobile sources. Table 3-13 and Table 3-14 provide mobile fossil fuel CH_4 and N_2O emission estimates in MMT CO_2 Eq.[26]

Mobile combustion was responsible for a small portion of national CH_4 emissions (0.3 percent) but was the fourth largest source of U.S. N_2O emissions (4.0 percent). From 1990 to 2014, mobile source CH_4 emissions declined by 64 percent, to 2.0 MMT CO_2 Eq. (82 kt CH_4), due largely to control technologies employed in on-road vehicles since the mid-1990s to reduce CO, NO_x, NMVOC, and CH_4 emissions. Mobile source emissions of N_2O decreased by 60 percent, to 16.3 MMT CO_2 Eq. (55 kt N_2O). Earlier generation control technologies initially resulted in higher N_2O emissions, causing a 28 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 69 percent decrease in mobile source N_2O emissions from 1997 to 2014 (Figure 3-13). Overall, CH_4 and N_2O emissions were predominantly from gasoline-fueled passenger cars and light-duty trucks.

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[24] 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.

[25] 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 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 Commercial 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 emissions estimates are bottom-up estimates, based on total activity (fuel use, VMT) and emissions factors by source and technology type. These reporting schemes are in accordance with IPCC guidance. For informational purposes only, CO_2 emissions from non-transportation mobile sources are presented separately from their overall end-use sector in Annex 3.2.

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

Figure 3-13: Mobile Source CH_4 and N_2O Emissions (MMT CO_2 Eq.)

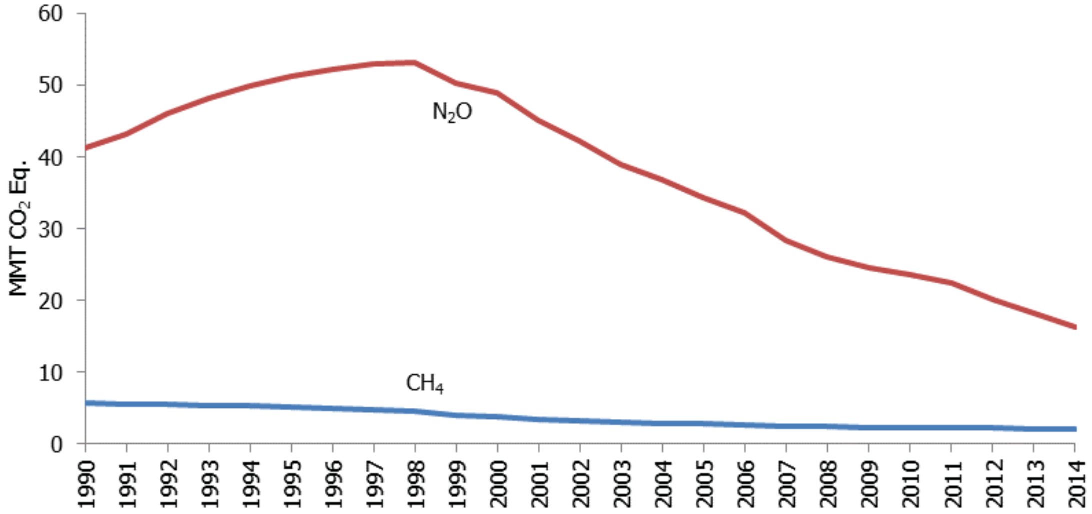

Table 3-13: CH_4 Emissions from Mobile Combustion (MMT CO_2 Eq.)

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

Note: Totals may not sum due to independent rounding.

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

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

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

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

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

[e] "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.

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

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

[h] In 2015, EPA incorporated the NONROAD2008 model into MOVES2014. This year's inventory uses the NONROAD component of MOVES2014a for years 1999 through 2014. This update resulted in small changes (<2%) to the 1999-2013 time series for NONROAD fuel consumption due to differences in the gasoline and diesel default fuel densities used within the model iterations.

+ Less than 0.05 MMT CO$_2$ Eq.

Table 3-14: N$_2$O Emissions from Mobile Combustion (MMT CO$_2$ Eq.)

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

Note: Totals may not sum due to independent rounding.

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

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

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

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

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

[e] "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.

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

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

[h] In 2015, EPA incorporated the NONROAD2008 model into MOVES2014. This year's inventory uses the NONROAD component of MOVES2014a for years 1999 through 2014. This update resulted in small changes (<2%) to the 1999-2013 time series for NONROAD fuel consumption due to differences in the gasoline and diesel default fuel densities used within the model iterations.

[i] Updates to the jet fuel heat content used in the mobile N_2O emissions estimates for years 1990 through present resulted in small changes to the time series emissions compared to the previous Inventory.

+ Less than 0.05 MMT CO_2 Eq.

CO_2 from Fossil Fuel Combustion

Methodology

The methodology used by the United States for estimating CO_2 emissions from fossil fuel combustion is conceptually similar to the approach recommended by the IPCC for countries that intend to develop detailed, sectoral-based emission estimates in line with a Tier 2 method in the *2006 IPCC Guidelines for National Greenhouse Gas Inventories* (IPCC 2006).[27] The use of the most recently published calculation methodologies by the IPCC, as contained in the *2006 IPCC Guidelines*, is considered to improve the rigor and accuracy of this Inventory and is fully in line with IPCC Good Practice Guidance. A detailed description of the U.S. methodology is presented in Annex 2.1, and is characterized by the following steps:

1. *Determine total fuel consumption by fuel type and sector*. Total fossil fuel consumption for each year is estimated by aggregating consumption data by end-use sector (e.g., commercial, industrial, etc.), primary fuel type (e.g., coal, petroleum, gas), and secondary fuel category (e.g., motor gasoline, distillate fuel oil, etc.). Fuel consumption data for the United States were obtained directly from the EIA of the U.S. Department of Energy (DOE), primarily from the Monthly Energy Review and published supplemental tables on petroleum product detail (EIA 2015a). The EIA does not include territories in its national energy statistics, so fuel consumption data for territories were collected separately from EIA's International Energy Statistics (EIA 2014) and Jacobs (2010).[28]

   For consistency of reporting, the IPCC has recommended that countries report energy data using the International Energy Agency (IEA) reporting convention and/or IEA data. Data in the IEA format are presented "top down"—that is, energy consumption for fuel types and categories are estimated from energy production data (accounting for imports, exports, stock changes, and losses). The resulting quantities are referred to as "apparent consumption." The data collected in the United States by EIA on an annual basis and used in this Inventory are predominantly from mid-stream or conversion energy consumers such as refiners and electric power generators. These annual surveys are supplemented with end-use energy consumption surveys, such as the Manufacturing Energy Consumption Survey, that are conducted on a

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

[28] Fuel consumption by U.S. territories (i.e., American Samoa, Guam, Puerto Rico, U.S. Virgin Islands, Wake Island, and other U.S. Pacific Islands) is included in this report and contributed total emissions of 41.2 MMT CO_2 Eq. in 2013.

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

Also, note that U.S. fossil fuel energy statistics are generally presented using gross calorific values (GCV) (i.e., higher heating values). Fuel consumption activity data presented here have not been adjusted to correspond to international standards, which are to report energy statistics in terms of net calorific values (NCV) (i.e., lower heating values).[30]

2. *Subtract uses accounted for in the Industrial Processes and Product Use chapter*. Portions of the fuel consumption data for seven fuel categories—coking coal, distillate fuel, industrial other coal, petroleum coke, natural gas, residual fuel oil, and other oil—were reallocated to the Industrial Processes and Product Use chapter, as they were consumed during non-energy related industrial activity. To make these adjustments, additional data were collected from AISI (2004 through 2013), Coffeyville (2014), U.S. Census Bureau (2011), EIA (2015a), USGS (1991 through 2011), USGS (1994 through 2011), USGS (1995, 1998, 2000 through 2002), USGS (2007), USGS (2009), USGS (2010), USGS (2011), USGS (1991 through 2010a), USGS (1991 through 2010b), USGS (2012a) and USGS (2012b).[31]

3. *Adjust for conversion of fuels and exports of CO_2*. Fossil fuel consumption estimates are adjusted downward to exclude fuels created from other fossil fuels and exports of CO_2.[32] Synthetic natural gas is created from industrial coal, and is currently included in EIA statistics for both coal and natural gas. Therefore, synthetic natural gas is subtracted from energy consumption statistics.[33] Since October 2000, the Dakota Gasification Plant has been exporting CO_2 to Canada by pipeline. Since this CO_2 is not emitted to the atmosphere in the United States, energy used to produce this CO_2 is subtracted from energy consumption statistics. To make these adjustments, additional data for ethanol were collected from EIA (2015), data for synthetic natural gas were collected from EIA (2014), and data for CO_2 exports were collected from the Eastman Gasification Services Company (2011), Dakota Gasification Company (2006), Fitzpatrick (2002), Erickson (2003), EIA (2008) and DOE (2012).

4. *Adjust Sectoral Allocation of Distillate Fuel Oil and Motor Gasoline*. EPA had conducted a separate bottom-up analysis of transportation fuel consumption based on data from the Federal Highway Administration that indicated that the amount of distillate and motor gasoline consumption allocated to the transportation sector in the EIA statistics should be adjusted. Therefore, for these estimates, the transportation sector's distillate fuel and motor gasoline consumption was adjusted to match the value obtained from the bottom-up analysis. As the total distillate and motor gasoline consumption estimate from EIA are considered to be accurate at the national level, the distillate and motor gasoline consumption totals for the residential, commercial, and industrial sectors were adjusted proportionately. The data sources used in the bottom-up analysis of transportation fuel consumption include AAR (2008 through 2015), Benson (2002 through 2004), DOE (1993 through 2015), EIA (2007), EIA (1991 through 2015), EPA (2015a), and FHWA (1996 through 2015).[34]

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[29] 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.

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

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

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

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

[34] The source of highway vehicle VMT and fuel consumption is FHWA's VM-1 table. In 2011, FHWA changed its methods for estimating data in the VM-1 table. These methodological changes included how vehicles are classified, moving from a system based on body type to one that is based on wheelbase. These changes were first incorporated for the 1990-2010 Inventory and apply to the 2007 to 2013 time period. This resulted in large changes in VMT and fuel consumption data by vehicle class, thus

5. *Adjust for fuels consumed for non-energy uses*. U.S. aggregate energy statistics include consumption of fossil fuels for non-energy purposes. These are fossil fuels that are manufactured into plastics, asphalt, lubricants, or other products. Depending on the end-use, this can result in storage of some or all of the C contained in the fuel for a period of time. As the emission pathways of C used for non-energy purposes are vastly different than fuel combustion (since the C in these fuels ends up in products instead of being combusted), these emissions are estimated separately in the Carbon Emitted and Stored in Products from Non-Energy Uses of Fossil Fuels section in this chapter. Therefore, the amount of fuels used for non-energy purposes was subtracted from total fuel consumption. Data on non-fuel consumption was provided by EIA (2015a).

6. *Subtract consumption of international bunker fuels.* According to the UNFCCC reporting guidelines emissions from international transport activities, or bunker fuels, should not be included in national totals. U.S. energy consumption statistics include these bunker fuels (e.g., distillate fuel oil, residual fuel oil, and jet fuel) as part of consumption by the transportation end-use sector, however, so emissions from international transport activities were calculated separately following the same procedures used for emissions from consumption of all fossil fuels (i.e., estimation of consumption, and determination of C content).[35] The Office of the Under Secretary of Defense (Installations and Environment) and the Defense Logistics Agency Energy (DLA Energy) of the U.S. Department of Defense (DoD) (DLA Energy 2015) supplied data on military jet fuel and marine fuel use. Commercial jet fuel use was obtained from FAA (2016); residual and distillate fuel use for civilian marine bunkers was obtained from DOC (1991 through 2014) for 1990 through 2001 and 2007 through 2014, and DHS (2008) for 2003 through 2006. Consumption of these fuels was subtracted from the corresponding fuels in the transportation end-use sector. Estimates of international bunker fuel emissions for the United States are discussed in detail later in the International Bunker Fuels section of this chapter.

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

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

9. *Allocate transportation emissions by vehicle type.* This report provides a more detailed accounting of emissions from transportation because it is such a large consumer of fossil fuels in the United States. For fuel types other than jet fuel, fuel consumption data by vehicle type and transportation mode were used to allocate emissions by fuel type calculated for the transportation end-use sector. Heat contents and densities were obtained from EIA (2015a) and USAF (1998).[36]
    - For on-road vehicles, annual estimates of combined motor gasoline and diesel fuel consumption by vehicle category were obtained from FHWA (1996 through 2014); for each vehicle category, the

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

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

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

percent gasoline, diesel, and other (e.g., CNG, LPG) fuel consumption are estimated using data from DOE (1993 through 2013).

- For non-road vehicles, activity data were obtained from AAR (2008 through 2015), APTA (2007 through 2015), APTA (2006), BEA (2015), Benson (2002 through 2004), DOE (1993 through 2015), DLA Energy (2015), DOC (1991 through 2015), DOT (1991 through 2015), EIA (2009a), EIA (2015a), EIA (2013), EIA (1991 through 2015), EPA (2015), and Gaffney (2007).
- 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 with the *2006 IPCC Guidelines for National Greenhouse Gas Inventories* (see Annex 3.3). Carbon dioxide emissions from other aircraft were calculated directly based on reported consumption of fuel as reported by EIA. Allocation to domestic military uses was made using DoD data (see Annex 3.8). General aviation jet fuel consumption is calculated as the remainder of total jet fuel use (as determined by EIA) nets all other jet fuel use as determined by FAA and DoD. For more information, see Annex 3.2.

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

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

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

This year's effort represents an attempt to align, reconcile, and coordinate the facility-level reporting of fossil fuel combustion emissions under EPA's GHGRP with the national-level approach presented in this report. Consistent with recommendations for reporting the Inventory to the UNFCCC, progress was made on certain fuel types for specific industries and has been included in the Common Reporting Format (CRF) tables that are submitted to the UNFCCC along with this report.[38] However, a full mapping was not completed this year due to fuel category differences between national statistics published by EIA and facility-level reported GHGRP data. Furthermore, given that calendar year 2010 was the first year in which emissions data were reported to EPA's GHGRP, the current Inventory's examination only focused on 2010, 2011, 2012, 2013, and 2014. For the current exercise, the efforts in reconciling fuels focused on standard, common fuel types (e.g., natural gas, distillate fuel oil, etc.) where the fuels in EIA's national statistics aligned well with facility-level GHGRP data. For these reasons, the current information presented in the CRF tables should be viewed as an initial attempt at this exercise. Additional efforts will be made for future inventory reports to improve the mapping of fuel types, and examine ways to reconcile and coordinate any differences between facility-level data and national statistics. Additionally, in order to expand this effort through the full time series presented in this report, further analyses will be conducted linking GHGRP facility-level reporting with the information published by EIA in its MECS data, other available MECS survey years, and any further informative sources of data. It is believed that the current analysis has led to improvements in

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

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

the presentation of data in the Inventory, but further work will be conducted, and future improvements will be realized in subsequent Inventory reports.

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

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

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

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

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

Fossil fuels are the dominant source of energy in the United States, and CO_2 is the dominant greenhouse gas emitted as a product from their combustion. Energy-related CO_2 emissions are impacted by not only lower levels of energy consumption but also by lowering the C intensity of the energy sources employed (e.g., fuel switching from coal to natural gas). The amount of C emitted from the combustion of fossil fuels is dependent upon the C content of the fuel and the fraction of that C that is oxidized. Fossil fuels vary in their average C content, ranging from about 53 MMT CO_2 Eq./QBtu for natural gas to upwards of 95 MMT CO_2 Eq./QBtu for coal and petroleum coke.[40] In general, the C content per unit of energy of fossil fuels is the highest for coal products, followed by petroleum, and then natural gas. The overall C intensity of the U.S. economy is thus dependent upon the quantity and combination of fuels and other energy sources employed to meet demand.

Table 3-15 provides a time series of the C intensity for each sector of the U.S. economy. The time series incorporates only the energy consumed from the direct combustion of fossil fuels in each sector. For example, the C intensity for the residential sector does not include the energy from or emissions related to the consumption of electricity for lighting. Looking only at this direct consumption of fossil fuels, the residential sector exhibited the lowest C intensity, which is related to the large percentage of its energy derived from natural gas for heating. The C intensity of the commercial sector has predominantly declined since 1990 as commercial businesses shift away from petroleum to natural gas. The industrial sector was more dependent on petroleum and coal than either the residential or commercial sectors, and thus had higher C intensities over this period. The C intensity of the transportation sector was closely related to the C content of petroleum products (e.g., motor gasoline and jet fuel, both around 70 MMT CO_2 Eq./EJ), which were the primary sources of energy. Lastly, the electricity generation sector had the highest C intensity due to its heavy reliance on coal for generating electricity.

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

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

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

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

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

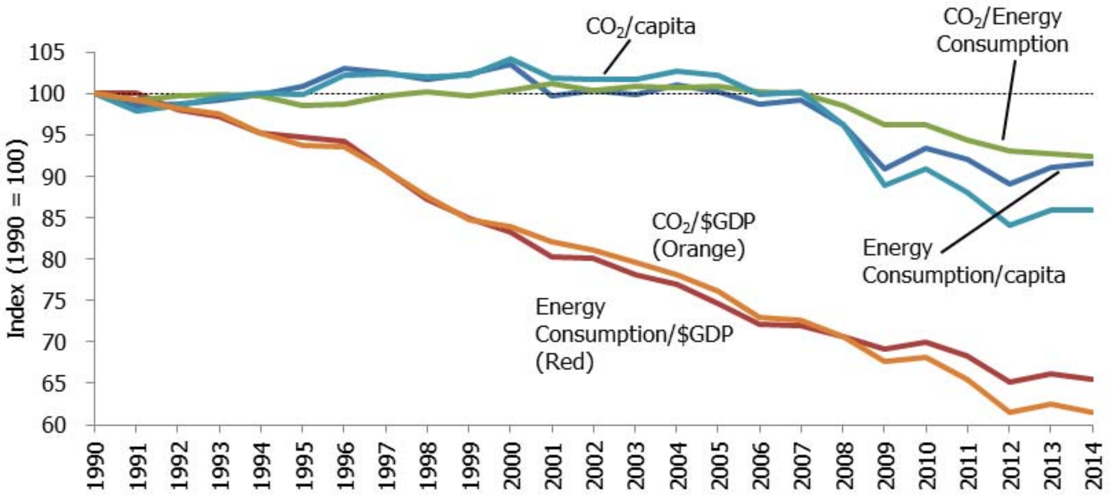
[b] Does not include electricity produced using nuclear or renewable energy.

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

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

Over the twenty-five-year period of 1990 through 2014, however, the C intensity of U.S. energy consumption has been fairly constant, as the proportion of fossil fuels used by the individual sectors has not changed significantly. Per capita energy consumption fluctuated little from 1990 to 2007, but in 2014 was approximately 8.5 percent below levels in 1990 (see Figure 3-14). Due to a general shift from a manufacturing-based economy to a service-based economy, as well as overall increases in efficiency, energy consumption and energy-related CO_2 emissions per dollar of gross domestic product (GDP) have both declined since 1990 (BEA 2015).

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



C intensity estimates were developed using nuclear and renewable energy data from EIA (2015a), EPA (2010a), and fossil fuel consumption data as discussed above and presented in Annex 2.1.

Uncertainty and Time Series Consistency

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

Nevertheless, there are uncertainties in the consumption data, carbon content of fuels and products, and carbon oxidation efficiencies. For example, given the same primary fuel type (e.g., coal, petroleum, or natural gas), the amount of carbon contained in the fuel per unit of useful energy can vary. For the United States, however, the impact of these uncertainties on overall CO_2 emission estimates is believed to be relatively small. See, for example, Marland and Pippin (1990).

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

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

Various sources of uncertainty surround the estimation of emissions from international bunker fuels, which are subtracted from the U.S. totals (see the detailed discussions on these uncertainties provided in the International Bunker Fuels section of this chapter). Another source of uncertainty is fuel consumption by U.S. Territories. The United States does not collect energy statistics for its territories at the same level of detail as for the fifty states and the District of Columbia. Therefore, estimating both emissions and bunker fuel consumption by these territories is difficult.

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

The uncertainty analysis was performed by primary fuel type for each end-use sector, using the IPCC-recommended 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 120 input variables were modeled for CO_2 from energy-related Fossil Fuel Combustion (including about 10 for non-energy fuel consumption and about 20 for International Bunker Fuels).

In developing the uncertainty estimation model, uniform distributions were assumed for all activity-related input variables and emission factors, based on the SAIC/EIA (2001) report.[41] Triangular distributions were assigned for the oxidization factors (or combustion efficiencies). The uncertainty ranges were assigned to the input variables based on the data reported in SAIC/EIA (2001) and on conversations with various agency personnel.[42]

The uncertainty ranges for the activity-related input variables were typically asymmetric around their inventory estimates; the uncertainty ranges for the emissions factors were symmetric. Bias (or systematic uncertainties)

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

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

associated with these variables accounted for much of the uncertainties associated with these variables (SAIC/EIA 2001).[43] For purposes of this uncertainty analysis, each input variable was simulated 10,000 times through Monte Carlo sampling.

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 3-16. Fossil fuel combustion CO_2 emissions in 2014 were estimated to be between 5,097.2 and 5,455.5 MMT CO_2 Eq. at a 95 percent confidence level. This indicates a range of 2 percent below to 5 percent above the 2014 emission estimate of 5,208.7 MMT CO_2 Eq.

Table 3-16: 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)

	2014 Emission Estimate	Uncertainty Range Relative to Emission Estimate[a]			
Fuel/Sector	(MMT CO_2 Eq.)	(MMT CO_2 Eq.)		(%)	
		Lower Bound	Upper Bound	Lower Bound	Upper Bound
Coal[b]	**1,653.7**	**1,595.9**	**1,809.7**	**-3%**	**+9%**
Residential	NE	NE	NE	NE	NE
Commercial	4.5	4.3	5.2	-5%	+15%
Industrial	75.3	71.7	87.1	-5%	+16%
Transportation	NE	NE	NE	NE	NE
Electricity Generation	1,570.4	1,509.3	1,722.0	-4%	+10%
U.S. Territories	3.4	3.0	4.0	-12%	+19%
Natural Gas[b]	**1,426.6**	**1,412.3**	**1,492.8**	**-1%**	**+5%**
Residential	277.6	270.0	297.1	-3%	+7%
Commercial	189.2	183.8	202.5	-3%	+7%
Industrial	466.0	451.9	499.5	-3%	+7%
Transportation	47.6	46.3	51.0	-3%	+7%
Electricity Generation	443.2	430.3	465.5	-3%	+5%
U.S. Territories	3.0	2.6	3.5	-12%	+17%
Petroleum[b]	**2,128.0**	**1,992.7**	**2,251.6**	**-6%**	**+6%**
Residential	67.6	63.8	71.0	-6%	+5%
Commercial	37.9	35.9	39.7	-5%	+5%
Industrial	272.9	218.4	322.2	-20%	+18%
Transportation	1,689.8	1,576.0	1,800.5	-7%	+7%
Electric Utilities	25.3	24.1	27.3	-5%	+8%
U.S. Territories	34.6	32.0	38.4	-7%	+11%
Total (excluding Geothermal)[b]	**5,208.2**	**5,096.8**	**5,455.1**	**-2%**	**+5%**
Geothermal	0.4	NE	NE	NE	NE
Total (including Geothermal)[b,c]	**5,208.7**	**5,097.2**	**5,455.5**	**-2%**	**+5%**

NA (Not Applicable)

NE (Not Estimated)

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

[b] The low and high estimates for total emissions were calculated separately through simulations and, hence, the low and high emission estimates for the sub-source categories do not sum to total emissions.

[c] Geothermal emissions added for reporting purposes, but an uncertainty analysis was not performed for CO_2 emissions from geothermal production.

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

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

QA/QC and Verification

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

Recalculations Discussion

The Energy Information Administration (EIA 2015a) updated energy consumption statistics across the time series relative to the previous Inventory. One such revision is the historical coal and petroleum product consumption in the industrial sector for the entire time series. In addition, EIA revised 2013 natural gas consumption in the transportation sector and 2013 kerosene and Liquefied Petroleum Gas (LPG) consumption in the residential and commercial sectors.

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

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

Overall, these changes resulted in an average annual decrease of 1.1 MMT CO_2 Eq. (less than 0.1 percent) in CO_2 emissions from fossil fuel combustion for the period 1990 through 2013, relative to the previous report.

Planned Improvements

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

The availability of facility-level combustion emissions through EPA's GHGRP will continue to be examined to help better characterize the industrial sector's energy consumption in the United States, and further classify business establishments according to industrial economic activity type. Most methodologies used in EPA's GHGRP are consistent with IPCC, though for EPA's GHGRP, facilities collect detailed information specific to their operations according to detailed measurement standards, which may differ with the more aggregated data collected for the Inventory to estimate total, national U.S. emissions. In addition, and unlike the reporting requirements for this chapter under the UNFCCC reporting guidelines, some facility-level fuel combustion emissions reported under the GHGRP may also include industrial process emissions.[44] In line with UNFCCC reporting guidelines, fuel combustion emissions are included in this chapter, while process emissions are included in the Industrial Processes and Product Use chapter of this report. In examining data from EPA's GHGRP that would be useful to improve the emission estimates for the 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

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

and IPCC fuel types per the national energy statistics. Additional work will commence to ensure 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 continue to be relied upon.[45]

Another planned improvement is to develop improved estimates of domestic waterborne fuel consumption. The inventory estimates for residual and distillate fuel used by ships and boats is based in part on data on bunker fuel use from the U.S. Department of Commerce. Domestic fuel consumption is estimated by subtracting fuel sold for international use from the total sold in the United States. It may be possible to more accurately estimate domestic fuel use and emissions by using detailed data on marine ship activity. The feasibility of using domestic marine activity data to improve the estimates is currently being investigated.

An additional potential improvement is to include CO_2 emissions from natural gas (LNG and CNG) use in medium- and heavy-duty trucks, light trucks and passenger cars. Currently data from the Transportation Energy Data book is used to allocate CO_2 emissions to vehicle categories. However, this data source only estimates natural gas use in buses. We are currently investigating the use of alternative data sources from the EIA that would allow some of the CO_2 from natural gas consumption to be allocated to these other vehicle categories.

In addition, we are investigating an approach to account for CO_2 emissions from the use of urea-based additives in catalytic converters for on-road vehicles between 2010 and 2014. The approach would utilize the MOVES model to estimate fuel use by diesel vehicles with urea-based catalysts. The *2006 IPCC Guidelines* estimates urea use between one and three percent of diesel fuel used.

CH_4 and N_2O from Stationary Combustion

Methodology

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). Beginning with the current Inventory report, the electric power sector utilizes a Tier 2 methodology, whereas all other sectors utilize a Tier 1 methodology. The activity data and emission factors used are described in the following subsections.

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

National coal, natural gas, fuel oil, and wood consumption data were grouped by sector: industrial, commercial, residential, and U.S. Territories. For the CH_4 and N_2O estimates, wood consumption data for the United States was obtained from EIA's Monthly Energy Review (EIA 2015a). Fuel consumption data for coal, natural gas, and fuel oil for the United States were also obtained from EIA's Monthly Energy Review and unpublished supplemental tables on petroleum product detail (EIA 2015a). Because the United States does not include territories in its national energy statistics, fuel consumption data for territories were provided separately by EIA's International Energy Statistics (EIA 2014) and Jacobs (2010).[46] Fuel consumption for the industrial sector was adjusted to subtract out construction and agricultural use, which is reported under mobile sources.[47] Construction and agricultural fuel use was obtained from EPA (2014). Estimates for wood biomass consumption for fuel combustion do not include wood wastes, liquors, municipal solid waste, tires, etc., that are reported as biomass by EIA. Tier 1 default emission factors for these three end-use sectors were provided by the *2006 IPCC Guidelines for National Greenhouse Gas*

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

[46] 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.

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

Inventories (IPCC 2006). U.S. Territories' emission factors were estimated using the U.S. emission factors for the primary sector in which each fuel was combusted.

Electric Power Sector

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

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

Energy consumption estimates were not available from 1990 to 1995 in the EPA (2015a) dataset, and as a result, consumption was calculated using total electric power consumption from EIA (2015a) and the ratio of combustion technology and fuel types from EPA (2015a). The consumption estimates from 1990 to 1995 were estimated by applying the 1996 consumption ratio by combustion technology type to the total EIA consumption for each year from 1990 to 1995. Emissions were estimated by multiplying fossil fuel and wood consumption by technology- and fuel-specific Tier 2 IPCC emission factors.

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

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

Uncertainty and Time-Series Consistency

Methane emission estimates from stationary sources exhibit high uncertainty, primarily due to difficulties in calculating emissions from wood combustion (i.e., fireplaces and wood stoves). The estimates of 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.[48] For these variables, the uncertainty

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

ranges were assigned to the input variables based on the data reported in SAIC/EIA (2001).[49] 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).

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 3-17. Stationary combustion CH_4 emissions in 2014 (*including* biomass) were estimated to be between 4.6 and 20.6 MMT CO_2 Eq. at a 95 percent confidence level. This indicates a range of 42 percent below to 155 percent above the 2014 emission estimate of 8.1 MMT CO_2 Eq.[50] Stationary combustion N_2O emissions in 2014 (*including* biomass) were estimated to be between 17.9 and 34.4 MMT CO_2 Eq. at a 95 percent confidence level. This indicates a range of 24 percent below to 47 percent above the 2014 emissions estimate of 23.4 MMT CO_2 Eq.

Table 3-17: 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	2014 Emission Estimate (MMT CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (MMT CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Stationary Combustion	CH_4	8.1	4.6	20.6	-42%	+155%
Stationary Combustion	N_2O	23.4	17.9	34.4	-24%	+47%

[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.

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

QA/QC and Verification

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

Recalculations Discussion

Methane and N_2O emissions from stationary sources (excluding CO_2) across the entire time series were revised due revised data from EIA (2015a) and EPA (2015a) relative to the previous Inventory. The historical data changes resulted in an average annual decrease of less than 0,1 MMT CO_2 Eq. (less than 0.1 percent) in both CH_4 and N_2O emissions from stationary combustion for the period 1990 through 2013.

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

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

Planned Improvements

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

Future improvements to the CH_4 and N_2O from Stationary Combustion category involve research into the availability of CH_4 and N_2O from stationary combustion data, and analyzing data reported under EPA's GHGRP. In examining data from EPA's GHGRP that would be useful to improve the emission estimates for CH_4 and N_2O from Stationary Combustion category, particular attention will be made to ensure time series consistency, as the facility-level reporting data from EPA's GHGRP are not available for all Inventory years as reported in this Inventory. In implementing improvements and integration of data from EPA's GHGRP, the latest guidance from the IPCC on the use of facility-level data in national inventories will be relied upon.[51]

CH_4 and N_2O from Mobile Combustion

Methodology

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

On-Road Vehicles

Estimates of CH_4 and N_2O emissions from gasoline and diesel on-road vehicles are based on VMT and emission factors by vehicle type, fuel type, model year, and emission control technology. Emission estimates for alternative fuel vehicles (AFVs) are based on VMT and emission factors by vehicle and fuel type.[52]

Emission factors for gasoline and diesel on-road vehicles utilizing Tier 2 and Low Emission Vehicle (LEV) technologies were developed by ICF (2006b); all other gasoline and diesel on-road vehicle emissions factors were developed by ICF (2004). These factors were derived from EPA, California Air Resources Board (CARB) and Environment Canada laboratory test results of different vehicle and control technology types. The EPA, CARB and Environment Canada tests were designed following the Federal Test Procedure (FTP), which covers three separate driving segments, since vehicles emit varying amounts of greenhouse gases depending on the driving segment. These driving segments are: (1) a transient driving cycle that includes cold start and running emissions, (2) a cycle that represents running emissions only, and (3) a transient driving cycle that includes hot start and running emissions. For each test run, a bag was affixed to the tailpipe of the vehicle and the exhaust was collected; the content of this bag was then analyzed to determine quantities of gases present. The emissions characteristics of segment 2 were used to define running emissions, and subtracted from the total FTP emissions to determine start emissions. These were then recombined based upon the ratio of start to running emissions for each vehicle class from MOBILE6.2, an EPA emission factor model that predicts gram per mile emissions of CO_2, CO, HC, NO_x, and PM from vehicles under various conditions, to approximate average driving characteristics.[53]

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

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

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

Emission factors for AFVs were developed by ICF (2006a) after examining Argonne National Laboratory's GREET 1.7–Transportation Fuel Cycle Model (ANL 2006) and Lipman and Delucchi (2002). These sources describe AFV emission factors in terms of ratios to conventional vehicle emission factors. Ratios of AFV to conventional vehicle emissions factors were then applied to estimated Tier 1 emissions factors from light-duty gasoline vehicles to estimate light-duty AFVs. Emissions factors for heavy-duty AFVs were developed in relation to gasoline heavy-duty vehicles. A complete discussion of the data source and methodology used to determine emission factors from AFVs is provided in Annex 3.2.

Annual VMT data for 1990 through 2014 were obtained from the Federal Highway Administration's (FHWA) Highway Performance Monitoring System database as reported in Highway Statistics (FHWA 1996 through 2015).[54] VMT estimates were then allocated from FHWA's vehicle categories to fuel-specific vehicle categories using the calculated shares of vehicle fuel use for each vehicle category by fuel type reported in DOE (1993 through 2015) and information on total motor vehicle fuel consumption by fuel type from FHWA (1996 through 2015). VMT for AFVs were estimated based on Browning (2015). The age distributions of the U.S. vehicle fleet were obtained from EPA (2015b, 2000), and the average annual age-specific vehicle mileage accumulation of U.S. vehicles were obtained from EPA (2015b).

Control technology and standards data for on-road vehicles were obtained from EPA's Office of Transportation and Air Quality (EPA 2007a, 2007b, 2000, 1998, and 1997) and Browning (2005). These technologies and standards are defined in Annex 3.2, and were compiled from EPA (1994a, 1994b, 1998, 1999a) and IPCC (2006).

Non-Road Vehicles

To estimate emissions from non-road vehicles, fuel consumption data were employed as a measure of activity, and multiplied by fuel-specific emission factors (in grams of N_2O and CH_4 per kilogram of fuel consumed).[55] Activity data were obtained from AAR (2008 through 2015), APTA (2007 through 2015), APTA (2006), BEA (1991 through 2015), Benson (2002 through 2004), DHS (2008), DLA Energy (2015), DOC (1991 through 2015), DOE (1993 through 2015), DOT (1991 through 2015), EIA (2002, 2007, 2015a), EIA (2007 through 2015), EIA (1991 through 2015), EPA (2015b), Esser (2003 through 2004), FAA (2016), FHWA (1996 through 2015), Gaffney (2007), and Whorton (2006 through 2014). Emission factors for non-road modes were taken from IPCC (2006) and Browning (2009).

Uncertainty and Time-Series Consistency

A quantitative uncertainty analysis was conducted for the mobile source sector using the IPCC-recommended Approach 2 uncertainty estimation methodology, Monte Carlo Stochastic Simulation technique, using @RISK software. The uncertainty analysis was performed on 2014 estimates of 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 and (2) emission factor data, by on-road vehicle, fuel, and control technology type, (3) fuel consumption, data, by non-road vehicle and equipment type, and (4) emission factor data, by non-road vehicle and equipment type.

Uncertainty analyses were not conducted for NO_x, CO, or NMVOC emissions. Emission factors for these gases have been extensively researched since emissions of these gases from motor vehicles are regulated in the United States, and the uncertainty in these emission estimates is believed to be relatively low. For more information, see

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[54] The source of VMT is FHWA's VM-1 table. In 2011, FHWA changed its methods for estimating data in the VM-1 table. These methodological changes included how vehicles are classified, moving from a system based on body-type to one that is based on wheelbase. These changes were first incorporated for the 2010 Inventory and apply to the 2007-14 time period. This resulted in large changes in VMT by vehicle class, thus leading to a shift in emissions among on-road vehicle classes. For example, the category "Passenger Cars" has been replaced by "Light-duty Vehicles-Short Wheelbase" and "Other 2 axle-4 Tire Vehicles" has been replaced by "Light-duty Vehicles, Long Wheelbase." This change in vehicle classification has moved some smaller trucks and sport utility vehicles from the light truck category to the passenger vehicle category in this emission inventory. These changes are reflected in a large drop in light-truck emissions between 2006 and 2007.

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

Section 3.7. 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.

Mobile combustion CH_4 emissions from all mobile sources in 2014 were estimated to be between 1.8 and 2.4 MMT CO_2 Eq. at a 95 percent confidence level. This indicates a range of 12 percent below to 18 percent above the corresponding 2014 emission estimate of 2.0 MMT CO_2 Eq. Also at a 95 percent confidence level, mobile combustion N_2O emissions from mobile sources in 2014 were estimated to be between 15.7 and 20.7 MMT CO_2 Eq., indicating a range of 4 percent below to 27 percent above the corresponding 2014 emission estimate of 16.3 MMT CO_2 Eq.

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

Source	Gas	2014 Emission Estimate[a] (MMT CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (MMT CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Mobile Sources	CH_4	2.0	1.8	2.4	-12%	+18%
Mobile Sources	N_2O	16.3	15.7	20.7	-4%	+27%

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

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

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

QA/QC and Verification

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

Recalculations Discussion

Decreases to CH_4 and N_2O emissions from mobile combustion are largely due to updates made to the Motor Vehicle Emissions Simulator (MOVES 2014a) model that is used to estimate on-road gasoline vehicle distribution and mileage across the time series. These changes are due to the updated MOVES age distributions for years 1999-2013 in this year's inventory. These changes in the age distribution increased the percentage of vehicles and VMT for some vehicle types in newer model years that have better emissions control technology. For aircrafts, a weighted jet fuel heat content was applied to the jet fuel N_2O emissions calculation. The weighted factor accounts for the different heat contents of jet fuels used in commercial aviation, general aviation and the military. This resulted in a 0.4 percent increase in the heat content and a similar increase in N_2O emissions.

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

Overall, these changes resulted in an average annual decrease of 0.1 MMT CO_2 Eq. (4 percent) in CH_4 emissions and an average annual decrease of 1.4 MMT CO_2 Eq. (3 percent) in N_2O emissions from mobile combustion for the period 1990 through 2013, relative to the previous report.

Planned Improvements

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

- Develop improved estimates of domestic waterborne fuel consumption. The inventory estimates for residual and distillate fuel used by ships and boats is based in part on data on bunker fuel use from the U.S. Department of Commerce. Domestic fuel consumption is estimated by subtracting fuel sold for international use from the total sold in the United States. It may be possible to more accurately estimate domestic fuel use and emissions by using detailed data on marine ship activity. The feasibility of using domestic marine activity data to improve the estimates is currently being investigated. Additionally, the feasibility of including data from a broader range of domestic and international sources for domestic bunker fuels, including data from studies such as the *Third IMO GHG Study 2014*, is being considered.

- Continue to examine the use of EPA's MOVES model in the development of the inventory estimates, including use for uncertainty analysis. Although the Inventory uses some of the underlying data from MOVES, such as vehicle age distributions by model year, MOVES is not used directly in calculating mobile source emissions. The use of MOVES will be further explored.

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

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

CO_2 emissions arise from non-energy uses via several pathways. Emissions may occur during the manufacture of a product, as is the case in producing plastics or rubber from fuel-derived feedstocks. Additionally, emissions may occur during the product's lifetime, such as during solvent use. Overall, throughout the time series and across all uses, about 60 percent of the total C consumed for non-energy purposes was stored in products, and not released to the atmosphere; the remaining 40 percent was emitted.

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

As shown in Table 3-19, fossil fuel emissions in 2014 from the non-energy uses of fossil fuels were 114.3 MMT CO_2 Eq., which constituted approximately 2 percent of overall fossil fuel emissions. In 2014, the consumption of fuels for non-energy uses (after the adjustments described above) was 4,571.6 TBtu, an increase of 8.4 percent since 1990 (see Table 3-20). About 55.9 MMT (205.1 MMT CO_2 Eq.) of the C in these fuels was stored, while the remaining 31.2 MMT C (114.3 MMT CO_2 Eq.) was emitted.

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

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

Methodology

The first step in estimating C stored in products was to determine the aggregate quantity of fossil fuels consumed for non-energy uses. The C content of these feedstock fuels is equivalent to potential emissions, or the product of consumption and the fuel-specific C content values. Both the non-energy fuel consumption and C content data were supplied by the EIA (2013, 2015b) (see Annex 2.1). Consumption of natural gas, LPG, pentanes plus, naphthas, other oils, and special naphtha were adjusted to account for net exports of these products that are not reflected in the raw data from EIA. Consumption values for industrial coking coal, petroleum coke, other oils, and natural gas in Table 3-20 and Table 3-21 have been adjusted to subtract non-energy uses that are included in the source categories of the Industrial Processes and Product Use chapter.[56,57] Consumption values were also adjusted to subtract net exports of intermediary chemicals.

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

- For several fuel types—petrochemical feedstocks (including natural gas for non-fertilizer uses, LPG, pentanes plus, naphthas, other oils, still gas, special naphtha, and industrial other coal), asphalt and road oil, lubricants, and waxes—U.S. data on C stocks and flows were used to develop C storage factors, calculated as the ratio of (a) the C stored by the fuel's non-energy products to (b) the total C content of the fuel consumed. A lifecycle approach was used in the development of these factors in order to account for losses in the production process and during use. Because losses associated with municipal solid waste management are handled separately in this sector under the Incineration of Waste source category, the storage factors do not account for losses at the disposal end of the life cycle.
- For industrial coking coal and distillate fuel oil, storage factors were taken from IPCC (2006), which in turn draws from Marland and Rotty (1984).

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

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

- For the remaining fuel types (petroleum coke, miscellaneous products, and other petroleum), IPCC does not provide guidance on storage factors, and assumptions were made based on the potential fate of C in the respective NEU products.

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

Year	1990	2005	2010	2011	2012	2013	2014
Industry	**4,215.8**	**5,110.9**	**4,572.7**	**4,470.2**	**4,377.4**	**4,621.4**	**4,571.6**
Industrial Coking Coal	+	80.4	64.8	60.8	132.5	119.6	23.0
Industrial Other Coal	8.2	11.9	10.3	10.3	10.3	10.3	10.3
Natural Gas to Chemical Plants	281.6	260.9	298.7	297.1	292.7	297.0	305.1
Asphalt & Road Oil	1,170.2	1,323.2	877.8	859.5	826.7	783.3	792.6
LPG	1,120.5	1,610.1	1,834.0	1,865.7	1,887.3	2,062.9	2,109.4
Lubricants	186.3	160.2	149.5	141.8	130.5	138.1	144.0
Pentanes Plus	117.6	95.5	75.3	26.4	40.3	45.4	43.5
Naphtha (<401 ° F)	326.3	679.6	474.5	469.4	432.2	498.8	435.2
Other Oil (>401 ° F)	662.1	499.5	433.2	368.2	267.4	209.1	236.2
Still Gas	36.7	67.7	147.8	163.6	160.6	166.7	164.6
Petroleum Coke	27.2	105.2	+	+	+	+	+
Special Naphtha	100.9	60.9	25.3	21.8	14.1	96.6	104.4
Distillate Fuel Oil	7.0	11.7	5.8	5.8	5.8	5.8	5.8
Waxes	33.3	31.4	17.1	15.1	15.3	16.5	14.8
Miscellaneous Products	137.8	112.8	158.7	164.7	161.6	171.2	182.7
Transportation	**176.0**	**151.3**	**141.2**	**133.9**	**123.2**	**130.4**	**136.0**
Lubricants	176.0	151.3	141.2	133.9	123.2	130.4	136.0
U.S. Territories	**86.7**	**121.9**	**56.4**	**56.7**	**58.1**	**57.4**	**53.6**
Lubricants	0.7	4.6	1.0	1.0	1.0	1.0	1.0
Other Petroleum (Misc. Prod.)	86.0	117.3	55.4	55.7	57.1	56.4	52.6
Total	**4,478.5**	**5,384.1**	**4,770.3**	**4,660.9**	**4,558.7**	**4,809.2**	**4,761.2**

+ Does not exceed 0.05 TBtu

NA (Not applicable)

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

Sector/Fuel Type	Adjusted Non-Energy Use[a] (TBtu)	Carbon Content Coefficient (MMT C/QBtu)	Potential Carbon (MMT C)	Storage Factor	Carbon Stored (MMT C)	Carbon Emissions (MMT C)	Carbon Emissions (MMT CO_2 Eq.)
Industry	**4,571.6**	**NA**	**83.3**	**NA**	**55.6**	**27.7**	**101.6**
Industrial Coking Coal	23.0	31.00	0.7	0.04	0.1	0.6	2.4
Industrial Other Coal	10.3	25.82	0.3	0.65	0.2	0.1	0.3
Natural Gas to Chemical Plants	305.1	14.46	4.4	0.65	2.9	1.5	5.6
Asphalt & Road Oil	792.6	20.55	16.3	1.00	16.2	0.1	0.3
LPG	2,109.4	17.06	36.0	0.65	23.6	12.4	45.6
Lubricants	144.0	20.20	2.9	0.09	0.3	2.6	9.7
Pentanes Plus	43.5	19.10	0.8	0.65	0.5	0.3	1.1
Naphtha (<401° F)	435.2	18.55	8.1	0.65	5.3	2.8	10.2
Other Oil (>401° F)	236.2	20.17	4.8	0.65	3.1	1.6	6.0
Still Gas	164.6	17.51	2.9	0.65	1.9	1.0	3.6
Petroleum Coke	+	27.85	+	0.04	+	+	+
Special Naphtha	104.4	19.74	2.1	0.65	1.3	0.7	2.6
Distillate Fuel Oil	5.8	20.17	0.1	0.04	0.1	0.1	0.2

Waxes	14.8	19.80	0.3	0.58	0.2	0.1	0.5
Miscellaneous Products	182.7	20.31	3.7	0.04	0.0	3.7	13.6
Transportation	**136.0**	**NA**	**2.7**	**NA**	**0.3**	**2.5**	**9.1**
Lubricants	136.0	20.20	2.7	0.09	0.3	2.5	9.1
U.S. Territories	**53.6**	**NA**	**1.1**	**NA**	**0.1**	**1.0**	**3.5**
Lubricants	1.0	20.20	+	0.09	+	+	0.1
Other Petroleum (Misc. Prod.)	52.6	20.00	1.1	0.04	0.1	0.9	3.5
Total	**4,761.2**		**87.1**		**55.9**	**31.2**	**114.3**

+ Does not exceed 0.05 TBtu
NA (Not applicable)
[a] To avoid double counting, net exports have been deducted.
Note: Totals may not sum due to independent rounding.

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

Where storage factors were calculated specifically for the United States, data were obtained on (1) products such as asphalt, plastics, synthetic rubber, synthetic fibers, cleansers (soaps and detergents), pesticides, food additives, antifreeze and deicers (glycols), and silicones; and (2) industrial releases including energy recovery, Toxics Release Inventory (TRI) releases, hazardous waste incineration, and volatile organic compound, solvent, and non-combustion CO emissions. Data were taken from a variety of industry sources, government reports, and expert communications. Sources include EPA reports and databases such as compilations of air emission factors (EPA 2001), *National Emissions Inventory (NEI) Air Pollutant Emissions Trends Data* (EPA 2015a), *Toxics Release Inventory, 1998* (2000b), *Biennial Reporting System* (EPA 2004, 2009), *Resource Conservation and Recovery Act Information System* (EPA 2013b, 2015b), pesticide sales and use estimates (EPA 1998, 1999, 2002, 2004, 2011), and the Chemical Data Access Tool (EPA 2012); the EIA Manufacturer's Energy Consumption Survey (MECS) (EIA 1994, 1997, 2001, 2005, 2010, 2013b, 2015b); the National Petrochemical & Refiners Association (NPRA 2002); the U.S. Bureau of the Census (1999, 2004, 2009); Bank of Canada (2012, 2013, 2014); Financial Planning Association (2006); INEGI (2006); the United States International Trade Commission (1990-2015); Gosselin, Smith, and Hodge (1984); EPA's Municipal Solid Waste (MSW) Facts and Figures (EPA 2013a; 2014a); the Rubber Manufacturers' Association (RMA 2009, 2011, 2014); the International Institute of Synthetic Rubber Products (IISRP 2000, 2003); the Fiber Economics Bureau (FEB 2001-2013); the EPA Chemical Data Access Tool (CDAT) (EPA 2014b); and the American Chemistry Council (ACC 2003-2011, 2012, 2013, 2014a, 2014b, 2015). Specific data sources are listed in full detail in Annex 2.3.

Uncertainty and Time-Series Consistency

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

As noted above, the non-energy use analysis is based on U.S.-specific storage factors for (1) feedstock materials (natural gas, LPG, pentanes plus, naphthas, other oils, still gas, special naphthas, and other industrial coal), (2) asphalt, (3) lubricants, and (4) waxes. For the remaining fuel types (the "other" category in Table 3-20 and Table 3-21), the storage factors were taken directly from the *2006 IPCC Guidelines for National Greenhouse Gas Inventories*, where available, and otherwise assumptions were made based on the potential fate of carbon in the respective NEU products. To characterize uncertainty, five separate analyses were conducted, corresponding to each of the five categories. In all cases, statistical analyses or expert judgments of uncertainty were not available directly from the information sources for all the activity variables; thus, uncertainty estimates were determined using assumptions based on source category knowledge.

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 3-22 (emissions) and Table 3-23 (storage factors). Carbon emitted from non-energy uses of fossil fuels in 2014 was estimated to be between 86.2 and 162.9 MMT CO_2 Eq. at a 95 percent confidence level. This indicates a range of 25 percent below to 42 percent above the 2014 emission estimate of 114.3 MMT CO_2 Eq. The uncertainty in the emission estimates is a function of uncertainty in both the quantity of fuel used for non-energy purposes and the storage factor.

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

Source	Gas	2014 Emission Estimate (MMT CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (MMT CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Feedstocks	CO_2	75.1	49.6	125.3	-34%	67%
Asphalt	CO_2	0.3	0.1	0.6	-57%	117%
Lubricants	CO_2	18.9	15.5	21.9	-18%	16%
Waxes	CO_2	0.5	0.3	0.7	-28%	63%
Other	CO_2	19.6	14.1	21.7	-28%	11%
Total	**CO_2**	**114.3**	**86.2**	**162.9**	**-25%**	**42%**

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

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

Source	Gas	2014 Storage Factor (%)	Uncertainty Range Relative to Emission Estimate[a] (%)		(%, Relative)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Feedstocks	CO_2	65%	52%	72%	-20%	10%
Asphalt	CO_2	99.6%	99.1%	99.8%	-0.5%	0.25%
Lubricants	CO_2	9%	4%	17%	-57%	88%
Waxes	CO_2	58%	49%	70%	-15%	22%
Other	CO_2	4%	4%	24%	-3%	479%

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

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

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

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

QA/QC and Verification

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

For petrochemical import and export data, special attention was paid to NAICS numbers and titles to verify that none had changed or been removed. Import and export totals were compared for 2011 as well as their trends across the time series.

Petrochemical input data reported by EIA will continue to be investigated in an attempt to address an input/output discrepancy in the NEU model. Since 2001, the C accounted for in the feedstocks C balance outputs (i.e., storage plus emissions) exceeds C inputs. Prior to 2001, the C balance inputs exceed outputs. Starting in 2001 through 2009, outputs exceeded inputs. In 2010 and 2011, inputs exceeded outputs, and in 2012, outputs slightly exceeded inputs. A portion of this discrepancy has been reduced (see Recalculations Discussion, below) and two strategies have been developed to address the remaining portion (see Planned Improvements, below).

Recalculations Discussion

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

Planned Improvements – TO BE UPDATED

There are several improvements planned for the future:

- More accurate accounting of C in petrochemical feedstocks. EPA has worked with EIA to determine the cause of input/output discrepancies in the C mass balance contained within the NEU model. In the future, two strategies to reduce or eliminate this discrepancy will continue to be pursued. First, accounting of C in imports and exports will be improved. The import/export adjustment methodology will be examined to ensure that net exports of intermediaries such as ethylene and propylene are fully accounted for. Second, reconsider the use of top-down C input calculation in estimating emissions will be reconsidered. Alternative approaches that rely more substantially on the bottom-up C output calculation will be considered instead.
- Response to potential changes in NEU input data. In 2013 EIA initiated implementation of new data reporting definitions for Natural Gas Liquids (NGL) and Liquefied Petroleum Gases (LPG); the new definitions may affect the characterization of the input data that EIA provides for the NEU model and may therefore result in the need for changes to the NEU methodology. EIA also obtains and applies proprietary data for LPG inputs that are not directly applied as NEU input data because the data are proprietary. The potential use of the proprietary data (in an aggregated, non-proprietary form) as inputs to the NEU model will be investigated with EIA.
- Improving the uncertainty analysis. Most of the input parameter distributions are based on professional judgment rather than rigorous statistical characterizations of uncertainty.
- Better characterizing flows of fossil C. Additional fates may be researched, including the fossil C load in organic chemical wastewaters, plasticizers, adhesives, films, paints, and coatings. There is also a need to

further clarify the treatment of fuel additives and backflows (especially methyl tert-butyl ether, MTBE).

- Reviewing the trends in fossil fuel consumption for non-energy uses. Annual consumption for several fuel types is highly variable across the time series, including industrial coking coal and other petroleum (miscellaneous products). A better understanding of these trends will be pursued to identify any mischaracterized or misreported fuel consumption for non-energy uses. For example, “miscellaneous products” category includes miscellaneous products that are not reported elsewhere in the EIA data set. The EIA does not have firm data concerning the amounts of various products that are being reported in the “miscellaneous products” category; however, EIA has indicated that recovered sulfur from petroleum and natural gas processing, and potentially also C black feedstock could be reported in this category. Recovered sulfur would not be reported in the NEU calculation or elsewhere in the Inventory.
- Updating the average C content of solvents was researched, since the entire time series depends on one year’s worth of solvent composition data. Unfortunately, the data on C emissions from solvents that were readily available do not provide composition data for all categories of solvent emissions and also have conflicting definitions for volatile organic compounds, the source of emissive C in solvents. Additional sources of solvents data will be identified in order to update the C content assumptions.
- Updating the average C content of cleansers (soaps and detergents) was researched; although production and consumption data for cleansers are published every 5 years by the Census Bureau, the composition (C content) of cleansers has not been recently updated. Recently available composition data sources may facilitate updating the average C content for this category.
- Revising the methodology for consumption, production, and C content of plastics was researched; because of recent changes to the type of data publicly available for plastics, the NEU model for plastics applies data obtained from personal communications. Potential revisions to the plastics methodology to account for the recent changes in published data will be investigated.
- Although U.S.-specific storage factors have been developed for feedstocks, asphalt, lubricants, and waxes, default values from IPCC are still used for two of the non-energy fuel types (industrial coking coal, distillate oil), and broad assumptions are being used for miscellaneous products and other petroleum. Over the long term, there are plans to improve these storage factors by analyzing C fate similar to those described in Annex 2.3 or deferring to more updated default storage factors from IPCC where available.
- Reviewing the storage of carbon black across various sectors in the Inventory; in particular, the carbon black abraded and stored in tires.

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

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

The emissions are reported in the Energy sector, as opposed to the IPPU sector, to reflect national circumstances in its choice of methodology and to increase transparency of this source category’s unique country-specific data sources and methodology. The country-specific methodology used for the Carbon Emitted from Non-Energy Uses of Fossil Fuels source category is based on a carbon balance (i.e., C inputs-outputs) calculation of the aggregate

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

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

amount of fossil fuels used for non-energy uses, including inputs of lubricants, waxes, asphalt and road oil (see section 3.2, Table 3-21). For those inputs, U.S. country-specific data on C stocks and flows are used to develop carbon storage factors, which are calculated as the ratio of the C stored by the fossil fuel non-energy products to the total C content of the fuel consumed, taking into account losses in the production process and during product use.[60] The country-specific methodology to reflect national circumstances starts with the aggregate amount of fossil fuels used for non-energy uses and applies a C balance calculation, breaking out the C emissions from non-energy use of lubricants, waxes, and asphalt and road oil. Due to U.S. national circumstances, reporting these C emissions separately under IPPU would involve making artificial adjustments to both the C inputs and C outputs of the non-energy use C balance. These artificial adjustments would also result in the C emissions for lubricants, waxes, and asphalt and road oil being reported under IPPU, while the C storage for lubricants, waxes, and asphalt and road oil would be reported under Energy. To avoid presenting an incomplete C balance and a less transparent approach for the Carbon Emitted from Non-Energy Uses of Fossil Fuels source category calculation, the entire calculation of C storage and C emissions is therefore conducted in the Non-Energy Uses of Fossil Fuels category calculation methodology, and both the C storage and C emissions for lubricants, waxes, and asphalt and road oil are reported under the Energy sector.

3.3 Incineration of Waste (IPCC Source Category 1A1a)

Incineration is used to manage about 7 to 19 percent of the solid wastes generated in the United States, depending on the source of the estimate and the scope of materials included in the definition of solid waste (EPA 2000, Goldstein and Madtes 2001, Kaufman et al. 2004, Simmons et al. 2006, van Haaren et al. 2010). In the context of this section, waste includes all municipal solid waste (MSW) as well as scrap tires. In the United States, almost all incineration of MSW occurs at waste-to-energy facilities or industrial facilities where useful energy is recovered, and thus emissions from waste incineration are accounted for in the Energy chapter. Similarly, scrap tires are combusted for energy recovery in industrial and utility boilers, pulp and paper mills, and cement kilns. Incineration of waste results in conversion of the organic inputs to CO_2. According to IPCC guidelines, when the CO_2 emitted is of fossil origin, it is counted as a net anthropogenic emission of CO_2 to the atmosphere. Thus, the emissions from waste incineration are calculated by estimating the quantity of waste combusted and the fraction of the waste that is C derived from fossil sources.

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

Approximately 29.6 million metric tons of MSW were incinerated in the United States in 2013 (EPA 2015). Data for the amount of MSW incinerated in 2014 were not available, so data for 2014 was assumed to be equal to data for 2013. CO_2 emissions from incineration of waste rose 18 percent since 1990, to an estimated 9.4 MMT CO_2 Eq. (9,421 kt) in 2014, as the volume of scrap tires and other fossil C-containing materials in waste increased (see Table 3-24 and Table 3-25). Waste incineration is also a source of CH_4 and N_2O emissions (De Soete 1993, IPCC 2006).

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[60] Data and calculations for lubricants and waxes and asphalt and road oil are in Annex 2.3: Methodology and Data for Estimating CO_2 Emissions from Fossil Fuel Combustion.

CH_4 emissions from the incineration of waste were estimated to be less than 0.05 MMT CO_2 Eq. (less than 0.5 kt CH_4) in 2014, and have not changed significantly since 1990. N_2O emissions from the incineration of waste were estimated to be 0.3 MMT CO_2 Eq. (1 kt N_2O) in 2014, and have not changed significantly since 1990.

Table 3-24: CO_2, CH_4, and N_2O Emissions from the Incineration of Waste (MMT CO_2 Eq.)

Gas/Waste Product	1990	2005	2010	2011	2012	2013	2014[a]
CO_2	**8.0**	**12.5**	**11.0**	**10.5**	**10.4**	**9.4**	**9.4**
Plastics	5.6	6.9	6.0	5.8	5.7	4.9	4.9
Synthetic Rubber in Tires	0.3	1.6	1.5	1.4	1.3	1.2	1.2
Carbon Black in Tires	0.4	2.0	1.8	1.7	1.5	1.4	1.4
Synthetic Rubber in MSW	0.9	0.8	0.7	0.7	0.7	0.7	0.7
Synthetic Fibers	0.8	1.2	1.1	1.1	1.1	1.3	1.3
CH_4	+	+	+	+	+	+	+
N_2O	**0.5**	**0.4**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**
Total	**8.4**	**12.8**	**11.4**	**10.9**	**10.7**	**9.7**	**9.7**

[a] Set equal to 2013 value.

Table 3-25: CO_2, CH_4, and N_2O Emissions from the Incineration of Waste (kt)

Gas/Waste Product	1990	2005	2010	2011	2012	2013	2014[a]
CO_2	**7,972**	**12,454**	**11,026**	**10,550**	**10,362**	**9,421**	**9,421**
Plastics	5,588	6,919	5,969	5,757	5,709	4,857	4,857
Synthetic Rubber in Tires	308	1,599	1,461	1,363	1,262	1,158	1,158
Carbon Black in Tires	385	1,958	1,783	1,663	1,537	1,412	1,412
Synthetic Rubber in MSW	854	765	701	712	705	729	729
Synthetic Fibers	838	1,212	1,112	1,056	1,149	1,265	1,265
CH_4	+	+	+	+	+	+	+
N_2O	**2**	**1**	**1**	**1**	**1**	**1**	**1**

[a] Set equal to 2013 value.

Methodology

Emissions of CO_2 from the incineration of waste include CO_2 generated by the incineration of plastics, synthetic fibers, and synthetic rubber in MSW, as well as the incineration of synthetic rubber and carbon black in scrap tires. These emissions were estimated by multiplying the amount of each material incinerated by the C content of the material and the fraction oxidized (98 percent). Plastics incinerated in municipal solid wastes were categorized into seven plastic resin types, each material having a discrete C content. Similarly, synthetic rubber is categorized into three product types, and synthetic fibers were categorized into four product types, each having a discrete C content. Scrap tires contain several types of synthetic rubber, carbon black, and synthetic fibers. Each type of synthetic rubber has a discrete C content, and carbon black is 100 percent C. Emissions of 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.

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

For each of the methods used to calculate CO_2 emissions from the incineration of waste, data on the quantity of product combusted and the C content of the product are needed. For plastics, synthetic rubber, and synthetic fibers in MSW, the amount of specific materials discarded as municipal solid waste (i.e., the quantity generated minus the quantity recycled) was taken from *Municipal Solid Waste Generation, Recycling, and Disposal in the United States: Facts and Figures* (EPA 2000 through 2003, 2005 through 2014), *Advancing Sustainable Materials Management: Facts and Figures 2013: Assessing Trends in Material Generation, Recycling and Disposal in the United States* (EPA 2015) and detailed unpublished backup data for some years not shown in the reports (Schneider 2007). For 2014, the amount of MSW incinerated was assumed to be equal to that in 2013, due to the lack of available data. The proportion of total waste discarded that is incinerated was derived from Shin (2014). Data on total waste incinerated was not available for 2012 through 2014, so these values were assumed to equal to the 2011 value. For synthetic rubber and carbon black in scrap tires, information was obtained from U.S. Scrap Tire Management Summary for 2005 through 2013 data (RMA 2014). Average C contents for the "Other" plastics category and synthetic rubber in municipal solid wastes were calculated from 1998 and 2002 production statistics: C content for 1990 through 1998 is based on the 1998 value; C content for 1999 through 2001 is the average of 1998 and 2002 values; and C content for 2002 to date is based on the 2002 value. Carbon content for synthetic fibers was calculated from 1999 production statistics. Information about scrap tire composition was taken from the Rubber Manufacturers' Association internet site (RMA 2012a).

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

Incineration of waste, including MSW, also results in emissions of N_2O and CH_4. These emissions were calculated as a function of the total estimated mass of waste incinerated and emission factors. As noted above, N_2O and CH_4 emissions are a function of total waste incinerated in each year; for 1990 through 2008, these data were derived from the information published in BioCycle (van Haaren et al. 2010). Data for 2009 and 2010 were interpolated between 2008 and 2011 values. Data for 2011 were derived from Shin (2014). Data on total waste incinerated was not available in the BioCycle data set for 2012 through2014, so these values were assumed to equal the 2011 Biocycle data set value.

Table 3-26 provides data on municipal solid waste discarded and percentage combusted for the total waste stream.The emission factors of N_2O and CH_4 emissions per quantity of municipal solid waste combusted are default emission factors for the default continuously-fed stoker unit MSW incineration technology type and were taken from the *2006 IPCC Guidelines* (IPCC 2006).

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

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

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

Uncertainty and Time-Series Consistency

An Approach 2 Monte Carlo analysis was performed to determine the level of uncertainty surrounding the estimates of 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. Uncertainty estimates and distributions for waste generation variables (i.e., plastics, synthetic rubber, and textiles generation) were obtained through a conversation with one of the authors of the Municipal Solid Waste in the United States reports. Statistical analyses or expert judgments of uncertainty were not available directly from the information sources for the other variables; thus, uncertainty estimates for these variables were determined using assumptions based on source category knowledge and the known uncertainty estimates for the waste generation variables.

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

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 3-27. Waste incineration CO_2 emissions in 2014 were estimated to be between 8.5 and 11.5 MMT CO_2 Eq. at a 95 percent confidence level. This indicates a range of 10 percent below to 14 percent above the 2014 emission estimate of 9.4 MMT CO_2 Eq. Also at a 95 percent confidence level, waste incineration N_2O emissions in 2014 were estimated to be between 0.1 and 0.8 MMT CO_2 Eq. This indicates a range of 53 percent below to 163 percent above the 2014 emission estimate of 0.3 MMT CO_2 Eq.

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

Source	Gas	2014 Emission Estimate (MMT CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (MMT CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Incineration of Waste	CO_2	9.4	8.5	11.5	-10%	+14%
Incineration of Waste	N_2O	0.3	0.1	0.8	-53%	+163%

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

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

QA/QC and Verification

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

Recalculations Discussion

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

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

Planned Improvements

The availability of facility-level waste incineration data through EPA's GHGRP will be examined to help better characterize waste incineration operations in the United States. This characterization could include future improvements as to the operations involved in waste incineration for energy, whether in the power generation sector or the industrial sector. Additional examinations will be necessary as, unlike the reporting requirements for this chapter under the UNFCCC reporting guidelines,[61] some facility-level waste incineration emissions reported under EPA's GHGRP may also include industrial process emissions. In line with UNFCCC reporting guidelines, emissions for waste incineration with energy recovery are included in this chapter, while process emissions are included in the Industrial Processes and Product Use chapter of this report. In examining data from EPA's GHGRP that would be useful to improve the emission estimates for the waste incineration category, particular attention will also be made to ensure time series consistency, as the facility-level reporting data from EPA's GHGRP are not available for all inventory years as reported in this Inventory. Additionally, analyses will focus on ensuring CO_2 emissions from the biomass component of waste are separated in the facility-level reported data, and on maintaining consistency with national waste generation and fate statistics currently used to estimate total, national U.S. greenhouse gas emissions. In implementing improvements and integration of data from EPA's GHGRP, the latest guidance from the IPCC on the use of facility-level data in national inventories will be relied upon.[62] GHGRP data is available for MSW combustors, which contains information on the CO_2, CH_4, and N_2O emissions from MSW combustion, plus the fraction of the emissions that are biogenic. To calculate biogenic versus total CO_2 emissions, a default biogenic fraction of 0.6 is used. The biogenic fraction will be calculated using the current input data and assumptions to verify the current MSW emission estimates.

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

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

3.4 Coal Mining (IPCC Source Category 1B1a) (TO BE UPDATED)

Three types of coal mining-related activities release CH_4 to the atmosphere: underground mining, surface mining, and post-mining (i.e., coal-handling) activities. While surface mines account for the majority of U.S. coal production (see Table 3-30), underground coal mines contribute the largest share of CH_4 emissions (see Table 3-28 and Table 3-29) due to the higher CH_4 content of coal in the deeper underground coal seams. In 2013, 395 underground coal mines and 637 surface mines were operating in the U.S. Also in 2013, the U.S. was the second largest coal producer in the world (891 MMT), after China (3,561 MMT) and followed by India (613 MMT) (IEA 2014).

Underground 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

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

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

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 and depth. Surface coal mines typically produce lower rank coals and remove less than 250 feet of overburden, thus the 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 2013 were estimated to be 64.6 MMT CO_2 Eq. (2,584 kt CH_4), a decline of 33 percent since 1990 (see Table 3-28 and Table 3-29). Of this amount, underground mines accounted for approximately 71.6 percent, surface mines accounted for 15.0 percent, and post-mining emissions accounted for 13.4 percent.

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

Activity	1990	2005	2009	2010	2011	2012	2013
UG Mining	74.2	42.0	59.2	61.6	50.2	47.3	46.2
Liberated	80.8	59.7	78.7	85.2	71.0	65.8	65.8
Recovered & Used	(6.6)	(17.7)	(19.5)	(23.6)	(20.8)	(18.5)	(19.6)
Surface Mining	10.8	11.9	11.5	11.5	11.6	10.3	9.7
Post-Mining (Under Ground)	9.2	7.6	6.7	6.8	6.9	6.7	6.6
Post-Mining (Surface)	2.3	2.6	2.5	2.5	2.5	2.2	2.1
Total	**96.5**	**64.1**	**79.9**	**82.3**	**71.2**	**66.5**	**64.6**

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

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

Activity	1990	2005	2009	2010	2011	2012	2013
UG Mining	2,968	1,682	2,367	2,463	2,008	1,891	1,849
Liberated	3,234	2,390	3,149	3,406	2,839	2,631	2,633
Recovered & Used	(266)	(708)	(782)	(943)	(831)	(740)	(784)
Surface Mining	430	475	461	461	465	410	388
Post-Mining (UG)	368	306	267	270	276	268	263
Post-Mining (Surface)	93	103	100	100	101	89	84
Total	**3,860**	**2,565**	**3,194**	**3,293**	**2,849**	**2,658**	**2,584**

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

Methodology

The methodology for estimating CH_4 emissions from coal mining consists of two steps. The first step is to estimate emissions from underground mines. There are two sources of underground mine emissions: ventilation systems and degasification systems. These emissions are estimated on a mine-by-mine basis and then are summed to determine total emissions. The second step of the analysis involves estimating CH_4 emissions from surface mines and post-mining activities. In contrast to 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 from degasification systems. Some mines recover and use the generated 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

Because the U.S. Mine Safety and Health Administration (MSHA) samples CH_4 emissions from ventilation systems for all mines with detectable CH_4 concentrations[63] to ensure miner safety, these mine-by-mine measurements are used to estimate CH_4 emissions from ventilation systems. Since 2011, the EPA has also collected information on ventilation emissions from underground coal mines liberating greater than 36,500,000 actual cubic feet of CH_4 per year (about 14,700 metric tons CO_2 Eq.) through its GHGRP (EPA 2014).[64] Many of the underground coal mines reporting to EPA's GHGRP use the quarterly CH_4 emission data collected by MSHA. However, some mines use their own measurements and samples, which are taken on a quarterly basis. The 2013 ventilation emissions were calculated using the GHGRP data from the mines that take their own measurements and the MSHA data for all other mines.

Step 1.2: Estimate CH_4 Liberated from Degasification Systems

Some gassier 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. Several data sets were used to estimate the quantity of CH_4 collected by each of the twenty-four mines using degasification systems in 2013. For Alabama mines that sold recovered CH_4 to a pipeline, pipeline sales data published by state petroleum and natural gas agencies were used to estimate degasification emissions. The well data was also used to estimate CH_4 collected from mined-through pre-drainage wells. For most other mines that either sold CH_4 to a pipeline, used CH_4 on site, or vented CH_4 from degasification systems, data on degasification emissions reported to the EPA's GHGRP (EPA 2014) were used.

Step 1.3: Estimate CH_4 Recovered from Degasification Systems and Utilized (Emissions Avoided)

Finally, the amount of CH_4 recovered by degasification and ventilation systems and then used (i.e., not vented) was estimated. In 2013, fifteen active coal mines had CH_4 recovery and use projects, of which thirteen mines sold the recovered CH_4 to a pipeline. One of the mines that sold gas to a pipeline also used CH_4 to fuel a thermal coal dryer. One mine used recovered CH_4 for electrical power generation, and two other mines used recovered CH_4 to heat mine ventilation air or dry coal. Emissions avoided as a result of pipeline sales projects at Alabama and West Virginia mines were estimated using gas sales data reported by the state agencies. For all other mines with pipeline sales or used methane for electric power or heating, either the coal mine operators or project developers supplied information regarding methane recovery or GHGRP data were used.

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

Mine-specific data were 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 (see Table 3-30) (EIA 2014) was multiplied by basin-specific gas contents and a 150 percent emission factor (to account for CH_4 from over- and under-burden) to estimate CH_4 emissions. The emission factor was revised downward in 2012 from 200 percent, based on more recent studies in Canada and Australia (King 1994, Saghafi 2013). The 150 percent emission factor was applied to all inventory years since 1990, retroactively. For post-mining activities, basin-specific coal production was multiplied by basin-specific gas contents and a 32.5 percent emission factor for CH_4 desorption during coal transportation and storage (Creedy 1993). Basin-specific *in situ* gas content data was compiled from AAPG (1984) and USBM (1986). Beginning in 2006, revised data on *in situ* CH_4 content and emission factors have been taken from EPA (1996) and EPA (2005).

Table 3-30: Coal Production (kt)

Year	Underground	Surface	Total
1990	384,244	546,808	931,052
2005	334,398	691,448	1,025,846

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[63] 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.

[64] Underground coal mines report to EPA under Subpart FF of the program.

2009	301,241	671,475	972,716
2010	305,862	676,177	982,039
2011	313,529	684,807	998,337
2012	310,608	610,307	920,915
2013	309,546	581,270	890,815

Uncertainty and Time-Series Consistency

A quantitative uncertainty analysis was conducted for the coal mining source category using the IPCC-recommended Approach 2 uncertainty estimation methodology. Because emission estimates from underground ventilation systems were based on actual measurement data from MSHA or EPA's GHGRP, uncertainty is relatively low. A degree of imprecision was introduced because the measurements used were not continuous but rather an average of quarterly instantaneous readings. Additionally, the measurement equipment used can be expected to have resulted in an average of 10 percent overestimation of annual CH_4 emissions (Mutmansky & Wang 2000). GHGRP data was used for a number of the mines beginning in 2013, however, the equipment uncertainty is applied to both MSHA and GHGRP data.

Estimates of CH_4 recovered by degasification systems are relatively certain for utilized CH_4 because of the availability of gas sales information. In addition, many coal mine operators provided information on mined-through dates for pre-drainage wells. Many of the recovery estimates use data on wells within 100 feet of a mined area. However, uncertainty exists concerning the radius of influence of each well. The number of wells counted, and thus the avoided emissions, may vary if the drainage area is found to be larger or smaller than estimated.

Continuous CH_4 monitoring is required of mines that report utilized methane on or off-site to EPA's GHGRP. Beginning in 2013, use of GHGRP data for mines without publicly-available gas usage or sales records has reduced the uncertainty from previous estimations. In addition, since 2012, GHGRP data has been used to estimate CH_4 emissions from vented degasification wells, thus reducing the uncertainty associated with that subsource.

Compared to underground mines, there is considerably more uncertainty associated with surface mining and post-mining emissions because of the difficulty in developing accurate emission factors from field measurements. However, since underground emissions comprise the majority of total coal mining emissions, the uncertainty associated with underground emissions is the primary factor that determines overall uncertainty. The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 3-31. Coal mining CH_4 emissions in 2013 were estimated to be between 56.6 and 74.7 MMT CO_2 Eq. at a 95 percent confidence level. This indicates a range of 12.4 percent below to 15.6 percent above the 2013 emission estimate of 64.6 MMT CO_2 Eq.

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

Source	Gas	2013 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	64.6	56.6	74.7	-12.4%	+15.6%

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

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2013. Details on the emission trends through time are described in more detail in the Methodology section.

Recalculations Discussion

For the current Inventory, emission estimates have been revised to reflect the GWPs provided in the *IPCC Fourth Assessment Report* (AR4) (IPCC 2007). AR4 GWP values differ slightly from those presented in the *IPCC Second Assessment Report* (SAR) (IPCC 1996) (used in the previous inventories) which results in time-series recalculations for most inventory sources. Under the most recent reporting guidelines (UNFCCC 2014), countries are required to report using the AR4 GWPs, which reflect an updated understanding of the atmospheric properties of each greenhouse gas. The GWPs of CH_4 and most fluorinated greenhouse gases have increased, leading to an overall increase in CO_2-equivalent emissions from CH_4. The GWPs of N_2O and SF_6 have decreased, leading to a decrease in CO_2-equivalent emissions for these greenhouse gases. The AR4 GWPs have been applied across the entire time series for consistency. For more information please see the Recalculations and Improvements Chapter.

Prior to the current Inventory, vented degasification emissions from underground coal mines were typically estimated based on drainage efficiencies reported by either the mining company or MSHA. However, beginning in 2011, underground coal mines began reporting CH_4 emissions from degasification systems to EPA under its GHGRP, which requires degasification quantities to be measured weekly, thus offering a more accurate account than previous methods. As a result, data reported to EPA's GHGRP in 2012 and 2013 were used to estimate vented degasification volumes for those mines. GHGRP data was also used in 2013 for degas-used volumes at mines using methane on-site or without available gas sales records. In addition, for forty-nine mines, the 2013 VAM emission estimates included VAM data measured at least quarterly and reported to the GHGRP. Emissions avoided at mines with VAM mitigation projects (2) were estimated based on emission reductions registered at the Climate Action Reserve GHG Registry (CAR 2014).

Planned Improvements

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

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

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 7.2 to 10.8 MMT CO_2 Eq. from 1990 through 2013, varying, in general, by less than 1 percent to approximately 19 percent from year to year. Fluctuations were due mainly to the number of mines closed during a given year as well as the magnitude of the emissions from those mines when active. Gross abandoned mine emissions peaked in 1996 (10.8 MMT CO_2 Eq.) due to the large number of mine closures from 1994 to 1996 (72 gassy mines closed during the three-year period). In spite of this rapid rise, abandoned mine emissions have been generally on the decline since 1996. Since 2002, there have been fewer than twelve gassy mine closures each year. There were eight gassy mine closures in 2013. In 2013, gross abandoned mine emissions decreased slightly to 8.8 MMT CO_2 Eq. (see Table 3-32 and Table 3-33). Gross emissions are reduced by CH_4 recovered and used at 37 mines, resulting in net emissions in 2013 of 6.2 MMT CO_2 Eq.

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

Activity	1990	2005	2009	2010	2011	2012	2013
Abandoned Underground Mines	7.2	8.4	9.9	9.7	9.3	8.9	8.8
Recovered & Used	+	1.8	3.6	3.2	2.9	2.7	2.6
Total	**7.2**	**6.6**	**6.4**	**6.6**	**6.4**	**6.2**	**6.2**

+ Does not exceed 0.05 MMT CO_2 Eq.

Note: Totals may not sum due to independent rounding.

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

Activity	1990	2005	2009	2010	2011	2012	2013
Abandoned Underground Mines	288	334	398	389	373	358	353
Recovered & Used	+	70	143	126	116	109	104
Total	**288**	**264**	**254**	**263**	**257**	**249**	**249**

Note: Totals may not sum due to independent rounding.

+ Does not exceed 0.5 kt.

Methodology

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

In order to estimate CH_4 emissions over time for a given 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:

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

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/yr
t = Elapsed time from t_o (years)

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

The decline curves created to model the gas emission rate of coal mines must account for factors that decrease the rate of emission after mining activities cease, such as sealing and flooding. Based on field measurement data, it was assumed that most U.S. mines prone to flooding will become completely flooded within eight years and therefore no longer have any measurable CH_4 emissions. Based on this assumption, an average decline rate for flooded mines was established by fitting a decline curve to emissions from field measurements. An exponential equation was developed from emissions data measured at eight abandoned mines known to be filling with water located in two of the five basins. Using a least squares, curve-fitting algorithm, emissions data were matched to the exponential equation shown below. There was not enough data to establish basin-specific equations as was done with the vented, non-flooding mines (EPA 2004).

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

where,

q = Gas flow rate at time t in mmcfd
qi = Initial gas flow rate at time zero (to), mmcfd
D = Decline rate, 1/yr
t = Elapsed time from to (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) account for 98 percent of all CH_4 emissions. This same relationship is assumed for abandoned mines. It was determined that the 492 abandoned mines closed after 1972 produced emissions greater than 100 mcfd when active. Further, the status of 283 of the 492 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 3-34: Number of Gassy Abandoned Mines Present in U.S. Basins, grouped by Class according to Post-Abandonment State

Basin	Sealed	Vented	Flooded	Total Known	Unknown	Total Mines
Central Appl.	33	25	48	106	137	243
Illinois	32	3	14	49	27	76
Northern Appl.	42	22	16	80	36	116
Warrior Basin	0	0	16	16	0	16
Western Basins	27	3	2	32	9	41
Total	**134**	**53**	**96**	**283**	**209**	**492**

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

During the 1970s, 78 percent of CH_4 emissions from coal mining came from seventeen counties in seven states. In addition, mine closure dates were obtained for two states, Colorado and Illinois, for the hundred year period extending from 1900 through 1999. The data were used to establish a frequency of mine closure histogram (by decade) and applied to the other five states with gassy mine closures. As a result, basin-specific decline curve equations were applied to 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 emissions 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. Coal mine degasification data are not available for years prior to 1990, thus the initial emission rates used reflect ventilation emissions only for pre-1990 closures. CH_4 degasification amounts were added to the quantity of CH_4 vented to determine the total CH_4 liberation rate for all mines that closed between 1992 and 2013. Since the sample of gassy mines (with active mine emissions greater than 100 mcfd) is assumed to account for 78 percent of the pre-1972 and 98 percent of the post-1971 abandoned mine emissions, the modeled results were multiplied by 1.22 and 1.02 to account for all U.S. abandoned mine emissions.

From 1993 through 2013, emission totals were downwardly adjusted to reflect abandoned mine CH_4 emissions avoided from those mines. The Inventory totals were not adjusted for abandoned mine reductions from 1990 through 1992 because no data was reported for abandoned coal mining CH_4 recovery projects during that time.

Uncertainty and Time-Series Consistency

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

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

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 3-35. Annual abandoned coal mine CH_4 emissions in 2013 were estimated to be between 5.0 and 7.7 MMT CO_2 Eq. at a 95 percent confidence level. This indicates a range of 20 percent below to 24 percent above the 2013 emission estimate of 6.2 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 after 1972. Emissions from mines closed prior to 1972 have the largest degree of uncertainty because no mine-specific CH_4 liberation rates exist.

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

Source	Gas	2013 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	6.2	5.0	7.7	-20%	+24%

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

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2013. Details on the emission trends through time are described in more detail in the Methodology section, above.

3.6 Petroleum Systems (IPCC Source Category 1B2a)

Substantial new data are available on natural gas and petroleum systems from the EPA's Greenhouse Gas Reporting Program (GHGRP). The EPA is evaluating approaches for incorporating this new data into its emission estimates for the *Inventory of U.S. GHG Emissions and Sinks: 1990-2014*.

The details of the revisions under consideration for the current Inventory, and key questions for stakeholder feedback are available in segment-level memoranda at http://www3.epa.gov/climatechange/ghgemissions/usinventoryreport/natural-gas-systems.html. For petroleum systems, revisions under consideration impact the production segment only.

Below, updated draft estimates of CH_4 emissions for the year 2013 are presented to provide reviewers of the public review draft an indication of the sector-wide emissions estimates resulting from changes under consideration. Carbon dioxide emissions have not been updated in the public review draft, but will be updated in the final Inventory.

The EPA is continuing to evaluate stakeholder feedback on the updates under consideration. For the final Inventory, the 2013 estimates presented in this section will be refined, and a full time series of emissions estimates will be developed based on feedback received through the earlier stakeholder reviews of the memos and through this public review period.

Methane emissions from petroleum systems are primarily associated with onshore and offshore crude oil production, transportation, and refining operations. During each of these activities, CH_4 is released to the atmosphere as fugitive emissions, vented emissions, emissions from operational upsets, and emissions from fuel combustion. Fugitive and vented CO_2 emissions from petroleum systems are primarily associated with crude oil production and refining operations but are negligible in transportation operations. Total CH_4 emissions from petroleum systems in 2013 were 63.4 MMT CO_2 Eq. (2,535 kt).

Production Field Operations. The EPA is considering several revisions to the production segment. For information on these revisions, and requests for stakeholder feedback please see the Production Segment memo.[65] The information presented here was calculated using the approaches under consideration in the memo, as discussed below in the Recalculations Discussion section.

Production field operations account for over 98 percent of total CH_4 emissions from petroleum systems. Vented CH_4 from field operations account for approximately 92 percent of the net emissions from the production sector, fugitive emissions are 5 percent, uncombusted CH_4 emissions (i.e., unburned fuel) account for 4 percent, and process upset emissions are approximately 0.1 percent. The most dominant sources of emissions, in order of magnitude, are intermittent bleed pneumatic controllers, oil tanks, chemical injection pumps, high bleed pneumatic controllers, shallow water offshore oil platforms, gas engines, oil wellheads (light crude services), and low bleed pneumatic devices. These eight sources alone emit over 96 percent of the production field operations emissions. Offshore platform emissions are a combination of fugitive, vented, and uncombusted fuel emissions from all equipment housed on oil platforms producing oil and associated gas. Emissions from gas engines are due to unburned CH_4 that vents with the exhaust. Emissions from oil wellheads are due to fugitive losses. The remaining 4 percent of the emissions are distributed among 26 additional activities within the four categories: vented, fugitive, combustion, and process upset emissions.

Vented CO_2 associated with production field operations account for approximately 99 percent of the total CO_2 emissions from production field operations, while fugitive and process upsets together account for less than 1 percent of the emissions. The most dominant sources of vented CO_2 emissions are oil tanks, high bleed pneumatic controllers, shallow water offshore oil platforms, low bleed pneumatic controllers, and oil wellheads (light crude services). These five sources together account for slightly over 98 percent of the non-combustion CO_2 emissions from production field operations, while the remaining 1 percent of the emissions is distributed among 24 additional activities within the three categories: vented, fugitive, and process upsets. Note that CO_2 from associated gas flaring is accounted in natural gas systems production emissions. CO_2 emissions from flaring for both natural gas and oil were 16 MMT CO_2 Eq. in 2013.

Crude Oil Transportation. Crude oil transportation activities account for approximately 0.7 percent of total CH_4 emissions from the oil industry. Venting from tanks, truck loading, rail loading, and marine vessel loading operations account for 82 percent of CH_4 emissions from crude oil transportation. Fugitive emissions, almost entirely from floating roof tanks, account for 14 percent of CH_4 emissions from crude oil transportation. The remaining 4 percent is distributed among two additional sources within the vented emissions category (i.e., pump station maintenance and pipeline pigging). Emissions from pump engine drivers and heaters were not estimated due to lack of data.

Since 1990, CH_4 emissions from transportation have increased by almost 4 percent. However, because emissions from crude oil transportation account for such a small percentage of the total emissions from the petroleum industry, this has had little impact on the overall emissions. Methane emissions have increased by approximately 11 percent from 2012 levels.

Crude Oil Refining. Crude oil refining processes and systems account for slightly above 3 percent of total CH_4 emissions from the oil industry because most of the CH_4 in crude oil is removed or escapes before the crude oil is delivered to the refineries. There is an insignificant amount of CH_4 in all refined products. Within refineries, combustion emissions account for about 60 percent of the CH_4 emissions, while vented and fugitive emissions account for approximately 26 and 13 percent, respectively. Flare emissions are the primary combustion emissions contributor. Refinery system blowdowns for maintenance and process vents are the primary venting contributors. Most of the fugitive CH_4 emissions from refineries are from equipment leaks and storage tanks.

CH_4 emissions from refining of crude oil have increased by approximately 24 percent since 1990; however, similar to the transportation subcategory, this increase has had little effect on the overall emissions of CH_4. Since 1990, CH_4 emissions have fluctuated between 27 and 34 kt.

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[65] http://www3.epa.gov/climatechange/ghgemissions/usinventoryreport/DRAFT_Proposed_Revision_to_Production_Segment_Emissions_2-3-2016.pdf

Flare emissions from crude oil refining accounts for 95 percent of the total CO_2 emissions in petroleum systems. Refinery CO_2 emissions increased by 36 percent from 1990 to 2013.

Table 3-36: CH_4 Emissions from Petroleum Systems (MMT CO_2 Eq.)

Activity	1990	2005	2009	2010	2011	2012	2013	2014
Production Field Operations (Potential)							**63.1**	
Pneumatic controller venting[a]							37.8	
Tank venting							7.9	
Combustion & process upsets							2.8	
Misc. venting & fugitives							13.1	
Wellhead fugitives							1.5	
Production Voluntary Reductions							(0.8)	
Production Field Operations (Net)							**62.4**	
Crude Oil Transportation							**0.2**	
Refining							**0.8**	
Total							**63.4**	

Note: Totals may not sum due to independent rounding.

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

Table 3-37: CH_4 Emissions from Petroleum Systems (kt)

Activity	1990	2005	2009	2010	2011	2012	2013	2014
Production Field Operations (Potential)							**2,525**	
Pneumatic controller venting[a]							1,512	
Tank venting							318	
Combustion & process upsets							113	
Misc. venting & fugitives							553	
Wellhead fugitives							60	
Production Voluntary Reductions							(31)	
Production Field Operations (Net)							**2,494**	
Crude Oil Transportation							**7**	
Refining							**34**	
Total							**2,535**	

Note: Totals may not sum due to independent rounding.

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

Table 3-38: CO_2 Emissions from Petroleum Systems (MMT CO_2 Eq.)

Activity	1990	2005	2009	2010	2011	2012	2013	2014
Production Field Operations	**0.4**	**0.3**	**0.3**	**0.3**	**0.3**	**0.4**	**0.5**	
Pneumatic controller venting	+	+	+	+	+	+	+	
Tank venting	0.3	0.2	0.3	0.3	0.3	0.4	0.4	
Misc. venting & fugitives	+	+	+	+	+	+	+	
Wellhead fugitives	+	+	+	+	+	+	+	
Process upsets	+	+	+	+	+	+	+	
Crude Refining	**4.1**	**4.6**	**4.4**	**3.8**	**4.1**	**4.7**	**5.5**	
Total	**4.4**	**4.9**	**4.7**	**4.2**	**4.5**	**5.1**	**6.0**	

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

Table 3-39: CO_2 Emissions from Petroleum Systems (kt)

Activity	1990	2005	2009	2010	2011	2012	2013	2014
Production Field Operations	**375**	**285**	**305**	**317**	**333**	**394**	**461**	
Pneumatic controller venting	27	23	24	24	25	26	26	
Tank venting	328	246	265	276	291	351	417	
Misc. venting & fugitives	16	13	14	14	14	14	14	
Wellhead fugitives	3	3	3	3	3	3	3	
Process upsets	0.2	0.1	0.1	0.2	0.2	0.2	0.2	
Crude Refining	**4,070**	**4,620**	**4,351**	**3,836**	**4,134**	**4,666**	**5,540**	
Total	**4,445**	**4,904**	**4,656**	**4,153**	**4,467**	**5,060**	**6,001**	

Note: Totals may not sum due to independent rounding.

Methodology

EPA has made revisions to the methodology and data sources for many sources in the Inventory. Please see the Recalculations Discussion section below.

The methodology for estimating CH_4 emissions from petroleum systems is based on comprehensive studies of CH_4 emissions from U.S. petroleum systems (GRI/EPA 1996, EPA 1999) and EPA's GHGRP data. The 1996 and 1999 studies calculated emission estimates for 57 activities occurring in petroleum systems from the oil wellhead through crude oil refining, including 33 activities for crude oil production field operations, 11 for crude oil transportation activities, and 13 for refining operations. Annex 3.5 provides greater detail on the emission estimates for these 57 activities. The estimates of CH_4 emissions from petroleum systems do not include emissions downstream of oil refineries because these emissions are negligible.

Key references for activity data and emission factors are DrillingInfo (2014), the Energy Information Administration annual and monthly reports (EIA 1990 through 2014), (EIA 1995 through 2014a, 2014b, 2014c), "Methane Emissions from the Natural Gas Industry by the Gas Research Institute and EPA" (EPA/GRI 1996a-d), "Estimates of Methane Emissions from the U.S. Oil Industry" (EPA 1999), consensus of industry peer review panels, BOEMRE and BOEM reports (BOEMRE 2004, BOEM 2011), analysis of BOEMRE data (EPA 2005, BOEMRE 2004), the Oil & Gas Journal (OGJ 2014a, 2013b), the Interstate Oil and Gas Compact Commission (IOGCC 2011), the United States Army Corps of Engineers, (1995-2012), and the GHGRP (2010-2013).

The methodology for estimating CH_4 emissions from the 46 oil industry activities (excluding refining activities) employs emission factors initially developed by EPA (1999). Activity data for the years 1990 through 2013 were collected from a wide variety of statistical resources. Emissions are estimated for each activity by multiplying emission factors (e.g., emission rate per equipment item or per activity) by the corresponding activity data (e.g., equipment count or frequency of activity). EPA (1999) provides emission factors for all activities except those related to offshore oil production and field storage tanks. For offshore oil production, two emission factors were calculated using data collected for all federal offshore platforms (EPA 2015, BOEM 2014). One emission factor is for oil platforms in shallow water, and one emission factor is for oil platforms in deep water. Emission factors are held constant for the period 1990 through 2013. The number of platforms in shallow water and the number of platforms in deep water are used as activity data and are taken from Bureau of Ocean Energy Management (BOEM) (formerly Bureau of Ocean Energy Management, Regulation, and Enforcement [BOEMRE]) datasets (BOEM 2011a,b,c). For oil storage tanks, the emissions factor was calculated as the total emissions per barrel of crude charge from E&P Tank data weighted by the distribution of produced crude oil gravities from the HPDI production database (EPA 1999, HPDI 2011).

For some years, complete activity data were not available. In such cases, one of three approaches was employed. Where appropriate, the activity data were calculated from related statistics using ratios developed for EPA (1996). For example, EPA (1996) found that the number of heater treaters (a source of CH_4 emissions) is related to both number of producing wells and annual production. To estimate the activity data for heater treaters, reported statistics for wells and production were used, along with the ratios developed for EPA (1996). In other cases, the activity data were held constant from 1990 through 2013 based on EPA (1999). Lastly, the previous year's data were used when data for the current year were unavailable. The CH_4 and CO_2 sources in the production sector share common activity data. See Annex 3.5 for additional detail.

For petroleum refining activities, 2010 to 2013 emissions were directly obtained from EPA's GHGRP. All refineries are required to report their CH_4 and CO_2 emissions for all major activities since 2010. The national totals of these emissions for each activity were used for the 2010 to 2013 emissions. The national emission totals for each activity were also divided by refinery feed rates for those four Inventory years to develop average activity-specific emission factors. These emission factors were used to estimate national emissions for each refinery activity from 1990 to 2009 based on national refinery feed rates for the respective Inventory year. (EPA 2015c).

The Inventory estimate for Petroleum Systems takes into account Natural Gas STAR reductions. Voluntary reductions included in the Petroleum Sector calculations were those reported to Natural Gas STAR for the following activities: artificial lift: gas lift; artificial lift: use compression; artificial lift: use pumping unit; consolidate crude oil production and water storage tanks; lower heater-treater temperature; re-inject gas for enhanced oil recovery; re-inject gas into crude; and route casinghead gas to vapor recovery unit or compressor. In addition, a portion of the total Gas STAR reductions from pneumatic controllers in the production sector are applied to potential emissions in the petroleum sector.

The methodology for estimating CO_2 emissions from petroleum systems combines vented, fugitive, and process upset emissions sources from 29 activities for crude oil production field operations and three activities from petroleum refining. For the production field operations, emissions are estimated for each activity by multiplying emission factors by their corresponding activity data. The 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. One exception to this methodology are the emission factors for crude oil storage tanks, which are obtained from E&P Tank simulation runs, and the emission factor for asphalt blowing, which was derived using the methodology and sample data from API (2009). Other exceptions to this methodology are the three petroleum refining activities (i.e., flares, asphalt blowing, and process vents); the CO_2 emissions data for 2010 to 2013 were directly obtained from the GHGRP. The 2010 to 2013 CO_2 emissions GHGRP data along with the refinery feed data for 2010 to 2013 were used to derive CO_2 emission factors (i.e., sum of activity emissions/sum of refinery feed). The emission factors were then applied to the annual refinery feed to estimate CO_2 emissions for 1990 to 2009.

Uncertainty and Time-Series Consistency

The most recent uncertainty analysis for the natural gas and petroleum systems emissions estimates in the Inventory was conducted for the 1990-2009 Inventory that was released in 2011. Since the analysis was last conducted, several of the methods used in the Inventory have changed, and industry practices and equipment have evolved. In addition, new studies and other data sources such as those discussed in this memorandum offer improvement to understanding and quantifying the uncertainty of some emission source estimates.

As updates to the Inventory data and methods are selected, the EPA will review information on uncertainty and consider how the Inventory uncertainty assessment can be updated to reflect the new information.

A quantitative uncertainty analysis was conducted in 2010 to determine the level of uncertainty surrounding estimates of emissions from petroleum systems using the IPCC-recommended Approach 2 methodology (Monte Carlo Simulation technique). The @RISK software model was used to quantify the uncertainty associated with the emission estimates using the 7 highest-emitting sources ("top 7 sources") for the year 1995. The @RISK analysis provides for the specification of probability density functions for key variables within a computational structure that mirrors the calculation of the Inventory estimate. The IPCC guidance notes that in using this method, "some uncertainties that are not addressed by statistical means may exist, including those arising from omissions or double counting, or other conceptual errors, or from incomplete understanding of the processes that may lead to inaccuracies in estimates developed from models." As a result, the understanding of the uncertainty of emission estimates for this category evolves and improves as the underlying methodologies and datasets improve.

The uncertainty analysis conducted in 2010 has not yet been updated for the 1990 through 2013 Inventory years; instead, the uncertainty percentage ranges calculated previously were applied to 2013 emission estimates. The majority of sources in the current Inventory were calculated using the same emission factors and activity data for which PDFs were developed in the 1990 through 2009 uncertainty analysis. As explained in the Methodology section above and the Recalculations Discussion below, several emission sources have undergone recent methodology revisions, and the 2009 uncertainty ranges will not reflect the uncertainty associated with the recently revised emission factors and activity data sources. Please see discussion on Planned Improvements.

The results presented below provide with 95 percent certainty the range within which emissions from this source category are likely to fall for the year 2013, based on the previously conducted uncertainty assessment using the recommended IPCC methodology. The heterogeneous nature of the petroleum industry makes it difficult to sample facilities that are completely representative of the entire industry. Additionally, highly variable emission rates were measured among many system components, making the calculated average emission rates uncertain. The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 3-40. Petroleum systems CH_4 emissions in 2013 were estimated to be between 19.2 and 62.8 MMT CO_2 Eq., while CO_2 emissions were estimated to be between 4.6 and 14.9 MMT CO_2 Eq. at a 95 percent confidence level. This indicates a range of 24 percent below to 149 percent above the 2013 emission estimates of 25.2 and 6.0 MMT CO_2 Eq. for CH_4 and CO_2, respectively.

Table 3-40: Approach 2 Quantitative Uncertainty Estimates for CH_4 Emissions from Petroleum Systems (MMT CO_2 Eq. and Percent)

Source	Gas	2013 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]
Petroleum Systems	CH_4	25.2	19.2	62.8	-24%	149%
Petroleum Systems	CO_2	6.0	4.6	14.9	-24%	149%

[a] Range of 2013 relative uncertainty predicted by Monte Carlo Stochastic Simulation, based on 1995 base year activity factors, for a 95 percent confidence interval.

[b] All reported values are rounded after calculation. As a result, lower and upper bounds may not be duplicable from other rounded values as shown in table.

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 2013. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification Discussion

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

Recalculations Discussion

The EPA received information and data related to the emission estimates through the Inventory preparation process, previous Inventories' formal public notice periods, GHGRP data, and new studies. The EPA carefully evaluated relevant information available, and made revisions to the production segment methodology in the public review draft—including revised equipment activity data as well as pneumatic controller activity and emissions data.

In February 2016, the EPA released a draft memo that discussed the changes under consideration and requested stakeholder feedback on those changes.

- Revisions under Consideration for Natural Gas and Petroleum Production Emissions[66]

The EPA is continuing to evaluate stakeholder feedback on the updates under consideration. For the final Inventory, the 2013 estimates presented in this section will be refined, and a full time series of emissions estimates will be developed based on feedback received through the earlier stakeholder reviews of information released in the segment-specific memoranda, and through this public review period.

The combined impact of revisions to 2013 natural gas production segment emissions described below, compared to the 1990-2013 Inventory, is an increase in petroleum system CH_4 emissions of approximately 38 MMT CO_2 Eq., or 151 percent.

Trend information has not yet been calculated, but it is expected that across the 1990-2013 time series, compared to the previous (2015) Inventory, in the current (2016) Inventory, the total CH_4 emissions estimate will increase, with the largest increases in the estimate occurring in later years of the time series.

Production

This section references the Production Segment memo, available at http://www3.epa.gov/climatechange/ghgemissions/usinventoryreport/DRAFT_Proposed_Revision_to_Production_Segment_Emissions_2-3-2016.pdf.

Using newly available GHGRP activity data, the EPA has developed activity factors (i.e., counts per gas well) for separators, headers, heater-treaters, pneumatic pumps, and pneumatic controllers. The EPA has applied these updated activity factors (see Reporting Year (RY) 2014) values in Table 7 of the Production Segment memo) to calculate emissions from these sources in this public review draft. The impact of using activity factors developed from GHGRP data is an increase in calculated emissions. For the year 2013, the CH_4 emissions increase due to use of revised activity factors for major equipment and pneumatic pumps is approximately 5.8 MMT CO_2 Eq.

Using the GHGRP data, the EPA has also developed technology-specific activity data and emission factors for pneumatic controllers. Reported data under EPA's GHGRP allow for development of emission factors specific to bleed type (continuous high bleed, continuous low bleed, and intermittent bleed) and separation of activity data into these categories. For the public review draft, EPA has used this separation of pneumatic controller counts by bleed types, and emission factors developed from reported GHGRP data. See RY2013 values in Table 11 (activity data for proportion of controllers in each category), and RY2011-2014 values in Table 10 (emission factors) of the Production Segment memo. Comparing the updated 2013 estimate to the previous Inventory 2013 estimate, the impact of using bleed type-specific emission factors and activity data developed from GHGRP data is an increase of approximately 32.3 MMT CO_2 Eq.

The EPA is considering approaches to develop the Inventory time series (1990–2014) that will create consistency between earlier years' estimates that generally rely on data from GRI/EPA 1996, and more recent years' estimates that rely on GHGRP data. For years 1992 through 2010, the EPA is considering calculating equipment counts by linearly interpolating between the data points of calculated national equipment counts in 1992 (using GRI/EPA) and calculated national equipment counts in 2011 (using GHGRP).

The EPA's approach for revising the GHG Inventory methodology to incorporate GHGRP data obviates the need to apply Gas STAR reductions data for certain sources in the production segment. EPA plans to carry forward reported reductions for sources that are not being revised to use a net emission factor approach. There are also Gas STAR reductions in the production segment that are not classified as applicable to specific emission sources ("other voluntary reductions" are 0.8 MMT CO_2 Eq. CH_4 in year 2013). Some portion of the "other voluntary reductions" might apply to the emission sources for which the EPA is revising the methodology to use a net emission factor approach. The EPA is investigating potential disaggregation of "other voluntary reductions." The EPA has retained Gas STAR reductions classified as "other voluntary reductions" in year 2013 emission calculations for the public review draft.

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[66] Available at: < http://www3.epa.gov/climatechange/ghgemissions/usinventoryreport/DRAFT_Proposed_Revision_to_Production_Segment_Emissions_2-3-2016.pdf>

Planned Improvements

EPA will continue to refine the emission estimates to reflect the most robust information available, including stakeholder feedback received on the Inventory improvement memos, and this public review draft.

Box 3-7: Carbon Dioxide Transport, Injection, and Geological Storage (TO BE UPDATED)

Carbon dioxide is produced, captured, transported, and used for Enhanced Oil Recovery (EOR) as well as commercial and non-EOR industrial applications. This CO_2 is produced from both naturally-occurring CO_2 reservoirs and from industrial sources such as natural gas processing plants and ammonia plants. In the Inventory, emissions from naturally-produced CO_2 are estimated based on the 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. The naturally-occurring CO_2 used in EOR operations is assumed to be fully sequestered. Additionally, all anthropogenic CO_2 emitted from natural gas processing and ammonia plants is assumed to be emitted to the atmosphere, regardless of whether the CO_2 is captured or not. These emissions are currently included in the Natural Gas Systems and the Ammonia Production sections of the Inventory report, respectively.

IPCC 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 emissions estimates for geologic storage.

In the United States, facilities that conduct geologic sequestration of CO_2 and all other facilities that inject CO_2 underground, including facilities conducting EOR, are required to report greenhouse gas data annually to EPA through its GHGRP. Facilities conducting geologic sequestration of CO_2 are required to develop and implement an EPA-approved site-specific monitoring, reporting and verification plan, and to report the amount of CO_2 sequestered using a mass balance approach. Data from this program will be evaluated closely and opportunities for improving the emission estimates will be considered.

Preliminary estimates indicate that the amount of CO_2 captured from industrial and natural sites is 46.2 MMT CO_2 Eq. (46,198 kt) (see Table 3-41 and Table 3-42). Site-specific monitoring and reporting data for CO_2 injection sites (i.e., EOR operations) were not readily available, therefore, these estimates assume all CO_2 is emitted. Values for 2011 to 2013 were proxied from 2010 data.

Table 3-41: Potential Emissions from CO_2 Capture and Transport (MMT CO_2 Eq.)

Stage	1990	2005	2009	2010	2011	2012	2013
Acid Gas Removal Plants	4.8	5.8	7.0	11.6	11.6	11.6	11.6
Naturally Occurring CO_2	20.8	28.3	39.7	34.0	34.0	34.0	34.0
Ammonia Production Plants	+	0.7	0.6	0.7	0.7	0.7	0.7
Pipelines Transporting CO_2	+	+	+	+	+	+	+
Total	**25.6**	**34.7**	**47.3**	**46.2**	**46.2**	**46.2**	**46.2**

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

Table 3-42: Potential Emissions from CO_2 Capture and Transport (kt)

Stage	1990	2005	2009	2010	2011	2012	2013
Acid Gas Removal Plants	4,832	5,798	7,035	11,554	11,554	11,554	11,554
Naturally Occurring CO_2	20,811	28,267	39,725	33,967	33,967	33,967	33,967
Ammonia Production Plants	+	676	580	677	677	677	677

Pipelines Transporting CO_2	8	7	8	8	8	8	8
Total	**25,643**	**34,742**	**47,340**	**46,198**	**46,198**	**46,198**	**46,198**

+ Does not exceed 0.5 kt.

Note: Totals do not include emissions from pipelines transporting CO_2. Totals may not sum due to independent rounding.

3.7 Natural Gas Systems (IPCC Source Category 1B2b)

Substantial new data are available on natural gas and petroleum systems from the EPA's Greenhouse Gas Reporting Program (GHGRP) and a number of new studies. The EPA is evaluating approaches for incorporating this new data into its emission estimates for the *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2014*.

The details of the revisions under consideration for this year's Inventory, and key questions for stakeholder feedback are available in segment-level memoranda at http://www3.epa.gov/climatechange/ghgemissions/usinventoryreport/natural-gas-systems.html.

Below, updated draft estimates of methane emissions for the year 2013 are presented to provide reviewers of the public review draft an indication of the sector-wide emissions estimates resulting from the combined changes under consideration. CO_2 emissions have not been updated in the public review draft, but will be updated in the final Inventory.

The EPA is continuing to evaluate stakeholder feedback on the updates under consideration. For the final Inventory, the 2013 estimates presented in this section will be refined, and a full time series of emissions estimates will be developed based on feedback received through the earlier stakeholder reviews of the memos and through this public review period.

The U.S. natural gas system encompasses hundreds of thousands of wells, hundreds of processing facilities, and over a million miles of transmission and distribution pipelines. Overall, natural gas systems emitted approximately 169 MMT CO_2 Eq. (6,745 kt) of CH_4 in 2013.

CH_4 and non-combustion 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, bleed and discharge emissions from pneumatic controllers, and fugitive emissions from system components. Routine maintenance emissions originate from pipelines, equipment, and wells during repair and maintenance activities. Pressure surge relief systems and accidents can lead to system upset emissions. Below is a characterization of the four major stages of the natural gas system. Each of the stages is described and the different factors affecting CH_4 and non-combustion CO_2 emissions are discussed.

Field Production (including Gathering and Boosting). In these initial stages, wells are used to withdraw raw gas from underground formations, and emissions arise from the wells themselves, gathering pipelines, and well-site gas treatment facilities such as dehydrators and separators. The EPA is considering several revisions to the production (including gathering and boosting) segment. For information on these revisions, and requests for stakeholder feedback please see the Production Segment memo[67] and the Gathering and Boosting memo.[68] The information

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[67] Available online at <http://www3.epa.gov/climatechange/ghgemissions/usinventoryreport/DRAFT_Proposed_Revision_to_Production_Segment_Emissions_2-3-2016.pdf>

[68] Available online at <http://www3.epa.gov/climatechange/ghgemissions/usinventoryreport/DRAFT_Proposed_Revision_to_NG_Gathering-Boosting_Segment_Emissions_2-2-2016.pdf>

presented here was calculated using the approaches under consideration in the EPA memoranda, as discussed below in the Recalculations Discussion section.

Emissions from gathering and boosting stations, pneumatic controllers, venting for liquids unloading, kimray pumps, condensate tanks, pipeline leaks, and chemical injection pumps account for the majority of CH_4 emissions in 2013. Emissions from production account for over 60 percent of CH_4 emissions from natural gas systems in 2013.

Trend information for the revised production segment has not yet been calculated. Based on the methods under consideration for revising the time series, it is expected that the recalculated time series will show an increasing trend from 1990 for CH_4 emissions from production and gathering and boosting. For example, for gathering and boosting stations, under the approach under consideration, estimated CH_4 emissions would nearly double from 1990-2013. Other key emissions sources in the production segment are calculated using gas well counts as an activity data driver. Total national gas well counts doubled from 1990-2013. At the same time, changes in technology and practices have also occurred, which in some cases, such as switching from high bleed to low bleed pneumatic controllers, reduces the growth in emissions that would be expected based on well count trends alone.

Flaring emissions account for the majority of the non-combustion CO_2 emissions. CO_2 emissions from production increased 63 percent from 1990 to 2013 due to increases in onshore and offshore flaring.

Processing. In this stage, natural gas liquids and various other constituents from the raw gas are removed, resulting in “pipeline quality” gas, which is injected into the transmission system. The EPA has not yet assessed potential revisions for this segment. Information presented here is from the previous (2015) Inventory.

Fugitive CH_4 emissions from compressors, including compressor seals, are the primary emission source from this stage. The majority of non-combustion CO_2 emissions come from acid gas removal units, which are designed to remove CO_2 from natural gas. Processing plants account for 14 percent of CH_4 emissions and 58 percent of non-combustion CO_2 emissions from natural gas systems. CH_4 emissions from processing increased by 6 percent from 1990 to 2013 as emissions from compressors increased as the quantity of gas produced increased.

CO_2 emissions from processing decreased by 22 percent from 1990 to 2013, as a decrease in the quantity of gas processed resulted in a decrease in acid gas removal emissions.

Transmission and Storage. Natural gas transmission involves high pressure, large diameter pipelines that transport gas long distances from field production and processing areas to distribution systems or large volume customers such as power plants or chemical plants. Compressor station facilities, which contain large reciprocating and turbine compressors, are used to move the gas throughout the U.S. transmission system.

The EPA is considering several revisions to the transmission and storage segment. For information on these revisions, and requests for stakeholder feedback please see the Transmission and Storage Segment memo.[69] The information presented here was calculated using the approaches under consideration in the EPA memorandum, as discussed below in the Recalculations Discussion section.

Transmission station venting and fugitives, pipeline venting, uncombusted engine exhaust, and storage station venting and fugitives account for the majority of the emissions from this stage. Natural gas is also injected and stored in underground formations, or liquefied and stored in above ground tanks, during periods of low demand (e.g., summer), and withdrawn, processed, and distributed during periods of high demand (e.g., winter). Compressors and dehydrators are the primary contributors to emissions from these storage facilities. CH_4 emissions from the transmission and storage sector account for approximately 17 percent of emissions from natural gas systems.

Trend information for transmission and storage has not yet been calculated. Based on the methods under consideration for revising the time series, it is expected that the recalculated time series will show a decreasing trend from 1990 for CH_4 emissions from transmission and storage. Key industry changes impacting the trend include a shift to larger and fewer centrifugal compressors from smaller reciprocating compressors, and a shift toward the centrifugal compressors being equipped with dry seals rather than wet seals.

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[69] Available online at <http://www3.epa.gov/climatechange/ghgemissions/usinventoryreport/DRAFT_Proposed_Revisions_to_NG_Transmission_Storage_Segment_Emissions_2016-01-20.pdf>

CO_2 emissions from transmission and storage account for less than 1 percent of the non-combustion CO_2 emissions from natural gas systems. CO_2 emissions from transmission and storage have increased by 5 percent from 1990 to 2013 as the number of compressors has increased.

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 1,252,866 miles of distribution mains in 2013, an increase of nearly 310,000 miles since 1990 (PHMSA 2014).

The EPA is considering several revisions to the distribution segment. For information on these revisions, and requests for stakeholder feedback please see the Distribution Segment memo.[70] The information presented here was calculated using the approaches under consideration in the memorandum, as discussed below in the recalculations discussion section.

Distribution system emissions, which account for 7 percent of CH_4 emissions from natural gas systems, result mainly from fugitive emissions from pipelines and stations.

Trend information for the distribution segment has not yet been calculated. Based on the methods under consideration for updating the time series, it is expected that the recalculated time series will show a decreasing trend from 1990 for CH_4 emissions from distribution. Key industry changes impacting the trend include updates at M&R stations and changes to lower emitting pipeline materials.

Distribution CO_2 emissions in 2013 were 14 percent lower than 1990 levels (CO_2 emission from this segment are less than 0.1 MMTCO_2 Eq. across the time series).

Total CH_4 emissions for the four major stages of natural gas systems are shown in MMT CO_2 Eq. (Table 3-43) and kt (Table 3-44). For the final Inventory, more disaggregated information on potential emissions and emissions will be available in Annex 3.6. See Methodology for Estimating CH_4 and CO_2 Emissions from Natural Gas Systems.

Table 3-43: CH_4 Emissions from Natural Gas Systems (MMT CO_2 Eq.)[a]

Stage	1990	2005	2009	2010	2011	2012	2013	2014
Production							106	
Processing							23	
Transmission and Storage							29	
Distribution							11	
Total							**169**	

[a] These values represent CH_4 emitted to the atmosphere. CH_4 that is captured, flared, or otherwise controlled (and not emitted to the atmosphere) has been calculated and removed from emission totals.
Note: Totals may not sum due to independent rounding.

Table 3-44: CH_4 Emissions from Natural Gas Systems (kt)[a]

Stage	1990	2005	2009	2010	2011	2012	2013	2014
Production							4,230	
Processing							906	
Transmission and Storage							1.151	
Distribution							458	
Total							**6,745**	

[a] These values represent CH_4 emitted to the atmosphere. CH_4 that is captured, flared, or otherwise controlled (and not emitted to the atmosphere) has been calculated and removed from emission totals.
Note: Totals may not sum due to independent rounding.

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[70] Available online at <http://www3.epa.gov/climatechange/ghgemissions/usinventoryreport/Proposed_Revisions_to_NG_Distribution_Segment_Emissions.pdf>

Table 3-45: Non-combustion CO_2 Emissions from Natural Gas Systems (MMT CO_2 Eq.)

Stage	1990	2005	2009	2010	2011	2012	2013	2014
Field Production	9.8	8.1	10.9	10.9	14.0	13.2	15.9	
Processing	27.8	21.7	21.2	21.3	21.5	21.5	21.8	
Transmission and Storage		0.1	0.1	0.1	0.1	0.1	0.1	
Distribution	+	+	+	+	+	+	+	
Total		**30.0**	**32.2**	**32.3**	**35.6**	**34.8**	**37.8**	

Note: Totals may not sum due to independent rounding.

+ Emissions are less than 0.1 MMT CO_2 Eq.

Table 3-46: Non-combustion CO_2 Emissions from Natural Gas Systems (kt)

Stage	1990	2005	2009	2010	2011	2012	2013	2014
Field Production	9,775	8,142	10,906	10,883	13,980	13,196	15,947	
Processing	27,763	21,746	21,188	21,346	21,466	21,469	21,757	
Transmission and Storage	62	64	65	65	65	63	65	
Distribution	46	42	41	40	40	37	40	
Total	37,645	**29,995**	**32,201**	**32,334**	**35,551**	**34,764**	**37,808**	

Note: Totals may not sum due to independent rounding.

Methodology

EPA has made revisions to the methodology and data sources for many sources in the Inventory. Please see the Recalculations Discussion section below.

The methodology for natural gas emissions estimates presented in this Inventory involves the calculation of CH_4 and CO_2 emissions for over 100 emissions sources, and then the summation of emissions for each natural gas sector stage.

The calculation of emissions for each source of emissions in natural gas systems generally occurs in three steps:

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

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

Step 3. Calculate Net Emissions – Deduct methane that is not emitted from the total methane potential estimates to develop net CH_4 emissions, and calculate CO_2 emissions

This approach of calculating potential CH_4 and then applying reductions data to calculate net emissions was used to ensure an accurate time series that reflects real emission trends. As noted below, key data on emissions from many sources are from a 1996 report containing data collected in 1992. Since the time of this study, practices and technologies have changed. While this study still represents best available data for some emission sources, using these emission factors alone to represent actual emissions without adjusting for emissions controls would in many cases overestimate emissions. As updated emission factors reflecting changing practices are not available for most sources, the 1992 emission factors continue to be used for many sources for all years of the Inventory, but they are considered to be potential emissions factors, representing what emissions would be if practices and technologies had not changed over time.

For the Inventory, the calculated potential emissions are adjusted using data on reductions reported to Natural Gas STAR, and data on regulations that result in CH_4 reductions. As more data become available, alternate approaches may be considered. For example, new data on liquids unloading and on hydraulically fractured gas well completions and workovers enabled EPA to disaggregate or stratify these sources into distinct sub-categories based upon different technology types, each with unique emission factors and activity data.

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

In the first step, potential CH_4 is calculated by multiplying activity data (such as miles of pipeline or number of wells) by factors that relate that activity data to potential CH_4. Potential CH_4 is the amount of CH_4 that would be emitted in the absence of any control technology or mitigation activity. It is important to note that potential CH_4 factors in most cases do not represent emitted CH_4, and must be adjusted for any emissions-reducing technologies, or practices, as appropriate. For more information, please see the Annex.

Potential Methane Factors

The primary basis for estimates of CH_4 and non-combustion-related CO_2 emissions from the U.S. natural gas industry is a detailed study by the Gas Research Institute and EPA (EPA/GRI 1996). The EPA/GRI study developed over 80 CH_4 emission factors to characterize emissions from the various components within the operating stages of the U.S. natural gas system. The EPA/GRI study was based on a combination of process engineering studies, collection of activity data and measurements at representative gas facilities conducted in the early 1990s. Methane compositions from the Gas Technology Institute (GTI, formerly GRI) Unconventional Natural Gas and Gas Composition Databases (GTI 2001) are adjusted year to year using gross production for oil and gas supply National Energy Modeling System (NEMS) regions from the EIA. Therefore, emission factors may vary from year to year due to slight changes in the CH_4 composition for each NEMS oil and gas supply module region. The majority of emission factors used in the Inventory were derived from the EPA/GRI study. The emission factors used to estimate CH_4 were also used to calculate non-combustion CO_2 emissions. Data from GTI 2001 were used to adapt the CH_4 emission factors into non-combustion related CO_2 emission factors. Additional information about CO_2 content in transmission quality natural gas was obtained from numerous U.S. transmission companies to help further develop the non-combustion CO_2 emission factors.

Although the Inventory primarily uses EPA/GRI emission factors, updates were made to the emissions estimates for several sources in recent Inventories. For liquids unloading, in the 2013 Inventory, the methodology was revised to calculate national emissions through the use region-specific emission factors developed from well data collected in a survey conducted by API/ANGA (API/ANGA 2012). In this methodology, the emission factors used for liquids unloading are not potential factors, but are factors for actual emissions. For gas well completions and workovers (refracturing) with hydraulic fracturing, in this Inventory, EPA used the 2011, 2012, and 2013 GHGRP Subpart W data to stratify the emission sources into four different categories and developed CH_4 emission factors for each category. See the Recalculations Discussion below, and EPA memos "Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2013: Revision to Hydraulically Fractured Gas Well Completions and Workovers Estimate" and "Updating GHG Inventory Estimate for Hydraulically Fractured Gas Well Completions and Workovers" for more information on the methodology for this emission source (EPA 2013d and EPA 2015c).

In addition, in 2015, an update was made to the emission factors applied to offshore platforms. Previously, the Inventory relied on the Bureau of Ocean Energy Management's (BOEM's) Gulf Offshore Activity Data System (GOADS) year 2000 inventory to develop emission factors for offshore platforms; the methodology has been updated to use more recent GOADS inventory data to develop emission factors. See the Recalculations Discussion below, and EPA memo "Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2013: Revision to Offshore Platforms Emissions Estimate" (EPA 2015b).

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

Updates to emission factors using GHGRP data for natural gas systems and other data continue to be evaluated.

Activity Data

Activity data were taken from the following sources: DrillingInfo, Inc (DrillingInfo 2014); American Gas Association (AGA 1991–1998); Bureau of Ocean Energy Management, Regulation and Enforcement (previous Minerals and Management Service) (BOEMRE 2011a, 2011b, 2011c, 2011d); Natural Gas Liquids Reserves Report (EIA 2005); Natural Gas Monthly (EIA 2014a, 2014b, 2014c); the Natural Gas STAR Program annual emissions savings (EPA 2013c); Oil and Gas Journal (OGJ 1997–2014); Pipeline and Hazardous Materials Safety

Administration (PHMSA 2014); Federal Energy Regulatory Commission (FERC 2014); Greenhouse Gas Reporting Program (EPA 2014); other Energy Information Administration data and publications (EIA 2001, 2004, 2012, 2013, 2014). Data for estimating emissions from hydrocarbon production tanks were incorporated (EPA 1999). Coalbed CH_4 well activity factors were taken from the Wyoming Oil and Gas Conservation Commission (Wyoming 2014) and the Alabama State Oil and Gas Board (Alabama 2014).

For a few sources, recent direct activity data are not available. For these sources, either 2012 data was used as proxy for 2013 data, or a set of industry activity data drivers was developed and used to update activity data. 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. For example, recent data on various types of field separation equipment in the production stage (i.e., heaters, separators, and dehydrators) are unavailable. Each of these types of field separation equipment was determined to relate to the number of non-associated gas wells. Using the number of each type of field separation equipment estimated by GRI/EPA in 1992, and the number of non-associated gas wells in 1992, a factor was developed that is used to estimate the number of each type of field separation equipment throughout the time series. More information on activity data and drivers is available in Annex 3.6.

Step 2. Compile Reductions Data—Calculate the amount of the CH_4 that is not emitted, using data on voluntary action and regulations

The emissions calculated in Step 1 above represent potential emissions from an activity, and do not take into account any use of technologies and practices that reduce emissions. To take into account use of such technologies, data, where available, are collected on both regulatory and voluntary reductions. Regulatory actions reducing emissions include National Emission Standards for Hazardous Air Pollutants (NESHAP) regulations for dehydrator vents and condensate tanks. Voluntary reductions included in the Inventory are those reported to Natural Gas STAR for activities such as replacing a high bleed pneumatic device with a low bleed device, and replacing wet seals with dry seals at reciprocating compressors. For more information on these reductions, please see the Annex. The emission estimates presented in Table 3-43 and Table 3-44 are the CH_4 that is emitted to the atmosphere (i.e., net emissions), not potential emissions without capture or flaring.

The Inventory includes impacts of the New Source Performance Standards (NSPS), which came into effect in October 2012, for oil and gas (EPA 2013b). By separating gas well completions and workovers with hydraulic fracturing into four categories and developing control technology-specific CH_4 emission factors for each category, EPA is implicitly accounting for NSPS reductions from hydraulically fractured gas wells. The NSPS also has VOC reduction requirements for compressors, storage vessels, pneumatic controllers, and equipment leaks at processing plants, which will also impact CH_4 emissions in future Inventories.

Step 3. Calculate Net Emissions—Deduct CH_4 that is not emitted from the total CH_4 potential estimates to develop net CH_4 emissions, and calculate CO_2 emissions

In the final step, emission reductions from voluntary and regulatory actions are deducted from the total calculated potential emissions to estimate the net emissions that are presented in Table 3-43, and included in the Inventory totals. Note that for liquids unloading, condensate tanks, gas well completions and workovers with hydraulic fracturing, and centrifugal compressors, emissions are calculated directly using emission factors that vary by technology and account for any control measures in place that reduce CH_4 emissions. See Annex table A-17 for more information on net emissions for specific sources.

Uncertainty and Time-Series Consistency

The most recent uncertainty analysis for the natural gas and petroleum systems emission estimates in the Inventory was conducted for the 1990-2009 Inventory report that was released in 2011. Since the analysis was last conducted, several of the methods used in the Inventory have changed, and industry practices and equipment have evolved. In addition, new studies and other data sources such as those discussed in this memorandum offer improvement to understanding and quantifying the uncertainty of some emission source estimates.

As updates to the greenhouse gas Inventory data and methods are selected, the EPA will review information on uncertainty and consider how the greenhouse gas Inventory uncertainty assessment can be updated to reflect the new information.

A quantitative uncertainty analysis was conducted in 2010 to determine the level of uncertainty surrounding estimates of emissions from natural gas systems using the IPCC-recommended Approach 2 methodology (Monte Carlo Simulation technique). The @RISK software model was used to quantify the uncertainty associated with the emissions estimates using the 12 highest-emitting sources (“top 12 sources”) for the year 2009. The @RISK analysis provides for the specification of probability density functions for key variables within a computational structure that mirrors the calculation of the Inventory estimate. The IPCC guidance notes that in using this method, "some uncertainties that are not addressed by statistical means may exist, including those arising from omissions or double counting, or other conceptual errors, or from incomplete understanding of the processes that may lead to inaccuracies in estimates developed from models." As a result, the understanding of the uncertainty of emissions estimates for this category evolves and improves as the underlying methodologies and datasets improve.

The uncertainty analysis conducted in 2010 has not yet been updated for the 1990 through 2013 Inventory years; instead, the uncertainty percentage ranges calculated previously were applied to 2013 emissions estimates. The majority of sources in the current Inventory were calculated using the same emission factors and activity data for which PDFs were developed in the 1990 through 2009 uncertainty analysis. As explained in the Methodology section above and the recalculations discussion below, several emission sources have undergone recent methodology revisions, and the 2009 uncertainty ranges will not reflect the uncertainty associated with the recently revised emission factors and activity data sources. Please see discussion on Planned Improvements.

The results presented below provide with 95 percent certainty the range within which emissions from this source category are likely to fall for the year 2013, based on the previously-conducted uncertainty assessment using the recommended IPCC methodology. The heterogeneous nature of the natural gas industry makes it difficult to sample facilities that are completely representative of the entire industry. Additionally, highly variable emission rates were measured among many system components, making the calculated average emission rates uncertain. The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 3-47. Natural gas systems CH_4 emissions in 2013 were estimated to be between 127.5 and 187.3 MMT CO_2 Eq. at a 95 percent confidence level. Natural gas systems non-energy CO_2 emissions in 2013 were estimated to be between 30.6 and 49.1 MMT CO_2 Eq. at 95 percent confidence level.

Table 3-47: Approach 2 Quantitative Uncertainty Estimates for CH_4 and Non-energy CO_2 Emissions from Natural Gas Systems (MMT CO_2 Eq. and Percent)

Source	Gas	2013 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	157.4	127.5	187.3	-19%	+30%
Natural Gas Systems[c]	CO_2	37.8	30.6	49.1	-19%	+30%

[a] Range of emission estimates predicted by Monte Carlo Simulation for a 95 percent confidence interval.
[b] All reported values are rounded after calculation. As a result, lower and upper bounds may not be duplicable from other rounded values as shown in Table 3-44 and Table 3-45.
[c] An uncertainty analysis for the non-energy CO_2 emissions was not performed. The relative uncertainty estimated (expressed as a percent) from the CH_4 uncertainty analysis was applied to the point estimate of non-energy CO_2 emissions.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2013. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification Discussion

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

Recalculations Discussion

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

From December 2015 through February 2016, the EPA released four draft memos that discussed the changes under consideration and requested stakeholder feedback on those changes.

- Revisions under Consideration for Natural Gas and Petroleum Production Emissions[71]
- Revisions under Consideration for Gathering and Boosting Emissions[72]
- Revisions under Consideration for Transmission and Storage Emissions[73]
- Revisions under Consideration for Distribution Emissions[74]

The EPA is continuing to evaluate stakeholder feedback on the updates under consideration. For the final GHG Inventory, the 2013 estimates presented in this section will be refined, and a full time series of emissions estimates will be developed based on feedback received through the earlier stakeholder reviews of information released in the segment-specific memoranda, and through this public review period. The combined impact of all revisions to 2013 natural gas production segment emissions in the public review draft, described below, compared to the 2015 Inventory, is an increase in CH_4 emissions of approximately 10 MMT CO_2 Eq., or 6 percent. Recalculations for the production segment (including gathering and boosting facilities) resulted in a large increase in the 2013 CH_4 emission estimate, from 47.0 MMT CO_2 Eq. in the previous (2015) Inventory, to 105.7 MMT CO_2 Eq. in the current (2016) Inventory. Recalculations for the transmission and storage segment resulted in a large decrease in the 2013 CH_4 emission estimate, from 54.4 MMT CO_2 Eq. in the previous (2015) Inventory, to 28.8 MMT CO_2 Eq. in the current (2016) Inventory. Recalculations for the distribution segment also resulted in a large decrease in the 2013 CH_4 emission estimate, from 33.3 MMT CO_2 Eq. in the previous (2015) Inventory, to 10.2 MMT CO_2 Eq. in the current (2016) Inventory.

Time series information has not yet been calculated, but it is expected that across the 1990 through 2013 time series, compared to the previous (2015) Inventory, in the current (2016) Inventory, the total CH_4 emissions estimate will increase, with the largest increases in the estimate occurring in later years of the time series.

Production

This section references the Production Segment memo, available at http://www3.epa.gov/climatechange/ghgemissions/usinventoryreport/DRAFT_Proposed_Revision_to_Production_Segment_Emissions_2-3-2016.pdf, and the Gathering and Boosting memo, available at

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[71] Available online at: <http://www3.epa.gov/climatechange/ghgemissions/usinventoryreport/DRAFT_Proposed_Revision_to_Production_Segment_Emissions_2-3-2016.pdf>

[72] Available online at: <http://www3.epa.gov/climatechange/ghgemissions/usinventoryreport/DRAFT_Proposed_Revision_to_NG_Gathering-Boosting_Segment_Emissions_2-2-2016.pdf>

[73] Available online at: <http://www3.epa.gov/climatechange/ghgemissions/usinventoryreport/DRAFT_Proposed_Revisions_to_NG_Transmission_Storage_Segment_Emissions_2016-01-20.pdf>

[74] Available online at: < http://www3.epa.gov/climatechange/ghgemissions/usinventoryreport/Proposed_Revisions_to_NG_Distribution_Segment_Emissions.pdf >

http://www3.epa.gov/climatechange/ghgemissions/usinventoryreport/DRAFT_Proposed_Revision_to_NG_Gathering-Boosting_Segment_Emissions_2-2-2016.pdf.

Key data sources assessed for potential updates to the production segment include GHGRP and Marchese et al.

Using newly available GHGRP activity data, the EPA has developed activity factors (i.e., counts per gas well) for compressors, separators, dehydrators, in-line heaters, meters/piping, pneumatic pumps, and pneumatic controllers. The EPA has applied these updated activity factors (see Reporting Year (RY) 2014 values in Table 7 of the Production Segment memo) to calculate emissions from these sources in this public review draft. The impact of using activity factors developed from GHGRP data is an increase in emissions. Comparing the updated 2013 estimate to the previous Inventory 2013 estimate, the CH_4 emissions increase due to use of revised activity factors for compressors, separators, dehydrators, in-line heaters, meters/piping, and pneumatic pumps is approximately 3.3 MMT CO_2 Eq.

Using the GHGRP data, the EPA has also developed technology-specific activity data and emission factors for pneumatic controllers. Reported data under EPA's GHGRP allow for development of emission factors specific to bleed type (continuous high bleed, continuous low bleed, and intermittent bleed) and separation of activity data into these categories. For the public review draft, EPA has used this separation of pneumatic controller counts by bleed types, and emission factors developed from reported GHGRP data. See RY2013 values in Table 11 (activity data for proportion of controllers in each category), and RY2011-2014 values in Table 10 (emission factors) of the Production Segment memo. Comparing the updated 2013 estimate to the previous Inventory 2013 estimate, the impact of using bleed type-specific emission factors and activity data developed from GHGRP data is an increase of approximately 12.5 MMT CO_2 Eq.

The EPA is considering approaches to develop the greenhouse gas Inventory time series (1990–2014) for these sources that will create consistency between earlier years' estimates that generally rely on data from GRI/EPA 1996, and more recent years' estimates calculated with GHGRP data. For years 1992-2010, the EPA is considering calculating well counts by interpolating the equipment counts per well from the data points of 1992 (GRI/EPA) and 2011 (GHGRP).

A 2015 study, Marchese et al. assessed CH_4 emissions from an expanded universe of gathering stations than were previously included in the Inventory. The Marchese et al. study analyzed emissions from five different types of gathering stations: compression only; compression and dehydration; compression, dehydration, and acid gas removal; dehydration only; and dehydration and acid gas removal. Previous Inventories estimated emissions from only gathering compression stations. In the public review draft estimate presented here, the EPA has applied a station-level emission factor and national activity estimates developed from the Marchese et al. data. See the Gathering and Boosting memo for more information. The impact of using revised activity data and emission factors for gathering stations cannot be straightforwardly determined based on the structure of previous GHG Inventories (e.g., dehydrator emissions in previous Inventories are not differentiated between well pad and gathering facility locations); however due to the activity data revision alone, production segment emissions greatly increase compared to previous estimates. For the year 2013, the CH_4 emissions from gathering facilities are 43.3 MMT CO_2 Eq. The EPA is considering applying the emission factor to all years of the time series, and replacing current activity data estimates with station counts based on the Marchese et al. estimate (scaled for earlier years based on national natural gas marketed production).

The EPA's approach for revising the Inventory methodology to incorporate GHGRP data and Marchese et al. data obviates the need to apply Gas STAR reductions data for certain sources in the production segment. EPA plans to carry forward reported reductions for sources that are not being revised to use a net emission factor approach. There are also significant Gas STAR reductions in the production segment that are not classified as applicable to specific emission sources ("other voluntary reductions" are 16 MMT CO_2 Eq. CH_4 in year 2013). Some portion of the "other voluntary reductions" might apply to the emission sources for which the EPA is revising the methodology to use a net emission factor approach. The EPA is investigating potential disaggregation of "other voluntary reductions." The EPA has retained Gas STAR reductions classified as "other voluntary reductions" in year 2013 emission calculations for the public review draft.

Transmission and Storage

This section references the Transmission and Storage memo, available at http://www3.epa.gov/climatechange/ghgemissions/usinventoryreport/DRAFT_Proposed_Revisions_to_NG_Transmission_Storage_Segment_Emissions_2016-01-20.pdf.

Key data sources assessed for the transmission and storage segment updates include GHGRP and Zimmerle et al.

For transmission and storage non-compressor fugitive emissions in the public review draft, EPA has used Zimmerle et al. data to develop the activity data for transmission stations ("Alternative") and EIA data on active storage fields, along with the Zimmerle estimate of storage stations per storage field to develop storage station counts. See Table 3 of the Transmission and Storage memo. The EPA then applied emission factors from Zimmerle et al. to calculate emissions for fugitives from these sources. See Table 4 of the Transmission and Storage memo.

The EPA is considering using interpolation between GRI/EPA emission factors in early years and Zimmerle et al. emission factors in recent years, which will reflect net emissions across the Inventory time series. However, the station fugitive emission factors in previous Inventories included station fugitives but not compressor fugitives, and separate emission factors were applied for compressor emissions (including compressor fugitive and vented sources). Because Zimmerle et al. grouped compressor fugitives with station fugitives, the two sets of emission factors (GRI/EPA and Zimmerle et al.) cannot be directly compared. Therefore in this public review draft, the EPA calculated total station-level emission factors for transmission and storage stations that include station and compressor fugitive sources as well as compressor vented sources.

In this public review draft, the EPA incorporated Zimmerle et al. national population estimates of reciprocating and centrifugal compressor activity data, along with the GHGRP proportions of centrifugal compressor seal types (wet versus dry seals), and Zimmerle et al. emission factor data, in development of emission estimates for compressors in transmission and storage. See Table 12 (reciprocating compressors EF from Zimmerle et al.), Table 14 (reciprocating and centrifugal compressor counts from Zimmerle et al.), Table 18 (split between wet and dry seal from Subpart W), and Table 22 (Zimmerle et al. EF for centrifugal compressors), in the Transmission and Storage memo.

For example, the EPA is considering approaches to calculate the Inventory time series (1990–2014) that will create consistency between earlier years' and more recent years' estimates for compressors. For example, for all years between 1992 and 2012, a linear correlation between 1992 and 2012 counts could be applied.

The overall impact of using revised emissions data and activity data from Zimmerle et al. and GHGRP is a decrease in emissions for station fugitives and compressors. Comparing the updated 2013 estimate to the previous Inventory 2013 estimate, the CH_4 emissions decrease due to use of revised emission factors and activity data for transmission and storage station fugitives and compressor venting is approximately 21.7 MMT CO_2 Eq.

In the public review draft value presented here, the transmission and storage pneumatic controller values have been calculated using the Zimmerle et al. data on controllers per station and emission factors. See Table 26, and Table 29 of the Transmission and Storage memo. The overall impact of using revised emissions data and activity data from Zimmerle et al. or GHGRP would be a decrease in emissions from transmission station pneumatic controllers and either a slight increase or decrease in emissions from storage station pneumatic controllers (depending on use of Zimmerle et al. data or subpart GHGRP, respectively) for recent time series years. Comparing the updated 2013 estimate to the previous Inventory 2013 estimate, the CH_4 emissions decrease due to use of revised emission factors and activity data for transmission and storage station pneumatic controllers is 4.0 MMT CO_2 Eq. The EPA may apply current Inventory AD and/or EF to early years of the time series, and assume a linear correlation to develop year-specific AD and/or EFs for intermediate years, and apply the GHGRP or Zimmerle et al. AD and EF to recent years of the Inventory time series.

The EPA's approach for revising the Inventory methodology to incorporate Zimmerle et al. and GHGRP data in the transmission segment would result in net emissions being directly calculated for these sources in each time series year. This obviates the need to apply Gas STAR reductions data for these sources. Previous Inventories have applied Gas STAR reductions to other specific transmission and storage segment sources including compressor engine and pipeline venting. EPA plans to carry forward reported reductions for these sources since they are not being revised to use a net emission factor approach. There are also Gas STAR reductions in the transmission and storage segment that are not classified as applicable to specific emission sources ("other voluntary reductions" are 3.6 MMT CO_2 Eq. CH_4 in year 2013). Some portion of the "other voluntary reductions" might apply to the emission sources for which the EPA is revising methodology to use a net emission factor approach. The EPA is investigating potential disaggregation of “other voluntary reductions.” The EPA has retained Gas STAR reductions classified as “other voluntary reductions” in year 2013 emission calculations for the public review draft.

Distribution

This section references the Distribution memo, available at. http://www3.epa.gov/climatechange/ghgemissions/usinventoryreport/Proposed_Revisions_to_NG_Distribution_Segment_Emissions.pdf.

Key data reviewed for updates to the distribution segment include GHGRP, and Lamb et al.

For M&R stations, in this public review draft, the EPA used GHGRP reported activity data for counts of above ground and below ground stations. The EPA scaled the GHGRP station counts to the national level based on the miles of distribution pipeline main reported by GHGRP reporters, compared to the PHMSA national total miles of distribution pipeline main. The EPA then applied the existing Inventory (from GRI) proportions of stations in the various station inlet pressure categories to the scaled counts of above ground and below ground M&R stations, and the station-level emission factors from Lamb et al. See Table 3 (GHGRP reported activity data), Table 2 (GHG Inventory split between station types) and Table 4 (Lamb et al. emission factors) in the Distribution Memo. Comparing the updated 2013 estimate to the previous Inventory 2013 estimate, the M&R stations CH_4 emissions decrease due to use of revised emission factors and activity data is approximately 13.6 MMT CO_2 Eq.

For pipeline leaks, in this public review draft, the EPA used the previous activity data sources for miles of pipeline by material (PHMSA) and for leaks per mile (GRI), and Lamb et al. data on emissions per leak. See Table 7 (activity data on miles of pipeline), and Table 8 (leaks per mile, 2015 Inventory, leak rate, Lamb et al.) in the Distribution Memo. Comparing the updated 2013 estimate to the previous Inventory 2013 estimate, the pipeline leaks CH_4 emissions decrease due to use of revised emission factors is approximately 10.5 MMT CO_2 Eq.

For the time series, the EPA does not plan to revise existing estimates for M&R activity data for years before GHGRP data are available (1990–2011). Using interpolation between GRI/EPA emission factors in early years and Lamb et al. emission factors in recent years for M&R stations and pipeline leaks will reflect net emissions across the Inventory time series without the need to incorporate Gas STAR reductions.

The EPA also considered recent data available to estimate emissions from customer meters. In this public review draft, the EPA revised the emission factors for residential customer meters and commercial/industrial customer meters. The EPA recalculated the residential customer meter emission factor by combining data from the 1996 GRI/EPA study (basis for existing greenhouse gas Inventory emission factor) with newer data from a GTI 2009 study and Clearstone 2011 study. See Table 14 of the Distribution segment memo for the emission factor data for residential meters. The EPA weighted emission factors developed in each study by the number of meters surveyed in each study to develop the revised emission factor. In this public review draft, the EPA applied the GTI 2009 commercial customer meter emission factor to the total count of commercial and industrial meters in the greenhouse gas Inventory. See Table 14 of the Distribution memo for the GTI emission factor for commercial meters. In addition, the EPA used an updated data source for national customer meter counts (EIA data); previously, national customer meter counts were scaled from a 1992 based year value but are now available directly for every year of the time series from EIA. Comparing the updated 2013 estimate to the previous Inventory 2013 estimate, the customer meters CH_4 emissions increase due to use of revised emission factors and activity data is approximately 0.3 MMT CO_2 Eq. The EPA is considering making this change (to use updated activity data and emission factors) for each year of the time series.

For pipeline blowdowns and mishaps/dig-ins, the previous Inventories used base year 1992 distribution main and service miles and scaled the value for non-1992 years using relative residential gas consumption. However, scaling mileage based on residential gas consumption introduced volatility across the time series that does not likely correlate to pipeline mileage trends (as gas consumption is affected by other factors such as equipment efficiency and climate). The EPA used PHMSA data for the activity data to calculate the estimate in this public review draft. See Table 18 for PHMSA AD. The overall impact of using the revised activity data for pipeline blowdowns and mishaps/dig-ins is an increase in emissions. Comparing the updated 2013 estimate to the previous Inventory 2013 estimate, the pipeline blowdowns CH_4 emissions increase due to use of revised activity data is approximately 0.04 MMT CO_2 Eq.; and for mishaps/dig-ins is approximately 0.6 MMT CO_2 Eq.

The EPA's approach for revising Inventory methodology to incorporate Lamb et al. and subpart W data would result in net emissions being directly calculated for M&R stations, pipeline leaks, and customer meters in each time series year. This obviates the need to apply Gas STAR reductions data for these sources. Previous GHG Inventories have applied Gas STAR reductions to mishaps/dig-ins. EPA plans to carry forward reported reductions for this source since it is not being revised to use a net emission factor approach. There are also Gas STAR reductions in the distribution segment that are not classified as applicable to specific emission sources ("other voluntary reductions" are 1.0 MMT CO_2 Eq. CH_4 in year 2013). Some portion of the "other voluntary reductions" might apply to the emission sources for which the EPA is revising methodology to use a net emission factor approach. The EPA is investigating potential disaggregation of "other voluntary reductions." The EPA has retained Gas STAR reductions classified as "other voluntary reductions" in year 2013 emission calculations for the public review draft.

Planned Improvements

EPA will continue to refine the emission estimates to reflect the most robust information available, including stakeholder feedback received on the greenhouse gas inventory improvement memos, and this public review draft.

3.8 Energy Sources of Indirect Greenhouse Gas Emissions

In addition to the main greenhouse gases addressed above, many energy-related activities generate emissions of indirect greenhouse gases. Total emissions of nitrogen oxides (NO_x), carbon monoxide (CO), and non-CH_4 volatile organic compounds (NMVOCs) from energy-related activities from 1990 to 2014 are reported in Table 3-48.

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

Gas/Source	1990	2005	2010	2011	2012	2013	2014
NO_x	**21,106**	**16,602**	**12,004**	**11,796**	**11,051**	**10,557**	**9,995**
Mobile Combustion	10,862	10,295	7,290	7,294	6,788	6,283	5,777
Stationary Combustion	10,023	5,858	4,092	3,807	3,567	3,579	3,522
Oil and Gas Activities	139	321	545	622	622	622	622
Waste Combustion	82	128	77	73	73	73	73
International Bunker Fuels[a]	*1,956*	*1,704*	*1,790*	*1,553*	*1,398*	*1,139*	*1,138*
CO	**125,640**	**64,985**	**45,148**	**44,088**	**42,273**	**40,459**	**38,643**
Mobile Combustion	119,360	58,615	39,475	38,305	36,491	34,676	32,861
Stationary Combustion	5,000	4,648	4,103	4,170	4,170	4,170	4,169
Waste Combustion	978	1,403	1,084	1,003	1,003	1,003	1,003
Oil and Gas Activities	302	318	487	610	610	610	610
International Bunker Fuels[a]	*103*	*133*	*136*	*137*	*133*	*129*	*135*
NMVOCs	**12,620**	**7,191**	**7,464**	**7,759**	**7,449**	**7,139**	**6,830**
Mobile Combustion	10,932	5,724	4,591	4,562	4,252	3,942	3,632
Oil and Gas Activities	554	510	2,205	2,517	2,517	2,517	2,517
Stationary Combustion	912	716	576	599	599	599	599
Waste Combustion	222	241	92	81	81	81	81
International Bunker Fuels[a]	*57*	*54*	*56*	*51*	*46*	*41*	*42*

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

Note: Totals may not sum due to independent rounding.

Methodology

Emission estimates for 1990 through 2014 were obtained from data published on the National Emission Inventory (NEI) Air Pollutant Emission Trends web site (EPA 2015), and disaggregated based on EPA (2003). Emission estimates for 2012, 2013, and 2014 for non-EGU and non-mobile sources are held constant from 2011 in EPA (2015). Emissions were calculated either for individual categories or for many categories combined, using basic activity data (e.g., the amount of raw material processed) as an indicator of emissions. National activity data were collected for individual applications from various agencies.

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

Uncertainty and Time-Series Consistency

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

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

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

Emissions resulting from the combustion of fuels used for international transport activities, termed international bunker fuels under the UNFCCC, are not included in national emission totals, but are reported separately based upon location of fuel sales. The decision to report emissions from international bunker fuels separately, instead of allocating them to a particular country, was made by the Intergovernmental Negotiating Committee in establishing the Framework Convention on Climate Change.[75] These decisions are reflected in the IPCC methodological guidance, including the *2006 IPCC Guidelines*, in which countries are requested to report emissions from ships or aircraft that depart from their ports with fuel purchased within national boundaries and are engaged in international transport separately from national totals (IPCC 2006).[76]

Two transport modes are addressed under the IPCC definition of international bunker fuels: aviation and marine.[77] 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 IPCC Guidelines distinguish between different modes of air traffic. Civil aviation comprises aircraft used for the commercial transport of passengers and freight, military aviation comprises aircraft under the control of national armed forces, and general aviation applies to recreational and small corporate aircraft. The IPCC Guidelines further define international bunker fuel use from civil aviation as the fuel combusted for civil (e.g., commercial) aviation purposes by aircraft arriving or departing on international flight segments. However, as mentioned above, and in

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[75] 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).

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

[77] 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).

keeping with the IPCC Guidelines, only the fuel purchased in the United States and used by aircraft taking-off (i.e., departing) from the United States are reported here. The standard fuel used for civil aviation is kerosene-type jet fuel, while the typical fuel used for general aviation is aviation gasoline.[78]

Emissions of CO_2 from aircraft are essentially a function of fuel use. N_2O 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 considered 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. CO_2 is the primary greenhouse gas emitted from marine shipping.

Overall, aggregate greenhouse gas emissions in 2014 from the combustion of international bunker fuels from both aviation and marine activities were 104.2 MMT CO_2 Eq., or 0.3 percent below emissions in 1990 (see Table 3-49 and Table 3-50). Emissions from international flights and international shipping voyages departing from the United States have increased by 82.2 percent and decreased by 48.4 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.

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

Gas/Mode	1990	2005	2010	2011	2012	2013	2014
CO_2	**103.5**	**113.1**	**117.0**	**111.7**	**105.8**	**99.8**	**103.2**
Aviation	38.0	60.1	61.0	64.8	64.5	65.7	69.4
Commercial	*30.0*	*55.6*	*57.4*	*61.7*	*61.4*	*62.8*	*66.3*
Military	*8.1*	*4.5*	*3.6*	*3.1*	*3.1*	*2.9*	*3.1*
Marine	65.4	53.0	56.0	46.9	41.3	34.1	33.8
CH_4	**0.2**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Aviation[a]	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Marine	0.2	0.1	0.1	0.1	0.1	0.1	0.1
N_2O	**0.9**	**1.0**	**1.0**	**1.0**	**0.9**	**0.9**	**0.9**
Aviation	0.4	0.6	0.6	0.6	0.6	0.6	0.7
Marine	0.5	0.4	0.4	0.4	0.3	0.2	0.2
Total	**104.5**	**114.2**	**118.1**	**112.8**	**106.8**	**100.7**	**104.2**

Note: Totals may not sum due to independent rounding. Includes aircraft cruise altitude emissions.
[a] CH_4 emissions from aviation are estimated to be zero.

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

Gas/Mode	1990	2005	2010	2011	2012	2013	2014
CO_2	**103,463**	**113,139**	**116,992**	**111,660**	**105,805**	**99,763**	**103,201**
Aviation	38,034	60,125	60,967	64,790	64,524	65,664	69,411
Marine	65,429	53,014	56,025	46,870	41,281	34,099	33,791
CH_4	**7**	**5**	**6**	**5**	**4**	**3**	**3**
Aviation[a]	0	0	0	0	0	0	0
Marine	7	5	6	5	4	3	3
N_2O	**3**	**3**	**3**	**3**	**3**	**3**	**3**
Aviation	1	2	2	2	2	2	2
Marine	2	1	1	1	1	1	**1**

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

Note: Totals may not sum due to independent rounding. Includes aircraft cruise altitude emissions.
[a] CH_4 emissions from aviation are estimated to be zero.

Table 3-51: Aviation CO_2 and N_2O Emissions for International Transport (MMT CO_2 Eq.)

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

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

Methodology

Emissions of CO_2 were estimated by applying C content and fraction oxidized factors to fuel consumption activity data. This approach is analogous to that described under CO_2 from Fossil Fuel Combustion. Carbon content and fraction oxidized factors for jet fuel, distillate fuel oil, and residual fuel oil were taken directly from EIA and are presented in Annex 2.1, Annex 2.2, and Annex 3.8 of this Inventory. Density conversions were taken from Chevron (2000), ASTM (1989), and USAF (1998). Heat content for distillate fuel oil and residual fuel oil were taken from EIA (2015) and USAF (1998), and heat content for jet fuel was taken from EIA (2015). 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 *2006 IPCC Guidelines* (IPCC 2006). For aircraft emissions, the following values, in units of grams of pollutant per kilogram of fuel consumed (g/kg), were employed: 0.1 for N_2O (IPCC 2006). For marine vessels consuming either distillate diesel or residual fuel oil the following values (g/MJ), were employed: 0.32 for CH_4 and 0.08 for N_2O. Activity data for aviation included solely jet fuel consumption statistics, while the marine mode included both distillate diesel and residual fuel oil.

Activity data on domestic and international aircraft fuel consumption were developed by the U.S. Federal Aviation Administration (FAA) using radar-informed data from the FAA Enhanced Traffic Management System (ETMS) for 1990, 2000 through 2014 as modeled with the Aviation Environmental Design Tool (AEDT). This bottom-up approach is built from modeling dynamic aircraft performance for each flight occurring within an individual calendar year. The analysis incorporates data on the aircraft type, date, flight identifier, departure time, arrival time, departure airport, arrival airport, ground delay at each airport, and real-world flight trajectories. To generate results for a given flight within AEDT, the radar-informed aircraft data is correlated with engine and aircraft performance data to calculate fuel burn and exhaust emissions. Information on exhaust emissions for in-production aircraft engines comes from the International Civil Aviation Organization (ICAO) Aircraft Engine Emissions Databank (EDB). This bottom-up approach is in accordance with the Tier 3B method from the *2006 IPCC Guidelines* (IPCC 2006).

International aviation CO_2 estimates for 1990 and 2000 through 2014 are obtained from FAA's AEDT model (FAA 2016). The radar-informed method that was used to estimate CO_2 emissions for commercial aircraft for 1990, and 2000 through 2014 is not possible for 1991 through 1999 because the radar data set is not available for years prior to 2000. FAA developed OAG schedule-informed inventories modeled with AEDT and great circle trajectories for 1990, 2000 and 2010. Because fuel consumption and 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.

Data on U.S. Department of Defense (DoD) aviation bunker fuels and total jet fuel consumed by the U.S. military was supplied by the Office of the Under Secretary of Defense (Installations and Environment), DoD. Estimates of the percentage of each Service's total operations that were international operations were developed by DoD. Military aviation bunkers included international operations, operations conducted from naval vessels at sea, and operations conducted from U.S. installations principally over international water in direct support of military operations at sea. Military aviation bunker fuel emissions were estimated using military fuel and operations data synthesized from unpublished data from DoD's Defense Logistics Agency Energy (DLA Energy 2015). Together, the data allow the quantity of fuel used in military international operations to be estimated. Densities for each jet fuel type were obtained from a report from the U.S. Air Force (USAF 1998). Final jet fuel consumption estimates are presented in Table 3-52. See Annex 3.8 for additional discussion of military data.

Activity data on distillate diesel and residual fuel oil consumption by cargo or passenger carrying marine vessels departing from U.S. ports were taken from unpublished data collected by the Foreign Trade Division of the U.S. Department of Commerce's Bureau of the Census (DOC 2015) for 1990 through 2001, 2007 through 2014, and the Department of Homeland Security's Bunker Report for 2003 through 2006 (DHS 2008). Fuel consumption data for 2002 was interpolated due to inconsistencies in reported fuel consumption data. Activity data on distillate diesel consumption by military vessels departing from U.S. ports were provided by DLA Energy (2015). The total amount of fuel provided to naval vessels was reduced by 21 percent to account for fuel used while the vessels were not-underway (i.e., in port). Data on the percentage of steaming hours underway versus not-underway were provided by the U.S. Navy. These fuel consumption estimates are presented in. Table 3-53.

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

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

Note: Totals may not sum due to independent rounding.

Table 3-53: Marine Fuel Consumption for International Transport (Million Gallons)

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

Note: Totals may not sum due to independent rounding.

Uncertainty and Time-Series Consistency

Emission estimates related to the consumption of international bunker fuels are subject to the same uncertainties as those from domestic aviation and marine mobile combustion emissions; however, additional uncertainties result from the difficulty in collecting accurate fuel consumption activity data for international transport activities separate from domestic transport activities.[79] For example, smaller aircraft on shorter routes often carry sufficient fuel to complete several flight segments without refueling in order to minimize time spent at the airport gate or take advantage of lower fuel prices at particular airports. This practice, called tankering, when done on international flights, complicates the use of fuel sales data for estimating bunker fuel emissions. Tankering is less common with the type of large, long-range aircraft that make many international flights from the United States, however. Similar practices occur in the marine shipping industry where fuel costs represent a significant portion of overall operating costs and fuel prices vary from port to port, leading to some tankering from ports with low fuel costs.

Uncertainties exist with regard to the total fuel used by military aircraft and ships, and in the activity data on military operations and training that were used to estimate percentages of total fuel use reported as bunker fuel emissions. Total aircraft and ship fuel use estimates were developed from DoD records, which document fuel sold to the Navy and Air Force from the Defense Logistics Agency. These data may slightly over or under estimate actual total fuel

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

use in aircraft and ships because each Service may have procured fuel from, and/or may have sold to, traded with, and/or given fuel to other ships, aircraft, governments, or other entities. There are uncertainties in aircraft operations and training activity data. Estimates for the quantity of fuel actually used in Navy and Air Force flying activities reported as bunker fuel emissions had to be estimated based on a combination of available data and expert judgment. Estimates of marine bunker fuel emissions were based on Navy vessel steaming hour data, which reports fuel used while underway and fuel used while not underway. This approach does not capture some voyages that would be classified as domestic for a commercial vessel. Conversely, emissions from fuel used while not underway preceding an international voyage are reported as domestic rather than international as would be done for a commercial vessel. There is uncertainty associated with ground fuel estimates for 1997 through 2001. Small fuel quantities may have been used in vehicles or equipment other than that which was assumed for each fuel type.

There are also uncertainties in fuel end-uses by fuel-type, emissions factors, fuel densities, diesel fuel sulfur content, aircraft and vessel engine characteristics and fuel efficiencies, and the methodology used to back-calculate the data set to 1990 using the original set from 1995. The data were adjusted for trends in fuel use based on a closely correlating, but not matching, data set. All assumptions used to develop the estimate were based on process knowledge, Department and military Service data, and expert judgments. The magnitude of the potential errors related to the various uncertainties has not been calculated, but is believed to be small. The uncertainties associated with future military bunker fuel emission estimates could be reduced through additional data collection.

Although aggregate fuel consumption data have been used to estimate emissions from aviation, the recommended method for estimating emissions of gases other than CO_2 in the *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.[80]

There is also concern regarding the reliability of the existing DOC (2015) data on marine vessel fuel consumption reported at U.S. customs stations due to the significant degree of inter-annual variation.

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

QA/QC and Verification

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

Planned Improvements

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

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

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

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

In 2014, total CO_2 emissions from the burning of woody biomass in the industrial, residential, commercial, and electricity generation sectors were approximately 217.7 MMT CO_2 Eq. (217,654 kt) (see Table 3-54 and Table 3-55). As the largest consumer of woody biomass, the industrial sector was responsible for 57.1 percent of the CO_2 emissions from this source. The residential sector was the second largest emitter, constituting 27.5 percent of the total, while the commercial and electricity generation sectors accounted for the remainder.

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

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

Note: Totals may not sum due to independent rounding.

Table 3-55: CO_2 Emissions from Wood Consumption by End-Use Sector (kt)

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

Note: Totals may not sum due to independent rounding.

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

In 2014, the United States consumed an estimated 1,111.3 trillion Btu of ethanol, and as a result, produced approximately 76.1 MMT CO_2 Eq. (76,075 kt) (see Table 3-56 and Table 3-57) of CO_2 emissions. Ethanol production and consumption has grown significantly since 1990 due to the favorable economics of blending ethanol into gasoline and federal policies that have encouraged use of renewable fuels.

Table 3-56: CO_2 Emissions from Ethanol Consumption (MMT CO_2 Eq.)

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

+ Does not exceed 0.05 MMT CO_2 Eq.

Note: Totals may not sum due to independent rounding.

Table 3-57: CO_2 Emissions from Ethanol Consumption (kt)

End-Use Sector	1990		2005		2010	2011	2012	2013	2014
Transportation[a]	4,136		22,414		71,287	71,537	71,510	73,354	74,661
Industrial	56		468		1,134	1,146	1,142	1,206	1,227
Commercial	34		60		226	198	175	183	186
Total	**4,227**		**22,943**		**72,647**	**72,881**	**72,827**	**74,743**	**76,075**

[a] See Annex 3.2, Table A-92 for additional information on transportation consumption of these fuels.

Note: Totals may not sum due to independent rounding.

Methodology

Woody biomass emissions were estimated by applying two EIA gross heat contents (Lindstrom 2006) to U.S. consumption data (EIA 2015) (see Table 3-58), provided in energy units for the industrial, residential, commercial, and electric generation sectors. One heat content (16.95 MMBtu/MT wood and wood waste) was applied to the industrial sector's consumption, while the other heat content (15.43 MMBtu/MT wood and wood waste) was applied to the consumption data for the other sectors. An EIA emission factor of 0.434 MT C/MT wood (Lindstrom 2006) was then applied to the resulting quantities of woody biomass to obtain CO_2 emission estimates. It was assumed that the woody biomass contains black liquor and other wood wastes, has a moisture content of 12 percent, and is converted into CO_2 with 100 percent efficiency. The emissions from ethanol consumption were calculated by applying an emission factor of 18.67 MMT C/QBtu (EPA 2010) to U.S. ethanol consumption estimates that were provided in energy units (EIA 2015) (see Table 3-59).

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

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

Note: Totals may not sum due to independent rounding.

Table 3-59: Ethanol Consumption by Sector (Trillion Btu)

End-Use Sector	1990		2005		2010	2011	2012	2013	2014
Transportation	60.4		327.4		1,041.4	1,045.0	1,044.6	1,071.5	1,090.6
Industrial	0.8		6.8		16.6	16.7	16.7	17.6	17.9
Commercial	0.5		0.9		3.3	2.9	2.6	2.7	2.7
Total	**61.7**		**335.1**		**1,061.2**	**1,064.6**	**1,063.8**	**1,091.8**	**1,111.3**

Note: Totals may not sum due to independent rounding.

Uncertainty and Time-Series Consistency

It is assumed that the combustion efficiency for woody biomass is 100 percent, which is believed to be an overestimate of the efficiency of wood combustion processes in the United States. Decreasing the combustion efficiency would decrease emission estimates. Additionally, the heat content applied to the consumption of woody biomass in the residential, commercial, and electric power sectors is unlikely to be a completely accurate representation of the heat content for all the different types of woody biomass consumed within these sectors. Emission estimates from ethanol production are more certain than estimates from woody biomass consumption due to better activity data collection methods and uniform combustion techniques.

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

Recalculations Discussion

Wood consumption values for 2013 were revised relative to the previous Inventory based on updated information from EIA's *Monthly Energy Review* (EIA 2015). These revisions of historical data for wood biomass consumption resulted in an average annual increase in emissions from wood biomass consumption of 0.1 MMT CO_2 Eq. (less than 0.1 percent) from 1990 through 2013. Ethanol consumption values remained constant relative to the previous Inventory throughout the entire time-series.

Planned Improvements

The availability of facility-level combustion emissions through EPA's GHGRP will be examined to help better characterize the industrial sector's energy consumption in the United States, and further classify business establishments according to industrial economic activity type. Most methodologies used in EPA's GHGRP are consistent with IPCC, though for EPA's GHGRP, facilities collect detailed information specific to their operations according to detailed measurement standards, which may differ with the more aggregated data collected for the Inventory to estimate total, national U.S. emissions. In addition, and unlike the reporting requirements for this chapter under the UNFCCC reporting guidelines, some facility-level fuel combustion emissions reported under the GHGRP may also include industrial process emissions.[81] In line with UNFCCC reporting guidelines, fuel combustion emissions are included in this chapter, while process emissions are included in the Industrial Processes and Product Use chapter of this report. In examining data from EPA's GHGRP that would be useful to improve the emission estimates for the 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.[82]

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

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

4. Industrial Processes and Product Use

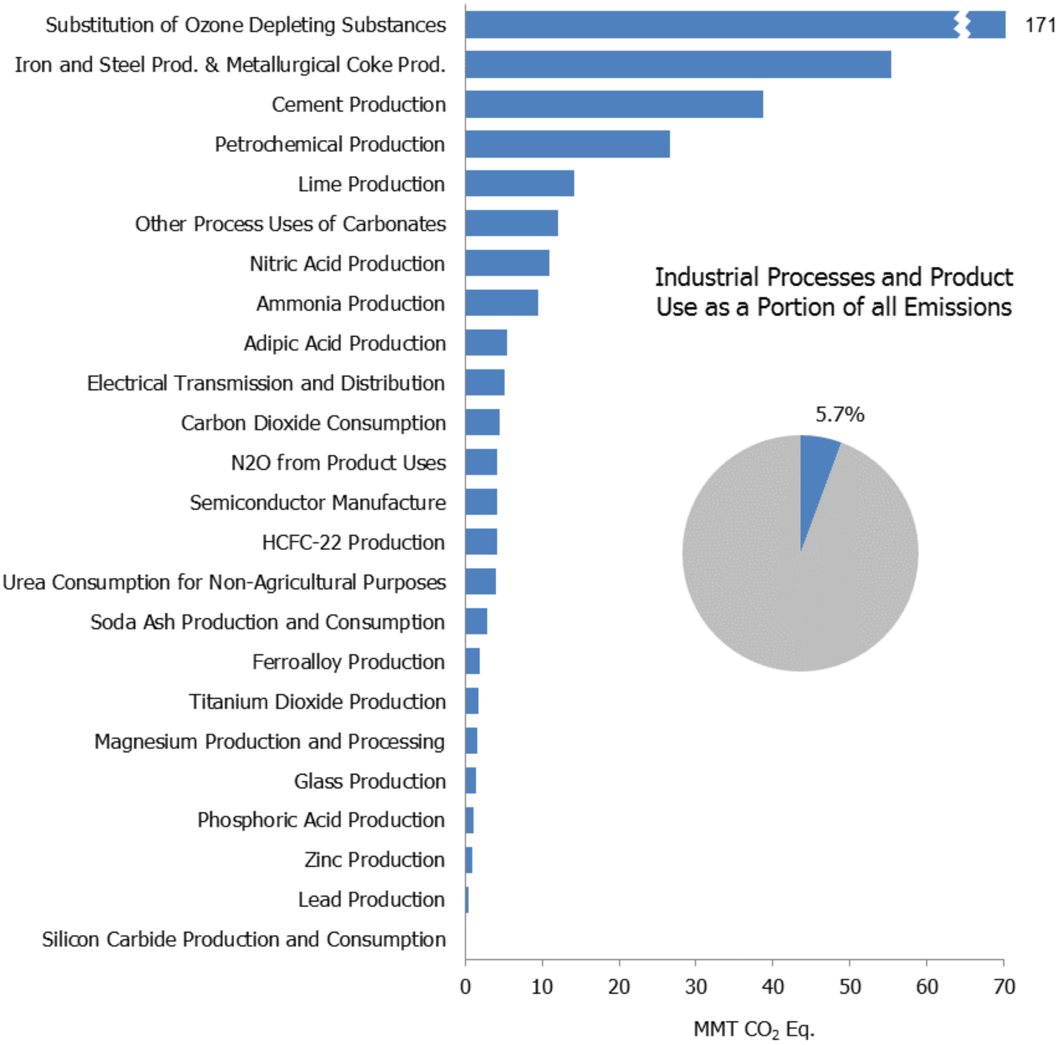
The Industrial Processes and Product Use (IPPU) chapter includes greenhouse gas emissions occurring from industrial processes and from the use of greenhouse gases in products. The industrial processes and product use categories included in this chapter are presented in Figure 4-1.

Greenhouse gas emissions are produced as the byproducts of various non-energy-related industrial activities. That is, these emissions are produced either from an industrial process itself, and are not directly a result of energy consumed during the process. For example, raw materials can be chemically or physically transformed from one state to another. This transformation can result in the release of greenhouse gases such as carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O). The processes included in this chapter include iron and steel production and metallurgical coke production, cement production, lime production, other process uses of carbonates (e.g., flux stone, flue gas desulfurization, and glass manufacturing), ammonia production and urea consumption, petrochemical production, aluminum production, soda ash production and use, titanium dioxide production, CO_2 consumption, ferroalloy production, glass production, zinc production, phosphoric acid production, lead production, silicon carbide production and consumption, nitric acid production, and adipic acid production.

In addition, greenhouse gases are often used in products or by end-consumers. These gases include industrial sources of man-made compounds such as hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), sulfur hexafluoride (SF_6), nitrogen trifluoride (NF_3), and nitrous oxide (N_2O). The present contribution of HFCs, PFCs, SF_6, and NF_3 gases to the radiative forcing effect of all anthropogenic greenhouse gases is small; however, because of their extremely long lifetimes, many of them will continue to accumulate in the atmosphere as long as emissions continue. In addition, many of these gases have high global warming potentials; SF_6 is the most potent greenhouse gas the Intergovernmental Panel on Climate Change (IPCC) has evaluated. Use of HFCs is growing rapidly since they are the primary substitutes for ozone depleting substances (ODSs), which are being phased-out under the Montreal Protocol on Substances that Deplete the Ozone Layer. HFCs, PFCs, SF_6, and NF_3 are employed and emitted by a number of other industrial sources in the United States such as aluminum production, HCFC-22 production, semiconductor manufacture, electric power transmission and distribution, and magnesium metal production and processing. N_2O is emitted by the production of adipic acid and nitric acid, semiconductor manufacturing, end-consumers in product uses through the administration of anesthetics, and by industry as a propellant in aerosol products.

In 2014, IPPU generated emissions of 388.6 million metric tons of CO_2 equivalent (MMT CO_2 Eq.), or 5.7 percent of total U.S. greenhouse gas emissions. Carbon dioxide emissions from all industrial processes were 178.6 MMT CO_2 Eq. (178,572 kt CO_2) in 2014, or 3.2 percent of total U.S. CO_2 emissions. Methane emissions from industrial processes resulted in emissions of approximately 0.2 MMT CO_2 Eq. (32 kt CH_4) in 2014, which was less than 1 percent of U.S. CH_4 emissions. N_2O emissions from IPPU were 20.8 MMT CO_2 Eq. (70 kt N_2O) in 2014, or 5.1 percent of total U.S. N_2O emissions. In 2014 combined emissions of HFCs, PFCs, SF_6, and NF_3 totaled 189.1 MMT CO_2 Eq. Total emissions from IPPU in 2014 were 14.0 percent more than 1990 emissions. Indirect greenhouse gas emissions also result from IPPU, and are presented in Table 4-108 in kilotons (kt).

Figure 4-1: 2014 Industrial Processes and Product Use Chapter Greenhouse Gas Sources ($MMT\ CO_2$ Eq.)



The increase in overall IPPU emissions since 1990 reflects a range of emission trends among the emission sources. Emissions resulting from most types of metal production have declined significantly since 1990, largely due to production shifting to other countries, but also due to transitions to less-emissive methods of production (in the case of iron and steel) and to improved practices (in the case of PFC emissions from aluminum production). Emissions from mineral sources have either increased or not changed significantly since 1990 but largely track economic cycles, while CO_2 and CH_4 emissions from chemical sources have either decreased or not changed significantly. HFC emissions from the substitution of ozone depleting substances have increased drastically since 1990, while the emission trends of HFCs, PFCs, SF_6, and NF_3 from other sources are mixed. N_2O emissions from the production of adipic and nitric acid have decreased, while N_2O emissions from product uses has remained nearly constant over time. Trends are explained further within each emission source category throughout the chapter.

Table 4-1 summarizes emissions for the IPPU chapter in MMT CO_2 Eq. using *IPCC Fourth Assessment Report* (AR4) GWP values, following the requirements of the revised UNFCCC reporting guidelines for national inventories (IPCC 2007). [1] Unweighted native gas emissions in kt are also provided in Table 4-2. The source descriptions that follow in the chapter are presented in the order as reported to the UNFCCC in the common

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[1] See <http://unfccc.int/resource/docs/2013/cop19/eng/10a03.pdf >.

reporting format tables, corresponding generally to: mineral products, chemical production, metal production, and emissions from the uses of HFCs, PFCs, SF$_6$, and NF$_3$.

Table 4-1: Emissions from Industrial Processes and Product Use (MMT CO$_2$ Eq.)

Gas/Source	1990	2005	2010	2011	2012	2013	2014
CO$_2$	207.1	190.3	168.8	172.9	169.5	171.7	178.6
Iron and Steel Production & Metallurgical Coke Production	99.7	66.5	55.7	59.9	54.2	52.2	55.4
Iron and Steel Production	*97.2*	*64.5*	*53.6*	*58.5*	*53.7*	*50.4*	*53.4*
Metallurgical Coke Production	*2.5*	*2.0*	*2.1*	*1.4*	*0.5*	*1.8*	*1.9*
Cement Production	33.3	45.9	31.3	32.0	35.1	36.1	38.8
Petrochemical Production	21.6	27.4	27.2	26.3	26.5	26.4	26.5
Lime Production	11.7	14.6	13.4	14.0	13.7	14.0	14.1
Other Process Uses of Carbonates	4.9	6.3	9.6	9.3	8.0	10.4	12.1
Ammonia Production	13.0	9.2	9.2	9.3	9.4	10.0	9.4
Carbon Dioxide Consumption	1.5	1.4	4.4	4.1	4.0	4.2	4.5
Urea Consumption for Non-Agricultural Purposes	3.8	3.7	4.7	4.0	4.4	4.2	4.0
Aluminum Production	6.8	4.1	2.7	3.3	3.4	3.3	3.3
Soda Ash Production and Consumption	2.8	3.0	2.7	2.7	2.8	2.8	2.8
Ferroalloy Production	2.2	1.4	1.7	1.7	1.9	1.8	1.9
Titanium Dioxide Production	1.2	1.8	1.8	1.7	1.5	1.7	1.8
Glass Production	1.5	1.9	1.5	1.3	1.2	1.3	1.3
Phosphoric Acid Production	1.5	1.3	1.1	1.2	1.1	1.1	1.1
Zinc Production	0.6	1.0	1.2	1.3	1.5	1.4	1.0
Lead Production	0.5	0.6	0.5	0.5	0.5	0.5	0.5
Silicon Carbide Production and Consumption	0.4	0.2	0.2	0.2	0.2	0.2	0.2
Magnesium Production and Processing	+	+	+	+	+	+	+
CH$_4$	**0.3**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.2**
Petrochemical Production	0.2	0.1	+	+	0.1	0.1	0.1
Ferroalloy Production	+	+	+	+	+	+	+
Silicon Carbide Production and Consumption	+	+	+	+	+	+	+
Iron and Steel Production & Metallurgical Coke Production	+	+	+	+	+	+	+
Iron and Steel Production	+	+	+	+	+	+	+
Metallurgical Coke Production	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
N$_2$O	**31.6**	**22.8**	**20.1**	**25.5**	**20.4**	**19.1**	**20.8**
Nitric Acid Production	12.1	11.3	11.5	10.9	10.5	10.7	10.9
Adipic Acid Production	15.2	7.1	4.2	10.2	5.5	4.0	5.4
N$_2$O from Product Uses	4.2	4.2	4.2	4.2	4.2	4.2	4.2
Semiconductor Manufacturing	+	0.1	0.1	0.2	0.2	0.2	0.2
HFCs	**46.6**	**133.3**	**161.7**	**166.1**	**167.1**	**169.6**	**175.8**
Substitution of Ozone Depleting Substances[a]	0.3	113.0	153.5	157.1	161.4	165.3	171.4
HCFC-22 Production	46.1	20.0	8.0	8.8	5.5	4.1	4.1
Semiconductor Manufacture	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Magnesium Production and Processing	0.0	0.0	+	+	+	0.1	0.1
PFCs	**24.3**	**6.6**	**4.4**	**6.9**	**6.0**	**5.8**	**5.8**
Aluminum Production	21.5	3.4	1.9	3.5	2.9	3.0	3.0
Semiconductor Manufacture	2.8	3.2	2.6	3.4	3.0	2.9	2.9
SF$_6$	**31.1**	**14.0**	**9.5**	**10.0**	**7.7**	**6.9**	**6.9**

Electrical Transmission and Distribution	25.4	10.6	7.0	6.8	5.7	5.1	5.1
Magnesium Production and Processing	5.2	2.7	2.1	2.8	1.6	1.4	1.4
Semiconductor Manufacture	0.5	0.7	0.4	0.4	0.4	0.4	0.4
NF_3	**+**	**0.5**	**0.5**	**0.7**	**0.6**	**0.6**	**0.6**
Semiconductor Manufacture	+	0.5	0.5	0.7	0.6	0.6	0.6
Total	**340.9**	**367.6**	**365.2**	**382.2**	**371.4**	**373.8**	**388.6**

Note: Totals may not sum due to independent rounding.

+ Does not exceed 0.05 MMT CO_2 Eq.

[a] Small amounts of PFC emissions also result from this source.

Table 4-2: Emissions from Industrial Processes and Product Use (kt)

Gas/Source	1990	2005	2010	2011	2012	2013	2014
CO_2	**207,054**	**190,273**	**168,781**	**172,898**	**169,472**	**171,714**	**178,572**
Iron and Steel Production & Metallurgical Coke Production	99,669	66,543	55,671	59,928	54,229	52,201	55,355
Iron and Steel Production	*97,166*	*64,499*	*53,586*	*58,501*	*53,686*	*50,378*	*53,417*
Metallurgical Coke Production	*2,503*	*2,044*	*2,085*	*1,426*	*543*	*1,824*	*1,938*
Cement Production	33,278	45,910	31,256	32,010	35,051	36,146	38,755
Petrochemical Production	21,609	27,380	27,246	26,326	26,464	26,437	26,509
Lime Production	11,700	14,552	13,381	13,981	13,715	14,045	14,125
Other Process Uses of Carbonates	4,907	6,339	9,560	9,335	8,022	10,414	12,077
Ammonia Production	13,047	9,196	9,188	9,292	9,377	9,962	9,436
Carbon Dioxide Consumption	1,472	1,375	4,425	4,083	4,019	4,188	4,471
Urea Consumption for Non-Agricultural Purposes	3,784	3,653	4,730	4,029	4,449	4,179	4,007
Aluminum Production	6,831	4,142	2,722	3,292	3,439	3,255	3,255
Soda Ash Production and Consumption	2,822	2,960	2,697	2,712	2,763	2,804	2,827
Ferroalloy Production	2,152	1,392	1,663	1,735	1,903	1,785	1,914
Titanium Dioxide Production	1,195	1,755	1,769	1,729	1,528	1,715	1,755
Glass Production	1,535	1,928	1,481	1,299	1,248	1,317	1,341
Phosphoric Acid Production	1,529	1,342	1,087	1,151	1,093	1,119	1,095
Zinc Production	632	1,030	1,182	1,286	1,486	1,429	956
Lead Production	516	553	542	538	527	546	518
Silicon Carbide Production and Consumption	375	219	181	170	158	169	173
Magnesium Production and Processing	1	3	1	3	2	2	2
CH_4	**12**	**4**	**3**	**3**	**4**	**4**	**6**
Petrochemical Production	9	3	2	2	3	3	5
Ferroalloy Production	1	+	+	+	1	+	1
Silicon Carbide Production and Consumption	1	+	+	+	+	+	+
Iron and Steel Production & Metallurgical Coke Production	1	1	+	+	+	+	+
Iron and Steel Production	*1*	*1*	+	+	+	+	+
Metallurgical Coke Production	0	0	0	0	0	0	0
N_2O	**106**	**76**	**68**	**86**	**69**	**64**	**70**
Nitric Acid Production	41	38	39	37	35	36	37
Adipic Acid Production	51	24	14	34	19	13	18
N_2O from Product Uses	14	14	14	14	14	14	14
Semiconductor Manufacturing	+	+	+	1	1	1	1
HFCs	**M**	**M**	**M**	**M**	**M**	**M**	**M**
Substitution of Ozone Depleting Substances[a]	M	M	M	M	M	M	M

HCFC-22 Production	3	1	1	1	+	+	+
Semiconductor Manufacture	+	+	+	+	+	+	+
Magnesium Production and Processing	0	0	+	+	+	+	+
PFCs	**M**	**M**	**M**	**M**	**M**	**M**	**M**
Aluminum Production	M	M	M	M	M	M	M
Semiconductor Manufacture	M	M	M	M	M	M	M
SF_6	**2**	**1**	**+**	**1**	**+**	**+**	**+**
Electrical Transmission and Distribution	1	+	+	+	+	+	+
Magnesium Production and Processing	+	+	+	+	+	+	+
Semiconductor Manufacture	+	+	+	+	+	+	+
NF_3	**+**	**+**	**+**	**+**	**+**	**+**	**+**
Semiconductor Manufacture	+	+	+	+	+	+	+

+ Does not exceed 0.5 kt.

M (Mixture of gases)

Note: Totals may not sum due to independent rounding.

[a] Small amounts of PFC emissions also result from this source.

The UNFCCC incorporated the *2006 IPCC Guidelines for National Greenhouse Gas Inventories (2006 IPCC Guidelines)* as the standard for Annex I countries at the Nineteenth Conference of the Parties (Warsaw, November 11-23, 2013). This chapter presents emission estimates calculated in accordance with the methodological guidance provided in these guidelines.

QA/QC and Verification Procedures

For industrial processes and product use sources, a detailed QA/QC plan was developed and implemented. This plan was based on the overall U.S. QA/QC plan, but was tailored to include specific procedures recommended for these sources. Two types of checks were performed using this plan: (1) general, or Tier 1, procedures that focus on annual procedures and checks to be used when gathering, maintaining, handling, documenting, checking, and archiving the data, supporting documents, and files, and (2) source-category specific, or Tier 2, procedures that focus on checks of the emission factors, activity data, and methodologies used for estimating emissions from the relevant industrial process and product use sources. Examples of these procedures include checks to ensure that activity data and emission estimates are consistent with historical trends; that, where possible, consistent and reputable data sources are used across sources; that interpolation or extrapolation techniques are consistent across sources; and that common datasets and factors are used where applicable. Tier 1 quality assurance and quality control procedures have been performed for all industrial process and product use sources. Tier 2 procedures were performed for more significant emission categories, consistent with the *IPCC Good Practice Guidelines*.

For most industrial process and product use categories, activity data is obtained through a survey of manufacturers conducted by various organizations (specified within each source); the uncertainty of the activity data is a function of the reliability of reported plant-level production data and is influenced by the completeness of the survey response. The emission factors used are defaults from IPCC, derived using calculations that assume precise and efficient chemical reactions, or were based upon empirical data in published references. As a result, uncertainties in the emission coefficients can be attributed to, among other things, inefficiencies in the chemical reactions associated with each production process or to the use of empirically-derived emission factors that are biased; therefore, they may not represent U.S. national averages. Additional assumptions are described within each source.

The uncertainty analysis performed to quantify uncertainties associated with the 2014 emission estimates from industrial processes and product use continues a multi-year process for developing credible quantitative uncertainty estimates for these source categories using the IPCC Tier 2 approach. As the process continues, the type and the characteristics of the actual probability density functions underlying the input variables are identified and better characterized (resulting in development of more reliable inputs for the model, including accurate characterization of correlation between variables), based primarily on expert judgment. Accordingly, the quantitative uncertainty estimates reported in this section should be considered illustrative and as iterations of ongoing efforts to produce accurate uncertainty estimates. The correlation among data used for estimating emissions for different sources can influence the uncertainty analysis of each individual source. While the uncertainty analysis recognizes very significant connections among sources, a more comprehensive approach that accounts for all linkages will be identified as the uncertainty analysis moves forward.

Box 4-1: Industrial Processes Data from EPA's Greenhouse Gas Reporting Program

On October 30, 2009, the U.S. EPA published a rule requiring annual of greenhouse gas data from large GHG emissions 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). The rule applies to direct greenhouse gas emitters, fossil fuel suppliers, industrial gas suppliers, and facilities that inject CO_2 underground for sequestration or other reasons and requires reporting by sources or suppliers in 41 industrial categories. Annual reporting is at the facility level, except for certain suppliers of fossil fuels and industrial greenhouse gases. In general, the threshold for reporting is 25,000 metric tons or more of CO_2 Eq. per year, but reporting is required for all facilities in some industries. Calendar year 2010 was the first year for which data were reported for facilities subject to 40 CFR part 98, though some source categories first reported data for calendar year 2011.

EPA's GHGRP dataset and the data presented in this Inventory report are complementary. EPA presents the data collected by EPA's GHGRP through a data publication tool (ghgdata.epa.gov) that allows data to be viewed in several formats, including maps, tables, charts, and graphs for individual facilities or groups of facilities. Most methodologies used in EPA's GHGRP are consistent with IPCC, though for EPA's GHGRP, facilities collect detailed information specific to their operations according to detailed measurement standards. This may differ from the more aggregated data collected for the Inventory to estimate total, national U.S. emissions. It should be noted that the definitions for source categories in the GHGRP may differ from those used in this Inventory in meeting the UNFCCC reporting guidelines (IPCC 2011). In line with the UNFCCC reporting guidelines, the Inventory report is a comprehensive accounting of all emissions from source categories identified in the IPCC guidelines. Further information on the reporting categorizations in EPA's GHGRP and specific data caveats associated with monitoring methods in EPA's GHGRP has been provided on the EPA's GHGRP website.

For certain source categories in this Inventory (e.g., nitric acid production and petrochemical production), EPA has also integrated data values that have been calculated by aggregating GHGRP data that is considered confidential business information (CBI) at the facility level. EPA, with industry engagement, has put forth criteria to confirm that a given data aggregation shields underlying CBI from public disclosure. EPA is publishing only data values that meet these aggregation criteria.[2] Specific uses of aggregated facility-level data are described in the respective methodological sections. For other source categories in this chapter, as indicated in the respective planned improvements sections, EPA is continuing to analyze how facility-level GHGRP data may be used to improve the national estimates presented in this Inventory, giving particular consideration to ensuring time series consistency and completeness.

4.1 Cement Production (IPCC Source Category 2A1)

Cement production is an energy- and raw material-intensive process that results in the generation of CO_2 from both the energy consumed in making the cement and the chemical process itself. Emissions from fuels consumed for energy purposes during the production of cement are accounted for in the Energy chapter.

During the cement production process, calcium carbonate ($CaCO_3$) is heated in a cement kiln at a temperature of about 1,450°C (2,700°F) to form lime (i.e., calcium oxide or CaO) and CO_2 in a process known as calcination or

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[2] U.S. EPA Greenhouse Gas Reporting Program. Developments on Publication of Aggregated Greenhouse Gas Data, November 25, 2014. See <http://www.epa.gov/ghgreporting/confidential-business-information-ghg-reporting>

calcining. The quantity of CO_2 emitted during cement production is directly proportional to the lime content of the clinker. During calcination, each mole of limestone ($CaCO_3$) heated in the clinker kiln forms one mole of lime (CaO) and one mole of CO_2:

$$CaCO_3 + heat \rightarrow CaO + CO_2$$

Next, the lime is combined with silica-containing materials to produce clinker (an intermediate product), with the earlier byproduct CO_2 being released to the atmosphere. The clinker is then allowed to cool, mixed with a small amount of gypsum and potentially other materials (e.g., slag, etc.), and used to make Portland cement.[3]

CO_2 emitted from the chemical process of cement production is the second largest source of industrial CO_2 emissions in the United States. Cement is produced in 34 states and Puerto Rico. Texas, California, Missouri, Florida, and Michigan were the five leading cement-producing States in 2014 and accounted for approximately 53 percent of total U.S. production (USGS 2015b). Clinker production in 2014 increased approximately 7 percent from 2013 levels. This increase can be attributed to an increase in spending in new residential construction and nonresidential buildings. In 2014, U.S. clinker production totaled 74,946 kilotons (USGS 2015a). The resulting CO_2 emissions were estimated to be 38.8 MMT CO_2 Eq. (38,755 kt) (see Table 4-3).

Table 4-3: CO_2 Emissions from Cement Production (MMT CO_2 Eq. and kt)

Year	MMT CO_2 Eq.	kt
1990	33.3	33,278
2005	45.9	45,910
2010	31.3	31,256
2011	32.0	32,010
2012	35.1	35,051
2013	36.1	36,146
2014	38.8	38,755

Greenhouse gas emissions from cement production increased every year from 1991 through 2006 (with the exception of a slight decrease in 1997), but decreased in the following years until 2009. Emissions from cement production were at their lowest levels in 2009 (2009 emissions are approximately 28 percent lower than 2008 emissions and 12 percent lower than 1990). Since 2010, emissions have increased slightly. In 2014, emissions from cement production increased by 7 percent from 2013 levels.

Emissions since 1990 have increased by 16 percent. Emissions decreased significantly between 2008 and 2009, due to the economic recession and associated decrease in demand for construction materials. Emissions increased slightly from 2009 levels in 2010, and continued to gradually increase during the 2011 through 2014 time period due to increasing consumption. Cement continues to be a critical component of the construction industry; therefore, the availability of public and private construction funding, as well as overall economic conditions, have considerable impact on the level of cement production.

Methodology

CO_2 emissions were estimated using the Tier 2 methodology from the *2006 IPCC Guidelines*. The Tier 2 methodology was used because detailed and complete data (including weights and composition) for carbonate(s) consumed in clinker production are not available, and thus a rigorous Tier 3 approach is impractical. Tier 2 specifies the use of aggregated plant or national clinker production data and an emission factor, which is the product of the average lime fraction for clinker of 65 percent and a constant reflecting the mass of CO_2 released per unit of lime.

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[3] Approximately three percent of total clinker production is used to produce masonry cement, which is produced using plasticizers (e.g., ground limestone, lime, etc.) and Portland cement (USGS 2011). Carbon dioxide emissions that result from the production of lime used to create masonry cement are included in the Lime Manufacture source category.

The USGS mineral commodity expert for cement has confirmed that this is a reasonable assumption for the United States (Van Oss 2013a). This calculation yields an emission factor of 0.51 tons of CO_2 per ton of clinker produced, which was determined as follows:

$$EF_{clinker} = 0.6460\ \text{CaO} \times [(44.01\ \text{g/mole}\ \text{CO}_2) \div (56.08\ \text{g/mole CaO})] = 0.5070\ \text{tons}\ \text{CO}_2\text{/ton clinker}$$

During clinker production, some of the clinker precursor materials remain in the kiln as non-calcinated, partially calcinated, or fully calcinated cement kiln dust (CKD). The emissions attributable to the calcinated portion of the CKD are not accounted for by the clinker emission factor. The IPCC recommends that these additional CKD CO_2 emissions should be estimated as two percent of the CO_2 emissions calculated from clinker production (when data on CKD generation are not available). Total cement production emissions were calculated by adding the emissions from clinker production to the emissions assigned to CKD (IPCC 2006).

Furthermore, small amounts of impurities (i.e., not calcium carbonate) may exist in the raw limestone used to produce clinker. The proportion of these impurities is generally minimal, although a small amount (1 to 2 percent) of magnesium oxide (MgO) may be desirable as a flux. Per the IPCC Tier 2 methodology, a correction for magnesium oxide is not used, since the amount of magnesium oxide from carbonate is likely very small and the assumption of a 100 percent carbonate source of CaO already yields an overestimation of emissions (IPCC 2006). The 1990 through 2012 activity data for clinker production (see Table 4-4) were obtained from USGS (Van Oss 2013b). Clinker production data for 2013 and 2014 were also obtained from USGS (USGS 2015a). The data were compiled by USGS (to the nearest ton) through questionnaires sent to domestic clinker and cement manufacturing plants, including the facilities in Puerto Rico.

Table 4-4: Clinker Production (kt)

Year	Clinker
1990	64,355
2005	88,783
2010	60,444
2011	61,903
2012	67,784
2013	69,901
2014	74,946

Note: Clinker production from 1990-2014 includes Puerto Rico. Data were obtained from USGS (Van Oss 2013a; USGS 2014), whose original data source was USGS and U.S. Bureau of Mines Minerals Yearbooks (2013 data obtained from mineral industry surveys for cement in June 2014; 2014 data obtained from mineral industry surveys for cement in June 2015).

Uncertainty and Time-Series Consistency

The uncertainties contained in these estimates are primarily due to uncertainties in the lime content of clinker and in the percentage of CKD recycled inside the cement kiln. Uncertainty is also associated with the assumption that all calcium-containing raw materials are $CaCO_3$, when a small percentage likely consists of other carbonate and non-carbonate raw materials. The lime content of clinker varies from 60 to 67 percent; 65 percent is used as a representative value (Van Oss 2013a). CKD loss can range from 1.5 to 8 percent depending upon plant specifications. Additionally, some amount of CO_2 is reabsorbed when the cement is used for construction. As cement reacts with water, alkaline substances such as calcium hydroxide are formed. During this curing process, these compounds may react with CO_2 in the atmosphere to create calcium carbonate. This reaction only occurs in roughly the outer 0.2 inches of surface area. Because the amount of CO_2 reabsorbed is thought to be minimal, it was not estimated.

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 4-5. Based on the uncertainties associated with total U.S. clinker production, the CO_2 emission factor for clinker production, and the emission factor for additional CO_2 emissions from CKD, 2014 CO_2 emissions from cement production were estimated to be between 36.5 and 41.1 MMT CO_2 Eq. at the 95 percent confidence level. This confidence level indicates a range of approximately 6 percent below and 6 percent above the emission estimate of 38.8 MMT CO_2 Eq.

Table 4-5: Approach 2 Quantitative Uncertainty Estimates for CO_2 Emissions from Cement Production (MMT CO_2 Eq. and Percent)

Source	Gas	2014 Emission Estimate (MMT CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (MMT CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Cement Production	CO_2	38.8	36.5	41.1	-6%	+6%

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

Planned Improvements

Future improvements involve continuing to evaluate and analyze data reported under EPA's GHGRP that would be useful to improve the emission estimates for the Cement Production source category. Particular attention will be made to ensure time series consistency of the emissions estimates presented in future Inventory reports, consistent with IPCC and UNFCCC guidelines. This is required as facility-level reporting data from EPA's GHGRP, with the program's initial requirements for reporting of emissions in calendar year 2010, are not available for all inventory years (i.e., 1990 through 2009) as required for this Inventory. In implementing improvements and integration of data from EPA's GHGRP, the latest guidance from the IPCC on the use of facility-level data in national inventories will be relied upon.[4]

4.2 Lime Production (IPCC Source Category 2A2)

Lime is an important manufactured product with many industrial, chemical, and environmental applications. Lime production involves three main processes: stone preparation, calcination, and hydration. Carbon dioxide is generated during the calcination stage, when limestone—mostly calcium carbonate ($CaCO_3$)—is roasted at high temperatures in a kiln to produce CaO and CO_2. The CO_2 is given off as a gas and is normally emitted to the atmosphere.

$$CaCO_3 \rightarrow CaO + CO_2$$

Some of the CO_2 generated during the production process, however, is recovered at some facilities for use in sugar refining and precipitated calcium carbonate (PCC) production.[5] Emissions from fuels consumed for energy purposes during the production of lime are accounted for in the Energy chapter.

For U.S. operations, the term "lime" actually refers to a variety of chemical compounds. These include calcium oxide (CaO), or high-calcium quicklime; calcium hydroxide ($Ca(OH)_2$), or hydrated lime; dolomitic quicklime ([CaO•MgO]); and dolomitic hydrate ([$Ca(OH)_2$•MgO] or [$Ca(OH)_2$•$Mg(OH)_2$]).

The current lime market is approximately distributed across five end-use categories as follows: metallurgical uses, 38 percent; environmental uses, 31 percent; chemical and industrial uses, 22 percent; construction uses, 8 percent;

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

[5] PCC is obtained from the reaction of CO_2 with calcium hydroxide. It is used as a filler and/or coating in the paper, food, and plastic industries.

and refractory dolomite, 1 percent. The major uses are in steel making, flue gas desulfurization systems at coal-fired electric power plants, construction, and water purification. Lime is also used as a CO_2 scrubber, and there has been experimentation on the use of lime to capture CO_2 from electric power plants.

Lime production in the United States—including Puerto Rico— was reported to be 19,399 kilotons in 2014 (Corathers 2015). Principal lime producing states are Missouri, Alabama, Kentucky, Ohio, Texas (USGS 2014), Nevada, and Pennsylvania.

U.S. lime production resulted in estimated net CO_2 emissions of 14.1 MMT CO_2 Eq. (14,125 kt) (see Table 4-6 and Table 4-7). The trends in CO_2 emissions from lime production are directly proportional to trends in production, which are described below.

Table 4-6: CO_2 Emissions from Lime Production (MMT CO_2 Eq. and kt)

Year	MMT CO_2 Eq.	kt
1990	11.7	11,700
2005	14.6	14,552
2010	13.4	13,381
2011	14.0	13,981
2012	13.7	13,715
2013	14.0	14,045
2014	14.1	14,125

Table 4-7: Potential, Recovered, and Net CO_2 Emissions from Lime Production (kt)

Year	Potential	Recovered[a]	Net Emissions
1990	11,959	259	11,700
2005	15,074	522	14,552
2010	13,776	395	13,381
2011	14,389	407	13,981
2012	14,188	473	13,715
2013	14,513	467	14,045
2014	14,630	505	14,125

[a] For sugar refining and PCC production.

Note: Totals may not sum due to independent rounding.

In 2014, lime production was nearly the same as 2013 levels (increase of 1 percent) at 19,399 kilotons.

Methodology

To calculate emissions, the amounts of high-calcium and dolomitic lime produced were multiplied by their respective emission factors using the Tier 2 approach from the *2006 IPCC Guidelines* (IPCC 2006). The emission factor is the product of the stoichiometric ratio between CO_2 and CaO, and the average CaO and MgO content for lime. The CaO and MgO content for lime is assumed to be 95 percent for both high-calcium and dolomitic lime (IPCC 2006). The emission factors were calculated as follows:

For high-calcium lime:

$$[(44.01\ \text{g/mole}\ CO_2) \div (56.08\ \text{g/mole CaO})] \times (0.9500\ \text{CaO/lime}) = 0.7455\ \text{g}\ CO_2\text{/g lime}$$

For dolomitic lime:

$$[(88.02\ \mathrm{g/mole\ CO_2}) \div (96.39\ \mathrm{g/mole\ CaO})] \times (0.9500\ \mathrm{CaO/lime}) = 0.8675\ \mathrm{g\ CO_2/g\ lime}$$

Production was adjusted to remove the mass of chemically combined water found in hydrated lime, determined according to the molecular weight ratios of H_2O to ($Ca(OH)_2$ and [$Ca(OH)_2$•$Mg(OH)_2$]) (IPCC 2006). These factors set the chemically combined water content to 24.3 percent for high-calcium hydrated lime, and 27.2 percent for dolomitic hydrated lime.

The *2006 IPCC Guidelines* (Tier 2 method) also recommends accounting for emissions from lime kiln dust (LKD) through application of a correction factor. LKD is a byproduct of the lime manufacturing process. LKD is a very fine-grained material and is especially useful for applications requiring very small particle size. Most common LKD applications include soil reclamation and agriculture. Currently, data on annual LKD production is not readily available to develop a country specific correction factor. Lime emission estimates were multiplied by a factor of 1.02 to account for emissions from LKD (IPCC 2006).

Lime emission estimates were further adjusted to account for the amount of CO_2 captured for use in on-site processes. All the domestic lime facilities are required to report these data to EPA under its GHGRP. The total national-level annual amount of CO_2 captured for on-site process use was obtained from EPA's GHGRP (EPA 2015) based on reported facility level data for years 2010 through 2014. The amount of CO_2 captured/recovered for on-site process use is deducted from the total potential emissions (i.e., from lime production and LKD). The net lime emissions are presented in Table 4-6 and Table 4-7. GHGRP data on CO_2 removals (i.e., CO_2 captured/recovered) was available only for 2010 through 2014. Since GHGRP data are not available for 1990 through 2009, IPCC "splicing" techniques were used as per the *2006 IPCC Guidelines* on time series consistency (*2006 IPCC Guidelines*, Volume 1, Chapter 5). The prior estimates for CO_2 removal for 1990 through 2009 were adjusted based on the "overlap" technique recommended by IPCC. Refer to the Recalculations Discussion section, below, for more details.

Lime production data (by type, high-calcium- and dolomitic-quicklime, high-calcium- and dolomitic-hydrated, and dead-burned dolomite) for 1990 through 2014 (see Table 4-8) were obtained from USGS (1992 through 2014, Corathers 2015) and are compiled by USGS to the nearest ton. Natural hydraulic lime, which is produced from CaO and hydraulic calcium silicates, is not manufactured in the United States (USGS 2011). Total lime production was adjusted to account for the water content of hydrated lime by converting hydrate to oxide equivalent based on recommendations from the IPCC, and is presented in Table 4-9 (IPCC 2006). The CaO and CaO•MgO contents of lime were obtained from the IPCC (IPCC 2006). Since data for the individual lime types (high calcium and dolomitic) were not provided prior to 1997, total lime production for 1990 through 1996 was calculated according to the three year distribution from 1997 to 1999.

Table 4-8: High-Calcium- and Dolomitic-Quicklime, High-Calcium- and Dolomitic-Hydrated, and Dead-Burned-Dolomite Lime Production (kt)

Year	High-Calcium Quicklime	Dolomitic Quicklime	High-Calcium Hydrated	Dolomitic Hydrated	Dead-Burned Dolomite
1990	11,166	2,234	1,781	319	342
2005	14,100	2,990	2,220	474	200
2010	13,300	2,570	1,910	239	200
2011	13,900	2,690	2,010	230	200
2012	13,600	2,710	2,020	237	200
2013	13,800	2,870	2,050	260	200
2014	14,000	2,730	2,190	279	200

Table 4-9: Adjusted Lime Production (kt)

Year	High-Calcium	Dolomitic
1990	12,466	2,800
2005	15,721	3,522

2010	14,694	2,937
2011	15,367	3,051
2012	15,075	3,076
2013	15,297	3,252
2014	15,599	3,125

Note: Minus water content of hydrated lime

Uncertainty and Time Series Consistency

The uncertainties contained in these estimates can be attributed to slight differences in the chemical composition of lime products and CO_2 recovery rates for on-site process use over the time series. Although the methodology accounts for various formulations of lime, it does not account for the trace impurities found in lime, such as iron oxide, alumina, and silica. Due to differences in the limestone used as a raw material, a rigid specification of lime material is impossible. As a result, few plants produce lime with exactly the same properties.

In addition, a portion of the CO_2 emitted during lime production will actually be reabsorbed when the lime is consumed, especially at captive lime production facilities. As noted above, lime has many different chemical, industrial, environmental, and construction applications. In many processes, CO_2 reacts with the lime to create calcium carbonate (e.g., water softening). Carbon dioxide reabsorption rates vary, however, depending on the application. For example, 100 percent of the lime used to produce precipitated calcium carbonate reacts with CO_2; whereas most of the lime used in steel making reacts with impurities such as silica, sulfur, and aluminum compounds. Quantifying the amount of CO_2 that is reabsorbed would require a detailed accounting of lime use in the United States and additional information about the associated processes where both the lime and byproduct CO_2 are "reused" are required to quantify the amount of CO_2 that is reabsorbed. Research conducted thus far has not yielded the necessary information to quantify CO_2 reabsorption rates.[6] However, some additional information on the amount of CO_2 consumed on site at lime facilities has been obtained from EPA's GHGRP.

In some cases, lime is generated from calcium carbonate byproducts at pulp mills and water treatment plants.[7] The lime generated by these processes is included in the USGS data for commercial lime consumption. In the pulping industry, mostly using the Kraft (sulfate) pulping process, lime is consumed in order to causticize a process liquor (green liquor) composed of sodium carbonate and sodium sulfide. The green liquor results from the dilution of the smelt created by combustion of the black liquor where biogenic C is present from the wood. Kraft mills recover the calcium carbonate "mud" after the causticizing operation and calcine it back into lime—thereby generating CO_2—for reuse in the pulping process. Although this re-generation of lime could be considered a lime manufacturing process, the CO_2 emitted during this process is mostly biogenic in origin, and therefore is not included in the industrial processes totals (Miner and Upton 2002). In accordance with IPCC methodological guidelines, any such emissions are calculated by accounting for net carbon (C) fluxes from changes in biogenic C reservoirs in wooded or crop lands (see the Land Use, Land-Use Change, and Forestry chapter).

In the case of water treatment plants, lime is used in the softening process. Some large water treatment plants may recover their waste calcium carbonate and calcine it into quicklime for reuse in the softening process. Further research is necessary to determine the degree to which lime recycling is practiced by water treatment plants in the United States.

Another uncertainty is the assumption that calcination emissions for LKD are around 2 percent. The National Lime Association (NLA) has commented that the estimates of emissions from LKD in the United States could be closer to

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[6] Representatives of the National Lime Association estimate that CO_2 reabsorption that occurs from the use of lime may offset as much as a quarter of the CO_2 emissions from calcination (Males 2003).

[7] Some carbide producers may also regenerate lime from their calcium hydroxide byproducts, which does not result in emissions of CO_2. In making calcium carbide, quicklime is mixed with coke and heated in electric furnaces. The regeneration of lime in this process is done using a waste calcium hydroxide (hydrated lime) [$CaC_2 + 2H_2O \rightarrow C_2H_2 + Ca(OH)_2$], not calcium carbonate [$CaCO_3$]. Thus, the calcium hydroxide is heated in the kiln to simply expel the water [$Ca(OH)_2$ + heat $\rightarrow CaO + H_2O$] and no CO_2 is released.

6 percent. They also note that additional emissions (approximately 2 percent) may also be generated through production of other byproducts/wastes (off-spec lime that is not recycled, scrubber sludge) at lime plants (Seeger 2013). There is limited data publicly available on LKD generation rates and also quantities, types of other byproducts/wastes produced at lime facilities. Further research and data is needed to improve understanding of additional calcination emissions to consider revising the current assumptions that are based on IPCC guidelines. In preparing estimates for the current inventory, EPA initiated a dialogue with NLA to discuss data needs to generate a country specific LKD factor and is reviewing the information provided by NLA.

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 4-10. Lime CO_2 emissions for 2014 were estimated to be between 13.8 and 14.5 MMT CO_2 Eq. at the 95 percent confidence level. This confidence level indicates a range of approximately 3 percent below and 3 percent above the emission estimate of 14.1 MMT CO_2 Eq.

Table 4-10: Approach 2 Quantitative Uncertainty Estimates for CO_2 Emissions from Lime Production (MMT CO_2 Eq. and Percent)

Source	Gas	2014 Emission Estimate (MMT CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (MMT CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Lime Production	CO_2	14.1	13.8	14.5	-3%	+3%

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

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

Recalculations Discussion

Dead-burned dolomite production data for 2013 were updated relative to the previous Inventory based on the more recent *Minerals Yearbook: Lime 2013 [Advanced Release]* (USGS 2014). This caused a slight decrease in 2013 emissions, by approximately 0.2 percent.

Planned Improvements

Future improvements involve evaluating recently obtained data to improve current assumptions associated with emissions from production of LKD and other byproducts/wastes as discussed in the Uncertainty and Time Series Consistency section per comments from the NLA. In response to comments, EPA met with NLA on April 7, 2015 to outline specific information required to apply IPCC methods to develop a country-specific correction factor to more accurately estimate emissions from production of LKD. In response to this technical meeting, at the writing of this report, NLA has compiled and shared historical emissions information reported by member facilities on an annual basis under voluntary reporting initiatives over 2002 through 2011 associated with generation of total calcined byproducts and LKD (LKD reporting only differentiated starting in 2010). This emissions information was reported on a voluntary basis consistent with NLA's facility-level reporting protocol also recently provided. Pending resources and data availability, historical CO_2 recovery rates at U.S. facilities producing lime will be investigated to further evaluate results from use of overlap method to improve time series consistency.

4.3 Glass Production (IPCC Source Category 2A3)

Glass production is an energy and raw-material intensive process that results in the generation of CO_2 from both the energy consumed in making glass and the glass process itself. Emissions from fuels consumed for energy purposes during the production of glass are accounted for in the Energy sector.

Glass production employs a variety of raw materials in a glass-batch. These include formers, fluxes, stabilizers, and sometimes colorants. The major raw materials (i.e., fluxes and stabilizers) which emit process-related CO_2 emissions during the glass melting process are limestone, dolomite, and soda ash. The main former in all types of glass is silica (SiO_2). Other major formers in glass include feldspar and boric acid (i.e., borax). Fluxes are added to lower the temperature at which the batch melts. Most commonly used flux materials are soda ash (sodium carbonate, Na_2CO_3) and potash (potassium carbonate, K_2O). Stabilizers are used to make glass more chemically stable and to keep the finished glass from dissolving and/or falling apart. Commonly used stabilizing agents in glass production are limestone ($CaCO_3$), dolomite ($CaCO_3MgCO_3$), alumina (Al_2O_3), magnesia (MgO), barium carbonate ($BaCO_3$), strontium carbonate ($SrCO_3$), lithium carbonate (Li_2CO_3), and zirconia (ZrO_2) (OIT 2002). Glass makers also use a certain amount of recycled scrap glass (cullet), which comes from in-house return of glassware broken in the process or other glass spillage or retention such as recycling or cullet broker services.

The raw materials (primarily limestone, dolomite and soda ash) release CO_2 emissions in a complex high-temperature chemical reaction during the glass melting process. This process is not directly comparable to the calcination process used in lime manufacturing, cement manufacturing, and process uses of carbonates (i.e., limestone/dolomite use), but has the same net effect in terms of CO_2 emissions (IPCC 2006). The U.S. glass industry can be divided into four main categories: containers, flat (window) glass, fiber glass, and specialty glass. The majority of commercial glass produced is container and flat glass (EPA 2009). The United States is one of the major global exporters of glass. Domestically, demand comes mainly from the construction, auto, bottling, and container industries. There are over 1,500 companies that manufacture glass in the United States, with the largest being Corning, Guardian Industries, Owens-Illinois, and PPG Industries.[8]

In 2014, 775 kilotons of limestone and 2,410 kilotons of soda ash were consumed for glass production (USGS 2015a, Willett 2015). Dolomite consumption data for glass manufacturing was reported to be zero for 2014. Use of limestone and soda ash in glass production resulted in aggregate CO_2 emissions of 1.3 MMT CO_2 Eq. (1,341 kt) (see Table 4-11). Overall, emissions have decreased 13 percent from 1990 through 2014.

Emissions from glass production have remained relatively constant over the time series with some fluctuations since 1990. In general, these fluctuations were related to the behavior of the export market and the U.S. economy. Specifically, the extended downturn in residential and commercial construction and automotive industries between 2008 and 2010 resulted in reduced consumption of glass products, causing a drop in global demand for limestone/dolomite and soda ash, and a corresponding decrease in emissions. Furthermore, the glass container sector is one of the leading soda ash consuming sectors in the United States. Some commercial food and beverage package manufacturers are shifting from glass containers towards lighter and more cost effective polyethylene terephthalate (PET) based containers, putting downward pressure on domestic consumption of soda ash (USGS 1995 through 2014).

Table 4-11: CO_2 Emissions from Glass Production (MMT CO_2 Eq. and kt)

Year	MMT CO_2 Eq.	kt
1990	1.5	1,535
2005	1.9	1,928

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[8] Excerpt from Glass & Glass Product Manufacturing Industry Profile, First Research. Available online at <http://www.firstresearch.com/Industry-Research/Glass-and-Glass-Product-Manufacturing.html>.

2010	1.5	1,481
2011	1.3	1,299
2012	1.2	1,248
2013	1.3	1,317
2014	1.3	1,341

Methodology

Carbon dioxide emissions were calculated based on the *2006 IPCC Guidelines* Tier 3 method by multiplying the quantity of input carbonates (limestone, dolomite, and soda ash) by the carbonate-based emission factor (in metric tons CO_2/metric ton carbonate): limestone, 0.43971; dolomite, 0.47732; and soda ash, 0.41492.

Consumption data for 1990 through 2014 of limestone, dolomite, and soda ash used for glass manufacturing were obtained from the USGS *Minerals Yearbook: Crushed Stone Annual Report* (1995 through 2015b), 2014 preliminary data from the USGS Crushed Stone Commodity Expert (Willett 2015), the *USGS Minerals Yearbook: Soda Ash Annual Report* (1995 through 2014), USGS Mineral Industry Surveys for Soda Ash in January 2015 (USGS 2015a) and the U.S. Bureau of Mines (1991 and 1993a), which are reported to the nearest ton. During 1990 and 1992, the USGS did not conduct a detailed survey of limestone and dolomite consumption by end-use. Consumption for 1990 was estimated by applying the 1991 percentages of total limestone and dolomite use constituted by the individual limestone and dolomite uses to 1990 total use. Similarly, the 1992 consumption figures were approximated by applying an average of the 1991 and 1993 percentages of total limestone and dolomite use constituted by the individual limestone and dolomite uses to the 1992 total.

Additionally, each year the USGS withholds data on certain limestone and dolomite end-uses due to confidentiality agreements regarding company proprietary data. For the purposes of this analysis, emissive end-uses that contained withheld data were estimated using one of the following techniques: (1) the value for all the withheld data points for limestone or dolomite use was distributed evenly to all withheld end-uses; or (2) the average percent of total limestone or dolomite for the withheld end-use in the preceding and succeeding years.

There is a large quantity of limestone and dolomite reported to the USGS under the categories “unspecified–reported” and “unspecified–estimated.” A portion of this consumption is believed to be limestone or dolomite used for glass manufacturing. The quantities listed under the “unspecified” categories were, therefore, allocated to glass manufacturing according to the percent limestone or dolomite consumption for glass manufacturing end use for that year.[9]

Based on the 2014 reported data, the estimated distribution of soda ash consumption for glass production compared to total domestic soda ash consumption is 48 percent (USGS 2015a).

Table 4-12: Limestone, Dolomite, and Soda Ash Consumption Used in Glass Production (kt)

Activity	**1990**	**2005**	**2010**	**2011**	**2012**	**2013**	**2014**
Limestone	430	920	999	614	555	693	775
Dolomite	59	541	0	0	0	0	0
Soda Ash	3,177	3,050	2,510	2,480	2,420	2,440	2,410
Total	**3,666**	**4,511**	**3,509**	**3,094**	**2,975**	**3,133**	**3,185**

Uncertainty and Time-Series Consistency

The uncertainty levels presented in this section arise in part due to variations in the chemical composition of limestone used in glass production. In addition to calcium carbonate, limestone may contain smaller amounts of magnesia, silica, and sulfur, among other minerals (potassium carbonate, strontium carbonate and barium carbonate, and dead burned dolomite). Similarly, the quality of the limestone (and mix of carbonates) used for glass manufacturing will depend on the type of glass being manufactured.

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[9] This approach was recommended by USGS.

The estimates below also account for uncertainty associated with activity data. Large fluctuations in reported consumption exist, reflecting year-to-year changes in the number of survey responders. The uncertainty resulting from a shifting survey population is exacerbated by the gaps in the time series of reports. The accuracy of distribution by end use is also uncertain because this value is reported by the manufacturer of the input carbonates (limestone, dolomite & soda ash) and not the end user. For 2014, there has been no reported consumption of dolomite for glass manufacturing. This data has been reported to USGS by dolomite manufacturers and not end-users (i.e., glass manufacturers). There is a high uncertainty associated with this estimate, as dolomite is a major raw material consumed in glass production. Additionally, there is significant inherent uncertainty associated with estimating withheld data points for specific end uses of limestone and dolomite. The uncertainty of the estimates for limestone and dolomite used in glass making is especially high; however, since glass making accounts for a small percent of consumption, its contribution to the overall emissions estimate is low. Lastly, much of the limestone consumed in the United States is reported as “other unspecified uses;” therefore, it is difficult to accurately allocate this unspecified quantity to the correct end-uses. Further research is needed into alternate and more complete sources of data on carbonate-based raw material consumption by the glass industry.

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 4-13. In 2014, glass production CO_2 emissions were estimated to be between 1.3 and 1.4 MMT CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 4 percent below and 5 percent above the emission estimate of 1.3 MMT CO_2 Eq.

Table 4-13: Approach 2 Quantitative Uncertainty Estimates for CO_2 Emissions from Glass Production (MMT CO_2 Eq. and Percent)

Source	Gas	2014 Emission Estimate (MMT CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (MMT CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Glass Production	CO_2	1.3	1.3	1.4	-4%	+5%

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

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

Recalculations Discussion

Limestone and dolomite consumption data for 2013 were revised to reflect updated USGS data (USGS 2015b). This change resulted in an increase of CO_2 emissions by approximately 14 percent. The preliminary data for 2013 was obtained directly from the USGS Crushed Stone Commodity Expert (Willett 2014). In April 2015, USGS published the *2013 Minerals Yearbook* for Crushed Stone and the preliminary data were revised to reflect the latest USGS published data. The published time series was reviewed to ensure time series consistency. Details on the emission trends through time are described in more detail in the Methodology section, above.

Planned Improvements

Currently, only limestone and soda ash consumption data for glass manufacturing is publicly available. While limestone and soda ash are the predominant carbonates used in glass manufacturing, there are other carbonates that are also consumed for glass manufacturing, although in smaller quantities. Pending resources, future improvements will include research into other sources of data for carbonate consumption by the glass industry.

Additionally, future improvements will also continuing to evaluate and analyze data reported under EPA’s GHGRP that would be useful to improve the emission estimates for the Glass Production source category. Particular attention will be made to ensure time series consistency of the emissions estimates presented in future Inventory reports, consistent with IPCC and UNFCCC guidelines. This is required as the facility-level reporting data from EPA’s GHGRP, with the program's initial requirements for reporting of emissions in calendar year 2010, are not available for all inventory years (i.e., 1990 through 2009) as required for this Inventory. In addition, EPA’s GHGRP has an emission threshold for reporting, so the data do not account for all glass production in the United States. 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.[10]

4.4 Other Process Uses of Carbonates (IPCC Source Category 2A4)

Limestone ($CaCO_3$), dolomite ($CaCO_3MgCO_3$)[11], and other carbonates such as soda ash, magnesite, and siderite are basic materials used by a wide variety of industries, including construction, agriculture, chemical, metallurgy, glass production, and environmental pollution control. This section addresses only limestone and dolomite use. For industrial applications, carbonates such as limestone and dolomite are heated sufficiently enough to calcine the material and generate CO_2 as a byproduct.

$$CaCO_3 \rightarrow CaO + CO_2$$

$$MgCO_3 \rightarrow MgO + CO_2$$

Examples of such applications include limestone used as a flux or purifier in metallurgical furnaces, as a sorbent in flue gas desulfurization (FGD) systems for utility and industrial plants, and as a raw material for the production of glass, lime, and cement. Emissions from limestone and dolomite used in other process sectors such as cement, lime, glass production, and iron and steel, are excluded from this section and reported under their respective source categories (e.g., glass manufacturing IPCC Source Category 2A3.) Emission from soda ash consumption is reported under respective categories (e.g., glass manufacturing IPCC Source Category 2A3 and soda ash production and consumption IPCC Source Category 2B7). Emissions from fuels consumed for energy purposes during these processes are accounted for in the Energy chapter.

Limestone is widely distributed throughout the world in deposits of varying sizes and degrees of purity. Large deposits of limestone occur in nearly every state in the United States, and significant quantities are extracted for industrial applications. The leading limestone producing States are Texas, Missouri, Florida, Ohio, and Pennsylvania, which contribute 43 percent of the total U.S. output (USGS 2015). Similarly, dolomite deposits are also widespread throughout the world. Dolomite deposits are found in the United States, Canada, Mexico, Europe, Africa, and Brazil. In the United States, the leading dolomite producing states are Illinois, Pennsylvania, and New York, which contribute 55 percent of the total U.S. output (USGS 2015).

In 2014, 25,085 kt of limestone and 3,359 kt of dolomite were consumed for these emissive applications, excluding glass manufacturing (Willett 2015). Usage of limestone and dolomite resulted in aggregate CO_2 emissions of 12.1 MMT CO_2 Eq. (12,077 kt) (see Table 4-14 and Table 4-15). Overall, emissions have increased 146 percent from 1990 through 2014.

Table 4-14: CO_2 Emissions from Other Process Uses of Carbonates (MMT CO_2 Eq.)

Year	Flux Stone	FGD	Magnesium Production	Other Miscellaneous Uses	Total
1990	2.6	1.4	0.1	0.8	4.9
2005	2.6	3.0	0.0	0.7	6.3
2010	1.6	7.1	0.0	0.9	9.6
2011	1.5	5.4	0.0	2.4	9.3
2012	1.1	5.8	0.0	1.1	8.0

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

[11] Limestone and dolomite are collectively referred to as limestone by the industry, and intermediate varieties are seldom distinguished.

2013	2.3	6.3	0.0	1.8	10.4
2014	2.9	7.2	0.0	1.9	12.1

Notes: Totals may not sum due to independent rounding. “Other miscellaneous uses” include chemical stone, mine dusting or acid water treatment, acid neutralization, and sugar refining.

Table 4-15: CO_2 Emissions from Other Process Uses of Carbonates (kt)

Year	Flux Stone	FGD	Magnesium Production	Other Miscellaneous Uses	Total
1990	2,592	1,432	64	819	4,907
2005	2,649	2,973	0	718	6,339
2010	1,560	7,064	0	937	9,560
2011	1,467	5,420	0	2,449	9,335
2012	1,077	5,797	0	1,148	8,022
2013	2,307	6,309	0	1,798	10,414
2014	2,932	7,212	0	1,933	12,077

Methodology

Carbon dioxide emissions were calculated based on the *2006 IPCC Guidelines* Tier 2 method by multiplying the quantity of limestone or dolomite consumed by the emission factor for limestone or dolomite calcination, respectively, Table 2.1–limestone: 0.43971 metric ton CO_2/metric ton carbonate, and dolomite: 0.47732 metric ton CO_2/metric ton carbonate.[12] This methodology was used for flux stone, flue gas desulfurization systems, chemical stone, mine dusting or acid water treatment, acid neutralization, and sugar refining. Flux stone used during the production of iron and steel was deducted from the Other Process Uses of Carbonates estimate and attributed to the Iron and Steel Production estimate. Similarly limestone and dolomite consumption for glass manufacturing, cement, and lime manufacturing are excluded from this category and attributed to their respective categories.

Historically, the production of magnesium metal was the only other significant use of limestone and dolomite that produced CO_2 emissions. At the end of 2001, the sole magnesium production plant operating in the United States that produced magnesium metal using a dolomitic process that resulted in the release of CO_2 emissions ceased its operations (USGS 1995b through 2012; USGS 2013a).

Consumption data for 1990 through 2014 of limestone and dolomite used for flux stone, flue gas desulfurization systems, chemical stone, mine dusting or acid water treatment, acid neutralization, and sugar refining (see Table 4-16) were obtained from the USGS *Minerals Yearbook: Crushed Stone Annual Report* (1995a through 2015), preliminary data for 2014 from USGS Crushed Stone Commodity Expert (Willett 2015), and the U.S. Bureau of Mines (1991 and 1993a), which are reported to the nearest ton. The production capacity data for 1990 through 2014 of dolomitic magnesium metal also came from the USGS (1995b through 2012, USGS 2013a) and the U.S. Bureau of Mines (1990 through 1993b). During 1990 and 1992, the USGS did not conduct a detailed survey of limestone and dolomite consumption by end-use. Consumption for 1990 was estimated by applying the 1991 percentages of total limestone and dolomite use constituted by the individual limestone and dolomite uses to 1990 total use. Similarly, the 1992 consumption figures were approximated by applying an average of the 1991 and 1993 percentages of total limestone and dolomite use constituted by the individual limestone and dolomite uses to the 1992 total.

Additionally, each year the USGS withholds data on certain limestone and dolomite end-uses due to confidentiality agreements regarding company proprietary data. For the purposes of this analysis, emissive end-uses that contained withheld data were estimated using one of the following techniques: (1) the value for all the withheld data points for limestone or dolomite use was distributed evenly to all withheld end-uses; (2) the average percent of total limestone

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[12] *IPCC 2006 Guidelines*, Volume 3: Chapter 2

or dolomite for the withheld end-use in the preceding and succeeding years; or (3) the average fraction of total limestone or dolomite for the end-use over the entire time period.

There is a large quantity of crushed stone reported to the USGS under the category “unspecified uses.” A portion of this consumption is believed to be limestone or dolomite used for emissive end uses. The quantity listed for “unspecified uses” was, therefore, allocated to each reported end-use according to each end-use’s fraction of total consumption in that year.[13]

Table 4-16: Limestone and Dolomite Consumption (kt)

Activity	1990	2005	2010	2011	2012	2013	2014
Flux Stone	6,737	7,022	4,440	4,396	3,666	6,345	7,648
Limestone	5,804	3,165	1,921	2,531	3,108	4,380	4,304
Dolomite	933	3,857	2,520	1,865	559	1,965	3,344
FGD	3,258	6,761	16,064	12,326	13,185	14,347	16,402
Other Miscellaneous Uses	1,835	1,632	2,121	5,548	2,610	3,973	4,395
Total	**11,830**	**15,415**	**22,626**	**22,270**	**19,461**	**24,665**	**28,444**

Uncertainty and Time-Series Consistency

The uncertainty levels presented in this section account for uncertainty associated with activity data. Data on limestone and dolomite consumption are collected by USGS through voluntary national surveys. USGS contacts the mines (i.e., producers of various types of crushed stone) for annual sales data. Data on other carbonate consumption are not readily available. The producers report the annual quantity sold to various end-users/industry types. USGS estimates the historical response rate for the crushed stone survey to be approximately 70 percent, the rest is estimated by USGS. Large fluctuations in reported consumption exist, reflecting year-to-year changes in the number of survey responders. The uncertainty resulting from a shifting survey population is exacerbated by the gaps in the time series of reports. The accuracy of distribution by end use is also uncertain because this value is reported by the producer/mines and not the end user. Additionally, there is significant inherent uncertainty associated with estimating withheld data points for specific end uses of limestone and dolomite. Lastly, much of the limestone consumed in the United States is reported as “other unspecified uses;” therefore, it is difficult to accurately allocate this unspecified quantity to the correct end-uses.

Uncertainty in the estimates also arises in part due to variations in the chemical composition of limestone. In addition to calcium carbonate, limestone may contain smaller amounts of magnesia, silica, and sulfur, among other minerals. The exact specifications for limestone or dolomite used as flux stone vary with the pyrometallurgical process and the kind of ore processed.

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 4-17. Other Process Uses of Carbonates CO_2 emissions in 2014 were estimated to be between 10.7 and 14.0 MMT CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 12 percent below and 15 percent above the emission estimate of 12.1 MMT CO_2 Eq.

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[13] This approach was recommended by USGS, the data collection agency.

Table 4-17: Approach 2 Quantitative Uncertainty Estimates for CO_2 Emissions from Other Process Uses of Carbonates (MMT CO_2 Eq. and Percent)

Source	Gas	2014 Emission Estimate (MMT CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (MMT CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Other Process Uses of Carbonates	CO_2	12.1	10.7	14.0	-12%	+15%

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

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

Recalculations Discussion

Limestone and dolomite consumption data, by end-use, for 2013 were updated relative to the previous Inventory based on the recently published *2013 Minerals Yearbook: Crushed Stone*. In the previous Inventory report (i.e., 1990-2013), preliminary data were used for 2013 and updated for the current Inventory. In April 2015, USGS published the *2013 Minerals Yearbook for Crushed Stone* and the preliminary data were revised to reflect the latest USGS published data. The published time series was reviewed to ensure time series consistency. This update caused an increase in total limestone and dolomite consumption for emissive end uses in 2013 by approximately 120 percent. The revised 2013 emission estimate increased by approximately 135 percent relative to the previous report due to this change.

4.5 Ammonia Production (IPCC Source Category 2B1)

Emissions of CO_2 occur during the production of synthetic ammonia, primarily through the use of natural gas, petroleum coke, or naphtha as a feedstock. The natural gas-, naphtha-, and petroleum coke-based processes produce CO_2 and hydrogen (H_2), the latter of which is used in the production of ammonia. The brine electrolysis process for production of ammonia does not lead to process-based CO_2 emissions. Emissions from fuels consumed for energy purposes during the production of ammonia are accounted for in the Energy chapter.

In the United States, the majority of ammonia is produced using a natural gas feedstock; however one synthetic ammonia production plant located in Kansas is producing ammonia from petroleum coke feedstock. In some U.S. plants, some of the CO_2 produced by the process is captured and used to produce urea rather than being emitted to the atmosphere. There are approximately 13 companies operating 26 ammonia producing facilities in 17 states. More than 56 percent of domestic ammonia production capacity is concentrated in the States of Louisiana (29 percent), Oklahoma (21 percent), and Texas (6 percent) (USGS 2015).

There are five principal process steps in synthetic ammonia production from natural gas feedstock. The primary reforming step converts CH_4 to CO_2, carbon monoxide (CO), and H_2 in the presence of a catalyst. Only 30 to 40 percent of the CH_4 feedstock to the primary reformer is converted to CO and CO_2 in this step of the process. The secondary reforming step converts the remaining CH_4 feedstock to CO and CO_2. The CO in the process gas from the secondary reforming step (representing approximately 15 percent of the process gas) is converted to CO_2 in the presence of a catalyst, water, and air in the shift conversion step. Carbon dioxide is removed from the process gas by the shift conversion process, and the hydrogen gas is combined with the nitrogen (N_2) gas in the process gas during the ammonia synthesis step to produce ammonia. The CO_2 is included in a waste gas stream with other process impurities and is absorbed by a scrubber solution. In regenerating the scrubber solution, CO_2 is released from the solution.

The conversion process for conventional steam reforming of CH_4, including the primary and secondary reforming and the shift conversion processes, is approximately as follows:

$$0.88CH_4 + 1.26Air + 1.24H_2O \rightarrow 0.88CO_2 + N_2 + 3H_2$$

$$N_2 + 3H_2 \rightarrow 2NH_3$$

To produce synthetic ammonia from petroleum coke, the petroleum coke is gasified and converted to CO_2 and H_2. These gases are separated, and the H_2 is used as a feedstock to the ammonia production process, where it is reacted with N_2 to form ammonia.

Not all of the CO_2 produced during the production of ammonia is emitted directly to the atmosphere. Some of the ammonia and some of the CO_2 produced by the synthetic ammonia process are used as raw materials in the production of urea [$CO(NH_2)_2$], which has a variety of agricultural and industrial applications.

The chemical reaction that produces urea is:

$$2NH_3 + CO_2 \rightarrow NH_2COONH_4 \rightarrow CO(NH_2)_2 + H_2O$$

Only the CO_2 emitted directly to the atmosphere from the synthetic ammonia production process is accounted for in determining emissions from ammonia production. The CO_2 that is captured during the ammonia production process and used to produce urea does not contribute to the CO_2 emission estimates for ammonia production presented in this section. Instead, CO_2 emissions resulting from the consumption of urea are attributed to the urea consumption or urea application source category (under the assumption that the carbon stored in the urea during its manufacture is released into the environment during its consumption or application). Emissions of CO_2 resulting from agricultural applications of urea are accounted for in the *Cropland Remaining Cropland* section of the Land Use, Land-Use Change, and Forestry chapter. Emissions of CO_2 resulting from non-agricultural applications of urea (e.g., use as a feedstock in chemical production processes) are accounted for in the Urea Consumption for Non-Agricultural Purposes section of this chapter.

Total emissions of CO_2 from ammonia production in 2014 were 9.4 MMT CO_2 Eq. (9,436 kt), and are summarized in Table 4-18 and Table 4-19. Ammonia production relies on natural gas as both a feedstock and a fuel, and as such, market fluctuations and volatility in natural gas prices affect the production of ammonia. Since 1990, emissions from ammonia production have decreased by 28 percent. Emissions in 2014 have decreased by approximately 5 percent from the 2013 levels.

Table 4-18: CO_2 Emissions from Ammonia Production (MMT CO_2 Eq.)

Source	1990		2005		2010	2011	2012	2013	2014
Ammonia Production	13.0		9.2		9.2	9.3	9.4	10.0	9.4
Total	**13.0**		**9.2**		**9.2**	**9.3**	**9.4**	**10.0**	**9.4**

Table 4-19: CO_2 Emissions from Ammonia Production (kt)

Source	1990		2005		2010	2011	2012	2013	2014
Ammonia Production	13,047		9,196		9,188	9,292	9,377	9,962	9,436
Total	**13,047**		**9,196**		**9,188**	**9,292**	**9,377**	**9,962**	**9,436**

Methodology

Carbon dioxide emissions from production of synthetic ammonia from natural gas feedstock is based on the *2006 IPCC Guidelines* (IPCC 2006) Tier 1 and 2 method. A country-specific emission factor is developed and applied to national ammonia production to estimate emissions. The method uses a CO_2 emission factor published by the European Fertilizer Manufacturers Association (EFMA) that is based on natural gas-based ammonia production technologies that are similar to those employed in the United States. This CO_2 emission factor of 1.2 metric tons CO_2/metric ton NH_3 (EFMA 2000a) is applied to the percent of total annual domestic ammonia production from natural gas feedstock.

Emissions of CO_2 from ammonia production are then adjusted to account for the use of some of the CO_2 produced from ammonia production as a raw material in the production of urea. The CO_2 emissions reported for ammonia production are reduced by a factor of 0.733 multiplied by total annual domestic urea production. This corresponds to a stoichiometric CO_2/urea factor of 44/60, assuming complete conversion of NH_3 and CO_2 to urea (IPCC 2006, EFMA 2000b).

All synthetic ammonia production and subsequent urea production are assumed to be from the same process—conventional catalytic reforming of natural gas feedstock, with the exception of ammonia production from petroleum coke feedstock at one plant located in Kansas. Annual ammonia and urea production are shown in Table 4-20. The CO_2 emission factor for production of ammonia from petroleum coke is based on plant-specific data, wherein all carbon contained in the petroleum coke feedstock that is not used for urea production is assumed to be emitted to the atmosphere as CO_2 (Bark 2004). Ammonia and urea are assumed to be manufactured in the same manufacturing complex, as both the raw materials needed for urea production are produced by the ammonia production process. The CO_2 emission factor of 3.57 metric tons CO_2/metric ton NH_3 for the petroleum coke feedstock process (Bark 2004) is applied to the percent of total annual domestic ammonia production from petroleum coke feedstock.

The emission factor of 1.2 metric ton CO_2/metric ton NH_3 for production of ammonia from natural gas feedstock was taken from the EFMA Best Available Techniques publication, Production of Ammonia (EFMA 2000a). The EFMA reported an emission factor range of 1.15 to 1.30 metric ton CO_2/metric ton NH_3, with 1.2 metric ton CO_2/metric ton NH_3 as a typical value (EFMA 2000a). Technologies (e.g., catalytic reforming process, etc.) associated with this factor are found to closely resemble those employed in the United States for use of natural gas as a feedstock. The EFMA reference also indicates that more than 99 percent of the CH_4 feedstock to the catalytic reforming process is ultimately converted to CO_2. As noted earlier, emissions from fuels consumed for energy purposes during the production of ammonia are accounted for in the Energy chapter. The total ammonia production data for 2011, 2012, 2013, and 2014 were obtained from American Chemistry Council (2015). For years before 2011, ammonia production data (See Table 4-20) were obtained from Coffeyville Resources (Coffeyville 2005, 2006, 2007a, 2007b, 2009, 2010, 2011, and 2012) and the Census Bureau of the U.S. Department of Commerce (U.S. Census Bureau 1991 through 1994, 1998 through 2010) as reported in Current Industrial Reports Fertilizer Materials and Related Products annual and quarterly reports. Urea-ammonia nitrate production from petroleum coke for years through 2011 was obtained from Coffeyville Resources (Coffeyville 2005, 2006, 2007a, 2007b, 2009, 2010, 2011, and 2012), and from CVR Energy, Inc. Annual Report (CVR 2012 ,2014, and 2015) for 2012, 2013, and 2014. Urea production data for 1990 through 2008 were obtained from the Minerals Yearbook: Nitrogen (USGS 1994 through 2009). Urea production data for 2009 through 2010 were obtained from the U.S. Census Bureau (U.S. Census Bureau 2010 and 2011). The U.S. Census Bureau ceased collection of urea production statistics, and urea production data for 2011, 2012, and 2013 were obtained from the Minerals Yearbook: Nitrogen (USGS 2014, 2015). The urea production data for 2014 are not yet published and so 2013 data were used as proxies for 2014.

Table 4-20: Ammonia Production and Urea Production (kt)

Year	Ammonia Production	Urea Production
1990	15,425	7,450
2005	10,143	5,270
2010	10,084	5,122
2011	10,325	5,430
2012	10,305	5,220
2013	10,930	5,480
2014	10,515	5,480

Uncertainty and Time-Series Consistency

The uncertainties presented in this section are primarily due to how accurately the emission factor used represents an average across all ammonia plants using natural gas feedstock. Uncertainties are also associated with ammonia production estimates and the assumption that all ammonia production and subsequent urea production was from the same process—conventional catalytic reforming of natural gas feedstock, with the exception of one ammonia production plant located in Kansas that is manufacturing ammonia from petroleum coke feedstock. Uncertainty is also associated with the representativeness of the emission factor used for the petroleum coke-based ammonia process. It is also assumed that ammonia and urea are produced at collocated plants from the same natural gas raw material.

Recovery of CO_2 from ammonia production plants for purposes other than urea production (e.g., commercial sale, etc.) has not been considered in estimating the CO_2 emissions from ammonia production, as data concerning the disposition of recovered CO_2 are not available. Such recovery may or may not affect the overall estimate of CO_2 emissions depending upon the end use to which the recovered CO_2 is applied. Further research is required to determine whether byproduct CO_2 is being recovered from other ammonia production plants for application to end uses that are not accounted for elsewhere.

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 4-21. Ammonia Production CO_2 emissions were estimated to be between 8.7 and 10.2 MMT CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 8 percent below and 8 percent above the emission estimate of 9.4 MMT CO_2 Eq.

Table 4-21: Approach 2 Quantitative Uncertainty Estimates for CO_2 Emissions from Ammonia Production (MMT CO_2 Eq. and Percent)

Source	Gas	2014 Emission Estimate (MMT CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (MMT CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Ammonia Production	CO_2	9.4	8.7	10.2	-8%	+8%

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

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

Recalculations Discussion

Production estimates for urea production for 2013 were updated relative to the previous Inventory using information obtained from the recent *2013 Minerals Yearbook: Nitrogen* (USGS 2015). For the previous version of the Inventory (i.e., 1990-2013), 2012 data was used as a proxy for 2013 as the 2013 data were not published prior to the previous Inventory report. This update resulted in a slight decrease of emissions by approximately 2 percent for 2013 relative to the previous report.

Planned Improvements

Future improvements involve continuing to evaluate and analyze data reported under EPA's GHGRP to improve the emission estimates for the Ammonia Production source category. Particular attention will be made to ensure time series consistency of the emissions estimates presented in future Inventory reports, consistent with IPCC and UNFCCC guidelines. This is required as the facility-level reporting data from EPA's GHGRP, with the program's initial requirements for reporting of emissions in calendar year 2010, are not available for all inventory years (i.e., 1990 through 2009) as required for this Inventory. In implementing improvements and integration of data from EPA's GHGRP, the latest guidance from the IPCC on the use of facility-level data in national inventories will be relied upon.[14] Specifically, the planned improvements include assessing data to update the emission factors to include both fuel and feedstock CO_2 emissions and incorporate CO_2 capture and storage. Methodologies will also be updated if additional ammonia production plants are found to use hydrocarbons other than natural gas for ammonia production.

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

4.6 Urea Consumption for Non-Agricultural Purposes

Urea is produced using ammonia and CO_2 as raw materials. All urea produced in the United States is assumed to be produced at ammonia production facilities where both ammonia and CO_2 are generated. There are approximately 20 of these facilities operating in the United States.

The chemical reaction that produces urea is:

$$2NH_3 + CO_2 \rightarrow NH_2COONH_4 \rightarrow CO(NH_2)_2 + H_2O$$

This section accounts for CO_2 emissions associated with urea consumed exclusively for non-agricultural purposes. Carbon dioxide emissions associated with urea consumed for fertilizer are accounted for in the *Cropland Remaining Cropland* section of the Land Use, Land-Use Change, and Forestry chapter.

Urea is used as a nitrogenous fertilizer for agricultural applications and also in a variety of industrial applications. The industrial applications of urea include its use in adhesives, binders, sealants, resins, fillers, analytical reagents, catalysts, intermediates, solvents, dyestuffs, fragrances, deodorizers, flavoring agents, humectants and dehydrating agents, formulation components, monomers, paint and coating additives, photosensitive agents, and surface treatments agents. In addition, urea is used for abating NO_x emissions from coal-fired power plants and diesel transportation motors.

Emissions of CO_2 from urea consumed for non-agricultural purposes in 2014 were estimated to be 4.0 MMT CO_2 Eq. (4,007 kt), and are summarized in Table 4-22 and Table 4-23. 2014 data on urea production data, urea exports and imports are not yet published. 2013 data has been used as proxy for 2014. Net CO_2 emissions from urea consumption for non-agricultural purposes in 2014 have increased by approximately 6 percent from 1990.

Table 4-22: CO_2 Emissions from Urea Consumption for Non-Agricultural Purposes (MMT CO_2 Eq.)

Source	1990		2005		2010	2011	2012	2013	2014
Urea Consumption	3.8		3.7		4.7	4.0	4.4	4.2	4.0
Total	**3.8**		**3.7**		**4.7**	**4.0**	**4.4**	**4.2**	**4.0**

Table 4-23: CO_2 Emissions from Urea Consumption for Non-Agricultural Purposes (kt)

Source	1990		2005		2010	2011	2012	2013	2014
Urea Consumption	3,784		3,653		4,730	4,029	4,449	4,179	4,007
Total	**3,784**		**3,653**		**4,730**	**4,029**	**4,449**	**4,179**	**4,007**

Methodology

Emissions of CO_2 resulting from urea consumption for non-agricultural purposes are estimated by multiplying the amount of urea consumed in the United States for non-agricultural purposes by a factor representing the amount of CO_2 used as a raw material to produce the urea. This method is based on the assumption that all of the carbon in urea is released into the environment as CO_2 during use, and consistent with the *2006 IPCC Guidelines* (IPCC 2006).

The amount of urea consumed for non-agricultural purposes in the United States is estimated by deducting the quantity of urea fertilizer applied to agricultural lands, which is obtained directly from the Land Use, Land-Use Change, and Forestry chapter (see Table 6-25) and is reported in Table 4-24, from the total domestic supply of urea. The domestic supply of urea is estimated based on the amount of urea produced plus the sum of net urea imports and exports. A factor of 0.733 tons of CO_2 per ton of urea consumed is then applied to the resulting supply of urea for non-agricultural purposes to estimate CO_2 emissions from the amount of urea consumed for non-agricultural purposes. The 0.733 tons of CO_2 per ton of urea emission factor is based on the stoichiometry of producing urea from ammonia and CO_2. This corresponds to a stoichiometric CO_2/urea factor of 44/60, assuming complete conversion of NH_3 and CO_2 to urea (IPCC 2006, EFMA 2000).

Urea production data for 1990 through 2008 were obtained from the *Minerals Yearbook: Nitrogen* (USGS 1994 through 2009). Urea production data for 2009 through 2010 were obtained from the U.S. Census Bureau (2011). The U.S. Census Bureau ceased collection of urea production statistics in 2011, therefore, urea production data for 2011, 2012, and 2013 were obtained from the *Minerals Yearbook: Nitrogen* (USGS 2014 through 2015). Urea production data for 2014 are not yet publicly available and so 2013 data have been used as proxy.

Urea import data for 2014 are not yet publicly available and so 2013 data have been used as proxy. Urea import data for 2013 were obtained from the *Minerals Yearbook: Nitrogen* (USGS 2015). Urea import data for 2011 and 2012 were taken from U.S. Fertilizer Import/Exports from USDA Economic Research Service Data Sets (U.S. Department of Agriculture 2012). Urea import data for the previous years were obtained from the U.S. Census Bureau *Current Industrial Reports Fertilizer Materials and Related Products* annual and quarterly reports for 1997 through 2010 (U.S. Census Bureau 1998 through 2011), The Fertilizer Institute (TFI 2002) for 1993 through 1996, and the United States International Trade Commission Interactive Tariff and Trade DataWeb (U.S. ITC 2002) for 1990 through 1992 (see Table 4-24). Urea export data for 2014 are not yet publicly available and so 2013 data have been used as proxy. Urea export data for 2013 were obtained from the *Minerals Yearbook: Nitrogen* (USGS 2015). Urea export data for 1990 through 2012 were taken from U.S. Fertilizer Import/Exports from USDA Economic Research Service Data Sets (U.S. Department of Agriculture 2012).

Table 4-24: Urea Production, Urea Applied as Fertilizer, Urea Imports, and Urea Exports (kt)

Year	Urea Production	Urea Applied as Fertilizer	Urea Imports	Urea Exports
1990	7,450	3,296	1,860	854
2005	5,270	4,779	5,026	536
2010	5,122	5,152	6,631	152
2011	5,430	5,589	5,860	207
2012	5,220	5,762	6,944	336
2013	5,480	5,921	6,470	330
2014	5,480	6,156	6,470	330

Uncertainty and Time-Series Consistency

There is limited publicly-available data on the quantities of urea produced and consumed for non-agricultural purposes. Therefore, the amount of urea used for non-agricultural purposes is estimated based on a balance that relies on estimates of urea production, urea imports, urea exports, and the amount of urea used as fertilizer. The primary uncertainties associated with this source category are associated with the accuracy of these estimates as well as the fact that each estimate is obtained from a different data source. Because urea production estimates are no longer available from the USGS, there is additional uncertainty associated with urea produced beginning in 2011. There is also uncertainty associated with the assumption that all of the carbon in urea is released into the environment as CO_2 during use.

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 4-25. CO_2 emissions associated with urea consumption for non-agricultural purposes were estimated to be between 3.5 and 4.5 MMT CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 12 percent below and 12 percent above the emission estimate of 4.0 MMT CO_2 Eq.

Table 4-25: Approach 2 Quantitative Uncertainty Estimates for CO_2 Emissions from Urea Consumption for Non-Agricultural Purposes (MMT CO_2 Eq. and Percent)

Source	Gas	2014 Emission Estimate	Uncertainty Range Relative to Emission Estimate[a]

		(MMT CO_2 Eq.)	(MMT CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Urea Consumption for Non-Agricultural Purposes	CO_2	4.0	3.5	4.5	-12%	+12%

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

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

Recalculations Discussion

Production estimates for urea production and estimates for urea exports and imports for 2013 were updated using information obtained from the *Minerals Yearbook: Nitrogen* (USGS 2015). Also, the amount of urea consumed for agricultural purposes in the United States for 2013 was revised based on the most recent data obtained from the Land Use, Land-Use Change, and Forestry chapter (see Table 6-25). These updates resulted in a decrease in the emission estimate relative to the previous report of approximately 10 percent in 2013.

4.7 Nitric Acid Production (IPCC Source Category 2B2)

Nitrous oxide (N_2O) is emitted during the production of nitric acid (HNO_3), an inorganic compound used primarily to make synthetic commercial fertilizers. It is also a major component in the production of adipic acid—a feedstock for nylon—and explosives. Virtually all of the nitric acid produced in the United States is manufactured by the high-temperature catalytic oxidation of ammonia (EPA 1998). There are two different nitric acid production methods: weak nitric acid and high-strength nitric acid. The first method utilizes oxidation, condensation, and absorption to produce nitric acid at concentrations between 30 and 70 percent nitric acid. High-strength acid (90 percent or greater nitric acid) can be produced from dehydrating, bleaching, condensing, and absorption of the weak nitric acid. The basic process technology for producing nitric acid has not changed significantly over time. Most U.S. plants were built between 1960 and 2000. As of 2014, there are 34 active weak nitric acid production plants, including one high-strength nitric acid production plant in U.S. (EPA 2010; EPA 2015).

During this reaction, N_2O is formed as a byproduct and is released from reactor vents into the atmosphere. Emissions from fuels consumed for energy purposes during the production of nitric acid are accounted for in the Energy chapter.

Nitric acid is made from the reaction of ammonia (NH_3) with oxygen (O_2) in two stages. The overall reaction is:

$$4NH_3 + 8O_2 \rightarrow 4HNO_3 + 4H_2O$$

Currently, the nitric acid industry controls emissions of NO and NO_2 (i.e., NO_x). As such, the industry in the United States uses a combination of non-selective catalytic reduction (NSCR) and selective catalytic reduction (SCR) technologies. In the process of destroying NO_x, NSCR systems are also very effective at destroying N_2O. However, NSCR units are generally not preferred in modern plants because of high energy costs and associated high gas temperatures. NSCR systems were installed in nitric plants built between 1971 and 1977 with NSCRs installed at approximately one-third of the weak acid production plants. U.S. facilities are using both tertiary (i.e., NSCR) and secondary controls (i.e., alternate catalysts).

N_2O emissions from this source were estimated to be 10.9 MMT CO_2 Eq. (37 kt of N_2O) in 2014 (see Table 4-26). Emissions from nitric acid production have decreased by 10 percent since 1990, with the trend in the time series closely tracking the changes in production. Emissions have decreased by 24 percent since 1997, the highest year of production in the time series.

Table 4-26: N_2O Emissions from Nitric Acid Production (MMT CO_2 Eq. and kt N_2O)

Year	MMT CO_2 Eq.	kt N_2O
1990	12.1	41
2005	11.3	38
2010	11.5	39
2011	10.9	37
2012	10.5	35
2013	10.7	36
2014	10.9	37

Methodology

Emissions of N_2O were calculated using the estimation methods provided by the *2006 IPCC Guidelines* (IPCC 2006) and country specific methods from N_2O EPA's Greenhouse Gas Reporting Program (GHGRP). The *2006 IPCC Guidelines* Tier 2 method was used to estimate emissions from nitric acid production for 1990 through 2009, and a country-specific approach similar to the IPCC Tier 3 method was used to estimate N_2O emissions for 2010 through 2014.

2010 through 2014

Process N_2O emissions and nitric acid production data were obtained directly from EPA's GHGRP for 2010 through 2014 by aggregating reported facility-level data (EPA 2015). In the United States, all nitric acid facilities producing weak nitric acid (30-70 percent in strength) are required to report annual greenhouse gas emissions data to EPA as per the requirements of its GHGRP. As of 2014, there are 34 facilities that report to EPA, including the known single high-strength nitric acid production facility in the United States (EPA 2015). All nitric acid (weak acid) facilities are required to calculate process emissions using a site-specific emission factor developed through annual performance testing under typical operating conditions or by directly measuring N_2O emissions using monitoring equipment. The high-strength nitric acid facility also reports N_2O emissions associated with weak acid production and this may capture all relevant emissions, pending additional further EPA research. More details on the calculation and monitoring methods applicable to Nitric Acid facilities can be found under Subpart V: Nitric Acid Production of the regulation, Part 98.[15]

1990 through 2009

Using the GHGRP data for 2010,[16] country-specific N_2O emission factors were calculated for nitric acid production with abatement and without abatement (i.e., controlled and uncontrolled emission factors). The following 2010 emission factors were derived for production with abatement and without abatement: 3.3 kg N_2O/metric ton HNO_3 produced at plants using abatement technologies (e.g., tertiary systems such as NSCR systems) and 5.98 kg N_2O/metric ton HNO_3 produced at plants not equipped with abatement technology. Country-specific weighted emission factors were derived by weighting these emission factors by percent production with abatement and without abatement over time periods 1990-2008 and 2009. These weighted emission factors were used to estimate N_2O emissions from nitric acid production for years prior to the availability of EPA's GHGRP data (i.e., 1990 through 2008 and 2009). A separate weighted factor is included for 2009 due to data availability for that year. At that time, EPA had initiated compilation of a nitric acid database to improve estimation of emissions from this industry and obtained updated information on application of controls via review of permits and outreach with

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[15] Located at <http://www.ecfr.gov/cgi-bin/text-idx?tpl=/ecfrbrowse/Title40/40cfr98_main_02.tpl>.

[16] National N_2O process emissions, national production, and national share of nitric acid production with abatement and without abatement technology was aggregated from the GHGRP facility-level data for 2010-2014 (i.e., percent production with and without abatement).

facilities and trade associations. The research indicated recent installation of abatement technologies at additional facilities.

Based on the available data, it was assumed that emission factors for 2010 would be more representative of operating conditions in 1990 through 2009 than more recent years. Initial review of historical data indicates that percent production with and without abatement can change over time and also year over year due to changes in application of facility-level abatement technologies, maintenance of abatement technologies, and also due to plant closures and start-ups (EPA 2012, 2013; Desai 2012; CAR 2013). The installation dates of N_2O abatement technologies are not known at most facilities, but it is assumed that facilities reporting abatement technology use have had this technology installed and operational for the duration of the time series considered in this report (especially NSCRs).

The country-specific weighted N_2O emission factors were used in conjunction with annual production to estimate N_2O emissions for 1990 through 2009, using the following equations:

$$E_i = P_i \times EF_{weighted,i}$$

$$EF_{weighted,i} = \left[\left(\%P_{C,i} \times EF_c\right) + \left(\%P_{unc,i} \times EF_{unc}\right)\right]$$

where,

E_i = Annual N_2O Emissions for year i (kg/yr)
P_i = Annual nitric acid production for year i (metric tons HNO_3)
$EF_{weighted,i}$ = Weighted N_2O emission factor for year i (kg N_2O/metric ton HNO_3)
$\%P_{c,i}$ = Percent national production of HNO_3 with N_2O abatement technology (%)
EF_c = N_2O emission factor, with abatement technology (kg N_2O/metric ton HNO_3)
$\%P_{unc,i}$ = Percent national production of HNO_3 without N_2O abatement technology (%)
EF_{unc} = N_2O emission factor, without abatement technology (kg N_2O/metric ton HNO_3)
i = year from 1990 through 2009

- For 2009: Weighted N_2O emission factor – 5.45 kg N_2O/metric ton HNO_3.
- For 1990-2008: Weighted N_2O emission factor – 5.65 kg N_2O/metric ton HNO_3.

Nitric acid production data for the United States for 1990 through 2009 were obtained from the U.S. Census Bureau (U.S. Census Bureau 2008, 2009, 2010a, 2010b) (see Table 4-27). Publicly-available information on plant-level abatement technologies was used to estimate the shares of nitric acid production with and without abatement for 2008 and 2009 (EPA 2012, 2013; Desai 2012; CAR 2013). Publicly-available data on use of abatement technologies were not available for 1990-2007. Therefore, the share of national production with and without abatement for 2008 was assumed to be constant for 1990 through 2007.

Table 4-27: Nitric Acid Production (kt)

Year	kt
1990	7,195
2005	6,711
2010	7,444
2011	7,606
2012	7,453
2013	7,572
2014	7,656

Uncertainty and Time-Series Consistency

Uncertainty associated with the parameters used to estimate N_2O emissions includes that of production data, the share of U.S. nitric acid production attributable to each emission abatement technology over the time series (especially prior to 2010), and the associated emission factors applied to each abatement technology type. While some information has been obtained through outreach with industry associations, limited information is available over the time series (especially prior to 2010) for a variety of facility level variables, including plant specific production levels, plant production technology (e.g., low, high pressure, etc.), and abatement technology type, installation date of abatement technology, and accurate destruction and removal efficiency rates.

The results of this Approach 2 quantitative uncertainty analysis are summarized in Table 4-28. N_2O emissions from nitric acid production were estimated were estimated to be between 10.4 and 11.5 MMT CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 5 percent below to 5 percent above the 2014 emissions estimate of 10.9 MMT CO_2 Eq.

Table 4-28: Approach 2 Quantitative Uncertainty Estimates for N_2O Emissions from Nitric Acid Production (MMT CO_2 Eq. and Percent)

Source	Gas	2014 Emission Estimate (MMT CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a]			
			(MMT CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Nitric Acid Production	N_2O	10.9	10.4	11.5	-5%	+5%

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

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

4.8 Adipic Acid Production (IPCC Source Category 2B3)

Adipic acid is produced through a two-stage process during which N_2O is generated in the second stage. Emissions from fuels consumed for energy purposes during the production of adipic acid are accounted for in the Energy chapter. The first stage of manufacturing usually involves the oxidation of cyclohexane to form a cyclohexanone/ cyclohexanol mixture. The second stage involves oxidizing this mixture with nitric acid to produce adipic acid. Nitrous oxide is generated as a byproduct of the nitric acid oxidation stage and is emitted in the waste gas stream (Thiemens and Trogler 1991). The second stage is represented by the following chemical reaction:

$$(CH_2)_5CO(cyclohexanone) + (CH_2)_5CHOH(cyclohexanol) + wHNO_3 \\ \rightarrow HOOC(CH_2)_4COOH(adipic\ acid) + xN_2O + yH_2O$$

Process emissions from the production of adipic acid vary with the types of technologies and level of emission controls employed by a facility. In 1990, two major adipic acid-producing plants had N_2O abatement technologies in place and, as of 1998, three major adipic acid production facilities had control systems in place (Reimer et al. 1999). One small plant, which last operated in April 2006 and represented approximately two percent of production, did not control for N_2O (VA DEQ 2009; ICIS 2007; VA DEQ 2006). In 2014, catalytic reduction, non-selective catalytic reduction (NSCR) and thermal reduction abatement technologies were applied as N_2O abatement measures at adipic acid facilities (EPA 2015).

Worldwide, only a few adipic acid plants exist. The United States, Europe, and China are the major producers. In 2014, the United States had two companies with a total of three adipic acid production facilities (two in Texas and one in Florida), all of which were operational (EPA 2015). The United States accounts for the largest share of global adipic acid production capacity (30 percent), followed by the European Union (29 percent) and China (22 percent) (SEI 2010). Adipic acid is a white crystalline solid used in the manufacture of synthetic fibers, plastics, coatings, urethane foams, elastomers, and synthetic lubricants. Commercially, it is the most important of the aliphatic dicarboxylic acids, which are used to manufacture polyesters. Eighty-four percent of all adipic acid produced in the United States is used in the production of nylon 6,6; 9 percent is used in the production of polyester polyols; 4 percent is used in the production of plasticizers; and the remaining 4 percent is accounted for by other uses, including unsaturated polyester resins and food applications (ICIS 2007). Food grade adipic acid is used to provide some foods with a "tangy" flavor (Thiemens and Trogler 1991).

Nitrous oxide emissions from adipic acid production were estimated to be 5.4 MMT CO_2 Eq. (18 kt N_2O) in 2014 (see Table 4-29). National adipic acid production has increased by approximately 36 percent over the period of 1990 through 2014, to approximately 1,025,000 metric tons (ACC 2015). Over the period 1990 through 2014, emissions have been reduced by 64 percent due to both the widespread installation of pollution control measures in the late 1990s and plant idling in the late 2000s. In April 2006, the smallest of the four facilities ceased production of adipic acid (VA DEQ 2009); furthermore, one of the major adipic acid production facilities was not operational in 2009 or 2010 (Desai 2010). All three remaining facilities were in operation in 2014. Very little information on annual trends in the activity data exist for adipic acid.

Table 4-29: N_2O Emissions from Adipic Acid Production (MMT CO_2 Eq. and kt N_2O)

Year	MMT CO_2 Eq.	kt N_2O
1990	15.2	51
2005	7.1	24
2010	4.2	14
2011	10.2	34
2012	5.5	19
2013	4.0	13
2014	5.4	18

Methodology

Emissions are estimated using both Tier 2 and Tier 3 methods consistent with the *2006 IPCC Guidelines* (IPCC 2006). Due to confidential business information, plant names are not provided in this section. Therefore, the four adipic acid-producing facilities will be referred to as Plants 1 through 4. Plant 4 was closed in April 2006. Overall, as noted above, the three plants that are currently operating facilities use abatement equipment. Plants 1 and 2 employ catalytic destruction and Plant 3 employs thermal destruction.

2010 through 2014

All emission estimates for 2010 through 2014 were obtained through analysis of EPA's GHGRP data (EPA 2014 through 2015), which is consistent with the *2006 IPCC Guidelines* (IPCC 2006) Tier 3 method. Facility-level greenhouse gas emissions data were obtained from the GHGRP for the years 2010 through 2014 (EPA 2014 through 2015) and aggregated to national N_2O emissions. Consistent with IPCC Tier 3 methods, all adipic acid production facilities are required to calculate emissions using a facility-specific emission factor developed through annual performance testing under typical operating conditions or by directly measuring N_2O emissions using monitoring equipment. More information on the monitoring methods for process N_2O emissions applicable to adipic acid production facilities under Subpart E can be found in the electronic code of federal regulations.[17]

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[17] See <http://www.ecfr.gov/cgi-bin/text-idx?tpl=/ecfrbrowse/Title40/40cfr98_main_02.tpl>.

1990 through 2009

For years prior to EPA's GHGRP reporting, for both Plants 1 and 2, 1990 to 2009 emission estimates were obtained directly from the plant engineer and account for reductions due to control systems in place at these plants during the time series. These prior estimates are considered confidential business information and hence are not published (Desai 2010). These estimates were based on continuous process monitoring equipment installed at the two facilities. In 2009 and 2010, no adipic acid production occurred at Plant 1 per reporting to EPA's GHGRP (EPA 2012; Desai 2011b).

For the Plant 4, 1990 through 2009 N_2O emissions were estimated using the following Tier 2 equation from the *2006 IPCC Guidelines* until shutdown of the plant in 2006:

$$E_{aa} = Q_{aa} \times EF_{aa} \times (1 - [DF \times UF])$$

where,

E_{aa} = N_2O emissions from adipic acid production, metric tons
Q_{aa} = Quantity of adipic acid produced, metric tons
EF_{aa} = Emission factor, metric ton N_2O/metric ton adipic acid produced
DF = N_2O destruction factor
UF = Abatement system utility factor

The adipic acid production is multiplied by an emission factor (i.e., N_2O emitted per unit of adipic acid produced), which has been estimated, based on experiments that the reaction stoichiometry for N_2O production in the preparation of adipic acid, to be approximately 0.3 metric tons of N_2O per metric ton of product (IPCC 2006). The "N_2O destruction factor" in the equation represents the percentage of N_2O emissions that are destroyed by the installed abatement technology. The "abatement system utility factor" represents the percentage of time that the abatement equipment operates during the annual production period. No abatement equipment was installed at the Inolex/Allied Signal facility, which last operated in April 2006 (VA DEQ 2009). Plant-specific production data for this facility were obtained across the time series from 1990 through 2006 from the Virginia Department of Environmental Quality (VA DEQ 2010). The plant-specific production data were then used for calculating emissions as described above.

For Plant 3, 2005 through 2009 emissions were obtained directly from the plant (Desai 2011a). For 1990 through 2004, emissions were estimated using plant-specific production data and the IPCC factors as described above for Plant 4. Plant-level adipic acid production for 1990 through 2003 was estimated by allocating national adipic acid production data to the plant level using the ratio of known plant capacity to total national capacity for all U.S. plants (ACC 2015; CMR 2001, 1998; CW 1999; C&EN 1992 through 1995). For 2004, actual plant production data were obtained and used for emission calculations (CW 2005).

Plant capacities for 1990 through 1994 were obtained from *Chemical & Engineering News*, "Facts and Figures" and "Production of Top 50 Chemicals" (C&EN 1992 through 1995). Plant capacities for 1995 and 1996 were kept the same as 1994 data. The 1997 plant capacities were taken from *Chemical Market Reporter*, "Chemical Profile: Adipic Acid" (CMR 1998). The 1998 plant capacities for all four plants and 1999 plant capacities for three of the plants were obtained from *Chemical Week*, Product Focus: Adipic Acid/Adiponitrile (CW 1999). Plant capacities for 2000 for three of the plants were updated using *Chemical Market Reporter*, "Chemical Profile: Adipic Acid" (CMR 2001). For 2001 through 2003, the plant capacities for three plants were kept the same as the year 2000 capacities. Plant capacity for 1999 to 2003 for the one remaining plant was kept the same as 1998.

National adipic acid production data (see Table 4-30) from 1990 through 2014 were obtained from the American Chemistry Council (ACC 2015).

Table 4-30: Adipic Acid Production (kt)

Year	kt
1990	755
2005	865

2010	720
2011	840
2012	950
2013	980
2014	1,025

Uncertainty and Time-Series Consistency

Uncertainty associated with N_2O emission estimates includes the methods used by companies to monitor and estimate emissions. While some information has been obtained through outreach with facilities, limited information is available over the time series on these methods, abatement technology destruction and removal efficiency rates and plant specific production levels.

The results of this Approach 2 quantitative uncertainty analysis are summarized in Table 4-31. Nitrous oxide emissions from adipic acid production for 2014 were estimated to be between 5.2 and 5.6 MMT CO_2 Eq. at the 95 percent confidence level. These values indicate a range of approximately 4 percent below to 4 percent above the 2014 emission estimate of 5.4 MMT CO_2 Eq.

Table 4-31: Approach 2 Quantitative Uncertainty Estimates for N_2O Emissions from Adipic Acid Production (MMT CO_2 Eq. and Percent)

Source	Gas	2014 Emission Estimate (MMT CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (MMT CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Adipic Acid Production	N_2O	5.4	5.2	5.6	-4%	+4%

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

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

4.9 Silicon Carbide Production and Consumption (IPCC Source Category 2B5)

Carbon dioxide (CO_2) and methane (CH_4) are emitted from the production of silicon carbide (SiC), a material used as an industrial abrasive. Silicon carbide is produced for abrasive, metallurgical, and other non-abrasive applications in the United States. Production for metallurgical and other non-abrasive applications is not available and therefore both CO_2 and CH_4 estimates are based solely upon production estimates of silicon carbide for abrasive applications. Emissions from fuels consumed for energy purposes during the production of silicon carbide are accounted for in the Energy chapter.

To produce SiC, silica sand or quartz (SiO_2) is reacted with carbon in the form of petroleum coke. A portion (about 35 percent) of the carbon contained in the petroleum coke is retained in the SiC. The remaining carbon is emitted as CO_2, CH_4, or CO. The overall reaction is shown below (but in practice it does not proceed according to stoichiometry):

$$SiO_2 + 3C \rightarrow SiC + 2CO\ (+ O_2 \rightarrow 2CO_2)$$

Carbon dioxide is also emitted from the consumption of SiC for metallurgical and other non-abrasive applications.

Markets for manufactured abrasives, including SiC, are heavily influenced by activity in the U.S. manufacturing sector, especially in the aerospace, automotive, furniture, housing, and steel manufacturing sectors. The USGS reports that a portion (approximately 50 percent) of SiC is used in metallurgical and other non-abrasive applications, primarily in iron and steel production (USGS 2006a). As a result of the economic downturn in 2008 and 2009, demand for SiC decreased in those years. Low cost imports, particularly from China, combined with high relative operating costs for domestic producers, continue to put downward pressure on the production of SiC in the United States. However, demand for SiC consumption in the United States has recovered somewhat from its low in 2009 (USGS 2012a). Silicon carbide is manufactured at a single facility located in Illinois (USGS 2015a).

Carbon dioxide emissions from SiC production and consumption in 2014 were 0.2 MMT CO_2 Eq. (173 kt CO_2). Approximately 53 percent of these emissions resulted from SiC production while the remainder resulted from SiC consumption. Methane emissions from SiC production in 2014 were 0.01 MMT CO_2 Eq. (0.4 kt CH_4) (see Table 4-32: and Table 4-33). Emissions have fluctuated in recent years, but 2014 emissions are only about 46 percent of emissions in 1990.

Table 4-32: CO_2 and CH_4 Emissions from Silicon Carbide Production and Consumption (MMT CO_2 Eq.)

Year	1990	2005	2010	2011	2012	2013	2014
CO_2	0.4	0.2	0.2	0.2	0.2	0.2	0.2
CH_4	+	+	+	+	+	+	+
Total	**0.4**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**

+ Does not exceed 0.05 MMT CO_2 Eq.

Table 4-33: CO_2 and CH_4 Emissions from Silicon Carbide Production and Consumption (kt)

Year	1990	2005	2010	2011	2012	2013	2014
CO_2	375	219	181	170	158	169	173
CH_4	1	+	+	+	+	+	+

+ Does not exceed 0.5 kt.

Methodology

Emissions of CO_2 and CH_4 from the production of SiC were calculated using the Tier 1 method provided by the *2006 IPCC Guidelines* (IPCC 2006). Annual estimates of SiC production were multiplied by the appropriate emission factor, as shown below:

$$E_{sc,CO2} = EF_{sc,CO2} \times Q_{sc}$$

$$E_{sc,CH4} = EF_{sc,CH4} \times Q_{sc} \times \left(\frac{1\ metric\ ton}{1000\ kg}\right)$$

where,

$E_{sc,CO2}$ = CO_2 emissions from production of SiC, metric tons
$EF_{sc,CO2}$ = Emission factor for production of SiC, metric ton CO_2/metric ton SiC
Q_{sc} = Quantity of SiC produced, metric tons
$E_{sc,CH4}$ = CH_4 emissions from production of SiC, metric tons
$EF_{sc,CH4}$ = Emission factor for production of SiC, kilogram CH_4/metric ton SiC

Emission factors were taken from the *2006 IPCC Guidelines* (IPCC 2006):

- 2.62 metric tons CO_2/metric ton SiC
- 11.6 kg CH_4/metric ton SiC

Emissions of CO_2 from silicon carbide consumption for metallurgical uses were calculated by multiplying the annual utilization of SiC for metallurgical uses (reported annually in the USGS *Minerals Yearbook: Silicon*) by the carbon content of SiC (31.5 percent), which was determined according to the molecular weight ratio of SiC.

Emissions of CO_2 from silicon carbide consumption for other non-abrasive uses were calculated by multiplying the annual SiC consumption for non-abrasive uses by the carbon content of SiC (31.5 percent). The annual SiC consumption for non-abrasive uses was calculated by multiplying the annual SiC consumption (production plus net imports) by the percent used in metallurgical and other non-abrasive uses (50 percent) (USGS 2006a) and then subtracting the SiC consumption for metallurgical use.

Production data for 1990 through 2013 were obtained from the *Minerals Yearbook: Manufactured Abrasives* (USGS 1991a through 2015b). Production data for 2014 were obtained from the *Minerals Industry Surveys: Abrasives (Manufactured)* (USGS 2015a). Silicon carbide consumption by major end use for 1990 through 2012 were obtained from the *Minerals Yearbook: Silicon* (USGS 1991b through 2013) (see Table 4-34). Silicon carbide consumption data for 2013 and 2014 are not yet publicly available and so 2012 data were used as proxy. Net imports for the entire time series were obtained from the U.S. Census Bureau (2005 through 2015).

Table 4-34: Production and Consumption of Silicon Carbide (Metric Tons)

Year	Production	Consumption
1990	105,000	172,465
2005	35,000	220,149
2010	35,000	154,540
2011	35,000	136,222
2012	35,000	114,265
2013	35,000	134,055
2014	35,000	140,723

Uncertainty and Time-Series Consistency

There is uncertainty associated with the emission factors used because they are based on stoichiometry as opposed to monitoring of actual SiC production plants. An alternative would be to calculate emissions based on the quantity of petroleum coke used during the production process rather than on the amount of silicon carbide produced. However, these data were not available. For CH_4, there is also uncertainty associated with the hydrogen-containing volatile compounds in the petroleum coke (IPCC 2006). There is also uncertainty associated with the use or destruction of methane generated from the process in addition to uncertainty associated with levels of production, net imports, consumption levels, and the percent of total consumption that is attributed to metallurgical and other non-abrasive uses.

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 4-35. Silicon carbide production and consumption CO_2 emissions were estimated to be between 9 percent below and 9 percent above the emission estimate of 0.17 MMT CO_2 Eq. at the 95 percent confidence level. Silicon carbide production CH_4 emissions were estimated to be between 9 percent below and 10 percent above the emission estimate of 0.01 MMT CO_2 Eq. at the 95 percent confidence level.

Table 4-35: Approach 2 Quantitative Uncertainty Estimates for CH_4 and CO_2 Emissions from Silicon Carbide Production and Consumption (MMT CO_2 Eq. and Percent)

Source	Gas	2014 Emission Estimate (MMT CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (MMT CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Silicon Carbide Production and Consumption	CO_2	0.17	0.16	0.19	-9%	+9%

Silicon Carbide Production	CH_4	+	+	+	-9%	+10%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.
+ Does not exceed 0.05 MMT CO_2 Eq.

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

Planned Improvements

Future improvements involve continuing to evaluate and analyze data reported under EPA's GHGRP to improve the emission estimates for the Silicon Carbide Production and Consumption source category. Particular attention will be made to ensure time series consistency of the emission estimates presented in future Inventory reports, consistent with IPCC and UNFCCC guidelines. This is required as the facility-level reporting data from EPA's GHGRP, with the program's initial requirements for reporting of emissions in calendar year 2010, are not available for all inventory years (i.e., 1990 through 2009) as required for this Inventory. In implementing improvements and integration of data from EPA's GHGRP, the latest guidance from the IPCC on the use of facility-level data in national inventories will be relied upon.[18] In addition, improvements will involve continued research to determine if calcium carbide production and consumption data are available for the United States. If these data are available, calcium carbide emission estimates will be included in this source category.

4.10 Titanium Dioxide Production (IPCC Source Category 2B6)

Titanium dioxide (TiO_2) is manufactured using one of two processes: the chloride process and the sulfate process. The chloride process uses petroleum coke and chlorine as raw materials and emits process-related CO_2. Emissions from fuels consumed for energy purposes during the production of titanium dioxide are accounted for in the Energy chapter. The chloride process is based on the following chemical reactions:

$$2FeTiO_3 + 7Cl_2 + 3C \rightarrow 2TiCl_4 + 2FeCl_3 + 3CO_2$$

$$2TiCl_4 + 2O_2 \rightarrow 2TiO_2 + 4Cl_2$$

The sulfate process does not use petroleum coke or other forms of carbon as a raw material and does not emit CO_2.

The carbon in the first chemical reaction is provided by petroleum coke, which is oxidized in the presence of the chlorine and $FeTiO_3$ (rutile ore) to form CO_2. Since 2004, all TiO_2 produced in the United States has been produced using the chloride process, and a special grade of "calcined" petroleum coke is manufactured specifically for this purpose.

The principal use of TiO_2 is as a pigment in white paint, lacquers, and varnishes; it is also used as a pigment in the manufacture of plastics, paper, and other products. In 2014, U.S. TiO_2 production totaled 1,310,000 metric tons (USGS 2015a). There were a total 6 plants producing TiO_2 in the United States—2 located in Mississippi, and single plants located in Delaware, Louisiana, Ohio, and Tennessee.

Emissions of CO_2 from titanium dioxide production in 2014 were estimated to be 1.8 MMT CO_2 Eq. (1,755 kt CO_2), which represents an increase of 47 percent since 1990 (see Table 4-36).

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

Table 4-36: CO_2 Emissions from Titanium Dioxide (MMT CO_2 Eq. and kt)

Year	MMT CO_2 Eq.	kt
1990	1.2	1,195
2005	1.8	1,755
2010	1.8	1,769
2011	1.7	1,729
2012	1.5	1,528
2013	1.7	1,715
2014	1.8	1,755

Methodology

Emissions of CO_2 from TiO_2 production were calculated by multiplying annual national TiO_2 production by chloride process-specific emission factors using a Tier 1 approach provided in *2006 IPCC Guidelines* (IPCC 2006). The Tier 1 equation is as follows:

$$E_{td} = EF_{td} \times Q_{td}$$

where,

E_{td} = CO_2 emissions from TiO_2 production, metric tons
EF_{td} = Emission factor (chloride process), metric ton CO_2/metric ton TiO_2
Q_{td} = Quantity of TiO_2 produced

Data were obtained for the total amount of TiO_2 produced each year. For years prior to 2004, it was assumed that TiO_2 was produced using the chloride process and the sulfate process in the same ratio as the ratio of the total U.S. production capacity for each process. As of 2004, the last remaining sulfate process plant in the United States closed; therefore, 100 percent of post-2004 production uses the chloride process (USGS 2005). The percentage of production from the chloride process is estimated at 100 percent since 2004. An emission factor of 1.34 metric tons CO_2/metric ton TiO_2 was applied to the estimated chloride-process production (IPCC 2006). It was assumed that all TiO_2 produced using the chloride process was produced using petroleum coke, although some TiO_2 may have been produced with graphite or other carbon inputs.

The emission factor for the TiO_2 chloride process was taken from the *2006 IPCC Guidelines* (IPCC 2006). Titanium dioxide production data and the percentage of total TiO_2 production capacity that is chloride process for 1990 through 2013 (see Table 4-37:) were obtained through the *Minerals Yearbook: Titanium Annual Report* (USGS 1991 through 2015b). Production data for 2014 was obtained from the *Minerals Commodity Summary: Titanium and Titanium Dioxide* (USGS 2015a). Data on the percentage of total TiO_2 production capacity that is chloride process were not available for 1990 through 1993, so data from the 1994 USGS *Minerals Yearbook* were used for these years. Because a sulfate process plant closed in September 2001, the chloride process percentage for 2001 was estimated based on a discussion with Joseph Gambogi (2002). By 2002, only one sulfate process plant remained online in the United States and this plant closed in 2004 (USGS 2005).

Table 4-37: Titanium Dioxide Production (kt)

Year	kt
1990	979
2005	1,310
2010	1,320
2011	1,290
2012	1,140
2013	1,280

2014	1,310

Uncertainty and Time-Series Consistency

Each year, USGS collects titanium industry data for titanium mineral and pigment production operations. If TiO_2 pigment plants do not respond, production from the operations is estimated on the basis of prior year production levels and industry trends. Variability in response rates varies from 67 to 100 percent of TiO_2 pigment plants over the time series.

Although some TiO_2 may be produced using graphite or other carbon inputs, information and data regarding these practices were not available. Titanium dioxide produced using graphite inputs, for example, may generate differing amounts of CO_2 per unit of TiO_2 produced as compared to that generated through the use of petroleum coke in production. While the most accurate method to estimate emissions would be to base calculations on the amount of reducing agent used in each process rather than on the amount of TiO_2 produced, sufficient data were not available to do so.

As of 2004, the last remaining sulfate-process plant in the United States closed. Since annual TiO_2 production was not reported by USGS by the type of production process used (chloride or sulfate) prior to 2004 and only the percentage of total production capacity by process was reported, the percent of total TiO_2 production capacity that was attributed to the chloride process was multiplied by total TiO_2 production to estimate the amount of TiO_2 produced using the chloride process. Finally, the emission factor was applied uniformly to all chloride-process production, and no data were available to account for differences in production efficiency among chloride-process plants. In calculating the amount of petroleum coke consumed in chloride-process TiO_2 production, literature data were used for petroleum coke composition. Certain grades of petroleum coke are manufactured specifically for use in the TiO_2 chloride process; however, this composition information was not available.

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 4-38. Titanium dioxide consumption CO_2 emissions were estimated to be between 1.5 and 2.0 MMT CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 12 percent below and 13 percent above the emission estimate of 1.8 MMT CO_2 Eq.

Table 4-38: Approach 2 Quantitative Uncertainty Estimates for CO_2 Emissions from Titanium Dioxide Production (MMT CO_2 Eq. and Percent)

Source	Gas	2014 Emission Estimate (MMT CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (MMT CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Titanium Dioxide Production	CO_2	1.8	1.5	2.0	-12%	+13%

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

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

Recalculations Discussion

Production data for 2013 were updated relative to the previous Inventory based on recently published data in the USGS *Minerals Yearbook: Titanium 2013* (USGS 2015b). This resulted in a 7 percent increase in 2013 CO_2 emissions from TiO_2 production relative to the previous report.

Planned Improvements

Pending resources, a potential improvement to the Inventory estimates for this source category would include the derivation of country-specific emission factors, based on annual data reported under EPA's GHGRP for 2010 through 2014 (i.e., aggregated emissions and titanium production). Information on TiO_2 production is collected by

EPA's GHGRP for all facilities for years 2010 through 2014 and would also have to be assessed against criteria EPA has established to publish aggregated confidential business information (CBI) reported under EPA's GHGRP. In order to provide estimates for the entire time series (i.e., 1990 through 2009), the applicability of more recent GHGRP data to previous years' estimates will need to be evaluated, and additional data that could be utilized in the calculations for this source category may need to be researched. 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.[19]

In addition, planned improvements include researching the significance of titanium-slag production in electric furnaces and synthetic-rutile production using the Becher process in the United States. Significant use of these production processes will be included in future Inventories.

4.11 Soda Ash Production and Consumption (IPCC Source Category 2B7)

Carbon dioxide is generated as a byproduct of calcining trona ore to produce soda ash, and is eventually emitted into the atmosphere. In addition, CO_2 may also be released when soda ash is consumed. Emissions from fuels consumed for energy purposes during the production and consumption of soda ash are accounted for in the Energy sector.

Calcining involves placing crushed trona ore into a kiln to convert sodium bicarbonate into crude sodium carbonate that will later be filtered into pure soda ash. The emission of CO_2 during trona-based production is based on the following reaction:

$$2Na_2CO_3 \bullet NaHCO_3 \bullet 2H_2O(Trona) \rightarrow 3Na_2CO_3(Soda\ Ash) + 5H_2O + CO_2$$

Soda ash (sodium carbonate, Na_2CO_3) is a white crystalline solid that is readily soluble in water and strongly alkaline. Commercial soda ash is used as a raw material in a variety of industrial processes and in many familiar consumer products such as glass, soap and detergents, paper, textiles, and food. (Emissions from soda ash used in glass production are reported under IPCC Source Category 2A3. Glass production is its own sub-category and historical soda ash consumption figures have been adjusted to reflect this change.) After glass manufacturing, soda ash is used primarily to manufacture many sodium-based inorganic chemicals, including sodium bicarbonate, sodium chromates, sodium phosphates, and sodium silicates (USGS 2015b). Internationally, two types of soda ash are produced, natural and synthetic. The United States produces only natural soda ash and is second only to China in total soda ash production. Trona is the principal ore from which natural soda ash is made.

The United States represents about one-fourth of total world soda ash output. Only two states produce natural soda ash: Wyoming and California. Of these two states, only net emissions of CO_2 from Wyoming were calculated due to specifics regarding the production processes employed in the state.[20] Based on preliminary 2014 reported data, the estimated distribution of soda ash by end-use in 2014 (excluding glass production) was chemical production, 56 percent; soap and detergent manufacturing, 13 percent; distributors, 10 percent; flue gas desulfurization, 8 percent; other uses, 8 percent; pulp and paper production, 2 percent; and water treatment, 2 percent (USGS 2015a).

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

[20] In California, soda ash is manufactured using sodium carbonate-bearing brines instead of trona ore. To extract the sodium carbonate, the complex brines are first treated with CO_2 in carbonation towers to convert the sodium carbonate into sodium bicarbonate, which then precipitates from the brine solution. The precipitated sodium bicarbonate is then calcined back into sodium carbonate. Although CO_2 is generated as a byproduct, the CO_2 is recovered and recycled for use in the carbonation stage and is not emitted. A third state, Colorado, produced soda ash until the plant was idled in 2004. The lone producer of sodium bicarbonate no longer mines trona in the state. For a brief time, sodium bicarbonate was produced using soda ash feedstocks mined in Wyoming and shipped to Colorado. Prior to 2004, because the trona was mined in Wyoming, the production numbers given by the USGS included the feedstocks mined in Wyoming and shipped to Colorado. In this way, the sodium bicarbonate production that took place in Colorado was accounted for in the Wyoming numbers.

U.S. natural soda ash is competitive in world markets because the majority of the world output of soda ash is made synthetically. Although the United States continues to be a major supplier of world soda ash, China, which surpassed the United States in soda ash production in 2003, is the world's leading producer.

In 2014, CO_2 emissions from the production of soda ash from trona were approximately 1.7 MMT CO_2 Eq. (1,685 kt CO_2). Soda ash consumption in the United States generated 1.1 MMT CO_2 Eq. (1,143 kt CO_2) in 2014. Total emissions from soda ash production and consumption in 2014 were 2.8 MMT CO_2 Eq. (2,827 kt CO_2) (see Table 4-39 and Table 4-40).

Total emissions in 2014 increased by approximately 1 percent from emissions in 2013, and have stayed approximately the same as the 1990 levels.

Emissions have remained relatively constant over the time series with some fluctuations since 1990. In general, these fluctuations were related to the behavior of the export market and the U.S. economy. The U.S. soda ash industry continued a trend of increased production and value in 2014 since experiencing a decline in domestic and export sales caused by adverse global economic conditions in 2009. The annual average unit value of soda ash set a record high in 2013, and soda ash exports increased as well, accounting for 56 percent of total production (USGS 2015b).

Table 4-39: CO_2 Emissions from Soda Ash Production and Consumption Not Associated with Glass Manufacturing (MMT CO_2 Eq.)

Year	Production	Consumption	Total
1990	1.4	1.4	2.8
2005	1.7	1.3	3.0
2010	1.5	1.1	2.7
2011	1.6	1.1	2.7
2012	1.7	1.1	2.8
2013	1.7	1.1	2.8
2014	1.7	1.1	2.8

Note: Totals may not sum due to independent rounding.

Table 4-40: CO_2 Emissions from Soda Ash Production and Consumption Not Associated with Glass Manufacturing (kt)

Year	Production	Consumption	Total
1990	1,431	1,390	2,822
2005	1,655	1,305	2,960
2010	1,548	1,148	2,697
2011	1,607	1,105	2,712
2012	1,665	1,097	2,763
2013	1,694	1,109	2,804
2014	1,685	1,143	2,827

Note: Totals may not sum due to independent rounding.

Methodology

During the production process, trona ore is calcined in a rotary kiln and chemically transformed into a crude soda ash that requires further processing. Carbon dioxide and water are generated as byproducts of the calcination process. Carbon dioxide emissions from the calcination of trona can be estimated based on the chemical reaction shown above. Based on this formula, which is consistent with an IPCC Tier 1 approach, approximately 10.27 metric tons of trona are required to generate one metric ton of CO_2, or an emission factor of 0.0974 metric tons CO_2 per metric ton trona (IPCC 2006). Thus, the 17.3 million metric tons of trona mined in 2014 for soda ash production (USGS 2015a) resulted in CO_2 emissions of approximately 1.7 MMT CO_2 Eq. (1,685 kt).

Once produced, most soda ash is consumed in chemical and soap production, with minor amounts in pulp and paper, flue gas desulfurization, and water treatment (excluding soda ash consumption for glass manufacturing). As soda ash is consumed for these purposes, additional CO_2 is usually emitted. In these applications, it is assumed that one mole of carbon is released for every mole of soda ash used. Thus, approximately 0.113 metric tons of carbon (or 0.415 metric tons of CO_2) are released for every metric ton of soda ash consumed.

The activity data for trona production and soda ash consumption (see Table 4-41) for 1990 to 2014 were obtained from USGS *Minerals Yearbook for Soda Ash* (1994 through 2015b) and USGS *Mineral Industry Surveys for Soda Ash* (USGS 2015a). Soda ash production and consumption data were collected by the USGS from voluntary surveys of the U.S. soda ash industry.

Table 4-41: Soda Ash Production and Consumption Not Associated with Glass Manufacturing (kt)

Year	Production[a]	Consumption[b]
1990	14,700	3,351
2005	17,000	3,144
2010	15,900	2,768
2011	16,500	2,663
2012	17,100	2,645
2013	17,400	2,674
2014	17,300	2,754

[a] Soda ash produced from trona ore only.

[b] Soda ash consumption is sales reported by producers which exclude imports. Historically, imported soda ash is less than 1 percent of the total U.S. consumption (Kostick 2012).

Uncertainty and Time-Series Consistency

Emission estimates from soda ash production have relatively low associated uncertainty levels in that reliable and accurate data sources are available for the emission factor and activity data. Soda ash production data was collected by the USGS from voluntary surveys. A survey request was sent to each of the five soda ash producers, all of which responded, representing 100 percent of the total production data (USGS 2014a). One source of uncertainty is the purity of the trona ore used for manufacturing soda ash. The emission factor used for this estimate assumes the ore is 100 percent pure, and likely overestimates the emissions from soda ash manufacture. The average water-soluble sodium carbonate-bicarbonate content for ore mined in Wyoming ranges from 85.5 to 93.8 percent (USGS 1995).The primary source of uncertainty, however, results from the fact that emissions from soda ash consumption are dependent upon the type of processing employed by each end-use. Specific emission factors for each end-use are not available, so a Tier 1 default emission factor is used for all end uses. Therefore, there is uncertainty surrounding the emission factors from the consumption of soda ash.

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 4-42. Soda Ash Production and Consumption CO_2 emissions were estimated to be between 2.5 and 2.9 MMT CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 7 percent below and 6 percent above the emission estimate of 2.8 MMT CO_2 Eq.

Table 4-42: Approach 2 Quantitative Uncertainty Estimates for CO_2 Emissions from Soda Ash Production and Consumption (MMT CO_2 Eq. and Percent)

Source	Gas	2014 Emission Estimate (MMT CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (MMT CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Soda Ash Production and Consumption	CO_2	2.8	2.5	2.9	-7%	+6%

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

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

Recalculation Discussion

During the development of the current Inventory, an error in the transcription of the *2006 IPCC Guidelines* default trona production emission factor was identified. This error was corrected in the current Inventory and resulted in a slight change of emissions over the entire time series (approximately 3 percent), compared with the previous Inventory.

Planned Improvements

In future Inventory reports, soda ash consumed for other uses of carbonates will be extracted from the current soda ash consumption emission estimates and included under those sources or other process uses of carbonates (IPCC Category 2A4).

EPA will continue to analyze and assess uses of facility-level data from EPA's GHGRP to improve the emission estimates for Soda Ash Production source category. Particular attention will be made to ensure time series consistency of the emissions estimates presented in future Inventory reports, consistent with IPCC and UNFCCC guidelines. This is required as the facility-level reporting data from EPA's GHGRP, with the program's initial requirements for reporting of emissions in calendar year 2010, are not available for all inventory years (i.e., 1990 through 2009) as required for this Inventory. In implementing improvements and integration of data from EPA's GHGRP, the latest guidance from the IPCC on the use of facility-level data in national inventories will be relied upon.[21]

4.12 Petrochemical Production (IPCC Source Category 2B8)

The production of some petrochemicals results in the release of small amounts of CO_2 and CH_4 emissions. Petrochemicals are chemicals isolated or derived from petroleum or natural gas. Carbon dioxide emissions from the production of acrylonitrile, carbon black, ethylene, ethylene dichloride, ethylene oxide and methanol; and CH_4 emissions from the production of methanol and acrylonitrile are presented here and reported under IPCC Source Category 2B5. The petrochemical industry uses primary fossil fuels (i.e., natural gas, coal, petroleum, etc.) for non-fuel purposes in the production of carbon black and other petrochemicals. Emissions from fuels and feedstocks

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

transferred out of the system for use in energy purposes (e.g., such as indirect or direct process heat or steam production) are currently accounted for in the Energy sector.

Worldwide more than 90 percent of acrylonitrile (vinyl cyanide, C_3H_3N) is made by way of direct ammoxidation of propylene with ammonia (NH_3) and oxygen over a catalyst. This process is referred to as the SOHIO process, after the Standard Oil Company of Ohio (SOHIO) (IPCC 2006). The primary use of acrylonitrile is as the raw material for the manufacture of acrylic and modacrylic fibers. Other major uses include the production of plastics (acrylonitrile-butadiene-styrene [ABS] and styrene-acrylonitrile [SAN]), nitrile rubbers, nitrile barrier resins, adiponitrile and acrylamide. All U.S. acrylonitrile facilities use the SOHIO process (AN 2014). The SOHIO process involves a fluidized bed reaction of chemical-grade propylene, ammonia, and oxygen over a catalyst. The process produces acrylonitrile as its primary product and the process yield depends on the type of catalyst used and the process configuration. The ammoxidation process also produces byproduct CO_2, CO, and water from the direct oxidation of the propylene feedstock, and produces other hydrocarbons from side reactions in the ammoxidation process.

Carbon black is a black powder generated by the incomplete combustion of an aromatic petroleum- or coal-based feedstock at a high temperature. Most carbon black produced in the United States is added to rubber to impart strength and abrasion resistance, and the tire industry is by far the largest consumer. The other major use of carbon black is as a pigment. The predominant process used in the United States is the furnace black (or oil furnace) process. In the furnace black process, carbon black oil (a heavy aromatic liquid) is continuously injected into the combustion zone of a natural gas-fired furnace. Furnace heat is provided by the natural gas and a portion of the carbon black feedstock; the remaining portion of the carbon black feedstock is pyrolyzed to carbon black. The resultant CO_2 and uncombusted CH_4 emissions are released from thermal incinerators used as control devices, process dryers, and equipment leaks. Carbon black is also produced in the United States by the thermal cracking of acetylene-containing feedstocks (i.e., acetylene black process), by the thermal cracking of other hydrocarbons (i.e., thermal black process), and by the open burning of carbon black feedstock (i.e., lamp black process); each of these process are used at only one U.S. plant each (EPA 2000).

Ethylene (C_2H_4) is consumed in the production processes of the plastics industry including polymers such as high, low, and linear low density polyethylene (HDPE, LDPE, LLDPE); polyvinyl chloride (PVC); ethylene dichloride; ethylene oxide; and ethylbenzene. Virtually all ethylene is produced from steam cracking of ethane, propane, butane, naphtha, gas oil, and other feedstocks. The representative chemical equation for steam cracking of ethane to ethylene is shown below:

$$C_2H_6 \rightarrow\ C_2H_4 +\ H_2$$

Small amounts of CH_4 are also generated from the steam cracking process. In addition, CO_2 and CH_4 emissions are also generated from combustion units..

Ethylene dichloride ($C_2H_4Cl_2$) is used to produce vinyl chloride monomer, which is the precursor to polyvinyl chloride (PVC). Ethylene dichloride was used as a fuel additive until 1996 when leaded gasoline was phased out. Ethylene dichloride is produced from ethylene by either direct chlorination, oxychlorination, or a combination of the two processes (i.e., the "balanced process"); most U.S. facilities use the balanced process. The direct chlorination and oxychlorination reactions are shown below:

$$C_2H_4 + Cl_2 \rightarrow C_2H_4Cl_2 \text{ (direct chlorination)}$$

$$C_2H_4 +\ \tfrac{1}{2}O_2 + 2HCl \rightarrow C_2H_4Cl_2 + 2H_2O \text{ (oxychlorination)}$$

$$C_2H_4 +\ 3O_2 \rightarrow 2CO_2 + 2H_2O \text{ (direct oxidation of ethylene during oxychlorination)}$$

In addition to the byproduct CO_2 produced from the direction oxidation of the ethylene feedstock, CO_2 and CH_4 emissions are also generated from combustion units.

Ethylene oxide (C_2H_4O) is used in the manufacture of glycols, glycol ethers, alcohols, and amines. Approximately 70 percent of ethylene oxide produced worldwide is used in the manufacture of glycols, including monoethylene glycol. Ethylene oxide is produced by reacting ethylene with oxygen over a catalyst. The oxygen may be supplied to the process through either an air (air process) or a pure oxygen stream (oxygen process). The byproduct CO_2 from the direct oxidation of the ethylene feedstock is removed from the process vent stream using a recycled carbonate solution, and the recovered CO_2 may be vented to the atmosphere or recovered for further utilization in other sectors, such as food production (IPCC 2006). The combined ethylene oxide reaction and byproduct CO_2 reaction is exothermic and generates heat, which is recovered to produce steam for the process. The ethylene oxide process also produces other liquid and off-gas byproducts (e.g., ethane, etc.) that may be burned for energy recovery within the process. Almost all facilities, except one in Texas, use the oxygen process to manufacture ethylene oxide (EPA 2008).

Methanol (CH_3OH) is a chemical feedstock most often converted into formaldehyde, acetic acid and olefins. It is also an alternative transportation fuel, as well as an additive used by municipal wastewater treatment facilities in the denitrification of wastewater. Methanol is most commonly synthesized from a synthesis gas (i.e., "syngas" – a mixture containing H_2, CO, and CO_2) using a heterogeneous catalyst. There are a number of process techniques that can be used to produce syngas. Worldwide, steam reforming of natural gas is the most common method; however, in the United States only two facilities use steam reforming of natural gas. Other syngas production processes in the United States include partial oxidation of natural gas and coal gasification.

Emissions of CO_2 and CH_4 from petrochemical production in 2014 were 26.5 MMT CO_2 Eq. (26,509 kt CO_2) and 0.1 MMT CO_2 Eq. (5 kt CH_4), respectively (see Table 4-43 and Table 4-44). Since 1990, total CO_2 emissions from petrochemical production increased by approximately 23 percent. Methane emissions from petrochemical (methanol and acrylonitrile) production have decreased by approximately 43 percent since 1990, given declining production.

Table 4-43: CO_2 and CH_4 Emissions from Petrochemical Production (MMT CO_2 Eq.)

Year	1990		2005		2010	2011	2012	2013	2014
CO_2	21.6		27.4		27.2	26.3	26.5	26.4	26.5
CH_4	0.2		0.1		+	+	0.1	0.1	0.1
Total	**21.8**		**27.5**		**27.3**	**26.4**	**26.5**	**26.5**	**26.6**

+ Does not exceed 0.05 MMT CO_2 Eq.

Table 4-44: CO_2 and CH_4 Emissions from Petrochemical Production (kt)

Year	1990		2005		2010	2011	2012	2013	2014
CO_2	21,609		27,380		27,246	26,326	26,464	26,437	26,509
CH_4	9		3		2	2	3	3	5

Methodology

Emissions of CO_2 and CH_4 were calculated using the estimation methods provided by the *2006 IPCC Guidelines* (IPCC 2006) and country-specific methods from EPA's Greenhouse Gas Reporting Program (GHGRP). The *2006 IPCC Guidelines* Tier 1 method was used to estimate CO_2 and CH_4 emissions from production of acrylonitrile and methanol, and a country-specific approach similar to the IPCC Tier 2 method was used to estimate CO_2 emissions from carbon black, ethylene, ethylene oxide, and ethylene dichloride. The Tier 2 method for petrochemicals is a total feedstock carbon mass balance method used to estimate total CO_2 emissions, but is not applicable for estimating CH_4 emissions. As noted in the *2006 IPCC Guidelines*, the total feedstock carbon mass balance method (Tier 2) is based on the assumption that all of the carbon input to the process is converted either into primary and secondary products or into CO_2. Further, the guideline states that while the total carbon mass balance method estimates total carbon emissions from the process but does not directly provide an estimate of the amount of the total carbon emissions emitted as CO_2, CH_4, or NMVOCs. This method accounts for all the carbon as CO_2, including CH_4.

Carbon Black, Ethylene, Ethylene Dichloride and Ethylene Oxide

2010-2014

Carbon dioxide emissions and national production were aggregated directly from EPA's GHGRP dataset for 2010 through 2014 (EPA GHGRP 2015). In 2014, GHGRP data reported CO_2 emissions of 3,272,934 metric tons from carbon black production; 18,805,943 metric tons of CO_2 from ethylene production; 591,127 metric tons of CO_2 from ethylene dichloride production; and 1,333,768 metric tons of CO_2 from ethylene oxide production. These emissions reflect application of a country-specific approach similar to the IPCC Tier 2 method and were used to estimate CO_2 emissions from the production of carbon black, ethylene, ethylene dichloride, and ethylene oxide. Since 2010, EPA's GHGRP, under Subpart X, requires all domestic producers of petrochemicals to report annual emissions and supplemental emissions information (e.g., production data, etc.) to facilitate verification of reported emissions. Under EPA's GHGRP, petrochemical production facilities are required to use either a mass balance approach or CEMS to measure and report emissions for each petrochemical process unit to estimate facility-level process CO_2 emissions. The mass balance method is used by most facilities[22] and assumes that all the carbon input is converted into primary and secondary products, byproducts, or is emitted to the atmosphere as CO_2. To apply the mass balance, facilities must measure the volume or mass of each gaseous and liquid feedstock and product, mass rate of each solid feedstock and product, and carbon content of each feedstock and product for each process unit and sum for their facility.[23] More details on the greenhouse gas calculation and monitoring methods applicable to petrochemical facilities can be found under Subpart X (Petrochemical Production) of the regulation (40 CFR Part 98).[24]

1990-2009

For prior years, for these petrochemical types, an average national CO_2 emission factor was calculated based on the 2010 through 2013 GHGRP data and applied to production for earlier years in the time series (i.e., 1990 through 2009) to estimate CO_2 emissions from carbon black, ethylene, ethylene dichloride, and ethylene oxide. Carbon dioxide emission factors were derived from EPA's GHGRP data by dividing annual CO_2 emissions for petrochemical type "i" with annual production for petrochemical type "i" and then averaging the derived emission factors obtained for each calendar year 2010 through 2014 (EPA GHGRP 2015). The average emission factors for each petrochemical type were applied across all prior years because petrochemical production processes in the United States have not changed significantly since 1990, though some operational efficiencies have been implemented at facilities over the time series.

The average country-specific CO_2 emission factors that were calculated from the 2010 through 2014 GHGRP data are as follows:

- 2.59 metric tons CO_2/metric ton carbon black produced
- 0.79 metric tons CO_2/metric ton ethylene produced
- 0.040 metric tons CO_2/metric ton ethylene dichloride produced
- 0.46 metric tons CO_2/metric ton ethylene oxide produced

Annual production data for carbon black for 1990 through 2009 were obtained from the International Carbon Black Association (Johnson 2003 and 2005 through 2010). Annual production data for ethylene and ethylene dichloride for 1990 through 2009 were obtained from the American Chemistry Council's (ACC's) *Guide to the Business of Chemistry* (ACC 2002, 2003, 2005 through 2011). Annual production data for ethylene oxide were obtained from ACC's *U.S. Chemical Industry Statistical Handbook* for 2003 through 2009 (ACC 2014a) and from ACC's *Business of Chemistry* for 1990 through 2002 (ACC 2014b). As noted above, annual 2010 through 2014 production data for carbon black, ethylene, ethylene dichloride, and ethylene oxide, were obtained from EPA's GHGRP (EPA GHGRP 2015).

Acrylonitrile

Carbon dioxide and methane emissions from acrylonitrile production were estimated using the Tier 1 method in the *2006 IPCC Guidelines* (IPCC 2006). Annual acrylonitrile production data were used with IPCC default Tier 1 CO_2 and CH_4 emission factors to estimate emissions for 1990 through 2014. Emission factors used to estimate acrylonitrile production emissions are as follows:

- 0.18 kg CH_4/metric ton acrylonitrile produced

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[22] A few facilities producing ethylene dichloride used CO_2 CEMS, which has been included in the aggregated GHGRP emissions.

[23] For ethylene processes only, because nearly all process emissions are from the combustion of process off-gas. Under GHGRP, Subpart X, ethylene facilities can report emissions from burning of process gases using the optional combustion methodology for ethylene production processes, which is requires estimating emissions based on fuel quantity and carbon contents of the fuel. This is consistent with the *2006 IPCC Guidelines* (p. 3.57) which recommends including combustion emissions from fuels obtained from feedstocks (e.g., off-gases) in petrochemical production under in the IPPU sector.

[24] Available online at: http://www.ecfr.gov/cgi-bin/text-idx?tpl=/ecfrbrowse/Title40/40cfr98_main_02.tpl>

- 1.00 metric tons CO_2/metric ton acrylonitrile produced

Annual acrylonitrile production data for 1990 through 2014 were obtained from ACC's *Business of Chemistry* (ACC 2015).

Methanol

Carbon dioxide and methane emissions from methanol production were estimated using Tier 1 method in the *2006 IPCC Guidelines* (IPCC 2006). Annual methanol production data were used with IPCC default Tier 1 CO_2 and CH_4 emission factors to estimate emissions for 1990 through 2014. Emission factors used to estimate methanol production emissions are as follows:

- 2.3 kg CH_4/metric ton methanol produced
- 0.67 metric tons CO_2/metric ton methanol produced

Annual methanol production data for 1990 through 2014 were obtained from the ACC's *Business of Chemistry* (ACC 2015).

Table 4-45: Production of Selected Petrochemicals (kt)

Chemical	1990	2005	2010	2011	2012	2013	2014
Carbon Black	1,307	1,651	1,309	1,338	1,283	1,228	1,207
Ethylene	16,542	23,975	24,355	25,143	24,763	25,341	25,509
Ethylene Dichloride	6,283	11,260	8,149	8,621	11,309	11,462	11,288
Ethylene Oxide	2,429	3,220	2,925	3,014	3,106	3,148	3,138
Acrylonitrile	1,214	1,325	1,160	1,055	1,220	1,075	1,095
Methanol	3,750	1,225	730	700	995	1,235	2,105

Uncertainty and Time-Series Consistency

The CH_4 and CO_2 emission factors used for acrylonitrile and methanol production are based on a limited number of studies. Using plant-specific factors instead of default or average factors could increase the accuracy of the emission estimates; however, such data were not available for the current Inventory report.

The results of the quantitative uncertainty analysis for the CO_2 emissions from carbon black production, ethylene, ethylene dichloride, and ethylene oxide are based on reported GHGRP data. Refer to the methodology section for more details on how these emissions were calculated and reported to EPA's GHGRP. There is some uncertainty in the applicability of the average emission factors for each petrochemical type across all prior years. While petrochemical production processes in the United States have not changed significantly since 1990, some operational efficiencies have been implemented at facilities over the time series.

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 4-46. Petrochemical production CO_2 emissions were estimated to be between 25.3 and 27.8 MMT CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 5 percent below to 5 percent above the emission estimate of 26.5 MMT CO_2 Eq. Petrochemical production CH_4 emissions were estimated to be between 0.05 and 0.15 MMT CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 55 percent below to 45 percent above the emission estimate of 0.1 MMT CO_2 Eq.

Table 4-46: Approach 2 Quantitative Uncertainty Estimates for CH_4 Emissions from Petrochemical Production and CO_2 Emissions from Carbon Black Production (MMT CO_2 Eq. and Percent)

Source	Gas	2014 Emission Estimate (MMT CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (MMT CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Petrochemical Production	CO_2	26.5	25.3	27.8	-5%	+5%

Petrochemical Production	CH_4	0.1	0.05	0.15	-55%	+45%

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

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

Recalculation Discussion

Acrylonitrile production data were obtained from ACC (2015). The ACC data included annual production quantities for the 1990 through 2014 time series. These data included revised acrylonitrile production quantities for several years of the time series compared to the production data used in the previous Inventory. This update in the production data caused a change in acrylonitrile emissions compared to the previous Inventory report. As a result of this update, emissions for some years increased and emissions for other years decreased. The change in annual emissions from the previous Inventory ranged from -9 percent (in 2010) to 11 percent (in 2009).

Methanol production data for 1990 through 2014 were also obtained from ACC (2015). In the previous Inventory, methanol production data for 1990 through 2013 were obtained from ACC and Argus Media Inc. (ARGUS JJ&A 2014). As a result of this update, emissions for some years increased slightly and emissions for other years decreased slightly.

Planned Improvements

Pending resources, a potential improvement for this source category would focus on analyzing the fuel and feedstock data from EPA's GHGRP to better disaggregate energy-related emissions and allocate them more accurately between the Energy and IPPU sectors of the Inventory. Some degree of double counting may occur between CO_2 estimates of non-energy use of fuels in the energy sector and CO_2 process emissions from petrochemical production in this sector. Data integration is not feasible at this time as feedstock data from EIA used to estimate non-energy uses of fuels are aggregated by fuel type, rather than disaggregated by both fuel type and particular industries (e.g., petrochemical production). EPA, through its GHGRP, currently does not collect complete data on quantities of fuel consumed as feedstocks by petrochemical producers, only feedstock type. Updates to reporting requirements may address this issue future reporting years for the GHGRP data allowing for easier data integration between the non-energy uses of fuels category and the petrochemicals category presented in this chapter.

4.13 HCFC-22 Production (IPCC Source Category 2B9a) (TO BE UPDATED)

Trifluoromethane (HFC-23 or CHF_3) is generated as a byproduct during the manufacture of chlorodifluoromethane (HCFC-22), which is primarily employed in refrigeration and air conditioning systems and as a chemical feedstock for manufacturing synthetic polymers. Between 1990 and 2000, U.S. production of HCFC-22 increased significantly as HCFC-22 replaced chlorofluorocarbons (CFCs) in many applications. Between 2000 and 2007, U.S. production fluctuated but generally remained above 1990 levels. In 2008 and 2009, U.S. production declined markedly and has remained near 2009 levels since. Because HCFC-22 depletes stratospheric ozone, its production for non-feedstock uses is scheduled to be phased out by 2020 under the U.S. Clean Air Act.[25] Feedstock production, however, is permitted to continue indefinitely.

HCFC-22 is produced by the reaction of chloroform ($CHCl_3$) and hydrogen fluoride (HF) in the presence of a catalyst, $SbCl_5$. The reaction of the catalyst and HF produces $SbCl_xF_y$, (where $x + y = 5$), which reacts with

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[25] As construed, interpreted, and applied in the terms and conditions of the *Montreal Protocol on Substances that Deplete the Ozone Layer*. [42 U.S.C. §7671m(b), CAA §614]

chlorinated hydrocarbons to replace chlorine atoms with fluorine. The HF and chloroform are introduced by submerged piping into a continuous-flow reactor that contains the catalyst in a hydrocarbon mixture of chloroform and partially fluorinated intermediates. The vapors leaving the reactor contain HCFC-21 ($CHCl_2F$), HCFC-22 ($CHClF_2$), HFC-23 (CHF_3), HCl, chloroform, and HF. The under-fluorinated intermediates (HCFC-21) and chloroform are then condensed and returned to the reactor, along with residual catalyst, to undergo further fluorination. The final vapors leaving the condenser are primarily HCFC-22, HFC-23, HCl and residual HF. The HCl is recovered as a useful byproduct, and the HF is removed. Once separated from HCFC-22, the HFC-23 may be released to the atmosphere, recaptured for use in a limited number of applications, or destroyed.

Two facilities produced HCFC-22 in the U.S. in 2013. Emissions of HFC-23 from this activity in 2013 were estimated to be 4.1 MMT CO_2 Eq. (0.3 kt) (see Table 4-47). This quantity represents a 25 percent decrease from 2012 emissions and a 91 percent decline from 1990 emissions. The decrease from 2012 emissions and the decrease from 1990 emissions were caused by a decrease in HCFC-22 production and a decrease in the HFC-23 emission rate (kg HFC-23 emitted/kg HCFC-22 produced). The decrease in the emission rate is primarily attributable to six factors: (a) five plants that did not capture and destroy the HFC-23 generated have ceased production of HCFC-22 since 1990, (b) one plant that captures and destroys the HFC-23 generated began to produce HCFC-22, (c) one plant implemented and documented a process change that reduced the amount of HFC-23 generated, and (d) the same plant began recovering HFC-23, primarily for destruction and secondarily for sale, (e) another plant began destroying HFC-23, and (f) the same plant, whose emission factor was higher than that of the other two plants, ceased production of HCFC-22 in 2013.

Table 4-47: HFC-23 Emissions from HCFC-22 Production (MMT CO_2 Eq. and kt HFC-23)

Year	MMT CO_2 Eq.	kt HFC-23
1990	46.1	3
2005	20.0	1
2009	6.8	0.5
2010	8.0	0.5
2011	8.8	0.6
2012	5.5	0.4
2013	4.1	0.3

Methodology

To estimate HFC-23 emissions for five of the eight HCFC-22 plants that have operated in the United States since 1990, methods comparable to the Tier 3 methods in the *2006 IPCC Guidelines* (IPCC 2006) were used. Emissions for 2010 through 2013 were obtained through reports submitted by U.S. HCFC-22 production facilities to EPA's GHGRP. EPA's GHGRP mandates that all HCFC-22 production facilities report their annual emissions of HFC-23 from HCFC-22 production processes and HFC-23 destruction processes. Previously, data were obtained by EPA through collaboration with an industry association that received voluntarily reported HCFC-22 production and HFC-23 emissions annually from all U.S. HCFC-22 producers from 1990 through 2009. These emissions were aggregated and reported to EPA on an annual basis.

For the other three plants, the last of which closed in 1993, methods comparable to the Tier 1 method in the *2006 IPCC Guidelines* were used. Emissions from these three plants have been calculated using the recommended emission factor for unoptimized plants operating before 1995 (0.04 kg HCFC-23/kg HCFC-22 produced).

The five plants that have operated since 1994 measure (or, for the plants that have since closed, measured) concentrations of HFC-23 to estimate their emissions of HFC-23. Plants using thermal oxidation to abate their HFC-23 emissions monitor the performance of their oxidizers to verify that the HFC-23 is almost completely destroyed. Plants that release (or historically have released) some of their byproduct HFC-23 periodically measure HFC-23 concentrations in the output stream using gas chromatography. This information is combined with information on quantities of products (e.g., HCFC-22) to estimate HFC-23 emissions.

To estimate 1990 through 2009 emissions, reports from an industry association were used that aggregated HCFC-22 production and HFC-23 emissions from all U.S. HCFC-22 producers and reported them to EPA (ARAP 1997, 1999, 2000, 2001, 2002, 2003, 2004, 2005, 2006, 2007, 2008, 2009, 2010). To estimate 2010 through 2013 emissions, facility-level data (including both HCFC-22 production and HFC-23 emissions) reported through the EPA's GHGRP were analyzed. In 1997 and 2008, comprehensive reviews of plant-level estimates of HFC-23 emissions and HCFC-22 production were performed (RTI 1997; RTI 2008). The 1997 and 2008 reviews enabled U.S. totals to be reviewed, updated, and where necessary, corrected, and also for plant-level uncertainty analyses (Monte-Carlo simulations) to be performed for 1990, 1995, 2000, 2005, and 2006. Estimates of annual U.S. HCFC-22 production are presented in Table 4-48.

Table 4-48: HCFC-22 Production (kt)

Year	kt
1990	139
2005	156
2009	91
2010	101
2011	110
2012	96
2013	C

Note: HCFC-22 production in 2013 is considered Confidential Business Information (CBI) as there were only two producers of HCFC-22 in 2013.

Uncertainty and Time-Series Consistency

The uncertainty analysis presented in this section was based on a plant-level Monte Carlo Stochastic Simulation for 2006. The Monte Carlo analysis used estimates of the uncertainties in the individual variables in each plant's estimating procedure. This analysis was based on the generation of 10,000 random samples of model inputs from the probability density functions for each input. A normal probability density function was assumed for all measurements and biases except the equipment leak estimates for one plant; a log-normal probability density function was used for this plant's equipment leak estimates. The simulation for 2006 yielded a 95-percent confidence interval for U.S. emissions of 6.8 percent below to 9.6 percent above the reported total.

The relative errors yielded by the Monte Carlo Stochastic Simulation for 2006 were applied to the U.S. emission estimate for 2013. The resulting estimates of absolute uncertainty are likely to be reasonably accurate because (1) the methods used by the three plants to estimate their emissions are not believed to have changed significantly since 2006, and (2) although the distribution of emissions among the plants may have changed between 2006 and 2013 (because both HCFC-22 production and the HFC-23 emission rate declined significantly), the two plants that contribute significantly to emissions were estimated to have similar relative uncertainties in their 2006 (as well as 2005) emission estimates. Thus, changes in the relative contributions of these two plants to total emissions are not likely to have a large impact on the uncertainty of the national emission estimate.

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 4-49. HFC-23 emissions from HCFC-22 production were estimated to be between 3.8 and 4.5 MMT CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 7 percent below and 10 percent above the emission estimate of 4.1 MMT CO_2 Eq.

Table 4-49: Approach 2 Quantitative Uncertainty Estimates for HFC-23 Emissions from HCFC-22 Production (MMT CO_2 Eq. and Percent)

Source	Gas	2013 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
HCFC-22 Production	HFC-23	4.1	3.8	4.5	-7%	+10%

[a] Range of emissions reflects a 95 percent confidence interval.

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2013. Details on the emission trends through time are described in more detail in the Methodology section, above.

Recalculations Discussion

For the current Inventory, emission estimates have been revised to reflect the GWPs provided in the *IPCC Fourth Assessment Report* (AR4) (IPCC 2007). AR4 GWP values differ slightly from those presented in the *IPCC Second Assessment Report* (SAR) (IPCC 1996) (used in the previous inventories), which results in time-series recalculations for most inventory sources. Under the most recent reporting guidelines (UNFCCC 2014), countries are required to report using the AR4 GWPs, which reflect an updated understanding of the atmospheric properties of each greenhouse gas. The GWP of HFC-23 has increased, leading to an overall increase in emissions. For more information please see the Recalculations and Improvements Chapter.

4.14 Carbon Dioxide Consumption (IPCC Source Category 2B10)

Carbon dioxide is used for a variety of commercial applications, including food processing, chemical production, carbonated beverage production, and refrigeration, and is also used in petroleum production for enhanced oil recovery (EOR). Carbon dioxide used for EOR is injected into the underground reservoirs to increase the reservoir pressure to enable additional petroleum to be produced. For the most part, CO_2 used in non-EOR applications will eventually be released to the atmosphere, and for the purposes of this analysis CO_2 used in commercial applications other than EOR is assumed to be emitted to the atmosphere. Carbon dioxide used in EOR applications is discussed in the Energy chapter under “Carbon Capture and Storage, including Enhanced Oil Recovery” and is not discussed in this section.

Carbon dioxide is produced from naturally-occurring CO_2 reservoirs, as a byproduct from the energy and industrial production processes (e.g., ammonia production, fossil fuel combustion, ethanol production), and as a byproduct from the production of crude oil and natural gas, which contain naturally occurring CO_2 as a component. Only CO_2 produced from naturally occurring CO_2 reservoirs, and as a byproduct from energy and industrial processes, and used in industrial applications other than EOR is included in this analysis. Carbon dioxide captured from biogenic sources (e.g., ethanol production plants) is not included in the Inventory. Carbon dioxide captured from crude oil and gas production is used in EOR applications and is therefore reported in the Energy chapter.

Carbon dioxide is produced as a byproduct of crude oil and natural gas production. This CO_2 is separated from the crude oil and natural gas using gas processing equipment, and may be emitted directly to the atmosphere, or captured and reinjected into underground formations, used for EOR, or sold for other commercial uses. A further discussion of CO_2 used in EOR is described in the Energy chapter under the text box titled “Carbon Dioxide Transport, Injection, and Geological Storage.”

In 2014, the amount of CO_2 produced and captured for commercial applications and subsequently emitted to the atmosphere was 4.5 MMT CO_2 Eq. (4,471 kt) (see Table 4-50). This is an increase of approximately 7 percent from the previous year and an increase of approximately 204 percent since 1990.

Table 4-50: CO_2 Emissions from CO_2 Consumption (MMT CO_2 Eq. and kt)

Year	MMT CO_2 Eq.	kt
1990	1.5	1,472
2005	1.4	1,375

Year	MMT CO_2 Eq.	kt
2010	4.4	4,425
2011	4.1	4,083
2012	4.0	4,019
2013	4.2	4,188
2014	4.5	4,471

Methodology

Carbon dioxide emission estimates for 1990 through 2014 were based on the quantity of CO_2 extracted and transferred for industrial applications (i.e., non-EOR end-uses). Some of the CO_2 produced by these facilities is used for EOR and some is used in other commercial applications (e.g., chemical manufacturing, food production). It is assumed that 100 percent of the CO_2 production used in commercial applications other than EOR is eventually released into the atmosphere.

2010 through 2014

For 2010 through 2014, data from U.S. EPA's GHGRP (Subpart PP) were aggregated from facility-level reports to develop a national-level estimate for use in the Inventory (EPA GHGRP 2015). Facilities report CO_2 extracted or produced from natural reservoirs and industrial sites, and CO_2 captured from energy and industrial processes and transferred to various end-use applications to EPA's GHGRP. This analysis includes only reported CO_2 transferred to food and beverage end-uses. EPA is continuing to analyze and assess integration of CO_2 transferred to other end-uses to enhance the completeness of estimates under this source category. Other end-uses include industrial applications, such as metal fabrication. EPA is analyzing the information reported to ensure that other end-use data excludes non-emissive applications and publication will not reveal confidential business information. Reporters subject to EPA's GHGRP Subpart PP are also required to report the quantity of CO_2 that is imported and/or exported. Currently, these data are not publicly available through the GHGRP due to data confidentiality issues and hence are excluded from this analysis.

Facilities subject to Subpart PP of EPA's GHGRP are required to measure CO_2 extracted or produced. More details on the calculation and monitoring methods applicable to extraction and production facilities can be found under Subpart PP: Suppliers of Carbon Dioxide of the regulation, Part 98.[26] The number of facilities that reported data to EPA's GHGRP Subpart PP (Suppliers of Carbon Dioxide) for 2010 through 2014 is much higher (ranging from 44 to 48) than the number of facilities included in the Inventory for the 1990 to 2009 time period prior to the availability of GHGRP data (4 facilities). The difference is largely due to the fact the 1990 to 2009 data includes only CO_2 transferred to end-use applications from naturally occurring CO_2 reservoirs and excludes industrial sites.

1990 through 2009

For 1990 through 2009, data from EPA's GHGRP are not available. For this time period, CO_2 production data from four naturally-occurring CO_2 reservoirs were used to estimate annual CO_2 emissions. These facilities were Jackson Dome in Mississippi, Brave and West Bravo Domes in New Mexico, and McCallum Dome in Colorado. The facilities in Mississippi and New Mexico produced CO_2 for use in both EOR and in other commercial applications (e.g., chemical manufacturing, food production). The fourth facility in Colorado (McCallum Dome**)** produced CO_2 for commercial applications only (New Mexico Bureau of Geology and Mineral Resources 2006).

Carbon dioxide production data and the percentage of production that was used for non-EOR applications for the Jackson Dome, Mississippi facility were obtained from Advanced Resources International (ARI 2006, 2007) for 1990 to 2000, and from the Annual Reports of Denbury Resources (Denbury Resources 2002 through 2010) for 2001 to 2009 (see Table 4-51). Denbury Resources reported the average CO_2 production in units of MMCF CO_2 per day for 2001 through 2009 and reported the percentage of the total average annual production that was used for EOR. Production from 1990 to 1999 was set equal to 2000 production, due to lack of publicly available production

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[26] <http://www.ecfr.gov/cgi-bin/text-idx?tpl=/ecfrbrowse/Title40/40cfr98_main_02.tpl>

data for 1990 through 1999. Carbon dioxide production data for the Bravo Dome and West Bravo Dome were obtained from ARI for 1990 through 2009 (ARI 1990-2010). Data for the West Bravo Dome facility were only available for 2009. The percentage of total production that was used for non-EOR applications for the Bravo Dome and West Bravo Dome facilities for 1990 through 2009 were obtained from New Mexico Bureau of Geology and Mineral Resources (Broadhead 2003 and New Mexico Bureau of Geology and Mineral Resources 2006). Production data for the McCallum Dome (Jackson County), Colorado facility were obtained from the Colorado Oil and Gas Conservation Commission (COGCC) for 1999 through 2009 (COGCC 2014). Production data for 1990 to 1998 and percentage of production used for EOR were assumed to be the same as for 1999, due to lack of publicly-available data.

Table 4-51: CO_2 Production (kt CO_2) and the Percent Used for Non-EOR Applications

Year	Jackson Dome, MS CO_2 Production (kt) (% Non-EOR)	Bravo Dome, NM CO_2 Production (kt) (% Non-EOR)	West Bravo Dome, NM CO_2 Production (kt) (% Non-EOR)	McCallum Dome, CO CO_2 Production (kt) (% Non-EOR)	Total CO_2 Production from Extraction and Capture Facilities (kt)	% Non-EOR*
1990	1,344 (100%)	63 (1%)	+	65 (100%)	NA	NA
2005	1,254 (27%)	58 (1%)	+	63 (100%)	NA	NA
2010	NA	NA	NA	NA	64,724	7%
2011	NA	NA	NA	NA	66,241	6%
2012	NA	NA	NA	NA	66,326	6%
2013	NA	NA	NA	NA	68,435	6%
2014	NA	NA	NA	NA	71,431	6%

* Includes only food & beverage applications

\+ Does not exceed 0%.

NA – Not available. For 2010-2014, the publicly available GHGRP data were aggregated at the national level. Facility-level data are not publicly available from EPA's GHGRP.

Uncertainty and Time-Series Consistency

There is uncertainty associated with the data reported through EPA's GHGRP. As noted, reporting of end-uses is not required, so there is uncertainty associated with the amount of CO_2 consumed for food and beverage applications, in addition to the exclusion of the amount of CO_2 transferred to all other end-use categories. This latter category might include CO_2 quantities that are being used for non-EOR industrial applications such as firefighting. Second, uncertainty is associated with the exclusion of imports/exports data for CO_2 suppliers. Currently these data are not publicly available through EPA's GHGRP and hence are excluded from this analysis.

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 4-52. Carbon dioxide consumption CO_2 emissions for 2014 were estimated to be between 3.9 and 5.1 MMT CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 12 percent below to 13 percent above the emission estimate of 4.5 MMT CO_2 Eq.

Table 4-52: Approach 2 Quantitative Uncertainty Estimates for CO_2 Emissions from CO_2 Consumption (MMT CO_2 Eq. and Percent)

Source	Gas	2014 Emission Estimate (MMT CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (MMT CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
CO_2 Consumption	CO_2	4.5	3.9	5.1	-12%	+13%

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

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

Planned Improvements

EPA will continue to evaluate the potential to include additional GHGRP data on other emissive end-uses to improve accuracy and completeness of estimates for this source category.

4.15 Phosphoric Acid Production (IPCC Source Category 2B10)

Phosphoric acid (H_3PO_4) is a basic raw material used in the production of phosphate-based fertilizers. Phosphoric acid production from natural phosphate rock is a source of CO_2 emissions, due to the chemical reaction of the inorganic carbon (calcium carbonate) component of the phosphate rock.

Phosphate rock is mined in Florida, North Carolina, Idaho, and Utah and is used primarily as a raw material for wet-process phosphoric acid production. The composition of natural phosphate rock varies depending upon the location where it is mined. Natural phosphate rock mined in the United States generally contains inorganic carbon in the form of calcium carbonate (limestone) and also may contain organic carbon. The calcium carbonate component of the phosphate rock is integral to the phosphate rock chemistry. Phosphate rock can also contain organic carbon that is physically incorporated into the mined rock but is not an integral component of the phosphate rock chemistry.

The phosphoric acid production process involves chemical reaction of the calcium phosphate ($Ca_3(PO_4)_2$) component of the phosphate rock with sulfuric acid (H_2SO_4) and recirculated phosphoric acid (H_3PO_4) (EFMA 2000). However, the generation of CO_2 is due to the associated limestone-sulfuric acid reaction, as shown below:

$$CaCO_3 + H_2SO_4 + H_2O \rightarrow CaSO_4 \bullet 2H_2O + CO_2$$

Total U.S. phosphate rock production sold or used in 2014 was 28.1 million metric tons (USGS 2015a). Approximately 80 percent of domestic phosphate rock production was mined in Florida and North Carolina, while the remaining 20 percent of production was mined in Idaho and Utah. Total imports of phosphate rock in 2014 were approximately 2.6 million metric tons (USGS 2015a). Most of the imported phosphate rock (74 percent) is from Morocco, with the remaining 26 percent being from Peru (USGS 2015a). All phosphate rock mining companies are vertically integrated with fertilizer plants that produce phosphoric acid located near the mines. Some additional phosphoric acid production facilities are located in Texas, Louisiana, and Mississippi that used imported phosphate rock.

Over the 1990 to 2014 period, domestic production has decreased by nearly 44 percent. Total CO_2 emissions from phosphoric acid production were 1.1 MMT CO_2 Eq. (1,095 kt CO_2) in 2014 (see Table 4-53). Domestic consumption of phosphate rock in 2014 was estimated to have decreased by approximately 2 percent over 2013 levels, owing to producers drawing from higher than average inventories and the closure of a mine in Florida. Domestic consumption also decreased because of lower phosphoric acid and fertilizer production (USGS 2015a).

Table 4-53: CO_2 Emissions from Phosphoric Acid Production (MMT CO_2 Eq. and kt)

Year	MMT CO_2 Eq.	kt
1990	1.5	1,529
2005	1.3	1,342
2010	1.1	1,087
2011	1.2	1,151
2012	1.1	1,093
2013	1.1	1,119
2014	1.1	1,095

Methodology

Carbon dioxide emissions from production of phosphoric acid from phosphate rock are estimated by multiplying the average amount of inorganic carbon (expressed as CO_2) contained in the natural phosphate rock as calcium carbonate by the amount of phosphate rock that is used annually to produce phosphoric acid, accounting for domestic production and net imports for consumption. The estimation methodology is as follows:

$$E_{pa} = C_{pr} \times Q_{pr}$$

where,

E_{pa} = CO_2 emissions from phosphoric acid production, metric tons
C_{pr} = Average amount of carbon (expressed as CO_2) in natural phosphate rock, metric ton CO_2/ metric ton phosphate rock
Q_{pr} = Quantity of phosphate rock used to produce phosphoric acid

The CO_2 emissions calculation methodology is based on the assumption that all of the inorganic carbon (calcium carbonate) content of the phosphate rock reacts to produce CO_2 in the phosphoric acid production process and is emitted with the stack gas. The methodology also assumes that none of the organic carbon content of the phosphate rock is converted to CO_2 and that all of the organic carbon content remains in the phosphoric acid product.

From 1993 to 2004, the *USGS Mineral Yearbook: Phosphate Rock* disaggregated phosphate rock mined annually in Florida and North Carolina from phosphate rock mined annually in Idaho and Utah, and reported the annual amounts of phosphate rock exported and imported for consumption (see Table 4-54). For the years 1990 through 1992, and 2005 through 2014, only nationally aggregated mining data was reported by USGS. For the years 1990, 1991, and 1992, the breakdown of phosphate rock mined in Florida and North Carolina, and the amount mined in Idaho and Utah, are approximated using average share of U.S. production in those states from 1993 to 2004 data. For the years 2005 through 2014, the same approximation method is used, but the share of U.S. production in those states data were obtained from the USGS commodity specialist for phosphate rock (USGS 2012). Data for domestic sales or consumption of phosphate rock, exports of phosphate rock (primarily from Florida and North Carolina), and imports of phosphate rock for consumption for 1990 through 2014 were obtained from *USGS Minerals Yearbook: Phosphate Rock* (USGS 1994 through 2015b), and from *USGS Minerals Commodity Summaries: Phosphate Rock in 2015* (USGS 2015a). From 2004 through 2014, the USGS reported no exports of phosphate rock from U.S. producers (USGS 2005 through 2015b).

The carbonate content of phosphate rock varies depending upon where the material is mined. Composition data for domestically mined and imported phosphate rock were provided by the Florida Institute of Phosphate Research (FIPR 2003a). Phosphate rock mined in Florida contains approximately 1 percent inorganic carbon, and phosphate rock imported from Morocco contains approximately 1.46 percent inorganic carbon. Calcined phosphate rock mined in North Carolina and Idaho contains approximately 0.41 percent and 0.27 percent inorganic carbon, respectively (see Table 4-55).

Carbonate content data for phosphate rock mined in Florida are used to calculate the CO_2 emissions from consumption of phosphate rock mined in Florida and North Carolina (80 percent of domestic production) and carbonate content data for phosphate rock mined in Morocco are used to calculate CO_2 emissions from consumption of imported phosphate rock. The CO_2 emissions calculation is based on the assumption that all of the domestic production of phosphate rock is used in uncalcined form. As of 2006, the USGS noted that one phosphate rock producer in Idaho produces calcined phosphate rock; however, no production data were available for this single producer (USGS 2006). The USGS confirmed that no significant quantity of domestic production of phosphate rock is in the calcined form (USGS 2012b).

Table 4-54: Phosphate Rock Domestic Consumption, Exports, and Imports (kt)

Location/Year	1990	2005	2010	2011	2012	2013	2014
U.S. Domestic Consumption	49,800	35,200	28,100	28,600	27,300	28,800	28,100
FL and NC	42,494	28,160	22,480	22,880	21,840	23,040	22,480
ID and UT	7,306	7,040	5,620	5,720	5,460	5,760	5,620
Exports—FL and NC	6,240	-	-	-	-	-	-

Imports	451		2,630		2,400	3,350	3,080	2,560	2,570
Total U.S. Consumption	**44,011**		**37,830**		**30,500**	**31,950**	**30,380**	**31,360**	**30,670**

Table 4-55: Chemical Composition of Phosphate Rock (Percent by weight)

Composition	Central Florida	North Florida	North Carolina (calcined)	Idaho (calcined)	Morocco
Total Carbon (as C)	1.60	1.76	0.76	0.60	1.56
Inorganic Carbon (as C)	1.00	0.93	0.41	0.27	1.46
Organic Carbon (as C)	0.60	0.83	0.35	0.00	0.10
Inorganic Carbon (as CO_2)	3.67	3.43	1.50	1.00	5.00

Source: FIPR 2003a

Uncertainty and Time-Series Consistency

Phosphate rock production data used in the emission calculations were developed by the USGS through monthly and semiannual voluntary surveys of the active phosphate rock mines during 2014. For previous years in the time series, USGS provided the data disaggregated regionally; however, beginning in 2006, only total U.S. phosphate rock production was reported. Regional production for 2014 was estimated based on regional production data from previous years and multiplied by regionally-specific emission factors. There is uncertainty associated with the degree to which the estimated 2014 regional production data represents actual production in those regions. Total U.S. phosphate rock production data are not considered to be a significant source of uncertainty because all the domestic phosphate rock producers report their annual production to the USGS. Data for exports of phosphate rock used in the emission calculation are reported by phosphate rock producers and are not considered to be a significant source of uncertainty. Data for imports for consumption are based on international trade data collected by the U.S. Census Bureau. These U.S. government economic data are not considered to be a significant source of uncertainty.

An additional source of uncertainty in the calculation of CO_2 emissions from phosphoric acid production is the carbonate composition of phosphate rock; the composition of phosphate rock varies depending upon where the material is mined, and may also vary over time. The Inventory relies on one study (FIPR 2003a) of chemical composition of the phosphate rock; limited data are available beyond this study. Another source of uncertainty is the disposition of the organic carbon content of the phosphate rock. A representative of the FIPR indicated that in the phosphoric acid production process, the organic C content of the mined phosphate rock generally remains in the phosphoric acid product, which is what produces the color of the phosphoric acid product (FIPR 2003b). Organic carbon is therefore not included in the calculation of CO_2 emissions from phosphoric acid production.

A third source of uncertainty is the assumption that all domestically-produced phosphate rock is used in phosphoric acid production and used without first being calcined. Calcination of the phosphate rock would result in conversion of some of the organic C in the phosphate rock into CO_2. However, according to air permit information available to the public, at least one facility has calcining units permitted for operation (NCDENR 2013).

Finally, USGS indicated that approximately 7 percent of domestically-produced phosphate rock is used to manufacture elemental phosphorus and other phosphorus-based chemicals, rather than phosphoric acid (USGS 2006). According to USGS, there is only one domestic producer of elemental phosphorus, in Idaho, and no data were available concerning the annual production of this single producer. Elemental phosphorus is produced by reducing phosphate rock with coal coke, and it is therefore assumed that 100 percent of the carbonate content of the phosphate rock will be converted to CO_2 in the elemental phosphorus production process. The calculation for CO_2 emissions is based on the assumption that phosphate rock consumption, for purposes other than phosphoric acid production, results in CO_2 emissions from 100 percent of the inorganic carbon content in phosphate rock, but none from the organic carbon content.

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 4-56. Phosphoric acid production CO_2 emissions were estimated to be between 0.9 and 1.4 MMT CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 19 percent below and 20 percent above the emission estimate of 1.1 MMT CO_2 Eq.

Table 4-56: Approach 2 Quantitative Uncertainty Estimates for CO_2 Emissions from Phosphoric Acid Production (MMT CO_2 Eq. and Percent)

Source	Gas	2014 Emission Estimate (MMT CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (MMT CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Phosphoric Acid Production	CO_2	1.1	0.9	1.4	-19%	+20%

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

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

Recalculations Discussion

Relative to the previous Inventory, the phosphate rock consumption data (sold or used and imports for consumption) for 2013 were revised based on updated data publicly available from USGS (USGS 2015). This revision caused a decrease in the 2013 emission estimate by approximately 2 percent.

Additionally, during the development of the current Inventory emission estimates, it was discovered that the phosphate rock CO_2 content had been incorrectly transcribed in the previous Inventory. This error was corrected in the current Inventory and resulted in a slight change of emissions over the entire time series.

Planned Improvements

EPA continues to evaluate potential improvements to the Inventory estimates for this source category, which include direct integration of GHGRP data for 2010 through 2014 and the use of reported GHGRP data to update the inorganic C content of phosphate rock for prior years. In order to provide estimates for the entire time series (i.e., 1990 through 2009), the applicability of EPA's GHGRP data for the averaged inorganic C content data (by region) from 2010 through 2014 to previous years' estimates will need to be evaluated. 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.[27]

4.16 Iron and Steel Production (IPCC Source Category 2C1) and Metallurgical Coke Production

Iron and steel production is a multi-step process that generates process-related emissions of CO_2 and CH_4 as raw materials are refined into iron and then transformed into crude steel. Emissions from conventional fuels (e.g., natural gas, fuel oil, etc.) consumed for energy purposes during the production of iron and steel are accounted for in the Energy chapter.

Iron and steel production includes six distinct production processes: coke production, sinter production, direct reduced iron (DRI) production, pig iron production, electric arc furnace (EAF) steel production, and basic oxygen furnace (BOF) steel production. The number of production processes at a particular plant is dependent upon the specific plant configuration. In addition to the production processes mentioned above, CO_2 is also generated at iron

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

and steel mills through the consumption of process byproducts (e.g., blast furnace gas, coke oven gas, etc.) used for various purposes including heating, annealing, and electricity generation. Process byproducts sold for use as synthetic natural gas are deducted and reported in the Energy chapter. In general, CO_2 emissions are generated in these production processes through the reduction and consumption of various carbon-containing inputs (e.g., ore, scrap, flux, coke byproducts, etc.). In addition, fugitive CH_4 emissions are also generated by the sinter production process.

Currently, there are between 15 and 20 integrated iron and steel steelmaking facilities that utilize BOFs to refine and produce steel from iron and more than 100 steelmaking facilities that utilize EAFs to produce steel primarily from recycled ferrous scrap. In addition, there are 18 cokemaking facilities, of which 7 facilities are co-located with integrated iron and steel facilities. Slightly more than 62 percent of the raw steel produced in the United States is produced in one of seven states: Alabama, Arkansas, Indiana, Kentucky, Mississippi, Ohio, and Tennessee (AISI 2015a).

Total production of crude steel in the United States between 2000 and 2008 ranged from a low of 99,320,000 tons to a high of 109,880,000 tons (2001 and 2004, respectively). Due to the decrease in demand caused by the global economic downturn (particularly from the automotive industry), crude steel production in the United States sharply decreased to 65,459,000 tons in 2009. In 2010, crude steel production rebounded to 88,731,000 tons as economic conditions improved and then continued to increase to 95,237,000 tons in 2011 and 97,770,000 tons in 2012; crude steel production slightly decreased to 95,766,000 tons in 2013 and then slightly increased to 97,195,000 tons in 2014 (AISI 2015a). The United States was the third largest producer of raw steel in the world, behind China and Japan, accounting for approximately 5.3 percent of world production in 2013 (AISI 2015a).

The majority of CO_2 emissions from the iron and steel production process come from the use of coke in the production of pig iron and from the consumption of other process byproducts, with lesser amounts emitted from the use of flux and from the removal of carbon from pig iron used to produce steel.

According to the *2006 IPCC Guidelines* (IPCC 2006), the production of metallurgical coke from coking coal is considered to be an energy use of fossil fuel and the use of coke in iron and steel production is considered to be an industrial process source. Therefore, the *2006 IPCC Guidelines* suggest that emissions from the production of metallurgical coke should be reported separately in the Energy sector, while emissions from coke consumption in iron and steel production should be reported in the IPPU sector. However, the approaches and emission estimates for both metallurgical coke production and iron and steel production are both presented here because much of the relevant activity data is used to estimate emissions from both metallurgical coke production and iron and steel production. For example, some byproducts (e.g., coke oven gas, etc.) of the metallurgical coke production process are consumed during iron and steel production, and some byproducts of the iron and steel production process (e.g., blast furnace gas, etc.) are consumed during metallurgical coke production. Emissions associated with the consumption of these byproducts are attributed at the point of consumption. Emissions associated with the use of conventional fuels (e.g., natural gas, fuel oil, etc.) for electricity generation, heating and annealing, or other miscellaneous purposes downstream of the iron and steelmaking furnaces are reported in the Energy chapter.

Metallurgical Coke Production

Emissions of CO_2 from metallurgical coke production in 2014 were 1.9 MMT CO_2 Eq. (1,938 kt CO_2) (see Table 4-57 and Table 4-58). Emissions increased in 2014 from 2013 levels, but have decreased overall since 1990. Domestic coke production data for 2014 are not yet published and so 2013 data were used as proxy for 2014. Coke production in 2014 was 26 percent lower than in 2000 and 45 percent below 1990. Overall, emissions from metallurgical coke production have declined by 23 percent (0.6 MMT CO_2 Eq.) from 1990 to 2014.

Table 4-57: CO_2 Emissions from Metallurgical Coke Production (MMT CO_2 Eq.)

Gas	1990	2005	2010	2011	2012	2013	2014
CO_2	2.5	2.0	2.1	1.4	0.5	1.8	1.9
Total	**2.5**	**2.0**	**2.1**	**1.4**	**0.5**	**1.8**	**1.9**

Table 4-58: CO_2 Emissions from Metallurgical Coke Production (kt)

Gas	1990	2005	2010	2011	2012	2013	2014
CO_2	2,503	2,044	2,085	1,426	543	1,824	1,938

Iron and Steel Production

Emissions of CO_2 and CH_4 from iron and steel production in 2014 were 53.4 MMT CO_2 Eq. (53,417 kt) and 0.0094 MMT CO_2 Eq. (0.4 kt), respectively (see Table 4-59 through Table 4-62), totaling approximately 53.4 MMT CO_2 Eq. Emissions decreased in 2014 and have decreased overall since 1990 due to restructuring of the industry, technological improvements, and increased scrap steel utilization. Carbon dioxide emission estimates include emissions from the consumption of carbonaceous materials in the blast furnace, EAF, and BOF, as well as blast furnace gas and coke oven gas consumption for other activities at the steel mill.

In 2014, domestic production of pig iron decreased by 3 percent from 2013 levels. Overall, domestic pig iron production has declined since the 1990s. Pig iron production in 2014 was 39 percent lower than in 2000 and 41 percent below 1990. Carbon dioxide emissions from steel production have decreased by 4 percent (0.3 MMT CO_2 Eq.) since 1990, while overall CO_2 emissions from iron and steel production have declined by 45 percent (43.7 MMT CO_2 Eq.) from 1990 to 2014.

Table 4-59: CO_2 Emissions from Iron and Steel Production (MMT CO_2 Eq.)

Source/Activity Data	1990	2005	2010	2011	2012	2013	2014
Sinter Production	2.4	1.7	1.0	1.2	1.2	1.1	1.1
Iron Production	45.6	17.5	17.8	18.4	10.9	11.9	16.8
Steel Production	7.9	9.4	9.2	9.3	9.9	8.6	7.6
Other Activities[a]	41.2	35.9	25.5	29.7	31.7	28.7	27.9
Total	**97.2**	**64.5**	**53.6**	**58.5**	**53.7**	**50.4**	**53.4**

[a] Includes emissions from blast furnace gas and coke oven gas combustion for activities at the steel mill other than consumption in blast furnace, EAFs, or BOFs.

Note: Totals may not sum due to independent rounding.

Table 4-60: CO_2 Emissions from Iron and Steel Production (kt)

Source/Activity Data	1990	2005	2010	2011	2012	2013	2014
Sinter Production	2,448	1,663	1,045	1,188	1,159	1,117	1,104
Iron Production	45,592	17,545	17,802	18,375	10,917	11,934	16,754
Steel Production	7,933	9,356	9,235	9,255	9,860	8,617	7,648
Other Activities [a]	41,193	35,934	25,504	29,683	31,750	28,709	27,911
Total	**97,166**	**64,499**	**53,586**	**58,501**	**53,686**	**50,378**	**53,417**

[a] Includes emissions from blast furnace gas and coke oven gas combustion for activities at the steel mill other than consumption in blast furnace, EAFs, or BOFs.

Note: Totals may not sum due to independent rounding.

Table 4-61: CH_4 Emissions from Iron and Steel Production (MMT CO_2 Eq.)

Source/Activity Data	1990	2005	2010	2011	2012	2013	2014
Sinter Production	+	+	+	+	+	+	+
Total	**+**	**+**	**+**	**+**	**+**	**+**	**+**

\+ Does not exceed 0.05 MMT CO_2 Eq.

Table 4-62: CH_4 Emissions from Iron and Steel Production (kt)

Source/Activity Data	1990	2005	2010	2011	2012	2013	2014
Sinter Production	0.9	0.6	0.4	0.4	0.4	0.4	0.4
Total	**0.9**	**0.6**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**

Methodology

Emission estimates presented in this chapter are largely based on Tier 2 methodologies provided by the *2006 IPCC Guidelines* (IPCC 2006). These Tier 2 methodologies call for a mass balance accounting of the carbonaceous inputs and outputs during the iron and steel production process and the metallurgical coke production process. Tier 1 methods are used for certain iron and steel production processes (i.e., sinter production and DRI production) for which available data are insufficient for utilizing a Tier 2 method.

The Tier 2 methodology equation is as follows:

$$E_{CO_2} = \left[\sum_a (Q_a \times C_a) - \sum_b (Q_b \times C_b)\right] \times \frac{44}{12}$$

where,

E_{CO2} = Emissions from coke, pig iron, EAF steel, or BOF steel production, metric tons
a = Input material *a*
b = Output material *b*
Q_a = Quantity of input material *a*, metric tons
C_a = Carbon content of input material *a*, metric tons C/metric ton material
Q_b = Quantity of output material *b*, metric tons
C_b = Carbon content of output material *b*, metric tons C/metric ton material
44/12 = Stoichiometric ratio of CO_2 to C

The Tier 1 methodology equations are as follows:

$$E_{s,p} = Q_s \times EF_{s,p}$$

$$E_{d,CO2} = Q_d \times EF_{d,CO2}$$

where,

$E_{s,p}$ = Emissions from sinter production process for pollutant *p* (CO_2 or CH_4), metric ton
Q_s = Quantity of sinter produced, metric tons
$EF_{s,p}$ = Emission factor for pollutant *p* (CO_2 or CH_4), metric ton *p*/metric ton sinter
$E_{d,CO2}$ = Emissions from DRI production process for CO_2, metric ton
Q_d = Quantity of DRI produced, metric tons
$EF_{d,CO2}$ = Emission factor for CO_2, metric ton CO_2/metric ton DRI

Metallurgical Coke Production

Coking coal is used to manufacture metallurgical coke that is used primarily as a reducing agent in the production of iron and steel, but is also used in the production of other metals including zinc and lead (see Zinc Production and Lead Production sections of this chapter). Emissions associated with producing metallurgical coke from coking coal are estimated and reported separately from emissions that result from the iron and steel production process. To estimate emissions from metallurgical coke production, a Tier 2 method provided by the *2006 IPCC Guidelines* (IPCC 2006) was utilized. The amount of carbon contained in materials produced during the metallurgical coke production process (i.e., coke, coke breeze, coke oven gas, and coal tar) is deducted from the amount of carbon contained in materials consumed during the metallurgical coke production process (i.e., natural gas, blast furnace gas, and coking coal). Light oil, which is produced during the metallurgical coke production process, is excluded from the deductions due to data limitations. The amount of carbon contained in these materials is calculated by multiplying the material-specific carbon content by the amount of material consumed or produced (see Table 4-63). The amount of coal tar produced was approximated using a production factor of 0.03 tons of coal tar per ton of coking coal consumed. The amount of coke breeze produced was approximated using a production factor of 0.075 tons of coke breeze per ton of coking coal consumed (AISI 2008c; DOE 2000). Data on the consumption of carbonaceous materials (other than coking coal) as well as coke oven gas production were available for integrated steel mills only (i.e., steel mills with co-located coke plants). Therefore, carbonaceous material (other than coking coal) consumption and coke oven gas production were excluded from emission estimates for merchant coke plants. Carbon contained in coke oven gas used for coke-oven underfiring was not included in the deductions to avoid double-counting.

Table 4-63: Material Carbon Contents for Metallurgical Coke Production

Material	kg C/kg
Coal Tar	0.62
Coke	0.83
Coke Breeze	0.83
Coking Coal	0.73
Material	**kg C/GJ**
Coke Oven Gas	12.1
Blast Furnace Gas	70.8

Source: IPCC 2006, Table 4.3. Coke Oven Gas and Blast Furnace Gas, Table 1.3.

Although the *2006 IPCC Guidelines* provide a Tier 1 CH_4 emission factor for metallurgical coke production (i.e., 0.1 g CH_4 per metric ton of coke production), it is not appropriate to use because CO_2 emissions were estimated using the Tier 2 mass balance methodology. The mass balance methodology makes a basic assumption that all carbon that enters the metallurgical coke production process either exits the process as part of a carbon-containing output or as CO_2 emissions. A preliminary assessment of facility-level greenhouse gas emissions reported by coke production facilities under EPA's GHGRP also indicates that CH_4 emissions from coke production are low. Estimation of CH_4 emissions using a Tier 1 approach to estimate these emissions is likely to significantly overestimate these emissions. EPA is currently finalizing compilation of this information to include in the Inventory.

Data relating to the mass of coking coal consumed at metallurgical coke plants and the mass of metallurgical coke produced at coke plants were taken from the Energy Information Administration (EIA), *Quarterly Coal Report: October through December* (EIA 1998 through 2015a) (see Table 4-64). Data on the volume of natural gas consumption, blast furnace gas consumption, and coke oven gas production for metallurgical coke production at integrated steel mills were obtained from the American Iron and Steel Institute (AISI), *Annual Statistical Report* (AISI 2004 through 2015a) and through personal communications with AISI (2008c) (see Table 4-65). The factor for the quantity of coal tar produced per ton of coking coal consumed was provided by AISI (2008c). The factor for the quantity of coke breeze produced per ton of coking coal consumed was obtained through Table 2-1 of the report *Energy and Environmental Profile of the U.S. Iron and Steel Industry* (DOE 2000). Data on natural gas consumption and coke oven gas production at merchant coke plants were not available and were excluded from the emission estimate. Carbon contents for coking coal, metallurgical coke, coal tar, coke oven gas, and blast furnace gas were provided by the *2006 IPCC Guidelines* (IPCC 2006). The carbon content for coke breeze was assumed to equal the carbon content of coke.

Table 4-64: Production and Consumption Data for the Calculation of CO_2 and CH_4 Emissions from Metallurgical Coke Production (Thousand Metric Tons)

Source/Activity Data	1990	2005	2010	2011	2012	2013	2014[a]
Metallurgical Coke Production							
Coking Coal Consumption at Coke Plants	35,269	21,259	19,135	19,445	18,825	19,481	19,481
Coke Production at Coke Plants	25,054	15,167	13,628	13,989	13,764	13,898	13,898
Coal Breeze Production	2,645	1,594	1,435	1,458	1,412	1,461	1,461
Coal Tar Production	1,058	638	574	583	565	584	584

[a] 2013 data were used as a proxy because 2014 data are not yet published.

Table 4-65: Production and Consumption Data for the Calculation of CO_2 Emissions from Metallurgical Coke Production (Million ft^3)

Source/Activity Data	1990	2005	2010	2011	2012	2013	2014
Metallurgical Coke Production							
Coke Oven Gas Production	250,767	114,213	95,405	109,044	113,772	108,162	102,899
Natural Gas Consumption	599	2,996	3,108	3,175	3,267	3,247	3,039
Blast Furnace Gas Consumption	24,602	4,460	3,181	3,853	4,351	4,255	4,346

Iron and Steel Production

Emissions of CO_2 from sinter production and direct reduced iron production were estimated by multiplying total national sinter production and the total national direct reduced iron production by Tier 1 CO_2 emission factors (see Table 4-66). Because estimates of sinter production and direct reduced iron production were not available, production was assumed to equal consumption.

Table 4-66: CO_2 Emission Factors for Sinter Production and Direct Reduced Iron Production

Material Produced	Metric Ton CO_2/Metric Ton
Sinter	0.2
Direct Reduced Iron	0.7

Source: IPCC 2006, Table 4.1.

To estimate emissions from pig iron production in the blast furnace, the amount of carbon contained in the produced pig iron and blast furnace gas were deducted from the amount of carbon contained in inputs (i.e., metallurgical coke, sinter, natural ore, pellets, natural gas, fuel oil, coke oven gas, and direct coal injection). The carbon contained in the pig iron, blast furnace gas, and blast furnace inputs was estimated by multiplying the material-specific carbon content by each material type (see Table 4-67). Carbon in blast furnace gas used to pre-heat the blast furnace air is combusted to form CO_2 during this process. Carbon contained in blast furnace gas used as a blast furnace input was not included in the deductions to avoid double-counting.

Emissions from steel production in EAFs were estimated by deducting the carbon contained in the steel produced from the carbon contained in the EAF anode, charge carbon, and scrap steel added to the EAF. Small amounts of carbon from direct reduced iron, pig iron, and flux additions to the EAFs were also included in the EAF calculation. For BOFs, estimates of carbon contained in BOF steel were deducted from carbon contained in inputs such as natural gas, coke oven gas, fluxes, and pig iron. In each case, the carbon was calculated by multiplying material-specific carbon contents by each material type (see Table 4-67). For EAFs, the amount of EAF anode consumed was approximated by multiplying total EAF steel production by the amount of EAF anode consumed per metric ton of steel produced (0.002 metric tons EAF anode per metric ton steel produced [AISI 2008c]). The amount of flux (e.g., limestone and dolomite) used during steel manufacture was deducted from the Other Process Uses of Carbonates source category to avoid double-counting.

Carbon dioxide emissions from the consumption of blast furnace gas and coke oven gas for other activities occurring at the steel mill were estimated by multiplying the amount of these materials consumed for these purposes by the material-specific carbon content (see Table 4-67).

Carbon dioxide emissions associated with the sinter production, direct reduced iron production, pig iron production, steel production, and other steel mill activities were summed to calculate the total CO_2 emissions from iron and steel production (see Table 4-59 and Table 4-60).

Table 4-67: Material Carbon Contents for Iron and Steel Production

Material	kg C/kg
Coke	0.83
Direct Reduced Iron	0.02

Dolomite	0.13
EAF Carbon Electrodes	0.82
EAF Charge Carbon	0.83
Limestone	0.12
Pig Iron	0.04
Steel	0.01
Material	**kg C/GJ**
Coke Oven Gas	12.1
Blast Furnace Gas	70.8

Source: IPCC 2006, Table 4.3. Coke Oven Gas and Blast Furnace Gas, Table 1.3.

The production process for sinter results in fugitive emissions of CH_4, which are emitted via leaks in the production equipment, rather than through the emission stacks or vents of the production plants. The fugitive emissions were calculated by applying Tier 1 emission factors taken from the *2006 IPCC Guidelines* (IPCC 2006) for sinter production (see Table 4-68). Although the *1995 IPCC Guidelines* (IPCC/UNEP/OECD/IEA 1995) provide a Tier 1 CH_4 emission factor for pig iron production, it is not appropriate to use because CO_2 emissions were estimated using the Tier 2 mass balance methodology. The mass balance methodology makes a basic assumption that all carbon that enters the pig iron production process either exits the process as part of a carbon-containing output or as CO_2 emissions; the estimation of CH_4 emissions is precluded. A preliminary analysis of facility-level emissions reported by sinter facilities further supports this assumption and indicates that CH_4 emissions are very low to negligible. Estimation of CH_4 emissions using a Tier 1 approach will significantly overestimate these emissions. The production of direct reduced iron also results in emissions of CH_4 through the consumption of fossil fuels (e.g., natural gas, etc.); however, these emission estimates are excluded due to data limitations.

Table 4-68: CH_4 Emission Factors for Sinter and Pig Iron Production

Material Produced	Factor	Unit
Sinter	0.07	kg CH_4/metric ton

Source: Sinter (IPCC 2006, Table 4.2)

Sinter consumption data for 1990 through 2014 were obtained from AISI's *Annual Statistical Report* (AISI 2004 through 2015a) and through personal communications with AISI (2008c) (see Table 4-69). In general, direct reduced iron (DRI) consumption data were obtained from the *USGS Minerals Yearbook – Iron and Steel Scrap* (USGS 1991 through 2014) and personal communication with the USGS Iron and Steel Commodity Specialist (Fenton 2015). However, data for DRI consumed in EAFs were not available for the years 1990 and 1991. EAF DRI consumption in 1990 and 1991 was calculated by multiplying the total DRI consumption for all furnaces by the EAF share of total DRI consumption in 1992. Also, data for DRI consumed in BOFs were not available for the years 1990 through 1993. BOF DRI consumption in 1990 through 1993 was calculated by multiplying the total DRI consumption for all furnaces (excluding EAFs and cupola) by the BOF share of total DRI consumption (excluding EAFs and cupola) in 1994.

The Tier 1 CO_2 emission factors for sinter production and direct reduced iron production were obtained through the *2006 IPCC Guidelines* (IPCC 2006). Time series data for pig iron production, coke, natural gas, fuel oil, sinter, and pellets consumed in the blast furnace; pig iron production; and blast furnace gas produced at the iron and steel mill and used in the metallurgical coke ovens and other steel mill activities were obtained from AISI's Annual Statistical Report (AISI 2004 through 2015a) and through personal communications with AISI (2008c) (see Table 4-69 and Table 4-70).

Data for EAF steel production, flux, EAF charge carbon, and natural gas consumption were obtained from AISI's *Annual Statistical Report* (AISI 2004 through 2015a) and through personal communications with AISI (2006 through 2015b and 2008c). The factor for the quantity of EAF anode consumed per ton of EAF steel produced was provided by AISI (2008c). Data for BOF steel production, flux, natural gas, natural ore, pellet sinter consumption as well as BOF steel production were obtained from AISI's *Annual Statistical Report* (AISI 2004 through 2015a) and through personal communications with AISI (2008c). Data for EAF and BOF scrap steel, pig iron, and DRI consumption were obtained from the *USGS Minerals Yearbook – Iron and Steel Scrap* (USGS 1991 through 2014). Data on coke oven gas and blast furnace gas consumed at the iron and steel mill (other than in the EAF, BOF, or blast furnace) were obtained from AISI's *Annual Statistical Report* (AISI 2004 through 2015a) and through personal communications with AISI (2008c).

Data on blast furnace gas and coke oven gas sold for use as synthetic natural gas were obtained from EIA's *Natural Gas Annual* (EIA 2015a). Carbon contents for direct reduced iron, EAF carbon electrodes, EAF charge carbon, limestone, dolomite, pig iron, and steel were provided by the *2006 IPCC Guidelines* (IPCC 2006). The carbon contents for natural gas, fuel oil, and direct injection coal were obtained from EIA (2015b) and EPA (2010). Heat contents for fuel oil and direct injection coal were obtained from EIA (1992, 2011); natural gas heat content was obtained from Table 37 of AISI's *Annual Statistical Report* (AISI 2004 through 2015a). Heat contents for coke oven gas and blast furnace gas were provided in Table 37 of AISI's *Annual Statistical Report* (AISI 2004 through 2015a) and confirmed by AISI staff (Carroll 2015).

Table 4-69: Production and Consumption Data for the Calculation of CO_2 and CH_4 Emissions from Iron and Steel Production (Thousand Metric Tons)

Source/Activity Data	1990	2005	2010	2011	2012	2013	2014
Sinter Production							
Sinter Production	12,239	8,315	5,225	5,941	5,795	5,583	5,521
Direct Reduced Iron Production							
Direct Reduced Iron Production	516	1,303	1,441	1,582	3,530	3,350	2,113
Pig Iron Production							
Coke Consumption	24,946	13,832	10,883	11,962	9,571	9,308	11,136
Pig Iron Production	49,669	37,222	26,844	30,228	32,063	30,309	29,375
Direct Injection Coal Consumption	1,485	2,573	2,279	2,604	2,802	2,675	2,425
EAF Steel Production							
EAF Anode and Charge Carbon Consumption	67	1,127	1,189	1,257	1,318	1,122	1,127
Scrap Steel Consumption	42,691	46,600	47,500	50,500	50,900	47,300	48,873
Flux Consumption	319	695	640	726	748	771	771
EAF Steel Production	33,511	52,194	49,339	52,108	52,415	52,641	55,174
BOF Steel Production							
Pig Iron Consumption	47,307	34,400	31,200	31,300	31,500	29,600	23,755
Scrap Steel Consumption	14,713	11,400	9,860	8,800	8,350	7,890	5,917
Flux Consumption	576	582	431	454	476	454	454
BOF Steel Production	43,973	42,705	31,158	34,291	36,282	34,238	33,000

Table 4-70: Production and Consumption Data for the Calculation of CO_2 Emissions from Iron and Steel Production (Million ft^3 unless otherwise specified)

Source/Activity Data	1990	2005	2010	2011	2012	2013	2014
Pig Iron Production							
Natural Gas Consumption	56,273	59,844	47,814	59,132	62,469	48,812	47,734
Fuel Oil Consumption (thousand gallons)	163,397	16,170	27,505	21,378	19,240	17,468	16,674
Coke Oven Gas Consumption	22,033	16,557	14,233	17,772	18,608	17,710	16,896
Blast Furnace Gas Production	1,439,380	1,299,980	911,180	1,063,326	1,139,578	1,026,973	1,000,536
EAF Steel Production							
Natural Gas Consumption	15,905	19,985	10,403	6,263	11,145	10,514	9,622
BOF Steel Production							
Coke Oven Gas Consumption	3,851	524	546	554	568	568	524

Other Activities							
Coke Oven Gas Consumption	224,883	97,132	80,626	90,718	94,596	89,884	85,479
Blast Furnace Gas Consumption	1,414,778	1,295,520	907,999	1,059,473	1,135,227	1,022,718	996,190

Uncertainty and Time-Series Consistency

The estimates of CO_2 emissions from metallurgical coke production are based on material production and consumption data and average carbon contents. Uncertainty is associated with the total U.S. coking coal consumption, total U.S. coke production and materials consumed during this process. Data for coking coal consumption and metallurgical coke production are from different data sources (EIA) than data for other carbonaceous materials consumed at coke plants (AISI), which does not include data for merchant coke plants. There is uncertainty associated with the fact that coal tar and coke breeze production were estimated based on coke production because coal tar and coke breeze production data were not available. Since merchant coke plant data is not included in the estimate of other carbonaceous materials consumed at coke plants, the mass balance equation for CO_2 from metallurgical coke production cannot be reasonably completed. Therefore, for the purpose of this analysis, uncertainty parameters are applied to primary data inputs to the calculation (i.e., coking coal consumption and metallurgical coke production) only.

The estimates of CO_2 emissions from iron and steel production are based on material production and consumption data and average carbon contents. There is uncertainty associated with the assumption that direct reduced iron and sinter consumption are equal to production. There is uncertainty associated with the assumption that all coal used for purposes other than coking coal is for direct injection coal; some of this coal may be used for electricity generation. There is also uncertainty associated with the carbon contents for pellets, sinter, and natural ore, which are assumed to equal the carbon contents of direct reduced iron. For EAF steel production, there is uncertainty associated with the amount of EAF anode and charge carbon consumed due to inconsistent data throughout the time series. Also for EAF steel production, there is uncertainty associated with the assumption that 100 percent of the natural gas attributed to “steelmaking furnaces” by AISI is process-related and nothing is combusted for energy purposes. Uncertainty is also associated with the use of process gases such as blast furnace gas and coke oven gas. Data are not available to differentiate between the use of these gases for processes at the steel mill versus for energy generation (i.e., electricity and steam generation); therefore, all consumption is attributed to iron and steel production. These data and carbon contents produce a relatively accurate estimate of CO_2 emissions. However, there are uncertainties associated with each.

For the purposes of the CH_4 calculation from iron and steel production it is assumed that all of the CH_4 escapes as fugitive emissions and that none of the CH_4 is captured in stacks or vents. Additionally, the CO_2 emissions calculation is not corrected by subtracting the carbon content of the CH_4, which means there may be a slight double-counting of carbon as both CO_2 and CH_4.

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 4-71 for metallurgical coke production and iron and steel production. Total CO_2 emissions from metallurgical coke production and iron and steel production were estimated to be between 47.2 and 63.6 MMT CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 15 percent below and 15 percent above the emission estimate of 55.4 MMT CO_2 Eq. Total CH_4 emissions from metallurgical coke production and iron and steel production were estimated to be between 0.008 and 0.01 MMT CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 19 percent below and 19 percent above the emission estimate of 0.009 MMT CO_2 Eq.

Table 4-71: Approach 2 Quantitative Uncertainty Estimates for CO_2 and CH_4 Emissions from Iron and Steel Production and Metallurgical Coke Production (MMT CO_2 Eq. and Percent)

Source	Gas	2014 Emission Estimate (MMT CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (MMT CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Metallurgical Coke & Iron and Steel Production	CO_2	55.4	47.2	63.6	-15%	+15%

Metallurgical Coke & Iron and Steel Production	CH_4	+	+	+	-19%	+19%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.
+ Does not exceed 0.05 MMT CO_2 Eq.

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

Recalculations Discussion

Several adjustments were incorporated into the emission calculations for the Iron and Steel Production and Metallurgical Coke Production source categories. These adjustments applied to the entire time series from 1990 to 2014 and are briefly described below.

Previous Inventory reports included CH_4 emissions calculated using a Tier 1 CH_4 emission factor for three different production processes: metallurgical coke, sinter, and pig iron. However, the use of a Tier 1 CH_4 emission factor was not appropriate and may significantly overestimate emissions for the metallurgical coke and pig iron production processes in the U.S., because the CO_2 emissions for these production processes were estimated using the Tier 2 mass balance methodology. The Tier 2 mass balance methodology makes a basic assumption that all carbon that enters the specific production process either exits the process as part of a carbon-containing output or as CO_2 emissions; the estimation of CH_4 emissions is necessarily precluded by definition. Because CO_2 emissions for the sinter production process were estimated using a Tier 1 CO_2 emission factor, it is still appropriate to use a Tier 1 CH_4 emission factor for the sinter production process. Due to exclusion of CH_4 emissions from the metallurgical coke and pig iron production processes, CH_4 emissions reported in the Inventory were significantly reduced. This assumption and the revisions are further supported by a preliminary analysis of facility-level greenhouse gas emissions reported to EPA's GHGRP.

Previous Inventory reports have also relied significantly on activity data (i.e., production and input statistics) from AISI's *Annual Statistical Report* (AISI 2004 through 2015a); three key fuels used in the Tier 2 mass balance methodology were natural gas, coke oven gas, and blast furnace gas. For all three of these fuels, volumetric consumption was multiplied by a heat content to obtain the quantity of energy, which was then multiplied by carbon content to obtain the quantity of carbon. The heat content of natural gas was obtained from EIA's *Natural Gas Annual* (EIA 2015a) and varied from year to year with values ranging from 1,022 to 1,031 BTU/ft^3, while the heat contents of coke oven gas (500 BTU/ft^3) and blast furnace gas (90 BTU/ft^3) were obtained from the report, *Energy and Environmental Profile of the U.S. Iron and Steel Industry* (DOE 2000). However, close examination of Table 37 of the AISI's *Annual Statistical Report* (AISI 2004 through 2015a) indicates that the reported quantities of natural gas and blast furnace gas have different reporting bases based on heat contents (i.e., 1,000 BTU/ft^3 for natural gas and 95 BTU/ft^3 for blast furnace gas); the reporting basis for coke oven gas is identically 500 BTU/ft^3. AISI staff confirmed that the reporting bases included in Table 37 of the AISI's *Annual Statistical Report* (AISI 2004 through 2015a) have been used dating back to at least 1990. Therefore, the use of other heat contents with AISI's data is not appropriate. The heat content of natural gas was changed to 1,000 BTU/ft^3 for all years in the time series and the heat content of blast furnace gas was changed to 95 BTU/ft^3. Because blast furnace gas is used as both an input and an output in the Tier 2 mass balance methodology, the use of revised heat contents for natural gas and blast furnace gas only resulted in a slight decrease in estimated CO_2 emissions; however, the CO_2 emissions for individual production processes did change noticeably. For instance, across the entire time series, an increase in CO_2 emissions from heating, annealing, and other processes was essentially offset by a decrease in CO_2 emissions from the iron production process.

Planned Improvements

Future improvements involve evaluating and analyzing data reported under EPA's GHGRP to improve the emission estimates for the Iron and Steel Production source category. Particular attention will be made to ensure time series consistency of the emissions estimates presented in future Inventory reports, consistent with IPCC and UNFCCC guidelines. This is required as the facility-level reporting data from EPA's GHGRP, with the program's initial requirements for reporting of emissions in calendar year 2010, are not available for all inventory years (i.e., 1990 through 2009) as required for this Inventory. In implementing improvements and integration of data from EPA's

GHGRP, the latest guidance from the IPCC on the use of facility-level data in national inventories will be relied upon.[28]

Additional improvements include accounting for emission estimates for the production of metallurgical coke to the Energy chapter as well as identifying the amount of carbonaceous materials, other than coking coal, consumed at merchant coke plants. Other potential improvements include identifying the amount of coal used for direct injection and the amount of coke breeze, coal tar, and light oil produced during coke production. Efforts will also be made to identify information to better characterize emissions from the use of process gases and fuels within the Energy and Industrial Processes and Product Use chapters.

4.17 Ferroalloy Production (IPCC Source Category 2C2)

Carbon dioxide and CH_4 are emitted from the production of several ferroalloys. Ferroalloys are composites of iron (Fe) and other elements such as silicon (Si), manganese (Mn), and chromium (Cr). Emissions from fuels consumed for energy purposes during the production of ferroalloys are accounted for in the Energy chapter. Emissions from the production of two types of ferrosilicon (25 to 55 percent and 56 to 95 percent silicon), silicon metal (96 to 99 percent silicon), and miscellaneous alloys (32 to 65 percent silicon) have been calculated. Emissions from the production of ferrochromium and ferromanganese are not included here because of the small number of manufacturers of these materials in the United States, and therefore, government information disclosure rules prevent the publication of production data for these production facilities.

Similar to emissions from the production of iron and steel, CO_2 is emitted when metallurgical coke is oxidized during a high-temperature reaction with iron and the selected alloying element. Due to the strong reducing environment, CO is initially produced, and eventually oxidized to CO_2. A representative reaction equation for the production of 50 percent ferrosilicon (FeSi) is given below:

$$\mathrm{Fe_2O_3 + 2SiO_2 + 7C \rightarrow 2FeSi + 7CO}$$

While most of the carbon contained in the process materials is released to the atmosphere as CO_2, a percentage is also released as CH_4 and other volatiles. The amount of CH_4 that is released is dependent on furnace efficiency, operation technique, and control technology.

When incorporated in alloy steels, ferroalloys are used to alter the material properties of the steel. Ferroalloys are used primarily by the iron and steel industry, and production trends closely follow that of the iron and steel industry. Twelve companies in the United States produce ferroalloys (USGS 2015a).

Emissions of CO_2 from ferroalloy production in 2014 were 1.9 MMT CO_2 Eq. (1,914 kt CO_2) (see Table 4-72 and Table 4-73), which is an 11 percent reduction since 1990. Emissions of CH_4 from ferroalloy production in 2014 were 0.01 MMT CO_2 Eq. (0.5 kt CH_4), which is a 21 percent decrease since 1990.

Table 4-72: CO_2 and CH_4 Emissions from Ferroalloy Production (MMT CO_2 Eq.)

Gas	1990	2005	2010	2011	2012	2013	2014
CO_2	2.2	1.4	1.7	1.7	1.9	1.8	1.9
CH_4	+	+	+	+	+	+	+
Total	**2.2**	**1.4**	**1.7**	**1.7**	**1.9**	**1.8**	**1.9**

+ Does not exceed 0.05 MMT CO_2 Eq.

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

Table 4-73: CO_2 and CH_4 Emissions from Ferroalloy Production (kt)

Gas	1990		2005		2010	2011	2012	2013	2014
CO_2	2,152		1,392		1,663	1,735	1,903	1,785	1,914
CH_4	1		+		+	+	1	+	1

+ Does not exceed 0.5 kt.

Methodology

Emissions of CO_2 and CH_4 from ferroalloy production were calculated using a Tier 1 method from the *2006 IPCC Guidelines* (IPCC 2006) by multiplying annual ferroalloy production by material-specific default emission factors provided by IPCC (2006). The Tier 1 equations for CO_2 and CH_4 emissions are as follows:

$$E_{CO2} = \sum_i (MP_i \times EF_i)$$

Where,

E_{CO2} = CO_2 emissions, metric tons
MP_i = Production of ferroalloy type *i*, metric tons
EF_i = Generic emission factor for ferroalloy type *i*, metric tons CO2/metric ton specific ferroalloy product

$$E_{CH4} = \sum_i (MP_i \times EF_i)$$

Where,

E_{CH4} = CH_4 emissions, kg
MP_i = Production of ferroalloy type *i*, metric tons
EF_i = Generic emission factor for ferroalloy type *i*, kg CH_4/metric ton specific ferroalloy product

Default emission factors were used because country-specific emission factors are not currently available. The following emission factors were used to develop annual CO_2 and CH_4 estimates:

- Ferrosilicon, 25 to 55 percent Si and Miscellaneous Alloys, 32 to 65 percent Si – 2.5 metric tons CO_2/metric ton of alloy produced; 1.0 kg CH_4/metric ton of alloy produced.
- Ferrosilicon, 56 to 95 percent Si – 4.0 metric tons CO_2/metric ton alloy produced; 1.0 kg CH_4/metric ton of alloy produced.
- Silicon Metal – 5.0 metric tons CO_2/metric ton metal produced; 1.2 kg CH_4/metric ton metal produced.

It was assumed that 100 percent of the ferroalloy production was produced using petroleum coke in an electric arc furnace process (IPCC 2006), although some ferroalloys may have been produced with coking coal, wood, other biomass, or graphite carbon inputs. The amount of petroleum coke consumed in ferroalloy production was calculated assuming that the petroleum coke used is 90 percent C and 10 percent inert material (Onder and Bagdoyan 1993).

Ferroalloy production data for 1990 through 2014 (see Table 4-74) were obtained from the USGS through the *Minerals Yearbook: Silicon* (USGS 1996 through 2013) and the *Mineral Industry Surveys: Silicon* (USGS 2014, 2015b). The following data were available from the USGS publications for the time-series:

- Ferrosilicon, 25 to 55 percent Si: Annual production data were available from 1990 through 2010.
- Ferrosilicon, 56 to 95 percent Si: Annual production data were available from 1990 through 2010.
- Silicon Metal: Annual production data were available from 1990 through 2005. The production data for 2005 were used as proxy for 2006 through 2010.

- Miscellaneous Alloys, 32 to 65 percent Si: Annual production data were available from 1990-1999. Starting 2000, USGS reported miscellaneous alloys and ferrosilicon containing 25 to 55 percent silicon as a single category.

Starting with the 2011 publication, USGS reported all the ferroalloy production data as a single category (i.e., Total Silicon Materials Production). This is due to the small number of ferroalloy manufacturers in the United States and government information disclosure rules. Ferroalloy product shares developed from the 2010 production data (i.e., ferroalloy product production/total ferroalloy production) were used with the total silicon materials production quantity to estimate the production quantity by ferroalloy product type for 2011 through 2014 (USGS 2013, 2014, 2015b).

Table 4-74: Production of Ferroalloys (Metric Tons)

Year	Ferrosilicon 25%-55%	Ferrosilicon 56%-95%	Silicon Metal	Misc. Alloys 32-65%
1990	321,385	109,566	145,744	72,442
2005	123,000	86,100	148,000	NA
2010	153,000	135,000	148,000	NA
2011	159,667	140,883	154,450	NA
2012	175,108	154,507	169,385	NA
2013	164,229	144,908	158,862	NA
2014	176,161	155,436	170,404	NA

NA (Not Available for product type, aggregated along with ferrosilicon, 25%-55% Si)

Uncertainty and Time-Series Consistency

Annual ferroalloy production was reported by the USGS in three broad categories until the 2010 publication: ferroalloys containing 25 to 55 percent silicon (including miscellaneous alloys), ferroalloys containing 56 to 95 percent silicon, and silicon metal (through 2005 only, 2005 value used as proxy for 2005 through 2010). Starting with the *2011 Minerals Yearbook*, USGS started reporting all the ferroalloy production under a single category: Total silicon materials production. The total silicon materials quantity was allocated across the three categories based on the 2010 production shares for the three categories. Refer to the Methodology section for further details. Additionally, production data for silvery pig iron (alloys containing less than 25 percent silicon) are not reported by the USGS to avoid disclosing proprietary company data. Emissions from this production category, therefore, were not estimated.

Also, some ferroalloys may be produced using wood or other biomass as a primary or secondary carbon source (carbonaceous reductants), however information and data regarding these practices were not available. Emissions from ferroalloys produced with wood or other biomass would not be counted under this source because wood-based carbon is of biogenic origin.[29] Even though emissions from ferroalloys produced with coking coal or graphite inputs would be counted in national trends, they may be generated with varying amounts of CO_2 per unit of ferroalloy produced. The most accurate method for these estimates would be to base calculations on the amount of reducing agent used in the process, rather than the amount of ferroalloys produced. These data, however, were not available, and are also often considered confidential business information.

Emissions of CH_4 from ferroalloy production will vary depending on furnace specifics, such as type, operation technique, and control technology. Higher heating temperatures and techniques such as sprinkle charging will reduce CH_4 emissions; however, specific furnace information was not available or included in the CH_4 emission estimates.

The results of the Approach 2 quantitative uncertainty analysis are summarized in Table 4-75. Ferroalloy production CO_2 emissions were estimated to be between 1.7 and 2.1 MMT CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 12 percent below and 12 percent above the emission estimate of 1.9

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[29] Emissions and sinks of biogenic carbon are accounted for in the Land Use, Land-Use Change, and Forestry chapter.

MMT CO_2 Eq. Ferroalloy production CH_4 emissions were estimated to be between a range of approximately 12 percent below and 12 percent above the emission estimate of 0.01 MMT CO_2 Eq.

Table 4-75: Approach 2 Quantitative Uncertainty Estimates for CO_2 Emissions from Ferroalloy Production (MMT CO_2 Eq. and Percent)

Source	Gas	2014 Emission Estimate (MMT CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (MMT CO_2 Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Ferroalloy Production	CO_2	1.9	1.7	2.1	-12%	+12%
Ferroalloy Production	CH_4	+	+	+	-12%	+12%

[a] Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.
+ Does not exceed 0.05 MMT CO_2 Eq.

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

Planned Improvements

Future improvements involve evaluating and analyzing data reported under EPA's GHGRP that would be useful to improve the emission estimates for the Ferroalloy Production source category. Particular attention will be made to ensure time series consistency of the emissions estimates presented in future Inventory reports, consistent with IPCC and UNFCCC guidelines. This is required as the facility-level reporting data from EPA's GHGRP, with the program's initial requirements for reporting of emissions in calendar year 2010, are not available for all inventory years (i.e., 1990 through 2009) as required for this Inventory. In implementing improvements and integration of data from EPA's GHGRP, the latest guidance from the IPCC on the use of facility-level data in national inventories will be relied upon.[30]

4.18 Aluminum Production (IPCC Source Category 2C3) (TO BE UPDATED)

Aluminum is a light-weight, malleable, and corrosion-resistant metal that is used in many manufactured products, including aircraft, automobiles, bicycles, and kitchen utensils. As of recent reporting, the United States was the fourth largest producer of primary aluminum, with approximately 4 percent of the world total production (USGS 2014). The United States was also a major importer of primary aluminum. The production of primary aluminum—in addition to consuming large quantities of electricity—results in process-related emissions of CO_2 and two perfluorocarbons (PFCs): Perfluoromethane (CF_4) and perfluoroethane (C_2F_6).

CO_2 is emitted during the aluminum smelting process when alumina (aluminum oxide, Al_2O_3) is reduced to aluminum using the Hall-Heroult reduction process. The reduction of the alumina occurs through electrolysis in a molten bath of natural or synthetic cryolite (Na_3AlF_6). The reduction cells contain a carbon lining that serves as the cathode. Carbon is also contained in the anode, which can be a C mass of paste, coke briquettes, or prebaked C blocks from petroleum coke. During reduction, most of this C is oxidized and released to the atmosphere as CO_2.

Process emissions of CO_2 from aluminum production were estimated to be 3.3 MMT CO_2 Eq. (3,255 kt) in 2013 (see Table 4-76). The C anodes consumed during aluminum production consist of petroleum coke and, to a minor extent, coal tar pitch. The petroleum coke portion of the total CO_2 process emissions from aluminum production is considered to be a non-energy use of petroleum coke, and is accounted for here and not under the CO_2 from Fossil

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

Fuel Combustion source category of the Energy sector. Similarly, the coal tar pitch portion of these CO_2 process emissions is accounted for here.

Table 4-76: CO_2 Emissions from Aluminum Production (MMT CO_2 Eq. and kt)

Year	MMT CO_2 Eq.	kt
1990	6.8	6,831
2005	4.1	4,142
2009	3.0	3,009
2010	2.7	2,722
2011	3.3	3,292
2012	3.4	3,439
2013	3.3	3,255

In addition to CO_2 emissions, the aluminum production industry is also a source of PFC emissions. During the smelting process, when the alumina ore content of the electrolytic bath falls below critical levels required for electrolysis, rapid voltage increases occur, which are termed "anode effects." These anode effects cause C from the anode and fluorine from the dissociated molten cryolite bath to combine, thereby producing fugitive emissions of CF_4 and C_2F_6. In general, the magnitude of emissions for a given smelter and level of production depends on the frequency and duration of these anode effects. As the frequency and duration of the anode effects increase, emissions increase.

Since 1990, emissions of CF_4 and C_2F_6 have declined by 87 percent and 81 percent, respectively, to 2.3 MMT CO_2 Eq. of CF_4 (0.31 kt) and 0.7 MMT CO_2 Eq. of C_2F_6 (0.05 kt) in 2013, as shown in Table 4-77 and Table 4-78. This decline is due both to reductions in domestic aluminum production and to actions taken by aluminum smelting companies to reduce the frequency and duration of anode effects. These actions include technology and operational changes such as employee training, use of computer monitoring, and changes in alumina feeding techniques. Since 1990, aluminum production has declined by 52 percent, while the combined CF_4 and C_2F_6 emission rate (per metric ton of aluminum produced) has been reduced by 71 percent. Emissions increased by approximately 1 percent between 2012 and 2013 due to a slight increase in both CF_4 and C_2F_6 emissions per metric ton of aluminum produced.

Table 4-77: PFC Emissions from Aluminum Production (MMT CO_2 Eq.)

Year	CF_4	C_2F_6	Total
1990	17.9	3.5	21.5
2005	2.9	0.6	3.4
2009	1.5	0.4	1.9
2010	1.4	0.5	1.9
2011	2.7	0.8	3.5
2012	2.3	0.7	2.9
2013	2.3	0.7	3.0

Note: Totals may not sum due to independent rounding.

Table 4-78: PFC Emissions from Aluminum Production (kt)

Year	CF_4	C_2F_6
1990	2.4	0.3
2005	0.4	+
2009	0.2	+
2010	0.2	+
2011	0.4	0.1
2012	0.3	0.1
2013	0.3	0.1

+ Does not exceed 0.05 kt.

In 2013, U.S. primary aluminum production totaled approximately 1.9 million metric tons, a 6 percent decrease from 2012 production levels (USAA 2014). In 2013, five companies managed production at ten operational primary aluminum smelters. Three smelters were closed temporarily for the entire year in 2013 (USGS 2014). During 2013, monthly U.S. primary aluminum production was lower for every month in 2013, when compared to the corresponding months in 2012 (USAA 2014).

For 2014, total production was approximately 1.7 million metric tons compared to 1.9 million metric tons in 2013, a 12 percent decrease (USAA 2014). Based on the decrease in production, process CO_2 and PFC emissions are likely to be lower in 2014 compared to 2013 if there are no significant changes in process controls at operational facilities.

Methodology

Process CO_2 and perfluorocarbon (PFC)—i.e., perfluoromethane (CF_4) and perfluoroethane (C_2F_6)—emission estimates from primary aluminum production for 2010 through 2013 are available from EPA's GHGRP—Subpart F (Aluminum Production) (EPA 2014). Under EPA's GHGRP, facilities began reporting primary aluminum production process emissions (for 2010) in 2011; as a result, GHGRP data (for 2010 through 2013) are available to be incorporated into the Inventory. EPA's GHGRP mandates that all facilities that contain an aluminum production process must report: CF_4 and C_2F_6 emissions from anode effects in all prebake and Søderberg electrolysis cells, carbon dioxide (CO_2) emissions from anode consumption during electrolysis in all prebake and Søderberg cells, and all CO_2 emissions from onsite anode baking. To estimate the process emissions, EPA's GHGRP uses the process-specific equations (and certain technology-specific defaults) detailed in subpart F (aluminum production).[31] These equations are based on the Tier 2/Tier 3 IPCC (2006) methods for primary aluminum production, and Tier 1 methods when estimating missing data elements. It should be noted that the same methods (i.e., *2006 IPCC Guidelines*) were used for estimating the emissions prior to the availability of the reported GHGRP data in the Inventory.

Process CO_2 Emissions from Anode Consumption and Anode Baking

CO_2 emission estimates for the years prior to the introduction of EPA's GHGRP in 2010 were estimated with IPCC (2006) methods, but individual facility reported data were combined with process-specific emissions modeling. These estimates were based on information previously gathered from EPA's Voluntary Aluminum Industrial Partnership (VAIP) program, U.S. Geological Survey (USGS) Mineral Commodity reviews, and The Aluminum Association (USAA) statistics, among other sources. Since pre- and post-GHGRP estimates use the same methodology, emission estimates are comparable across the time series.

Most of the CO_2 emissions released during aluminum production occur during the electrolysis reaction of the C anode, as described by the following reaction:

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[31] *See* Code of Federal Regulations, Title 40: Protection of Environment, Part 98: Mandatory Greenhouse Gas Reporting, Subpart F—Aluminum Production. Available online at: <www.epa.gov/ghgreporting/documents/pdf/infosheets/aluminumproduction.pdf>.

$$2Al_2O_3 + 3C \rightarrow 4Al + 3CO_2$$

For prebake smelter technologies, CO_2 is also emitted during the anode baking process. These emissions can account for approximately 10 percent of total process CO_2 emissions from prebake smelters.

Depending on the availability of smelter-specific data, the CO_2 emitted from electrolysis at each smelter was estimated from: (1) The smelter's annual anode consumption, (2) the smelter's annual aluminum production and rate of anode consumption (per ton of aluminum produced) for previous and/or following years, or, (3) the smelter's annual aluminum production and IPCC default CO_2 emission factors. The first approach tracks the consumption and carbon content of the anode, assuming that all C in the anode is converted to CO_2. Sulfur, ash, and other impurities in the anode are subtracted from the anode consumption to arrive at a C consumption figure. This approach corresponds to either the IPCC Tier 2 or Tier 3 method, depending on whether smelter-specific data on anode impurities are used. The second approach interpolates smelter-specific anode consumption rates to estimate emissions during years for which anode consumption data are not available. This approach avoids substantial errors and discontinuities that could be introduced by reverting to Tier 1 methods for those years. The last approach corresponds to the IPCC Tier 1 method (2006), and is used in the absence of present or historic anode consumption data.

The equations used to estimate CO_2 emissions in the Tier 2 and 3 methods vary depending on smelter type (IPCC 2006). For Prebake cells, the process formula accounts for various parameters, including net anode consumption, and the sulfur, ash, and impurity content of the baked anode. For anode baking emissions, the formula accounts for packing coke consumption, the sulfur and ash content of the packing coke, as well as the pitch content and weight of baked anodes produced. For Søderberg cells, the process formula accounts for the weight of paste consumed per metric ton of aluminum produced, and pitch properties, including sulfur, hydrogen, and ash content.

Through the VAIP, anode consumption (and some anode impurity) data have been reported for 1990, 2000, 2003, 2004, 2005, 2006, 2007, 2008, and 2009. Where available, smelter-specific process data reported under the VAIP were used; however, if the data were incomplete or unavailable, information was supplemented using industry average values recommended by IPCC (2006). Smelter-specific CO_2 process data were provided by 18 of the 23 operating smelters in 1990 and 2000, by 14 out of 16 operating smelters in 2003 and 2004, 14 out of 15 operating smelters in 2005, 13 out of 14 operating smelters in 2006, 5 out of 14 operating smelters in 2007 and 2008, and 3 out of 13 operating smelters in 2009. For years where CO_2 emissions data or CO_2 process data were not reported by these companies, estimates were developed through linear interpolation, and/or assuming representative (e.g., previously reported or industry default) values.

In the absence of any previous historical smelter specific process data (i.e., 1 out of 13 smelters in 2009, 1 out of 14 smelters in 2006, 2007, and 2008, 1 out of 15 smelters in 2005, and 5 out of 23 smelters between 1990 and 2003), CO_2 emission estimates were estimated using Tier 1 Søderberg and/or Prebake emission factors (metric ton of CO_2 per metric ton of aluminum produced) from IPCC (2006).

Process PFC Emissions from Anode Effects

Smelter-specific PFC emissions from aluminum production for 2010 through 2013 were reported to EPA under its GHGRP. To estimate their PFC emissions and report them under EPA's GHGRP, smelters use an approach identical to the Tier 3 approach in the *2006 IPCC Guidelines* (IPCC 2006). Specifically, they use a smelter-specific slope coefficient as well as smelter-specific operating data to estimate an emission factor using the following equation:

$$\text{PFC } (CF_4 \text{ or } C_2F_6) \text{ kg/metric ton Al} = S \times (\text{Anode Effect Minutes/Cell-Day})$$

where,

S = Slope coefficient ((kg PFC/metric ton Al)/(Anode Effect Minutes/Cell-Day))

Anode Effect Minutes/Cell-Day = (Anode Effect Frequency/Cell-Day) × Anode Effect Duration (minutes)

They then multiply this emission factor by aluminum production to estimate PFC emissions. All U.S. aluminum smelters are required to report their emissions under EPA's GHGRP.

PFC emissions for the years prior to 2010 were estimated using the same equation, but the slope-factor used for some smelters was technology-specific rather than smelter-specific, making the method a Tier 2 rather than a Tier 3 approach for those smelters. Emissions and background data were reported to EPA under the VAIP. For 1990 through 2009, smelter-specific slope coefficients were available and were used for smelters representing between 30 and 94 percent of U.S. primary aluminum production. The percentage changed from year to year as some smelters closed or changed hands and as the production at remaining smelters fluctuated. For smelters that did not report smelter-specific slope coefficients, IPCC technology-specific slope coefficients were applied (IPCC 2006). The slope coefficients were combined with smelter-specific anode effect data collected by aluminum companies and reported under the VAIP to estimate emission factors over time. For 1990 through 2009, smelter-specific anode effect data were available for smelters representing between 80 and 100 percent of U.S. primary aluminum production. Where smelter-specific anode effect data were not available, representative values (e.g., previously reported or industry averages) were used.

For all smelters, emission factors were multiplied by annual production to estimate annual emissions at the smelter level. For 1990 through 2009, smelter-specific production data were available for smelters representing between 30 and 100 percent of U.S. primary aluminum production. (For the years after 2000, this percentage was near the high end of the range.) Production at non-reporting smelters was estimated by calculating the difference between the production reported under VAIP and the total U.S. production supplied by USGS or USAA, and then allocating this difference to non-reporting smelters in proportion to their production capacity. Emissions were then aggregated across smelters to estimate national emissions.

Between 1990 and 2009, production data were provided under the VAIP by 21 of the 23 U.S. smelters that operated during at least part of that period. For the non-reporting smelters, production was estimated based on the difference between reporting smelters and national aluminum production levels (from USGS and USAA), with allocation to specific smelters based on reported production capacities (from USGS).

National primary aluminum production data for 2013 were obtained via The Aluminum Association (USAA 2014). For 1990 through 2001, and 2006 (see Table 4-79) data were obtained from USGS Mineral Industry Surveys: Aluminum Annual Report (USGS 1995, 1998, 2000, 2001, 2002, 2007). For 2002 through 2005, and 2007 through 2011, national aluminum production data were obtained from the USAA's Primary Aluminum Statistics (USAA 2004–2006, 2008–2013).

Table 4-79: Production of Primary Aluminum (kt)

Year	kt
1990	4,048
2005	2,478
2009	1,727
2010	1,727
2011	1,986
2012	2,070
2013	1,948

Uncertainty and Time Series Consistency

Uncertainty was assigned to the CO_2, CF_4, and C_2F_6 emission values reported by each individual facility to EPA's GHGRP. As previously mentioned, the methods for estimating emissions for EPA's GHGRP and this report are the same, and follow the IPCC (2006) methodology. As a result, it was possible to assign uncertainty bounds (and distributions) based on an analysis of the uncertainty associated with the facility-specific emissions estimated for previous Inventory years. Uncertainty surrounding the reported CO_2, CF_4, and C_2F_6 emission values were determined to have a normal distribution with uncertainty ranges of ±6, ±16, and ±20 percent, respectively. A Monte Carlo analysis was applied to estimate the overall uncertainty of the CO_2, CF_4, and C_2F_6 emission estimates for the U.S. aluminum industry as a whole, and the results are provided below.

The results of this Approach 2 quantitative uncertainty analysis are summarized in Table 4-80. Aluminum production-related CO_2 emissions were estimated to be between 3.2 and 3.3 MMT CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 2 percent below to 2 percent above the emission estimate of 3.3 MMT CO_2 Eq. Also, production-related CF_4 emissions were estimated to be between 2.2 and 2.4 MMT CO_2

Eq. at the 95 percent confidence level. This indicates a range of approximately 6 percent below to 7 percent above the emission estimate of 2.3 MMT CO_2 Eq. Finally, aluminum production-related C_2F_6 emissions were estimated to be between 0.6 and 0.7 MMT CO_2 Eq. at the 95 percent confidence level. This indicates a range of approximately 11 percent below to 11 percent above the emission estimate of 0.7 MMT CO_2 Eq.

Table 4-80: Approach 2 Quantitative Uncertainty Estimates for CO_2 and PFC Emissions from Aluminum Production (MMT CO_2 Eq. and Percent)

Source	Gas	2013 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
Aluminum Production	CO_2	3.3	3.2	3.3	−2%	+2%
Aluminum Production	CF_4	2.3	2.2	2.4	−6%	+7%
Aluminum Production	C_2F_6	0.7	0.6	0.7	−11%	+11%

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

Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2013. Details on the emission trends through time are described in more detail in the Methodology section, above.

QA/QC and Verification

Tier 1 and Tier 2 QA/QC activities were conducted consistent with the U.S. QA/QC plan. Source-specific quality control measures for Aluminum Production included checking input data, documentation, and calculations to ensure data were properly handled through the inventory process. Errors that were found during this process were corrected as necessary.

Recalculations Discussion

For the current Inventory, emission estimates have been revised to reflect the GWPs provided in the *IPCC Fourth Assessment Report* (AR4) (IPCC 2007). AR4 GWP values differ slightly from those presented in the *IPCC Second Assessment Report* (SAR) (IPCC 1996) (used in the previous Inventory reports) which results in time-series recalculations for most Inventory sources. Under the most recent reporting guidelines (UNFCCC 2014), countries are required to report using the AR4 GWPs, which reflect an updated understanding of the atmospheric properties of each greenhouse gas. The GWPs of CH_4 and most fluorinated greenhouse gases have increased, leading to an overall increase in CO_2-equivalent emissions from PFCs. The AR4 GWPs have been applied across the entire time series for consistency. For more information please see the Recalculations and Improvements Chapter.

As a result, emission estimates for each year from 1990 to 2012 increased by 14 percent for CF_4, and increased by 33 percent for C_2F_6, relative to the emission estimates in the previous Inventory report.

Planned Improvements

Future improvements involve plans to replace proxy (e.g., interpolated) data with additional historical VAIP data that recently became available in order to calculate more accurate PFC emission estimates for the historical time series.

4.19 Magnesium Production and Processing (IPCC Source Category 2C4) (TO BE UPDATED)

The magnesium metal production and casting industry uses sulfur hexafluoride (SF_6) as a cover gas to prevent the rapid oxidation of molten magnesium in the presence of air. Sulfur hexafluoride has been used in this application around the world for more than thirty years. A dilute gaseous mixture of SF_6 with dry air and/or CO_2 is blown over molten magnesium metal to induce and stabilize the formation of a protective crust. A small portion of the SF_6 reacts with the magnesium to form a thin molecular film of mostly magnesium oxide and magnesium fluoride. The amount of SF_6 reacting in magnesium production and processing is considered to be negligible and thus all SF_6 used is assumed to be emitted into the atmosphere. , Alternative cover gases, such as AM-cover™ (containing HFC-134a), Novec™ 612 (FK-5-1-12) and dilute SO_2 systems can, and are being used by some facilities in the United States. However, many facilities in the United States are still using traditional SF_6 cover gas systems.

The magnesium industry emitted 1.4 MMT CO_2 Eq. (0.06 kt) of SF_6, 0.08 MMT CO_2 Eq. (0.06 kt) of HFC-134a, and 0.002 MMT CO_2 Eq. (2.1 kt) of CO_2, in 2013. This represents a decrease of approximately 8 percent from total 2012 emissions (see Table 4-81). The decrease can be attributed to reduction in primary, secondary, and die casting SF_6 emissions between 2012 and 2013 as reported through EPA's GHGRP, with the largest absolute reduction being seen for secondary emissions. The reduction in SF_6 emissions is likely due in part to decreased production from reporting facilities in 2013. The decrease in SF_6 emissions can also be attributed by continuing industry efforts to utilize SF_6 alternatives, such as HFC-134a, Novec^{TM}612 and SO_2, to reduce greenhouse gas emissions. In 2013, total HFC-134a emissions increased from 0.01 MMT CO_2 Eq. to 0.08 MMT CO_2 Eq., while the FK 5-1-12 emissions were constant. The emissions of carrier gas, CO_2, also decreased from 2.3 kt in 2012 to 2.1 kt in 2013.

Table 4-81: SF_6, HFC-134a, FK 5-1-12 and CO_2 Emissions from Magnesium Production and Processing (MMT CO_2 Eq.)

Year	1990	2005	2009	2010	2011	2012	2013
SF_6	5.2	2.7	1.6	2.1	2.8	1.6	1.4
HFC-134a	0.0	0.0	+	+	+	+	0.1
CO_2	+	+	+	+	+	+	+
FK 5-1-12	*0.0*	*0.0*	+	+	+	+	+
Total[a]	**5.2**	**2.8**	**1.7**	**2.1**	**2.8**	**1.7**	**1.5**

Note: Totals may not sum due to independent rounding.
+ Does not exceed 0.05 MMT CO_2 Eq.
[a] Total does not include FK 5-1-12. Values shown for informational purposes only.

Table 4-82: SF_6, HFC-134a, FK 5-1-12 and CO_2 Emissions from Magnesium Production and Processing (kt)

Year	1990	2005	2009	2010	2011	2012	2013
SF_6	0.2	0.1	0.1	0.1	0.1	0.1	0.1
HFC-134a	0.0	0.0	+	+	+	+	0.1
CO_2	1.4	2.9	1.2	1.3	3.1	2.3	2.1
FK 5-1-12	*0.0*	*0.0*	+	+	+	+	+

+ Does not exceed 0.5 kt.

Methodology

Emission estimates for the magnesium industry incorporate information provided by some industry participants in EPA's SF_6 Emission Reduction Partnership for the Magnesium Industry as well as emissions data reported through subpart T (Magnesium Production and Processing) of the EPA's GHGRP. The Partnership started in 1999 and, in

2010, participating companies represented 100 percent of U.S. primary and secondary production and 16 percent of the casting sector production (i.e., die, sand, permanent mold, wrought, and anode casting). SF_6 Emissions for 1999 through 2010 from primary production, secondary production (i.e., recycling), and die casting were generally reported by Partnership participants. Partners reported their SF_6 consumption, which was assumed to be equivalent to emissions. Along with SF_6, some Partners also reported their HFC-134a and FK 5-1-12 usage, which is assumed to be equal to emissions. 2010 was the last reporting year under the Partnership. Emissions data for 2011 through 2013 were obtained through EPA's GHGRP. Under the program, owners or operators of facilities that have a magnesium production or casting process must report emissions from use of cover or carrier gases, which include SF_6, HFC-134a, FK 5-1-12 and CO_2. Consequently, cover and carrier gas emissions from magnesium production and processing were estimated for three time periods, depending on the source of the emissions data: 1990 through 1998, 1999 through 2010, and 2011 through 2013. The methodologies described below also make use of magnesium production data published by the U.S. Geological Survey (USGS).

1990 through 1998

To estimate emissions for 1990 through 1998, industry SF_6 emission factors were multiplied by the corresponding metal production and consumption (casting) statistics from USGS. For this period, it was assumed that there was no use of HFC-134a or FK 5-1-12 cover gases and hence emissions were not estimated for these alternatives.

SF_6 emission factors from 1990 through 1998 were based on a number of sources and assumptions. Emission factors for primary production were available from U.S. primary producers for 1994 and 1995. The primary production emission factors were 1.2 kg SF_6 per metric ton for 1990 through 1993, and 1.1 kg SF_6 per metric ton for 1994 through 1997. The emission factor for secondary production from 1990 through 1998 was assumed to be constant at the 1999 average Partner value. Emission factor for die casting of 4.1 kg SF_6 per metric ton was available for the mid-1990s from an international survey (Gjestland & Magers 1996) that was used for years 1990 through 1996. For 1996 through 1998, the emission factor for die casting was assumed to decline linearly to the level estimated based on Partner reports in 1999. This assumption is consistent with the trend in SF_6 sales to the magnesium sector that is reported in the RAND survey of major SF_6 manufacturers, which shows a decline of 70 percent from 1996 to 1999 (RAND 2002). Sand casting emission factors for 1990 through 2001 were assumed to be the same as the 2002 emission factor. The emission factors for the other processes (i.e., permanent mold, wrought, and anode casting), about which less is known, were assumed to remain constant at levels defined in Table 4-81. These emission factors for the other processes (i.e., permanent mold, wrought, and anode casting) were based on discussions with industry representatives.

The quantities of CO_2 carrier gas used for each production type have been estimated using the 1999 estimated CO_2 emissions data and the annual calculated rate of change of SF_6 use in the 1990 through 1999 time period. For each year and production type, the rate of change of SF_6 use between the current year and the subsequent year was first estimated. This rate of change is then applied to the CO_2 emissions of the subsequent year to determine the CO_2 emission of the current year. The emissions of carrier gases for permanent mold, wrought and anode processes are not estimated in this Inventory.

1999 through 2010

The 1999 through 2010 emissions from primary and secondary production are based on information provided by EPA's industry Partners. In some instances, there were years of missing Partner data, including SF_6 consumption and metal processed. For these situations, emissions were estimated through interpolation where possible, or by holding company-reported emissions (as well as production) constant from the previous year. For alternative cover gases, including HFC-134a and FK 5-1-12, mainly reported data was relied upon. That is, unless a Partner reported using an alternative cover gas, it was not assumed it was used. Emissions of alternate gases were also estimated through linear interpolation where possible.

The die casting emission estimates for 1999 through 2010 are also based on information supplied by industry Partners. When a Partner was determined to be no longer in production, its metal production and usage rates were set to zero. Missing data on emissions or metal input was either interpolated or held constant at the last available reported value. In 1999 and from 2008 through 2010, Partners did not account for all die casting tracked by USGS, and, therefore, it was necessary to estimate the emissions of die casters who were not Partners. For 1999, die casters who were not Partners were assumed to be similar to Partners who cast small parts. Due to process requirements, these casters consume larger quantities of SF_6 per metric ton of processed magnesium than casters that process large parts. Consequently, emission estimates from this group of die casters were developed using an average emission factor of 5.2 kg SF_6 per metric ton of magnesium. This emission factor was developed using magnesium production and SF_6 usage data for the year 1999. For 2008 through 2010, the characteristics of the die casters who were not Partners were not well known, and therefore the emission factor for these die casters was set equal to 3.0 kg SF_6 per metric ton of magnesium, the average of the emission factors reported over the same period by the die casters who were Partners.

The emissions from other casting operations were estimated by multiplying emission factors (kg SF_6 per metric ton of metal produced or processed) by the amount of metal produced or consumed from USGS, with the exception of some years for which Partner sand casting emissions data are available. The emission factors for sand casting activities were acquired through the data reported by the Partnership for 2002 to 2006. For 1999-2001, the sand casting emission factor was held constant at the 2002 Partner-reported level. For 2007 through 2010, the sand casting Partner did not report and the reported emission factor from 2005 was applied to the Partner and to all other sand casters.

The emission factors for primary production, secondary production and sand casting for the 1999 to 2010 are not published to protect company-specific production information. However, the emission factor for primary production has not risen above the average 1995 Partner value of 1.1 kg SF_6 per metric ton. The emission factors for the other industry sectors (i.e., permanent mold, wrought, and anode casting) were based on discussions with industry representatives. The emission factors for casting activities are provided below in Table 4-83.

The emissions of HFC-134a and FK-5-1-12 were included in the estimates for only instances where Partners reported that information to the Partnership. Emissions of these alternative cover gases were not estimated for instances where emissions were not reported.

CO_2 carrier gas emissions were estimated using the emission factors developed based on GHGRP-reported carrier gas and cover gas data, by production type. It was assumed that the use of carrier gas, by production type, is proportional to the use of cover gases. Therefore, an emission factor, in kg CO_2 per kg cover gas and weighted by the cover gases used, was developed for each of the production types. GHGRP data on which these emissions factors are based was available for primary, secondary, die casting and sand casting. The emission factors were applied to the total quantity of all cover gases used (SF_6, HFC-134a, and FK5-1-12) by production type in this time period. Carrier gas emissions for the 1999 through 2010 time period were only estimated for those Partner companies that reported using CO_2 as a carrier gas through the GHGRP. Using this approach helped ensure time series consistency. The emissions of carrier gases for permanent mold, wrought and anode processes are not estimated in this Inventory.

Table 4-83: SF_6 Emission Factors (kg SF_6 per metric ton of magnesium)

Year	Die Casting[a]	Permanent Mold	Wrought	Anodes
1999	2.14[b]	2	1	1
2000	0.72	2	1	1
2001	0.72	2	1	1
2002	0.71	2	1	1
2003	0.81	2	1	1
2004	0.79	2	1	1
2005	0.77	2	1	1
2006	0.88	2	1	1
2007	0.64	2	1	1
2008	0.10	2	1	1
2009	2.30	2	1	1
2010	2.94	2	1	1

[a] Weighted average includes all die casters, Partners and non-Partners. For the majority of the time series (2000-2007), Partners made up 100 percent of die casters in the U.S.

[b] Weighted average that includes an estimated emission factor of 5.2 kg SF_6 per metric ton of magnesium for die casters that do not participate in the Partnership.