



Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2009



**INVENTORY OF U.S. GREENHOUSE GAS EMISSIONS AND SINKS:
1990 – 2009**

APRIL 15, 2011

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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>](http://www.epa.gov/climatechange).

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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.

Table of Contents

ACKNOWLEDGMENTS	I
PREFACE	III
TABLE OF CONTENTS	V
LIST OF TABLES, FIGURES, AND BOXES	VII
EXECUTIVE SUMMARY	ES-1
Background Information.....	ES-2
Recent Trends in U.S. Greenhouse Gas Emissions and Sinks.....	ES-3
Overview of Sector Emissions and Trends.....	ES-11
Other Information	ES-14
1. INTRODUCTION	1-1
1.1. Background Information	1-2
1.2. Institutional Arrangements	1-9
1.3. Inventory Process	1-9
1.4. Methodology and Data Sources.....	1-11
1.5. Key Categories	1-12
1.6. Quality Assurance and Quality Control (QA/QC).....	1-14
1.7. Uncertainty Analysis of Emission Estimates.....	1-16
1.8. Completeness	1-17
1.9. Organization of Report.....	1-17
2. TRENDS IN GREENHOUSE GAS EMISSIONS	2-1
2.1. Recent Trends in U.S. Greenhouse Gas Emissions and Sinks.....	2-1
2.2. Emissions by Economic Sector	2-16
2.3. Indirect Greenhouse Gas Emissions (CO, NO _x , NMVOCs, and SO ₂)	2-25
3. ENERGY	3-1
3.1. Fossil Fuel Combustion (IPCC Source Category 1A).....	3-3
3.2. Carbon Emitted from Non-Energy Uses of Fossil Fuels (IPCC Source Category 1A)	3-28
3.3. Incineration of Waste (IPCC Source Category 1A1a).....	3-33
3.4. Coal Mining (IPCC Source Category 1B1a)	3-37
3.5. Abandoned Underground Coal Mines (IPCC Source Category 1B1a)	3-40
3.6. Natural Gas Systems (IPCC Source Category 1B2b).....	3-43
3.7. Petroleum Systems (IPCC Source Category 1B2a).....	3-49
3.8. Energy Sources of Indirect Greenhouse Gas Emissions.....	3-54
3.9. International Bunker Fuels (IPCC Source Category 1: Memo Items).....	3-55
3.10. Wood Biomass and Ethanol Consumption (IPCC Source Category 1A).....	3-59
4. INDUSTRIAL PROCESSES	4-1

4.1.	Cement Production (IPCC Source Category 2A1)	4-4
4.2.	Lime Production (IPCC Source Category 2A2)	4-7
4.3.	Limestone and Dolomite Use (IPCC Source Category 2A3)	4-11
4.4.	Soda Ash Production and Consumption (IPCC Source Category 2A4)	4-13
4.5.	Ammonia Production (IPCC Source Category 2B1) and Urea Consumption	4-16
4.6.	Nitric Acid Production (IPCC Source Category 2B2)	4-19
4.7.	Adipic Acid Production (IPCC Source Category 2B3)	4-21
4.8.	Silicon Carbide Production (IPCC Source Category 2B4) and Consumption	4-24
4.9.	Petrochemical Production (IPCC Source Category 2B5)	4-26
4.10.	Titanium Dioxide Production (IPCC Source Category 2B5)	4-29
4.11.	Carbon Dioxide Consumption (IPCC Source Category 2B5)	4-31
4.12.	Phosphoric Acid Production (IPCC Source Category 2B5)	4-33
4.13.	Iron and Steel Production (IPCC Source Category 2C1) and Metallurgical Coke Production	4-37
4.14.	Ferroalloy Production (IPCC Source Category 2C2)	4-45
4.15.	Aluminum Production (IPCC Source Category 2C3)	4-47
4.16.	Magnesium Production and Processing (IPCC Source Category 2C4)	4-52
4.17.	Zinc Production (IPCC Source Category 2C5)	4-54
4.18.	Lead Production (IPCC Source Category 2C5)	4-58
4.19.	HCFC-22 Production (IPCC Source Category 2E1)	4-60
4.20.	Substitution of Ozone Depleting Substances (IPCC Source Category 2F)	4-62
4.21.	Semiconductor Manufacture (IPCC Source Category 2F6)	4-66
4.22.	Electrical Transmission and Distribution (IPCC Source Category 2F7)	4-71
4.23.	Industrial Sources of Indirect Greenhouse Gases	4-76
5.	SOLVENT AND OTHER PRODUCT USE	5-1
5.1.	Nitrous Oxide from Product Uses (IPCC Source Category 3D)	5-1
5.2.	Indirect Greenhouse Gas Emissions from Solvent Use	5-3
6.	AGRICULTURE	6-1
6.1.	Enteric Fermentation (IPCC Source Category 4A)	6-2
6.2.	Manure Management (IPCC Source Category 4B)	6-6
6.3.	Rice Cultivation (IPCC Source Category 4C)	6-12
6.4.	Agricultural Soil Management (IPCC Source Category 4D)	6-17
6.5.	Field Burning of Agricultural Residues (IPCC Source Category 4F)	6-27
7.	LAND USE, LAND-USE CHANGE, AND FORESTRY	7-1
7.1.	Representation of the U.S. Land Base	7-4
7.2.	Forest Land Remaining Forest Land	7-12
7.3.	Land Converted to Forest Land (IPCC Source Category 5A2)	7-24
7.4.	Cropland Remaining Cropland (IPCC Source Category 5B1)	7-24

7.5.	Land Converted to Cropland (IPCC Source Category 5B2).....	7-35
7.6.	Grassland Remaining Grassland (IPCC Source Category 5C1).....	7-38
7.7.	Land Converted to Grassland (IPCC Source Category 5C2)	7-42
7.8.	Wetlands Remaining Wetlands	7-45
7.9.	Settlements Remaining Settlements	7-49
7.10.	Land Converted to Settlements (Source Category 5E2).....	7-55
7.11.	Other (IPCC Source Category 5G).....	7-55
8.	WASTE	8-1
8.1.	Landfills (IPCC Source Category 6A1)	8-2
8.2.	Wastewater Treatment (IPCC Source Category 6B).....	8-7
8.3.	Composting (IPCC Source Category 6D)	8-18
8.4.	Waste Sources of Indirect Greenhouse Gases	8-19
9.	OTHER	9-1
10.	RECALCULATIONS AND IMPROVEMENTS.....	10-1
11.	REFERENCES.....	11-1

List of Tables, Figures, and Boxes

Tables

Table ES-1: Global Warming Potentials (100-Year Time Horizon) Used in this Report.....	ES-3
Table ES-2: Recent Trends in U.S. Greenhouse Gas Emissions and Sinks (Tg CO ₂ Eq. or million metric tons CO ₂ Eq.)	ES-4
Table ES-3: CO ₂ Emissions from Fossil Fuel Combustion by Fuel Consuming End-Use Sector (Tg or million metric tons CO ₂ Eq.).....	ES-8
Table ES-4: Recent Trends in U.S. Greenhouse Gas Emissions and Sinks by Chapter/IPCC Sector (Tg or million metric tons CO ₂ Eq.).....	ES-11
Table ES-5: Net CO ₂ Flux from Land Use, Land-Use Change, and Forestry (Tg or million metric tons CO ₂ Eq.)	ES-13
Table ES-6: Emissions from Land Use, Land-Use Change, and Forestry (Tg or million metric tons CO ₂ Eq.) ..	ES-13
Table ES-7: U.S. Greenhouse Gas Emissions Allocated to Economic Sectors (Tg or million metric tons CO ₂ Eq.)	ES-14
Table ES-8: U.S Greenhouse Gas Emissions by Economic Sector with Electricity-Related Emissions Distributed (Tg or million metric tons CO ₂ Eq.)	ES-15
Table ES-9: Recent Trends in Various U.S. Data (Index 1990 = 100)	ES-16
Table ES- 10: Emissions of NO _x , CO, NMVOCs, and SO ₂ (Gg).....	ES-17
Table 1-1: Global Atmospheric Concentration, Rate of Concentration Change, and Atmospheric Lifetime (years) of Selected Greenhouse Gases	1-3
Table 1-2: Global Warming Potentials and Atmospheric Lifetimes (Years) Used in this Report	1-7
Table 1-3: Comparison of 100-Year GWPs.....	1-8
Table 1-4: Key Categories for the United States (1990-2009)	1-13

Table 1-5: Estimated Overall Inventory Quantitative Uncertainty (Tg CO ₂ Eq. and Percent)	1-16
Table 1-6: IPCC Sector Descriptions.....	1-17
Table 1-7: List of Annexes	1-18
Table 2-1: Recent Trends in U.S. Greenhouse Gas Emissions and Sinks (Tg CO ₂ Eq.)	2-3
Table 2-2: Recent Trends in U.S. Greenhouse Gas Emissions and Sinks (Gg).....	2-5
Table 2-3: Recent Trends in U.S. Greenhouse Gas Emissions and Sinks by Chapter/IPCC Sector (Tg CO ₂ Eq.)...	2-7
Table 2-4: Emissions from Energy (Tg CO ₂ Eq.).....	2-8
Table 2-5: CO ₂ Emissions from Fossil Fuel Combustion by End-Use Sector (Tg CO ₂ Eq.).....	2-9
Table 2-6: Emissions from Industrial Processes (Tg CO ₂ Eq.).....	2-11
Table 2-7: N ₂ O Emissions from Solvent and Other Product Use (Tg CO ₂ Eq.).....	2-12
Table 2-8: Emissions from Agriculture (Tg CO ₂ Eq.).....	2-13
Table 2-9: Net CO ₂ Flux from Land Use, Land-Use Change, and Forestry (Tg CO ₂ Eq.).....	2-14
Table 2-10: Emissions from Land Use, Land-Use Change, and Forestry (Tg CO ₂ Eq.)	2-14
Table 2-11: Emissions from Waste (Tg CO ₂ Eq.)	2-15
Table 2-12: U.S. Greenhouse Gas Emissions Allocated to Economic Sectors (Tg CO ₂ Eq. and Percent of Total in 2009).....	2-16
Table 2-13: Electricity Generation-Related Greenhouse Gas Emissions (Tg CO ₂ Eq.)	2-19
Table 2-14: U.S Greenhouse Gas Emissions by Economic Sector and Gas with Electricity-Related Emissions Distributed (Tg CO ₂ Eq.) and Percent of Total in 2009.....	2-19
Table 2-15: Transportation-Related Greenhouse Gas Emissions (Tg CO ₂ Eq.)	2-22
Table 2-16: Recent Trends in Various U.S. Data (Index 1990 = 100).....	2-25
Table 2-17: Emissions of NO _x , CO, NMVOCs, and SO ₂ (Gg).....	2-26
Table 3-1: CO ₂ , CH ₄ , and N ₂ O Emissions from Energy (Tg CO ₂ Eq.).....	3-1
Table 3-2: CO ₂ , CH ₄ , and N ₂ O Emissions from Energy (Gg)	3-2
Table 3-3: CO ₂ , CH ₄ , and N ₂ O Emissions from Fossil Fuel Combustion (Tg CO ₂ Eq.)	3-3
Table 3-4: CO ₂ , CH ₄ , and N ₂ O Emissions from Fossil Fuel Combustion (Gg).....	3-3
Table 3-5: CO ₂ Emissions from Fossil Fuel Combustion by Fuel Type and Sector (Tg CO ₂ Eq.).....	3-3
Table 3-6: Annual Change in CO ₂ Emissions and Total 2009 Emissions from Fossil Fuel Combustion for Selected Fuels and Sectors (Tg CO ₂ Eq. and Percent)	3-4
Table 3-7: CO ₂ , CH ₄ , and N ₂ O Emissions from Fossil Fuel Combustion by Sector (Tg CO ₂ Eq.)	3-6
Table 3-8: CO ₂ , CH ₄ , and N ₂ O Emissions from Fossil Fuel Combustion by End-Use Sector (Tg CO ₂ Eq.)	3-7
Table 3-9: CO ₂ Emissions from Stationary Fossil Fuel Combustion (Tg CO ₂ Eq.)	3-8
Table 3-10: CH ₄ Emissions from Stationary Combustion (Tg CO ₂ Eq.).....	3-9
Table 3-11: N ₂ O Emissions from Stationary Combustion (Tg CO ₂ Eq.).....	3-9
Table 3-12: CO ₂ Emissions from Fossil Fuel Combustion in Transportation End-Use Sector (Tg CO ₂ Eq.) ^a	3-13
Table 3-13: CH ₄ Emissions from Mobile Combustion (Tg CO ₂ Eq.).....	3-15
Table 3-14: N ₂ O Emissions from Mobile Combustion (Tg CO ₂ Eq.)	15
Table 3-15: Carbon Intensity from Direct Fossil Fuel Combustion by Sector (Tg CO ₂ Eq./Qbtu)	19

Table 3-16: Tier 2 Quantitative Uncertainty Estimates for CO ₂ Emissions from Energy-related Fossil Fuel Combustion by Fuel Type and Sector (Tg CO ₂ Eq. and Percent).....	3-21
Table 3-17: Tier 2 Quantitative Uncertainty Estimates for CH ₄ and N ₂ O Emissions from Energy-Related Stationary Combustion, Including Biomass (Tg CO ₂ Eq. and Percent).....	3-24
Table 3-18: Tier 2 Quantitative Uncertainty Estimates for CH ₄ and N ₂ O Emissions from Mobile Sources (Tg CO ₂ Eq. and Percent).....	3-27
Table 3-19: CO ₂ Emissions from Non-Energy Use Fossil Fuel Consumption (Tg CO ₂ Eq.).....	3-28
Table 3-20: Adjusted Consumption of Fossil Fuels for Non-Energy Uses (TBtu).....	3-29
Table 3-21: 2009 Adjusted Non-Energy Use Fossil Fuel Consumption, Storage, and Emissions.....	3-30
Table 3-22: Tier 2 Quantitative Uncertainty Estimates for CO ₂ Emissions from Non-Energy Uses of Fossil Fuels (Tg CO ₂ Eq. and Percent)	3-31
Table 3-23: Tier 2 Quantitative Uncertainty Estimates for Storage Factors of Non-Energy Uses of Fossil Fuels (Percent)	3-32
Table 3-24: CO ₂ and N ₂ O Emissions from the Incineration of Waste (Tg CO ₂ Eq.).....	3-34
Table 3-25: CO ₂ and N ₂ O Emissions from the Incineration of Waste (Gg)	3-34
Table 3-26: Municipal Solid Waste Generation (Metric Tons) and Percent Combusted.....	3-36
Table 3-27: Tier 2 Quantitative Uncertainty Estimates for CO ₂ and N ₂ O from the Incineration of Waste (Tg CO ₂ Eq. and Percent)	3-36
Table 3-28: CH ₄ Emissions from Coal Mining (Tg CO ₂ Eq.)	3-37
Table 3-29: CH ₄ Emissions from Coal Mining (Gg)	3-38
Table 3-30: Coal Production (Thousand Metric Tons).....	3-39
Table 3-31: Tier 2 Quantitative Uncertainty Estimates for CH ₄ Emissions from Coal Mining (Tg CO ₂ Eq. and Percent).....	3-39
Table 3-32: CH ₄ Emissions from Abandoned Coal Mines (Tg CO ₂ Eq.).....	3-40
Table 3-33: CH ₄ Emissions from Abandoned Coal Mines (Gg).....	3-41
Table 3-34: Number of gassy abandoned mines occurring in U.S. basins grouped by class according to post-abandonment state	3-42
Table 3-35: Tier 2 Quantitative Uncertainty Estimates for CH ₄ Emissions from Abandoned Underground Coal Mines (Tg CO ₂ Eq. and Percent)	3-43
Table 3-36: CH ₄ Emissions from Natural Gas Systems (Tg CO ₂ Eq.)*	3-44
Table 3-37: CH ₄ Emissions from Natural Gas Systems (Gg)*	3-44
Table 3-38: Non-combustion CO ₂ Emissions from Natural Gas Systems (Tg CO ₂ Eq.).....	3-45
Table 3-39: Non-combustion CO ₂ Emissions from Natural Gas Systems (Gg)	3-45
Table 3-40: Tier 2 Quantitative Uncertainty Estimates for CH ₄ and Non-energy CO ₂ Emissions from Natural Gas Systems (Tg CO ₂ Eq. and Percent).....	3-46
Table 3-41: CH ₄ Emissions from Petroleum Systems (Tg CO ₂ Eq.).....	3-50
Table 3-42: CH ₄ Emissions from Petroleum Systems (Gg).....	3-50
Table 3-43: CO ₂ Emissions from Petroleum Systems (Tg CO ₂ Eq.).....	3-50
Table 3-44: CO ₂ Emissions from Petroleum Systems (Gg).....	3-50
Table 3-45: Tier 2 Quantitative Uncertainty Estimates for CH ₄ Emissions from Petroleum Systems (Tg CO ₂ Eq. and Percent).....	3-52

Table 3-46: Potential Emissions from CO ₂ Capture and Transport (Tg CO ₂ Eq.).....	3-54
Table 3-47: Potential Emissions from CO ₂ Capture and Transport (Gg)	3-54
Table 3-48: NO _x , CO, and NMVOC Emissions from Energy-Related Activities (Gg).....	3-54
Table 3-49: CO ₂ , CH ₄ , and N ₂ O Emissions from International Bunker Fuels (Tg CO ₂ Eq.)	3-56
Table 3-50: CO ₂ , CH ₄ and N ₂ O Emissions from International Bunker Fuels (Gg)	3-56
Table 3-51: Aviation Jet Fuel Consumption for International Transport (Million Gallons).....	3-57
Table 3-52: Marine Fuel Consumption for International Transport (Million Gallons)	3-58
Table 3-53: CO ₂ Emissions from Wood Consumption by End-Use Sector (Tg CO ₂ Eq.)	3-59
Table 3-54: CO ₂ Emissions from Wood Consumption by End-Use Sector (Gg)	3-60
Table 3-55: CO ₂ Emissions from Ethanol Consumption (Tg CO ₂ Eq.).....	3-60
Table 3-56: CO ₂ Emissions from Ethanol Consumption (Gg).....	3-60
Table 3-57: Woody Biomass Consumption by Sector (Trillion Btu)	3-60
Table 3-58: Ethanol Consumption by Sector (Trillion Btu)	3-61
Table 4-1: Emissions from Industrial Processes (Tg CO ₂ Eq.).....	4-1
Table 4-2: Emissions from Industrial Processes (Gg)	4-2
Table 4-3: CO ₂ Emissions from Cement Production (Tg CO ₂ Eq. and Gg)	4-5
Table 4-4: Clinker Production (Gg).....	4-6
Table 4-5: Tier 2 Quantitative Uncertainty Estimates for CO ₂ Emissions from Cement Production (Tg CO ₂ Eq. and Percent).....	4-6
Table 4-6: CO ₂ Emissions from Lime Production (Tg CO ₂ Eq. and Gg)	4-7
Table 4-7: Potential, Recovered, and Net CO ₂ Emissions from Lime Production (Gg)	4-8
Table 4-8: High-Calcium- and Dolomitic-Quicklime, High-Calcium- and Dolomitic-Hydrated, and Dead-Burned-Dolomite Lime Production (Gg).....	4-9
Table 4-9: Adjusted Lime Production ^a (Gg).....	4-9
Table 4-10: Tier 2 Quantitative Uncertainty Estimates for CO ₂ Emissions from Lime Production (Tg CO ₂ Eq. and Percent).....	4-10
Table 4-11: CO ₂ Emissions from Limestone & Dolomite Use (Tg CO ₂ Eq.).....	4-11
Table 4-12: CO ₂ Emissions from Limestone & Dolomite Use (Gg)	4-11
Table 4-13: Limestone and Dolomite Consumption (Thousand Metric Tons)	4-12
Table 4-14: Tier 2 Quantitative Uncertainty Estimates for CO ₂ Emissions from Limestone and Dolomite Use (Tg CO ₂ Eq. and Percent).....	4-13
Table 4-15: CO ₂ Emissions from Soda Ash Production and Consumption (Tg CO ₂ Eq.).....	4-14
Table 4-16: CO ₂ Emissions from Soda Ash Production and Consumption (Gg)	4-14
Table 4-17: Soda Ash Production and Consumption (Gg)	4-15
Table 4-18: Tier 2 Quantitative Uncertainty Estimates for CO ₂ Emissions from Soda Ash Production and Consumption (Tg CO ₂ Eq. and Percent).....	4-16
Table 4-19: CO ₂ Emissions from Ammonia Production and Urea Consumption (Tg CO ₂ Eq.)	4-17
Table 4-20: CO ₂ Emissions from Ammonia Production and Urea Consumption (Gg)	4-17
Table 4-21: Ammonia Production, Urea Production, Urea Net Imports, and Urea Exports (Gg)	4-18

Table 4-22: Tier 2 Quantitative Uncertainty Estimates for CO ₂ Emissions from Ammonia Production and Urea Consumption (Tg CO ₂ Eq. and Percent).....	4-19
Table 4-23: N ₂ O Emissions from Nitric Acid Production (Tg CO ₂ Eq. and Gg)	4-20
Table 4-24: Nitric Acid Production (Gg).....	4-20
Table 4-25: Tier 2 Quantitative Uncertainty Estimates for N ₂ O Emissions from Nitric Acid Production (Tg CO ₂ Eq. and Percent)	4-21
Table 4-26: N ₂ O Emissions from Adipic Acid Production (Tg CO ₂ Eq. and Gg).....	4-22
Table 4-27: Adipic Acid Production (Gg)	4-23
Table 4-28: Tier 2 Quantitative Uncertainty Estimates for N ₂ O Emissions from Adipic Acid Production (Tg CO ₂ Eq. and Percent).....	4-23
Table 4-29: CO ₂ and CH ₄ Emissions from Silicon Carbide Production and Consumption (Tg CO ₂ Eq.).....	4-24
Table 4-30: CO ₂ and CH ₄ Emissions from Silicon Carbide Production and Consumption (Gg)	4-24
Table 4-31: Production and Consumption of Silicon Carbide (Metric Tons).....	4-25
Table 4-32: Tier 2 Quantitative Uncertainty Estimates for CH ₄ and CO ₂ Emissions from Silicon Carbide Production and Consumption (Tg CO ₂ Eq. and Percent).....	4-25
Table 4-33: CO ₂ and CH ₄ Emissions from Petrochemical Production (Tg CO ₂ Eq.).....	4-26
Table 4-34: CO ₂ and CH ₄ Emissions from Petrochemical Production (Gg).....	4-26
Table 4-35: Production of Selected Petrochemicals (Thousand Metric Tons)	4-27
Table 4-36: Carbon Black Feedstock (Primary Feedstock) and Natural Gas Feedstock (Secondary Feedstock) Consumption (Thousand Metric Tons).....	4-28
Table 4-37: Tier 2 Quantitative Uncertainty Estimates for CH ₄ Emissions from Petrochemical Production and CO ₂ Emissions from Carbon Black Production (Tg CO ₂ Eq. and Percent).....	4-28
Table 4-38: CO ₂ Emissions from Titanium Dioxide (Tg CO ₂ Eq. and Gg).....	4-29
Table 4-39: Titanium Dioxide Production (Gg)	4-30
Table 4-40: Tier 2 Quantitative Uncertainty Estimates for CO ₂ Emissions from Titanium Dioxide Production (Tg CO ₂ Eq. and Percent).....	4-31
Table 4-41: CO ₂ Emissions from CO ₂ Consumption (Tg CO ₂ Eq. and Gg).....	4-32
Table 4-42: CO ₂ Production (Gg CO ₂) and the Percent Used for Non-EOR Applications for Jackson Dome and Bravo Dome.....	4-32
Table 4-43: Tier 2 Quantitative Uncertainty Estimates for CO ₂ Emissions from CO ₂ Consumption (Tg CO ₂ Eq. and Percent).....	4-33
Table 4-44: CO ₂ Emissions from Phosphoric Acid Production (Tg CO ₂ Eq. and Gg).....	4-34
Table 4-45: Phosphate Rock Domestic Production, Exports, and Imports (Gg)	4-35
Table 4-46: Chemical Composition of Phosphate Rock (percent by weight).....	4-35
Table 4-47: Tier 2 Quantitative Uncertainty Estimates for CO ₂ Emissions from Phosphoric Acid Production (Tg CO ₂ Eq. and Percent).....	4-36
Table 4-48: CO ₂ and CH ₄ Emissions from Metallurgical Coke Production (Tg CO ₂ Eq.).....	4-38
Table 4-49: CO ₂ and CH ₄ Emissions from Metallurgical Coke Production (Gg).....	4-38
Table 4-50: CO ₂ Emissions from Iron and Steel Production (Tg CO ₂ Eq.).....	4-39
Table 4-51: CO ₂ Emissions from Iron and Steel Production (Gg).....	4-39

Table 4-52: CH ₄ Emissions from Iron and Steel Production (Tg CO ₂ Eq.).....	4-39
Table 4-53: CH ₄ Emissions from Iron and Steel Production (Gg).....	4-39
Table 4-54: Material Carbon Contents for Metallurgical Coke Production.....	4-40
Table 4-55: Production and Consumption Data for the Calculation of CO ₂ and CH ₄ Emissions from Metallurgical Coke Production (Thousand Metric Tons)	4-40
Table 4-56: Production and Consumption Data for the Calculation of CO ₂ Emissions from Metallurgical Coke Production (million ft ³).....	4-41
Table 4-57: CO ₂ Emission Factors for Sinter Production and Direct Reduced Iron Production	4-41
Table 4-58: Material Carbon Contents for Iron and Steel Production	4-41
Table 4-59: CH ₄ Emission Factors for Sinter and Pig Iron Production	4-42
Table 4-60: Production and Consumption Data for the Calculation of CO ₂ and CH ₄ Emissions from Iron and Steel Production (Thousand Metric Tons).....	4-43
Table 4-61: Production and Consumption Data for the Calculation of CO ₂ Emissions from Iron and Steel Production (million ft ³ unless otherwise specified).....	4-43
Table 4-62: Tier 2 Quantitative Uncertainty Estimates for CO ₂ and CH ₄ Emissions from Iron and Steel Production and Metallurgical Coke Production (Tg. CO ₂ Eq. and Percent)	4-44
Table 4-63: CO ₂ and CH ₄ Emissions from Ferroalloy Production (Tg CO ₂ Eq.)	4-45
Table 4-64: CO ₂ and CH ₄ Emissions from Ferroalloy Production (Gg).....	4-46
Table 4-65: Production of Ferroalloys (Metric Tons).....	4-46
Table 4-66: Tier 2 Quantitative Uncertainty Estimates for CO ₂ Emissions from Ferroalloy Production (Tg CO ₂ Eq. and Percent).....	4-47
Table 4-67: CO ₂ Emissions from Aluminum Production (Tg CO ₂ Eq. and Gg)	4-48
Table 4-68: PFC Emissions from Aluminum Production (Tg CO ₂ Eq.).....	4-48
Table 4-69: PFC Emissions from Aluminum Production (Gg)	4-48
Table 4-70: Production of Primary Aluminum (Gg)	4-50
Table 4-71: Tier 2 Quantitative Uncertainty Estimates for CO ₂ and PFC Emissions from Aluminum Production (Tg CO ₂ Eq. and Percent).....	4-51
Table 4-72: SF ₆ Emissions from Magnesium Production and Processing (Tg CO ₂ Eq. and Gg).....	4-52
Table 4-73: SF ₆ Emission Factors (kg SF ₆ per metric ton of magnesium)	4-53
Table 4-74: Tier 2 Quantitative Uncertainty Estimates for SF ₆ Emissions from Magnesium Production and Processing (Tg CO ₂ Eq. and Percent).....	4-54
Table 4-75: CO ₂ Emissions from Zinc Production (Tg CO ₂ Eq. and Gg)	4-55
Table 4-76: Zinc Production (Metric Tons).....	4-56
Table 4-77: Tier 2 Quantitative Uncertainty Estimates for CO ₂ Emissions from Zinc Production (Tg CO ₂ Eq. and Percent).....	4-57
Table 4-78: CO ₂ Emissions from Lead Production (Tg CO ₂ Eq. and Gg).....	4-58
Table 4-79: Lead Production (Metric Tons).....	4-59
Table 4-80: Tier 2 Quantitative Uncertainty Estimates for CO ₂ Emissions from Lead Production (Tg CO ₂ Eq. and Percent).....	4-59
Table 4-81: HFC-23 Emissions from HCFC-22 Production (Tg CO ₂ Eq. and Gg).....	4-61

Table 4-82: HCFC-22 Production (Gg).....	4-61
Table 4-83: Quantitative Uncertainty Estimates for HFC-23 Emissions from HCFC-22 Production (Tg CO ₂ Eq. and Percent).....	4-62
Table 4-84: Emissions of HFCs and PFCs from ODS Substitutes (Tg CO ₂ Eq.).....	4-62
Table 4-85: Emissions of HFCs and PFCs from ODS Substitution (Mg)	4-63
Table 4-86: Emissions of HFCs and PFCs from ODS Substitutes (Tg CO ₂ Eq.) by Sector	4-63
Table 4-87: Tier 2 Quantitative Uncertainty Estimates for HFC and PFC Emissions from ODS Substitutes (Tg CO ₂ Eq. and Percent).....	4-66
Table 4-88: PFC, HFC, and SF ₆ Emissions from Semiconductor Manufacture (Tg CO ₂ Eq.).....	4-67
Table 4-89: PFC, HFC, and SF ₆ Emissions from Semiconductor Manufacture (Mg).....	4-67
Table 4-90: Tier 2 Quantitative Uncertainty Estimates for HFC, PFC, and SF ₆ Emissions from Semiconductor Manufacture (Tg CO ₂ Eq. and Percent).....	4-71
Table 4-91: SF ₆ Emissions from Electric Power Systems and Electrical Equipment Manufacturers (Tg CO ₂ Eq.)	4-72
Table 4-92: SF ₆ Emissions from Electric Power Systems and Electrical Equipment Manufacturers (Gg)	4-72
Table 4-93: Tier 2 Quantitative Uncertainty Estimates for SF ₆ Emissions from Electrical Transmission and Distribution (Tg CO ₂ Eq. and percent).....	4-75
Table 4-94: NO _x , CO, and NMVOC Emissions from Industrial Processes (Gg)	4-76
Table 5-1: N ₂ O Emissions from Solvent and Other Product Use (Tg CO ₂ Eq. and Gg)	5-1
Table 5-2: N ₂ O Production (Gg).....	5-1
Table 5-3: N ₂ O Emissions from N ₂ O Product Usage (Tg CO ₂ Eq. and Gg)	5-1
Table 5-4: Tier 2 Quantitative Uncertainty Estimates for N ₂ O Emissions from N ₂ O Product Usage (Tg CO ₂ Eq. and Percent).....	5-3
Table 5-5: Emissions of NO _x , CO, and NMVOC from Solvent Use (Gg)	5-4
Table 6-1: Emissions from Agriculture (Tg CO ₂ Eq.).....	6-1
Table 6-2: Emissions from Agriculture (Gg).....	6-1
Table 6-3: CH ₄ Emissions from Enteric Fermentation (Tg CO ₂ Eq.).....	6-2
Table 6-4: CH ₄ Emissions from Enteric Fermentation (Gg).....	6-2
Table 6-5: Quantitative Uncertainty Estimates for CH ₄ Emissions from Enteric Fermentation (Tg CO ₂ Eq. and Percent).....	6-5
Table 6-6: CH ₄ and N ₂ O Emissions from Manure Management (Tg CO ₂ Eq.).....	6-7
Table 6-7: CH ₄ and N ₂ O Emissions from Manure Management (Gg)	6-8
Table 6-8: Tier 2 Quantitative Uncertainty Estimates for CH ₄ and N ₂ O (Direct and Indirect) Emissions from Manure Management (Tg CO ₂ Eq. and Percent)	6-11
Table 6-9: CH ₄ Emissions from Rice Cultivation (Tg CO ₂ Eq.)	6-13
Table 6-10: CH ₄ Emissions from Rice Cultivation (Gg)	6-13
Table 6-11: Rice Areas Harvested (Hectares)	6-14
Table 6-12: Ratooned Area as Percent of Primary Growth Area.....	6-15
Table 6-13: Non-USDA Data Sources for Rice Harvest Information	6-15
Table 6-14: Tier 2 Quantitative Uncertainty Estimates for CH ₄ Emissions from Rice Cultivation (Tg CO ₂ Eq. and	

Percent).....	6-16
Table 6-15: N ₂ O Emissions from Agricultural Soils (Tg CO ₂ Eq.).....	6-17
Table 6-16: N ₂ O Emissions from Agricultural Soils (Gg).....	6-18
Table 6-17: Direct N ₂ O Emissions from Agricultural Soils by Land Use Type and N Input Type (Tg CO ₂ Eq.)...	6-18
Table 6-18: Indirect N ₂ O Emissions from all Land-Use Types (Tg CO ₂ Eq.).....	6-18
Table 6-19: Quantitative Uncertainty Estimates of N ₂ O Emissions from Agricultural Soil Management in 2009 (Tg CO ₂ Eq. and Percent).....	6-26
Table 6-20: CH ₄ and N ₂ O Emissions from Field Burning of Agricultural Residues (Tg CO ₂ Eq.).....	6-28
Table 6-21: CH ₄ , N ₂ O, CO, and NO _x Emissions from Field Burning of Agricultural Residues (Gg).....	6-28
Table 6-22: Agricultural Crop Production (Gg of Product).....	6-30
Table 6-23: U.S. Average Percent Crop Area Burned by Crop (Percent)	6-31
Table 6-24: Key Assumptions for Estimating Emissions from Field Burning of Agricultural Residues	6-31
Table 6-25: Greenhouse Gas Emission Ratios and Conversion Factors	6-31
Table 6-26: Tier 2 Quantitative Uncertainty Estimates for CH ₄ and N ₂ O Emissions from Field Burning of Agricultural Residues (Tg CO ₂ Eq. and Percent)	6-31
Table 7-1: Net CO ₂ Flux from Carbon Stock Changes in Land Use, Land-Use Change, and Forestry (Tg CO ₂ Eq.)	7-1
Table 7-2: Net CO ₂ Flux from Carbon Stock Changes in Land Use, Land-Use Change, and Forestry (Tg C).....	7-2
Table 7-3: Emissions from Land Use, Land-Use Change, and Forestry (Tg CO ₂ Eq.)	7-2
Table 7-4: Emissions from Land Use, Land-Use Change, and Forestry (Gg)	7-3
Table 7-5: Size of Land Use and Land-Use Change Categories on Managed Land Area by Land Use and Land Use Change Categories (thousands of hectares).....	7-5
Table 7-6: Net Annual Changes in C Stocks (Tg CO ₂ /yr) in Forest and Harvested Wood Pools.....	7-14
Table 7-7: Net Annual Changes in C Stocks (Tg C/yr) in Forest and Harvested Wood Pools.....	7-14
Table 7-8: Forest area (1000 ha) and C Stocks (Tg C) in Forest and Harvested Wood Pools.....	7-15
Table 7-9: Estimates of CO ₂ (Tg/yr) emissions for the lower 48 states and Alaska ¹	7-16
Table 7-10: Tier 2 Quantitative Uncertainty Estimates for Net CO ₂ Flux from Forest Land Remaining Forest Land: Changes in Forest C Stocks (Tg CO ₂ Eq. and Percent)	7-19
Table 7-11: Estimated Non-CO ₂ Emissions from Forest Fires (Tg CO ₂ Eq.) for U.S. Forests ¹	7-21
Table 7-12: Estimated Non-CO ₂ Emissions from Forest Fires (Gg Gas) for U.S. Forests ¹	7-21
Table 7-13: Estimated Carbon Released from Forest Fires for U.S. Forests	7-22
Table 7-14: Tier 2 Quantitative Uncertainty Estimates of Non-CO ₂ Emissions from Forest Fires in Forest Land Remaining Forest Land (Tg CO ₂ Eq. and Percent).....	7-22
Table 7-15: Direct N ₂ O Fluxes from Soils in <i>Forest Land Remaining Forest Land</i> (Tg CO ₂ Eq. and Gg N ₂ O)	7-23
Table 7-16: Quantitative Uncertainty Estimates of N ₂ O Fluxes from Soils in <i>Forest Land Remaining Forest Land</i> (Tg CO ₂ Eq. and Percent)	7-24
Table 7-17: Net CO ₂ Flux from Soil C Stock Changes in <i>Cropland Remaining Cropland</i> (Tg CO ₂ Eq.)	7-26
Table 7-18: Net CO ₂ Flux from Soil C Stock Changes in <i>Cropland Remaining Cropland</i> (Tg C).....	7-26
Table 7-19: Tier 2 Quantitative Uncertainty Estimates for Soil C Stock Changes occurring within <i>Cropland Remaining Cropland</i> (Tg CO ₂ Eq. and Percent).....	7-30

Table 7-20: Emissions from Liming of Agricultural Soils (Tg CO ₂ Eq.).....	7-31
Table 7-21: Emissions from Liming of Agricultural Soils (Tg C).....	7-31
Table 7-22: Applied Minerals (Million Metric Tons).....	7-32
Table 7-23: Tier 2 Quantitative Uncertainty Estimates for CO ₂ Emissions from Liming of Agricultural Soils (Tg CO ₂ Eq. and Percent).....	7-33
Table 7-24: CO ₂ Emissions from Urea Fertilization in <i>Cropland Remaining Cropland</i> (Tg CO ₂ Eq.).....	7-33
Table 7-25: CO ₂ Emissions from Urea Fertilization in <i>Cropland Remaining Cropland</i> (Tg C)	7-33
Table 7-26: Applied Urea (Million Metric Tons)	7-34
Table 7-27: Quantitative Uncertainty Estimates for CO ₂ Emissions from Urea Fertilization (Tg CO ₂ Eq. and Percent)	7-34
Table 7-28: Net CO ₂ Flux from Soil C Stock Changes in Land <i>Converted to Cropland</i> (Tg CO ₂ Eq.)	7-35
Table 7-29: Net CO ₂ Flux from Soil C Stock Changes in <i>Land Converted to Cropland</i> (Tg C).....	7-35
Table 7-30: Tier 2 Quantitative Uncertainty Estimates for Soil C Stock Changes occurring within <i>Land Converted to Cropland</i> (Tg CO ₂ Eq. and Percent).....	7-37
Table 7-31: Net CO ₂ Flux from Soil C Stock Changes in <i>Grassland Remaining Grassland</i> (Tg CO ₂ Eq.).....	7-38
Table 7-32: Net CO ₂ Flux from Soil C Stock Changes in Grassland Remaining Grassland (Tg C)	7-38
Table 7-33: Tier 2 Quantitative Uncertainty Estimates for C Stock Changes occurring within <i>Grassland Remaining Grassland</i> (Tg CO ₂ Eq. and Percent).....	7-40
Table 7-34: Net CO ₂ Flux from Soil C Stock Changes for <i>Land Converted to Grassland</i> (Tg CO ₂ Eq.)	7-42
Table 7-35: Net CO ₂ Flux from Soil C Stock Changes for <i>Land Converted to Grassland</i> (Tg C).....	7-42
Table 7-36: Tier 2 Quantitative Uncertainty Estimates for Soil C Stock Changes occurring within <i>Land Converted to Grassland</i> (Tg CO ₂ Eq. and Percent).....	7-44
Table 7-37: Emissions from <i>Peatlands Remaining Peatlands</i> (Tg CO ₂ Eq.)	7-46
Table 7-38: Emissions from <i>Peatlands Remaining Peatlands</i> (Gg).....	7-46
Table 7-39: Peat Production of Lower 48 States (in thousands of Metric Tons).....	7-47
Table 7-40: Peat Production of Alaska (in thousands of Cubic Meters).....	7-47
Table 7-41: Tier-2 Quantitative Uncertainty Estimates for CO ₂ Emissions from <i>Peatlands Remaining Peatlands</i>	7-48
Table 7-42: Net C Flux from Urban Trees (Tg CO ₂ Eq. and Tg C).....	7-49
Table 7-43: C Stocks (Metric Tons C), Annual C Sequestration (Metric Tons C/yr), Tree Cover (Percent), and Annual C Sequestration per Area of Tree Cover (kg C/m ² -yr) for 14 U.S. Cities.....	7-51
Table 7-44: Tier 2 Quantitative Uncertainty Estimates for Net C Flux from Changes in C Stocks in Urban Trees (Tg CO ₂ Eq. and Percent)	7-52
Table 7-45: Direct N ₂ O Fluxes from Soils in <i>Settlements Remaining Settlements</i> (Tg CO ₂ Eq. and Gg N ₂ O)	7-53
Table 7-46: Quantitative Uncertainty Estimates of N ₂ O Emissions from Soils in <i>Settlements Remaining Settlements</i> (Tg CO ₂ Eq. and Percent)	7-54
Table 7-47: Net Changes in Yard Trimming and Food Scrap Stocks in Landfills (Tg CO ₂ Eq.).....	7-55
Table 7-48: Net Changes in Yard Trimming and Food Scrap Stocks in Landfills (Tg C).....	7-56
Table 7-49: Moisture Content (%), C Storage Factor, Proportion of Initial C Sequestered (%), Initial C Content (%), and Decay Rate (year ⁻¹) for Landfilled Yard Trimmings and Food Scraps in Landfills	7-58

Table 7-50: C Stocks in Yard Trimmings and Food Scraps in Landfills (Tg C)	7-58
Table 7-51: Tier 2 Quantitative Uncertainty Estimates for CO ₂ Flux from Yard Trimmings and Food Scraps in Landfills (Tg CO ₂ Eq. and Percent).....	7-59
Table 8-1. Emissions from Waste (Tg CO ₂ Eq.).....	8-1
Table 8-2. Emissions from Waste (Gg)	8-2
Table 8-3. CH ₄ Emissions from Landfills (Tg CO ₂ Eq.)	8-3
Table 8-4. CH ₄ Emissions from Landfills (Gg).....	8-3
Table 8-5. Tier 2 Quantitative Uncertainty Estimates for CH ₄ Emissions from Landfills (Tg CO ₂ Eq. and Percent).....	8-5
Table 8-6. CH ₄ and N ₂ O Emissions from Domestic and Industrial Wastewater Treatment (Tg CO ₂ Eq.).....	8-7
Table 8-7. CH ₄ and N ₂ O Emissions from Domestic and Industrial Wastewater Treatment (Gg)	8-8
Table 8-8. U.S. Population (Millions) and Domestic Wastewater BOD ₅ Produced (Gg).....	8-10
Table 8-9. Domestic Wastewater CH ₄ Emissions from Septic and Centralized Systems (2009)	8-10
Table 8-10. Industrial Wastewater CH ₄ Emissions by Sector (2009).....	8-10
Table 8-11. U.S. Pulp and Paper, Meat, Poultry, Vegetables, Fruits and Juices, Ethanol, and Petroleum Refining Production (Tg)	8-10
Table 8-12. Variables Used to Calculate Percent Wastewater Treated Anaerobically by Industry (%).....	8-11
Table 8-13. Wastewater Flow (m ³ /ton) and BOD Production (g/L) for U.S. Vegetables, Fruits, and Juices Production	8-12
Table 8-14. U.S. Population (Millions), Available Protein (kg/person-year), and Protein Consumed (kg/person-year)	8-15
Table 8-15. Tier 2 Quantitative Uncertainty Estimates for CH ₄ Emissions from Wastewater Treatment (Tg CO ₂ Eq. and Percent).....	8-16
Table 8-16. CH ₄ and N ₂ O Emissions from Composting (Tg CO ₂ Eq.)	8-18
Table 8-17. CH ₄ and N ₂ O Emissions from Composting (Gg)	8-18
Table 8-18: U.S. Waste Composted (Gg).....	8-19
Table 8-19 : Tier 1 Quantitative Uncertainty Estimates for Emissions from Composting (Tg CO ₂ Eq. and Percent).....	19
Table 8-20: Emissions of NO _x , CO, and NMVOC from Waste (Gg).....	8-20
Table 10-1: Revisions to U.S. Greenhouse Gas Emissions (Tg CO ₂ Eq.)	10-2
Table 10-2: Revisions to Net Flux of CO ₂ to the Atmosphere from Land Use, Land-Use Change, and Forestry (Tg CO ₂ Eq.)	10-4

Figures

Figure ES-1: U.S. Greenhouse Gas Emissions by Gas	ES-4
Figure ES-2: Annual Percent Change in U.S. Greenhouse Gas Emissions	ES-4
Figure ES-3: Cumulative Change in Annual U.S. Greenhouse Gas Emissions Relative to 1990.....	ES-4
Figure ES-4: 2009 Greenhouse Gas Emissions by Gas (percents based on Tg CO ₂ Eq.).....	ES-6
Figure ES-5: 2009 Sources of CO ₂ Emissions.....	ES-7
Figure ES-6: 2009 CO ₂ Emissions from Fossil Fuel Combustion by Sector and Fuel Type.....	ES-7
Figure ES-7: 2009 End-Use Sector Emissions of CO ₂ , CH ₄ , and N ₂ O from Fossil Fuel Combustion	ES-7

Figure ES-8: 2009 Sources of CH ₄ Emissions.....	ES-9
Figure ES-9: 2009 Sources of N ₂ O Emissions	ES-10
Figure ES-10: 2009 Sources of HFCs, PFCs, and SF ₆ Emissions	ES-11
Figure ES-11: U.S. Greenhouse Gas Emissions and Sinks by Chapter/IPCC Sector	ES-11
Figure ES-12: 2009 U.S. Energy Consumption by Energy Source	ES-12
Figure ES-13: Emissions Allocated to Economic Sectors	ES-14
Figure ES-14: Emissions with Electricity Distributed to Economic Sectors	ES-16
Figure ES-15: U.S. Greenhouse Gas Emissions Per Capita and Per Dollar of Gross Domestic Product	ES-16
Figure ES-16: 2009 Key Categories	ES-18
Figure 1-1: U.S. QA/QC Plan Summary	ES-15
Figure 2-1: U.S. Greenhouse Gas Emissions by Gas.....	1-1
Figure 2-2: Annual Percent Change in U.S. Greenhouse Gas Emissions	2-1
Figure 2-3: Cumulative Change in Annual U.S. Greenhouse Gas Emissions Relative to 1990	2-1
Figure 2-4: U.S. Greenhouse Gas Emissions and Sinks by Chapter/IPCC Sector.....	2-7
Figure 2-5: 2009 Energy Chapter Greenhouse Gas Sources.....	2-8
Figure 2-6: 2009 U.S. Fossil Carbon Flows (Tg CO ₂ Eq.)	2-8
Figure 2-7: 2009 CO ₂ Emissions from Fossil Fuel Combustion by Sector and Fuel Type.....	2-9
Figure 2-8: 2009 End-Use Sector Emissions from Fossil Fuel Combustion	2-10
Figure 2-9: 2009 Industrial Processes Chapter Greenhouse Gas Sources	2-11
Figure 2-10: 2009 Agriculture Chapter Greenhouse Gas Sources.....	2-13
Figure 2-11: 2009 Waste Chapter Greenhouse Gas Sources	2-15
Figure 2-12: Emissions Allocated to Economic Sectors.....	2-16
Figure 2-13: Emissions with Electricity Distributed to Economic Sectors.....	2-19
Figure 2-14: U.S. Greenhouse Gas Emissions Per Capita and Per Dollar of Gross Domestic Product.....	2-25
Figure 3-1: 2009 Energy Chapter Greenhouse Gas Sources.....	3-1
Figure 3-2: 2009 U.S. Fossil Carbon Flows (Tg CO ₂ Eq.)	3-1
Figure 3-3: 2009 U.S. Energy Consumption by Energy Source	3-5
Figure 3-4: U.S. Energy Consumption (Quadrillion Btu).....	3-5
Figure 3-5: 2009 CO ₂ Emissions from Fossil Fuel Combustion by Sector and Fuel Type.....	3-5
Figure 3-6: Annual Deviations from Normal Heating Degree Days for the United States (1950–2009)	3-5
Figure 3-7: Annual Deviations from Normal Cooling Degree Days for the United States (1950–2009).....	3-5
Figure 3-8: Nuclear, Hydroelectric, and Wind Power Plant Capacity Factors in the United States (1990–2009)....	3-6
Figure 3-9: Electricity Generation Retail Sales by End-Use Sector	3-10
Figure 3-10: Industrial Production Indices (Index 2002=100)	3-11
Figure 3-11: Sales-Weighted Fuel Economy of New Passenger Cars and Light-Duty Trucks, 1990–2008.....	3-13
Figure 3-12: Sales of New Passenger Cars and Light-Duty Trucks, 1990–2008.....	3-13
Figure 3-13: Mobile Source CH ₄ and N ₂ O Emissions	3-15

Figure 3-14: U.S. Energy Consumption and Energy-Related CO ₂ Emissions Per Capita and Per Dollar GDP	3-20
Figure 4-1: 2009 Industrial Processes Chapter Greenhouse Gas Sources	4-1
Figure 6-1: 2009 Agriculture Chapter Greenhouse Gas Emission Sources	6-1
Figure 6-2: Sources and Pathways of N that Result in N ₂ O Emissions from Agricultural Soil Management.....	6-17
Figure 6-3: Major Crops, Average Annual Direct N ₂ O Emissions Estimated Using the DAYCENT Model, 1990-2009 (Tg CO ₂ Eq./year).....	6-19
Figure 6-4: Grasslands, Average Annual Direct N ₂ O Emissions Estimated Using the DAYCENT Model, 1990-2009 (Tg CO ₂ Eq./year).....	6-19
Figure 6-5: Major Crops, Average Annual N Losses Leading to Indirect N ₂ O Emissions Estimated Using the DAYCENT Model, 1990-2009 (Gg N/year)	6-19
Figure 6-6: Grasslands, Average Annual N Losses Leading to Indirect N ₂ O Emissions Estimated Using the DAYCENT Model, 1990-2009 (Gg N/year)	6-19
Figure 6-7: Comparison of Measured Emissions at Field Sites and Modeled Emissions Using the DAYCENT Simulation Model	6-26
Figure 7-1. Percent of Total Land Area in the General Land-Use Categories for 2009	7-6
Figure 7-2: Forest Sector Carbon Pools and Flows	7-13
Figure 7-3: Estimates of Net Annual Changes in C Stocks for Major C Pools	7-15
Figure 7-4: Average C Density in the Forest Tree Pool in the Conterminous United States, 2009	7-15
Figure 7-5: Total Net Annual CO ₂ Flux for Mineral Soils under Agricultural Management within States, 2009, <i>Cropland Remaining Cropland</i>	7-26
Figure 7-6: Total Net Annual CO ₂ Flux for Organic Soils under Agricultural Management within States, 2009, <i>Cropland Remaining Cropland</i>	7-26
Figure 7-7: Total Net Annual CO ₂ Flux for Mineral Soils under Agricultural Management within States, 2009, <i>Land Converted to Cropland</i>	7-36
Figure 7-8: Total Net Annual CO ₂ Flux for Organic Soils under Agricultural Management within States, 2009, <i>Land Converted to Cropland</i>	7-36
Figure 7-9: Total Net Annual CO ₂ Flux for Mineral Soils under Agricultural Management within States, 2009, <i>Grassland Remaining Grassland</i>	7-39
Figure 7-10: Total Net Annual CO ₂ Flux for Organic Soils under Agricultural Management within States, 2009, <i>Grassland Remaining Grassland</i>	7-39
Figure 7-11: Total Net Annual CO ₂ Flux for Mineral Soils under Agricultural Management within States, 2009, <i>Land Converted to Grassland</i>	7-42
Figure 7-12: Total Net Annual CO ₂ Flux for Organic Soils under Agricultural Management within States, 2009, <i>Land Converted to Grassland</i>	7-43
Figure 8-1: 2009 Waste Chapter Greenhouse Gas Sources	8-1

Boxes

Box ES-1: Methodological approach for estimating and reporting U.S. emissions and sinks.....	ES-1
Box ES-2: Recent Trends in Various U.S. Greenhouse Gas Emissions-Related Data	ES-16
Box ES-3: Recalculations of Inventory Estimates	ES-19
Box 1-1: Methodological approach for estimating and reporting U.S. emissions and sinks	1-2

Box 1-2: The IPCC Fourth Assessment Report and Global Warming Potentials.....	1-8
Box 1-3: IPCC Reference Approach	1-11
Box 2-1: Methodology for Aggregating Emissions by Economic Sector.....	2-23
Box 2-2: Recent Trends in Various U.S. Greenhouse Gas Emissions-Related Data.....	2-25
Box 2-3: Sources and Effects of Sulfur Dioxide	2-27
Box 3-1: Weather and Non-Fossil Energy Effects on CO ₂ from Fossil Fuel Combustion Trends	3-5
Box 3-2: Carbon Intensity of U.S. Energy Consumption	3-19
Box 3-3: Carbon Dioxide Transport, Injection, and Geological Storage.....	3-53
Box 6-1: Tier 1 vs. Tier 3 Approach for Estimating N ₂ O Emissions.....	6-20
Box 6-2: Comparison of Tier 2 U.S. Inventory Approach and IPCC (2006) Default Approach	6-29
Box 7-1: Methodological approach for estimating and reporting U.S. emissions and sinks	7-3
Box 7-2: CO ₂ Emissions from Forest Fires	7-15
Box 7-3: Tier 3 Approach for Soil C Stocks Compared to Tier 1 or 2 Approaches	7-27
Box 8-1: Methodological approach for estimating and reporting U.S. emissions and sinks	8-1
Box 8-2: Biogenic Wastes in Landfills.....	8-6

Executive Summary

An emissions inventory that identifies and quantifies a country's primary anthropogenic¹ 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 2009. 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 Revised 1996 Intergovernmental Panel on Climate Change (IPCC) Guidelines for National Greenhouse Gas Inventories (IPCC/UNEP/OECD/IEA 1997), the IPCC Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories (IPCC 2000), and the IPCC Good Practice Guidance for Land Use, Land-Use Change, and Forestry (IPCC 2003). Additionally, the U.S. emission inventory has continued to incorporate new methodologies and data from the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006). The structure of this report is consistent with the UNFCCC guidelines for inventory reporting.⁴ For most source categories, the IPCC methodologies were expanded, resulting in a more comprehensive and detailed estimate of emissions.

[BEGIN BOX]

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 and sinks in a given year for the U.S. 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

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/UNEP/OECD/IEA 1997).

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/2006/sbsta/eng/09.pdf>>.

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

⁶ See <http://unfccc.int/national_reports/annex_i_ghg_inventories/national_inventories_submissions/items/5270.php>.

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 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.

[END BOX]

Background Information

Naturally occurring greenhouse gases include water vapor, carbon dioxide (CO₂), methane (CH₄), nitrous oxide (N₂O), and ozone (O₃). 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 their national greenhouse gas emission inventories.⁷ Some other fluorine-containing halogenated substances—hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF₆)—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 emission inventories.

There are also several gases that do not have a direct global warming effect but indirectly affect terrestrial and/or solar radiation absorption by influencing the formation or destruction of greenhouse gases, including tropospheric and stratospheric ozone. These gases include carbon monoxide (CO), oxides of nitrogen (NO_x), and non-CH₄ volatile organic compounds (NMVOCs). Aerosols, which are extremely small particles or liquid droplets, such as those produced by sulfur dioxide (SO₂) or elemental carbon emissions, can also affect the absorptive characteristics of the atmosphere.

Although the direct greenhouse gases CO₂, CH₄, and N₂O occur naturally in the atmosphere, human activities have changed their atmospheric concentrations. From the pre-industrial era (i.e., ending about 1750) to 2005, concentrations of these greenhouse gases have increased globally by 36, 148, and 18 percent, respectively (IPCC 2007).

Beginning in the 1950s, the use of CFCs and other stratospheric ozone depleting substances (ODS) increased by nearly 10 percent per year until the mid-1980s, when international concern about ozone depletion led to the entry into force of the Montreal Protocol. Since then, the production of ODS is being phased out. In recent years, use of ODS substitutes such as HFCs and PFCs has grown as they begin to be phased in as replacements for CFCs and HCFCs. Accordingly, atmospheric concentrations of these substitutes have been growing (IPCC 2007).

Global Warming Potentials

Gases in the atmosphere can contribute to the greenhouse effect 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.

⁷ Emissions estimates of CFCs, HCFCs, halons and other ozone-depleting substances are included in the annexes of the Inventory report for informational purposes.

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.

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 2001). Direct radiative effects occur when the gas itself is a greenhouse gas. The reference gas used is CO₂, and therefore GWP-weighted emissions are measured in teragrams (or million metric tons) of CO₂ equivalent (Tg CO₂ Eq.).^{9,10} All gases in this Executive Summary are presented in units of Tg CO₂ Eq.

The UNFCCC reporting guidelines for national inventories were updated in 2006,¹¹ but continue to require the use of GWPs from the IPCC Second Assessment Report (SAR) (IPCC 1996). This requirement ensures that current estimates of aggregate greenhouse gas emissions for 1990 to 2009 are consistent with estimates developed prior to the publication of the IPCC Third Assessment Report (TAR) (IPCC 2001) and the IPCC Fourth Assessment Report (AR4) (IPCC 2007). Therefore, to comply with international reporting standards under the UNFCCC, official emission estimates are reported by the United States using SAR GWP values. All estimates are provided throughout the report in both CO₂ equivalents and unweighted units. A comparison of emission values using the SAR GWPs versus the TAR and AR4 GWPs 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 *	21
N ₂ O	310
HFC-23	11,700
HFC-32	650
HFC-125	2,800
HFC-134a	1,300
HFC-143a	3,800
HFC-152a	140
HFC-227ea	2,900
HFC-236fa	6,300
HFC-4310mee	1,300
CF ₄	6,500
C ₂ F ₆	9,200
C ₄ F ₁₀	7,000
C ₆ F ₁₄	7,400
SF ₆	23,900

Source: IPCC (1996)

* The CH₄ 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 the production of CO₂ is not included.

Global warming potentials are not provided for CO, NO_x, NMVOCs, SO₂, and aerosols because there is no agreed-upon method to estimate the contribution of gases that are short-lived in the atmosphere, spatially variable, or have only indirect effects on radiative forcing (IPCC 1996).

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

In 2009, total U.S. greenhouse gas emissions were 6,633.2 Tg or million metric tons CO₂ Eq. While total U.S. emissions have increased by 7.3 percent from 1990 to 2009, emissions decreased from 2008 to 2009 by 6.1 percent (427.9 Tg CO₂ Eq.). This decrease was primarily due to (1) a decrease in economic output resulting in a decrease in energy consumption across all sectors; and (2) a decrease in the carbon intensity of fuels used to generate electricity due to fuel switching as the price of coal increased, and the price of natural gas decreased significantly. Since 1990, U.S. emissions have increased at an average annual rate of 0.4 percent.

⁹ Carbon comprises 12/44^{ths} of carbon dioxide by weight.

¹⁰ One teragram is equal to 10¹² grams or one million metric tons.

¹¹ See <<http://unfccc.int/resource/docs/2006/sbsta/eng/09.pdf>>.

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 2009.

Figure ES-1: U.S. Greenhouse Gas Emissions by Gas

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

Figure ES-3: Cumulative Change in Annual U.S. Greenhouse Gas Emissions Relative to 1990

Table ES-2: Recent Trends in U.S. Greenhouse Gas Emissions and Sinks (Tg CO₂ Eq. or million metric tons CO₂ Eq.)

Gas/Source	1990	2000	2005	2006	2007	2008	2009
CO₂	5,099.7	5,975.0	6,113.8	6,021.1	6,120.0	5,921.4	5,505.2
Fossil Fuel Combustion	4,738.4	5,594.8	5,753.2	5,653.1	5,756.7	5,565.9	5,209.0
Electricity Generation	1,820.8	2,296.9	2,402.1	2,346.4	2,412.8	2,360.9	2,154.0
Transportation	1,485.9	1,809.5	1,896.6	1,878.1	1,894.0	1,789.9	1,719.7
Industrial	846.5	851.1	823.1	848.2	842.0	802.9	730.4
Residential	338.3	370.7	357.9	321.5	342.4	348.2	339.2
Commercial	219.0	230.8	223.5	208.6	219.4	224.2	224.0
U.S. Territories	27.9	35.9	50.0	50.3	46.1	39.8	41.7
Non-Energy Use of Fuels	118.6	144.9	143.4	145.6	137.2	141.0	123.4
Iron and Steel Production & Metallurgical Coke Production	99.5	85.9	65.9	68.8	71.0	66.0	41.9
Natural Gas Systems	37.6	29.9	29.9	30.8	31.1	32.8	32.2
Cement Production	33.3	40.4	45.2	45.8	44.5	40.5	29.0
Incineration of Waste	8.0	11.1	12.5	12.5	12.7	12.2	12.3
Ammonia Production and Urea Consumption	16.8	16.4	12.8	12.3	14.0	11.9	11.8
Lime Production	11.5	14.1	14.4	15.1	14.6	14.3	11.2
Cropland Remaining Cropland	7.1	7.5	7.9	7.9	8.2	8.7	7.8
Limestone and Dolomite Use	5.1	5.1	6.8	8.0	7.7	6.3	7.6
Soda Ash Production and Consumption	4.1	4.2	4.2	4.2	4.1	4.1	4.3
Aluminum Production	6.8	6.1	4.1	3.8	4.3	4.5	3.0
Petrochemical Production	3.3	4.5	4.2	3.8	3.9	3.4	2.7
Carbon Dioxide Consumption	1.4	1.4	1.3	1.7	1.9	1.8	1.8
Titanium Dioxide Production	1.2	1.8	1.8	1.8	1.9	1.8	1.5
Ferroalloy Production	2.2	1.9	1.4	1.5	1.6	1.6	1.5
Wetlands Remaining Wetlands	1.0	1.2	1.1	0.9	1.0	1.0	1.1
Phosphoric Acid Production	1.5	1.4	1.4	1.2	1.2	1.2	1.0
Zinc Production	0.7	1.0	1.1	1.1	1.1	1.2	1.0
Lead Production	0.5	0.6	0.6	0.6	0.6	0.6	0.5
Petroleum Systems	0.6	0.5	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	0.1
<i>Land Use, Land-Use</i>	<i>(861.5)</i>	<i>(576.6)</i>	<i>(1,056.5)</i>	<i>(1,064.3)</i>	<i>(1,060.9)</i>	<i>(1,040.5)</i>	<i>(1,015.1)</i>

<i>Change, and Forestry (Sink)^a</i>							
<i>Biomass - Wood^b</i>	215.2	218.1	206.9	203.8	203.3	198.4	183.8
<i>International Bunker Fuels^c</i>	111.8	98.5	109.7	128.4	127.6	133.7	123.1
<i>Biomass - Ethanol^b</i>	4.2	9.4	23.0	31.0	38.9	54.8	61.2
CH₄	674.9	659.9	631.4	672.1	664.6	676.7	686.3
Natural Gas Systems	189.8	209.3	190.4	217.7	205.2	211.8	221.2
Enteric Fermentation	132.1	136.5	136.5	138.8	141.0	140.6	139.8
Landfills	147.4	111.7	112.5	111.7	111.3	115.9	117.5
Coal Mining	84.1	60.4	56.9	58.2	57.9	67.1	71.0
Manure Management	31.7	42.4	46.6	46.7	50.7	49.4	49.5
Petroleum Systems	35.4	31.5	29.4	29.4	30.0	30.2	30.9
Wastewater Treatment	23.5	25.2	24.3	24.5	24.4	24.5	24.5
Forest Land Remaining							
Forest Land	3.2	14.3	9.8	21.6	20.0	11.9	7.8
Rice Cultivation	7.1	7.5	6.8	5.9	6.2	7.2	7.3
Stationary Combustion	7.4	6.6	6.6	6.2	6.5	6.5	6.2
Abandoned Underground							
Coal Mines	6.0	7.4	5.5	5.5	5.6	5.9	5.5
Mobile Combustion	4.7	3.4	2.5	2.3	2.2	2.0	2.0
Composting	0.3	1.3	1.6	1.6	1.7	1.7	1.7
Petrochemical Production	0.9	1.2	1.1	1.0	1.0	0.9	0.8
Iron and Steel Production & Metallurgical Coke Production	1.0	0.9	0.7	0.7	0.7	0.6	0.4
Field Burning of Agricultural Residues	0.3	0.3	0.2	0.2	0.2	0.3	0.2
Ferroalloy Production	+	+	+	+	+	+	+
Silicon Carbide Production and Consumption	+	+	+	+	+	+	+
Incineration of Waste	+	+	+	+	+	+	+
<i>International Bunker Fuels^c</i>	0.2	0.1	0.1	0.2	0.2	0.2	0.1
N₂O	315.2	341.0	322.9	326.4	325.1	310.8	295.6
Agricultural Soil Management	197.8	206.8	211.3	208.9	209.4	210.7	204.6
Mobile Combustion	43.9	53.2	36.9	33.6	30.3	26.1	23.9
Manure Management	14.5	17.1	17.3	18.0	18.1	17.9	17.9
Nitric Acid Production	17.7	19.4	16.5	16.2	19.2	16.4	14.6
Stationary Combustion	12.8	14.6	14.7	14.4	14.6	14.2	12.8
Forest Land Remaining							
Forest Land	2.7	12.1	8.4	18.0	16.7	10.1	6.7
Wastewater Treatment	3.7	4.5	4.8	4.8	4.9	5.0	5.0
N ₂ O from Product Uses	4.4	4.9	4.4	4.4	4.4	4.4	4.4
Adipic Acid Production	15.8	5.5	5.0	4.3	3.7	2.0	1.9
Composting	0.4	1.4	1.7	1.8	1.8	1.9	1.8
Settlements Remaining							
Settlements	1.0	1.1	1.5	1.5	1.6	1.5	1.5
Incineration of Waste	0.5	0.4	0.4	0.4	0.4	0.4	0.4
Field Burning of Agricultural Residues	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Wetlands Remaining							
Wetlands	+	+	+	+	+	+	+
<i>International Bunker Fuels^c</i>	1.1	0.9	1.0	1.2	1.2	1.2	1.1
HFCs	36.9	103.2	120.2	123.5	129.5	129.4	125.7
Substitution of Ozone Depleting Substances ^d	0.3	74.3	104.2	109.4	112.3	115.5	120.0

HCFC-22 Production	36.4	28.6	15.8	13.8	17.0	13.6	5.4
Semiconductor Manufacture	0.2	0.3	0.2	0.3	0.3	0.3	0.3
PFCs	20.8	13.5	6.2	6.0	7.5	6.6	5.6
Semiconductor Manufacture	2.2	4.9	3.2	3.5	3.7	4.0	4.0
Aluminum Production	18.5	8.6	3.0	2.5	3.8	2.7	1.6
SF₆	34.4	20.1	19.0	17.9	16.7	16.1	14.8
Electrical Transmission and Distribution	28.4	16.0	15.1	14.1	13.2	13.3	12.8
Magnesium Production and Processing	5.4	3.0	2.9	2.9	2.6	1.9	1.1
Semiconductor Manufacture	0.5	1.1	1.0	1.0	0.8	0.9	1.0
Total	6,181.8	7,112.7	7,213.5	7,166.9	7,263.4	7,061.1	6,633.2
Net Emissions (Sources and Sinks)	5,320.3	6,536.1	6,157.1	6,102.6	6,202.5	6,020.7	5,618.2

+ Does not exceed 0.05 Tg CO₂ Eq.

^a Parentheses indicate negative values or sequestration. The net CO₂ flux total includes both emissions and sequestration, and constitutes a net sink in the United States. Sinks are only included in net emissions total.

^b 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.

^c Emissions from International Bunker Fuels are not included in totals.

^d Small amounts of PFC emissions also result from this source.

Note: Totals may not sum due to independent rounding.

Figure ES-4 illustrates the relative contribution of the direct greenhouse gases to total U.S. emissions in 2009. The primary greenhouse gas emitted by human activities in the United States was CO₂, representing approximately 83.0 percent of total greenhouse gas emissions. The largest source of CO₂, and of overall greenhouse gas emissions, was fossil fuel combustion. CH₄ emissions, which have increased by 1.7 percent since 1990, resulted primarily from natural gas systems, enteric fermentation associated with domestic livestock, and decomposition of wastes in landfills. Agricultural soil management and mobile source fuel combustion were the major sources of N₂O emissions. Ozone depleting substance substitute emissions and emissions of HFC-23 during the production of HCFC-22 were the primary contributors to aggregate HFC emissions. PFC emissions resulted as a by-product of primary aluminum production and from semiconductor manufacturing, while electrical transmission and distribution systems accounted for most SF₆ emissions.

Figure ES-4: 2009 Greenhouse Gas Emissions by Gas (percents based on Tg CO₂ Eq.)

Overall, from 1990 to 2009, total emissions of CO₂ and CH₄ increased by 405.5 Tg CO₂ Eq. (8.0 percent) and 11.4 Tg CO₂ Eq. (1.7 percent), respectively. Conversely, N₂O emissions decreased by 19.6 Tg CO₂ Eq. (6.2 percent). During the same period, aggregate weighted emissions of HFCs, PFCs, and SF₆ rose by 54.1 Tg CO₂ Eq. (58.8 percent). From 1990 to 2009, HFCs increased by 88.8 Tg CO₂ Eq. (240.41 percent), PFCs decreased by 15.1 Tg CO₂ Eq. (73.0 percent), and SF₆ decreased by 19.5 Tg CO₂ Eq. (56.8 percent). Despite being emitted in smaller quantities relative to the other principal greenhouse gases, emissions of HFCs, PFCs, and SF₆ are significant because many of these gases have extremely high global warming potentials and, in the cases of PFCs and SF₆, 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 15.3 percent of total emissions in 2009. The following sections describe each gas' 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 CO₂ 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. Since the Industrial Revolution (i.e., about 1750), global atmospheric concentrations of CO₂ have risen about 36 percent (IPCC 2007), principally due to the combustion of fossil fuels. Within the United States, fossil fuel combustion accounted for 94.6 percent of CO₂ emissions in 2009. Globally, approximately 30,313 Tg of CO₂ were added to the atmosphere through the combustion of fossil fuels in 2009, of which the United States accounted for about 18 percent.¹² Changes in land use and forestry practices can also emit CO₂ (e.g., through conversion of forest land to agricultural or urban use) or can act as a sink for CO₂ (e.g., through net additions to forest biomass). In addition to fossil-fuel combustion, several other sources emit significant quantities of CO₂. These sources include, but are not limited to non-energy use of fuels, iron and steel production and cement production (Figure ES-5).

Figure ES-5: 2009 Sources of CO₂ Emissions

As the largest source of U.S. greenhouse gas emissions, CO₂ from fossil fuel combustion has accounted for approximately 78 percent of GWP-weighted emissions since 1990, growing slowly from 77 percent of total GWP-weighted emissions in 1990 to 79 percent in 2009. Emissions of CO₂ from fossil fuel combustion increased at an average annual rate of 0.4 percent from 1990 to 2009. The fundamental factors influencing this trend include (1) a generally growing domestic economy over the last 20 years, and (2) overall growth in emissions from electricity generation and transportation activities. Between 1990 and 2009, CO₂ emissions from fossil fuel combustion increased from 4,738.4 Tg CO₂ Eq. to 5,209.0 Tg CO₂ Eq.—a 9.9 percent total increase over the twenty-year period. From 2008 to 2009, these emissions decreased by 356.9 Tg CO₂ Eq. (6.4 percent), the largest decrease in any year over the twenty-year period.

Historically, changes in emissions from fossil fuel combustion have been the dominant factor affecting U.S. emission trends. Changes in CO₂ 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, 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: 2009 CO₂ Emissions from Fossil Fuel Combustion by Sector and Fuel Type

Figure ES-7: 2009 End-Use Sector Emissions of CO₂, CH₄, and N₂O from Fossil Fuel Combustion

The five major fuel consuming sectors contributing to CO₂ emissions from fossil fuel combustion are electricity generation, transportation, industrial, residential, and commercial. CO₂ 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.

¹² Global CO₂ emissions from fossil fuel combustion were taken from Energy Information Administration *International Energy Statistics 2010* < <http://tonto.eia.doe.gov/cfapps/ipdbproject/IEDIndex3.cfm> > EIA (2010a).

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 CO₂ emissions from fossil fuel combustion by end-use sector.

Table ES-3: CO₂ Emissions from Fossil Fuel Combustion by Fuel Consuming End-Use Sector (Tg or million metric tons CO₂ Eq.)

End-Use Sector	1990	2000	2005	2006	2007	2008	2009
Transportation	1,489.0	1,813.0	1,901.3	1,882.6	1,899.0	1,794.6	1,724.1
Combustion	1,485.9	1,809.5	1,896.6	1,878.1	1,894.0	1,789.9	1,719.7
Electricity	3.0	3.4	4.7	4.5	5.0	4.7	4.4
Industrial	1,533.2	1,640.8	1,560.0	1,560.2	1,572.0	1,517.7	1,333.7
Combustion	846.5	851.1	823.1	848.2	842.0	802.9	730.4
Electricity	686.7	789.8	737.0	712.0	730.0	714.8	603.3
Residential	931.4	1,133.1	1,214.7	1,152.4	1,198.5	1,182.2	1,123.8
Combustion	338.3	370.7	357.9	321.5	342.4	348.2	339.2
Electricity	593.0	762.4	856.7	830.8	856.1	834.0	784.6
Commercial	757.0	972.1	1,027.2	1,007.6	1,041.1	1,031.6	985.7
Combustion	219.0	230.8	223.5	208.6	219.4	224.2	224.0
Electricity	538.0	741.3	803.7	799.0	821.7	807.4	761.7
U.S. Territories^a	27.9	35.9	50.0	50.3	46.1	39.8	41.7
Total	4,738.4	5,594.8	5,753.2	5,653.1	5,756.7	5,565.9	5,209.0
Electricity Generation	1,820.8	2,296.9	2,402.1	2,346.4	2,412.8	2,360.9	2,154.0

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. Transportation activities (excluding international bunker fuels) accounted for 33 percent of CO₂ emissions from fossil fuel combustion in 2009.¹³ Virtually all of the energy consumed in this end-use sector came from petroleum products. Nearly 65 percent of the emissions resulted from gasoline consumption for personal vehicle use. The remaining emissions came from other transportation activities, including the combustion of diesel fuel in heavy-duty vehicles and jet fuel in aircraft. From 1990 to 2009, transportation emissions rose by 16 percent due, in large part, to increased demand for travel and the stagnation of fuel efficiency across the U.S. vehicle fleet. The number of vehicle miles traveled by light-duty motor vehicles (passenger cars and light-duty trucks) increased 39 percent from 1990 to 2009, as a result of a confluence of factors including population growth, economic growth, urban sprawl, and low fuel prices over much of this period.

Industrial End-Use Sector. Industrial CO₂ emissions, resulting both directly from the combustion of fossil fuels and indirectly from the generation of electricity that is consumed by industry, accounted for 26 percent of CO₂ from fossil fuel combustion in 2009. Approximately 55 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 22 and 19 percent, respectively, of CO₂ emissions from fossil fuel combustion in 2009. Both sectors relied heavily on electricity for meeting energy demands, with 70 and 77 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 these end-use sectors have increased 25 percent since 1990, due to increasing electricity consumption for lighting, heating, air

¹³ If emissions from international bunker fuels are included, the transportation end-use sector accounted for 35 percent of U.S. emissions from fossil fuel combustion in 2009.

conditioning, and operating appliances.

Electricity Generation. The United States relies on electricity to meet a significant portion of its energy demands. Electricity generators consumed 36 percent of U.S. energy from fossil fuels and emitted 41 percent of the CO₂ from fossil fuel combustion in 2009. The type of fuel combusted by electricity generators has a significant effect on their emissions. For example, some electricity is generated with low CO₂ emitting energy technologies, particularly non-fossil options such as nuclear, hydroelectric, or geothermal energy. However, electricity generators rely on coal for over half of their total energy requirements and accounted for 95 percent of all coal consumed for energy in the United States in 2009. Consequently, changes in electricity demand have a significant impact on coal consumption and associated CO₂ emissions.

Other significant CO₂ trends included the following:

- CO₂ emissions from non-energy use of fossil fuels have increased 4.7 Tg CO₂ Eq. (4.0 percent) from 1990 through 2009. Emissions from non-energy uses of fossil fuels were 123.4 Tg CO₂ Eq. in 2009, which constituted 2.2 percent of total national CO₂ emissions, approximately the same proportion as in 1990.
- CO₂ emissions from iron and steel production and metallurgical coke production decreased by 24.1 Tg CO₂ Eq. (36.6 percent) from 2008 to 2009, continuing a trend of decreasing emissions from 1990 through 2009 of 57.9 percent (57.7 Tg CO₂ Eq.). This decline is due to the restructuring of the industry, technological improvements, and increased scrap utilization.
- In 2009, CO₂ emissions from cement production decreased by 11.5 Tg CO₂ Eq. (28.4 percent) from 2008. After decreasing in 1991 by two percent from 1990 levels, cement production emissions grew every year through 2006; emissions decreased in the last three years. Overall, from 1990 to 2009, emissions from cement production decreased by 12.8 percent, a decrease of 4.3 Tg CO₂ Eq.
- Net CO₂ uptake from Land Use, Land-Use Change, and Forestry increased by 153.5 Tg CO₂ Eq. (17.8 percent) from 1990 through 2009. This increase was primarily due to an increase in the rate of net carbon accumulation in forest carbon stocks, particularly in aboveground and belowground tree biomass, and harvested wood pools. Annual carbon accumulation in landfilled yard trimmings and food scraps slowed over this period, while the rate of carbon accumulation in urban trees increased.

Methane Emissions

Methane (CH₄) is more than 20 times as effective as CO₂ at trapping heat in the atmosphere (IPCC 1996). Over the last two hundred and fifty years, the concentration of CH₄ in the atmosphere increased by 148 percent (IPCC 2007). Anthropogenic sources of CH₄ 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: 2009 Sources of CH₄ Emissions

Some significant trends in U.S. emissions of CH₄ include the following:

- In 2009, CH₄ emissions from coal mining were 71.0 Tg CO₂ Eq., a 3.9 Tg CO₂ Eq. (5.8 percent) increase over 2008 emission levels. The overall decline of 13.0 Tg CO₂ Eq. (15.5 percent) from 1990 results from the mining of less gassy coal from underground mines and the increased use of CH₄ collected from degasification systems.
- Natural gas systems were the largest anthropogenic source category of CH₄ emissions in the United States in 2009 with 221.2 Tg CO₂ Eq. of CH₄ emitted into the atmosphere. Those emissions have increased by 31.4 Tg CO₂ Eq. (16.6 percent) since 1990. Methane emissions from this source increased 4 percent from 2008 to 2009 due to an increase in production and production wells.
- Enteric Fermentation is the second largest anthropogenic source of CH₄ emissions in the United States. In 2009, enteric fermentation CH₄ emissions were 139.8 Tg CO₂ Eq. (20 percent of total CH₄ emissions), which represents an increase of 7.7 Tg CO₂ Eq. (5.8 percent) since 1990.

- Methane emissions from manure management increased by 55.9 percent since 1990, from 31.7 Tg CO₂ Eq. in 1990 to 49.5 Tg CO₂ Eq. in 2009. 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 CH₄ 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.
- Landfills are the third largest anthropogenic source of CH₄ emissions in the United States, accounting for 17 percent of total CH₄ emissions (117.5 Tg CO₂ Eq.) in 2009. From 1990 to 2009, CH₄ emissions from landfills decreased by 29.9 Tg CO₂ Eq. (20 percent), with small increases occurring in some interim years. This downward trend in overall emissions is the result of increases in the amount of landfill gas collected and combusted,¹⁴ which has more than offset the additional CH₄ emissions resulting from an increase in the amount of municipal solid waste landfilled.

Nitrous Oxide Emissions

N₂O 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 N₂O emissions are much lower than CO₂ emissions, N₂O is approximately 300 times more powerful than CO₂ at trapping heat in the atmosphere (IPCC 1996). Since 1750, the global atmospheric concentration of N₂O has risen by approximately 18 percent (IPCC 2007). The main anthropogenic activities producing N₂O in the United States are agricultural soil management, fuel combustion in motor vehicles, manure management, nitric acid production and stationary fuel combustion, (see Figure ES-9).

Figure ES-9: 2009 Sources of N₂O Emissions

Some significant trends in U.S. emissions of N₂O include the following:

- In 2009, N₂O emissions from mobile combustion were 23.9 Tg CO₂ Eq. (approximately 8.1 percent of U.S. N₂O emissions). From 1990 to 2009, N₂O emissions from mobile combustion decreased by 45.6 percent. However, from 1990 to 1998 emissions increased by 25.6 percent, due to control technologies that reduced NO_x emissions while increasing N₂O emissions. Since 1998, newer control technologies have led to an overall decline in N₂O from this source.
- N₂O emissions from adipic acid production were 1.9 Tg CO₂ Eq. in 2009, and have decreased significantly since 1996 from the widespread installation of pollution control measures. Emissions from adipic acid production have decreased by 87.7 percent since 1990, and emissions from adipic acid production have remained consistently lower than pre-1996 levels since 1998.
- Agricultural soils accounted for approximately 69.2 percent of N₂O emissions in the United States in 2009. Estimated emissions from this source in 2009 were 204.6 Tg CO₂ Eq. Annual N₂O emissions from agricultural soils fluctuated between 1990 and 2009, although overall emissions were 3.4 percent higher in 2009 than in 1990.

HFC, PFC, and SF₆ Emissions

HFCs and PFCs are families of synthetic chemicals that are used as alternatives to ODS, 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 SF₆, are potent greenhouse gases. In addition to having high global warming potentials, SF₆ 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

¹⁴ The CO₂ produced from combusted landfill CH₄ at landfills is not counted in national inventories as it is considered part of the natural C cycle of decomposition.

IPCC has evaluated (IPCC 1996).

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

Figure ES-10: 2009 Sources of HFCs, PFCs, and SF₆ Emissions

Some significant trends in U.S. HFC, PFC, and SF₆ emissions include the following:

- Emissions resulting from the substitution of ODS (e.g., CFCs) have been consistently increasing, from small amounts in 1990 to 120.0 Tg CO₂ Eq. in 2009. Emissions from ODS substitutes are both the largest and the fastest growing source of HFC, PFC, and SF₆ emissions. These emissions have been increasing as phase-outs required under the Montreal Protocol come into effect, especially after 1994, when full market penetration was made for the first generation of new technologies featuring ODS substitutes.
- HFC emissions from the production of HCFC-22 decreased by 85.2 percent (31.0 Tg CO₂ Eq.) from 1990 through 2009, due to a steady decline in the emission rate of HFC-23 (i.e., the amount of HFC-23 emitted per kilogram of HCFC-22 manufactured) and the use of thermal oxidation at some plants to reduce HFC-23 emissions.
- SF₆ emissions from electric power transmission and distribution systems decreased by 54.8 percent (15.6 Tg CO₂ Eq.) from 1990 to 2009, primarily because of higher purchase prices for SF₆ and efforts by industry to reduce emissions.
- PFC emissions from aluminum production decreased by 91.5 percent (17.0 Tg CO₂ Eq.) from 1990 to 2009, due to both industry emission reduction efforts and lower domestic aluminum production.

Overview of Sector Emissions and Trends

In accordance with the Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC/UNEP/OECD/IEA 1997), and the 2003 UNFCCC Guidelines on Reporting and Review (UNFCCC 2003), 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-year period of 1990 to 2009, total emissions in the Energy and Agriculture sectors grew by 463.3 Tg CO₂ Eq. (9 percent), and 35.7 Tg CO₂ Eq. (9 percent), respectively. Emissions decreased in the Industrial Processes, Waste, and Solvent and Other Product Use sectors by 32.9 Tg CO₂ Eq. (10 percent), 24.7 Tg CO₂ Eq. (14 percent) and less than 0.1 Tg CO₂ Eq. (0.4 percent), respectively. Over the same period, estimates of net C sequestration in the Land Use, Land-Use Change, and Forestry sector (magnitude of emissions plus CO₂ flux from all LULUCF source categories) increased by 143.5 Tg CO₂ Eq. (17 percent).

Figure ES-11: U.S. Greenhouse Gas Emissions and Sinks by Chapter/IPCC Sector

Table ES-4: Recent Trends in U.S. Greenhouse Gas Emissions and Sinks by Chapter/IPCC Sector (Tg or million metric tons CO₂ Eq.)

Chapter/IPCC Sector	1990	2000	2005	2006	2007	2008	2009
Energy	5,287.8	6,168.0	6,282.8	6,210.2	6,290.7	6,116.6	5,751.1
Industrial Processes	315.8	348.8	334.1	339.4	350.9	331.7	282.9
Solvent and Other Product Use	4.4	4.9	4.4	4.4	4.4	4.4	4.4
Agriculture	383.6	410.6	418.8	418.8	425.8	426.3	419.3
Land Use, Land-Use Change, and Forestry (Emissions)	15.0	36.3	28.6	49.8	47.5	33.2	25.0
Waste	175.2	143.9	144.9	144.4	144.1	149.0	150.5
Total Emissions	6,181.8	7,112.7	7,213.5	7,166.9	7,263.4	7,061.1	6,633.2
Net CO ₂ Flux from Land Use, Land-	(861.5)	(576.6)	(1,056.5)	(1,064.3)	(1,060.9)	(1,040.5)	(1,015.1)

Use Change, and Forestry (Sinks)*							
Net Emissions (Sources and Sinks)	5,320.3	6,536.1	6,157.1	6,102.6	6,202.5	6,020.7	5,618.2

* The net CO₂ flux total includes both emissions and sequestration, and constitutes a sink in the United States. Sinks are only included in net emissions total.

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. CO₂ emissions for the period of 1990 through 2009. In 2009, approximately 83 percent of the energy consumed in the United States (on a Btu basis) was produced through the combustion of fossil fuels. The remaining 17 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 CH₄ and N₂O emissions (49 percent and 13 percent of total U.S. emissions of each gas, respectively). Overall, emission sources in the Energy chapter account for a combined 87 percent of total U.S. greenhouse gas emissions in 2009.

Figure ES-12: 2009 U.S. Energy Consumption by Energy Source

Industrial Processes

The Industrial Processes chapter contains by-product or fugitive emissions of greenhouse gases from industrial processes not directly related to energy activities such as fossil fuel combustion. For example, industrial processes can chemically transform raw materials, which often release waste gases such as CO₂, CH₄, and N₂O. These processes include iron and steel production and metallurgical coke production, cement production, ammonia production and urea consumption, lime production, limestone and dolomite use (e.g., flux stone, flue gas desulfurization, and glass manufacturing), soda ash production and consumption, titanium dioxide production, phosphoric acid production, ferroalloy production, CO₂ consumption, silicon carbide production and consumption, aluminum production, petrochemical production, nitric acid production, adipic acid production, lead production, and zinc production. Additionally, emissions from industrial processes release HFCs, PFCs, and SF₆. Overall, emission sources in the Industrial Process chapter account for 4 percent of U.S. greenhouse gas emissions in 2009.

Solvent and Other Product Use

The Solvent and Other Product Use chapter contains greenhouse gas emissions that are produced as a by-product of various solvent and other product uses. In the United States, emissions from N₂O from product uses, the only source of greenhouse gas emissions from this sector, accounted for about 0.1 percent of total U.S. anthropogenic greenhouse gas emissions on a carbon equivalent basis in 2009.

Agriculture

The Agricultural chapter contains anthropogenic emissions from agricultural activities (except fuel combustion, which is addressed in the Energy chapter, and agricultural CO₂ 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. CH₄ and N₂O were the primary greenhouse gases emitted by agricultural activities. CH₄ emissions from enteric fermentation and manure management represented 20 percent and 7 percent of total CH₄ emissions from anthropogenic activities, respectively, in 2009. Agricultural soil management activities such as fertilizer application and other cropping practices were the largest source of U.S. N₂O emissions in 2009, accounting for 69 percent. In 2009, emission sources accounted for in the Agricultural chapters were responsible for 6.3 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 CH₄ and N₂O, and emissions and removals of CO₂ 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 uptake (sequestration) of C in the United States. Forests (including vegetation, soils, and harvested wood) accounted for 85 percent of total 2009 net CO₂ flux, urban trees accounted for 9 percent, mineral and organic soil carbon stock changes accounted for 4 percent, and landfilled yard trimmings and food scraps accounted for 1 percent of the total net flux in 2009. 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 5.5 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 2009 resulted in a net C sequestration of 1,015.1 Tg CO₂ Eq. (Table ES-5). This represents an offset of 18 percent of total U.S. CO₂ emissions, or 15 percent of total greenhouse gas emissions in 2009. Between 1990 and 2009, total land use, land-use change, and forestry net C flux resulted in a 17.8 percent increase in CO₂ sequestration, primarily due to an increase in the rate of net C accumulation in forest C stocks, particularly in aboveground and belowground tree biomass, and harvested wood pools. 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.

Table ES-5: Net CO₂ Flux from Land Use, Land-Use Change, and Forestry (Tg or million metric tons CO₂ Eq.)

Sink Category	1990	2000	2005	2006	2007	2008	2009
Forest Land Remaining Forest Land ¹	(681.1)	(378.3)	(911.5)	(917.5)	(911.9)	(891.0)	(863.1)
Cropland Remaining Cropland	(29.4)	(30.2)	(18.3)	(19.1)	(19.7)	(18.1)	(17.4)
Land Converted to Cropland	2.2	2.4	5.9	5.9	5.9	5.9	5.9
Grassland Remaining Grassland	(52.2)	(52.6)	(8.9)	(8.8)	(8.6)	(8.5)	(8.3)
Land Converted to Grassland	(19.8)	(27.2)	(24.4)	(24.2)	(24.0)	(23.8)	(23.6)
Settlements Remaining Settlements ²	(57.1)	(77.5)	(87.8)	(89.8)	(91.9)	(93.9)	(95.9)
Other (Landfilled Yard Trimmings and Food Scraps)	(24.2)	(13.2)	(11.5)	(11.0)	(10.9)	(11.2)	(12.6)
Total	(861.5)	(576.6)	(1,056.5)	(1,064.3)	(1,060.9)	(1,040.5)	(1,015.1)

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

Emissions from Land Use, Land-Use Change, and Forestry are shown in Table ES-6. The application of crushed limestone and dolomite to managed land (i.e., liming of agricultural soils) and urea fertilization resulted in CO₂ emissions of 7.8 Tg CO₂ Eq. in 2009, an increase of 11 percent relative to 1990. The application of synthetic fertilizers to forest and settlement soils in 2009 resulted in direct N₂O emissions of 1.9 Tg CO₂ Eq. Direct N₂O 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, direct N₂O emissions from fertilizer application to settlement soils increased by 55 percent since 1990. Forest fires resulted in CH₄ emissions of 7.8 Tg CO₂ Eq., and in N₂O emissions of 6.4 Tg CO₂ Eq. in 2009. CO₂ and N₂O emissions from peatlands totaled 1.1 Tg CO₂ Eq. and less than 0.01 Tg CO₂ Eq. in 2009, respectively.

Table ES-6: Emissions from Land Use, Land-Use Change, and Forestry (Tg or million metric tons CO₂ Eq.)

Source Category	1990	2000	2005	2006	2007	2008	2009
CO ₂	8.1	8.8	8.9	8.8	9.2	9.6	8.9
Cropland Remaining Cropland: Liming of Agricultural Soils	4.7	4.3	4.3	4.2	4.5	5.0	4.2
Cropland Remaining Cropland: Urea Fertilization	2.4	3.2	3.5	3.7	3.7	3.6	3.6

Wetlands Remaining Wetlands: Peatlands							
Remaining Peatlands	1.0	1.2	1.1	0.9	1.0	1.0	1.1
CH₄	3.2	14.3	9.8	21.6	20.0	11.9	7.8
Forest Land Remaining Forest Land: Forest Fires	3.2	14.3	9.8	21.6	20.0	11.9	7.8
N₂O	3.7	13.2	9.8	19.5	18.3	11.6	8.3
Forest Land Remaining Forest Land: Forest Fires	2.6	11.7	8.0	17.6	16.3	9.8	6.4
Forest Land Remaining Forest Land: Forest Soils	0.1	0.4	0.4	0.4	0.4	0.4	0.4
Settlements Remaining Settlements: Settlement Soils	1.0	1.1	1.5	1.5	1.6	1.5	1.5
Wetlands Remaining Wetlands: Peatlands							
Remaining Peatlands	+	+	+	+	+	+	+
Total	15.0	36.3	28.6	49.8	47.5	33.2	25.0

+ Less than 0.05 Tg CO₂ Eq.

Note: Totals may not sum due to independent rounding.

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 just over 78 percent of this chapter's emissions, and 17 percent of total U.S. CH₄ emissions.¹⁵ Additionally, wastewater treatment accounts for 20 percent of Waste emissions, 4 percent of U.S. CH₄ emissions, and 2 percent of U.S. N₂O emissions. Emissions of CH₄ and N₂O from composting are also accounted for in this chapter; generating emissions of 1.7 Tg CO₂ Eq. and 1.8 Tg CO₂ Eq., respectively. Overall, emission sources accounted for in the Waste chapter generated 2.3 percent of total U.S. greenhouse gas emissions in 2009.

Other Information

Emissions by Economic Sector

Throughout the Inventory of U.S. Greenhouse Gas Emissions and Sinks report, emission estimates are grouped into six sectors (i.e., chapters) defined by the IPCC: Energy; Industrial Processes; Solvent 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-7 summarizes emissions from each of these sectors, and Figure ES-13 shows the trend in emissions by sector from 1990 to 2009.

Figure ES-13: Emissions Allocated to Economic Sectors

Table ES-7: U.S. Greenhouse Gas Emissions Allocated to Economic Sectors (Tg or million metric tons CO₂ Eq.)

Implied Sectors	1990	2000	2005	2006	2007	2008	2009
Electric Power Industry	1,868.9	2,337.6	2,444.6	2,388.2	2,454.0	2,400.7	2,193.0
Transportation	1,545.2	1,932.3	2,017.4	1,994.4	2,003.8	1,890.7	1,812.4
Industry	1,564.4	1,544.0	1,441.9	1,497.3	1,483.0	1,446.9	1,322.7
Agriculture	429.0	485.1	493.2	516.7	520.7	503.9	490.0
Commercial	395.5	381.4	387.2	375.2	389.6	403.5	409.5
Residential	345.1	386.2	371.0	335.8	358.9	367.1	360.1
U.S. Territories	33.7	46.0	58.2	59.3	53.5	48.4	45.5

¹⁵ 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 of the Inventory report.

Total Emissions	6,181.8	7,112.7	7,213.5	7,166.9	7,263.4	7,061.1	6,633.2
Land Use, Land-Use Change, and Forestry (Sinks)	(861.5)	(576.6)	(1,056.5)	(1,064.3)	(1,060.9)	(1,040.5)	(1,015.1)
Net Emissions (Sources and Sinks)	5,320.3	6,536.1	6,157.1	6,102.6	6,202.5	6,020.7	5,618.2

Note: Totals may not sum due to independent rounding. Emissions include CO₂, CH₄, N₂O, HFCs, PFCs, and SF₆. See Table 2-12 for more detailed data.

Using this categorization, emissions from electricity generation accounted for the largest portion (33 percent) of U.S. greenhouse gas emissions in 2009. Transportation activities, in aggregate, accounted for the second largest portion (27 percent), while emissions from industry accounted for the third largest portion (20 percent) of U.S. greenhouse gas emissions in 2009. 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 20 percent of U.S. greenhouse gas emissions were contributed by, in order of importance, the agriculture, commercial, and residential sectors, plus emissions from U.S. territories. Activities related to agriculture accounted for 7 percent of U.S. emissions; unlike other economic sectors, agricultural sector emissions were dominated by N₂O emissions from agricultural soil management and CH₄ emissions from enteric fermentation. The commercial sector accounted for 6 percent of emissions while the residential sector accounted for 5 percent of emissions and U.S. territories accounted for 1 percent of emissions; emissions from these sectors primarily consisted of CO₂ emissions from fossil fuel combustion.

CO₂ 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-8 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.¹⁶ These source categories include CO₂ from fossil fuel combustion and the use of limestone and dolomite for flue gas desulfurization, CO₂ and N₂O from incineration of waste, CH₄ and N₂O from stationary sources, and SF₆ from electrical transmission and distribution systems.

When emissions from electricity are distributed among these sectors, Industrial activities account for the largest share of U.S. greenhouse gas emissions (29 percent) in 2009. Transportation is the second largest contributor to total U.S. emissions (28 percent). The commercial and residential sectors contributed the next largest shares of total U.S. greenhouse gas emissions in 2009. 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, CO₂ accounts for more than 80 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 2009.

Table ES-8: U.S Greenhouse Gas Emissions by Economic Sector with Electricity-Related Emissions Distributed (Tg or million metric tons CO₂ Eq.)

Implied Sectors	1990	2000	2005	2006	2007	2008	2009
Industry	2,238.3	2,314.4	2,162.5	2,194.6	2,192.9	2,146.5	1,910.9
Transportation	1,548.3	1,935.8	2,022.2	1,999.0	2,008.9	1,895.5	1,816.9
Commercial	947.7	1,135.8	1,205.1	1,188.5	1,225.3	1,224.5	1,184.9
Residential	953.8	1,162.2	1,242.9	1,181.5	1,229.6	1,215.1	1,158.9
Agriculture	460.0	518.4	522.7	544.1	553.2	531.1	516.0
U.S. Territories	33.7	46.0	58.2	59.3	53.5	48.4	45.5
Total Emissions	6,181.8	7,112.7	7,213.5	7,166.9	7,263.4	7,061.1	6,633.2
Land Use, Land-Use Change,	(861.5)	(576.6)	(1,056.5)	(1,064.3)	(1,060.9)	(1,040.5)	(1,015.1)

¹⁶ 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.

and Forestry (Sinks)								
Net Emissions (Sources and Sinks)	5,320.3	6,536.1	6,157.1	6,102.6	6,202.5	6,020.7	5,618.2	

See Table 2-14 for more detailed data.

Figure ES-14: Emissions with Electricity Distributed to Economic Sectors

[BEGIN BOX]

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 nonutilities combined—was the largest source of U.S. greenhouse gas emissions in 2009; (4) emissions per unit of total gross domestic product as a measure of national economic activity; and (5) emissions per capita.

Table ES-9 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 0.4 percent 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-9: Recent Trends in Various U.S. Data (Index 1990 = 100)

Variable	1990	2000	2005	2006	2007	2008	2009	Growth Rate^a
GDP ^b	100	140	157	162	165	165	160	2.5%
Electricity Consumption ^c	100	127	134	135	138	138	132	1.5%
Fossil Fuel Consumption ^c	100	117	119	117	119	116	108	0.5%
Energy Consumption ^c	100	116	118	118	120	118	112	0.6%
Population ^d	100	113	118	120	121	122	123	1.1%
Greenhouse Gas Emissions ^e	100	115	117	116	117	114	107	0.4%

^a Average annual growth rate

^b Gross Domestic Product in chained 2005 dollars (BEA 2010)

^c Energy content-weighted values (EIA 2010b)

^d U.S. Census Bureau (2010)

^e GWP-weighted values

Figure ES-15: U.S. Greenhouse Gas Emissions Per Capita and Per Dollar of Gross Domestic Product
Source: BEA (2010), U.S. Census Bureau (2010), and emission estimates in this report.

[END BOX]

Indirect Greenhouse Gases (CO, NO_x, NMVOCs, and SO₂)

The reporting requirements of the UNFCCC¹⁷ request that information be provided on indirect greenhouse gases, which include CO, NO_x, NMVOCs, and SO₂. 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 SO₂, 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.

Since 1970, the United States has published estimates of annual emissions of CO, NO_x, NMVOCs, and SO₂ (EPA 2010, EPA 2009),¹⁸ which are regulated under the Clean Air Act. Table ES- 10 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 ES- 10: Emissions of NO_x, CO, NMVOCs, and SO₂ (Gg)

Gas/Activity	1990	2000	2005	2006	2007	2008	2009
NO_x	21,707	19,116	15,900	15,039	14,380	13,547	11,468
Mobile Fossil Fuel Combustion	10,862	10,199	9,012	8,488	7,965	7,441	6,206
Stationary Fossil Fuel Combustion	10,023	8,053	5,858	5,545	5,432	5,148	4,159
Industrial Processes	591	626	569	553	537	520	568
Oil and Gas Activities	139	111	321	319	318	318	393
Incineration of Waste	82	114	129	121	114	106	128
Agricultural Burning	8	8	6	7	8	8	8
Solvent Use	1	3	3	4	4	4	3
Waste	0	2	2	2	2	2	2
CO	130,038	92,243	70,809	67,238	63,625	60,039	51,452
Mobile Fossil Fuel Combustion	119,360	83,559	62,692	58,972	55,253	51,533	43,355
Stationary Fossil Fuel Combustion	5,000	4,340	4,649	4,695	4,744	4,792	4,543
Industrial Processes	4,125	2,216	1,555	1,597	1,640	1,682	1,549
Incineration of Waste	978	1,670	1,403	1,412	1,421	1,430	1,403
Agricultural Burning	268	259	184	233	237	270	247
Oil and Gas Activities	302	146	318	319	320	322	345
Waste	1	8	7	7	7	7	7
Solvent Use	5	45	2	2	2	2	2
NMVOCs	20,930	15,227	13,761	13,594	13,423	13,254	9,313
Mobile Fossil Fuel Combustion	10,932	7,229	6,330	6,037	5,742	5,447	4,151
Solvent Use	5,216	4,384	3,851	3,846	3,839	3,834	2,583
Industrial Processes	2,422	1,773	1,997	1,933	1,869	1,804	1,322
Stationary Fossil Fuel Combustion	912	1,077	716	918	1,120	1,321	424
Oil and Gas Activities	554	388	510	510	509	509	599
Incineration of Waste	222	257	241	238	234	230	159
Waste	673	119	114	113	111	109	76
Agricultural Burning	NA	NA	NA	NA	NA	NA	NA
SO₂	20,935	14,830	13,466	12,388	11,799	10,368	8,599
Stationary Fossil Fuel Combustion	18,407	12,849	11,541	10,612	10,172	8,891	7,167
Industrial Processes	1,307	1,031	831	818	807	795	798
Mobile Fossil Fuel Combustion	793	632	889	750	611	472	455
Oil and Gas Activities	390	287	181	182	184	187	154
Incineration of Waste	38	29	24	24	24	23	24
Waste	0	1	1	1	1	1	1
Solvent Use	0	1	0	0	0	0	0

¹⁷ See <<http://unfccc.int/resource/docs/cop8/08.pdf>>.

¹⁸ NO_x and CO emission estimates from field burning of agricultural residues were estimated separately, and therefore not taken from EPA (2008).

Agricultural Burning	NA	NA	NA	NA	NA	NA	NA
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Source: (EPA 2010, EPA 2009) except for estimates from field burning of agricultural residues.
NA (Not Available)
Note: Totals may not sum due to independent rounding.

Key Categories

The 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006) defines a key category as a “[source or sink category] that is prioritized within the national inventory system because its estimate has a significant influence on a country’s total inventory of direct greenhouse gases in terms of the absolute level of emissions, the trend in emissions, or both.”¹⁹ 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 2009 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 1.5 and Annex 1.

Figure ES-16: 2009 Key Categories

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

While the current U.S. emissions inventory provides a solid foundation for the development of a more detailed and comprehensive national inventory, there are uncertainties associated with the emission estimates. Some of the current estimates, such as those for CO₂ 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 IPCC Good Practice Guidance (IPCC 2000) 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.

¹⁹ See Chapter 7 “Methodological Choice and Recalculation” in IPCC (2000). <<http://www.ipcc-nggip.iges.or.jp/public/gp/gpgaum.htm>>

[BEGIN BOX]

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 2009) 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.

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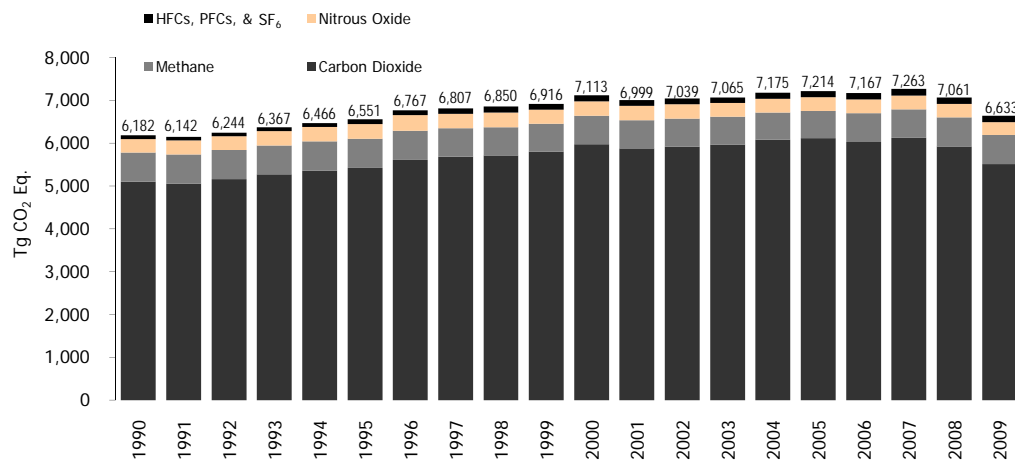


Figure ES-1: U.S. Greenhouse Gas Emissions by Gas

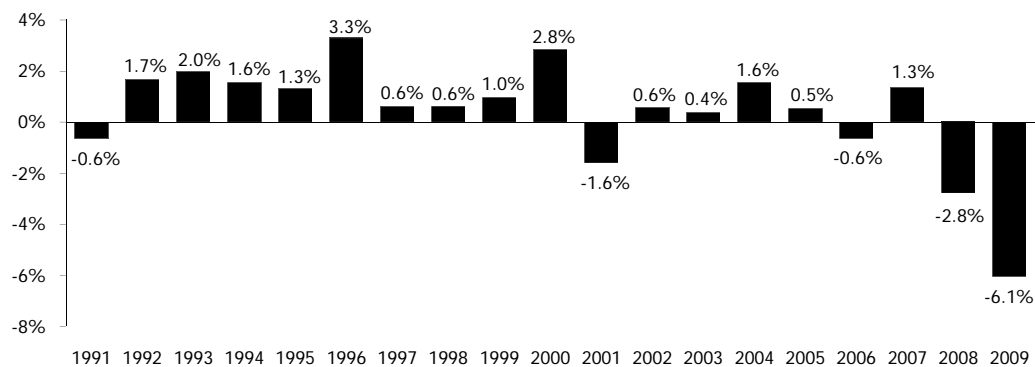


Figure ES-2: Annual Percent Change in U.S. Greenhouse Gas Emissions

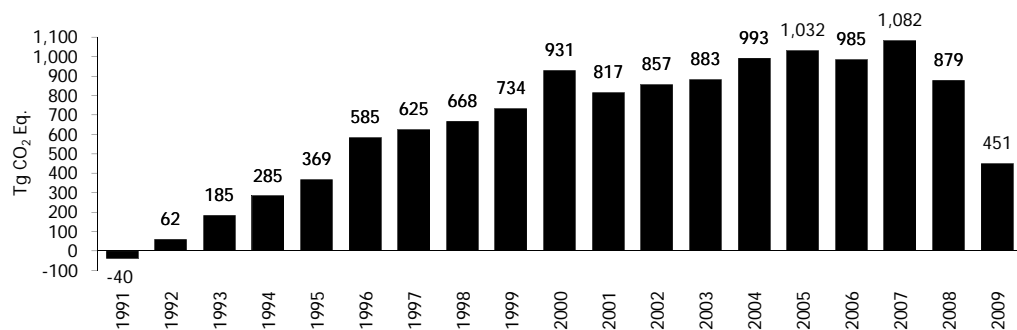


Figure ES-3: Cumulative Change in Annual U.S. Greenhouse Gas Emissions Relative to 1990

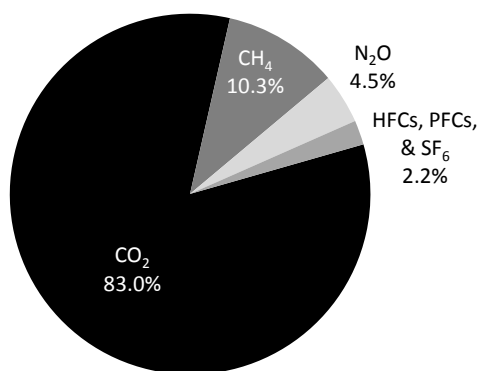


Figure ES-4: 2009 Greenhouse Gas Emissions by Gas (percents based on Tg CO₂ Eq.)

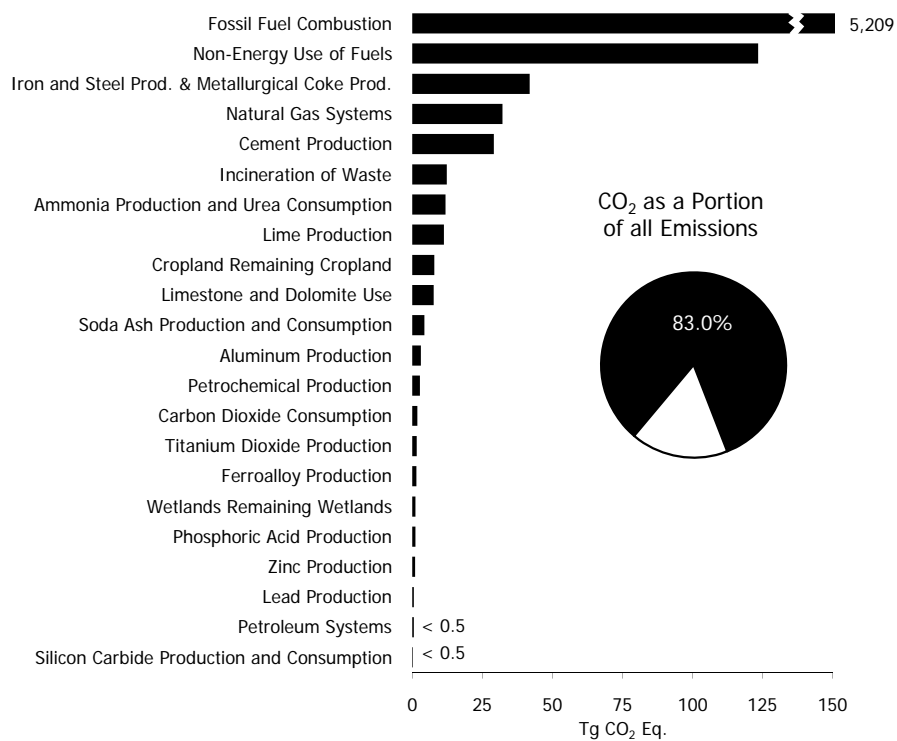


Figure ES-5: 2009 Sources of CO₂ Emissions

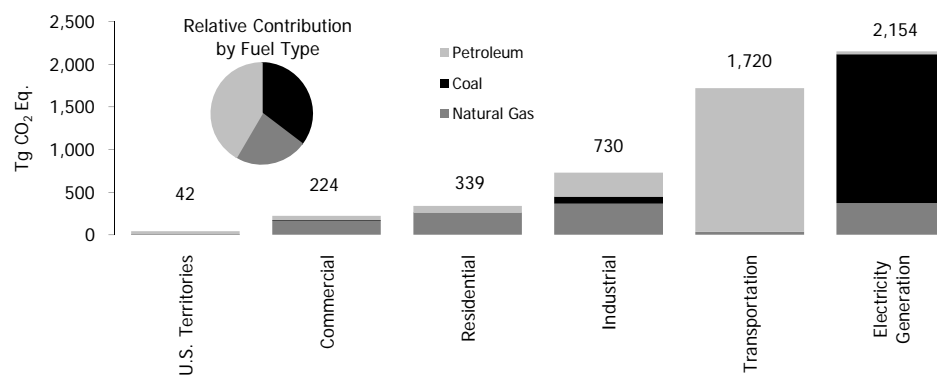


Figure ES-6: 2009 CO₂ Emissions from Fossil Fuel Combustion by Sector and Fuel Type
 Note: Electricity generation also includes emissions of less than 0.5 Tg CO₂ Eq. from geothermal-based electricity generation.

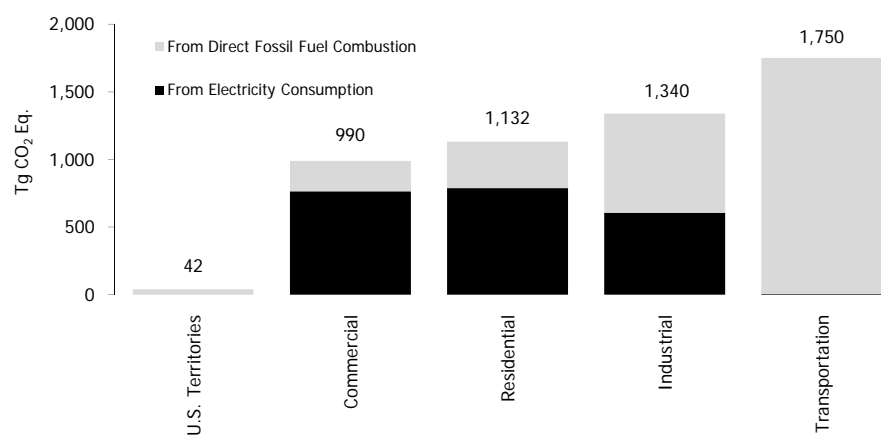


Figure ES-7: 2009 End-Use Sector Emissions of CO₂, CH₄, and N₂O from Fossil Fuel Combustion

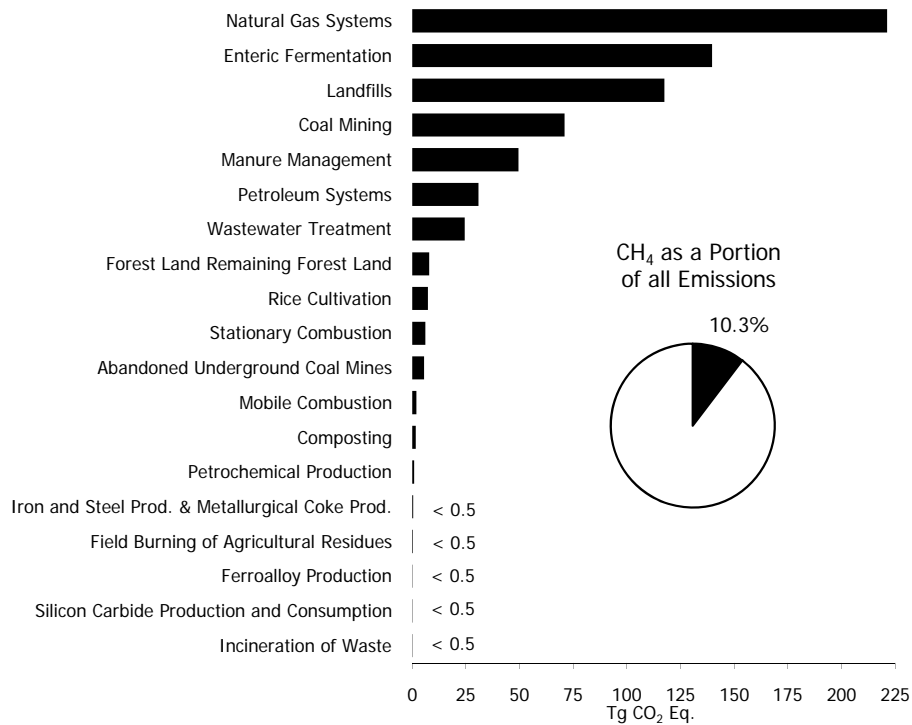


Figure ES-8: 2009 Sources of CH₄ Emissions

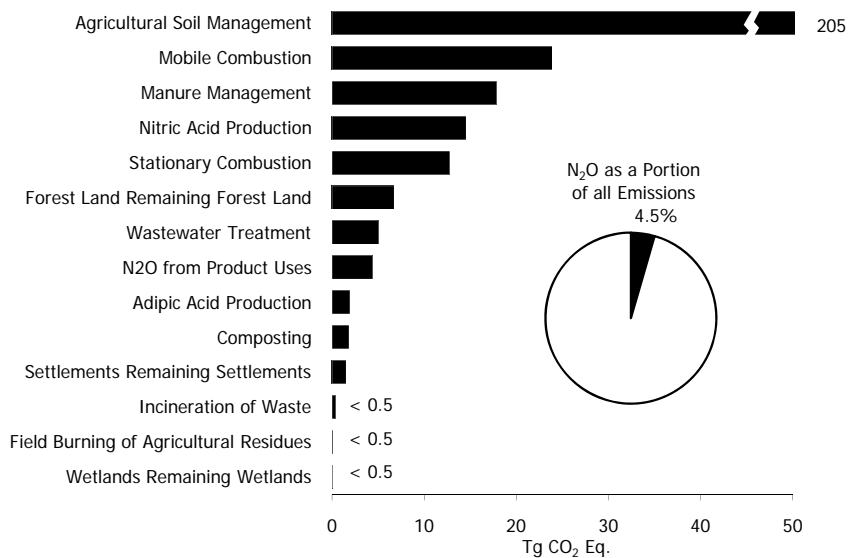


Figure ES-9: 2009 Sources of N₂O Emissions

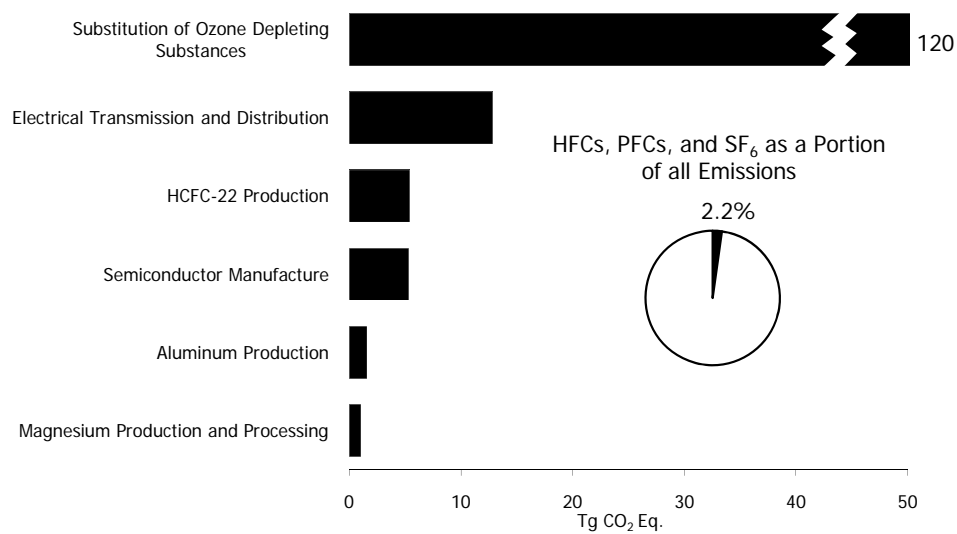
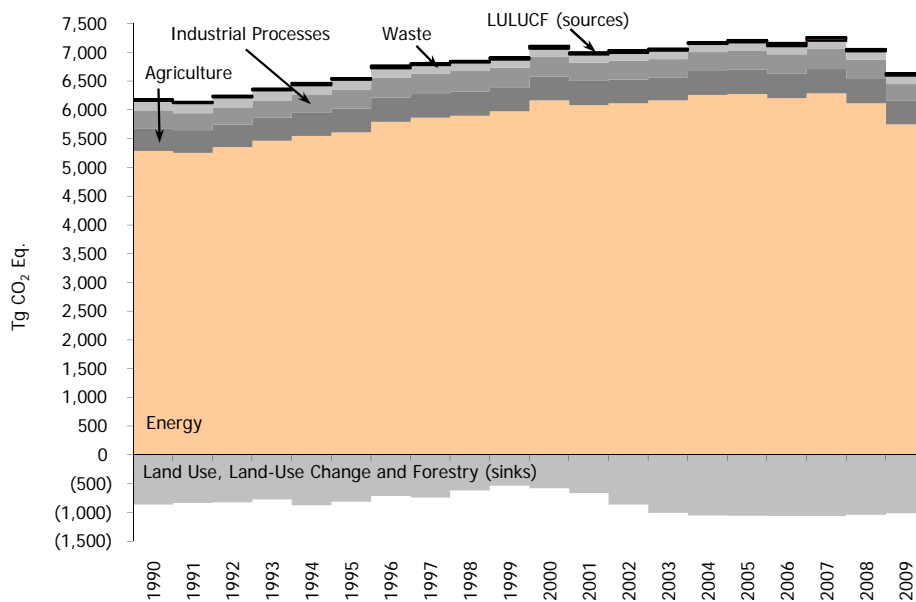


Figure ES-10: 2009 Sources of HFCs, PFCs, and SF₆ Emissions



Note: Relatively smaller amounts of GWP-weighted emissions are also emitted from the Solvent and Other Product Use sectors

Figure ES-11: U.S. Greenhouse Gas Emissions and Sinks by Chapter/IPCC Sector

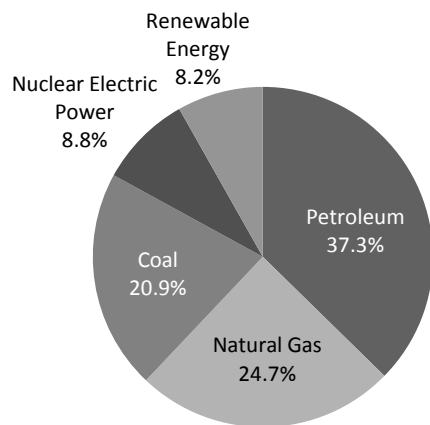


Figure ES-12: 2009 U.S. Energy Consumption by Energy Source

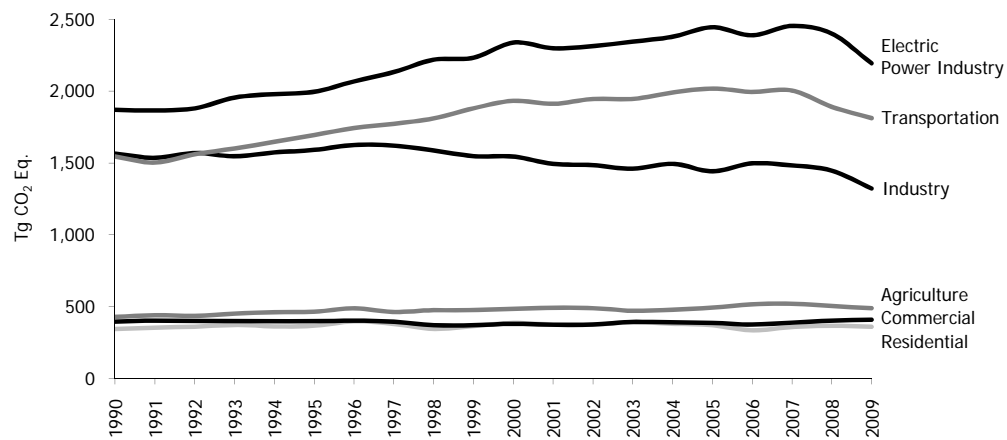


Figure ES-13: Emissions Allocated to Economic Sectors

Note: Does not include U.S. Territories.

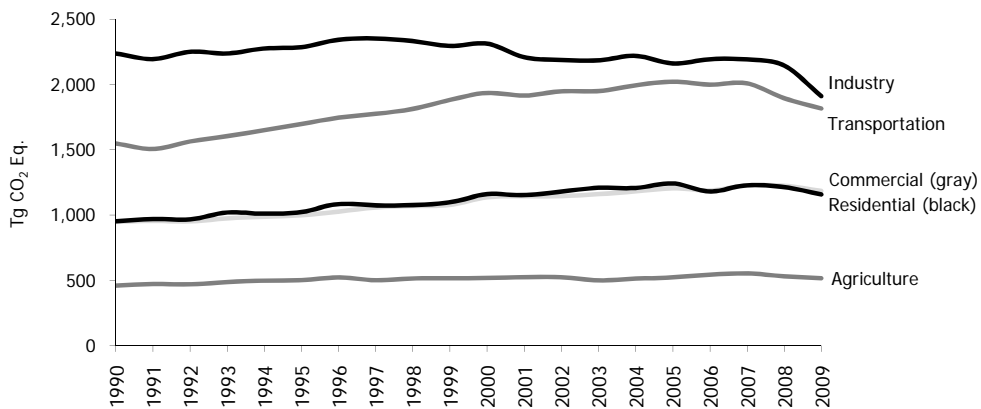


Figure ES-14: Emissions with Electricity Distributed to Economic Sectors

Note: Does not include U.S. Territories.

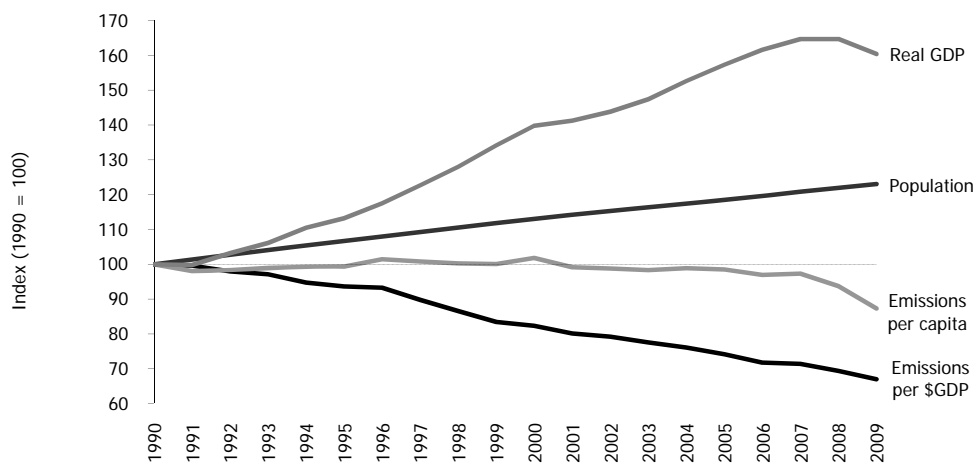


Figure ES-15: U.S. Greenhouse Gas Emissions Per Capita and Per Dollar of Gross Domestic Product

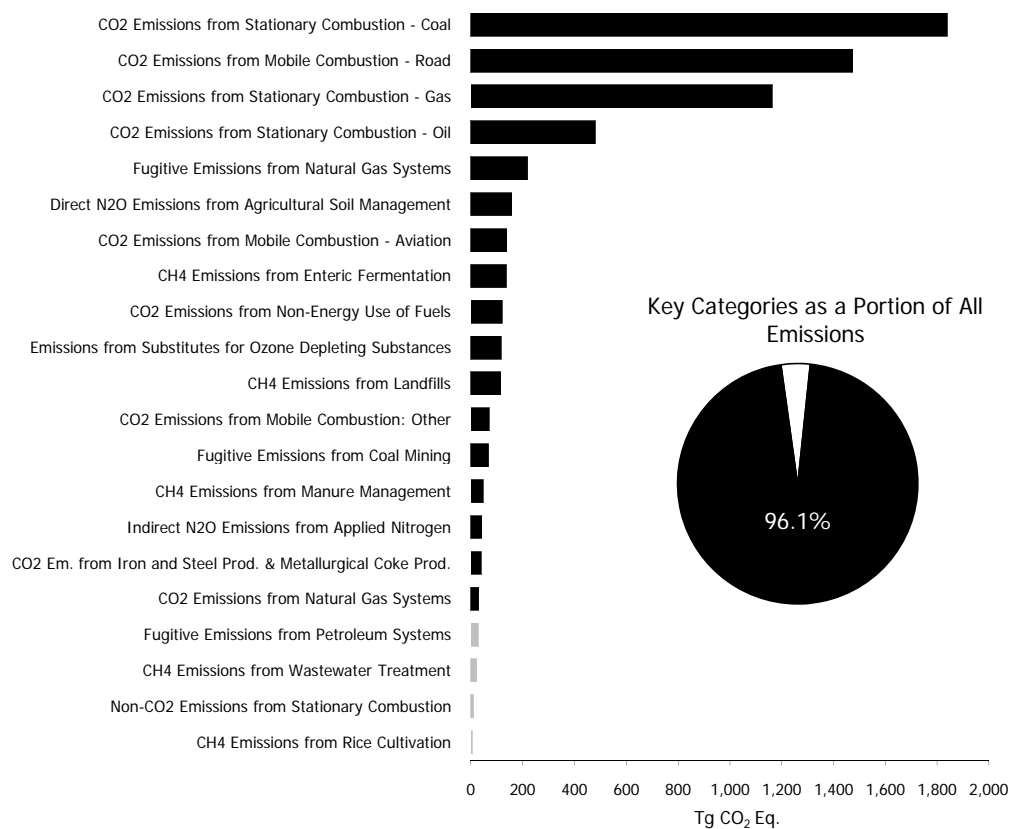


Figure ES-16: 2009 Key Categories

Notes: For a complete discussion of the key category analysis, see Annex 1.

Black bars indicate a Tier 1 level assessment key category.

Gray bars indicate a Tier 2 level assessment key category.

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 2009. 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 in order to show the relative contribution of each gas to global average radiative forcing.²⁰ 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.”^{21,22}

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...”²³ 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 accepted the Revised 1996 IPCC Guidelines at its Twelfth Session (Mexico City, September 11-13, 1996). This report presents information in accordance with these guidelines. In addition, this Inventory is in accordance with the IPCC Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories and the Good Practice Guidance for Land Use, Land-Use Change, and Forestry, which further expanded upon the methodologies in the Revised 1996 IPCC Guidelines. The IPCC has also accepted the 2006 Guidelines for National Greenhouse Gas Inventories (IPCC 2006) at its Twenty-Fifth Session (Mauritius, April 2006). The 2006 IPCC Guidelines build on the previous bodies of work and includes 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.” Many of the methodological improvements presented in the 2006 Guidelines have been adopted in this Inventory.

Overall, this inventory of anthropogenic greenhouse gas emissions 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. territories²⁴. The structure of this report is consistent with the current

²⁰ See the section below entitled *Global Warming Potentials* for an explanation of GWP values.

²¹ 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/UNEP/OECD/IEA 1997).

²² 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)

²³ 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>>.

²⁴ U.S. Territories include American Samoa, Guam, Puerto Rico, U.S. Virgin Islands, Wake Island, and other U.S. Pacific Islands.

[BEGIN BOX]

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 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 Intergovernmental Panel on Climate Change (IPCC).²⁵ Additionally, the calculated emissions and sinks in a given year for the U.S. are presented in a common manner in line with the UNFCCC reporting guidelines for the reporting of inventories under this international agreement.²⁶ 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 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.

[END BOX]

1.1. Background Information

Science

For over the past 200 years, the burning of fossil fuels such as coal and oil, deforestation, and other sources have caused the concentrations of heat-trapping "greenhouse gases" to increase significantly in our atmosphere. These gases absorb some of the energy being radiated from the surface of the earth and trap it in the atmosphere, 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, because without them the planet's surface would be about 60 °F cooler than present. But, as the concentrations of these gases continue to increase in the atmosphere, the Earth's temperature is climbing above past levels. According to NOAA and NASA data, the Earth's average surface temperature has increased by about 1.2 to 1.4 °F since 1900. The ten warmest years on record (since 1850) have all occurred in the past 13 years (EPA 2009). 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 could increase from 2.0 to 11.5 °F above 1990 levels by the end of this century (IPCC 2007). 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. But they are not sure by how much it will change, at what rate it will change, or what the exact effects will be.²⁷

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 (CO₂), and other trace gases in the

²⁵ See <<http://www.ipcc-nggip.iges.or.jp/public/index.html>>.

²⁶ See <http://unfccc.int/national_reports/annex_i_ghg_inventories/national_inventories_submissions/items/5270.php>

²⁷ For more information see <<http://www.epa.gov/climatechange/science>>

atmosphere that absorb the terrestrial radiation leaving the surface of the Earth (IPCC 2001). Changes in the atmospheric concentrations of these greenhouse gases can alter the balance of energy transfers between the atmosphere, space, land, and the oceans.²⁸ A gauge of these changes is called radiative forcing, which is a measure of the influence a factor has in altering the balance of incoming and outgoing energy in the Earth-atmosphere system (IPCC 2001). 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).

Climate change can be driven by changes in the atmospheric concentrations of a number of radiatively active gases and aerosols. We have clear evidence that human activities have affected concentrations, distributions and life cycles of these gases (IPCC 1996).

Naturally occurring greenhouse gases include water vapor, CO₂, methane (CH₄), nitrous oxide (N₂O), and ozone (O₃). 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.²⁹ Some other fluorine-containing halogenated substances—hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF₆)—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.

There are also several gases that, although they do not have a commonly agreed upon direct radiative forcing effect, do influence the global radiation budget. These tropospheric gases include carbon monoxide (CO), nitrogen dioxide (NO₂), sulfur dioxide (SO₂), and tropospheric (ground level) ozone O₃. 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 that are often composed of sulfur compounds, carbonaceous combustion products, crustal materials and other human induced pollutants. They can affect the absorptive characteristics of the atmosphere. Comparatively, however, the level of scientific understanding of aerosols is still very low (IPCC 2001).

CO₂, CH₄, and N₂O 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 (years) of Selected Greenhouse Gases

Atmospheric Variable	CO ₂	CH ₄	N ₂ O	SF ₆	CF ₄
Pre-industrial atmospheric concentration	278 ppm	0.715 ppm	0.270 ppm	0 ppt	40 ppt
Atmospheric concentration	385 ppm	1.741-1.865 ppm ^a	0.321-0.322 ppm ^a	5.6 ppt	74 ppt
Rate of concentration change	1.4 ppm/yr	0.005 ppm/yr ^b	0.26%/yr	Linear ^c	Linear ^c
Atmospheric lifetime (years)	50-200 ^d	12 ^e	114 ^e	3,200	>50,000

Source: Pre-industrial atmospheric concentrations and rate of concentration changes for all gases are from IPCC (2007). The current atmospheric concentration for CO₂ is from NOAA/ESRL (2009).

²⁸ For more on the science of climate change, see NRC (2001).

²⁹ Emissions estimates of CFCs, HCFCs, halons and other ozone-depleting substances are included in this document for informational purposes.

^a The range is the annual arithmetic averages from a mid-latitude Northern-Hemisphere site and a mid-latitude Southern-Hemisphere site for October 2006 through September 2007 (CDIAC 2009).

^b The growth rate for atmospheric CH₄ has been decreasing from 1.4 ppb/yr in 1984 to less than 0 ppb/yr in 2001, 2004, and 2005.

^c IPCC (2007) identifies the rate of concentration change for SF₆ and CF₄ as linear.

^d No single lifetime can be defined for CO₂ because of the different rates of uptake by different removal processes.

^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.

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 (H₂O). Overall, the most abundant and dominant greenhouse gas in the atmosphere is water vapor. Water vapor is neither long-lived nor well mixed in the atmosphere, varying spatially from 0 to 2 percent (IPCC 1996). In addition, atmospheric water can exist in several physical states including gaseous, liquid, and solid. Human activities are not believed to affect directly the average global concentration of water vapor, but, the radiative forcing produced by the increased concentrations of other greenhouse gases may indirectly affect the hydrologic cycle. While a warmer atmosphere has an increased water holding capacity, increased concentrations of water vapor affects the formation of clouds, which can both absorb and reflect solar and terrestrial radiation. Aircraft contrails, which consist of water vapor and other aircraft emittants, are similar to clouds in their radiative forcing effects (IPCC 1999).

Carbon Dioxide. 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 CO₂. Atmospheric CO₂ is part of this global carbon cycle, and therefore its fate is a complex function of geochemical and biological processes. CO₂ concentrations in the atmosphere increased from approximately 280 parts per million by volume (ppmv) in pre-industrial times to 385 ppmv in 2008, a 37.5 percent increase (IPCC 2007 and NOAA/ESRL 2009).^{30,31} The IPCC definitively states that “the present atmospheric CO₂ increase is caused by anthropogenic emissions of CO₂” (IPCC 2001). The predominant source of anthropogenic CO₂ 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 CO₂. In its fourth assessment, the IPCC stated “most of the observed increase in global average temperatures since the mid-20th century is very likely due to the observed increased in anthropogenic greenhouse gas concentrations,” of which CO₂ is the most important (IPCC 2007).

Methane. CH₄ 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 CH₄, as does the decomposition of municipal solid wastes. CH₄ 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 CH₄ have increased by about 143 percent since 1750, from a pre-industrial value of about 722 ppb to 1,741-1,865 ppb in 2007³², although the rate of increase has been declining. The IPCC has estimated that slightly more than half of the current CH₄ flux to the atmosphere is anthropogenic, from human activities such as agriculture, fossil fuel use, and waste disposal (IPCC 2007).

CH₄ is removed from the atmosphere through a reaction with the hydroxyl radical (OH) and is ultimately converted to CO₂. Minor removal processes also include reaction with chlorine in the marine boundary layer, a soil sink, and stratospheric reactions. Increasing emissions of CH₄ reduce the concentration of OH, a feedback that may increase the atmospheric lifetime of CH₄ (IPCC 2001).

Nitrous Oxide. Anthropogenic sources of N₂O emissions include agricultural soils, especially production of

³⁰ The pre-industrial period is considered as the time preceding the year 1750 (IPCC 2001).

³¹ 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 2001).

³² The range is the annual arithmetic averages from a mid-latitude Northern-Hemisphere site and a mid-latitude Southern-Hemisphere site for October 2006 through September 2007 (CDIAC 2009)

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 18 percent since 1750, from a pre-industrial value of about 270 ppb to 321-322 ppb in 2007³³, a concentration that has not been exceeded during the last thousand years. N_2O is primarily removed from the atmosphere by the photolytic action of sunlight in the stratosphere (IPCC 2007).

Ozone. Ozone is present in both the upper stratosphere,³⁴ where it shields the Earth from harmful levels of ultraviolet radiation, and at lower concentrations in the troposphere,³⁵ 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 1996). The depletion of stratospheric ozone and its radiative forcing was expected to reach a maximum in about 2000 before starting to recover. As of IPCC’s fourth assessment, “whether or not recently observed changes in ozone trends are already indicative of recovery of the global ozone layer is not yet clear.” (IPCC 2007)

The past increase in tropospheric ozone, which is also a greenhouse gas, is estimated to provide the third largest increase in direct radiative forcing since the pre-industrial era, behind CO_2 and CH_4 . Tropospheric ozone is produced from complex chemical reactions of volatile organic compounds 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 2001)

Halocarbons, Perfluorocarbons, and Sulfur Hexafluoride. 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 5³⁶ 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, and SF_6 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 2001). PFCs and SF_6 are predominantly emitted from various industrial processes including aluminum smelting, semiconductor manufacturing, electric power transmission and distribution, and magnesium

³³ The range is the annual arithmetic averages from a mid-latitude Northern-Hemisphere site and a mid-latitude Southern-Hemisphere site for October 2006 through September 2007 (CDIAC 2009).

³⁴ 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.

³⁵ 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.

³⁶ 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.

casting. Currently, the radiative forcing impact of PFCs and SF₆ 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 2001).

Carbon Monoxide. Carbon monoxide has an indirect radiative forcing effect by elevating concentrations of CH₄ and tropospheric ozone through chemical reactions with other atmospheric constituents (e.g., the hydroxyl radical, OH) that would otherwise assist in destroying CH₄ 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 CO₂. Carbon monoxide concentrations are both short-lived in the atmosphere and spatially variable.

Nitrogen Oxides. The primary climate change effects of nitrogen oxides (i.e., NO and NO₂) are indirect and result from their role in promoting the formation of ozone in the troposphere and, to a lesser degree, lower stratosphere, where it has positive radiative forcing effects.³⁷ Additionally, NO_x emissions from aircraft are also likely to decrease CH₄ concentrations, thus having a negative radiative forcing effect (IPCC 1999). 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 N₂O. Concentrations of NO_x are both relatively short-lived in the atmosphere and spatially variable.

Nonmethane Volatile Organic Compounds (NMVOCs). Non-CH₄ 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. They can be produced by natural events such as dust storms and volcanic activity, or by anthropogenic processes such as fuel combustion and biomass burning. Aerosols affect radiative forcing differently than greenhouse gases, and their radiative effects occur through direct and indirect mechanisms: directly by scattering and absorbing solar radiation; and indirectly by increasing droplet counts that modify the formation, precipitation efficiency, and radiative properties of clouds. Aerosols are removed from the atmosphere relatively rapidly by precipitation. Because aerosols generally have short atmospheric lifetimes, and have concentrations and compositions that vary regionally, spatially, and temporally, their contributions to radiative forcing are difficult to quantify (IPCC 2001).

The indirect radiative forcing from aerosols is typically divided into two effects. The first effect involves decreased droplet size and increased droplet concentration resulting from an increase in airborne aerosols. The second effect involves an increase in the water content and lifetime of clouds due to the effect of reduced droplet size on precipitation efficiency (IPCC 2001). Recent research has placed a greater focus on the second indirect radiative forcing effect of aerosols.

Various categories of aerosols exist, including naturally produced aerosols such as soil dust, sea salt, biogenic aerosols, sulfates, and volcanic aerosols, and anthropogenically manufactured aerosols such as industrial dust and carbonaceous³⁸ aerosols (e.g., black carbon, organic carbon) from transportation, coal combustion, cement manufacturing, waste incineration, and biomass burning.

The net effect of aerosols on radiative forcing is believed to be negative (i.e., net cooling effect on the climate), although because they remain in the atmosphere for only days to weeks, their concentrations respond rapidly to changes in emissions.³⁹ Locally, the negative radiative forcing effects of aerosols can offset the positive forcing of greenhouse gases (IPCC 1996). “However, the aerosol effects do not cancel the global-scale effects of the much longer-lived greenhouse gases, and significant climate changes can still result” (IPCC 1996).

The IPCC’s Third Assessment Report notes that “the indirect radiative effect of aerosols is now understood to also

³⁷ NO_x emissions injected higher in the stratosphere, primarily from fuel combustion emissions from high altitude supersonic aircraft, can lead to stratospheric ozone depletion.

³⁸ Carbonaceous aerosols are aerosols that are comprised mainly of organic substances and forms of black carbon (or soot) (IPCC 2001).

³⁹ 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 1996).

encompass effects on ice and mixed-phase clouds, but the magnitude of any such indirect effect is not known, although it is likely to be positive” (IPCC 2001). Additionally, current research suggests that another constituent of aerosols, black carbon, has a positive radiative forcing, and that its presence “in the atmosphere above highly reflective surfaces such as snow and ice, or clouds, may cause a significant positive radiative forcing (IPCC 2007). The primary anthropogenic emission sources of black carbon include diesel exhaust and open biomass burning.

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 2001). Direct radiative effects occur when the gas itself absorbs radiation. Indirect radiative forcing occurs when chemical 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 CO₂, and therefore GWP weighted emissions are measured in teragrams of CO₂ equivalent (Tg CO₂ Eq.)⁴⁰ The relationship between gigagrams (Gg) of a gas and Tg CO₂ Eq. can be expressed as follows:

$$\text{Tg CO}_2 \text{ Eq} = (\text{Gg of gas}) \times (\text{GWP}) \times \left(\frac{\text{Tg}}{1,000 \text{ Gg}} \right)$$

where,

Tg CO₂ Eq. = Teragrams of CO₂ Equivalents

Gg = Gigagrams (equivalent to a thousand metric tons)

GWP = Global Warming Potential

Tg = Teragrams

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. The parties to the UNFCCC have also agreed to use GWPs based upon a 100-year time horizon although other time horizon values are available.

Greenhouse gas emissions and removals should be presented on a gas-by-gas basis in units of mass... In addition, consistent with decision 2/CP.3, Parties should report aggregate emissions and removals of greenhouse gases, expressed in CO₂ equivalent terms at summary inventory level, using GWP values provided by the IPCC in its Second Assessment Report... based on the effects of greenhouse gases over a 100-year time horizon.⁴¹

Greenhouse gases with relatively long atmospheric lifetimes (e.g., CO₂, CH₄, N₂O, HFCs, PFCs, and SF₆) 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., SO₂ products and carbonaceous particles), however, vary regionally, and consequently it is difficult to quantify their global radiative forcing impacts. No GWP values are attributed to 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 ^a
CO ₂	50-200	1

⁴⁰ Carbon comprises 12/44^{ths} of carbon dioxide by weight.

⁴¹ Framework Convention on Climate Change; <<http://unfccc.int/resource/docs/cop8/08.pdf>>; 1 November 2002; Report of the Conference of the Parties at its eighth session; held at New Delhi from 23 October to 1 November 2002; Addendum; Part One: Action taken by the Conference of the Parties at its eighth session; Decision -/CP.8; Communications from Parties included in Annex I to the Convention: Guidelines for the Preparation of National Communications by Parties Included in Annex I to the Convention, Part 1: UNFCCC reporting guidelines on annual inventories; p. 7. (UNFCCC 2003)

CH ₄ ^b	12±3	21
N ₂ O	120	310
HFC-23	264	11,700
HFC-32	5.6	650
HFC-125	32.6	2,800
HFC-134a	14.6	1,300
HFC-143a	48.3	3,800
HFC-152a	1.5	140
HFC-227ea	36.5	2,900
HFC-236fa	209	6,300
HFC-4310mee	17.1	1,300
CF ₄	50,000	6,500
C ₂ F ₆	10,000	9,200
C ₄ F ₁₀	2,600	7,000
C ₆ F ₁₄	3,200	7,400
SF ₆	3,200	23,900

Source: (IPCC 1996)

^a 100-year time horizon

^b The GWP of CH₄ 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 CO₂ is not included.

[BEGIN BOX]

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

In 2007, the IPCC published its Fourth Assessment Report (AR4), which provided an updated and more comprehensive scientific assessment of climate change. Within this report, the GWPs of several gases were revised relative to the SAR and the IPCC's Third Assessment Report (TAR) (IPCC 2001). Thus the GWPs used in this report have been updated twice by the IPCC; although the SAR GWPs are used throughout this report, it is interesting to review the changes to the GWPs and the impact such improved understanding has on the total GWP-weighted emissions of the United States. Since the SAR and TAR, the IPCC has applied an improved calculation of CO₂ radiative forcing and an improved CO₂ response function. The GWPs are drawn from IPCC/TEAP (2005) and the TAR, with updates for those cases where new laboratory or radiative transfer results have been published. Additionally, the atmospheric lifetimes of some gases have been recalculated. In addition, the values for radiative forcing and lifetimes have been recalculated for a variety of halocarbons, which were not presented in the SAR. Table 1-3 presents the new GWPs, relative to those presented in the SAR.

Table 1-3: Comparison of 100-Year GWPs

Gas	SAR	TAR	AR4	Change from SAR	
				TAR	AR4
CO ₂	1	1	1	NC	0
CH ₄ *	21	23	25	2	4
N ₂ O	310	296	298	(14)	(12)
HFC-23	11,700	12,000	14,800	300	3,100
HFC-32	650	550	675	(100)	25
HFC-125	2,800	3,400	3,500	600	700
HFC-134a	1,300	1,300	1,430	NC	130
HFC-143a	3,800	4,300	4,470	500	670
HFC-152a	140	120	124	(20)	(16)
HFC-227ea	2,900	3,500	3,220	600	320
HFC-236fa	6,300	9,400	9,810	3,100	3,510
HFC-4310mee	1,300	1,500	1,640	200	340
CF ₄	6,500	5,700	7,390	(800)	890
C ₂ F ₆	9,200	11,900	12,200	2,700	3,000

C ₄ F ₁₀	7,000	8,600	8,860	1,600	1,860
C ₆ F ₁₄	7,400	9,000	9,300	1,600	1,900
SF ₆	23,900	22,200	22,800	(1,700)	(1,100)

Source: (IPCC 2007, IPCC 2001)

NC (No Change)

Note: Parentheses indicate negative values.

* The GWP of CH₄ 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 CO₂ is not included.

To comply with international reporting standards under the UNFCCC, official emission estimates are reported by the United States using SAR GWP values. The UNFCCC reporting guidelines for national inventories⁴² were updated in 2002 but continue to require the use of GWPs from the SAR so that current estimates of aggregate greenhouse gas emissions for 1990 through 2009 are consistent and comparable with estimates developed prior to the publication of the TAR and AR4. For informational purposes, emission estimates that use the updated GWPs are presented in detail in Annex 6.1 of this report. All estimates provided throughout this report are also presented in unweighted units.

[END BOX]

1.2. Institutional 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, 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. The 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 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.

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

⁴² See <<http://unfccc.int/resource/docs/cop8/08.pdf>>.

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 IPCC Good Practice Guidance, IPCC Good Practice Guidance for Land Use, Land Use Change and Forestry, 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 for printing, posted online, printed by the U.S. Government Printing Office, and made available for the public.

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 Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC/UNEP/OECD/IEA 1997). In addition, the United States references the additional guidance provided in the IPCC Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories (IPCC 2000), the IPCC Good Practice Guidance for Land Use, Land-Use Change, and Forestry (IPCC 2003), and 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 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 Revised 1996 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 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.

[BEGIN BOX]

Box 1-3: IPCC Reference Approach

The UNFCCC reporting guidelines require countries to complete a "top-down" reference approach for estimating CO₂ 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.

[END BOX]

1.5. Key Categories

The IPCC's Good Practice Guidance (IPCC 2000) defines a key category as a "[source or sink category] that is prioritized within the national inventory system because its estimate has a significant influence on a country's total inventory of direct greenhouse gases in terms of the absolute level of emissions, the trend in emissions, or both."⁴³ By definition, key categories include those sources that have the greatest contribution to the absolute level of national emissions. 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 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.

A Tier 1 approach, as defined in the IPCC's Good Practice Guidance (IPCC 2000), 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 the Tier 1 approach, a Tier 2 approach, as defined in the IPCC's Good Practice Guidance (IPCC 2000), was then implemented to identify any additional key categories not already identified in the Tier 1 assessment. This analysis, which includes each source categories' uncertainty assessments (or proxies) in its calculations, was also performed twice to include or exclude LULUCF categories.

In addition to conducting Tier 1 and 2 level and trend assessments, a qualitative assessment of the source categories, as described in the IPCC's Good Practice Guidance (IPCC 2000), 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 with IPCC guidelines. If these emissions were included in the totals, bunker fuels would qualify as a key category according to the Tier 1 approach. 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 the Tier 2 approach. 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 2009. The table also indicates the criteria used in identifying these categories (i.e., level, trend, Tier 1, Tier 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.

⁴³ See Chapter 7 "Methodological Choice and Recalculation" in IPCC (2000). <<http://www.ipcc-nggip.iges.or.jp/public/gp/gpgaum.htm>>

Table 1-4: Key Categories for the United States (1990-2009)

IPCC Source Categories	Gas	Tier 1				Tier 2				Qual ^a	2009 Emissions (Tg 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	CO ₂	•		•	•	•		•	•		1,841.0
CO ₂ Emissions from Mobile Combustion: Road	CO ₂	•	•	•	•	•	•	•	•		1,475.6
CO ₂ Emissions from Stationary Combustion - Gas	CO ₂	•	•	•	•	•	•	•	•		1,164.6
CO ₂ Emissions from Stationary Combustion - Oil	CO ₂	•	•	•	•	•	•	•	•		483.3
CO ₂ Emissions from Mobile Combustion: Aviation	CO ₂	•	•	•	•	•	•	•	•		140.7
CO ₂ Emissions from Non-Energy Use of Fuels	CO ₂	•		•	•	•		•			123.4
CO ₂ Emissions from Mobile Combustion: Other	CO ₂	•	•	•	•						73.5
CO ₂ Emissions from Natural Gas Systems	CO ₂	•	•	•	•	•	•	•	•		32.2
CO ₂ Emissions from Mobile Combustion: Marine	CO ₂	•	•	•	•						30.0
Fugitive Emissions from Natural Gas Systems	CH ₄	•	•	•	•	•	•	•	•		221.2
Fugitive Emissions from Coal Mining	CH ₄	•	•	•	•	•	•	•	•		71.0
Fugitive Emissions from Petroleum Systems	CH ₄	•	•	•	•	•	•	•	•		30.9
Non-CO ₂ Emissions from Stationary Combustion	CH ₄						•		•		6.2
N ₂ O Emissions from Mobile Combustion: Road	N ₂ O	•	•	•	•		•		•		20.3
Non-CO ₂ Emissions from Stationary Combustion	N ₂ O					•		•			12.8
International Bunker Fuels ^b	Several									•	124.4
Industrial Processes											
CO ₂ Emissions from Iron and Steel Production & Metallurgical Coke Production	CO ₂	•	•	•	•	•	•	•	•		41.9
CO ₂ Emissions from Cement Production	CO ₂		•	•	•						29.0
CO ₂ Emissions from Ammonia Production and Urea Consumption	CO ₂		•		•						11.8
CO ₂ Emissions from Aluminum Production	CO ₂										3.0
N ₂ O Emissions from Nitric Acid Production	N ₂ O				•		•				14.6
N ₂ O Emissions from Adipic Acid Production	N ₂ O		•		•		•		•		1.9
Emissions from Substitutes for Ozone Depleting Substances	HiGWP	•	•	•	•		•	•	•		120.0
SF ₆ Emissions from Electrical Transmission and Distribution	HiGWP		•		•		•		•		12.8
HFC-23 Emissions from HCFC-22 Production	HiGWP	•	•	•	•		•		•		5.4

IPCC Source Categories	Gas	Tier 1				Tier 2				Qual ^a	2009 Emissions (Tg 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		
PFC Emissions from Aluminum Production	HiGWP		•		•		•				1.6
SF ₆ Emissions from Magnesium Production and Processing	HiGWP		•		•						1.1
Agriculture											
CH ₄ Emissions from Enteric Fermentation	CH ₄	•		•		•		•			139.8
CH ₄ Emissions from Manure Management	CH ₄	•	•	•	•		•		•		49.5
CH ₄ Emissions from Rice Cultivation	CH ₄					•		•			7.3
Direct N ₂ O Emissions from Agricultural Soil Management	N ₂ O	•	•	•	•	•	•	•	•		160.2
Indirect N ₂ O Emissions from Applied Nitrogen	N ₂ O	•		•		•	•	•	•		44.4
Waste											
CH ₄ Emissions from Landfills	CH ₄	•	•	•	•	•	•	•	•		117.5
CH ₄ Emissions from Wastewater Treatment	CH ₄					•		•			24.5
Land Use, Land Use Change, and Forestry											
CO ₂ Emissions from Changes in Forest Carbon Stocks	CO ₂			•	•			•	•		(863.1)
CO ₂ Emissions from Urban Trees	CO ₂			•	•			•	•		(95.9)
CO ₂ Emissions from Cropland Remaining Cropland	CO ₂				•			•	•		(17.4)
CO ₂ Emissions from Landfilled Yard Trimmings and Food Scraps	CO ₂				•			•	•		(12.6)
CO ₂ Emissions from Grassland Remaining Grassland	CO ₂			•	•			•	•		(8.3)
CH ₄ Emissions from Forest Fires	CH ₄							•	•		7.8
N ₂ O Emissions from Forest Fires	N ₂ O								•		6.4
Subtotal Without LULUCF											6,512.7
Total Emissions Without LULUCF											6,608.2
Percent of Total Without LULUCF											99%
Subtotal With LULUCF											5,529.5
Total Emissions With LULUCF											5,618.2
Percent of Total With LULUCF											98%

^aQualitative criteria.

^bEmissions 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 1-1. These attributes include:

- specific detailed procedures and forms 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 the uncertainty of the inventory estimates;
- expert review as well as QC—for both the inventory estimates and the Inventory (which is the primary vehicle for disseminating the results of the inventory development process). In addition, the plan provides for public review of the Inventory;
- both Tier 1 (general) and Tier 2 (source-specific) quality controls and checks, as recommended by IPCC Good Practice Guidance;
- consideration of secondary data quality and source-specific quality checks (Tier 2 QC) in parallel and coordination with the uncertainty assessment; the development of protocols and templates provides for more structured communication and integration with the suppliers of secondary information;
- record-keeping provisions to track which procedures have been followed, and the results of the QA/QC and uncertainty analysis, and contains feedback mechanisms for corrective action based on the results of the investigations, thereby providing for continual data quality improvement and guided research efforts;
- implementation 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;
- a schedule for multi-year implementation; and
- promotion of coordination and interaction 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 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 1-1: 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 CO₂ 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. Despite these uncertainties, the UNFCCC reporting guidelines follow the recommendation in the 1996 IPCC Guidelines (IPCC/UNEP/OECD/IEA 1997) 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 CH₄ and N₂O 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 SF₆ from electrical transmission and distribution is limited due to a lack of activity data regarding national SF₆ consumption or average equipment leak rates.

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

The IPCC provides good practice guidance on two approaches—Tier 1 and Tier 2—to estimating uncertainty for individual source categories. Tier 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 IPCC Good Practice Guidance (IPCC 2000), 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 (Tg CO₂ Eq. and Percent)

Gas	2009 Emission Estimate ^a (Tg CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate ^b				Standard Mean ^c Deviation ^c (Tg CO ₂ Eq.)	
		Lower		Upper		Lower	Upper
		Bound ^d	Bound ^d	Bound	Bound		
CO ₂	5,504.8	5,436.6	5,813.8	-1%	6%	5,622.5	97.5
CH ₄ ^e	686.3	623.9	805.4	-9%	17%	702.8	45.3
N ₂ O ^e	295.6	261.7	425.3	-11%	44%	334.2	42.1
PFC, HFC & SF ₆ ^e	143.3	134.5	153.4	-6%	7%	143.7	4.8
Total	6,630.0	6,584.2	7,033.6	-1%	6%	6,803.2	115.0
Net Emissions (Sources and Sinks)	5,614.9	5,512.3	6,055.1	-2%	8%	5,785.4	139.1

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 3.1 Tg CO₂ 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 CH₄, N₂O and high GWP gases used in the inventory emission calculations for 2009.

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 reporter, 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 2009. Although this report is intended to be comprehensive, certain sources have been identified yet 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 Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC/UNEP/OECD/IEA 1997), and the 2006 UNFCCC Guidelines on Reporting and Review (UNFCCC 2006), this Inventory of U.S. Greenhouse Gas Emissions and Sinks is segregated into six 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.
Industrial Processes	By-product or fugitive emissions of greenhouse gases from industrial processes not directly related to energy activities such as fossil fuel combustion.
Solvent and Other Product Use	Emissions, of primarily NMVOCs, resulting from the use of solvents and N ₂ O from product uses.
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 ₂ O from forest management, other land-use activities, and land-use change.
Waste	Emissions from waste management activities.

Source: (IPCC/UNEP/OECD/IEA 1997)

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: 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 CO₂ 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 ₂ O, and Indirect Greenhouse Gases from Stationary Combustion
3.2.	Methodology for Estimating Emissions of CH ₄ , N ₂ O, and Indirect Greenhouse Gases from Mobile Combustion and Methodology for and Supplemental Information on Transportation-Related Greenhouse Gas Emissions
3.3.	Methodology for Estimating CH ₄ Emissions from Coal Mining
3.4.	Methodology for Estimating CH ₄ Emissions from Natural Gas Systems
3.5.	Methodology for Estimating CH ₄ and CO ₂ Emissions from Petroleum Systems
3.6.	Methodology for Estimating CO ₂ and N ₂ O Emissions from Incineration of Waste
3.7.	Methodology for Estimating Emissions from International Bunker Fuels used by the U.S. Military
3.8.	Methodology for Estimating HFC and PFC Emissions from Substitution of Ozone Depleting Substances
3.9.	Methodology for Estimating CH ₄ Emissions from Enteric Fermentation
3.10.	Methodology for Estimating CH ₄ and N ₂ O Emissions from Manure Management
3.11.	Methodology for Estimating N ₂ O Emissions from Agricultural Soil Management
3.12.	Methodology for Estimating Net Carbon Stock Changes in Forest Lands Remaining Forest Lands
3.13.	Methodology for Estimating Net Changes in Carbon Stocks in Mineral and Organic Soils on Croplands and Grasslands
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
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

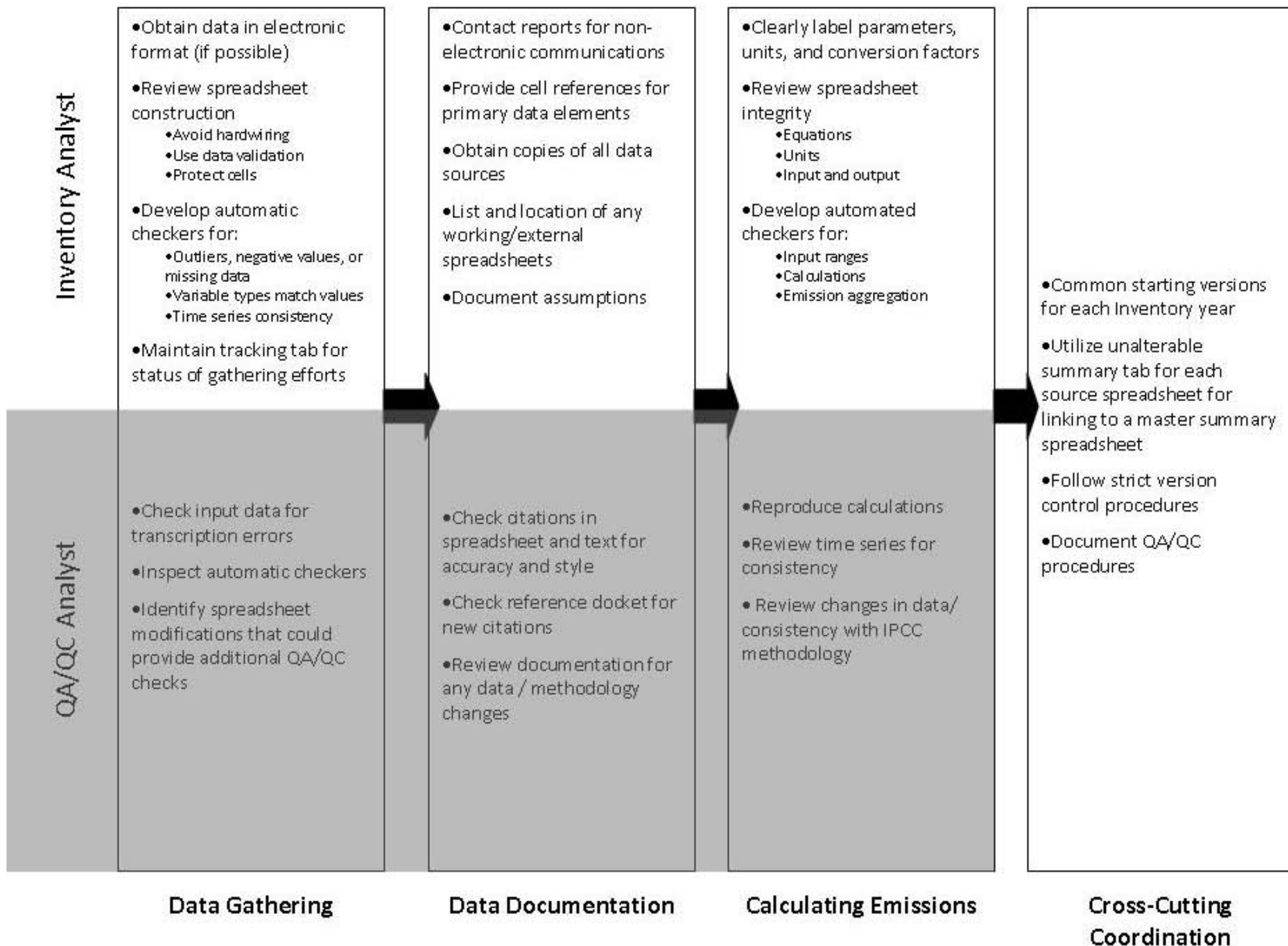
7.1. Overview

7.2. Methodology and Results

7.3. Planned Improvements

7.4. Additional Information on Uncertainty Analyses by Source

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



2. Trends in Greenhouse Gas Emissions

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

In 2009, total U.S. greenhouse gas emissions were 6,633.2 teragrams of carbon dioxide equivalents (Tg CO₂ Eq.); net emissions were 5,618.2 Tg CO₂ Eq. reflecting the influence of sinks (net CO₂ flux from Land Use, Land Use Change, and Forestry).⁴⁴ While total U.S. emissions have increased by 7.3 percent from 1990 to 2009, emissions decreased from 2008 to 2009 by 6.1 percent (427.9 Tg CO₂ Eq.). The following factors were primary contributors to this decrease: (1) a decrease in economic output resulting in a decrease in energy consumption across all sectors; and (2) a decrease in the carbon intensity of fuels used to generate electricity due to fuel switching as the price of coal increased, and the price of natural gas decreased significantly.

Figure 2-1: U.S. Greenhouse Gas Emissions by Gas

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

As the largest contributor to U.S. greenhouse gas emissions, carbon dioxide (CO₂) from fossil fuel combustion has accounted for approximately 79 percent of global warming potential (GWP) weighted emissions since 1990, from 77 percent of total GWP-weighted emissions in 1990 to 79 percent in 2009. Emissions from this source category grew by 9.9 percent (470.6 Tg CO₂ Eq.) from 1990 to 2009 and were responsible for most of the increase in national emissions during this period. From 2008 to 2009, these emissions decreased by 6.4 percent (356.9 Tg CO₂ Eq.). Historically, changes in emissions from fossil fuel combustion have been the dominant factor affecting U.S. emission trends.

Changes in CO₂ 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, 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 CO₂ 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 CO₂ 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 2005.

From 2005 to 2006, emissions from fuel combustion decreased for the first time since 2000 to 2001. This decrease occurred across all sectors, with the exception of the industrial sector and the U.S. Territories sector, due to a

⁴⁴ Estimates are presented in units of teragrams of carbon dioxide equivalent (Tg CO₂ Eq.), which weight each gas by its global warming potential, or GWP, value. See section on global warming potentials in the Executive Summary.

number of factors. The decrease in emissions from electricity generation is a result of a smaller share of electricity generated by coal and a greater share generated by natural gas. Coal consumption for electricity generation decreased by 1.3 percent while natural gas consumption for electricity generation increased by 6.0 percent in 2006 and nuclear power generation increased by less than 1 percent. The decrease in consumption of transportation fuels is primarily a result of the restraint on fuel consumption caused by rising fuel prices, which directly resulted in a decrease of petroleum consumption within this sector of about 1.1 percent in 2006. The significant decrease in emissions from the residential sector is primarily a result of decreased electricity consumption due to increases in the price of electricity, and warmer winter weather conditions compared to 2005. A moderate increase in industrial sector emissions is the result of growth in industrial output and growth in the U.S. economy. Renewable fuels used to generate electricity increased in 2006, with the greatest growth occurring in generation from wind by 48 percent.

After experiencing a decrease from 2005 to 2006, emissions from fuel combustion grew from 2006 to 2007 at a rate somewhat higher than the average growth rate since 1990. There were a number of factors contributing to this increase. More energy-intensive weather conditions in both the winter and summer resulted in an increase in consumption of heating fuels, as well as an increase in the demand for electricity. This demand for electricity was met with an increase in coal consumption of 1.7 percent, and with an increase in natural gas consumption of 9.9 percent. This increase in fossil fuel consumption, combined with a 14.7 percent decrease in hydropower generation from 2006 to 2007, resulted in an increase in emissions in 2007. The increase in emissions from the residential and commercial sectors is a result of increased electricity consumption due to warmer summer conditions and cooler winter conditions compared to 2006. In addition to these more energy-intensive weather conditions, electricity prices remained relatively stable compared to 2006, and natural gas prices decreased slightly. Emissions from the industrial sector decreased compared to 2006 as a result of a decrease in industrial production and fossil fuels used for electricity generation. Despite an overall decrease in electricity generation from renewable energy in 2007 driven by decreases in hydropower generation, wind and solar generation increased significantly.

Emissions from fossil fuel combustion decreased from 2007 to 2008. Several factors contributed to this decrease in emissions. An increase in energy prices coupled with the economic downturn led to a decrease in energy demand and a resulting decrease in emissions from 2007 to 2008. In 2008, the price of coal, natural gas, and petroleum used to generate electricity, as well as the price of fuels used for transportation, increased significantly. As a result of this price increase, coal, natural gas, and petroleum consumption used for electricity generation decreased by 1.4 percent, 2.5 percent, and 28.8 percent, respectively. The increase in the cost of fuels to generate electricity translated into an increase in the price of electricity, leading to a decrease in electricity consumption across all sectors except the commercial sector. The increase in transportation fuel prices led to a decrease in vehicle miles traveled (VMT) and a 5.5 percent decrease in transportation fossil fuel combustion emissions from 2007 to 2008. Cooler weather conditions in the summer led to a decrease in cooling degree days by 8.7 percent and a decrease in electricity demand compared to 2007, whereas cooler winter conditions led to a 5.6 percent increase in heating degree days compared to 2007 and a resulting increase in demand for heating fuels. The increased emissions from winter heating energy demand was offset by a decrease in emissions from summer cooling related electricity demand. Lastly, renewable energy⁴⁵ consumption for electricity generation increased by 9.6 percent from 2007 to 2008, driven by a significant increase in solar and wind energy consumption (of 19.4 percent and 60.2 percent, respectively). This increase in renewable energy generation contributed to a decrease in the carbon intensity of electricity generation.

From 2008 to 2009, CO₂ from fossil fuel combustion emissions experienced a decrease of 6.4 percent, the greatest decrease of any year over the course of the twenty-year period. Various factors contributed to this decrease in emissions. The continued economic downturn resulted in a 2.6 percent decrease in GDP, and a decrease in energy consumption across all sectors. The economic downturn also impacted total industrial production and manufacturing output, which decreased by 9.3 and 10.9 percent, respectively. In 2009, the price of coal used to generate electricity increased, while the price of natural gas used to generate electricity decreased significantly. As a result, natural gas was used for a greater share of electricity generation in 2009 than 2008, and coal was used for a smaller share. The fuel switching from coal to natural gas and additional electricity generation from other energy sources in 2009, which included a 6.8 percent increase in hydropower generation from the previous year, resulted in a decrease in carbon intensity, and in turn, a decrease in emissions from electricity generation. From 2008 to 2009, industrial sector emissions decreased significantly as a result of a decrease in output from energy-intensive industries of 16.6

⁴⁵ Renewable energy, as defined in EIA's energy statistics, includes the following energy sources: hydroelectric power, geothermal energy, biofuels, solar energy, and wind energy.

percent in nonmetallic mineral and 31.6 percent in primary metal industries. The residential and commercial sectors only experienced minor decreases in emissions as summer and winter weather conditions were less energy-intensive from 2008 to 2009, and the price of electricity only increased slightly. Heating degree days decreased slightly and cooling degree days decreased by 3.8 percent from 2008 to 2009.

Overall, from 1990 to 2009, total emissions of CO₂ and CH₄ increased by 405.5 Tg CO₂ Eq. (8.0 percent) and 11.4 Tg CO₂ Eq. (1.7 percent), respectively, while N₂O emissions decreased by 19.6 Tg CO₂ Eq. (6.2 percent). During the same period, aggregate weighted emissions of HFCs, PFCs, and SF₆ rose by 54.1 Tg CO₂ Eq. (58.8 percent). Despite being emitted in smaller quantities relative to the other principal greenhouse gases, emissions of HFCs, PFCs, and SF₆ are significant because many of them have extremely high GWPs and, in the cases of PFCs and SF₆, 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 15.3 percent of total emissions in 2009.

Table 2-1 summarizes emissions and sinks from all U.S. anthropogenic sources in weighted units of Tg CO₂ Eq., while unweighted gas emissions and sinks in gigagrams (Gg) are provided in Table 2-2.

Table 2-1: Recent Trends in U.S. Greenhouse Gas Emissions and Sinks (Tg CO₂ Eq.)

Gas/Source	1990	2000	2005	2006	2007	2008	2009
CO₂	5,099.7	5,975.0	6,113.8	6,021.1	6,120.0	5,921.4	5,505.2
Fossil Fuel Combustion	4,738.4	5,594.8	5,753.2	5,653.1	5,756.7	5,565.9	5,209.0
Electricity Generation	1,820.8	2,296.9	2,402.1	2,346.4	2,412.8	2,360.9	2,154.0
Transportation	1,485.9	1,809.5	1,896.6	1,878.1	1,894.0	1,789.9	1,719.7
Industrial	846.5	851.1	823.1	848.2	842.0	802.9	730.4
Residential	338.3	370.7	357.9	321.5	342.4	348.2	339.2
Commercial	219.0	230.8	223.5	208.6	219.4	224.2	224.0
U.S. Territories	27.9	35.9	50.0	50.3	46.1	39.8	41.7
Non-Energy Use of Fuels	118.6	144.9	143.4	145.6	137.2	141.0	123.4
Iron and Steel Production & Metallurgical Coke Production	99.5	85.9	65.9	68.8	71.0	66.0	41.9
Natural Gas Systems	37.6	29.9	29.9	30.8	31.1	32.8	32.2
Cement Production	33.3	40.4	45.2	45.8	44.5	40.5	29.0
Incineration of Waste	8.0	11.1	12.5	12.5	12.7	12.2	12.3
Ammonia Production and Urea Consumption	16.8	16.4	12.8	12.3	14.0	11.9	11.8
Lime Production	11.5	14.1	14.4	15.1	14.6	14.3	11.2
Cropland Remaining Cropland	7.1	7.5	7.9	7.9	8.2	8.7	7.8
Limestone and Dolomite Use	5.1	5.1	6.8	8.0	7.7	6.3	7.6
Soda Ash Production and Consumption	4.1	4.2	4.2	4.2	4.1	4.1	4.3
Aluminum Production	6.8	6.1	4.1	3.8	4.3	4.5	3.0
Petrochemical Production	3.3	4.5	4.2	3.8	3.9	3.4	2.7
Carbon Dioxide Consumption	1.4	1.4	1.3	1.7	1.9	1.8	1.8
Titanium Dioxide Production	1.2	1.8	1.8	1.8	1.9	1.8	1.5
Ferroalloy Production	2.2	1.9	1.4	1.5	1.6	1.6	1.5
Wetlands Remaining Wetlands	1.0	1.2	1.1	0.9	1.0	1.0	1.1
Phosphoric Acid Production	1.5	1.4	1.4	1.2	1.2	1.2	1.0
Zinc Production	0.7	1.0	1.1	1.1	1.1	1.2	1.0
Lead Production	0.5	0.6	0.6	0.6	0.6	0.6	0.5
Petroleum Systems	0.6	0.5	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	0.1
Land Use, Land-Use Change, and Forestry (Sink) ^a	(861.5)	(576.6)	(1,056.5)	(1,064.3)	(1,060.9)	(1,040.5)	(1,015.1)
Biomass—Wood ^b	215.2	218.1	206.9	203.8	203.3	198.4	183.8
International Bunker Fuels ^c	111.8	98.5	109.7	128.4	127.6	133.7	123.1

<i>Biomass—Ethanol^b</i>	4.2	9.4	23.0	31.0	38.9	54.8	61.2
CH₄	674.9	659.9	631.4	672.1	664.6	676.7	686.3
Natural Gas Systems	189.8	209.3	190.4	217.7	205.2	211.8	221.2
Enteric Fermentation	132.1	136.5	136.5	138.8	141.0	140.6	139.8
Landfills	147.4	111.7	112.5	111.7	111.3	115.9	117.5
Coal Mining	84.1	60.4	56.9	58.2	57.9	67.1	71.0
Manure Management	31.7	42.4	46.6	46.7	50.7	49.4	49.5
Petroleum Systems	35.4	31.5	29.4	29.4	30.0	30.2	30.9
Wastewater Treatment	23.5	25.2	24.3	24.5	24.4	24.5	24.5
Forest Land Remaining Forest							
Land	3.2	14.3	9.8	21.6	20.0	11.9	7.8
Rice Cultivation	7.1	7.5	6.8	5.9	6.2	7.2	7.3
Stationary Combustion	7.4	6.6	6.6	6.2	6.5	6.5	6.2
Abandoned Underground Coal							
Mines	6.0	7.4	5.5	5.5	5.6	5.9	5.5
Mobile Combustion	4.7	3.4	2.5	2.3	2.2	2.0	2.0
Composting	0.3	1.3	1.6	1.6	1.7	1.7	1.7
Petrochemical Production	0.9	1.2	1.1	1.0	1.0	0.9	0.8
Iron and Steel Production & Metallurgical Coke Production	1.0	0.9	0.7	0.7	0.7	0.6	0.4
Field Burning of Agriculture Residues	0.3	0.3	0.2	0.2	0.2	0.3	0.2
Ferroalloy Production	+	+	+	+	+	+	+
Silicon Carbide Production and Consumption	+	+	+	+	+	+	+
Incineration of Waste	+	+	+	+	+	+	+
<i>International Bunker Fuels^c</i>	<i>0.2</i>	<i>0.1</i>	<i>0.1</i>	<i>0.2</i>	<i>0.2</i>	<i>0.2</i>	<i>0.1</i>
N₂O	315.2	341.0	322.9	326.4	325.1	310.8	295.6
Agricultural Soil Management	197.8	206.8	211.3	208.9	209.4	210.7	204.6
Mobile Combustion	43.9	53.2	36.9	33.6	30.3	26.1	23.9
Manure Management	14.5	17.1	17.3	18.0	18.1	17.9	17.9
Nitric Acid Production	17.7	19.4	16.5	16.2	19.2	16.4	14.6
Stationary Combustion	12.8	14.6	14.7	14.4	14.6	14.2	12.8
Forest Land Remaining Forest							
Land	2.7	12.1	8.4	18.0	16.7	10.1	6.7
Wastewater Treatment	3.7	4.5	4.8	4.8	4.9	5.0	5.0
N ₂ O from Product Uses	4.4	4.9	4.4	4.4	4.4	4.4	4.4
Adipic Acid Production	15.8	5.5	5.0	4.3	3.7	2.0	1.9
Composting	0.4	1.4	1.7	1.8	1.8	1.9	1.8
Settlements Remaining							
Settlements	1.0	1.1	1.5	1.5	1.6	1.5	1.5
Incineration of Waste	0.5	0.4	0.4	0.4	0.4	0.4	0.4
Field Burning of Agricultural Residues	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Wetlands Remaining Wetlands	+	+	+	+	+	+	+
<i>International Bunker Fuels^c</i>	<i>1.1</i>	<i>0.9</i>	<i>1.0</i>	<i>1.2</i>	<i>1.2</i>	<i>1.2</i>	<i>1.1</i>
HFCs	36.9	103.2	120.2	123.5	129.5	129.4	125.7
Substitution of Ozone Depleting Substances ^d	0.3	74.3	104.2	109.4	112.3	115.5	120.0
HCFC-22 Production	36.4	28.6	15.8	13.8	17.0	13.6	5.4
Semiconductor Manufacture	0.2	0.3	0.2	0.3	0.3	0.3	0.3
PFCs	20.8	13.5	6.2	6.0	7.5	6.6	5.6
Semiconductor Manufacture	2.2	4.9	3.2	3.5	3.7	4.0	4.0
Aluminum Production	18.5	8.6	3.0	2.5	3.8	2.7	1.6
SF₆	34.4	20.1	19.0	17.9	16.7	16.1	14.8

Electrical Transmission and Distribution	28.4	16.0	15.1	14.1	13.2	13.3	12.8
Magnesium Production and Processing	5.4	3.0	2.9	2.9	2.6	1.9	1.1
Semiconductor Manufacture	0.5	1.1	1.0	1.0	0.8	0.9	1.0
Total	6,181.8	7,112.7	7,213.5	7,166.9	7,263.4	7,061.1	6,633.2
Net Emissions (Sources and Sinks)	5,320.3	6,536.1	6,157.1	6,102.6	6,202.5	6,020.7	5,618.2

+ Does not exceed 0.05 Tg CO₂ Eq.

^a The net CO₂ flux total includes both emissions and sequestration, and constitutes a sink in the United States. Sinks are only included in net emissions total. Parentheses indicate negative values or sequestration.

^b 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.

^c Emissions from International Bunker Fuels are not included in totals.

^d Small amounts of PFC emissions also result from this source.

Note: Totals may not sum due to independent rounding.

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

Gas/Source	1990	2000	2005	2006	2007	2008	2009
CO₂	5,099,719	5,974,991	6,113,751	6,021,089	6,120,009	5,921,443	5,505,204
Fossil Fuel Combustion	4,738,422	5,594,848	5,753,200	5,653,116	5,756,746	5,565,925	5,208,981
Electricity Generation	1,820,818	2,296,894	2,402,142	2,346,406	2,412,827	2,360,919	2,154,025
Transportation	1,485,937	1,809,514	1,896,606	1,878,125	1,893,994	1,789,918	1,719,685
Industrial	846,475	851,094	823,069	848,206	842,048	802,856	730,422
Residential	338,347	370,666	357,903	321,513	342,397	348,221	339,203
Commercial	218,964	230,828	223,512	208,582	219,356	224,167	223,993
U.S. Territories	27,882	35,853	49,968	50,284	46,123	39,845	41,652
Non-Energy Use of Fuels	118,630	144,933	143,392	145,574	137,233	140,952	123,356
Iron and Steel Production & Metallurgical Coke Production	99,528	85,935	65,925	68,772	71,045	66,015	41,871
Natural Gas Systems	37,574	29,877	29,902	30,755	31,050	32,828	32,171
Cement Production	33,278	40,405	45,197	45,792	44,538	40,531	29,018
Incineration of Waste	7,989	11,112	12,450	12,531	12,700	12,169	12,300
Ammonia Production and Urea Consumption	16,831	16,402	12,849	12,300	14,038	11,949	11,797
Lime Production	11,533	14,088	14,379	15,100	14,595	14,330	11,223
Cropland Remaining Cropland	7,084	7,541	7,854	7,875	8,202	8,654	7,832
Limestone and Dolomite Use	5,127	5,056	6,768	8,035	7,702	6,276	7,649
Soda Ash Production and Consumption	4,141	4,181	4,228	4,162	4,140	4,111	4,265
Aluminum Production	6,831	6,086	4,142	3,801	4,251	4,477	3,009
Petrochemical Production	3,311	4,479	4,181	3,837	3,931	3,449	2,735
Carbon Dioxide Consumption	1,416	1,421	1,321	1,709	1,867	1,780	1,763
Titanium Dioxide Production	1,195	1,752	1,755	1,836	1,930	1,809	1,541
Ferroalloy Production	2,152	1,893	1,392	1,505	1,552	1,599	1,469
Wetlands Remaining Wetlands	1,033	1,227	1,079	879	1,012	992	1,090
Phosphoric Acid Production	1,529	1,382	1,386	1,167	1,166	1,187	1,035
Zinc Production	667	997	1,088	1,088	1,081	1,230	966

Lead Production	516	594	553	560	562	551	525
Petroleum Systems	555	534	490	488	474	453	463
Silicon Carbide Production and Consumption	375	248	219	207	196	175	145
<i>Land Use, Land-Use Change, and Forestry (Sink)^a</i>	(861,535)	(576,588)	(1,056,459)	(1,064,330)	(1,060,882)	(1,040,461)	(1,015,074)
<i>Biomass - Wood^b</i>	215,186	218,088	206,865	203,846	203,316	198,361	183,777
<i>International Bunker Fuels^c</i>	111,828	98,482	109,750	128,384	127,618	133,704	123,127
<i>Biomass - Ethanol^b</i>	4,229	9,352	22,956	31,002	38,946	54,770	61,231
CH₄	32,136	31,423	30,069	32,004	31,647	32,225	32,680
Natural Gas Systems	9,038	9,968	9,069	10,364	9,771	10,087	10,535
Enteric Fermentation	6,290	6,502	6,500	6,611	6,715	6,696	6,655
Landfills	7,018	5,317	5,358	5,321	5,299	5,520	5,593
Coal Mining	4,003	2,877	2,710	2,774	2,756	3,196	3,382
Manure Management	1,511	2,019	2,217	2,226	2,416	2,353	2,356
Petroleum Systems	1,685	1,501	1,398	1,398	1,427	1,439	1,473
Wastewater Treatment	1,118	1,199	1,159	1,167	1,163	1,168	1,167
Forest Land Remaining							
Forest Land	152	682	467	1,027	953	569	372
Rice Cultivation	339	357	326	282	295	343	349
Stationary Combustion	354	315	312	293	308	310	293
Abandoned Underground Coal Mines	288	350	264	261	267	279	262
Mobile Combustion	223	160	119	112	105	97	93
Composting	15	60	75	75	79	80	79
Petrochemical Production	41	59	51	48	48	43	40
Iron and Steel Production & Metallurgical Coke Production	46	44	34	35	33	31	17
Field Burning of Agricultural Residues	13	12	9	11	11	13	12
Ferroalloy Production	1	1	+	+	+	+	+
Silicon Carbide Production and Consumption	1	1	+	+	+	+	+
Incineration of Waste	+	+	+	+	+	+	+
<i>International Bunker Fuels^c</i>	8	6	7	8	8	8	7
N₂O	1,017	1,100	1,042	1,053	1,049	1,002	954
Agricultural Soil Management	638	667	682	674	675	680	660
Mobile Combustion	142	172	119	108	98	84	77
Manure Management	47	55	56	58	58	58	58
Nitric Acid Production	57	63	53	52	62	53	47
Stationary Combustion	41	47	47	47	47	46	41
Forest Land Remaining							
Forest Land	9	39	27	58	54	33	22
Wastewater Treatment	12	14	15	16	16	16	16
N ₂ O from Product Uses	14	16	14	14	14	14	14
Adipic Acid Production	51	18	16	14	12	7	6
Composting	1	4	6	6	6	6	6
Settlements Remaining							
Settlements	3	4	5	5	5	5	5

Incineration of Waste	2	1	1	1	1	1	1
Field Burning of Agricultural Residues	+	+	+	+	+	+	+
Wetlands Remaining Wetlands	+	+	+	+	+	+	+
<i>International Bunker Fuels^c</i>	3	3	3	4	4	4	4
HFCs	M	M	M	M	M	M	M
Substitution of Ozone Depleting Substances ^d	M	M	M	M	M	M	M
HCFC-22 Production	3	2	1	1	1	1	+
Semiconductor Manufacture	+	+	+	+	+	+	+
PFCs	M	M	M	M	M	M	M
Semiconductor Manufacture	M	M	M	M	M	M	M
Aluminum Production	M	M	M	M	M	M	M
SF₆	1	1	1	1	1	1	1
Electrical Transmission and Distribution	1	1	1	1	1	1	1
Magnesium Production and Processing	+	+	+	+	+	+	+
Semiconductor Manufacture	+	+	+	+	+	+	+

+ Does not exceed 0.5 Gg.

M Mixture of multiple gases

^a The net CO₂ flux total includes both emissions and sequestration, and constitutes a sink in the United States. Sinks are only included in net emissions total. Parentheses indicate negative values or sequestration.

^b 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

^c Emissions from International Bunker Fuels are not included in totals.

^d Small amounts of PFC emissions also result from this source.

Note: Totals may not sum due to independent rounding.

Emissions of all gases can be summed from each source category from Intergovernmental Panel on Climate Change (IPCC) guidance. Over the twenty-year period of 1990 to 2009, total emissions in the Energy and Agriculture sectors grew by 463.3 Tg CO₂ Eq. (8.8 percent) and 35.7 Tg CO₂ Eq. (9.3 percent), respectively. Emissions decreased in the Industrial Processes, Waste, and Solvent and Other Product Use sectors by 32.9 Tg CO₂ Eq. (10.4 percent), 24.7 Tg CO₂ Eq. (14.1 percent) and less than 0.1 Tg CO₂ Eq. (less than 0.4 percent), respectively. Over the same period, estimates of net C sequestration in the Land Use, Land-Use Change, and Forestry sector increased by 153.5 Tg CO₂ Eq. (17.8 percent).

Figure 2-4: U.S. Greenhouse Gas Emissions and Sinks by Chapter/IPCC Sector

Table 2-3: Recent Trends in U.S. Greenhouse Gas Emissions and Sinks by Chapter/IPCC Sector (Tg CO₂ Eq.)

Chapter/IPCC Sector	1990	2000	2005	2006	2007	2008	2009
Energy	5,287.8	6,168.0	6,282.8	6,210.2	6,290.7	6,116.6	5,751.1
Industrial Processes	315.8	348.8	334.1	339.4	350.9	331.7	282.9
Solvent and Other Product Use	4.4	4.9	4.4	4.4	4.4	4.4	4.4
Agriculture	383.6	410.6	418.8	418.8	425.8	426.3	419.3
Land Use, Land-Use Change, and Forestry (Emissions)	15.0	36.3	28.6	49.8	47.5	33.2	25.0
Waste	175.2	143.9	144.9	144.4	144.1	149.0	150.5

Total Emissions	6,181.8	7,112.7	7,213.5	7,166.9	7,263.4	7,061.1	6,633.2
Net CO ₂ Flux from Land Use, Land-Use Change, and Forestry (Sinks)*	(861.5)	(576.6)	(1056.5)	(1064.3)	(1060.9)	(1040.5)	(1015.1)
Net Emissions (Sources and Sinks)	5,320.3	6,536.1	6,157.1	6,102.6	6,202.5	6,020.7	5,618.2

*The net CO₂ flux total includes both emissions and sequestration, and constitutes a sink in the United States. Sinks are only included in net emissions total. Please refer to Table 2-9 for a breakout by source.

Note: Totals may not sum due to independent rounding.

Note: Parentheses indicate negative values or sequestration.

Energy

Energy-related activities, primarily fossil fuel combustion, accounted for the vast majority of U.S. CO₂ emissions for the period of 1990 through 2009. In 2009, approximately 83 percent of the energy consumed in the United States (on a Btu basis) was produced through the combustion of fossil fuels. The remaining 17 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 CO₂ as well as other greenhouse gas emissions from energy consumption is presented in the Energy chapter. Energy-related activities are also responsible for CH₄ and N₂O emissions (49 percent and 13 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: 2009 Energy Chapter Greenhouse Gas Sources

Figure 2-6: 2009 U.S. Fossil Carbon Flows (Tg CO₂ Eq.)

Table 2-4: Emissions from Energy (Tg CO₂ Eq.)

Gas/Source	1990	2000	2005	2006	2007	2008	2009
CO₂	4,903.2	5,781.3	5,939.4	5,842.5	5,938.2	5,752.3	5,377.3
Fossil Fuel Combustion	4,738.4	5,594.8	5,753.2	5,653.1	5,756.7	5,565.9	5,209.0
Electricity Generation	1,820.8	2,296.9	2,402.1	2,346.4	2,412.8	2,360.9	2,154.0
Transportation	1,485.9	1,809.5	1,896.6	1,878.1	1,894.0	1,789.9	1,719.7
Industrial	846.5	851.1	823.1	848.2	842.0	802.9	730.4
Residential	338.3	370.7	357.9	321.5	342.4	348.2	339.2
Commercial	219.0	230.8	223.5	208.6	219.4	224.2	224.0
U.S. Territories	27.9	35.9	50.0	50.3	46.1	39.8	41.7
Non-Energy Use of Fuels	118.6	144.9	143.4	145.6	137.2	141.0	123.4
Natural Gas Systems	37.6	29.9	29.9	30.8	31.1	32.8	32.2
Incineration of Waste	8.0	11.1	12.5	12.5	12.7	12.2	12.3
Petroleum Systems	0.6	0.5	0.5	0.5	0.5	0.5	0.5
Biomass - Wood ^d	215.2	218.1	206.9	203.8	203.3	198.4	183.8
International Bunker Fuels ^b	111.8	98.5	109.7	128.4	127.6	133.7	123.1
Biomass - Ethanol ^a	4.2	9.4	23.0	31.0	38.9	54.8	61.2
CH₄	327.4	318.6	291.3	319.2	307.3	323.6	336.8
Natural Gas Systems	189.8	209.3	190.4	217.7	205.2	211.8	221.2
Coal Mining	84.1	60.4	56.9	58.2	57.9	67.1	71.0
Petroleum Systems	35.4	31.5	29.4	29.4	30.0	30.2	30.9
Stationary Combustion	7.4	6.6	6.6	6.2	6.5	6.5	6.2
Abandoned Underground							
Coal Mines	6.0	7.4	5.5	5.5	5.6	5.9	5.5
Mobile Combustion	4.7	3.4	2.5	2.3	2.2	2.0	2.0
Incineration of Waste	+	+	+	+	+	+	+

<i>International Bunker Fuels^b</i>	<i>0.2</i>	<i>0.1</i>	<i>0.1</i>	<i>0.2</i>	<i>0.2</i>	<i>0.2</i>	<i>0.1</i>
N₂O	57.2	68.1	52.1	48.5	45.2	40.7	37.0
Mobile Combustion	43.9	53.2	36.9	33.6	30.3	26.1	23.9
Stationary Combustion	12.8	14.6	14.7	14.4	14.6	14.2	12.8
Incineration of Waste	0.5	0.4	0.4	0.4	0.4	0.4	0.4
<i>International Bunker Fuels^b</i>	<i>1.1</i>	<i>0.9</i>	<i>1.0</i>	<i>1.2</i>	<i>1.2</i>	<i>1.2</i>	<i>1.1</i>
Total	5,287.8	6,168.0	6,282.8	6,210.2	6,290.7	6,116.6	5,751.1

+ Does not exceed 0.05 Tg CO₂ Eq.

^a 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

^b Emissions from International Bunker Fuels are not included in totals.

Note: Totals may not sum due to independent rounding.

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 CO₂ 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 the 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, Figure 2-7, and Figure 2-8 summarize CO₂ emissions from fossil fuel combustion by end-use sector.

Table 2-5: CO₂ Emissions from Fossil Fuel Combustion by End-Use Sector (Tg CO₂ Eq.)

End-Use Sector	1990	2000	2005	2006	2007	2008	2009
Transportation	1,489.0	1,813.0	1,901.3	1,882.6	1,899.0	1,794.6	1,724.1
Combustion	1,485.9	1,809.5	1,896.6	1,878.1	1,894.0	1,789.9	1,719.7
Electricity	3.0	3.4	4.7	4.5	5.0	4.7	4.4
Industrial	1,533.2	1,640.8	1,560.0	1,560.2	1,572.0	1,517.7	1,333.7
Combustion	846.5	851.1	823.1	848.2	842.0	802.9	730.4
Electricity	686.7	789.8	737.0	712.0	730.0	714.8	603.3
Residential	931.4	1,133.1	1,214.7	1,152.4	1,198.5	1,182.2	1,123.8
Combustion	338.3	370.7	357.9	321.5	342.4	348.2	339.2
Electricity	593.0	762.4	856.7	830.8	856.1	834.0	784.6
Commercial	757.0	972.1	1,027.2	1,007.6	1,041.1	1,031.6	985.7
Combustion	219.0	230.8	223.5	208.6	219.4	224.2	224.0
Electricity	538.0	741.3	803.7	799.0	821.7	807.4	761.7
U.S. Territories	27.9	35.9	50.0	50.3	46.1	39.8	41.7
Total	4,738.4	5,594.8	5,753.2	5,653.1	5,756.7	5,565.9	5,209.0
Electricity Generation	1,820.8	2,296.9	2,402.1	2,346.4	2,412.8	2,360.9	2,154.0

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.

Figure 2-7: 2009 CO₂ Emissions from Fossil Fuel Combustion by Sector and Fuel Type

Figure 2-8: 2009 End-Use Sector Emissions from Fossil Fuel Combustion

The main driver of emissions in the Energy sector is CO₂ from fossil fuel combustion. The transportation end-use sector accounted for 1,724.1 Tg CO₂ Eq. in 2009 or approximately 33 percent of total CO₂ emissions from fossil fuel combustion, the largest share of any end-use sector.⁴⁶ The industrial end-use sector accounted for 26 percent of CO₂ emissions from fossil fuel combustion. The residential and commercial end-use sectors accounted for an average 22 and 19 percent, respectively, of CO₂ emissions from fossil fuel combustion. Both end-use sectors were heavily reliant on electricity for meeting energy needs, with electricity consumption for lighting, heating, air conditioning, and operating appliances contributing 70 and 77 percent of emissions from the residential and commercial end-use sectors, respectively. Significant trends in emissions from energy source categories over the twenty-year period from 1990 through 2009 included the following:

- Total CO₂ emissions from fossil fuel combustion increased from 4,738.4 Tg CO₂ Eq. to 5,209.0 Tg CO₂ Eq.—a 9.9 percent total increase over the twenty-year period. From 2008 to 2009, these emissions decreased by 356.9 Tg CO₂ Eq. (6.4 percent), the largest decrease of any year over the twenty-year period.
- CO₂ emissions from non-energy use of fossil fuels increased 4.7 Tg CO₂ Eq. (4.0 percent) from 1990 through 2009. Emissions from non-energy uses of fossil fuels were 123.4 Tg CO₂ Eq. in 2009, which constituted 2.2 percent of total national CO₂ emissions.
- CO₂ emissions from incineration of waste (12.3 Tg CO₂ Eq. in 2009) increased by 4.3 Tg CO₂ Eq. (54 percent) from 1990 through 2009, as the volume of plastics and other fossil carbon-containing materials in municipal solid waste grew.
- CH₄ emissions from coal mining were 71.0 Tg CO₂ Eq. in 2009, a decline in emissions of 13.0 Tg CO₂ Eq. (15.5 percent) from 1990. This occurred as a result of the mining of less gassy coal from underground mines and the increased use of CH₄ collected from degasification systems.
- CH₄ emissions from natural gas systems were 221.2 Tg CO₂ Eq. in 2009; emissions have increased by 31.4 Tg CO₂ Eq. (16.6 percent) since 1990.
- In 2009, N₂O emissions from mobile combustion were 23.9 Tg CO₂ Eq. (approximately 8.1 percent of U.S. N₂O emissions). From 1990 to 2009, N₂O emissions from mobile combustion decreased by 45.6 percent. However, from 1990 to 1998 emissions increased by 26 percent, due to control technologies that reduced NO_x emissions while increasing N₂O emissions. Since 1998, newer control technologies have led to a steady decline in N₂O from this source.

Industrial Processes

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 CO₂, CH₄, and N₂O. These processes include iron and steel production and metallurgical coke production, cement production, ammonia production and urea consumption, lime production, limestone and dolomite use (e.g., flux stone, flue gas desulfurization, and glass manufacturing), soda ash production and consumption, titanium dioxide production, phosphoric acid production, ferroalloy production, CO₂ consumption, silicon carbide production and consumption, aluminum production, petrochemical production, nitric acid production, adipic acid production, lead production, and zinc production (see Figure 2-9). Industrial processes also release HFCs, PFCs and SF₆. In addition to their use as ODS substitutes, HFCs, PFCs, SF₆, 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. Table 2-6 presents greenhouse gas emissions from industrial processes by source category.

⁴⁶ Note that electricity generation is the largest emitter of CO₂ when electricity is not distributed among end-use sectors.

Figure 2-9: 2009 Industrial Processes Chapter Greenhouse Gas Sources

Table 2-6: Emissions from Industrial Processes (Tg CO₂ Eq.)

Gas/Source	1990	2000	2005	2006	2007	2008	2009
CO₂	188.4	184.9	165.4	169.9	172.6	159.5	119.0
Iron and Steel Production & Metallurgical Coke Production	99.5	85.9	65.9	68.8	71.0	66.0	41.9
<i>Iron and Steel Production</i>	<i>97.1</i>	<i>83.7</i>	<i>63.9</i>	<i>66.9</i>	<i>69.0</i>	<i>63.7</i>	<i>40.9</i>
<i>Metallurgical Coke Production</i>	<i>2.5</i>	<i>2.2</i>	<i>2.0</i>	<i>1.9</i>	<i>2.1</i>	<i>2.3</i>	<i>1.0</i>
Cement Production	33.3	40.4	45.2	45.8	44.5	40.5	29.0
Ammonia Production & Urea Consumption	16.8	16.4	12.8	12.3	14.0	11.9	11.8
Lime Production	11.5	14.1	14.4	15.1	14.6	14.3	11.2
Limestone and Dolomite Use	5.1	5.1	6.8	8.0	7.7	6.3	7.6
Soda Ash Production and Consumption	4.1	4.2	4.2	4.2	4.1	4.1	4.3
Aluminum Production	6.8	6.1	4.1	3.8	4.3	4.5	3.0
Petrochemical Production	3.3	4.5	4.2	3.8	3.9	3.4	2.7
Carbon Dioxide Consumption	1.4	1.4	1.3	1.7	1.9	1.8	1.8
Titanium Dioxide Production	1.2	1.8	1.8	1.8	1.9	1.8	1.5
Ferroalloy Production	2.2	1.9	1.4	1.5	1.6	1.6	1.5
Phosphoric Acid Production	1.5	1.4	1.4	1.2	1.2	1.2	1.0
Zinc Production	0.7	1.0	1.1	1.1	1.1	1.2	1.0
Lead Production	0.5	0.6	0.6	0.6	0.6	0.6	0.5
Silicon Carbide Production and Consumption	0.4	0.2	0.2	0.2	0.2	0.2	0.1
CH₄	1.9	2.2	1.8	1.7	1.7	1.6	1.2
Petrochemical Production	0.9	1.2	1.1	1.0	1.0	0.9	0.8
Iron and Steel Production & Metallurgical Coke Production	1.0	0.9	0.7	0.7	0.7	0.6	0.4
<i>Iron and Steel Production</i>	<i>1.0</i>	<i>0.9</i>	<i>0.7</i>	<i>0.7</i>	<i>0.7</i>	<i>0.6</i>	<i>0.4</i>
<i>Metallurgical Coke Production</i>	<i>+</i>	<i>+</i>	<i>+</i>	<i>+</i>	<i>+</i>	<i>+</i>	<i>+</i>
Ferroalloy Production	+	+	+	+	+	+	+
Silicon Carbide Production and Consumption	+	+	+	+	+	+	+
N₂O	33.5	24.9	21.5	20.5	22.9	18.5	16.5
Nitric Acid Production	17.7	19.4	16.5	16.2	19.2	16.4	14.6
Adipic Acid Production	15.8	5.5	5.0	4.3	3.7	2.0	1.9
HFCs	36.9	103.2	120.2	123.4	129.5	129.4	125.7
Substitution of Ozone Depleting Substances ^a	0.3	74.3	104.2	109.4	112.3	115.5	120.0
HCFC-22 Production	36.4	28.6	15.8	13.8	17.0	13.6	5.4
Semiconductor Manufacture	0.2	0.3	0.2	0.3	0.3	0.3	0.3
PFCs	20.8	13.5	6.2	6.0	7.5	6.6	5.6
Semiconductor Manufacture	2.2	4.9	3.2	3.5	3.7	4.0	4.0
Aluminum Production	18.5	8.6	3.0	2.5	3.8	2.7	1.6
SF₆	34.4	20.1	19.0	17.9	16.7	16.1	14.8
Electrical Transmission and Distribution	28.4	16.0	15.1	14.1	13.2	13.3	12.8
Magnesium Production and Processing	5.4	3.0	2.9	2.9	2.6	1.9	1.1
Semiconductor Manufacture	0.5	1.1	1.0	1.0	0.8	0.9	1.0
Total	315.8	348.8	334.1	339.4	350.9	331.7	282.9

+ Does not exceed 0.05 Tg CO₂ Eq.^a Small amounts of PFC emissions also result from this source.

Note: Totals may not sum due to independent rounding.

Overall, emissions from industrial processes decreased by 10.4 percent from 1990 to 2009 due to decreases in emissions from several industrial processes, such as iron and steel production and metallurgical coke production, HCFC-22 production, aluminum production, adipic acid production, and electrical transmission and distribution. Significant trends in emissions from industrial processes source categories over the twenty-year period from 1990 through 2009 included the following:

- Combined CO₂ and CH₄ emissions from iron and steel production and metallurgical coke production decreased by 36.6 percent to 42.2 Tg CO₂ Eq. from 2008 to 2009, and have declined overall by 58.2 Tg CO₂ Eq. (58.0 percent) from 1990 through 2009, due to restructuring of the industry, technological improvements, and increased scrap utilization.
- CO₂ emissions from ammonia production and urea consumption (11.8 Tg CO₂ Eq. in 2009) have decreased by 5.0 Tg CO₂ Eq. (29.9 percent) since 1990, due to a decrease in domestic ammonia production. This decrease in ammonia production is primarily attributed to market fluctuations.
- N₂O emissions from adipic acid production were 1.9 Tg CO₂ Eq. in 2009, and have decreased significantly in recent years from the widespread installation of pollution control measures. Emissions from adipic acid production have decreased by 87.7 percent since 1990 and by 89.0 percent since a peak in 1995.
- HFC emissions from ODS substitutes have been increasing from small amounts in 1990 to 120.0 Tg CO₂ Eq. in 2009. This increase results from 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 accelerate over the next decade as HCFCs—which are interim substitutes in many applications—are phased out under the provisions of the Copenhagen Amendments to the Montreal Protocol.
- PFC emissions from aluminum production decreased by about 91.5 percent (17.0 Tg CO₂ Eq.) from 1990 to 2009, due to both industry emission reduction efforts and lower domestic aluminum production.

Solvent and Other Product Use

Greenhouse gas emissions are produced as a by-product of various solvent and other product uses. In the United States, N₂O Emissions from Product Uses, the only source of greenhouse gas emissions from this sector, accounted for 4.4 Tg CO₂ Eq., or less than 0.1 percent of total U.S. emissions in 2009 (see Table 2-7).

Table 2-7: N₂O Emissions from Solvent and Other Product Use (Tg CO₂ Eq.)

Gas/Source	1990	2000	2005	2006	2007	2008	2009
N₂O	4.4	4.9	4.4	4.4	4.4	4.4	4.4
N ₂ O from Product Uses	4.4	4.9	4.4	4.4	4.4	4.4	4.4
Total	4.4	4.9	4.4	4.4	4.4	4.4	4.4

In 2009, N₂O emissions from product uses constituted 1.5 percent of U.S. N₂O emissions. From 1990 to 2009, emissions from this source category decreased by just under 0.4 percent, though slight increases occurred in intermediate years.

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 2009, agricultural activities were responsible for emissions of 419.3 Tg CO₂ Eq., or 6.3 percent of total U.S. greenhouse gas emissions. CH₄ and N₂O were the primary greenhouse gases emitted by agricultural activities. CH₄ emissions from enteric fermentation and manure management represented about 20.4 percent and 7.2 percent of total CH₄ emissions from anthropogenic activities, respectively, in 2009. Agricultural soil management activities, such as fertilizer application and other cropping practices, were the largest source of U.S. N₂O emissions in 2009, accounting for 69.2 percent.

Figure 2-10: 2009 Agriculture Chapter Greenhouse Gas Sources

Table 2-8: Emissions from Agriculture (Tg CO₂ Eq.)

Gas/Source	1990	2000	2005	2006	2007	2008	2009
CH₄	171.2	186.7	190.1	191.7	198.2	197.5	196.8
Enteric Fermentation	132.1	136.5	136.5	138.8	141.0	140.6	139.8
Manure Management	31.7	42.4	46.6	46.7	50.7	49.4	49.5
Rice Cultivation	7.1	7.5	6.8	5.9	6.2	7.2	7.3
Field Burning of Agricultural Residues	0.3	0.3	0.2	0.2	0.2	0.3	0.2
N₂O	212.4	224.0	228.7	227.1	227.6	228.8	222.5
Agricultural Soil Management	197.8	206.8	211.3	208.9	209.4	210.7	204.6
Manure Management	14.5	17.1	17.3	18.0	18.1	17.9	17.9
Field Burning of Agricultural Residues	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	383.6	410.6	418.8	418.8	425.8	426.3	419.3

Note: Totals may not sum due to independent rounding.

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

- Agricultural soils produced approximately 69 percent of N₂O emissions in the United States in 2009. Estimated emissions from this source in 2009 were 204.6 Tg CO₂ Eq. Annual N₂O emissions from agricultural soils fluctuated between 1990 and 2009, although overall emissions were 3.4 percent higher in 2009 than in 1990. Nitrous oxide emissions from this source have not shown any significant long-term trend, as their estimation is highly sensitive to the amount of N applied to soils, which has not changed significantly over the time-period, and to weather patterns and crop type.
- Enteric fermentation was the largest source of CH₄ emissions in 2009, at 139.8 Tg CO₂ Eq. Generally, emissions decreased from 1996 to 2003, though with a slight increase in 2002. This trend was mainly due to decreasing populations of both beef and dairy cattle and increased digestibility of feed for feedlot cattle. Emissions increased from 2004 through 2007, as both dairy and beef populations increased and the literature for dairy cow diets indicated a trend toward a decrease in feed digestibility for those years. Emissions decreased again in 2008 and 2009 as beef cattle populations decreased again. During the timeframe of this analysis, populations of sheep have decreased 49 percent since 1990 while horse populations have increased over 87 percent, mostly since 1999. Goat and swine populations have increased 25 percent and 23 percent, respectively, during this timeframe.
- Overall, emissions from manure management increased 46 percent between 1990 and 2009. This encompassed an increase of 56 percent for CH₄, from 31.7 Tg CO₂ Eq. in 1990 to 49.5 Tg CO₂ Eq. in 2009; and an increase of 23 percent for N₂O, from 14.5 Tg CO₂ Eq. in 1990 to 17.9 Tg CO₂ Eq. in 2009. 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 CH₄ emissions.

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 landfiling of yard trimmings and food scraps have resulted in an uptake (sequestration) of carbon in the United States, which offset about 15 percent of total U.S. greenhouse gas emissions in 2009. Forests (including vegetation, soils, and harvested wood) accounted for approximately 85 percent of total 2009 net CO₂ flux, urban trees accounted for 9 percent, mineral and organic soil carbon stock changes accounted for 4 percent, and landfilled yard trimmings and food scraps accounted for 1 percent of the total net flux in 2009. 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 5.5 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 carbon and food scraps in landfills.

Land use, land-use change, and forestry activities in 2009 resulted in a net C sequestration of 1,015.1 Tg CO₂ Eq. (276.8 Tg C) (Table 2-9). This represents an offset of approximately 18 percent of total U.S. CO₂ emissions, or 15 percent of total greenhouse gas emissions in 2009. Between 1990 and 2009, total land use, land-use change, and forestry net C flux resulted in a 17.8 percent increase in CO₂ sequestration.

Table 2-9: Net CO₂ Flux from Land Use, Land-Use Change, and Forestry (Tg CO₂ Eq.)

Sink Category	1990	2000	2005	2006	2007	2008	2009
Forest Land Remaining Forest							
Land	(681.1)	(378.3)	(911.5)	(917.5)	(911.9)	(891.0)	(863.1)
Cropland Remaining Cropland	(29.4)	(30.2)	(18.3)	(19.1)	(19.7)	(18.1)	(17.4)
Land Converted to Cropland	2.2	2.4	5.9	5.9	5.9	5.9	5.9
Grassland Remaining Grassland	(52.2)	(52.6)	(8.9)	(8.8)	(8.6)	(8.5)	(8.3)
Land Converted to Grassland	(19.8)	(27.2)	(24.4)	(24.2)	(24.0)	(23.8)	(23.6)
Settlements Remaining							
Settlements	(57.1)	(77.5)	(87.8)	(89.8)	(91.9)	(93.9)	(95.9)
Other (Landfilled Yard Trimmings and Food Scraps)	(24.2)	(13.2)	(11.5)	(11.0)	(10.9)	(11.2)	(12.6)
Total	(861.5)	(576.6)	(1,056.5)	(1,064.3)	(1,060.9)	(1,040.5)	(1,015.1)

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

Land use, land-use change, and forestry source categories also resulted in emissions of CO₂, CH₄, and N₂O that are not included in the net CO₂ flux estimates presented in Table 2-9. The application of crushed limestone and dolomite to managed land (i.e., soil liming) and urea fertilization resulted in CO₂ emissions of 7.8 Tg CO₂ Eq. in 2009, an increase of about 10.6 percent relative to 1990. Lands undergoing peat extraction resulted in CO₂ emissions of 1.1 Tg CO₂ Eq. (1,090 Gg), and N₂O emissions of less than 0.01 Tg CO₂ Eq. N₂O emissions from the application of synthetic fertilizers to forest soils have increased from 0.1 Tg CO₂ Eq. in 1990 to 0.4 Tg CO₂ Eq. in 2009. Settlement soils in 2009 resulted in direct N₂O emissions of 1.5 Tg CO₂ Eq., a 55 percent increase relative to 1990. Emissions from forest fires in 2009 resulted in CH₄ emissions of 7.8 Tg CO₂ Eq., and in N₂O emissions of 6.4 Tg CO₂ Eq. (Table 2-10).

Table 2-10: Emissions from Land Use, Land-Use Change, and Forestry (Tg CO₂ Eq.)

Source Category	1990	2000	2005	2006	2007	2008	2009
CO₂	8.1	8.8	8.9	8.8	9.2	9.6	8.9
Cropland Remaining Cropland: Liming of Agricultural Soils	4.7	4.3	4.3	4.2	4.5	5.0	4.2
Cropland Remaining Cropland: Urea Fertilization	2.4	3.2	3.5	3.7	3.7	3.6	3.6
Wetlands Remaining Wetlands: Peatlands							
Remaining Peatlands	1.0	1.2	1.1	0.9	1.0	1.0	1.1
CH₄	3.2	14.3	9.8	21.6	20.0	11.9	7.8
Forest Land Remaining Forest Land: Forest Fires	3.2	14.3	9.8	21.6	20.0	11.9	7.8
N₂O	3.7	13.2	9.8	19.5	18.3	11.6	8.3
Forest Land Remaining Forest Land: Forest Fires	2.6	11.7	8.0	17.6	16.3	9.8	6.4
Forest Land Remaining Forest Land: Forest Soils	0.1	0.4	0.4	0.4	0.4	0.4	0.4
Settlements Remaining Settlements: Settlement Soils	1.0	1.1	1.5	1.5	1.6	1.5	1.5
Wetlands Remaining Wetlands: Peatlands							
Remaining Peatlands	+	+	+	+	+	+	+
Total	15.0	36.3	28.6	49.8	47.5	33.2	25.0

+ Less than 0.05 Tg CO₂ Eq.

Note: Totals may not sum due to independent rounding.

Other significant trends from 1990 to 2009 in land use, land-use change, and forestry emissions include:

- Net C sequestration by forest land has increased by almost 27 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 20 years, although only at an average rate of 0.21 percent per year.
- Net sequestration of C by urban trees has increased by 68 percent over the period from 1990 to 2009. 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 48 percent since 1990. This is due in part to a decrease in the amount of yard trimmings and food scraps generated. In addition, the proportion of yard trimmings and food scraps landfilled has decreased, as there has been a significant rise in the number of municipal composting facilities in the United States.

Waste

Waste management and treatment activities are sources of greenhouse gas emissions (see Figure 2-11). In 2009, landfills were the third largest source of anthropogenic CH₄ emissions, accounting for 17 percent of total U.S. CH₄ emissions.⁴⁷ Additionally, wastewater treatment accounts for 4 percent of U.S. CH₄ emissions, and 2 percent of N₂O emissions. Emissions of CH₄ and N₂O from composting grew from 1990 to 2009, and resulted in emissions of 3.5 Tg CO₂ Eq. in 2009. A summary of greenhouse gas emissions from the Waste chapter is presented in Table 2-11.

Figure 2-11: 2009 Waste Chapter Greenhouse Gas Sources

Overall, in 2009, waste activities generated emissions of 150.5 Tg CO₂ Eq., or 2.3 percent of total U.S. greenhouse gas emissions.

Table 2-11: Emissions from Waste (Tg CO₂ Eq.)

Gas/Source	1990	2000	2005	2006	2007	2008	2009
CH₄	171.2	138.1	138.4	137.8	137.4	142.1	143.6
Landfills	147.4	111.7	112.5	111.7	111.3	115.9	117.5
Wastewater Treatment	23.5	25.2	24.3	24.5	24.4	24.5	24.5
Composting	0.3	1.3	1.6	1.6	1.7	1.7	1.7
N₂O	4.0	5.9	6.5	6.6	6.7	6.8	6.9
Wastewater Treatment	3.7	4.5	4.8	4.8	4.9	5.0	5.0
Composting	0.4	1.4	1.7	1.8	1.8	1.9	1.8
Total	175.2	143.9	144.9	144.4	144.1	149.0	150.5

Note: Totals may not sum due to independent rounding.

Some significant trends in U.S. emissions from Waste include the following:

- Combined CO₂ and CH₄ emissions from composting have generally increased since 1990, from 0.7 Tg CO₂ Eq. to 3.5 Tg CO₂ Eq. in 2009, an over four-fold increase over the time series.
- From 1990 to 2009, net CH₄ emissions from landfills decreased by 29.9 Tg CO₂ Eq. (20 percent), with small increases occurring in interim years. This downward trend in overall emissions is the result of increases in the amount of landfill gas collected and combusted,⁴⁸ which has more than offset the

⁴⁷ 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.

⁴⁸ The CO₂ produced from combusted landfill CH₄ at landfills is not counted in national inventories as it is considered part of the natural C cycle of decomposition.

additional CH₄ emissions resulting from an increase in the amount of municipal solid waste landfilled.

- From 1990 to 2009, CH₄ and N₂O emissions from wastewater treatment increased by 1.0 Tg CO₂ Eq. (4.4 percent) and 1.3 Tg CO₂ Eq. (36 percent), respectively.

2.2. Emissions by Economic Sector

Throughout this report, emission estimates are grouped into six sectors (i.e., chapters) defined by the IPCC and detailed above: Energy; Industrial Processes; Solvent and Other 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 (33 percent) of U.S. greenhouse gas emissions in 2009. Transportation activities, in aggregate, accounted for the second largest portion (27 percent). Emissions from industry accounted for about 20 percent of U.S. greenhouse gas emissions in 2009. 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 20 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 5 percent, and primarily consisted of CO₂ emissions from fossil fuel combustion. Activities related to agriculture accounted for roughly 7 percent of U.S. emissions; unlike other economic sectors, agricultural sector emissions were dominated by N₂O emissions from agricultural soil management and CH₄ emissions from enteric fermentation, rather than CO₂ from fossil fuel combustion. The commercial sector accounted for roughly 6 percent of emissions, while U.S. territories accounted for less than 1 percent.

CO₂ 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 2-12 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 2009.

Figure 2-12: Emissions Allocated to Economic Sectors

Table 2-12: U.S. Greenhouse Gas Emissions Allocated to Economic Sectors (Tg CO₂ Eq. and Percent of Total in 2009)

Sector/Source	1990	2000	2005	2006	2007	2008	2009	Percent ^a
Electric Power Industry	1,868.9	2,337.6	2,444.6	2,388.2	2,454.0	2,400.7	2,193.0	33.1%
CO ₂ from Fossil Fuel Combustion	1,820.8	2,296.9	2,402.1	2,346.4	2,412.8	2,360.9	2,154.0	32.5%
Electrical Transmission and Distribution	28.4	16.0	15.1	14.1	13.2	13.3	12.8	0.2%
Incineration of Waste	8.5	11.5	12.9	12.9	13.1	12.5	12.7	0.2%
Stationary Combustion	8.6	10.6	11.0	10.8	11.0	10.8	9.7	0.1%
Limestone and Dolomite Use	2.6	2.5	3.4	4.0	3.9	3.1	3.8	0.1%
Transportation	1,545.2	1,932.3	2,017.4	1,994.4	2,003.8	1,890.7	1,812.4	27.3%
CO ₂ from Fossil Fuel Combustion	1,485.9	1,809.5	1,896.6	1,878.1	1,894.0	1,789.9	1,719.7	25.9%
Substitution of Ozone Depleting Substances	+	55.7	72.9	72.2	68.8	64.9	60.2	0.9%
Mobile Combustion	47.4	55.1	37.7	34.2	30.7	26.4	24.0	0.4%
Non-Energy Use of Fuels	11.8	12.1	10.2	9.9	10.2	9.5	8.5	0.1%
Industry	1,564.4	1,544.0	1,441.9	1,497.3	1,483.0	1,446.9	1,322.7	19.9%
CO ₂ from Fossil Fuel Combustion	815.4	812.3	776.3	799.2	793.6	757.4	683.8	10.3%

Natural Gas Systems	227.4	239.2	220.4	248.4	236.2	244.6	253.4	3.8%
Non-Energy Use of Fuels	101.1	122.8	125.2	126.8	119.8	123.1	111.1	1.7%
Coal Mining	84.1	60.4	56.9	58.2	57.9	67.1	71.0	1.1%
Iron and Steel Production & Metallurgical Coke Production	100.5	86.9	66.6	69.5	71.7	66.7	42.2	0.6%
Petroleum Systems	35.9	32.0	29.9	29.8	30.4	30.7	31.4	0.5%
Cement Production	33.3	40.4	45.2	45.8	44.5	40.5	29.0	0.4%
Nitric Acid Production	17.7	19.4	16.5	16.2	19.2	16.4	14.6	0.2%
Ammonia Production and Urea Consumption	16.8	16.4	12.8	12.3	14.0	11.9	11.8	0.2%
Lime Production	11.5	14.1	14.4	15.1	14.6	14.3	11.2	0.2%
Substitution of Ozone Depleting Substances	+	3.2	6.4	7.1	7.8	8.5	10.9	0.2%
Abandoned Underground Coal Mines	6.0	7.4	5.5	5.5	5.6	5.9	5.5	0.1%
HCFC-22 Production	36.4	28.6	15.8	13.8	17.0	13.6	5.4	0.1%
Semiconductor Manufacture	2.9	6.2	4.4	4.7	4.8	5.1	5.3	0.1%
Aluminum Production	25.4	14.7	7.1	6.3	8.1	7.2	4.6	0.1%
N ₂ O from Product Uses	4.4	4.9	4.4	4.4	4.4	4.4	4.4	0.1%
Soda Ash Production and Consumption	4.1	4.2	4.2	4.2	4.1	4.1	4.3	0.1%
Limestone and Dolomite Use	2.6	2.5	3.4	4.0	3.9	3.1	3.8	0.1%
Stationary Combustion	4.7	4.8	4.4	4.6	4.4	4.1	3.6	0.1%
Petrochemical Production	4.2	5.7	5.3	4.8	4.9	4.4	3.6	0.1%
Adipic Acid Production	15.8	5.5	5.0	4.3	3.7	2.0	1.9	+
Carbon Dioxide Consumption	1.4	1.4	1.3	1.7	1.9	1.8	1.8	+
Titanium Dioxide Production	1.2	1.8	1.8	1.8	1.9	1.8	1.5	+
Ferroalloy Production	2.2	1.9	1.4	1.5	1.6	1.6	1.5	+
Mobile Combustion	0.9	1.1	1.3	1.3	1.3	1.3	1.3	+
Magnesium Production and Processing	5.4	3.0	2.9	2.9	2.6	1.9	1.1	+
Phosphoric Acid Production	1.5	1.4	1.4	1.2	1.2	1.2	1.0	+
Zinc Production	0.7	1.0	1.1	1.1	1.1	1.2	1.0	+
Lead Production	0.5	0.6	0.6	0.6	0.6	0.6	0.5	+
Silicon Carbide Production and Consumption	0.4	0.3	0.2	0.2	0.2	0.2	0.2	+
Agriculture	429.0	485.1	493.2	516.7	520.7	503.9	490.0	7.4%
N ₂ O from Agricultural Soil Management	197.8	206.8	211.3	208.9	209.4	210.7	204.6	3.1%
Enteric Fermentation	132.1	136.5	136.5	138.8	141.0	140.6	139.8	2.1%
Manure Management	46.2	59.5	63.8	64.8	68.9	67.3	67.3	1.0%
CO ₂ from Fossil Fuel Combustion	31.04	38.79	46.81	49.04	48.44	45.44	46.66	0.7%
CH ₄ and N ₂ O from Forest Fires	5.8	26.0	17.8	39.2	36.4	21.7	14.2	0.2%
Rice Cultivation	7.1	7.5	6.8	5.9	6.2	7.2	7.3	0.1%
Liming of Agricultural Soils	4.7	4.3	4.3	4.2	4.5	5.0	4.2	0.1%
Urea Fertilization	2.4	3.2	3.5	3.7	3.7	3.6	3.6	0.1%
CO ₂ and N ₂ O from Managed Peatlands	1.0	1.2	1.1	0.9	1.0	1.0	1.1	+
Mobile Combustion	0.3	0.4	0.5	0.5	0.5	0.5	0.5	+
N ₂ O from Forest Soils	0.1	0.4	0.4	0.4	0.4	0.4	0.4	+
Field Burning of Agricultural Residues	0.4	0.4	0.3	0.3	0.3	0.4	0.4	+

Stationary Combustion	+	+	+	+	+	+	+	+
Commercial	395.5	381.4	387.2	375.2	389.6	403.5	409.5	6.2%
CO ₂ from Fossil Fuel Combustion	219.0	230.8	223.5	208.6	219.4	224.2	224.0	3.4%
Landfills	147.4	111.7	112.5	111.7	111.3	115.9	117.5	1.8%
Substitution of Ozone Depleting Substances	+	5.4	17.6	21.1	24.9	29.1	33.7	0.5%
Wastewater Treatment	23.5	25.2	24.3	24.5	24.4	24.5	24.5	0.4%
Human Sewage	3.7	4.5	4.8	4.8	4.9	5.0	5.0	0.1%
Composting	0.7	2.6	3.3	3.3	3.5	3.5	3.5	0.1%
Stationary Combustion	1.3	1.3	1.2	1.2	1.2	1.2	1.2	+
Residential	345.1	386.2	371.0	335.8	358.9	367.1	360.1	5.4%
CO ₂ from Fossil Fuel Combustion	338.3	370.7	357.9	321.5	342.4	348.2	339.2	5.1%
Substitution of Ozone Depleting Substances	0.3	10.1	7.3	8.9	10.7	12.9	15.1	0.2%
Stationary Combustion	5.5	4.3	4.3	3.9	4.2	4.4	4.2	0.1%
Settlement Soil Fertilization	1.0	1.1	1.5	1.5	1.6	1.5	1.5	+
U.S. Territories	33.7	46.0	58.2	59.3	53.5	48.4	45.5	0.7%
CO ₂ from Fossil Fuel Combustion	27.9	35.9	50.0	50.3	46.1	39.8	41.7	0.6%
Non-Energy Use of Fuels	5.7	10.0	8.1	8.8	7.2	8.4	3.7	0.1%
Stationary Combustion	0.1	0.1	0.2	0.2	0.2	0.2	0.2	+
Total Emissions	6,181.8	7,112.7	7,213.5	7,166.9	7,263.4	7,061.1	6,633.2	100.0%
Sinks	(861.5)	(576.6)	(1,056.5)	(1,064.3)	(1,060.9)	(1,040.5)	(1,015.1)	-15.3%
CO ₂ Flux from Forests ^b	(681.1)	(378.3)	(911.5)	(917.5)	(911.9)	(891.0)	(863.1)	-13.0%
Urban Trees	(57.1)	(77.5)	(87.8)	(89.8)	(91.9)	(93.9)	(95.9)	-1.4%
CO ₂ Flux from Agricultural Soil								
Carbon Stocks	(99.2)	(107.6)	(45.6)	(46.1)	(46.3)	(44.4)	(43.4)	-0.7%
Landfilled Yard Trimmings and Food Scraps	(24.2)	(13.2)	(11.5)	(11.0)	(10.9)	(11.2)	(12.6)	-0.2%
Net Emissions	5,320.3	6,536.1	6,157.1	6,102.6	6,202.5	6,020.7	5,618.2	84.7%

Note: Includes all emissions of CO₂, CH₄, N₂O, HFCs, PFCs, and SF₆. Parentheses indicate negative values or sequestration.

Totals may not sum due to independent rounding.

ODS (Ozone Depleting Substances)

+ Does not exceed 0.05 Tg CO₂ Eq. or 0.05 percent.

^a Percent of total emissions for year 2009.

^b Includes the effects of net additions to stocks of carbon stored in 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 33 percent of total U.S. greenhouse gas emissions in 2009. Emissions increased by 17 percent since 1990, as electricity demand grew and fossil fuels remained the dominant energy source for generation. Electricity generation-related emissions decreased from 2008 to 2009 by 9 percent, primarily due to decreased CO₂ emissions from fossil fuel combustion. The decrease in electricity-related emissions was due to decreased economic output and the resulting decrease in electricity demand. Electricity-related emissions also declined due to a decrease in the carbon intensity of fuels used to generate electricity. This was caused by fuel switching as the price of coal increased and the price natural gas decreased significantly. The fuel switching from coal to natural gas and additional electricity generation from other energy sources in 2009, which included a 7 percent increase in hydropower generation from the previous year, resulted in a decrease in carbon intensity, and in turn, a decrease in emissions from electricity generation. The electricity generation sector in the United States is composed of traditional electric utilities as well as other entities, such as power marketers and non-utility power producers. The majority of electricity generated by these entities was

through the combustion of coal in boilers to produce high-pressure steam that is passed through a turbine. Table 2-13 provides a detailed summary of emissions from electricity generation-related activities.

Table 2-13: Electricity Generation-Related Greenhouse Gas Emissions (Tg CO₂ Eq.)

Gas/Fuel Type or Source	1990	2000	2005	2006	2007	2008	2009
CO₂	1,831.4	2,310.5	2,418.0	2,363.0	2,429.4	2,376.2	2,170.1
CO ₂ from Fossil Fuel							
Combustion	1,820.8	2,296.9	2,402.1	2,346.4	2,412.8	2,360.9	2,154.0
<i>Coal</i>	<i>1,547.6</i>	<i>1,927.4</i>	<i>1,983.8</i>	<i>1,953.7</i>	<i>1,987.3</i>	<i>1,959.4</i>	<i>1,747.6</i>
<i>Natural Gas</i>	<i>175.3</i>	<i>280.8</i>	<i>318.8</i>	<i>338.0</i>	<i>371.3</i>	<i>361.9</i>	<i>373.1</i>
<i>Petroleum</i>	<i>97.5</i>	<i>88.4</i>	<i>99.2</i>	<i>54.4</i>	<i>53.9</i>	<i>39.2</i>	<i>32.9</i>
<i>Geothermal</i>	<i>0.4</i>	<i>0.4</i>	<i>0.4</i>	<i>0.4</i>	<i>0.4</i>	<i>0.4</i>	<i>0.4</i>
Incineration of Waste	8.0	11.1	12.5	12.5	12.7	12.2	12.3
Limestone and Dolomite Use	2.6	2.5	3.4	4.0	3.9	3.1	3.8
CH₄	0.6	0.7	0.7	0.7	0.7	0.7	0.7
Stationary Combustion*	0.6	0.7	0.7	0.7	0.7	0.7	0.7
Incineration of Waste	+	+	+	+	+	+	+
N₂O	8.5	10.4	10.7	10.5	10.6	10.4	9.4
Stationary Combustion*	8.1	10.0	10.3	10.1	10.2	10.1	9.0
Incineration of Waste	0.5	0.4	0.4	0.4	0.4	0.4	0.4
SF₆	28.4	16.0	15.1	14.1	13.2	13.3	12.8
Electrical Transmission and Distribution	28.4	16.0	15.1	14.1	13.2	13.3	12.8
Total	1,868.9	2,337.6	2,444.6	2,388.2	2,454.0	2,400.7	2,193.0

Note: Totals may not sum due to independent rounding.

* Includes only stationary combustion emissions related to the generation of electricity.

+ Does not exceed 0.05 Tg CO₂ Eq. or 0.05 percent.

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 retail sales of electricity (EIA 2010 and Duffield 2006). These three source categories include CO₂ from Fossil Fuel Combustion, CH₄ and N₂O from Stationary Combustion, and SF₆ from Electrical Transmission and Distribution Systems.⁴⁹

When emissions from electricity are distributed among these sectors, industry activities account for the largest share of total U.S. greenhouse gas emissions (28.8 percent), followed closely by emissions from transportation (27.4 percent). Emissions from the residential and commercial sectors also increase substantially when emissions from electricity are included. In all sectors except agriculture, CO₂ accounts for more than 80 percent of greenhouse gas emissions, primarily from the combustion of fossil fuels.

Table 2-14 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 2009.

Figure 2-13: Emissions with Electricity Distributed to Economic Sectors

Table 2-14: U.S. Greenhouse Gas Emissions by Economic Sector and Gas with Electricity-Related Emissions Distributed (Tg CO₂ Eq.) and Percent of Total in 2009

Sector/Gas	1990	2000	2005	2006	2007	2008	2009	Percent ^a
Industry	2,238.3	2,314.4	2,162.5	2,194.6	2,192.9	2,146.5	1,910.9	28.8%
Direct Emissions	<i>1,564.4</i>	<i>1,544.0</i>	<i>1,441.9</i>	<i>1,497.3</i>	<i>1,483.0</i>	<i>1,446.9</i>	<i>1,322.7</i>	19.9%

⁴⁹ 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.

CO ₂	1,140.5	1,147.9	1,093.8	1,123.1	1,113.7	1,070.1	942.7	14.2%
CH ₄	318.8	312.5	285.7	314.1	301.9	318.1	331.2	5.0%
N ₂ O	41.8	34.0	30.0	29.1	31.4	26.8	24.5	0.4%
HFCs, PFCs, and SF ₆	63.3	49.6	32.5	31.0	36.0	31.9	24.2	0.4%
Electricity-Related	673.9	770.4	720.5	697.3	709.9	699.7	588.3	8.9%
CO ₂	660.3	761.5	712.7	689.9	702.8	692.5	582.2	8.8%
CH ₄	0.2	0.2	0.2	0.2	0.2	0.2	0.2	+
N ₂ O	3.1	3.4	3.2	3.1	3.1	3.0	2.5	+
SF ₆	10.2	5.3	4.5	4.1	3.8	3.9	3.4	0.1%
Transportation	1,548.3	1,935.8	2,022.2	1,999.0	2,008.9	1,895.5	1,816.9	27.4%
Direct Emissions	1,545.2	1,932.3	2,017.4	1,994.4	2,003.8	1,890.7	1,812.4	27.3%
CO ₂	1,497.8	1,821.6	1,906.8	1,888.0	1,904.2	1,799.4	1,728.2	26.1%
CH ₄	4.5	3.1	2.2	2.0	1.9	1.7	1.6	+
N ₂ O	42.9	51.9	35.5	32.1	28.8	24.6	22.4	0.3%
HFCs ^b	+	55.7	72.9	72.2	68.8	64.9	60.2	0.9%
Electricity-Related	3.1	3.5	4.8	4.6	5.1	4.7	4.5	0.1%
CO ₂	3.1	3.5	4.8	4.6	5.1	4.7	4.5	0.1%
CH ₄	+	+	+	+	+	+	+	+
N ₂ O	+	+	+	+	+	+	+	+
SF ₆	+	+	+	+	+	+	+	+
Commercial	947.7	1,135.8	1,205.1	1,188.5	1,225.3	1,224.5	1,184.9	17.9%
Direct Emissions	395.5	381.4	387.2	375.2	389.6	403.5	409.5	6.2%
CO ₂	219.0	230.8	223.5	208.6	219.4	224.2	224.0	3.4%
CH ₄	172.1	139.0	139.3	138.7	138.2	143.1	144.5	2.2%
N ₂ O	4.4	6.2	6.8	6.9	7.1	7.2	7.2	0.1%
HFCs	+	5.4	17.6	21.1	24.9	29.1	33.7	0.5%
Electricity-Related	552.2	754.4	817.9	813.2	835.7	821.0	775.4	11.7%
CO ₂	541.1	745.7	809.0	804.7	827.4	812.7	767.4	11.6%
CH ₄	0.2	0.2	0.2	0.2	0.2	0.2	0.2	+
N ₂ O	2.5	3.3	3.6	3.6	3.6	3.6	3.3	+
SF ₆	8.4	5.2	5.1	4.8	4.5	4.6	4.5	0.1%
Residential	953.8	1,162.2	1,242.9	1,181.5	1,229.6	1,215.1	1,158.9	17.5%
Direct Emissions	345.1	386.2	371.0	335.8	358.9	367.1	360.1	5.4%
CO ₂	338.3	370.7	357.9	321.5	342.4	348.2	339.2	5.1%
CH ₄	4.4	3.4	3.4	3.1	3.4	3.5	3.4	0.1%
N ₂ O	2.1	2.1	2.4	2.3	2.4	2.4	2.4	+
HFCs	0.3	10.1	7.3	8.9	10.7	12.9	15.1	0.2%
Electricity-Related	608.7	775.9	871.9	845.6	870.7	848.1	798.8	12.0%
CO ₂	596.5	767.0	862.4	836.7	862.0	839.4	790.5	11.9%
CH ₄	0.2	0.2	0.3	0.3	0.3	0.2	0.2	+
N ₂ O	2.8	3.4	3.8	3.7	3.8	3.7	3.4	0.1%
SF ₆	9.2	5.3	5.4	5.0	4.7	4.7	4.7	0.1%
Agriculture	460.0	518.4	522.7	544.1	553.2	531.1	516.0	7.8%
Direct Emissions	429.0	485.1	493.2	516.7	520.7	503.9	490.0	7.4%
CO ₂	39.2	47.6	55.7	57.8	57.7	55.1	55.6	0.8%
CH ₄	174.5	201.1	200.1	213.4	218.4	209.6	204.8	3.1%
N ₂ O	215.3	236.4	237.4	245.4	244.7	239.2	229.7	3.5%
Electricity-Related	31.0	33.3	29.4	27.4	32.5	27.2	25.9	0.4%
CO ₂	30.4	32.9	29.1	27.1	32.2	26.9	25.7	0.4%
CH ₄	+	+	+	+	+	+	+	+
N ₂ O	0.1	0.1	0.1	0.1	0.1	0.1	0.1	+
SF ₆	0.5	0.2	0.2	0.2	0.2	0.2	0.2	+
U.S. Territories	33.7	46.0	58.2	59.3	53.5	48.4	45.5	0.7%
Total	6,181.8	7,112.7	7,213.5	7,166.9	7,263.4	7,061.1	6,633.2	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 Tg CO₂ Eq. or 0.05 percent.

^a Percent of total emissions for year 2009.

^b Includes primarily HFC-134a.

Industry

The industrial end-use sector includes CO₂ emissions from fossil fuel combustion from all manufacturing facilities, in aggregate. This sector also includes emissions that are produced as a by-product 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 CH₄ emissions from coal mining, by-product CO₂ emissions from cement manufacture, and HFC, PFC, and SF₆ by-product 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. However, the decline in direct emissions has been sharper. 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 2009. The largest sources of transportation greenhouse gases in 2009 were passenger cars (35 percent), light duty trucks, which include sport utility vehicles, pickup trucks, and minivans (30 percent), freight trucks (20 percent) and commercial aircraft (6 percent). These figures include direct emissions from fossil fuel combustion, as well as HFC emissions from mobile air conditioners and refrigerated transport allocated to these vehicle types. Table 2-15 provides a detailed summary of greenhouse gas emissions from transportation-related activities with electricity-related emissions included in the totals.

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

From 2008 to 2009, CO₂ emissions from the transportation end-use sector declined 4 percent. The decrease in emissions can largely be attributed to decreased economic activity in 2009 and an associated decline in the demand for transportation. Modes such as medium- and heavy-duty trucks were significantly impacted by the decline in freight transport. Similarly, increased jet fuel prices were a factor in the 19 percent decrease in commercial aircraft emissions since 2007.

Almost all of the energy consumed for transportation was supplied by petroleum-based products, with more than half being related to gasoline consumption in automobiles and other highway vehicles. Other fuel uses, especially diesel fuel for freight trucks and jet fuel for aircraft, accounted for the remainder. The primary driver of transportation-related emissions was CO₂ from fossil fuel combustion, which increased by 16 percent from 1990 to 2009. This rise in CO₂ emissions, combined with an increase in HFCs from close to zero emissions in 1990 to 60.2 Tg CO₂ Eq. in 2009, led to an increase in overall emissions from transportation activities of 17 percent.

Although average fuel economy over this period increased slightly due primarily to the retirement of older vehicles, average fuel economy among new vehicles sold annually gradually declined from 1990 to 2004. The decline in new vehicle fuel economy between 1990 and 2004 reflected the increasing market share of light duty trucks, which grew from about one-fifth of new vehicle sales in the 1970s to slightly over half of the market by 2004. Increasing fuel prices have since decreased the momentum of light duty truck sales, and average new vehicle fuel economy has improved since 2005 as the market share of passenger cars increased. VMT growth among all passenger vehicles has also been impacted, remaining stagnant from 2004 to 2007, compared to an average annual growth rate of 2.5 percent over the period 1990 to 2004. The recession supplemented the effect of increasing fuel prices in 2008 and VMT declined by 2.1 percent, the first decrease in annual passenger vehicle VMT since 1990. Overall, VMT grew by 0.2 percent in 2009. Gasoline fuel consumption increased slightly, while consumption of diesel fuel continued to

decrease, due in part to a decrease in commercial activity and freight trucking as a result of the economic recession.

Table 2-15: Transportation-Related Greenhouse Gas Emissions (Tg CO₂ Eq.)

Gas/Vehicle Type	1990	2000	2005	2006	2007	2008	2009
Passenger Cars	657.4	695.3	709.5	682.9	672.0	632.5	627.4
CO ₂	629.3	644.2	662.3	639.1	632.8	597.9	597.2
CH ₄	2.6	1.6	1.1	1.0	0.9	0.8	0.7
N ₂ O	25.4	25.2	17.8	15.7	13.8	11.7	10.1
HFCs	+	24.3	28.4	27.1	24.6	22.1	19.3
Light-Duty Trucks	336.6	512.1	551.3	564.0	570.3	553.8	551.0
CO ₂	321.1	467.0	505.9	519.5	528.4	515.1	514.5
CH ₄	1.4	1.1	0.7	0.7	0.6	0.6	0.6
N ₂ O	14.1	22.4	13.7	12.6	11.2	9.5	9.4
HFCs	+	21.7	31.0	31.2	30.1	28.6	26.6
Medium- and Heavy-Duty Trucks	231.1	354.6	408.4	418.6	425.2	403.1	365.6
CO ₂	230.1	345.8	396.0	406.1	412.5	390.4	353.1
CH ₄	0.2	0.1	0.1	0.1	0.1	0.1	0.1
N ₂ O	0.8	1.2	1.1	1.1	1.1	1.0	0.8
HFCs	+	7.4	11.1	11.4	11.5	11.6	11.6
Buses	8.4	11.2	12.0	12.3	12.5	12.2	11.2
CO ₂	8.4	11.1	11.8	12.0	12.1	11.8	10.8
CH ₄	+	+	+	+	+	+	+
N ₂ O	+	+	+	+	+	+	+
HFCs	+	0.1	0.2	0.3	0.3	0.4	0.4
Motorcycles	1.8	1.9	1.7	1.9	2.1	2.2	2.2
CO ₂	1.7	1.8	1.6	1.9	2.1	2.1	2.1
CH ₄	+	+	+	+	+	+	+
N ₂ O	+	+	+	+	+	+	+
Commercial Aircraft^a	136.8	170.9	162.8	138.5	139.5	123.4	112.5
CO ₂	135.4	169.2	161.2	137.1	138.1	122.2	111.4
CH ₄	0.1	0.1	0.1	0.1	0.1	0.1	0.1
N ₂ O	1.3	1.6	1.5	1.3	1.3	1.2	1.1
Other Aircraft^b	44.4	33.5	35.9	35.1	33.2	35.2	29.6
CO ₂	43.9	33.1	35.5	34.7	32.8	34.8	29.3
CH ₄	0.1	0.1	0.1	0.1	0.1	0.1	+
N ₂ O	0.4	0.3	0.3	0.3	0.3	0.3	0.3
Ships and Boats^c	45.1	61.0	45.2	48.4	55.2	37.1	30.5
CO ₂	44.5	60.0	44.5	47.7	54.4	36.6	30.0
CH ₄	+	+	+	+	+	+	+
N ₂ O	0.6	0.9	0.6	0.7	0.8	0.5	0.4
HFCs	+	0.1	+	+	+	+	+
Rail	39.0	48.1	53.0	55.1	54.3	50.6	43.3
CO ₂	38.5	45.6	50.3	52.4	51.6	47.9	40.6
CH ₄	0.1	0.1	0.1	0.1	0.1	0.1	0.1
N ₂ O	0.3	0.3	0.4	0.4	0.4	0.4	0.3
HFCs	+	2.0	2.2	2.2	2.2	2.3	2.3
Other Emissions from Electricity Generation ^d	0.1	+	0.1	0.1	0.1	0.1	0.1
Pipelines^e	36.0	35.2	32.2	32.3	34.3	35.7	35.2
CO ₂	36.0	35.2	32.2	32.3	34.3	35.7	35.2
Lubricants	11.8	12.1	10.2	9.9	10.2	9.5	8.5
CO ₂	11.8	12.1	10.2	9.9	10.2	9.5	8.5
Total Transportation	1,548.3	1,935.8	2,022.2	1,999.0	2,008.9	1,895.4	1,816.9
<i>International Bunker</i>	<i>113.0</i>	<i>99.5</i>	<i>110.9</i>	<i>129.7</i>	<i>129.0</i>	<i>135.1</i>	<i>124.4</i>

Fuels^f

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 8500 lbs; medium- and heavy-duty trucks include vehicles larger than 8500 lbs. HFC emissions primarily reflect HFC-134a.

+ Does not exceed 0.05 Tg CO₂ 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 data collection problems.

^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 limestone and dolomite use (from pollution control equipment installed in electricity generation plants).

^e CO₂ estimates reflect natural gas used to power pipelines, but not electricity. While the operation of pipelines produces CH₄ and N₂O, these emissions are not directly attributed to pipelines in the US 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 increasing 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 sector includes a variety of processes, including enteric fermentation in domestic livestock, livestock manure management, and agricultural soil management. In 2009, agricultural soil management was the largest source of N₂O emissions, and enteric fermentation was the second largest source of CH₄ emissions in the United States. This sector also includes small amounts of CO₂ emissions from fossil fuel combustion by motorized farm equipment like tractors. The agriculture sector relies less heavily on electricity than the other sectors.

[BEGIN BOX]

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, CO₂ 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 CH₄ and N₂O are also based on the EIA electric utility sector. Additional sources include CO₂, CH₄, and N₂O 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 SF₆ from Electrical Transmission and Distribution, and a portion of CO₂ from Limestone and Dolomite Use (from pollution control equipment installed in electricity generation plants).

In the Transportation economic sector, the CO₂ 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 CH₄ and N₂O from Mobile Combustion, based on the EIA transportation sector. Substitutes of Ozone Depleting Substitutes 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, CO₂ 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 CO₂ 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 CH₄ and N₂O are also based on the EIA industrial sector, minus emissions apportioned to the Agriculture economic sector described below. Substitutes of Ozone Depleting Substitutes 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 CO₂ from Limestone and Dolomite Use (from pollution control equipment installed in large industrial facilities) are also included in the Industry economic sector. Finally, all remaining CO₂ 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 CO₂ emissions from fossil fuel combustion, and CH₄ and N₂O 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 N₂O emissions from Agricultural Soils, CH₄ from Enteric Fermentation (i.e., exhalation from the digestive tracts of domesticated animals), CH₄ and N₂O from Manure Management, CH₄ from Rice Cultivation, CO₂ emissions from Liming of Agricultural Soils and Urea Application, and CH₄ and N₂O from Forest Fires. N₂O 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 CO₂ emissions from the combustion of fossil fuels reported for the EIA residential sector. Stationary combustion emissions of CH₄ and N₂O are also based on the EIA residential fuel consuming sector. Substitutes of Ozone Depleting Substitutes are apportioned based on their specific end-uses within the source category, with emissions from residential air-conditioning systems to this economic sector. N₂O 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 CO₂ emissions from the combustion of fossil fuels reported in the EIA commercial fuel consuming sector data. Stationary combustion emissions of CH₄ and N₂O are also based on the EIA commercial sector. Substitutes of Ozone Depleting Substitutes 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 CH₄ from Landfills and CH₄ and N₂O from Wastewater Treatment and

Composting are included in this economic sector.

[END BOX]

[BEGIN BOX]

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 2009; (4) emissions per unit of total gross domestic product as a measure of national economic activity; or (5) emissions per capita.

Table 2-16 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 0.4 percent since 1990. This rate is slightly slower than that for total energy consumption and growth in national population since 1990 and much slower than that for electricity consumption and overall gross domestic product, respectively. Total U.S. greenhouse gas emissions are growing at a rate similar to that of fossil fuel consumption since 1990 (see Table 2-16).

Table 2-16: Recent Trends in Various U.S. Data (Index 1990 = 100)

Variable	1990	2000	2005	2006	2007	2008	2009	Growth Rate ^a
GDP ^b	100	140	157	162	165	165	160	2.5%
Electricity Consumption ^c	100	127	134	135	138	138	132	1.5%
Fossil Fuel Consumption ^c	100	117	119	117	119	116	108	0.5%
Energy Consumption ^c	100	116	118	118	120	118	112	0.6%
Population ^d	100	113	118	120	121	122	123	1.1%
Greenhouse Gas Emissions ^e	100	115	117	116	117	114	107	0.4%

^a Average annual growth rate

^b Gross Domestic Product in chained 2005 dollars (BEA 2010)

^c Energy-content-weighted values (EIA 2010)

^d U.S. Census Bureau (2010)

^e GWP-weighted values

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

Source: BEA (2010), U.S. Census Bureau (2010), and emission estimates in this report.

[END BOX]

2.3. Indirect Greenhouse Gas Emissions (CO, NO_x, NMVOCs, and SO₂)

The reporting requirements of the UNFCCC⁵⁰ request that information be provided on indirect greenhouse gases, which include CO, NO_x, NMVOCs, and SO₂. 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 SO₂, by affecting the absorptive characteristics of the atmosphere. Additionally, some of

⁵⁰ See <<http://unfccc.int/resource/docs/cop8/08.pdf>>.

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 NO₂) are created by lightning, fires, fossil fuel combustion, and in the stratosphere from N₂O. Non-CH₄ 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, SO₂ 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 CH₄ emissions—to form CO₂. Therefore, increased atmospheric concentrations of CO limit the number of hydroxyl molecules (OH) available to destroy CH₄.

Since 1970, the United States has published estimates of annual emissions of CO, NO_x, NMVOCs, and SO₂ (EPA 2010, EPA 2009),⁵¹ which are regulated under the Clean Air Act. Table 2-17 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 2-17: Emissions of NO_x, CO, NMVOCs, and SO₂ (Gg)

Gas/Activity	1990	2000	2005	2006	2007	2008	2009
NO_x	21,707	19,116	15,900	15,039	14,380	13,547	11,468
Mobile Fossil Fuel							
Combustion	10,862	10,199	9,012	8,488	7,965	7,441	6,206
Stationary Fossil Fuel							
Combustion	10,023	8,053	5,858	5,545	5,432	5,148	4,159
Industrial Processes	591	626	569	553	537	520	568
Oil and Gas Activities	139	111	321	319	318	318	393
Incineration of Waste	82	114	129	121	114	106	128
Agricultural Burning	8	8	6	7	8	8	8
Solvent Use	1	3	3	4	4	4	3
Waste	0	2	2	2	2	2	2
CO	130,038	92,243	70,809	67,238	63,625	60,039	51,452
Mobile Fossil Fuel							
Combustion	119,360	83,559	62,692	58,972	55,253	51,533	43,355
Stationary Fossil Fuel							
Combustion	5,000	4,340	4,649	4,695	4,744	4,792	4,543
Industrial Processes	4,125	2,216	1,555	1,597	1,640	1,682	1,549
Incineration of Waste	978	1,670	1,403	1,412	1,421	1,430	1,403
Agricultural Burning	268	259	184	233	237	270	247
Oil and Gas Activities	302	146	318	319	320	322	345
Waste	1	8	7	7	7	7	7
Solvent Use	5	45	2	2	2	2	2
NMVOCs	20,930	15,227	13,761	13,594	13,423	13,254	9,313
Mobile Fossil Fuel							
Combustion	10,932	7,229	6,330	6,037	5,742	5,447	4,151
Solvent Use	5,216	4,384	3,851	3,846	3,839	3,834	2,583
Industrial Processes	2,422	1,773	1,997	1,933	1,869	1,804	1,322
Stationary Fossil Fuel							
Combustion	912	1,077	716	918	1,120	1,321	424

⁵¹ NO_x and CO emission estimates from field burning of agricultural residues were estimated separately, and therefore not taken from EPA (2009) and EPA (2010).

Oil and Gas Activities	554	388	510	510	509	509	599
Incineration of Waste	222	257	241	238	234	230	159
Waste	673	119	114	113	111	109	76
Agricultural Burning	NA	NA	NA	NA	NA	NA	NA
SO₂	20,935	14,830	13,466	12,388	11,799	10,368	8,599
Stationary Fossil Fuel							
Combustion	18,407	12,849	11,541	10,612	10,172	8,891	7,167
Industrial Processes	1,307	1,031	831	818	807	795	798
Mobile Fossil Fuel							
Combustion	793	632	889	750	611	472	455
Oil and Gas Activities	390	287	181	182	184	187	154
Incineration of Waste	38	29	24	24	24	23	24
Waste	0	1	1	1	1	1	1
Solvent Use	0	1	0	0	0	0	0
Agricultural Burning	NA	NA	NA	NA	NA	NA	NA

Source: (EPA 2010, EPA 2009) except for estimates from field burning of agricultural residues.

NA (Not Available)

Note: Totals may not sum due to independent rounding.

[BEGIN BOX]

Box 2-3: Sources and Effects of Sulfur Dioxide

Sulfur dioxide (SO₂) 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) 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 SO₂ 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 SO₂ 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 SO₂ emissions in the Clean Air Act.

Electricity generation is the largest anthropogenic source of SO₂ emissions in the United States, accounting for 83 percent in 2009. 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.

[END BOX]

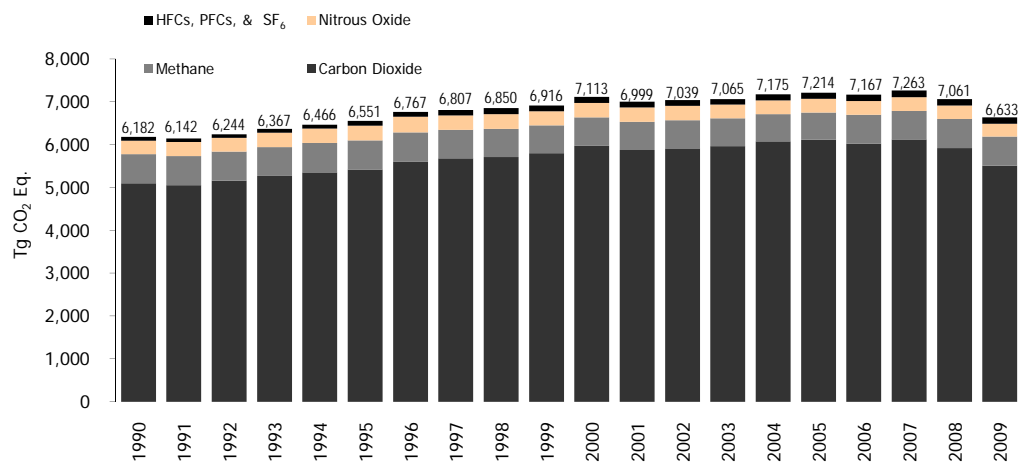


Figure 2-1: U.S. Greenhouse Gas Emissions by Gas

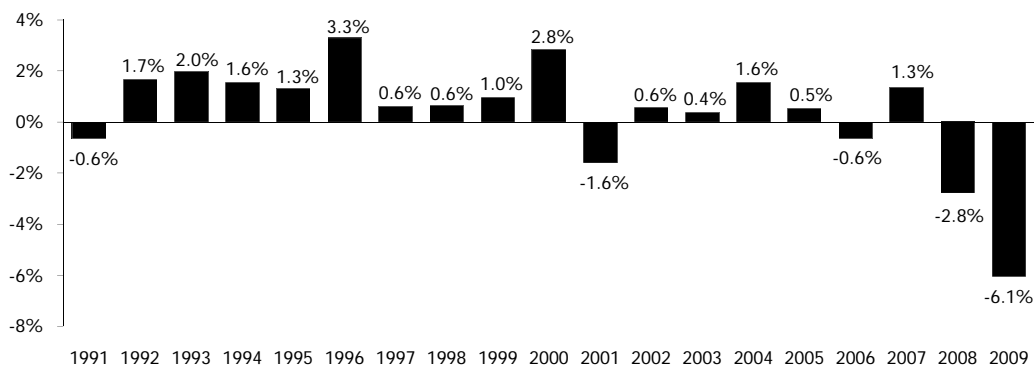


Figure 2-2: Annual Percent Change in U.S. Greenhouse Gas Emissions

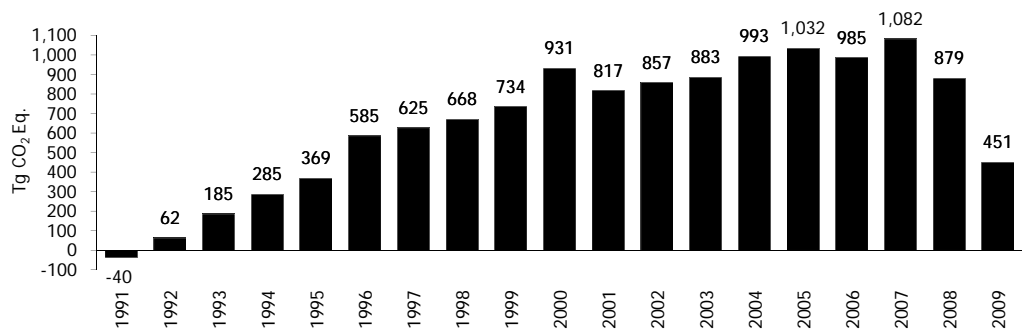


Figure 2-3: Cumulative Change in Annual U.S. Greenhouse Gas Emissions Relative to 1990

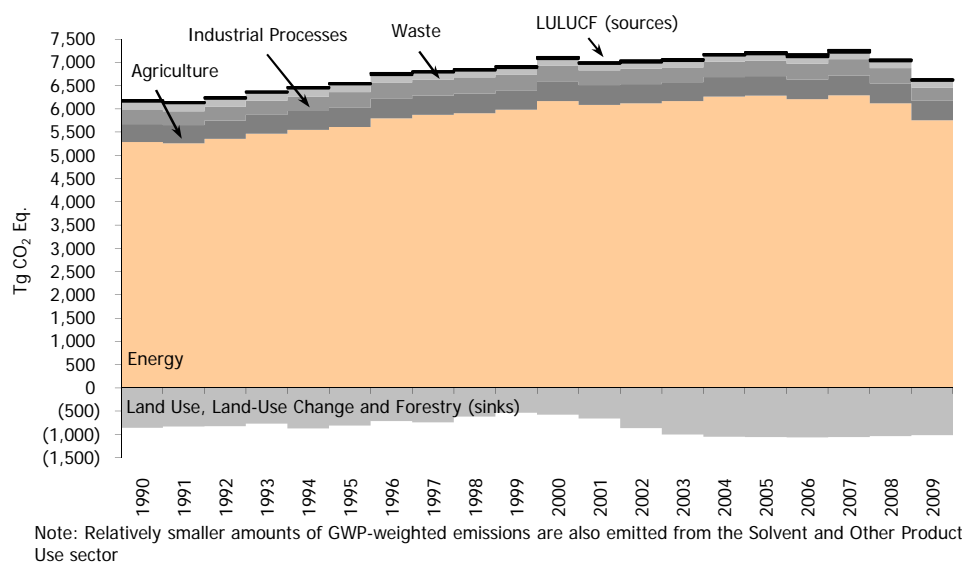


Figure 2-4: U.S. Greenhouse Gas Emissions and Sinks by Chapter/IPCC Sector

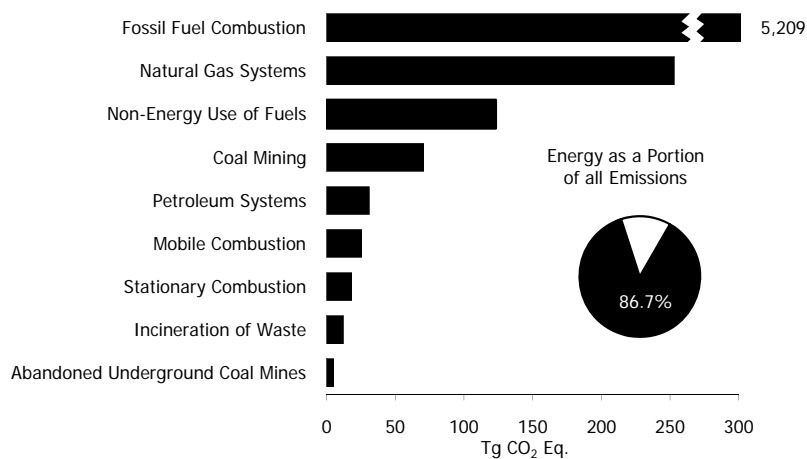


Figure 2-5: 2009 Energy Sector Greenhouse Gas Sources

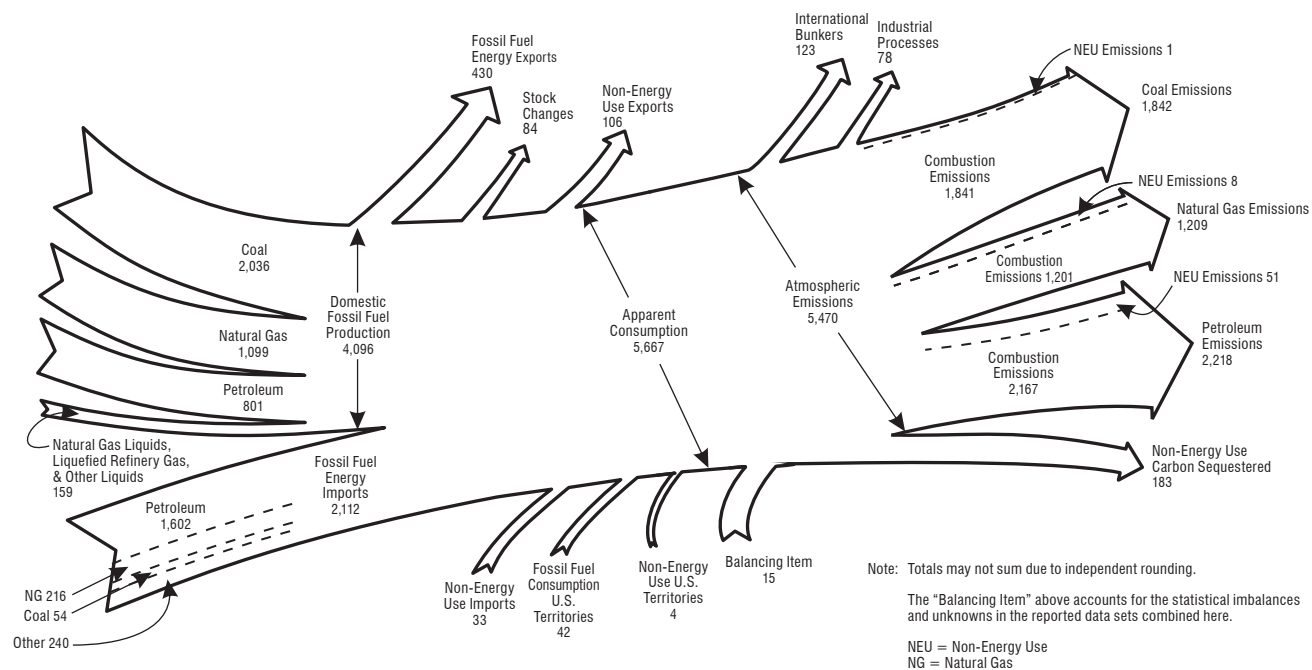


Figure 2-6 2009 U.S. Fossil Carbon Flows (Tg CO₂ Eq.)

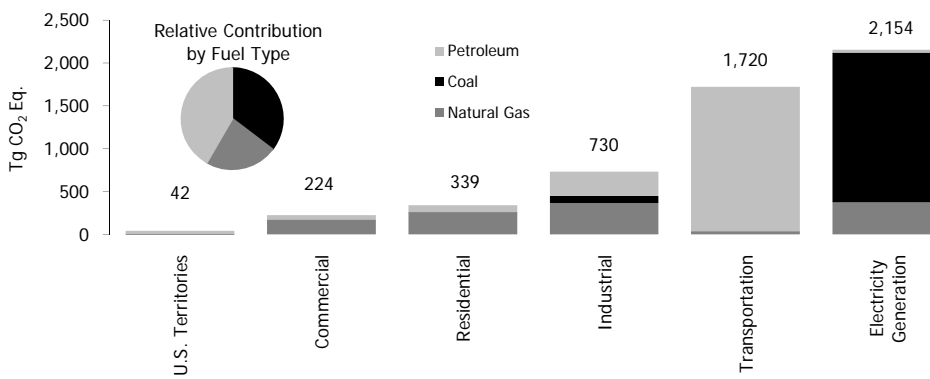


Figure 2-7: 2009 CO₂ Emissions from Fossil Fuel Combustion by Sector and Fuel Type
 Note: Electricity generation also includes emissions of less than 0.5 Tg CO₂ Eq. from geothermal-based electricity generation.

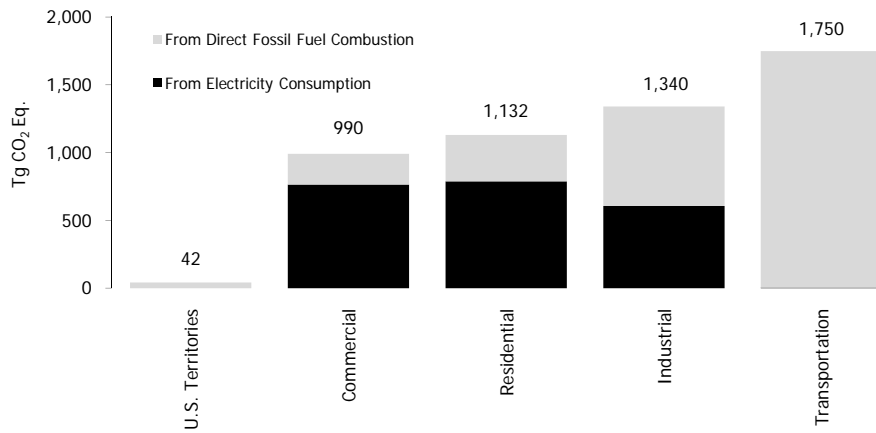


Figure 2-8: 2009 End-Use Sector Emissions from Fossil Fuel Combustion

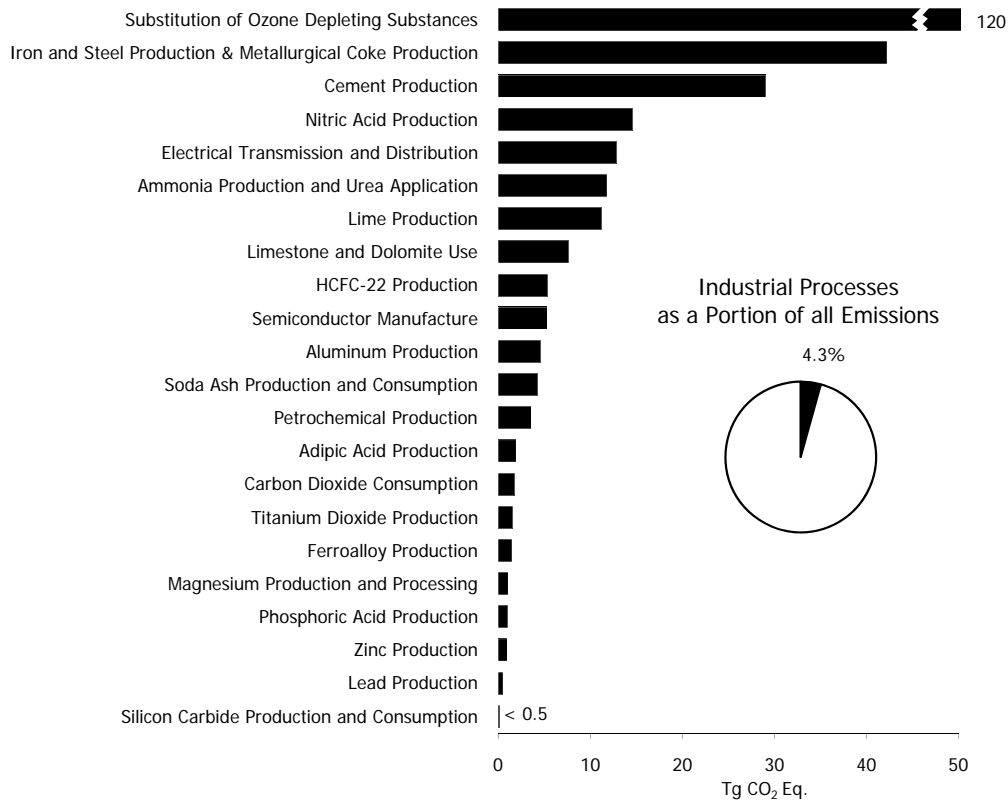


Figure 2-9: 2009 Industrial Processes Chapter Greenhouse Gas Sources

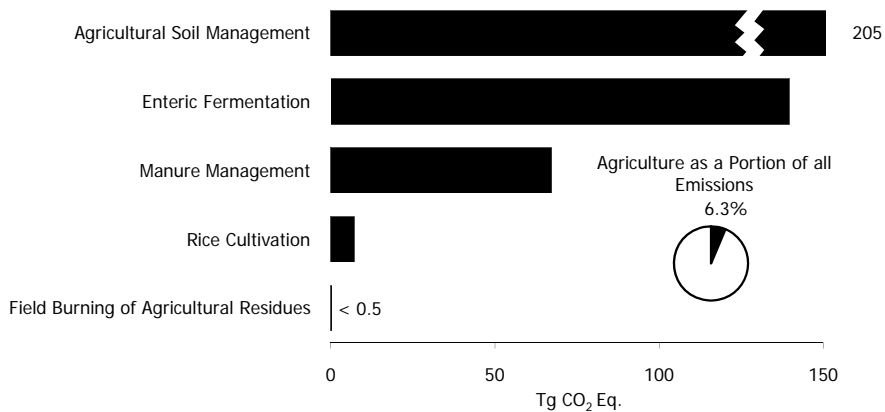


Figure 2-10: 2009 Agriculture Chapter Greenhouse Gas Sources

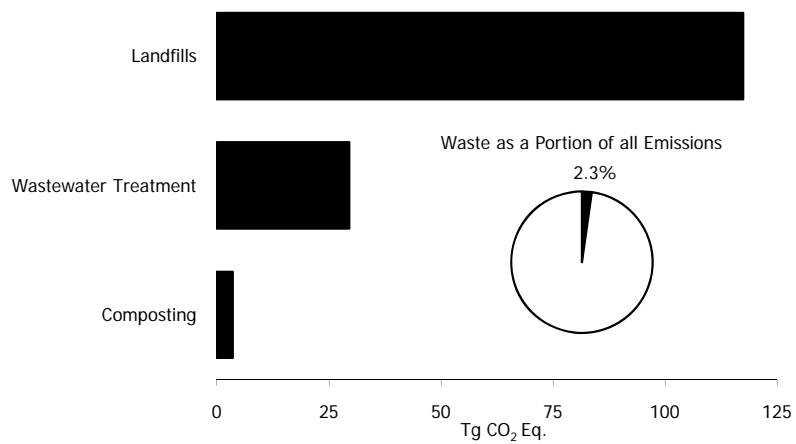


Figure 2-11: 2009 Waste Chapter Greenhouse Gas Sources

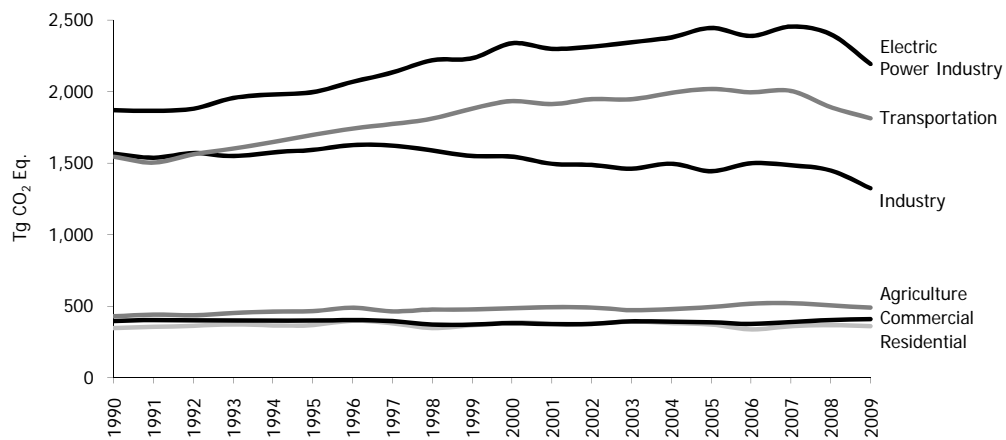


Figure 2-12: Emissions Allocated to Economic Sectors

Note: Does not include U.S. Territories.

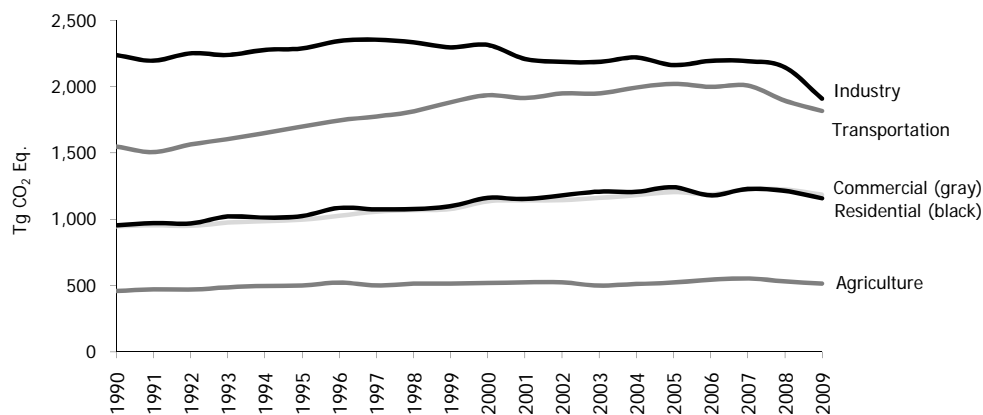


Figure 2-13: Emissions with Electricity Distributed to Economic Sectors

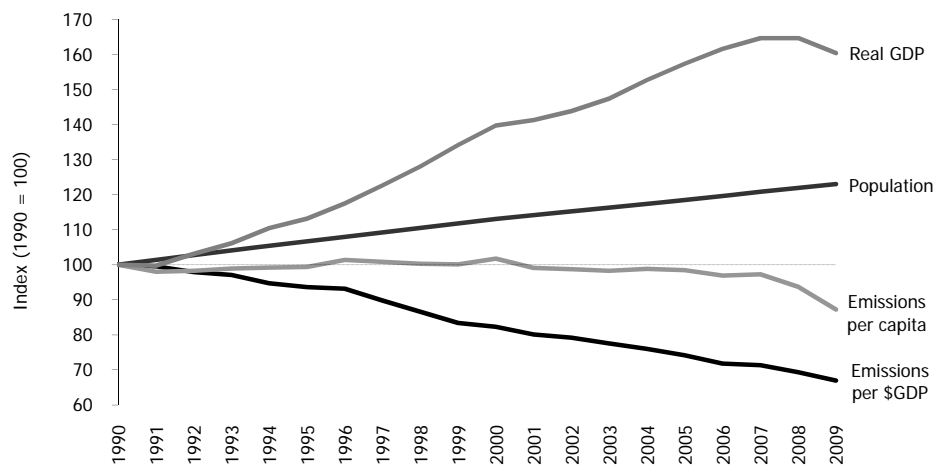


Figure 2-14: U.S. Greenhouse Gas Emissions Per Capita and Per Dollar of Gross Domestic Product

3. Energy

Energy-related activities were the primary sources of U.S. anthropogenic greenhouse gas emissions, accounting for 86.7 percent of total greenhouse gas emissions on a carbon dioxide (CO₂) equivalent basis⁵² in 2009. This included 98, 49, and 13 percent of the nation's CO₂, methane (CH₄), and nitrous oxide (N₂O) emissions, respectively. Energy-related CO₂ emissions alone constituted 81 percent of national emissions from all sources on a CO₂ equivalent basis, while the non-CO₂ emissions from energy-related activities represented a much smaller portion of total national emissions (5.6 percent collectively).

Emissions from fossil fuel combustion comprise the vast majority of energy-related emissions, with CO₂ being the primary gas emitted (see Figure 3-1). Globally, approximately 30,398 Tg of CO₂ were added to the atmosphere through the combustion of fossil fuels in 2009, of which the United States accounted for about 18 percent.⁵³ Due to their relative importance, fossil fuel combustion-related CO₂ emissions are considered separately, and in more detail than other energy-related emissions (see Figure 3-2). Fossil fuel combustion also emits CH₄ and N₂O, and mobile fossil fuel combustion was the second largest source of N₂O emissions in the United States.

Figure 3-1: 2009 Energy Chapter Greenhouse Gas Sources

Figure 3-2: 2009 U.S. Fossil Carbon Flows (Tg CO₂ Eq.)

Energy-related activities other than fuel combustion, such as the production, transmission, storage, and distribution of fossil fuels, also emit greenhouse gases. These emissions consist primarily of fugitive CH₄ from natural gas systems, petroleum systems, and coal mining.

Table 3-1 summarizes emissions from the Energy sector in units of teragrams (or million metric tons) of CO₂ equivalents (Tg CO₂ Eq.), while unweighted gas emissions in gigagrams (Gg) are provided in Table 3-2. Overall, emissions due to energy-related activities were 5,751.1 Tg CO₂ Eq. in 2009, an increase of 9 percent since 1990.

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

Gas/Source	1990	2000	2005	2006	2007	2008	2009
CO₂	4,903.2	5,781.3	5,939.4	5,842.5	5,938.2	5,752.3	5,377.3
Fossil Fuel Combustion	4,738.4	5,594.8	5,753.2	5,653.1	5,756.7	5,565.9	5,209.0
Electricity Generation	1,820.8	2,296.9	2,402.1	2,346.4	2,412.8	2,360.9	2,154.0
Transportation	1,485.9	1,809.5	1,896.6	1,878.1	1,894.0	1,789.9	1,719.7
Industrial	846.5	851.1	823.1	848.2	842.0	802.9	730.4
Residential	338.3	370.7	357.9	321.5	342.4	348.2	339.2
Commercial	219.0	230.8	223.5	208.6	219.4	224.2	224.0
U.S. Territories	27.9	35.9	50.0	50.3	46.1	39.8	41.7
Non-Energy Use of Fuels	118.6	144.9	143.4	145.6	137.2	141.0	123.4
Natural Gas Systems	37.6	29.9	29.9	30.8	31.1	32.8	32.2
Incineration of Waste	8.0	11.1	12.5	12.5	12.7	12.2	12.3
Petroleum Systems	0.6	0.5	0.5	0.5	0.5	0.5	0.5
<i>Biomass - Wood*</i>	<i>215.2</i>	<i>218.1</i>	<i>206.9</i>	<i>203.8</i>	<i>203.3</i>	<i>198.4</i>	<i>183.8</i>
<i>International Bunker Fuels*</i>	<i>111.8</i>	<i>98.5</i>	<i>109.7</i>	<i>128.4</i>	<i>127.6</i>	<i>133.7</i>	<i>123.1</i>
<i>Biomass - Ethanol*</i>	<i>4.2</i>	<i>9.4</i>	<i>23.0</i>	<i>31.0</i>	<i>38.9</i>	<i>54.8</i>	<i>61.2</i>
CH₄	327.4	318.6	291.3	319.2	307.3	323.6	336.8
Natural Gas Systems	189.8	209.3	190.4	217.7	205.2	211.8	221.2

⁵² Estimates are presented in units of teragrams of carbon dioxide equivalent (Tg CO₂ Eq.), which weight each gas by its global warming potential, or GWP, value. See section on global warming potentials in the Executive Summary.

⁵³ Global CO₂ emissions from fossil fuel combustion were taken from Energy Information Administration *International Energy Statistics 2010* < <http://tonto.eia.doe.gov/cfapps/ipdbproject/IEDIndex3.cfm> > EIA (2010).

Coal Mining	84.1	60.4	56.9	58.2	57.9	67.1	71.0
Petroleum Systems	35.4	31.5	29.4	29.4	30.0	30.2	30.9
Stationary Combustion	7.4	6.6	6.6	6.2	6.5	6.5	6.2
Abandoned Underground							
Coal Mines	6.0	7.4	5.5	5.5	5.6	5.9	5.5
Mobile Combustion	4.7	3.4	2.5	2.3	2.2	2.0	2.0
Incineration of Waste	+	+	+	+	+	+	+
<i>International Bunker Fuels*</i>	0.2	0.1	0.1	0.2	0.2	0.2	0.1
N₂O	57.2	68.1	52.1	48.5	45.2	40.7	37.0
Mobile Combustion	43.9	53.2	36.9	33.6	30.3	26.1	23.9
Stationary Combustion	12.8	14.6	14.7	14.4	14.6	14.2	12.8
Incineration of Waste	0.5	0.4	0.4	0.4	0.4	0.4	0.4
<i>International Bunker Fuels*</i>	1.1	0.9	1.0	1.2	1.2	1.2	1.1
Total	5,287.8	6,168.0	6,282.8	6,210.2	6,290.7	6,116.6	5,751.1

+ Does not exceed 0.05 Tg CO₂ Eq.

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

Note: Totals may not sum due to independent rounding.

Table 3-2: CO₂, CH₄, and N₂O Emissions from Energy (Gg)

Gas/Source	1990	2000	2005	2006	2007	2008	2009
CO₂	4,903,171	5,781,303	5,939,434	5,842,464	5,938,203	5,752,327	5,377,271
Fossil Fuel Combustion	4,738,422	5,594,848	5,753,200	5,653,116	5,756,746	5,565,925	5,208,981
Non-Energy Use of							
Fuels	118,630	144,933	143,392	145,574	137,233	140,952	123,356
Natural Gas Systems	37,574	29,877	29,902	30,755	31,050	32,828	32,171
Incineration of Waste	7,989	11,112	12,450	12,531	12,700	12,169	12,300
Petroleum Systems	555	534	490	488	474	453	463
<i>Biomass - Wood*</i>	215,186	218,088	206,865	203,846	203,316	198,361	183,777
<i>International Bunker Fuels*</i>	111,828	98,482	109,750	128,384	127,618	133,704	123,127
<i>Biomass - Ethanol*</i>	4,229	9,352	22,956	31,002	38,946	54,770	61,231
CH₄	15,590	15,171	13,872	15,202	14,634	15,408	16,037
Natural Gas Systems	9,038	9,968	9,069	10,364	9,771	10,087	10,535
Coal Mining	4,003	2,877	2,710	2,774	2,756	3,196	3,382
Petroleum Systems	1,685	1,501	1,398	1,398	1,427	1,439	1,473
Stationary Combustion	354	315	312	293	308	310	293
Abandoned							
Underground Coal							
Mines	288	350	264	261	267	279	262
Mobile Combustion	223	160	119	112	105	97	93
Incineration of Waste	+	+	+	+	+	+	+
<i>International Bunker Fuels*</i>	8	6	7	8	8	8	7
N₂O	185	220	168	156	146	131	120
Mobile Combustion	142	172	119	108	98	84	77
Stationary Combustion	41	47	47	47	47	46	41
Incineration of Waste	2	1	1	1	1	1	1
<i>International Bunker Fuels*</i>	3	3	3	4	4	4	4

+ Does not exceed 0.05 Tg CO₂ Eq.

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

Note: Totals may not sum due to independent rounding.

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

Emissions from the combustion of fossil fuels for energy include the gases CO₂, CH₄, and N₂O. Given that CO₂ is the primary gas emitted from fossil fuel combustion and represents the largest share of U.S. total emissions, CO₂ emissions from fossil fuel combustion are discussed at the beginning of this section. Following that is a discussion of emissions of all three gases from fossil fuel combustion presented by sectoral breakdowns. Methodologies for estimating CO₂ from fossil fuel combustion also differ from the estimation of CH₄ and N₂O emissions from stationary combustion and mobile combustion. Thus, three separate descriptions of methodologies, uncertainties, recalculations, and planned improvements are provided at the end of this section. Total CO₂, CH₄, and N₂O emissions from fossil fuel combustion are presented in Table 3-3 and Table 3-4.

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

Gas	1990	2000	2005	2006	2007	2008	2009
CO ₂	4,738.4	5,594.8	5,753.2	5,653.1	5,756.7	5,565.9	5,209.0
CH ₄	12.1	10.0	9.1	8.5	8.7	8.5	8.1
N ₂ O	56.8	67.7	51.7	48.1	44.9	40.4	36.7
Total	4,807.3	5,627.6	5,813.9	5,709.7	5,810.3	5,614.8	5,253.8

Note: Totals may not sum due to independent rounding.

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

Gas	1990	2000	2005	2006	2007	2008	2009
CO ₂	4,738,422	5,594,848	5,753,200	5,653,116	5,756,746	5,565,925	5,208,981
CH ₄	577	476	431	405	413	407	386
N ₂ O	183	219	167	155	145	130	118

Note: Totals may not sum due to independent rounding.

CO₂ from Fossil Fuel Combustion

CO₂ is the primary gas emitted from fossil fuel combustion and represents the largest share of U.S. total greenhouse gas emissions. CO₂ emissions from fossil fuel combustion are presented in Table 3-5. In 2009, CO₂ emissions from fossil fuel combustion decreased by 6.4 percent relative to the previous year. This decrease represents the largest annual decrease in CO₂ emissions from fossil fuel combustion for the twenty-year period.⁵⁴ The decrease in CO₂ emissions from fossil fuel combustion was a result of multiple factors including: (1) a decrease in economic output resulting in a decrease in energy consumption across all sectors; (2) a decrease in the carbon intensity of fuels used to generate electricity due to fuel switching as the price of coal increased, and the price natural gas decreased significantly; and (3) an increase in non-fossil fuel consumption by approximately 2 percent. In 2009, CO₂ emissions from fossil fuel combustion were 5,209.0 Tg CO₂ Eq., or almost 10 percent above emissions in 1990 (see Table 3-5).⁵⁵

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

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

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

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

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

NE (Not estimated)

NO (Not occurring)

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

Note: Totals may not sum due to independent rounding.

Trends in CO₂ emissions from fossil fuel combustion are influenced by many long-term and short-term factors. On a year-to-year basis, the overall demand for fossil fuels in the United States and other countries generally fluctuates in response to changes in general economic conditions, energy prices, weather, and the availability of non-fossil alternatives. For example, in a year with increased consumption of goods and services, low fuel prices, severe summer and winter weather conditions, nuclear plant closures, and lower precipitation feeding hydroelectric dams, there would likely be proportionally greater fossil fuel consumption than a year with poor economic performance, high fuel prices, mild temperatures, and increased output from nuclear and hydroelectric plants.

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

CO₂ emissions also depend on the source of energy and its carbon (C) intensity. The amount of C in fuels varies significantly by fuel type. For example, coal contains the highest amount of C per unit of useful energy. Petroleum has roughly 75 percent of the C per unit of energy as coal, and natural gas has only about 55 percent.⁵⁶ Table 3-6 shows annual changes in emissions during the last five years for coal, petroleum, and natural gas in selected sectors.

Table 3-6: Annual Change in CO₂ Emissions and Total 2009 Emissions from Fossil Fuel Combustion for Selected Fuels and Sectors (Tg CO₂ Eq. and Percent)

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

^a Excludes emissions from International Bunker Fuels.

^b Includes fuels and sectors not shown in table.

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

In the United States, 83 percent of the energy consumed in 2009 was produced through the combustion of fossil fuels such as coal, natural gas, and petroleum (see Figure 3-3 and Figure 3-4). The remaining portion was supplied by nuclear electric power (9 percent) and by a variety of renewable energy sources⁵⁷ (8 percent), primarily hydroelectric power and biofuels (EIA 2010). Specifically, petroleum supplied the largest share of domestic energy demands, accounting for an average of 42 percent of total fossil fuel based energy consumption in 2009. Natural gas and coal followed in order of importance, accounting for approximately 32 and 27 percent of total consumption, respectively. Petroleum was consumed primarily in the transportation end-use sector and the vast majority of coal was used in electricity generation. Natural gas was broadly consumed in all end-use sectors except transportation (see Figure 3-5) (EIA 2010).

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

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

Figure 3-5: 2009 CO₂ Emissions from Fossil Fuel Combustion by Sector and Fuel Type

Fossil fuels are generally combusted for the purpose of producing energy for useful heat and work. During the combustion process, the C stored in the fuels is oxidized and emitted as CO₂ and smaller amounts of other gases, including CH₄, CO, and NMVOCs.⁵⁸ These other C containing non-CO₂ gases are emitted as a by-product of incomplete fuel combustion, but are, for the most part, eventually oxidized to CO₂ in the atmosphere. Therefore, it is assumed that all of the C in fossil fuels used to produce energy is eventually converted to atmospheric CO₂.

[BEGIN BOX]

Box 3-1: Weather and Non-Fossil Energy Effects on CO₂ from Fossil Fuel Combustion Trends

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

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

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

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

⁵⁸ See the sections entitled Stationary Combustion and Mobile Combustion in this chapter for information on non-CO₂ gas emissions from fossil fuel combustion.

⁵⁹ Degree days are relative measurements of outdoor air temperature. Heating degree days are deviations of the mean daily temperature below 65° F, while cooling degree days are deviations of the mean daily temperature above 65° F. Heating degree days have a considerably greater affect on energy demand and related emissions than do cooling degree days. Excludes Alaska and Hawaii. Normals are based on data from 1971 through 2000. The variation in these normals during this time period was ±10 percent and ±14 percent for heating and cooling degree days, respectively (99 percent confidence interval).

Although no new U.S. nuclear power plants have been constructed in recent years, the utilization (i.e., capacity factors⁶⁰) of existing plants in 2009 remained high at just over 90 percent. Electricity output by hydroelectric power plants increased in 2009 by approximately 6.8 percent. Electricity generated by nuclear plants in 2009 provided nearly 3 times as much of the energy consumed in the United States as hydroelectric plants (EIA 2010). Nuclear, hydroelectric, and wind power capacity factors since 1990 are shown in Figure 3-8.

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

[END BOX]

Fossil Fuel Combustion Emissions by Sector

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

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

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

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

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

Other than CO₂, gases emitted from stationary combustion include the greenhouse gases CH₄ and N₂O and the

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

indirect greenhouse gases NO_x, CO, and NMVOCs.⁶¹ CH₄ and N₂O emissions from stationary combustion sources depend upon fuel characteristics, size and vintage, along with combustion technology, pollution control equipment, ambient environmental conditions, and operation and maintenance practices. N₂O 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. CH₄ emissions from stationary combustion are primarily a function of the CH₄ content of the fuel and combustion efficiency.

Mobile combustion produces greenhouse gases other than CO₂, including CH₄, N₂O, and indirect greenhouse gases including NO_x, CO, and NMVOCs. As with stationary combustion, N₂O and NO_x emissions from mobile combustion are closely related to fuel characteristics, air-fuel mixes, combustion temperatures, and the use of pollution control equipment. N₂O from mobile sources, in particular, can be formed by the catalytic processes used to control NO_x, CO, and hydrocarbon emissions. Carbon monoxide emissions from mobile combustion are significantly affected by combustion efficiency and the presence of post-combustion emission controls. CO emissions are highest when air-fuel mixtures have less oxygen than required for complete combustion. These emissions occur especially in idle, low speed, and cold start conditions. CH₄ and NMVOC emissions from motor vehicles are a function of the CH₄ content of the motor fuel, the amount of hydrocarbons passing uncombusted through the engine, and any post-combustion control of hydrocarbon emissions (such as catalytic converters).

An alternative method of presenting combustion emissions is to allocate emissions associated with electricity generation to the sectors in which it is used. Four end-use sectors were defined: industrial, transportation, residential, and commercial. In the table below, electricity generation emissions have been distributed to each end-use sector based upon the sector's share of national electricity consumption, with the exception of CH₄ and N₂O from transportation.⁶² Emissions from U.S. territories are also calculated separately due to a lack of end-use-specific consumption data. This method of distributing emissions assumes that 564 combustion sources focus on the alternative method as presented in Table 3-8.

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

End-Use Sector	1990	2000	2005	2006	2007	2008	2009
Transportation	1,537.6	1,869.5	1,940.8	1,918.6	1,931.5	1,822.8	1,750.0
CO ₂	1,489.0	1,813.0	1,901.3	1,882.6	1,899.0	1,794.6	1,724.1
CH ₄	4.7	3.4	2.5	2.4	2.2	2.0	2.0
N ₂ O	44.0	53.2	37.0	33.6	30.3	26.2	23.9
Industrial	1,541.2	1,649.3	1,567.9	1,568.1	1,579.7	1,525.1	1,340.1
CO ₂	1,533.2	1,640.8	1,560.0	1,560.2	1,572.0	1,517.7	1,333.7
CH ₄	1.8	1.8	1.7	1.7	1.6	1.6	1.4
N ₂ O	6.3	6.7	6.2	6.2	6.1	5.8	5.0
Residential	939.7	1,140.9	1,222.9	1,160.1	1,206.7	1,190.4	1,131.6
CO ₂	931.4	1,133.1	1,214.7	1,152.4	1,198.5	1,182.2	1,123.8
CH ₄	4.6	3.6	3.7	3.3	3.6	3.7	3.6
N ₂ O	3.7	4.2	4.6	4.4	4.5	4.5	4.2
Commercial	760.8	976.8	1,032.2	1,012.4	1,046.0	1,036.5	990.3
CO ₂	757.0	972.1	1,027.2	1,007.6	1,041.1	1,031.6	985.7
CH ₄	1.0	1.1	1.1	1.1	1.1	1.2	1.1
N ₂ O	2.8	3.6	3.8	3.8	3.8	3.8	3.5
U.S. Territories*	28.0	36.0	50.2	50.5	46.3	40.0	41.8
Total	4,807.3	5,672.6	5,813.9	5,709.7	5,810.3	5,614.8	5,253.8

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

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

⁶¹ Sulfur dioxide (SO₂) emissions from stationary combustion are addressed in Annex 6.3.

⁶² Separate calculations were performed for transportation-related CH₄ and N₂O. The methodology used to calculate these emissions are discussed in the mobile combustion section.

Stationary Combustion

The direct combustion of fuels by stationary sources in the electricity generation, industrial, commercial, and residential sectors represent the greatest share of U.S. greenhouse gas emissions. Table 3-9 presents CO₂ emissions from fossil fuel combustion by stationary sources. The CO₂ emitted is closely linked to the type of fuel being combusted in each sector (see Methodology section for CO₂ from fossil fuel combustion). Other than CO₂, gases emitted from stationary combustion include the greenhouse gases CH₄ and N₂O. Table 3-10 and Table 3-11 present CH₄ and N₂O emissions from the combustion of fuels in stationary sources. CH₄ and N₂O emissions from stationary combustion sources depend upon fuel characteristics, size and vintage, along with combustion technology, pollution control equipment, ambient environmental conditions, and operation and maintenance practices. N₂O 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. CH₄ emissions from stationary combustion are primarily a function of the CH₄ content of the fuel and combustion efficiency. Please refer to Table 3-7 for the corresponding presentation of all direct emission sources of fuel combustion.

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

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

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

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

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

+ Does not exceed 0.05 Tg CO₂ Eq.

Note: Totals may not sum due to independent rounding.

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

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

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

+ Does not exceed 0.05 Tg CO₂ Eq.

Note: Totals may not sum due to independent rounding.

Electricity Generation

The process of generating electricity is the single largest source of CO₂ emissions in the United States, representing 39 percent of total CO₂ emissions from all CO₂ emissions sources across the United States. CH₄ and N₂O accounted for a small portion of emissions from electricity generation, representing less than 0.1 percent and 0.4 percent, respectively.⁶³ Electricity generation also accounted for the largest share of CO₂ emissions from fossil fuel combustion, approximately 41 percent in 2009. CH₄ and N₂O from electricity generation represented 8 and 25 percent of emissions from CH₄ and N₂O emissions from fossil fuel combustion in 2009, respectively. Electricity was consumed primarily in the residential, commercial, and industrial end-use sectors for lighting, heating, electric motors, appliances, electronics, and air conditioning (see Figure 3-9).

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

The electric power industry includes all power producers, consisting of both regulated utilities and nonutilities (e.g. independent power producers, qualifying cogenerators, and other small power producers). For the underlying energy data used in this chapter, the Energy Information Administration (EIA) places electric power generation into three functional categories: the electric power sector, the commercial sector, and the industrial sector. The electric power sector consists of electric utilities and independent power producers whose primary business is the production of electricity,⁶⁴ while the other sectors consist of those producers that indicate their primary business is something other than the production of electricity.

The industrial, residential, and commercial end-use sectors, as presented in Table 3-8, were reliant on electricity for meeting energy needs. The residential and commercial end-use sectors were especially reliant on electricity consumption for lighting, heating, air conditioning, and operating appliances. Electricity sales to the residential and commercial end-use sectors in 2009 decreased approximately 1.2 percent and 1.0 percent, respectively. The trend in the commercial and residential sectors can largely be attributed to the decreased carbon intensity in the fuels used to generate electricity for these sectors. In addition, electricity consumption in both sectors decreased as a result of the less energy-intensive weather conditions compared to 2008. In 2009, the amount of electricity generated (in kWh) decreased by 4 percent from the previous year. This decline was due to the economic downturn, a decrease in the carbon intensity of fuels used to generate electricity due to fuel switching as the price of coal increased, and the price of natural gas decreased significantly, and an increase in non-fossil fuel sources used to generate electricity. As a result, CO₂ emissions from the electric power sector decreased by 8.8 percent as the consumption of coal and petroleum for electricity generation decreased by 10.8 percent and 16.6 percent, respectively, in 2009 and the consumption of natural gas for electricity generation, increased by 3.1 percent. The decrease in C intensity of the electricity supply (see Table 3-15) was the result of a decrease in the carbon intensity of fossil fuels consumed to generate electricity and an increase in renewable generation of 5 percent spurred by a 28 percent increase in wind-generated electricity.

⁶³ Since emissions estimates for U.S. territories cannot be disaggregated by gas in Table 3-7 and Table 3-8, the percentages for CH₄ and N₂O exclude U.S. territory estimates.

⁶⁴ Utilities primarily generate power for the U.S. electric grid for sale to retail customers. Nonutilities produce electricity for their own use, to sell to large consumers, or to sell on the wholesale electricity market (e.g., to utilities for distribution and resale to customers).

Industrial Sector

The industrial sector accounted for 14 percent of CO₂ emissions from fossil fuel combustion, 15 percent of CH₄ emissions from fossil fuel combustion, and 7 percent of N₂O emissions from fossil fuel combustion. CO₂, CH₄, and N₂O emissions resulted from the direct consumption of fossil fuels for steam and process heat production.

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

In theory, emissions from the industrial sector should be highly correlated with economic growth and industrial output, but heating of industrial buildings and agricultural energy consumption are also affected by weather conditions.⁶⁵ In addition, structural changes within the U.S. economy that lead to shifts in industrial output away from energy-intensive manufacturing products to less energy-intensive products (e.g., from steel to computer equipment) also have a significant effect on industrial emissions.

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

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

Despite the growth in industrial output (41 percent) and the overall U.S. economy (60 percent) from 1990 to 2009, CO₂ emissions from fossil fuel combustion in the industrial sector decreased by 13.7 percent over that time. A number of factors are believed to have caused this disparity between growth in industrial output and decrease in industrial emissions, including: (1) more rapid growth in output from less energy-intensive industries relative to traditional manufacturing industries, and (2) energy-intensive industries such as steel are employing new methods, such as electric arc furnaces, that are less carbon intensive than the older methods. In 2009, CO₂, CH₄, and N₂O emissions from fossil fuel combustion and electricity use within the industrial end-use sector totaled 1,340.1 Tg CO₂ Eq., or approximately 12.1 percent below 2008 emissions.

Residential and Commercial Sectors

The residential and commercial sectors accounted for 7 and 4 percent of CO₂ emissions from fossil fuel combustion, 42 and 11 percent of CH₄ emissions from fossil fuel combustion, and 2 and 1 percent of N₂O emissions from fossil fuel combustion, respectively. Emissions from these sectors were largely due to the direct consumption of natural gas and petroleum products, primarily for heating and cooking needs. Coal consumption was a minor component of energy use in both of these end-use sectors. In 2009, CO₂, CH₄, and N₂O emissions from fossil fuel combustion and electricity use within the residential and commercial end-use sectors were 1,131.6 Tg CO₂ Eq. and 990.3 Tg CO₂ Eq., respectively. Total CO₂, CH₄, and N₂O emissions from the residential and commercial sectors decreased by 4.9 and 4.5 percent from 2008 to 2009, respectively.

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

Emissions from natural gas consumption represent about 76 and 75 percent of the direct fossil fuel CO₂ emissions from the residential and commercial sectors, respectively. In 2009, natural gas CO₂ emissions from the residential and commercial sectors decreased by 2.8 percent and 1.3 percent, respectively. The decrease in natural gas emissions in both sectors is a result of less energy-intensive weather conditions in the United States compared to

⁶⁵ Some commercial customers are large enough to obtain an industrial price for natural gas and/or electricity and are consequently grouped with the industrial end-use sector in U.S. energy statistics. These misclassifications of large commercial customers likely cause the industrial end-use sector to appear to be more sensitive to weather conditions.

2008.

U.S. Territories

Emissions from U.S. territories are based on the fuel consumption in American Samoa, Guam, Puerto Rico, U.S. Virgin Islands, Wake Island, and other U.S. Pacific Islands. As described in the Methodology section for CO₂ from fossil fuel combustion, this data is collected separately from the sectoral-level data available for the general calculations. As sectoral information is not available for U.S. Territories, CO₂, CH₄, and N₂O emissions are not presented for U.S. Territories in the tables above, though the emissions will include some transportation and mobile combustion sources.

Transportation Sector

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

The transportation end-use sector accounted for 1,745.5 Tg CO₂ Eq. in 2009, which represented 33 percent of CO₂ emissions, 24 percent of CH₄ emissions, and 65 percent of N₂O emissions from fossil fuel combustion, respectively. Fuel purchased in the U.S. for international aircraft and marine travel accounted for an additional 123.1 Tg CO₂ in 2009; these emissions are recorded as international bunkers and are not included in U.S. totals according to UNFCCC reporting protocols. Among domestic transportation sources, light-duty vehicles (including passenger cars and light-duty trucks) represented 64 percent of CO₂ emissions, medium- and heavy-duty trucks 20 percent, commercial aircraft 6 percent, and other sources 9 percent. Light-duty truck CO₂ emissions increased by 60 percent (193.4 Tg) from 1990 to 2009, representing the largest percentage increase of any transportation mode. General aviation aircraft CO₂ emissions also increased by nearly 60 percent (5.7 Tg) from 1990 to 2009. CO₂ from the domestic operation of commercial aircraft decreased by 18 percent (24.0 Tg) from 1990 to 2009. Across all categories of aviation, CO₂ emissions decreased by 21.6 percent (38.7 Tg) between 1990 and 2009. This includes a 59 percent (20.3 Tg) decrease in emissions from domestic military operations. For further information on all greenhouse gas emissions from transportation sources, please refer to Annex 3.2. See Table 3-12 for a detailed breakdown of CO₂ emissions by mode and fuel type.

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

From 2008 to 2009, CO₂ emissions from the transportation end-use sector declined 4 percent. The decrease in emissions can largely be attributed to decreased economic activity in 2009 and an associated decline in the demand for transportation. Modes such as medium- and heavy-duty trucks were significantly impacted by the decline in freight transport. Similarly, increased jet fuel prices were a factor in the 19 percent decrease in commercial aircraft emissions since 2007.

Almost all of the energy consumed for transportation was supplied by petroleum-based products, with more than half being related to gasoline consumption in automobiles and other highway vehicles. Other fuel uses, especially diesel fuel for freight trucks and jet fuel for aircraft, accounted for the remainder. The primary driver of transportation-related emissions was CO₂ from fossil fuel combustion, which increased by 16 percent from 1990 to 2009. This rise in CO₂ emissions, combined with an increase in HFCs from close to zero emissions in 1990 to 60.2 Tg CO₂ Eq. in 2009, led to an increase in overall emissions from transportation activities of 17 percent.

Transportation Fossil Fuel Combustion CO₂ Emissions

Domestic transportation CO₂ emissions increased by 16 percent (235.1 Tg) between 1990 and 2009, an annualized increase of 0.8 percent. The 4 percent decline in emissions between 2008 and 2009 followed the previous year's trend of decreasing emissions. Almost all of the energy consumed by the transportation sector is petroleum-based,

including motor gasoline, diesel fuel, jet fuel, and residual oil.⁶⁶ Transportation sources also produce CH₄ and N₂O; these emissions are included in Table 3-13 and Table 3-14 in the “Mobile Combustion” Section. Annex 3.2 presents total emissions from all transportation and mobile sources, including CO₂, N₂O, CH₄, and HFCs.

Carbon dioxide emissions from passenger cars and light-duty trucks totaled 1,111.7 Tg in 2009, an increase of 17 percent (161.3 Tg) from 1990. CO₂ emissions from passenger cars and light-duty trucks peaked at 1,184.3 Tg in 2004, and since then have declined about 6 percent. Over the 1990s through early this decade, growth in vehicle travel substantially outweighed improvements in vehicle fuel economy; however, the rate of Vehicle Miles Traveled (VMT) growth slowed considerably starting in 2005 (and declined rapidly in 2008) while average vehicle fuel economy increased. Among new vehicles sold annually, average fuel economy gradually declined from 1990 to 2004 (Figure 3-11), reflecting substantial growth in sales of light-duty trucks—in particular, growth in the market share of sport utility vehicles—relative to passenger cars (Figure 3-12). New vehicle fuel economy improved beginning in 2005, largely due to higher light-duty truck fuel economy standards, which have risen each year since 2005. The overall increase in fuel economy is also due to a slightly lower light-duty truck market share, which peaked in 2004 at 52 percent and declined to 40 percent in 2009.

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

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

Light-duty truck⁶⁷ CO₂ emissions increased by 60 percent (193.4 Tg) from 1990 to 2009, representing the largest percentage increase of any transportation mode. General aviation aircraft CO₂ emissions also increased by nearly 60 percent (5.7 Tg) from 1990 to 2009. CO₂ from the domestic operation of commercial aircraft decreased by 18 percent (24.0 Tg) from 1990 to 2009. Across all categories of aviation⁶⁸, CO₂ emissions decreased by 21.6 percent (38.7 Tg) between 1990 and 2009. This includes a 59 percent (20.3 Tg) decrease in emissions from domestic military operations. For further information on all greenhouse gas emissions from transportation sources, please refer to Annex 3.2.

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

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

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

⁶⁷Includes “light-duty trucks” fueled by gasoline, diesel and LPG.

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

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

^a This table does not include emissions from non-transportation mobile sources, such as agricultural equipment and construction/mining equipment; it also does not include emissions associated with electricity consumption by pipelines or lubricants used in transportation.

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

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

Note: Totals may not sum due to independent rounding.

Note: See section 3.10 of this chapter, in line with IPCC methodological guidance and UNFCCC reporting obligations, for more information on ethanol.

+ Less than 0.05 Tg CO₂ Eq.

- Unreported or zero

Mobile Fossil Fuel Combustion CH₄ and N₂O Emissions

Mobile combustion includes emissions of CH₄ and N₂O from all transportation sources identified in the U.S. inventory with the exception of pipelines, which are stationary; mobile sources also include non-transportation sources such as construction/mining equipment, agricultural equipment, vehicles used off-road, and other sources (e.g., snowmobiles, lawnmowers, etc.). Annex 3.2 includes a summary of all emissions from both transportation and mobile sources. Table 3-13 and Table 3-14 provide CH₄ and N₂O emission estimates in Tg CO₂ Eq.⁶⁹

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

Mobile combustion was responsible for a small portion of national CH₄ emissions (0.3 percent) but was the second largest source of U.S. N₂O emissions (9 percent). From 1990 to 2009, mobile source CH₄ emissions declined by 58 percent, to 2.0 Tg CO₂ Eq. (93 Gg), due largely to control technologies employed in on-road vehicles since the mid-1990s to reduce CO, NO_x, NMVOC, and CH₄ emissions. Mobile source emissions of N₂O decreased by 46 percent, to 23.9 Tg CO₂ Eq. (77 Gg). Earlier generation control technologies initially resulted in higher N₂O emissions, causing a 26 percent increase in N₂O emissions from mobile sources between 1990 and 1998. Improvements in later-generation emission control technologies have reduced N₂O output, resulting in a 50 percent decrease in mobile source N₂O emissions from 1998 to 2009 (Figure 3-13). Overall, CH₄ and N₂O emissions were predominantly from gasoline-fueled passenger cars and light-duty trucks.

Figure 3-13: Mobile Source CH₄ and N₂O Emissions

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

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

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

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

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

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

Note: Totals may not sum due to independent rounding.

+ Less than 0.05 Tg CO₂ Eq.

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

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

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

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

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

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

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

Note: Totals may not sum due to independent rounding.

+ Less than 0.05 Tg CO₂ Eq.

CO₂ from Fossil Fuel Combustion

Methodology

The methodology used by the United States for estimating CO₂ emissions from fossil fuel combustion is conceptually similar to the approach recommended by the IPCC for countries that intend to develop detailed, sectoral-based emission estimates in line with a Tier 2 method in the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006). A detailed description of the U.S. methodology is presented in Annex 2.1, and is characterized by the following steps:

1. *Determine total fuel consumption by fuel type and sector.* Total fossil fuel consumption for each year is estimated by aggregating consumption data by end-use sector (e.g., commercial, industrial, etc.), primary fuel type (e.g., coal, petroleum, gas), and secondary fuel category (e.g., motor gasoline, distillate fuel oil, etc.). Fuel consumption data for the United States were obtained directly from the Energy Information Administration (EIA) of the U.S. Department of Energy (DOE), primarily from the Monthly Energy Review and published supplemental tables on petroleum product detail (EIA 2011). The EIA does not include territories in its national energy statistics, so fuel consumption data for territories were collected separately from Jacobs (2010).⁷⁰

For consistency of reporting, the IPCC has recommended that countries report energy data using the International Energy Agency (IEA) reporting convention and/or IEA data. Data in the IEA format are presented "top down"—that is, energy consumption for fuel types and categories are estimated from energy production data (accounting for imports, exports, stock changes, and losses). The resulting quantities are referred to as "apparent consumption." The data collected in the United States by EIA on an annual basis and used in this inventory are predominantly from mid-stream or conversion energy consumers such as refiners and electric power generators. These annual surveys are supplemented with end-use energy consumption surveys, such as the Manufacturing Energy Consumption Survey, that are conducted on a periodic basis (every 4 years). These consumption data sets help inform the annual surveys to arrive at the

⁷⁰ Fuel consumption by U.S. territories (i.e., American Samoa, Guam, Puerto Rico, U.S. Virgin Islands, Wake Island, and other U.S. Pacific Islands) is included in this report and contributed emissions of 42 Tg CO₂ Eq. in 2009.

national total and sectoral breakdowns for that total.⁷¹

It is also important to note that U.S. fossil fuel energy statistics are generally presented using gross calorific values (GCV) (i.e., higher heating values). Fuel consumption activity data presented here have not been adjusted to correspond to international standards, which are to report energy statistics in terms of net calorific values (NCV) (i.e., lower heating values).⁷²

2. *Subtract uses accounted for in the Industrial Processes chapter.* Portions of the fuel consumption data for seven fuel categories—coking coal, distillate fuel, industrial other coal, petroleum coke, natural gas, residual fuel oil, and other oil—were reallocated to the industrial processes chapter, as they were consumed during non-energy related industrial activity. To make these adjustments, additional data were collected from AISI (2004 through 2010), Coffeyville (2010), U.S. Census Bureau (2010), EIA (2010c), USGS (1991 through 2010), USGS (1994 through 2010), USGS (1995, 1998, 2000 through 2002, 2007, and 2009), USGS (1991 through 2009a), and USGS (1991 through 2009b).⁷³
3. *Adjust for conversion of fuels and exports of CO₂.* Fossil fuel consumption estimates are adjusted downward to exclude fuels created from other fossil fuels and exports of CO₂.⁷⁴ Synthetic natural gas is created from industrial coal, and is currently included in EIA statistics for both coal and natural gas. Therefore, synthetic natural gas is subtracted from energy consumption statistics.⁷⁵ Since October 2000, the Dakota Gasification Plant has been exporting CO₂ to Canada by pipeline. Since this CO₂ is not emitted to the atmosphere in the United States, energy used to produce this CO₂ is subtracted from energy consumption statistics. To make these adjustments, additional data for ethanol were collected from EIA (2011) and data for synthetic natural gas were collected from EIA (2009b), and data for CO₂ exports were collected from the Dakota Gasification Company (2006), Fitzpatrick (2002), Erickson (2003), and EIA (2007b).
4. *Adjust Sectoral Allocation of Distillate Fuel Oil and Motor Gasoline.* EPA had conducted a separate bottom-up analysis of transportation fuel consumption based on the Federal Highway Administration's (FHWA) VMT that indicated that the amount of distillate and motor gasoline consumption allocated to the transportation sector in the EIA statistics should be adjusted. Therefore, for these estimates, the transportation sector's distillate fuel and motor gasoline consumption was adjusted upward to match the value obtained from the bottom-up analysis based on VMT. As the total distillate and motor gasoline consumption estimate from EIA are considered to be accurate at the national level, the distillate consumption totals for the residential, commercial, and industrial sectors were adjusted downward proportionately. The data sources used in the bottom-up analysis of transportation fuel consumption include AAR (2009 through 2010), Benson (2002 through 2004), DOE (1993 through 2010), EIA (2009a), EIA (1991 through 2010), EPA (2009), and FHWA (1996 through 2010).⁷⁶

⁷¹ See IPCC Reference Approach for estimating CO₂ emissions from fossil fuel combustion in Annex 4 for a comparison of U.S. estimates using top-down and bottom-up approaches.

⁷² A crude convention to convert between gross and net calorific values is to multiply the heat content of solid and liquid fossil fuels by 0.95 and gaseous fuels by 0.9 to account for the water content of the fuels. Biomass-based fuels in U.S. energy statistics, however, are generally presented using net calorific values.

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

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

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

⁷⁶ FHWA data on vehicle miles traveled from the VM-1 table were not available for 2009 due to a delay caused by changes in data collection procedures. Based on data from FHWA's Traffic Volume Trends Program, the overall increase in VMT between 2008 and 2009 was estimated to be 0.2%. Total VMT was distributed among vehicle classes based on trends in fuel consumption by fuel type between 2008 and 2009, as described below.

Fuel use by vehicle class (also in the VM-1 table) was not available from FHWA for 2009, but changes in overall diesel and gasoline consumption were released in Table MF21. Fuel use in vehicle classes that were predominantly gasoline was estimated to grow by the rate of growth for gasoline between 2008 and 2009. Fuel use in vehicle classes that were predominantly diesel

5. *Adjust for fuels consumed for non-energy uses.* U.S. aggregate energy statistics include consumption of fossil fuels for non-energy purposes. These are fossil fuels that are manufactured into plastics, asphalt, lubricants, or other products. Depending on the end-use, this can result in storage of some or all of the C contained in the fuel for a period of time. As the emission pathways of C used for non-energy purposes are vastly different than fuel combustion (since the C in these fuels ends up in products instead of being combusted), these emissions are estimated separately in the Carbon Emitted and Stored in Products from Non-Energy Uses of Fossil Fuels section in this chapter. Therefore, the amount of fuels used for non-energy purposes was subtracted from total fuel consumption. Data on non-fuel consumption was provided by EIA (2011).
6. *Subtract consumption of international bunker fuels.* According to the UNFCCC reporting guidelines emissions from international transport activities, or bunker fuels, should not be included in national totals. U.S. energy consumption statistics include these bunker fuels (e.g., distillate fuel oil, residual fuel oil, and jet fuel) as part of consumption by the transportation end-use sector, however, so emissions from international transport activities were calculated separately following the same procedures used for emissions from consumption of all fossil fuels (i.e., estimation of consumption, and determination of C content).⁷⁷ The Office of the Under Secretary of Defense (Installations and Environment) and the Defense Energy Support Center (Defense Logistics Agency) of the U.S. Department of Defense (DoD) (DESC 2011) supplied data on military jet fuel and marine fuel use. Commercial jet fuel use was obtained from FAA (2006 and 2009); residual and distillate fuel use for civilian marine bunkers was obtained from DOC (1991 through 2010) for 1990 through 2001, 2007 and 2008, and DHS (2008) for 2003 through 2006. Consumption of these fuels was subtracted from the corresponding fuels in the transportation end-use sector. Estimates of international bunker fuel emissions for the United States are discussed in detail later in the International Bunker Fuels section of this chapter.
7. *Determine the total C content of fuels consumed.* Total C was estimated by multiplying the amount of fuel consumed by the amount of C in each fuel. This total C estimate defines the maximum amount of C that could potentially be released to the atmosphere if all of the C in each fuel was converted to CO₂. The C content coefficients used by the United States were obtained from EIA's Emissions of Greenhouse Gases in the United States 2008 (EIA 2009a), and an EPA analysis of C content coefficients used in the mandatory reporting rule (EPA 2010a). A discussion of the methodology used to develop the C content coefficients are presented in Annexes 2.1 and 2.2.
8. *Estimate CO₂ Emissions.* Total CO₂ emissions are the product of the adjusted energy consumption (from the previous methodology steps 1 through 6), the C content of the fuels consumed, and the fraction of C that is oxidized. The fraction oxidized was assumed to be 100 percent for petroleum, coal, and natural gas based on guidance in IPCC (2006) (see Annex 2.1).
9. *Allocate transportation emissions by vehicle type.* This report provides a more detailed accounting of emissions from transportation because it is such a large consumer of fossil fuels in the United States. For fuel types other than jet fuel, fuel consumption data by vehicle type and transportation mode were used to allocate emissions by fuel type calculated for the transportation end-use sector.
 - For on-road vehicles, annual estimates of combined motor gasoline and diesel fuel consumption by vehicle category were obtained from FHWA (1996 through 2010); for each vehicle category, the percent gasoline, diesel, and other (e.g., CNG, LPG) fuel consumption are estimated using data from DOE (1993 through 2010). Fuel use by vehicle class (found in the VM-1 table) was not available from FHWA for 2009, but changes in overall diesel and gasoline consumption were released in Table MF21. Fuel use in vehicle classes that were predominantly gasoline was estimated to grow by the rate of growth for gasoline between 2008 and 2009. Fuel use in vehicle classes that were predominantly diesel were estimated to fall by the same rate that diesel fuel consumption fell overall in 2009.
 - For non-road vehicles, activity data were obtained from AAR (2009 through 2010), APTA (2007 through 2010), BEA (1991 through 2009), Benson (2002 through 2004), DOE (1993 through 2010),

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

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

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

- For jet fuel used by aircraft, CO₂ emissions were calculated directly based on reported consumption of fuel as reported by EIA, and allocated to commercial aircraft using flight-specific fuel consumption data from the Federal Aviation Administration's (FAA) Aviation Environmental Design Tool (AEDT) (FAA 2011). ⁷⁸ Allocation to domestic general aviation was made using FAA Aerospace Forecast data, and allocation to domestic military uses was made using DoD data (see Annex 3.7).

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

[BEGIN BOX]

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

Fossil fuels are the dominant source of energy in the United States, and CO₂ is the dominant greenhouse gas emitted as a product from their combustion. Energy-related CO₂ emissions are impacted by not only lower levels of energy consumption but also by lowering the C intensity of the energy sources employed (e.g., fuel switching from coal to natural gas). The amount of C emitted from the combustion of fossil fuels is dependent upon the C content of the fuel and the fraction of that C that is oxidized. Fossil fuels vary in their average C content, ranging from about 53 Tg CO₂ Eq./Qbtu for natural gas to upwards of 95 Tg CO₂ Eq./Qbtu for coal and petroleum coke.⁸⁰ In general, the C content per unit of energy of fossil fuels is the highest for coal products, followed by petroleum, and then natural gas. The overall C intensity of the U.S. economy is thus dependent upon the quantity and combination of fuels and other energy sources employed to meet demand.

Table 3-15 provides a time series of the C intensity for each sector of the U.S. economy. The time series incorporates only the energy consumed from the direct combustion of fossil fuels in each sector. For example, the C intensity for the residential sector does not include the energy from or emissions related to the consumption of electricity for lighting. Looking only at this direct consumption of fossil fuels, the residential sector exhibited the lowest C intensity, which is related to the large percentage of its energy derived from natural gas for heating. The C intensity of the commercial sector has predominantly declined since 1990 as commercial businesses shift away from petroleum to natural gas. The industrial sector was more dependent on petroleum and coal than either the residential or commercial sectors, and thus had higher C intensities over this period. The C intensity of the transportation sector was closely related to the C content of petroleum products (e.g., motor gasoline and jet fuel, both around 70 Tg CO₂ Eq./EJ), which were the primary sources of energy. Lastly, the electricity generation sector had the highest C intensity due to its heavy reliance on coal for generating electricity.

Table 3-15: Carbon Intensity from Direct Fossil Fuel Combustion by Sector (Tg CO₂ Eq./Qbtu)

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

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

⁷⁹ For a more detailed description of the data sources used for the analysis of the transportation end use sector see the Mobile Combustion (excluding CO₂) and International Bunker Fuels sections of the Energy chapter, Annex 3.2, and Annex 3.7.

⁸⁰ One exajoule (EJ) is equal to 10¹⁸ joules or 0.9478 Qbtu.

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

^a Does not include electricity or renewable energy consumption.

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

^c Does not include nuclear or renewable energy consumption.

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

Over the twenty-year period of 1990 through 2009, however, the C intensity of U.S. energy consumption has been fairly constant, as the proportion of fossil fuels used by the individual sectors has not changed significantly. Per capita energy consumption fluctuated little from 1990 to 2007, but in 2009 was approximately 9 percent below levels in 1990 (see Figure 3-14). Due to a general shift from a manufacturing-based economy to a service-based economy, as well as overall increases in efficiency, energy consumption and energy-related CO₂ emissions per dollar of gross domestic product (GDP) have both declined since 1990 (BEA 2010).

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

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

[END BOX]

Uncertainty and Time Series Consistency

For estimates of CO₂ from fossil fuel combustion, the amount of CO₂ emitted is directly related to the amount of fuel consumed, the fraction of the fuel that is oxidized, and the carbon content of the fuel. Therefore, a careful accounting of fossil fuel consumption by fuel type, average carbon contents of fossil fuels consumed, and production of fossil fuel-based products with long-term carbon storage should yield an accurate estimate of CO₂ emissions.

Nevertheless, there are uncertainties in the consumption data, carbon content of fuels and products, and carbon oxidation efficiencies. For example, given the same primary fuel type (e.g., coal, petroleum, or natural gas), the amount of carbon contained in the fuel per unit of useful energy can vary. For the United States, however, the impact of these uncertainties on overall CO₂ emission estimates is believed to be relatively small. See, for example, Marland and Pippin (1990).

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

To calculate the total CO₂ emission estimate from energy-related fossil fuel combustion, the amount of fuel used in these non-energy production processes were subtracted from the total fossil fuel consumption for 2009. The amount of CO₂ emissions resulting from non-energy related fossil fuel use has been calculated separately and reported in the Carbon Emitted from Non-Energy Uses of Fossil Fuels section of this report. These factors all contribute to the uncertainty in the CO₂ estimates. Detailed discussions on the uncertainties associated with C emitted from Non-Energy Uses of Fossil Fuels can be found within that section of this chapter.

Various sources of uncertainty surround the estimation of emissions from international bunker fuels, which are subtracted from the U.S. totals (see the detailed discussions on these uncertainties provided in the International Bunker Fuels section of this chapter). Another source of uncertainty is fuel consumption by U.S. territories. The

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

Uncertainties in the emission estimates presented above also result from the data used to allocate CO₂ emissions from the transportation end-use sector to individual vehicle types and transport modes. In many cases, bottom-up estimates of fuel consumption by vehicle type do not match aggregate fuel-type estimates from EIA. Further research is planned to improve the allocation into detailed transportation end-use sector emissions.

The uncertainty analysis was performed by primary fuel type for each end-use sector, using the IPCC-recommended Tier 2 uncertainty estimation methodology, Monte Carlo Simulation technique, with @RISK software. For this uncertainty estimation, the inventory estimation model for CO₂ from fossil fuel combustion was integrated with the relevant variables from the inventory estimation model for International Bunker Fuels, to realistically characterize the interaction (or endogenous correlation) between the variables of these two models. About 120 input variables were modeled for CO₂ from energy-related Fossil Fuel Combustion (including about 10 for non-energy fuel consumption and about 20 for International Bunker Fuels).

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

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

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 3-16. Fossil fuel combustion CO₂ emissions in 2009 were estimated to be between 5,149.0 and 5,522.4 Tg CO₂ Eq. at a 95 percent confidence level. This indicates a range of 1 percent below to 6 percent above the 2009 emission estimate of 5,209.0 Tg CO₂ Eq.

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

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

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

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

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

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

NA (Not Applicable)

NE (Not Estimated)

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

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

^c Geothermal emissions added for reporting purposes, but an uncertainty analysis was not performed for CO₂ emissions from geothermal production.

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

QA/QC and Verification

A source-specific QA/QC plan for CO₂ from fossil fuel combustion was developed and implemented. This effort included a Tier 1 analysis, as well as portions of a Tier 2 analysis. The Tier 2 procedures that were implemented involved checks specifically focusing on the activity data and methodology used for estimating CO₂ emissions from fossil fuel combustion in the United States. Emission totals for the different sectors and fuels were compared and trends were investigated to determine whether any corrective actions were needed. Minor corrective actions were taken.

Recalculations Discussion

The Energy Information Administration (EIA 2011) updated energy consumption statistics across the time series. These revisions primarily impacted the emission estimates for 2007 and 2008. In addition, the coal emissions for U.S. Territories decreased from 2001 to 2008 due to the closure of a coal power plant in the U.S. Virgin Islands. Overall, these changes resulted in an average annual increase of 0.5 Tg CO₂ Eq. (less than 0.1 percent) in CO₂ emissions from fossil fuel combustion for the period 1990 through 2008.

Planned Improvements

To reduce uncertainty of CO₂ from fossil fuel combustion estimates, efforts will be taken to work with EIA and other agencies to improve the quality of the U.S. territories data. This improvement is not all-inclusive, and is part of an ongoing analysis and efforts to continually improve the CO₂ from fossil fuel combustion estimates. In addition, further expert elicitation may be conducted to better quantify the total uncertainty associated with emissions from this source.

Beginning in 2010, those facilities that emit over 25,000 tons of greenhouse gases (CO₂ Eq.) from stationary combustion across all sectors of the economy are required to calculate and report their greenhouse gas emissions to

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

CH₄ and N₂O from Stationary Combustion

Methodology

CH₄ and N₂O emissions from stationary combustion were estimated by multiplying fossil fuel and wood consumption data by emission factors (by sector and fuel type). National coal, natural gas, fuel oil, and wood consumption data were grouped by sector: industrial, commercial, residential, electricity generation, and U.S. territories. For the CH₄ and N₂O estimates, wood consumption data for the United States was obtained from EIA's Annual Energy Review (EIA 2010). Fuel consumption data for coal, natural gas, and fuel oil for the United States were obtained from EIA's Monthly Energy Review and unpublished supplemental tables on petroleum product detail (EIA 2011). Because the United States does not include territories in its national energy statistics, fuel consumption data for territories were provided separately by Jacobs (2010).⁸⁴ Fuel consumption for the industrial sector was adjusted to subtract out construction and agricultural use, which is reported under mobile sources.⁸⁵ Construction and agricultural fuel use was obtained from EPA (2010a). Estimates for wood biomass consumption for fuel combustion do not include wood wastes, liquors, municipal solid waste, tires, etc., that are reported as biomass by EIA.

Emission factors for the four end-use sectors were provided by the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006). U.S. territories' emission factors were estimated using the U.S. emission factors for the primary sector in which each fuel was combusted.

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

Uncertainty and Time-Series Consistency

CH₄ emission estimates from stationary sources exhibit high uncertainty, primarily due to difficulties in calculating emissions from wood combustion (i.e., fireplaces and wood stoves). The estimates of CH₄ and N₂O emissions presented are based on broad indicators of emissions (i.e., fuel use multiplied by an aggregate emission factor for different sectors), rather than specific emission processes (i.e., by combustion technology and type of emission control).

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

The uncertainty estimation model for this source category was developed by integrating the CH₄ and N₂O stationary source inventory estimation models with the model for CO₂ from fossil fuel combustion to realistically characterize the interaction (or endogenous correlation) between the variables of these three models. About 55 input variables were simulated for the uncertainty analysis of this source category (about 20 from the CO₂ emissions from fossil fuel combustion inventory estimation model and about 35 from the stationary source inventory models).

In developing the uncertainty estimation model, uniform distribution was assumed for all activity-related input variables and N₂O emission factors, based on the SAIC/EIA (2001) report.⁸⁶ For these variables, the uncertainty

⁸⁴ U.S. territories data also include combustion from mobile activities because data to allocate territories' energy use were unavailable. For this reason, CH₄ and N₂O emissions from combustion by U.S. territories are only included in the stationary combustion totals.

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

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

ranges were assigned to the input variables based on the data reported in SAIC/EIA (2001).⁸⁷ However, the CH₄ emission factors differ from those used by EIA. Since these factors were obtained from IPCC/UNEP/OECD/IEA (1997), uncertainty ranges were assigned based on IPCC default uncertainty estimates (IPCC 2000).

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 3-17. Stationary combustion CH₄ emissions in 2009 (including biomass) were estimated to be between 4.1 and 14.0 Tg CO₂ Eq. at a 95 percent confidence level. This indicates a range of 34 percent below to 127 percent above the 2009 emission estimate of 6.2 Tg CO₂ Eq.⁸⁸ Stationary combustion N₂O emissions in 2009 (*including* biomass) were estimated to be between 9.8 and 36.7 Tg CO₂ Eq. at a 95 percent confidence level. This indicates a range of 23 percent below to 187 percent above the 2009 emissions estimate of 12.8 Tg CO₂ Eq.

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

Source	Gas	2009 Emission Estimate (Tg CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate ^a			
			(Tg CO ₂ Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Stationary Combustion	CH ₄	6.2	4.1	14.0	-34%	+127%
Stationary Combustion	N ₂ O	12.8	9.8	36.7	-23%	+187%

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

The uncertainties associated with the emission estimates of CH₄ and N₂O are greater than those associated with estimates of CO₂ from fossil fuel combustion, which mainly rely on the carbon content of the fuel combusted. Uncertainties in both CH₄ and N₂O estimates are due to the fact that emissions are estimated based on emission factors representing only a limited subset of combustion conditions. For the indirect greenhouse gases, uncertainties are partly due to assumptions concerning combustion technology types, age of equipment, emission factors used, and activity data projections.

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

QA/QC and Verification

A source-specific QA/QC plan for stationary combustion was developed and implemented. This effort included a Tier 1 analysis, as well as portions of a Tier 2 analysis. The Tier 2 procedures that were implemented involved checks specifically focusing on the activity data and emission factor sources and methodology used for estimating CH₄, N₂O, and the indirect greenhouse gases from stationary combustion in the United States. Emission totals for the different sectors and fuels were compared and trends were investigated.

Recalculations Discussion

Historical CH₄ and N₂O emissions from stationary sources (excluding CO₂) were revised due to a couple of changes, mainly impacting 2007 and 2008 estimates. Slight changes to emission estimates for sectors are due to revised data from EIA (2010). Wood consumption data in EIA (2011) were revised for the residential, commercial, and industrial sectors for 2007 and 2008 as well as for the electric power sector for 2006 through 2008. The combination of the methodological and historical data changes resulted in an average annual increase of 0.01 Tg CO₂ Eq. (0.2 percent) in CH₄ emissions from stationary combustion and an average annual decrease of 0.08 Tg CO₂ Eq. (0.5 percent) in N₂O emissions from stationary combustion for the period 1990 through 2008.

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

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

Planned Improvements

Several items are being evaluated to improve the CH₄ and N₂O emission estimates from stationary combustion and to reduce uncertainty. Efforts will be taken to work with EIA and other agencies to improve the quality of the U.S. territories data. Because these data are not broken out by stationary and mobile uses, further research will be aimed at trying to allocate consumption appropriately. In addition, the uncertainty of biomass emissions will be further investigated since it was expected that the exclusion of biomass from the uncertainty estimates would reduce the uncertainty; and in actuality the exclusion of biomass increases the uncertainty. These improvements are not all-inclusive, but are part of an ongoing analysis and efforts to continually improve these stationary estimates.

Beginning in 2010, those facilities that emit over 25,000 tons of greenhouse gases (CO₂ Eq.) from stationary combustion across all sectors of the economy are required to calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. These data will be used in future inventories to improve the emission calculations through the use of these collected higher tier methodological data.

CH₄ and N₂O from Mobile Combustion

Methodology

Estimates of CH₄ and N₂O emissions from mobile combustion were calculated by multiplying emission factors by measures of activity for each fuel and vehicle type (e.g., light-duty gasoline trucks). Activity data included vehicle miles traveled (VMT) for on-road vehicles and fuel consumption for non-road mobile sources. The activity data and emission factors used are described in the subsections that follow. A complete discussion of the methodology used to estimate CH₄ and N₂O emissions from mobile combustion and the emission factors used in the calculations is provided in Annex 3.2.

On-Road Vehicles

Estimates of CH₄ and N₂O emissions from gasoline and diesel on-road vehicles are based on VMT and emission factors by vehicle type, fuel type, model year, and emission control technology. Emission estimates for alternative fuel vehicles (AFVs)⁸⁹ are based on VMT and emission factors by vehicle and fuel type.

Emission factors for gasoline and diesel on-road vehicles utilizing Tier 2 and Low Emission Vehicle (LEV) technologies were developed by ICF (2006b); all other gasoline and diesel on-road vehicle emissions factors were developed by ICF (2004). These factors were derived from EPA, California Air Resources Board (CARB) and Environment Canada laboratory test results of different vehicle and control technology types. The EPA, CARB and Environment Canada tests were designed following the Federal Test Procedure (FTP), which covers three separate driving segments, since vehicles emit varying amounts of greenhouse gases depending on the driving segment. These driving segments are: (1) a transient driving cycle that includes cold start and running emissions, (2) a cycle that represents running emissions only, and (3) a transient driving cycle that includes hot start and running emissions. For each test run, a bag was affixed to the tailpipe of the vehicle and the exhaust was collected; the content of this bag was then analyzed to determine quantities of gases present. The emissions characteristics of segment 2 were used to define running emissions, and subtracted from the total FTP emissions to determine start emissions. These were then recombined based upon the ratio of start to running emissions for each vehicle class from MOBILE6.2, an EPA emission factor model that predicts gram per mile emissions of CO₂, CO, HC, NO_x, and PM from vehicles under various conditions, to approximate average driving characteristics.⁹⁰

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

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

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

AFVs is provided in Annex 3.2.

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

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

Non-Road Vehicles

To estimate emissions from non-road vehicles, fuel consumption data were employed as a measure of activity, and multiplied by fuel-specific emission factors (in grams of N₂O and CH₄ per kilogram of fuel consumed).⁹² Activity data were obtained from AAR (2009 through 2010), APTA (2007 through 2010), APTA (2006), BEA (1991 through 2005), Benson (2002 through 2004), DHS (2008), DOC (1991 through 2008), DOE (1993 through 2010), DESC (2011), DOT (1991 through 2010), EIA (2008a, 2007a, 2007b, 2002), EIA (2007 through 2010), EIA (1991 through 2011), EPA (2009), Esser (2003 through 2004), FAA (2011, 2010, and 2006), Gaffney (2007), and (2006 through 2010). Emission factors for non-road modes were taken from IPCC/UNEP/OECD/IEA (1997) and Browning (2009).

Uncertainty and Time-Series Consistency

A quantitative uncertainty analysis was conducted for the mobile source sector using the IPCC-recommended Tier 2 uncertainty estimation methodology, Monte Carlo simulation technique, using @RISK software. The uncertainty analysis was performed on 2009 estimates of CH₄ and N₂O emissions, incorporating probability distribution functions associated with the major input variables. For the purposes of this analysis, the uncertainty was modeled for the following four major sets of input variables: (1) vehicle miles traveled (VMT) data, by on-road vehicle and fuel type and (2) emission factor data, by on-road vehicle, fuel, and control technology type, (3) fuel consumption, data, by non-road vehicle and equipment type, and (4) emission factor data, by non-road vehicle and equipment type.

Uncertainty analyses were not conducted for NO_x, CO, or NMVOC emissions. Emission factors for these gases have been extensively researched since emissions of these gases from motor vehicles are regulated in the United States, and the uncertainty in these emission estimates is believed to be relatively low. However, a much higher level of uncertainty is associated with CH₄ and N₂O emission factors, because emissions of these gases are not regulated in the United States (and, therefore, there are not adequate emission test data), and because, unlike CO₂ emissions, the emission pathways of CH₄ and N₂O are highly complex.

Mobile combustion CH₄ emissions from all mobile sources in 2009 were estimated to be between 1.8 and 2.2 Tg CO₂ Eq. at a 95 percent confidence level. This indicates a range of 9 percent below to 15 percent above the corresponding 2009 emission estimate of 2.0 Tg CO₂ Eq. Also at a 95 percent confidence level, mobile combustion N₂O emissions from mobile sources in 2009 were estimated to be between 20.5 and 27.9 Tg CO₂ Eq., indicating a range of 14 percent below to 17 percent above the corresponding 2009 emission estimate of 23.9 Tg CO₂ Eq.

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

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

Table 3-18: Tier 2 Quantitative Uncertainty Estimates for CH₄ and N₂O Emissions from Mobile Sources (Tg CO₂ Eq. and Percent)

Source	Gas	2009 Emission Estimate ^a (Tg CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate ^a			
			(Tg CO ₂ Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Mobile Sources	CH ₄	2.0	1.8	2.2	-9%	+15%
Mobile Sources	N ₂ O	23.9	20.5	27.9	-14%	+17%

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

This uncertainty analysis is a continuation of a multi-year process for developing quantitative uncertainty estimates for this source category using the IPCC Tier 2 approach to uncertainty analysis. As a result, as new information becomes available, uncertainty characterization of input variables may be improved and revised. For additional information regarding uncertainty in emission estimates for CH₄ and N₂O please refer to the Uncertainty Annex.

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

QA/QC and Verification

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

Recalculations Discussion

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

Planned Improvements

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

1. Develop updated emissions factors for diesel vehicles, motorcycle, and biodiesel vehicles. Previous emission factors were based upon extrapolations from other vehicle classes and new test data from Environment Canada and other sources may allow for better estimation of emission factors for these vehicles.
2. Develop new emission factors for non-road equipment. The current inventory estimates for non-CO₂ emissions from non-road sources are based on emission factors from IPCC guidelines published in 1996. Recent data on non-road sources from Environment Canada and the California Air Resources Board will be investigated in order to assess the feasibility of developing new N₂O and CH₄ emissions factors for non-road equipment.
3. Examine the feasibility of estimating aircraft N₂O and CH₄ emissions by the number of takeoffs and landings, instead of total fuel consumption. Various studies have indicated that aircraft N₂O and CH₄

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

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

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

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

CO₂ emissions arise from non-energy uses via several pathways. Emissions may occur during the manufacture of a product, as is the case in producing plastics or rubber from fuel-derived feedstocks. Additionally, emissions may occur during the product's lifetime, such as during solvent use. Overall, throughout the time series and across all uses, about 61 percent of the total C consumed for non-energy purposes was stored in products, and not released to the atmosphere; the remaining 39 percent was emitted.

There are several areas in which non-energy uses of fossil fuels are closely related to other parts of the inventory. For example, some of the NEU products release CO₂ at the end of their commercial life when they are combusted after disposal; these emissions are reported separately within the Energy chapter in the Incineration of Waste source category. In addition, there is some overlap between fossil fuels consumed for non-energy uses and the fossil-derived CO₂ emissions accounted for in the Industrial Processes chapter, especially for fuels used as reducing agents. To avoid double-counting, the "raw" non-energy fuel consumption data reported by EIA are modified to account for these overlaps. There are also net exports of petrochemicals that are not completely accounted for in the EIA data, and the inventory calculations make adjustments to address the effect of net exports on the mass of C in non-energy applications.

As shown in Table 3-19, fossil fuel emissions in 2009 from the non-energy uses of fossil fuels were 123.4 Tg CO₂ Eq., which constituted approximately 2 percent of overall fossil fuel emissions. In 2009, the consumption of fuels for non-energy uses (after the adjustments described above) was 4,451.0 TBtu, an increase of 0.2 percent since 1990 (see Table 3-20). About 49.9 Tg of the C (182.8 Tg CO₂ Eq.) in these fuels was stored, while the remaining 33.6 Tg C (123.4 Tg CO₂ Eq.) was emitted.

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

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

Methodology

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

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

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

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

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

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

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

+ Does not exceed 0.05 TBtu

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

Note: Totals may not sum due to independent rounding.

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

Sector/Fuel Type	Adjusted Non-Energy Use^a (TBtu)	Carbon Content Coefficient (Tg C/QBtu)	Potential Carbon (Tg C)	Storage Factor	Carbon Stored (Tg C)	Carbon Emissions (Tg C)	Carbon Emissions (Tg CO₂ Eq.)
Industry	4,267.7	-	79.8	-	49.5	30.3	111.1
Industrial Coking Coal	6.1	31.00	0.2	0.10	0.0	0.2	0.6
Industrial Other Coal	12.4	25.82	0.3	0.58	0.2	0.1	0.5
Natural Gas to Chemical Plants	366.0	14.47	5.3	0.58	3.1	2.2	8.1
Asphalt & Road Oil	873.1	20.55	17.9	1.00	17.9	0.1	0.3
LPG	1,446.2	17.06	24.7	0.58	14.3	10.3	37.9
Lubricants	134.5	20.20	2.7	0.09	0.2	2.5	9.0
Pentanes Plus	93.4	19.10	1.8	0.58	1.0	0.7	2.7
Naphtha (<401° F)	450.7	18.55	8.4	0.58	4.9	3.5	12.9
Other Oil (>401° F)	392.5	20.17	7.9	0.58	4.6	3.3	12.2
Still Gas	133.9	17.51	2.3	0.58	1.4	1.0	3.6
Petroleum Coke	133.0	27.85	3.7	0.30	1.1	2.6	9.5
Special Naphtha	44.2	19.74	0.9	0.58	0.5	0.4	1.3
Distillate Fuel Oil	17.5	20.17	0.4	0.50	0.2	0.2	0.6
Waxes	12.2	19.80	0.2	0.58	0.1	0.1	0.4
Miscellaneous Products	151.8	20.31	3.1	0.00	0.0	3.1	11.3
Transportation	127.1	-	2.6	-	0.2	2.3	8.5
Lubricants	127.1	20.20	2.6	0.09	0.2	2.3	8.5
U.S. Territories	56.3	-	1.1	-	0.1	1.0	3.7
Lubricants	1.0	20.20	+	0.09	+	+	0.1
Other Petroleum (Misc. Prod.)	55.2	20.00	1.1	0.10	0.1	1.0	3.6
Total	4,451.0	-	83.5	-	49.9	33.6	123.4

+ Does not exceed 0.05 Tg

- Not applicable.

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

Note: Totals may not sum due to independent rounding.

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

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

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

Uncertainty and Time-Series Consistency

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

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

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 3-22 (emissions) and Table 3-23 (storage factors). Carbon emitted from non-energy uses of fossil fuels in 2009 was estimated to be between 97.6 and 135.3 Tg CO₂ Eq. at a 95 percent confidence level. This indicates a range of 21 percent below to 10 percent above the 2009 emission estimate of 123.4 Tg CO₂ Eq. The uncertainty in the emission estimates is a function of uncertainty in both the quantity of fuel used for non-energy purposes and the storage factor.

Table 3-22: Tier 2 Quantitative Uncertainty Estimates for CO₂ Emissions from Non-Energy Uses of Fossil Fuels (Tg CO₂ Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate ^a			
			(Tg CO ₂ Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Feedstocks	CO ₂	79.3	63.4	96.1	-20%	21%
Asphalt	CO ₂	0.3	0.1	0.6	-58%	119%
Lubricants	CO ₂	17.7	14.6	20.5	-17%	16%
Waxes	CO ₂	0.4	0.3	0.7	-29%	74%
Other	CO ₂	25.7	10.3	27.0	-60%	5%
Total	CO₂	123.4	97.6	135.3	-21%	10%

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

NA (Not Applicable)

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

(Percent)						
Source	Gas	2009 Storage Factor (%)	Uncertainty Range Relative to Emission Estimate ^a			
			(%)		(% , Relative)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Feedstocks	CO ₂	58%	56%	60%	-3%	4%
Asphalt	CO ₂	99.6%	99.1%	99.8%	-0.5%	0.3%
Lubricants	CO ₂	9%	4%	17%	-57%	91%
Waxes	CO ₂	58%	49%	71%	-15%	22%
Other	CO ₂	17%	16%	66%	-3%	292%

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

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

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

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

QA/QC and Verification

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

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

Recalculations Discussion

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

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

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

Planned Improvements

There are several improvements planned for the future:

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

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

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

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

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

and Matdes 2001, Kaufman et al. 2004, Simmons et al. 2006, van Haaren et al. 2010). In the context of this section, waste includes all municipal solid waste (MSW) as well as tires. In the United States, almost all incineration of MSW occurs at waste-to-energy facilities or industrial facilities where useful energy is recovered, and thus emissions from waste incineration are accounted for in the Energy chapter. Similarly, tires are combusted for energy recovery in industrial and utility boilers. Incineration of waste results in conversion of the organic inputs to CO₂. According to IPCC guidelines, when the CO₂ emitted is of fossil origin, it is counted as a net anthropogenic emission of CO₂ to the atmosphere. Thus, the emissions from waste incineration are calculated by estimating the quantity of waste combusted and the fraction of the waste that is C derived from fossil sources.

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

Approximately 26 million metric tons of MSW was incinerated in the United States in 2009 (EPA 2011). CO₂ emissions from incineration of waste rose 54 percent since 1990, to an estimated 12.3 Tg CO₂ Eq. (12,300 Gg) in 2009, as the volume of tires and other fossil C-containing materials in waste increased (see Table 3-24 and Table 3-25). Waste incineration is also a source of N₂O and CH₄ emissions (De Soete 1993; IPCC 2006). N₂O emissions from the incineration of waste were estimated to be 0.4 Tg CO₂ Eq. (1 Gg N₂O) in 2009, and have not changed significantly since 1990. CH₄ emissions from the incineration of waste were estimated to be less than 0.05 Tg CO₂ Eq. (less than 0.5 Gg CH₄) in 2009, and have not changed significantly since 1990.

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

Gas/Waste Product	1990	2000	2005	2006	2007	2008	2009
CO₂	8.0	11.1	12.5	12.5	12.7	12.2	12.3
Plastics	5.6	6.1	6.9	6.7	6.7	6.1	6.2
Synthetic Rubber in Tires	0.3	1.5	1.6	1.7	1.8	1.8	1.8
Carbon Black in Tires	0.4	1.8	2.0	2.1	2.3	2.3	2.3
Synthetic Rubber in MSW	0.9	0.7	0.8	0.8	0.8	0.8	0.8
Synthetic Fibers	0.8	1.0	1.2	1.2	1.2	1.2	1.2
N₂O	0.5	0.4	0.4	0.4	0.4	0.4	0.4
CH₄	+	+	+	+	+	+	+
Total	8.5	11.5	12.9	12.9	13.1	12.5	12.7

+ Does not exceed 0.05 Tg CO₂ Eq.

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

Gas/Waste Product	1990	2000	2005	2006	2007	2008	2009
CO₂	7,989	11,112	12,450	12,531	12,700	12,169	12,300
Plastics	5,588	6,104	6,919	6,722	6,660	6,148	6,233
Synthetic Rubber in Tires	308	1,454	1,599	1,712	1,823	1,823	1,823
Carbon Black in Tires	385	1,818	1,958	2,113	2,268	2,268	2,268
Synthetic Rubber in MSW	872	689	781	775	791	770	782
Synthetic Fibers	838	1,046	1,194	1,208	1,159	1,161	1,195
N₂O	2	1	1	1	1	1	1
CH₄	+	+	+	+	+	+	+

+ Does not exceed 0.5 Gg.

Methodology

Emissions of CO₂ from the incineration of waste include CO₂ generated by the incineration of plastics, synthetic fibers, and synthetic rubber, as well as the incineration of synthetic rubber and carbon black in tires. These emissions

were estimated by multiplying the amount of each material incinerated by the C content of the material and the fraction oxidized (98 percent). Plastics incinerated in municipal solid wastes were categorized into seven plastic resin types, each material having a discrete C content. Similarly, synthetic rubber is categorized into three product types, and synthetic fibers were categorized into four product types, each having a discrete C content. Scrap tires contain several types of synthetic rubber, as well as carbon black. Each type of synthetic rubber has a discrete C content, and carbon black is 100 percent C. Emissions of CO₂ were calculated based on the amount of scrap tires used for fuel and the synthetic rubber and carbon black content of tires.

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

For each of the methods used to calculate CO₂ emissions from the incineration of waste, data on the quantity of product combusted and the C content of the product are needed. For plastics, synthetic rubber, and synthetic fibers, the amount of specific materials discarded as municipal solid waste (i.e., the quantity generated minus the quantity recycled) was taken from *Municipal Solid Waste Generation, Recycling, and Disposal in the United States: Facts and Figures* (EPA 1999 through 2003, 2005 through 2011) and detailed unpublished backup data for some years not shown in the reports (Schneider 2007). The proportion of total waste discarded that is incinerated was derived from data in BioCycle's "State of Garbage in America" (van Haaren et al. 2010). The most recent data provides the proportion of waste incinerated for 2008, so the corresponding proportion in 2009 is assumed to be equal to the proportion in 2008. For synthetic rubber and carbon black in scrap tires, information was obtained from U.S. Scrap Tire Markets in the United States, 2007 Edition (RMA 2009a). For 2008 and 2009, synthetic rubber mass in tires is assumed to be equal to that in 2007 due to a lack of more recently available data.

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

The assumption that 98 percent of organic C is oxidized (which applies to all waste incineration categories for CO₂ emissions) was reported in EPA's life cycle analysis of greenhouse gas emissions and sinks from management of solid waste (EPA 2006).

Incineration of waste, including MSW, also results in emissions of N₂O and CH₄. These emissions were calculated as a function of the total estimated mass of waste incinerated and an emission factor. As noted above, N₂O and CH₄ emissions are a function of total waste incinerated in each year; for 1990 through 2008, these data were derived from the information published in BioCycle (van Haaren et al. 2010). Data on total waste incinerated was not available for 2009, so this value was assumed to equal the most recent value available (2008). Table 3-26 provides data on municipal solid waste discarded and percentage combusted for the total waste stream. According to Covanta Energy (Bahor 2009) and confirmed by additional research based on ISWA (ERC 2009), all municipal solid waste combustors in the United States are continuously fed stoker units. The emission factors of N₂O and CH₄ emissions per quantity of municipal solid waste combusted are default emission factors for this technology type and were taken from the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006).

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

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

^a Assumed equal to 2008 value.

Source: van Haaren et al. (2010).

Uncertainty and Time-Series Consistency

A Tier 2 Monte Carlo analysis was performed to determine the level of uncertainty surrounding the estimates of CO₂ emissions and N₂O emissions from the incineration of waste (given the very low emissions for CH₄, no uncertainty estimate was derived). IPCC Tier 2 analysis allows the specification of probability density functions for key variables within a computational structure that mirrors the calculation of the inventory estimate. Uncertainty estimates and distributions for waste generation variables (i.e., plastics, synthetic rubber, and textiles generation) were obtained through a conversation with one of the authors of the Municipal Solid Waste in the United States reports. Statistical analyses or expert judgments of uncertainty were not available directly from the information sources for the other variables; thus, uncertainty estimates for these variables were determined using assumptions based on source category knowledge and the known uncertainty estimates for the waste generation variables.

The uncertainties in the waste incineration emission estimates arise from both the assumptions applied to the data and from the quality of the data. Key factors include MSW incineration rate; fraction oxidized; missing data on waste composition; average C content of waste components; assumptions on the synthetic/biogenic C ratio; and combustion conditions affecting N₂O emissions. The highest levels of uncertainty surround the variables that are based on assumptions (e.g., percent of clothing and footwear composed of synthetic rubber); the lowest levels of uncertainty surround variables that were determined by quantitative measurements (e.g., combustion efficiency, C content of C black).

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 3-27. Waste incineration CO₂ emissions in 2009 were estimated to be between 9.8 and 15.2 Tg CO₂ Eq. at a 95 percent confidence level. This indicates a range of 21 percent below to 24 percent above the 2009 emission estimate of 12.3 Tg CO₂ Eq. Also at a 95 percent confidence level, waste incineration N₂O emissions in 2009 were estimated to be between 0.2 and 1.5 Tg CO₂ Eq. This indicates a range of 51 percent below to 320 percent above the 2009 emission estimate of 0.4 Tg CO₂ Eq.

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

Source	Gas	2009 Emission Estimate (Tg CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate ^a			
			(Tg CO ₂ Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Incineration of Waste	CO ₂	12.3	9.8	15.2	-21%	+24%
Incineration of Waste	N ₂ O	0.4	0.2	1.5	-51%	+320%

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

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

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

QA/QC and Verification

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

Recalculations Discussion

Several changes were made to input variables compared to the previous Inventory, resulting in an overall decrease in the total emissions from the incineration of waste. Formerly, the percentage of overall rubber waste that is synthetic (i.e., fossil-derived rather than biogenic) varied across the product categories, ranging from 25 percent for clothing and footwear to 100 percent synthetic rubber for durable goods and containers and packaging. For the current Inventory, this variable was updated to be 70 percent synthetic rubber for all four waste categories based on an industry average (RMA, 2011). This change resulted in an average 1 percent decrease in CO₂ emissions throughout the time series. In addition, the percentage of waste incinerated was updated for 2008 based on data obtained from The State of Garbage in America report (van Haaren et al., 2010). Because the report is released every other year, the percentage incinerated in 2007 was also updated using linear interpolation from the 2006 and 2008 values. The change in the percentage incinerated, along with the change in the percentage synthetic rubber noted above, decreased the 2007 and 2008 estimates by 4 percent and 7 percent, respectively, relative to the previous report.

Planned Improvements

Beginning in 2010, those facilities that emit over 25,000 tons of greenhouse gases (CO₂ Eq.) from stationary combustion across all sectors of the economy are required to calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. These data will be used in future inventories to improve the emission calculations through the use of these collected higher tier methodological data.

Additional data sources for calculating the N₂O and CH₄ emission factors for U.S. incineration of waste may be investigated.

3.4. Coal Mining (IPCC Source Category 1B1a)

Three types of coal mining related activities release CH₄ to the atmosphere: underground mining, surface mining, and post-mining (i.e., coal-handling) activities. Underground coal mines contribute the largest share of CH₄ emissions. In 2009, 135 gassy underground coal mines in the United States employ ventilation systems to ensure that CH₄ levels remain within safe concentrations. These systems can exhaust significant amounts of CH₄ to the atmosphere in low concentrations. Additionally, 23 U.S. coal mines supplement ventilation systems with degasification systems. Degasification systems are wells drilled from the surface or boreholes drilled inside the mine that remove large volumes of CH₄ before, during, or after mining. In 2009, 14 coal mines collected CH₄ from degasification systems and utilized this gas, thus reducing emissions to the atmosphere. Of these mines, 13 coal mines sold CH₄ to the natural gas pipeline and one coal mine used CH₄ from its degasification system to heat mine ventilation air on site. In addition, one of the coal mines that sold gas to pipelines also used CH₄ to fuel a thermal coal dryer. Surface coal mines also release CH₄ as the overburden is removed and the coal is exposed, but the level of emissions is much lower than from underground mines. Finally, some of the CH₄ retained in the coal after mining is released during processing, storage, and transport of the coal.

Total CH₄ emissions in 2009 were estimated to be 71.0 Tg CO₂ Eq. (3,382 Gg), a decline of 16 percent since 1990 (see Table 3-28 and Table 3-29). Of this amount, underground mines accounted for 71 percent, surface mines accounted for 18 percent, and post-mining emissions accounted for 11 percent. The decline in CH₄ emissions from underground mines from 1996 to 2002 was the result of the reduction of overall coal production, the mining of less gassy coal, and an increase in CH₄ recovered and used. Since that time, underground coal production and the associated methane emissions have remained fairly level, while surface coal production and its associated emissions

have generally increased.

Table 3-28: CH₄ Emissions from Coal Mining (Tg CO₂ Eq.)

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

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

Table 3-29: CH₄ Emissions from Coal Mining (Gg)

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

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

Methodology

The methodology for estimating CH₄ emissions from coal mining consists of two parts. The first part involves estimating CH₄ emissions from underground mines. Because of the availability of ventilation system measurements, underground mine emissions can be estimated on a mine-by-mine basis and then summed to determine total emissions. The second step involves estimating emissions from surface mines and post-mining activities by multiplying basin-specific coal production by basin-specific emission factors.

Underground mines. Total CH₄ emitted from underground mines was estimated as the sum of CH₄ liberated from ventilation systems and CH₄ liberated by means of degasification systems, minus CH₄ recovered and used. The Mine Safety and Health Administration (MSHA) samples CH₄ emissions from ventilation systems for all mines with detectable⁹⁵ CH₄ concentrations. These mine-by-mine measurements are used to estimate CH₄ emissions from ventilation systems.

Some of the higher-emitting underground mines also use degasification systems (e.g., wells or boreholes) that remove CH₄ before, during, or after mining. This CH₄ can then be collected for use or vented to the atmosphere. Various approaches were employed to estimate the quantity of CH₄ collected by each of the twenty mines using these systems, depending on available data. For example, some mines report to EPA the amount of CH₄ liberated from their degasification systems. For mines that sell recovered CH₄ to a pipeline, pipeline sales data published by state petroleum and natural gas agencies were used to estimate degasification emissions. For those mines for which no other data are available, default recovery efficiency values were developed, depending on the type of degasification system employed.

Finally, the amount of CH₄ recovered by degasification systems and then used (i.e., not vented) was estimated. In 2009, 13 active coal mines sold recovered CH₄ into the local gas pipeline networks and one coal mine used recovered CH₄ on site for heating. Emissions avoided for these projects were estimated using gas sales data reported by various state agencies. For most mines with recovery systems, companies and state agencies provided individual well production information, which was used to assign gas sales to a particular year. For the few remaining mines, coal mine operators supplied information regarding the number of years in advance of mining that gas recovery

⁹⁵ MSHA records coal mine CH₄ readings with concentrations of greater than 50 ppm (parts per million) CH₄. Readings below this threshold are considered non-detectable.

occurs.

Surface Mines and Post-Mining Emissions. Surface mining and post-mining CH₄ emissions were estimated by multiplying basin-specific coal production, obtained from the Energy Information Administration's Annual Coal Report (see Table 3-30) (EIA 2010), by basin-specific emission factors. Surface mining emission factors were developed by assuming that surface mines emit two times as much CH₄ as the average in situ CH₄ content of the coal. Revised data on in situ CH₄ content and emissions factors are taken from EPA (2005), EPA (1996), and AAPG (1984). This calculation accounts for CH₄ released from the strata surrounding the coal seam. For post-mining emissions, the emission factor was assumed to be 32.5 percent of the average in situ CH₄ content of coals mined in the basin.

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

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

Uncertainty and Time-Series Consistency

A quantitative uncertainty analysis was conducted for the coal mining source category using the IPCC-recommended Tier 2 uncertainty estimation methodology. Because emission estimates from underground ventilation systems were based on actual measurement data, uncertainty is relatively low. A degree of imprecision was introduced because the measurements used were not continuous but rather an average of quarterly instantaneous readings. Additionally, the measurement equipment used can be expected to have resulted in an average of 10 percent overestimation of annual CH₄ emissions (Mutmanský and Wang 2000). Estimates of CH₄ recovered by degasification systems are relatively certain because many coal mine operators provided information on individual well gas sales and mined through dates. Many of the recovery estimates use data on wells within 100 feet of a mined area. Uncertainty also exists concerning the radius of influence of each well. The number of wells counted, and thus the avoided emissions, may vary if the drainage area is found to be larger or smaller than currently estimated.

Compared to underground mines, there is considerably more uncertainty associated with surface mining and post-mining emissions because of the difficulty in developing accurate emission factors from field measurements. However, since underground emissions comprise the majority of total coal mining emissions, the uncertainty associated with underground emissions is the primary factor that determines overall uncertainty. The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 3-31. Coal mining CH₄ emissions in 2009 were estimated to be between 62.0 and 82.4 Tg CO₂ Eq. at a 95 percent confidence level. This indicates a range of 12.7 percent below to 16.1 percent above the 2009 emission estimate of 71.0 Tg CO₂ Eq.

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

Source	Gas	2009 Emission Estimate (Tg CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate ^a			
			(Tg CO ₂ Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Coal Mining	CH ₄	71.0	62.0	82.4	-12.7%	+16.1%

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

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

Recalculations Discussion

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

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

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

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

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

Underground coal mines contribute the largest share of CH₄ emissions, with active underground mines the leading source of underground emissions. However, mines also continue to release CH₄ after closure. As mines mature and coal seams are mined through, mines are closed and abandoned. Many are sealed and some flood through intrusion of groundwater or surface water into the void. Shafts or portals are generally filled with gravel and capped with a concrete seal, while vent pipes and boreholes are plugged in a manner similar to oil and gas wells. Some abandoned mines are vented to the atmosphere to prevent the buildup of CH₄ that may find its way to surface structures through overburden fractures. As work stops within the mines, the CH₄ liberation decreases but it does not stop completely. Following an initial decline, abandoned mines can liberate CH₄ at a near-steady rate over an extended period of time, or, if flooded, produce gas for only a few years. The gas can migrate to the surface through the conduits described above, particularly if they have not been sealed adequately. In addition, diffuse emissions can occur when CH₄ migrates to the surface through cracks and fissures in the strata overlying the coal mine. The following factors influence abandoned mine emissions:

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

Gross abandoned mine CH₄ emissions ranged from 6.0 to 9.1 Tg CO₂ Eq. from 1990 through 2009, varying, in general, by less than 1 to approximately 19 percent from year to year. Fluctuations were due mainly to the number of mines closed during a given year as well as the magnitude of the emissions from those mines when active. Gross abandoned mine emissions peaked in 1996 (9.1 Tg CO₂ Eq.) due to the large number of mine closures from 1994 to 1996 (70 gassy mines closed during the three-year period). In spite of this rapid rise, abandoned mine emissions have been generally on the decline since 1996. There were fewer than fifteen gassy mine closures during each of the years from 1998 through 2009, with only ten closures in 2009. By 2009, gross abandoned mine emissions decreased slightly to 8.5 Tg CO₂ Eq. (see Table 3-32 and Table 3-33). Gross emissions are reduced by CH₄ recovered and used at 38 mines, resulting in net emissions in 2009 of 5.5 Tg CO₂ Eq.

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

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

Note: Totals may not sum due to independent rounding.

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

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

Note: Totals may not sum due to independent rounding.

Methodology

Estimating CH₄ emissions from an abandoned coal mine requires predicting the emissions of a mine from the time of abandonment through the inventory year of interest. The flow of CH₄ from the coal to the mine void is primarily dependent on the mine's emissions when active and the extent to which the mine is flooded or sealed. The CH₄ emission rate before abandonment reflects the gas content of the coal, rate of coal mining, and the flow capacity of the mine in much the same way as the initial rate of a water-free conventional gas well reflects the gas content of the producing formation and the flow capacity of the well. A well or a mine which produces gas from a coal seam and the surrounding strata will produce less gas through time as the reservoir of gas is depleted. Depletion of a reservoir will follow a predictable pattern depending on the interplay of a variety of natural physical conditions imposed on the reservoir. The depletion of a reservoir is commonly modeled by mathematical equations and mapped as a type curve. Type curves which are referred to as decline curves have been developed for abandoned coal mines. Existing data on abandoned mine emissions through time, although sparse, appear to fit the hyperbolic type of decline curve used in forecasting production from natural gas wells.

In order to estimate CH₄ emissions over time for a given mine, it is necessary to apply a decline function, initiated upon abandonment, to that mine. In the analysis, mines were grouped by coal basin with the assumption that they will generally have the same initial pressures, permeability and isotherm. As CH₄ leaves the system, the reservoir pressure, P_r , declines as described by the isotherm. The emission rate declines because the mine pressure (P_w) is essentially constant at atmospheric pressure, for a vented mine, and the PI term is essentially constant at the pressures of interest (atmospheric to 30 psia). A rate-time equation can be generated that can be used to predict future emissions. This decline through time is hyperbolic in nature and can be empirically expressed as:

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

where,

- q = Gas rate at time t in mmcf/d
- q_i = Initial gas rate at time zero (t_0) in million cubic feet per day mmcf/d)
- b = The hyperbolic exponent, dimensionless
- D_i = Initial decline rate, 1/yr
- t = Elapsed time from t_0 (years)

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

The decline curves created to model the gas emission rate of coal mines must account for factors that decrease the rate of emission after mining activities cease, such as sealing and flooding. Based on field measurement data, it was assumed that most U.S. mines prone to flooding will become completely flooded within eight years and therefore no longer have any measurable CH₄ emissions. Based on this assumption, an average decline rate for flooding mines was established by fitting a decline curve to emissions from field measurements. An exponential equation was developed from emissions data measured at eight abandoned mines known to be filling with water located in two of the five basins. Using a least squares, curve-fitting algorithm, emissions data were matched to the exponential equation shown below. There was not enough data to establish basin-specific equations as was done with the vented, non-flooding mines (EPA 2003).

$$q = q_{ie}^{-D_i t}$$

where,

- q = Gas flow rate at time t in mcf/d
- q_i = Initial gas flow rate at time zero (t_0) in mcf/d

D = Decline rate, 1/yr
t = Elapsed time from t₀ (years)

Seals have an inhibiting effect on the rate of flow of CH₄ into the atmosphere compared to the rate that would be emitted if the mine had an open vent. The total volume emitted will be the same, but will occur over a longer period. The methodology, therefore, treats the emissions prediction from a sealed mine similar to emissions from a vented mine, but uses a lower initial rate depending on the degree of sealing. The computational fluid dynamics simulator was again used with the conceptual abandoned mine model to predict the decline curve for inhibited flow. The percent sealed is defined as $100 \times (1 - (\text{initial emissions from sealed mine} / \text{emission rate at abandonment prior to sealing}))$. Significant differences are seen between 50 percent, 80 percent and 95 percent closure. These decline curves were therefore used as the high, middle, and low values for emissions from sealed mines (EPA 2003).

For active coal mines, those mines producing over 100 mcf/d account for 98 percent of all CH₄ emissions. This same relationship is assumed for abandoned mines. It was determined that 469 abandoned mines closing after 1972 produced emissions greater than 100 mcf/d when active. Further, the status of 273 of the 469 mines (or 58 percent) is known to be either: (1) vented to the atmosphere; (2) sealed to some degree (either earthen or concrete seals); or, (3) flooded (enough to inhibit CH₄ flow to the atmosphere). The remaining 42 percent of the mines were placed in one of the three categories by applying a probability distribution analysis based on the known status of other mines located in the same coal basin (EPA 2003).

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

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

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

During the 1970s, 78 percent of CH₄ emissions from coal mining came from seventeen counties in seven states. In addition, mine closure dates were obtained for two states, Colorado and Illinois, for the hundred year period extending from 1900 through 1999. The data were used to establish a frequency of mine closure histogram (by decade) and applied to the other five states with gassy mine closures. As a result, basin-specific decline curve equations were applied to 145 gassy coal mines estimated to have closed between 1920 and 1971 in the United States, representing 78 percent of the emissions. State-specific, initial emission rates were used based on average coal mine CH₄ emission rates during the 1970s (EPA 2003).

Abandoned mines emission estimates are based on all closed mines known to have active mine CH₄ ventilation emission rates greater than 100 mcf/d at the time of abandonment. For example, for 1990 the analysis included 145 mines closed before 1972 and 258 mines closed between 1972 and 1990. Initial emission rates based on MSHA reports, time of abandonment, and basin-specific decline curves influenced by a number of factors were used to calculate annual emissions for each mine in the database. Coal mine degasification data are not available for years prior to 1990, thus the initial emission rates used reflect ventilation emissions only for pre-1990 closures. CH₄ degasification amounts were added to the quantity of CH₄ ventilated for the total CH₄ liberation rate for 21 mines that closed between 1992 and 2009. Since the sample of gassy mines (with active mine emissions greater than 100 mcf/d) is assumed to account for 78 percent of the pre-1971 and 98 percent of the post-1971 abandoned mine emissions, the modeled results were multiplied by 1.22 and 1.02 to account for all U.S. abandoned mine emissions.

From 1993 through 2009, emission totals were downwardly adjusted to reflect abandoned mine CH₄ emissions

avoided from those mines. The inventory totals were not adjusted for abandoned mine reductions in 1990 through 1992, because no data was reported for abandoned coal mining CH₄ recovery projects during that time.

Uncertainty and Time-Series Consistency

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

As discussed above, the parameters for which values must be estimated for each mine in order to predict its decline curve are: (1) the coal's adsorption isotherm; (2) CH₄ flow capacity as expressed by permeability; and (3) pressure at abandonment. Because these parameters are not available for each mine, a methodological approach to estimating emissions was used that generates a probability distribution of potential outcomes based on the most likely value and the probable range of values for each parameter. The range of values is not meant to capture the extreme values, but values that represent the highest and lowest quartile of the cumulative probability density function of each parameter. Once the low, mid, and high values are selected, they are applied to a probability density function.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 3-35. Abandoned coal mines CH₄ emissions in 2009 were estimated to be between 4.0 and 7.3 Tg CO₂ Eq. at a 95 percent confidence level. This indicates a range of 27 percent below to 32 percent above the 2009 emission estimate of 5.5 Tg CO₂ Eq. One of the reasons for the relatively narrow range is that mine-specific data is used in the methodology. The largest degree of uncertainty is associated with the unknown status mines (which account for 42 percent of the mines), with a ± 57 percent uncertainty.

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

Source	Gas	2009 Emission Estimate (Tg CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate ^a			
			(Tg CO ₂ Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Abandoned Underground Coal Mines	CH ₄	5.5	4.0	7.3	-27%	+32%

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

Recalculations Discussion

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

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

The U.S. natural gas system encompasses hundreds of thousands of wells, hundreds of processing facilities, and over a million miles of transmission and distribution pipelines. Overall, natural gas systems emitted 221.2 Tg CO₂ Eq. (10,535 Gg) of CH₄ in 2009, a 17 percent increase over 1990 emissions (see Table 3-36 and Table 3-37), and 32.2 Tg CO₂ Eq. (32,171 Gg) of non-combustion CO₂ in 2009, a 14 percent decrease over 1990 emissions (see Table 3-38 and Table 3-39). Improvements in management practices and technology, along with the replacement of older equipment, have helped to stabilize emissions. Methane emissions increased since 2008 due to an increase in production and production wells.

CH₄ and non-combustion CO₂ emissions from natural gas systems are generally process related, with normal operations, routine maintenance, and system upsets being the primary contributors. Emissions from normal operations include: natural gas engines and turbine uncombusted exhaust, bleed and discharge emissions from pneumatic devices, and fugitive emissions from system components. Routine maintenance emissions originate from

pipelines, equipment, and wells during repair and maintenance activities. Pressure surge relief systems and accidents can lead to system upset emissions. Below is a characterization of the four major stages of the natural gas system. Each of the stages is described and the different factors affecting CH₄ and non-combustion CO₂ emissions are discussed.

Field Production. In this initial stage, wells are used to withdraw raw gas from underground formations. Emissions arise from the wells themselves, gathering pipelines, and well-site gas treatment facilities such as dehydrators and separators. Emissions from pneumatic devices, well clean-ups, and gas well completions and re-completions with hydraulic fracturing account for the majority of CH₄ emissions. Flaring emissions account for the majority of the non-combustion CO₂ emissions. Emissions from field production accounted for approximately 59 percent of CH₄ emissions and about 34 percent of non-combustion CO₂ emissions from natural gas systems in 2009.

Processing. In this stage, natural gas liquids and various other constituents from the raw gas are removed, resulting in “pipeline quality” gas, which is injected into the transmission system. Fugitive CH₄ emissions from compressors, including compressor seals, are the primary emission source from this stage. The majority of non-combustion CO₂ emissions come from acid gas removal units, which are designed to remove CO₂ from natural gas. Processing plants account for about 8 percent of CH₄ emissions and approximately 66 percent of non-combustion CO₂ emissions from natural gas systems.

Transmission and Storage. Natural gas transmission involves high pressure, large diameter pipelines that transport gas long distances from field production and processing areas to distribution systems or large volume customers such as power plants or chemical plants. Compressor station facilities, which contain large reciprocating and turbine compressors, are used to move the gas throughout the United States transmission system. Fugitive CH₄ emissions from these compressor stations and from metering and regulating stations account for the majority of the emissions from this stage. Pneumatic devices and engine uncombusted exhaust are also sources of CH₄ emissions from transmission facilities.

Natural gas is also injected and stored in underground formations, or liquefied and stored in above ground tanks, during periods of low demand (e.g., summer), and withdrawn, processed, and distributed during periods of high demand (e.g., winter). Compressors and dehydrators are the primary contributors to emissions from these storage facilities. CH₄ emissions from the transmission and storage sector account for approximately 20 percent of emissions from natural gas systems, while CO₂ emissions from transmission and storage account for less than 1 percent of the non-combustion CO₂ emissions from natural gas systems.

Distribution. Distribution pipelines take the high-pressure gas from the transmission system at “city gate” stations, reduce the pressure and distribute the gas through primarily underground mains and service lines to individual end users. There were over 1,208,000 miles of distribution mains in 2009, an increase from just over 944,000 miles in 1990 (OPS 2010b). Distribution system emissions, which account for approximately 13 percent of CH₄ emissions from natural gas systems and less than 1 percent of non-combustion CO₂ emissions, result mainly from fugitive emissions from gate stations and pipelines. An increased use of plastic piping, which has lower emissions than other pipe materials, has reduced emissions from this stage. Distribution system CH₄ emissions in 2009 were 13 percent lower than 1990 levels.

Table 3-36: CH₄ Emissions from Natural Gas Systems (Tg CO₂ Eq.)*

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

*Including CH₄ emission reductions achieved by the Natural Gas STAR program and NESHAP regulations.

Note: Totals may not sum due to independent rounding.

Table 3-37: CH₄ Emissions from Natural Gas Systems (Gg)*

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

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

*Including CH₄ emission reductions achieved by the Natural Gas STAR program and NESHAP regulations.

Note: Totals may not sum due to independent rounding.

Table 3-38: Non-combustion CO₂ Emissions from Natural Gas Systems (Tg CO₂ Eq.)

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

Note: Totals may not sum due to independent rounding.

+ Emissions are less than 0.1 Tg CO₂ Eq.

Table 3-39: Non-combustion CO₂ Emissions from Natural Gas Systems (Gg)

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

Note: Totals may not sum due to independent rounding.

Methodology

The primary basis for estimates of CH₄ and non-combustion-related CO₂ 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 CH₄ emission and activity factors to characterize emissions from the various components within the operating stages of the U.S. natural gas system. The same activity factors were used to estimate both CH₄ and non-combustion CO₂ emissions. However, the CH₄ emission factors were adjusted for CO₂ content when estimating fugitive and vented non-combustion CO₂ emissions. The EPA/GRI study was based on a combination of process engineering studies and measurements at representative gas facilities. From this analysis, a 1992 emission estimate was developed using the emission and activity factors, except where direct activity data was available (e.g., offshore platform counts, processing plant counts, transmission pipeline miles, and distribution pipelines). For other years, a set of industry activity factor drivers was developed that can be used to update activity factors. These drivers include statistics on gas production, number of wells, system throughput, miles of various kinds of pipe, and other statistics that characterize the changes in the U.S. natural gas system infrastructure and operations.

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

not common at the time the EPA/GRI survey was conducted. Since then, emissions data has become available through Natural Gas STAR experiences and presentations (EPA 2004, 2007) as these activities became more prevalent. The EPA/GRI study and previous Inventories did, however, include an estimate for well completions without hydraulic fracturing under the source category Completion Flaring. The changes for gas well cleanups, condensate storage tanks, centrifugal compressors, and gas well completions and gas well workovers (re-completions) with hydraulic fracturing are described below in the Recalculations section. See Annex 3.4 for more detailed information on the methodology and data used to calculate CH₄ and non-combustion CO₂ emissions from natural gas systems.

Activity factor data were taken from the following sources: American Gas Association (AGA 1991–1998); Bureau of Ocean Energy Management, Regulation and Enforcement (previous Minerals and Management Service) (BOEMRE 2010a-d); Monthly Energy Review (EIA 2010f); Natural Gas Liquids Reserves Report (EIA 2005); Natural Gas Monthly (EIA 2010b,c,e); the Natural Gas STAR Program annual emissions savings (EPA 2010); Oil and Gas Journal (OGJ 1997–2010); Office of Pipeline Safety (OPS 2010a-b); Federal Energy Regulatory Commission (FERC 2010) and other Energy Information Administration publications (EIA 2001, 2004, 2010a,d); World Oil Magazine (2010a-b). Data for estimating emissions from hydrocarbon production tanks were incorporated (EPA 1999). Coalbed CH₄ well activity factors were taken from the Wyoming Oil and Gas Conservation Commission (Wyoming 2009) and the Alabama State Oil and Gas Board (Alabama 2010). Other state well data was taken from: American Association of Petroleum Geologists (AAPG 2004); Brookhaven College (Brookhaven 2004); Kansas Geological Survey (Kansas 2010); Montana Board of Oil and Gas Conservation (Montana 2010); Oklahoma Geological Survey (Oklahoma 2010); Morgan Stanley (Morgan Stanley 2005); Rocky Mountain Production Report (Lippman 2003); New Mexico Oil Conservation Division (New Mexico 2010, 2005); Texas Railroad Commission (Texas 2010a-d); Utah Division of Oil, Gas and Mining (Utah 2010). Emission factors were taken from EPA/GRI (1996). GTI's Unconventional Natural Gas and Gas Composition Databases (GTI 2001) were used to adapt the CH₄ emission factors into non-combustion related CO₂ emission factors and adjust CH₄ emission factors from the EPA/GRI survey. Methane compositions from GTI 2001 are adjusted year to year using gross production by NEMS for oil and gas supply regions from the EIA. Therefore, emission factors may vary from year to year due to slight changes in the methane composition for each NEMS oil and gas supply module region. Additional information about CO₂ content in transmission quality natural gas was obtained via the internet from numerous U.S. transmission companies to help further develop the non-combustion CO₂ emission factors.

Uncertainty and Time-Series Consistency

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

The results presented below provide with 95 percent certainty the range within which emissions from this source category are likely to fall for the year 2009. The heterogeneous nature of the natural gas industry makes it difficult to sample facilities that are completely representative of the entire industry. Because of this, scaling up from model facilities introduces a degree of uncertainty. Additionally, highly variable emission rates were measured among many system components, making the calculated average emission rates uncertain. The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 3-40. Natural gas systems CH₄ emissions in 2009 were estimated to be between 179.1 and 287.6 Tg CO₂ Eq. at a 95 percent confidence level. Natural gas systems non-energy CO₂ emissions in 2009 were estimated to be between 26.1 and 41.9 Tg CO₂ Eq. at 95 percent confidence level.

Table 3-40: Tier 2 Quantitative Uncertainty Estimates for CH₄ and Non-energy CO₂ Emissions from Natural Gas Systems (Tg CO₂ Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO ₂ Eq.) ^c	Uncertainty Range Relative to Emission Estimate ^a			
			(Tg CO ₂ Eq.)		(%)	
			Lower Bound ^c	Upper Bound ^c	Lower Bound ^c	Upper Bound ^c

Natural Gas Systems	CH ₄	221.2	179.1	287.6	-19%	+30%
Natural Gas Systems ^b	CO ₂	32.2	26.1	41.9	-19%	+30%

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

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

^c All reported values are rounded after calculation. As a result, lower and upper bounds may not be duplicable from other rounded values as shown in table.

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

QA/QC and Verification Discussion

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

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

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

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

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

Recalculations Discussion

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

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

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

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

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

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

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

The net effect of these changes was to increase total CH₄ emissions from natural gas systems between 47 and 120 percent each year between 1990 and 2008 relative to the previous report. The natural gas production segment accounted for the largest increases, largely due to the methodological changes to gas well cleanups and the addition of gas well completions and workovers with hydraulic fracturing.

Planned Improvements

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

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

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

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

3.7. Petroleum Systems (IPCC Source Category 1B2a)

CH₄ emissions from petroleum systems are primarily associated with crude oil production, transportation, and refining operations. During each of these activities, CH₄ emissions are released to the atmosphere as fugitive emissions, vented emissions, emissions from operational upsets, and emissions from fuel combustion. Fugitive and vented CO₂ emissions from petroleum systems are primarily associated with crude oil production and refining operations but are negligible in transportation operations. Combusted CO₂ emissions from fuels are already accounted for in the Fossil Fuels Combustion source category, and hence have not been taken into account in the Petroleum Systems source category. Total CH₄ and CO₂ emissions from petroleum systems in 2009 were 30.9 Tg CO₂ Eq. (1,473 Gg CH₄) and 0.5 Tg CO₂ (463 Gg), respectively. Since 1990, CH₄ emissions have declined by 13 percent, due to industry efforts to reduce emissions and a decline in domestic oil production (see Table 3-41 and Table 3-42). CO₂ emissions have also declined by 17 percent since 1990 due to similar reasons (see Table 3-43 and Table 3-44).

Production Field Operations. Production field operations account for about 98 percent of total CH₄ emissions from petroleum systems. Vented CH₄ from field operations account for over 90 percent of the emissions from the production sector, unburned CH₄ combustion emissions account for 6.4 percent, fugitive emissions are 3.4 percent, and process upset emissions are slightly under two-tenths of a percent. The most dominant sources of emissions, in order of magnitude, are shallow water offshore oil platforms, natural-gas-powered high bleed pneumatic devices, oil tanks, natural-gas powered low bleed pneumatic devices, gas engines, deep water offshore platforms, and chemical injection pumps. These seven sources alone emit about 94 percent of the production field operations emissions. Offshore platform emissions are a combination of fugitive, vented, and unburned fuel combustion emissions from all equipment housed on oil platforms producing oil and associated gas. Emissions from high and low-bleed pneumatics occur when pressurized gas that is used for control devices is bled to the atmosphere as they cycle open and closed to modulate the system. Emissions from oil tanks occur when the CH₄ entrained in crude oil under pressure volatilizes once the crude oil is put into storage tanks at atmospheric pressure. Emissions from gas engines are due to unburned CH₄ that vents with the exhaust. Emissions from chemical injection pumps are due to the 25 percent that use associated gas to drive pneumatic pumps. The remaining six percent of the emissions are distributed among 26 additional activities within the four categories: vented, fugitive, combustion and process upset emissions. For more detailed, source-level data on CH₄ emissions in production field operations, refer to Annex 3.5.

Vented CO₂ associated with natural gas emissions from field operations account for 99 percent of the total CO₂ emissions from this source category, while fugitive and process upsets together account for less than 1 percent of the emissions. The most dominant sources of vented emissions are oil tanks, high bleed pneumatic devices, shallow water offshore oil platforms, low bleed pneumatic devices, and chemical injection pumps. These five sources together account for 98.5 percent of the non-combustion CO₂ emissions from this source category, while the remaining 1.5 percent of the emissions is distributed among 24 additional activities within the three categories: vented, fugitive and process upsets.

Crude Oil Transportation. Crude oil transportation activities account for less than one half of one percent of total CH₄ emissions from the oil industry. Venting from tanks and marine vessel loading operations accounts for 61 percent of CH₄ emissions from crude oil transportation. Fugitive emissions, almost entirely from floating roof tanks, account for 19 percent. The remaining 20 percent is distributed among six additional sources within these two categories. Emissions from pump engine drivers and heaters were not estimated due to lack of data.

Crude Oil Refining. Crude oil refining processes and systems account for slightly less than two percent of total CH₄ emissions from the oil industry because most of the CH₄ in crude oil is removed or escapes before the crude oil is delivered to the refineries. There is an insignificant amount of CH₄ in all refined products. Within refineries, vented

emissions account for about 86 percent of the emissions, while both fugitive and combustion emissions account for approximately seven percent each. Refinery system blowdowns for maintenance and the process of asphalt blowing—with air, to harden the asphalt—are the primary venting contributors. Most of the fugitive CH₄ emissions from refineries are from leaks in the fuel gas system. Refinery combustion emissions include small amounts of unburned CH₄ in process heater stack emissions and unburned CH₄ in engine exhausts and flares.

Asphalt blowing from crude oil refining accounts for 36 percent of the total non-combustion CO₂ emissions in petroleum systems.

Table 3-41: CH₄ Emissions from Petroleum Systems (Tg CO₂ Eq.)

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

Note: Totals may not sum due to independent rounding.

Table 3-42: CH₄ Emissions from Petroleum Systems (Gg)

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

Note: Totals may not sum due to independent rounding.

Table 3-43: CO₂ Emissions from Petroleum Systems (Tg CO₂ Eq.)

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

+ Does not exceed 0.05 Tg CO₂ Eq.

Note: Totals may not sum due to independent rounding.

Table 3-44: CO₂ Emissions from Petroleum Systems (Gg)

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

Note: Totals may not sum due to independent rounding.

Methodology

The methodology for estimating CH₄ emissions from petroleum systems is a bottom-up approach, based on comprehensive studies of CH₄ emissions from U.S. petroleum systems (EPA 1996, EPA 1999). These studies combined emission estimates from 64 activities occurring in petroleum systems from the oil wellhead through crude oil refining, including 33 activities for crude oil production field operations, 11 for crude oil transportation activities, and 20 for refining operations. Annex 3.5 provides greater detail on the emission estimates for these 64 activities. The estimates of CH₄ emissions from petroleum systems do not include emissions downstream of oil refineries because these emissions are negligible.

The methodology for estimating CH₄ emissions from the 64 oil industry activities employs emission factors initially developed by EPA (1999). Activity factors for the years 1990 through 2009 were collected from a wide variety of statistical resources. Emissions are estimated for each activity by multiplying emission factors (e.g., emission rate per equipment item or per activity) by their corresponding activity factor (e.g., equipment count or frequency of activity). EPA (1999) provides emission factors for all activities except those related to offshore oil production and field storage tanks. For offshore oil production, two emission factors were calculated using data collected over a one-year period for all federal offshore platforms (EPA 2005, BOEMRE 2004). One emission factor is for oil platforms in shallow water, and one emission factor is for oil platforms in deep water. Emission factors are held constant for the period 1990 through 2009. The number of platforms in shallow water and the number of platforms in deep water are used as activity factors and are taken from Bureau of Ocean Energy Management, Regulation, and Enforcement (BOEMRE) (formerly Minerals Management Service) statistics (BOEMRE 2010a-c). For oil storage tanks, the emissions factor was calculated as the total emissions per barrel of crude charge from E&P Tank data weighted by the distribution of produced crude oil gravities from the HPDI production database (EPA 1999, HPDI 2009).

For some years, complete activity factor data were not available. In such cases, one of three approaches was employed. Where appropriate, the activity factor was calculated from related statistics using ratios developed for EPA (1996). For example, EPA (1996) found that the number of heater treaters (a source of CH₄ emissions) is related to both number of producing wells and annual production. To estimate the activity factor for heater treaters, reported statistics for wells and production were used, along with the ratios developed for EPA (1996). In other cases, the activity factor was held constant from 1990 through 2009 based on EPA (1999). Lastly, the previous year's data were used when data for the current year were unavailable. The CH₄ and CO₂ sources in the production sector share common activity factors. See Annex 3.5 for additional detail.

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

The methodology for estimating CO₂ emissions from petroleum systems combines vented, fugitive, and process upset emissions sources from 29 activities for crude oil production field operations and one activity from petroleum refining. Emissions are estimated for each activity by multiplying emission factors by their corresponding activity factors. The emission factors for CO₂ are estimated by multiplying the CH₄ emission factors by a conversion factor, which is the ratio of CO₂ content and methane content in produced associated gas. The only exceptions to this methodology are the emission factors for crude oil storage tanks, which are obtained from E&P Tank simulation runs, and the emission factor for asphalt blowing, which was derived using the methodology and sample data from API (2009).

Uncertainty and Time-Series Consistency

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

The detailed, bottom-up Inventory analysis used to evaluate U.S. petroleum systems reduces the uncertainty related to the CH₄ emission estimates in comparison to a top-down approach. However, some uncertainty still remains. Emission factors and activity factors are based on a combination of measurements, equipment design data, engineering calculations and studies, surveys of selected facilities and statistical reporting. Statistical uncertainties arise from natural variation in measurements, equipment types, operational variability and survey and statistical methodologies. Published activity factors are not available every year for all 64 activities analyzed for petroleum systems; therefore, some are estimated. Because of the dominance of the seven major sources, which account for 92 percent of the total methane emissions, the uncertainty surrounding these seven sources has been estimated most rigorously, and serves as the basis for determining the overall uncertainty of petroleum systems emission estimates.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 3-45. Petroleum systems CH₄ emissions in 2009 were estimated to be between 23.5 and 76.9 Tg CO₂ Eq., while CO₂ emissions were estimated to be between 0.4 and 1.2 Tg CO₂ Eq. at a 95 percent confidence level. This indicates a range of 24 percent below to 149 percent above the 2009 emission estimates of 30.9 and 0.5 Tg CO₂ Eq. for CH₄ and CO₂, respectively.

Table 3-45: Tier 2 Quantitative Uncertainty Estimates for CH₄ Emissions from Petroleum Systems (Tg CO₂ Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO ₂ Eq.) ^b	Uncertainty Range Relative to Emission Estimate ^a			
			(Tg CO ₂ Eq.)		(%)	
			Lower Bound ^b	Upper Bound ^b	Lower Bound ^b	Upper Bound ^b
Petroleum Systems	CH ₄	30.9	23.5	76.9	-24%	149%
Petroleum Systems	CO ₂	0.5	0.4	1.2	-24%	149%

^a Range of 2009 relative uncertainty predicted by Monte Carlo Simulation, based on 1995 base year activity factors, for a 95 percent confidence interval.

^b All reported values are rounded after calculation. As a result, lower and upper bounds may not be duplicable from other rounded values as shown in table.

Note: Totals may not sum due to independent rounding

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

QA/QC and Verification Discussion

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

Recalculations Discussion

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

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

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

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

Planned Improvements

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

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

Data collected through EPA's Greenhouse Gas Reporting Program will be reviewed for potential improvements to petroleum systems emissions sources. The rule will collect actual activity data and improved quantification methods from those used in several of the studies which form the basis of this Inventory. This data will be incorporated as appropriate into the current Inventory to improve the accuracy and uncertainty of the emissions estimates. In particular, EPA will investigate whether certain emissions sources currently accounted for in the Energy sector should be separately accounted for in the petroleum systems inventory (e.g., CO₂ process emissions from hydrogen production).

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

[BEGIN BOX]

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

Carbon dioxide is produced, captured, transported, and used for Enhanced Oil Recovery (EOR) as well as commercial and non-EOR industrial applications. This CO₂ is produced from both naturally-occurring CO₂ reservoirs and from industrial sources such as natural gas processing plants and ammonia plants. In the current Inventory, emissions from naturally-produced CO₂ are estimated based on the application.

In the current Inventory report, the CO₂ that is used in non-EOR industrial and commercial applications (e.g., food processing, chemical production) is assumed to be emitted to the atmosphere during its industrial use. These emissions are discussed in the Carbon Dioxide Consumption section. The naturally-occurring CO₂ used in EOR operations is assumed to be fully sequestered. Additionally, all anthropogenic CO₂ emitted from natural gas processing and ammonia plants is assumed to be emitted to the atmosphere, regardless of whether the CO₂ is captured or not. These emissions are currently included in the Natural Gas Systems and the Ammonia Production sections of the Inventory report, respectively.

IPCC (IPCC, 2006) included, for the first time, methodological guidance to estimate emissions from the capture, transport, injection, and geological storage of CO₂. The methodology is based on the principle that the carbon capture and storage system should be handled in a complete and consistent manner across the entire Energy sector. The approach accounts for CO₂ captured at natural and industrial sites as well as emissions from capture, transport, and use. For storage specifically, a Tier 3 methodology is outlined for estimating and reporting emissions based on site-specific evaluations. However, IPCC (IPCC, 2006) notes that if a national regulatory process exists, emissions information available through that process may support development of CO₂ emissions estimates for geologic storage.

Beginning in 2010, facilities that conduct geologic sequestration of CO₂ and all other facilities that inject CO₂ underground will be required to calculate and report greenhouse gas data annually to EPA through its Greenhouse

Gas Reporting Program. The Greenhouse Gas Reporting Rule requires greenhouse gas reporting from facilities that inject CO₂ underground for geologic sequestration, and requires greenhouse gas reporting from all other facilities that inject CO₂ underground for any reason, including enhanced oil and gas recovery. Beginning in 2010, facilities conducting geologic sequestration of CO₂ are required to develop and implement an EPA-approved site-specific monitoring, reporting and verification (MRV) plan, and to report the amount of CO₂ sequestered using a mass balance approach. Data from this program, which will be reported to EPA in early 2012, for the 2011 calendar year, will provide additional facility-specific information about the carbon capture, transport and storage chain, EPA intends to evaluate that information closely and consider opportunities for improving our current inventory estimates.

Preliminary estimates indicate that the amount of CO₂ captured from industrial and natural sites is 47.3 Tg CO₂ (47,340 Gg CO₂) (see Table 3-46 and Table 3-47). Site-specific monitoring and reporting data for CO₂ injection sites (i.e., EOR operations) were not readily available, therefore, these estimates assume all CO₂ is emitted.

Table 3-46: Potential Emissions from CO₂ Capture and Transport (Tg CO₂ Eq.)

Year	1990	2000	2005	2006	2007	2008	2009
Acid Gas Removal Plants	4.8	2.3	5.8	6.2	6.4	6.6	7.0
Naturally Occurring CO ₂	20.8	23.2	28.3	30.2	33.1	36.1	39.7
Ammonia Production Plants	+	0.7	0.7	0.7	0.7	0.6	0.6
Pipelines Transporting CO ₂	+	+	+	+	+	+	+
Total	25.6	26.1	34.7	37.1	40.1	43.3	47.3

+ Does not exceed 0.05 Tg CO₂ Eq.

Note; Totals may not sum due to independent rounding.

Table 3-47: Potential Emissions from CO₂ Capture and Transport (Gg)

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

+ Does not exceed 0.5 Gg.

Note: Totals do not include emissions from pipelines transporting CO₂

Note; Totals may not sum due to independent rounding.

[END BOX]

3.8. Energy Sources of Indirect Greenhouse Gas Emissions

In addition to the main greenhouse gases addressed above, many energy-related activities generate emissions of indirect greenhouse gases. Total emissions of nitrogen oxides (NO_x), carbon monoxide (CO), and non-CH₄ volatile organic compounds (NMVOCs) from energy-related activities from 1990 to 2009 are reported in Table 3-48.

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

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

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

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

Note: Totals may not sum due to independent rounding.

Methodology

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

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

Uncertainty and Time-Series Consistency

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

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

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

Emissions resulting from the combustion of fuels used for international transport activities, termed international bunker fuels under the UNFCCC, are not included in national emission totals, but are reported separately based upon location of fuel sales. The decision to report emissions from international bunker fuels separately, instead of allocating them to a particular country, was made by the Intergovernmental Negotiating Committee in establishing the Framework Convention on Climate Change.⁹⁶ These decisions are reflected in the IPCC methodological guidance, including the 2006 IPCC Guidelines, in which countries are requested to report emissions from ships or aircraft that depart from their ports with fuel purchased within national boundaries and are engaged in international transport separately from national totals (IPCC 2006).⁹⁷

Greenhouse gases emitted from the combustion of international bunker fuels, like other fossil fuels, include CO₂, CH₄ and N₂O. Two transport modes are addressed under the IPCC definition of international bunker fuels: aviation and marine.⁹⁸ Emissions from ground transport activities—by road vehicles and trains—even when crossing

⁹⁶ See report of the Intergovernmental Negotiating Committee for a Framework Convention on Climate Change on the work of its ninth session, held at Geneva from 7 to 18 February 1994 (A/AC.237/55, annex I, para. 1c).

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

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

international borders are allocated to the country where the fuel was loaded into the vehicle and, therefore, are not counted as bunker fuel emissions.

The IPCC Guidelines distinguish between different modes of air traffic. Civil aviation comprises aircraft used for the commercial transport of passengers and freight, military aviation comprises aircraft under the control of national armed forces, and general aviation applies to recreational and small corporate aircraft. The IPCC Guidelines further define international bunker fuel use from civil aviation as the fuel combusted for civil (e.g., commercial) aviation purposes by aircraft arriving or departing on international flight segments. However, as mentioned above, and in keeping with the IPCC Guidelines, only the fuel purchased in the United States and used by aircraft taking-off (i.e., departing) from the United States are reported here. The standard fuel used for civil aviation is kerosene-type jet fuel, while the typical fuel used for general aviation is aviation gasoline.⁹⁹

Emissions of CO₂ from aircraft are essentially a function of fuel use. CH₄ and N₂O emissions also depend upon engine characteristics, flight conditions, and flight phase (i.e., take-off, climb, cruise, decent, and landing). CH₄ is the product of incomplete combustion and occur mainly during the landing and take-off phases. In jet engines, N₂O is primarily produced by the oxidation of atmospheric nitrogen, and the majority of emissions occur during the cruise phase. International marine bunkers comprise emissions from fuels burned by ocean-going ships of all flags that are engaged in international transport. Ocean-going ships are generally classified as cargo and passenger carrying, military (i.e., U.S. Navy), fishing, and miscellaneous support ships (e.g., tugboats). For the purpose of estimating greenhouse gas emissions, international bunker fuels are solely related to cargo and passenger carrying vessels, which is the largest of the four categories, and military vessels. Two main types of fuels are used on sea-going vessels: distillate diesel fuel and residual fuel oil. CO₂ is the primary greenhouse gas emitted from marine shipping.

Overall, aggregate greenhouse gas emissions in 2009 from the combustion of international bunker fuels from both aviation and marine activities were 124.4 Tg CO₂ Eq., or ten percent above emissions in 1990 (see Table 3-49 and Table 3-50). Emissions from international flights and international shipping voyages departing from the United States have increased by 49 percent and decreased by 18 percent, respectively, since 1990. The majority of these emissions were in the form of CO₂; however, small amounts of CH₄ and N₂O were also emitted.

Table 3-49: CO₂, CH₄, and N₂O Emissions from International Bunker Fuels (Tg CO₂ Eq.)

Gas/Mode	1990	2000	2005	2006	2007	2008	2009
CO₂	111.8	98.5	109.7	128.4	127.6	133.7	123.1
Aviation	46.4	58.8	56.7	74.6	73.8	75.5	69.4
Marine	65.4	39.7	53.0	53.8	53.9	58.2	53.7
CH₄	0.2	0.1	0.1	0.2	0.2	0.2	0.1
Aviation	+	+	+	+	+	+	+
Marine	0.1	0.1	0.1	0.1	0.1	0.1	0.1
N₂O	1.1	0.9	1.0	1.2	1.2	1.2	1.1
Aviation	0.5	0.6	0.6	0.8	0.8	0.8	0.7
Marine	0.5	0.3	0.4	0.4	0.4	0.5	0.4
Total	113.0	99.5	110.9	129.7	129.0	135.1	124.4

+ Does not exceed 0.05 Tg CO₂ Eq.

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

Table 3-50: CO₂, CH₄ and N₂O Emissions from International Bunker Fuels (Gg)

Gas/Mode	1990	2000	2005	2006	2007	2008	2009
CO₂	111,828	98,482	109,750	128,384	127,618	133,704	123,127
Aviation	46,399	58,785	56,736	74,552	73,762	75,508	69,404
Marine	65,429	39,697	53,014	53,832	53,856	58,196	53,723
CH₄	8	6	7	8	8	8	7
Aviation	2	2	2	2	2	2	2

Organization (ICAO) or the International Maritime Organization (IMO), which develop international codes, recommendations, and conventions, such as the International Convention of the Prevention of Pollution from Ships (MARPOL).

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

Marine	7		4		5	5	5	6	5
N₂O	3		3		3	4	4	4	4
Aviation	2		2		2	2	2	2	2
Marine	2		1		1	1	1	1	1

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

Methodology

Emissions of CO₂ were estimated by applying C content and fraction oxidized factors to fuel consumption activity data. This approach is analogous to that described under CO₂ from Fossil Fuel Combustion. C content and fraction oxidized factors for jet fuel, distillate fuel oil, and residual fuel oil were taken directly from EIA and are presented in Annex 2.1, Annex 2.2, and Annex 3.7 of this Inventory. Density conversions were taken from Chevron (2000), ASTM (1989), and USAF (1998). Heat content for distillate fuel oil and residual fuel oil were taken from EIA (2010) and USAF (1998), and heat content for jet fuel was taken from EIA (2010). A complete description of the methodology and a listing of the various factors employed can be found in Annex 2.1. See Annex 3.7 for a specific discussion on the methodology used for estimating emissions from international bunker fuel use by the U.S. military.

Emission estimates for CH₄ and N₂O were calculated by multiplying emission factors by measures of fuel consumption by fuel type and mode. Emission factors used in the calculations of CH₄ and N₂O emissions were obtained from the Revised 1996 IPCC Guidelines (IPCC/UNEP/OECD/IEA 1997). For aircraft emissions, the following values, in units of grams of pollutant per kilogram of fuel consumed (g/kg), were employed: 0.09 for CH₄ and 0.1 for N₂O. For marine vessels consuming either distillate diesel or residual fuel oil the following values (g/MJ), were employed: 0.32 for CH₄ and 0.08 for N₂O. Activity data for aviation included solely jet fuel consumption statistics, while the marine mode included both distillate diesel and residual fuel oil.

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

International aviation bunker fuel consumption from 1990 to 2009 was calculated by assigning the difference between the sum of domestic activity data (in Tbtu) from SAGE and the AEDT, and the reported EIA transportation jet fuel consumption to the international bunker fuel category for jet fuel from EIA (2010). Data on U.S. Department of Defense (DoD) aviation bunker fuels and total jet fuel consumed by the U.S. military was supplied by the Office of the Under Secretary of Defense (Installations and Environment), DoD. Estimates of the percentage of each Service's total operations that were international operations were developed by DoD. Military aviation bunkers included international operations, operations conducted from naval vessels at sea, and operations conducted from U.S. installations principally over international water in direct support of military operations at sea. Military aviation bunker fuel emissions were estimated using military fuel and operations data synthesized from unpublished data by the Defense Energy Support Center, under DoD's Defense Logistics Agency (DESC 2011). Together, the data allow the quantity of fuel used in military international operations to be estimated. Densities for each jet fuel type were obtained from a report from the U.S. Air Force (USAF 1998). Final jet fuel consumption estimates are presented in Table 3-51. See Annex 3.7 for additional discussion of military data.

Activity data on distillate diesel and residual fuel oil consumption by cargo or passenger carrying marine vessels departing from U.S. ports were taken from unpublished data collected by the Foreign Trade Division of the U.S. Department of Commerce's Bureau of the Census (DOC 1991 through 2010) for 1990 through 2001, 2007, through 2009, and the Department of Homeland Security's Bunker Report for 2003 through 2006 (DHS 2008). Fuel consumption data for 2002 was interpolated due to inconsistencies in reported fuel consumption data. Activity data on distillate diesel consumption by military vessels departing from U.S. ports were provided by DESC (2011). The total amount of fuel provided to naval vessels was reduced by 13 percent to account for fuel used while the vessels were not-underway (i.e., in port). Data on the percentage of steaming hours underway versus not-underway were provided by the U.S. Navy. These fuel consumption estimates are presented in Table 3-52.

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

Nationality	1990	2000	2005	2006	2007	2008	2009
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U.S. and Foreign Carriers	4,934		6,157		5,943	7,809	7,726	7,909	7,270
U.S. Military	862		480		462	400	410	386	368
Total	5,796		6,638		6,405	8,209	8,137	8,295	7,638

Note: Totals may not sum due to independent rounding.

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

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

Note: Totals may not sum due to independent rounding.

Uncertainty and Time-Series Consistency

Emission estimates related to the consumption of international bunker fuels are subject to the same uncertainties as those from domestic aviation and marine mobile combustion emissions; however, additional uncertainties result from the difficulty in collecting accurate fuel consumption activity data for international transport activities separate from domestic transport activities.¹⁰⁰ For example, smaller aircraft on shorter routes often carry sufficient fuel to complete several flight segments without refueling in order to minimize time spent at the airport gate or take advantage of lower fuel prices at particular airports. This practice, called tankering, when done on international flights, complicates the use of fuel sales data for estimating bunker fuel emissions. Tankering is less common with the type of large, long-range aircraft that make many international flights from the United States, however. Similar practices occur in the marine shipping industry where fuel costs represent a significant portion of overall operating costs and fuel prices vary from port to port, leading to some tankering from ports with low fuel costs.

Uncertainties exist with regard to the total fuel used by military aircraft and ships, and in the activity data on military operations and training that were used to estimate percentages of total fuel use reported as bunker fuel emissions. Total aircraft and ship fuel use estimates were developed from DoD records, which document fuel sold to the Navy and Air Force from the Defense Logistics Agency. These data may slightly over or under estimate actual total fuel use in aircraft and ships because each Service may have procured fuel from, and/or may have sold to, traded with, and/or given fuel to other ships, aircraft, governments, or other entities. There are uncertainties in aircraft operations and training activity data. Estimates for the quantity of fuel actually used in Navy and Air Force flying activities reported as bunker fuel emissions had to be estimated based on a combination of available data and expert judgment. Estimates of marine bunker fuel emissions were based on Navy vessel steaming hour data, which reports fuel used while underway and fuel used while not underway. This approach does not capture some voyages that would be classified as domestic for a commercial vessel. Conversely, emissions from fuel used while not underway preceding an international voyage are reported as domestic rather than international as would be done for a commercial vessel. There is uncertainty associated with ground fuel estimates for 1997 through 2001. Small fuel quantities may have been used in vehicles or equipment other than that which was assumed for each fuel type.

There are also uncertainties in fuel end-uses by fuel-type, emissions factors, fuel densities, diesel fuel sulfur content, aircraft and vessel engine characteristics and fuel efficiencies, and the methodology used to back-calculate the data set to 1990 using the original set from 1995. The data were adjusted for trends in fuel use based on a closely correlating, but not matching, data set. All assumptions used to develop the estimate were based on process knowledge, Department and military Service data, and expert judgments. The magnitude of the potential errors related to the various uncertainties has not been calculated, but is believed to be small. The uncertainties associated with future military bunker fuel emission estimates could be reduced through additional data collection.

Although aggregate fuel consumption data have been used to estimate emissions from aviation, the recommended method for estimating emissions of gases other than CO₂ in the Revised 1996 IPCC Guidelines is to use data by specific aircraft type (IPCC/UNEP/OECD/IEA 1997). The IPCC also recommends that cruise altitude emissions be estimated separately using fuel consumption data, while landing and take-off (LTO) cycle data be used to estimate

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

near-ground level emissions of gases other than CO₂.¹⁰¹

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

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

QA/QC and Verification

A source-specific QA/QC plan for international bunker fuels was developed and implemented. This effort included a Tier 1 analysis, as well as portions of a Tier 2 analysis. The Tier 2 procedures that were implemented involved checks specifically focusing on the activity data and emission factor sources and methodology used for estimating CO₂, CH₄, and N₂O from international bunker fuels in the United States. Emission totals for the different sectors and fuels were compared and trends were investigated. No corrective actions were necessary.

Recalculations Discussion

Slight changes to emission estimates are due to revisions made to historical activity data for aviation jet fuel consumption using the FAA's AEDT. These historical data changes resulted in changes to the emission estimates for 1990 through 2008 relative to the previous Inventory, which averaged to an annual decrease in emissions from international bunker fuels of 0.13 Tg CO₂ Eq. (0.1 percent) in CO₂ emissions, an annual decrease of less than 0.01 Tg CO₂ Eq. (0.05 percent) in CH₄ emissions, and an annual decrease of less than 0.01 Tg CO₂ Eq. (0.1 percent) in N₂O emissions.

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

The combustion of biomass fuels such as wood, charcoal, and wood waste and biomass-based fuels such as ethanol from corn and woody crops generates CO₂ in addition to CH₄ and N₂O already covered in this chapter. In line with the reporting requirements for inventories submitted under the UNFCCC, CO₂ emissions from biomass combustion have been estimated separately from fossil fuel CO₂ emissions and are not directly included in the energy sector contributions to U.S. totals. In accordance with IPCC methodological guidelines, any such emissions are calculated by accounting for net carbon (C) fluxes from changes in biogenic C reservoirs in wooded or crop lands. For a more complete description of this methodological approach, see the Land Use, Land-Use Change, and Forestry chapter (Chapter 7), which accounts for the contribution of any resulting CO₂ emissions to U.S. totals within the Land Use, Land-Use Change and Forestry sector's approach.

In 2009, total CO₂ emissions from the burning of woody biomass in the industrial, residential, commercial, and electricity generation sectors were approximately 183.8 Tg CO₂ Eq. (183,777 Gg) (see Table 3-53 and Table 3-54). As the largest consumer of woody biomass, the industrial sector was responsible for 62 percent of the CO₂ emissions from this source. Emissions from this sector decreased from 2008 to 2009 due to a corresponding decrease in wood consumption. The residential sector was the second largest emitter, constituting 24 percent of the total, while the commercial and electricity generation sectors accounted for the remainder.

Table 3-53: CO₂ Emissions from Wood Consumption by End-Use Sector (Tg CO₂ Eq.)

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

¹⁰¹ U.S. aviation emission estimates for CO, NO_x, and NMVOCs are reported by EPA's National Emission Inventory (NEI) Air Pollutant Emission Trends web site, and reported under the Mobile Combustion section. It should be noted that these estimates are based solely upon LTO cycles and consequently only capture near ground-level emissions, which are more relevant for air quality evaluations. These estimates also include both domestic and international flights. Therefore, estimates reported under the Mobile Combustion section overestimate IPCC-defined domestic CO, NO_x, and NMVOC emissions by including landing and take-off (LTO) cycles by aircraft on international flights, but underestimate because they do not include emissions from aircraft on domestic flight segments at cruising altitudes. The estimates in Mobile Combustion are also likely to include emissions from ocean-going vessels departing from U.S. ports on international voyages.

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

Note: Totals may not sum due to independent rounding.

Table 3-54: CO₂ Emissions from Wood Consumption by End-Use Sector (Gg)

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

Note: Totals may not sum due to independent rounding.

Biomass-derived fuel consumption in the United States transportation sector consisted primarily of ethanol use. Ethanol is primarily produced from corn grown in the Midwest, and was used mostly in the Midwest and South. Pure ethanol can be combusted, or it can be mixed with gasoline as a supplement or octane-enhancing agent. The most common mixture is a 90 percent gasoline, 10 percent ethanol blend known as gasohol. Ethanol and ethanol blends are often used to fuel public transport vehicles such as buses, or centrally fueled fleet vehicles.

In 2009, the United States consumed an estimated 894 trillion Btu of ethanol, and as a result, produced approximately 61.2 Tg CO₂ Eq. (61,231 Gg) (see Table 3-55 and Table 3-56) of CO₂ emissions. Ethanol production and consumption has grown steadily every year since 1990, with the exception of 1996 due to short corn supplies and high prices in that year.

Table 3-55: CO₂ Emissions from Ethanol Consumption (Tg CO₂ Eq.)

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

+ Does not exceed 0.05 Tg CO₂ Eq.

Table 3-56: CO₂ Emissions from Ethanol Consumption (Gg)

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

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

Methodology

Woody biomass emissions were estimated by applying two EIA gross heat contents (Lindstrom 2006) to U.S. consumption data (EIA 2010) (see Table 3-57), provided in energy units for the industrial, residential, commercial, and electric generation sectors. One heat content (16.95 MMBtu/MT wood and wood waste) was applied to the industrial sector's consumption, while the other heat content (15.43 MMBtu/MT wood and wood waste) was applied to the consumption data for the other sectors. An EIA emission factor of 0.434 MT C/MT wood (Lindstrom 2006) was then applied to the resulting quantities of woody biomass to obtain CO₂ emission estimates. It was assumed that the woody biomass contains black liquor and other wood wastes, has a moisture content of 12 percent, and is converted into CO₂ with 100 percent efficiency. The emissions from ethanol consumption were calculated by applying an emission factor of 18.67 Tg C/QBtu (EPA 2010) to U.S. ethanol consumption estimates that were provided in energy units (EIA 2010) (see Table 3-58).

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

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

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

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

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

Uncertainty and Time-Series Consistency

It is assumed that the combustion efficiency for woody biomass is 100 percent, which is believed to be an overestimate of the efficiency of wood combustion processes in the United States. Decreasing the combustion efficiency would decrease emission estimates. Additionally, the heat content applied to the consumption of woody biomass in the residential, commercial, and electric power sectors is unlikely to be a completely accurate representation of the heat content for all the different types of woody biomass consumed within these sectors. Emission estimates from ethanol production are more certain than estimates from woody biomass consumption due to better activity data collection methods and uniform combustion techniques.

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

Recalculations Discussion

Wood consumption values were revised for 2006 through 2008 based on updated information from EIA's Annual Energy Review (EIA 2010). This adjustment of historical data for wood biomass consumption resulted in an average annual decrease in emissions from wood biomass consumption of 0.8 Tg CO₂ Eq. (0.4 percent) from 1990 through 2008. The C content coefficient for ethanol was also revised to be consistent with the carbon content coefficients used for EPA's Mandatory Greenhouse Gas Reporting Rule. Slight adjustments were made to ethanol consumption based on updated information from EIA (2010), which slightly decreased estimates for ethanol consumed. As a result of these adjustments, average annual emissions from ethanol consumption increased by about 0.3 Tg CO₂ Eq. (1.9 percent) relative to the previous Inventory.

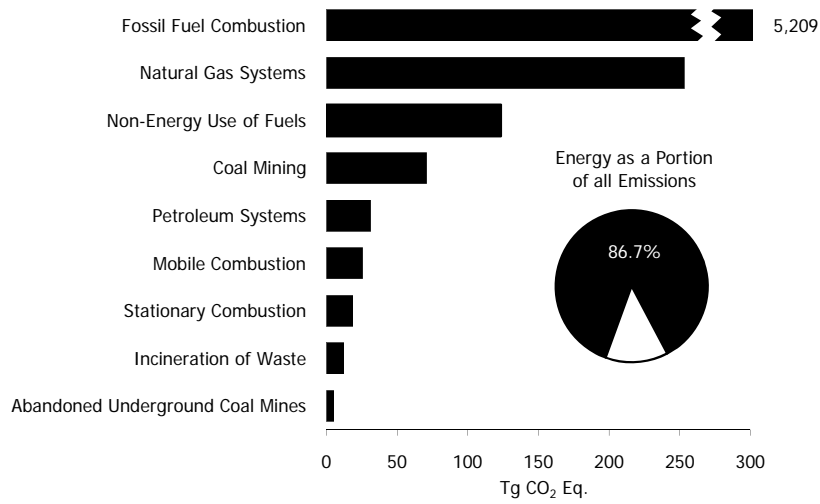


Figure 3-1: 2009 Energy Chapter Greenhouse Gas Sources

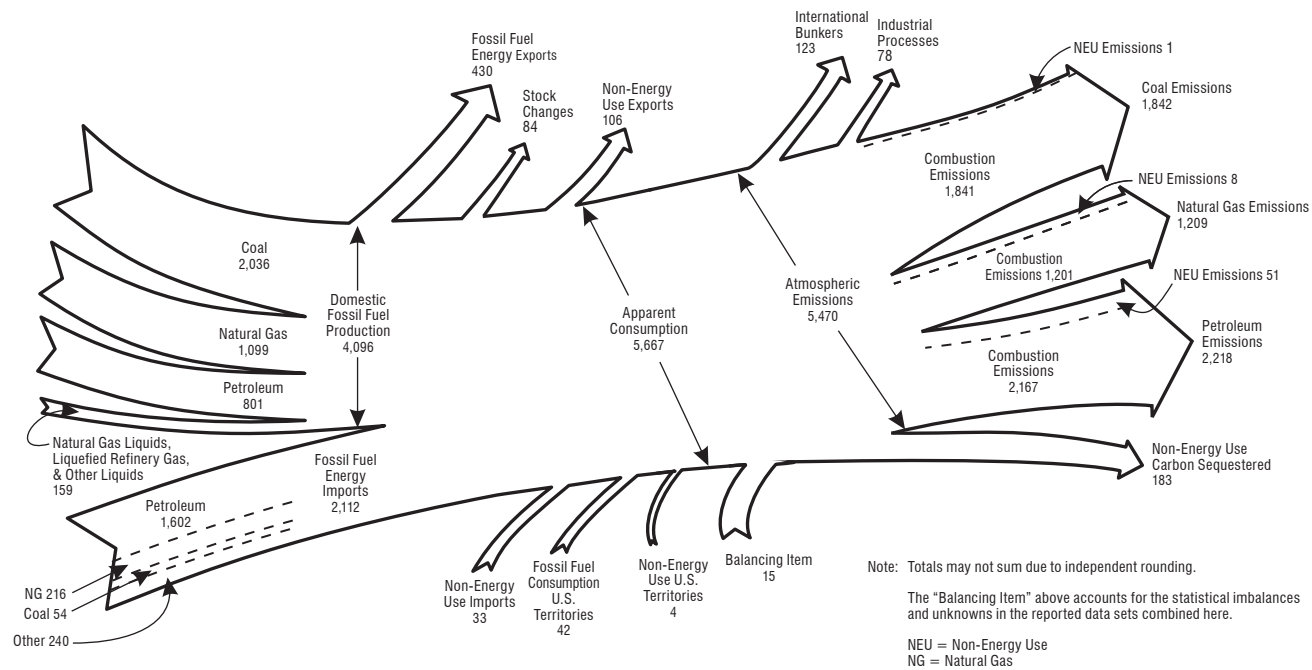


Figure 3-2 2009 U.S. Fossil Carbon Flows (Tg CO₂ Eq.)

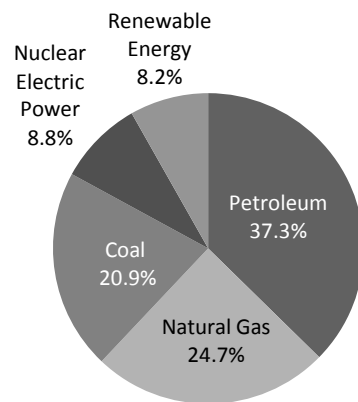


Figure 3-3: 2009 U.S. Energy Consumption by Energy Source

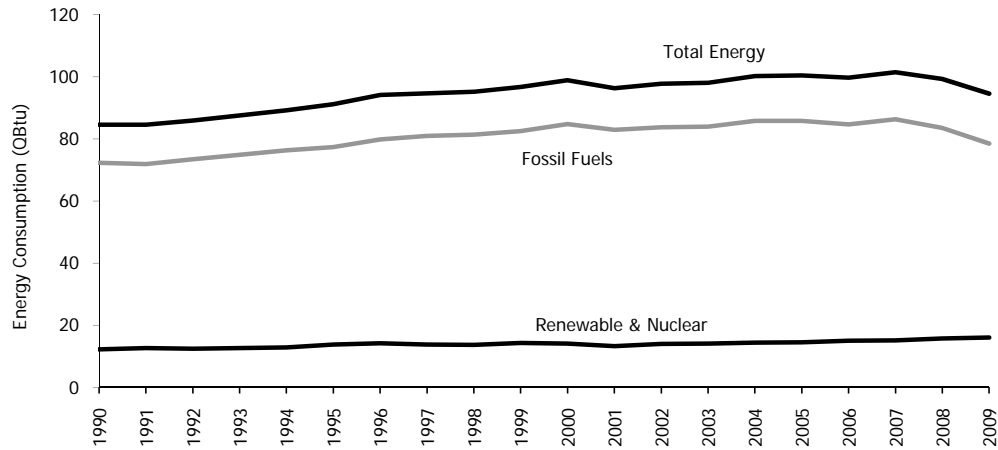


Figure 3-4: U.S. Energy Consumption (Quadrillion Btu)

Note: Expressed as gross calorific values.

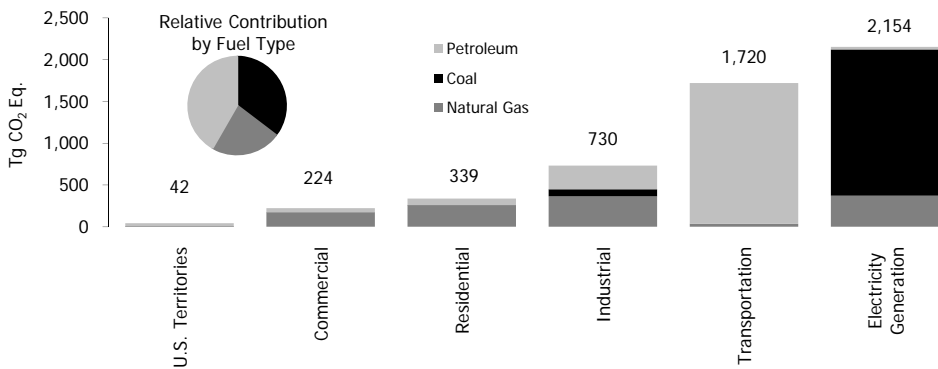


Figure 3-5: 2009 CO₂ Emissions from Fossil Fuel Combustion by Sector and Fuel Type

Note: The electricity generation sector also includes emissions of less than 0.5 Tg CO₂ Eq. from geothermal-based electricity generation.

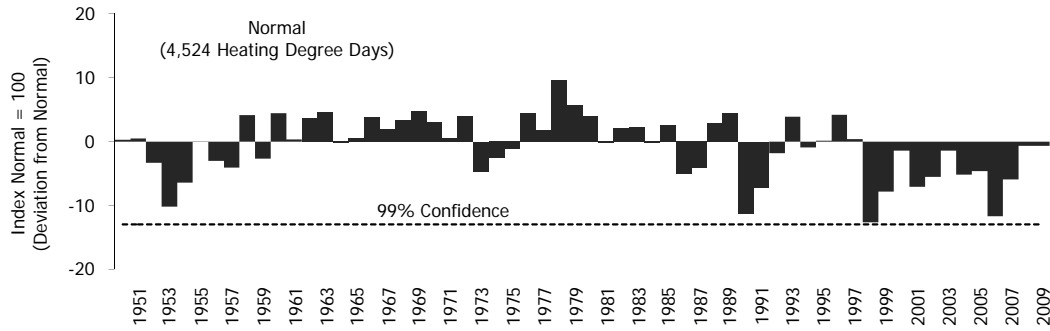


Figure 3-6: Annual Deviations from Normal Heating Degree Days for the United States (1950-2009)

Note: Climatological normal data are highlighted.

Statistical confidence interval for "normal" climatology period of 1971 through 2000.

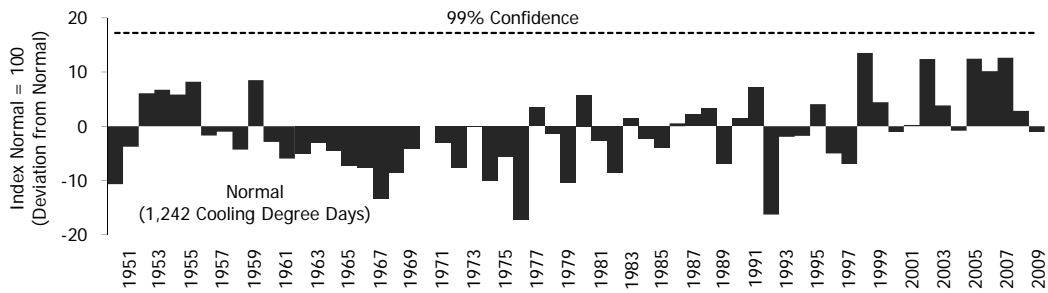


Figure 3-7: Annual Deviations from Normal Cooling Degree Days for the United States (1950-2009)

Note: Climatological normal data are highlighted.

Statistical confidence interval for "normal" climatology period of 1971 through 2000.

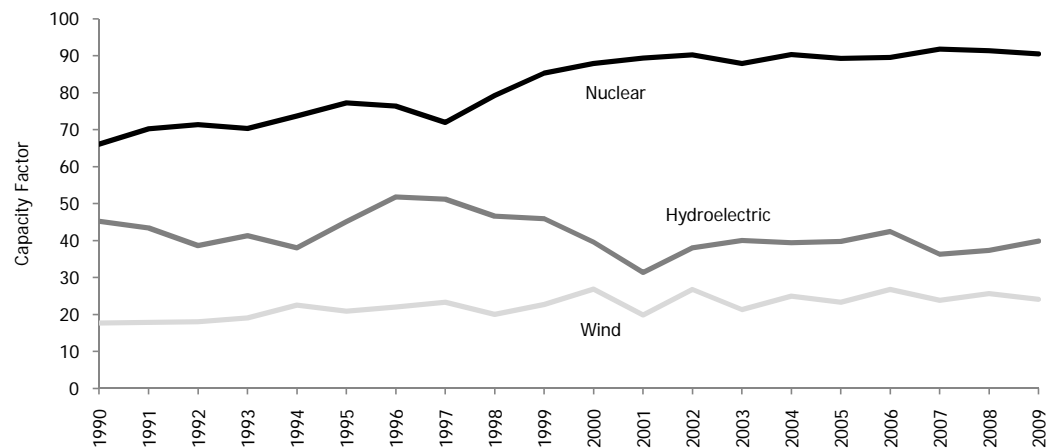


Figure 3-8: Nuclear, Hydroelectric, and Wind Power Plant Capacity Factors in the United States (1990-2009)

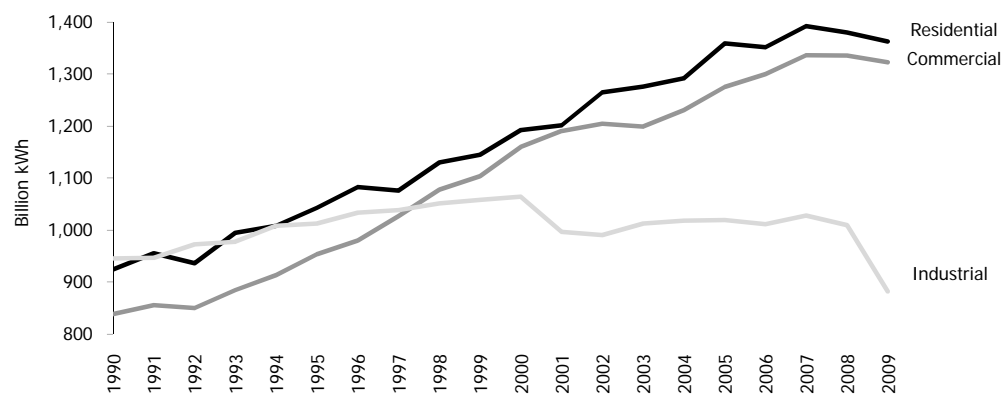


Figure 3-9: Electric Generation Retail Sales by End-Use Sector

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

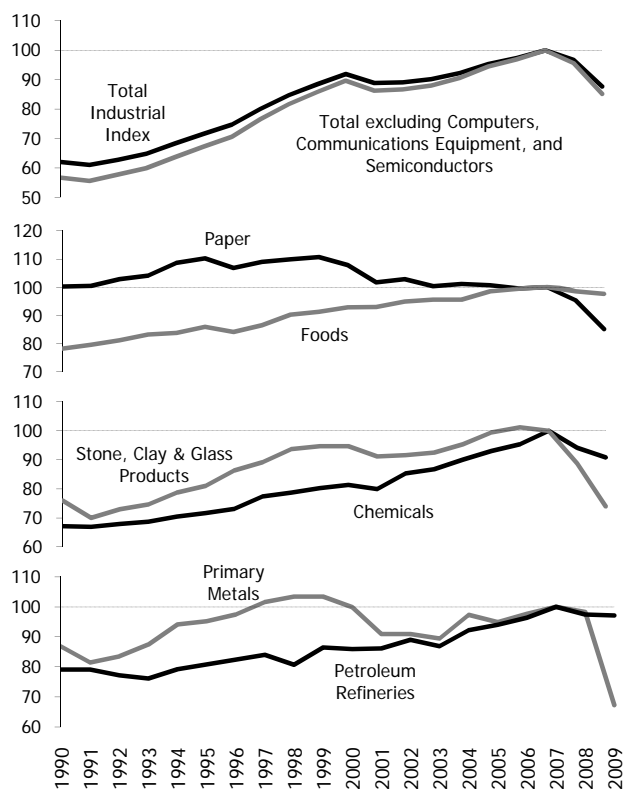


Figure 3-10: Industrial Production Indexes (Index 2007=100)

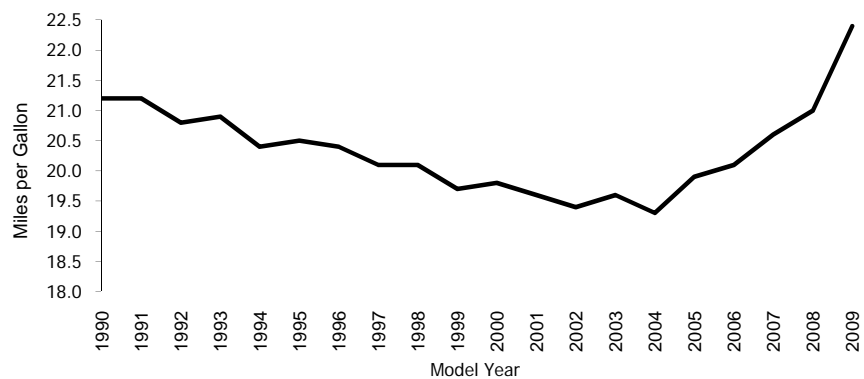


Figure 3-11: Sales-Weighted Fuel Economy of New Passenger Cars and Light-Duty Trucks, 1990-2009

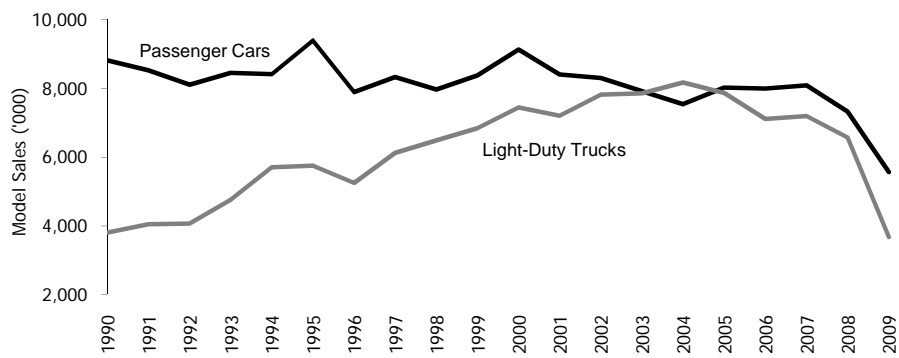


Figure 3-12: Sales of New Passenger Cars and Light-Duty Trucks, 1990-2009

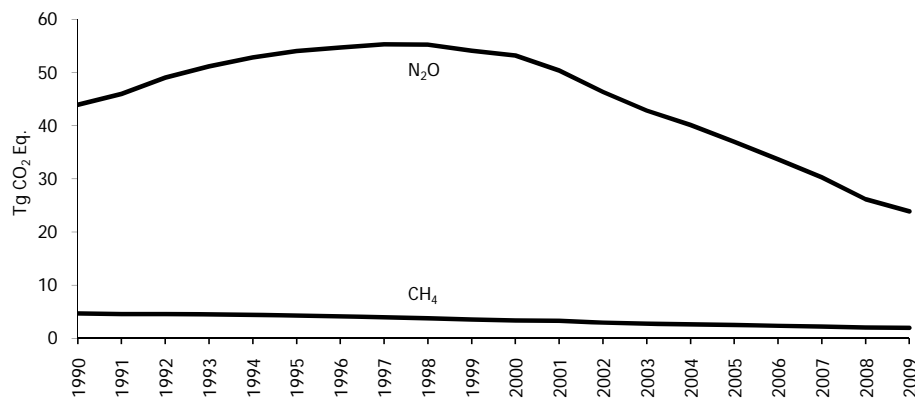


Figure 3-13: Mobile Source CH₄ and N₂O Emissions

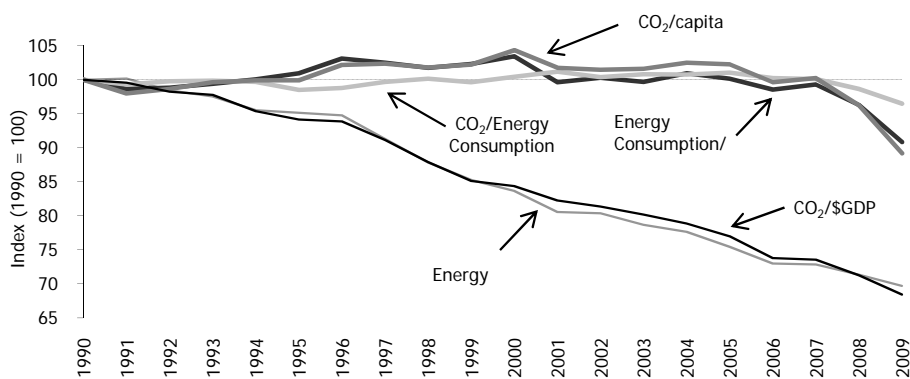


Figure 3-14: U.S. Energy Consumption and Energy-Related CO₂ Emissions Per Capita and Per Dollar GDP

4. Industrial Processes

Greenhouse gas emissions are produced as the by-products of various non-energy-related industrial activities. That is, these emissions are produced from an industrial process itself and are not directly a result of energy consumed during the process. For example, raw materials can be chemically transformed from one state to another. This transformation can result in the release of greenhouse gases such as carbon dioxide (CO₂), methane (CH₄), and nitrous oxide (N₂O). The processes addressed in this chapter include iron and steel production and metallurgical coke production, cement production, lime production, ammonia production and urea consumption, limestone and dolomite consumption (e.g., flux stone, flue gas desulfurization, and glass manufacturing), soda ash production and use, aluminum production, titanium dioxide production, CO₂ consumption, ferroalloy production, phosphoric acid production, zinc production, lead production, petrochemical production, silicon carbide production and consumption, nitric acid production, and adipic acid production (see Figure 4-1).

Figure 4-1: 2009 Industrial Processes Chapter Greenhouse Gas Sources

In addition to the three greenhouse gases listed above, there are also industrial sources of man-made fluorinated compounds called hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF₆). The present contribution of these 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; SF₆ is the most potent greenhouse gas the Intergovernmental Panel on Climate Change (IPCC) has evaluated. Usage 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. In addition to their use as ODS substitutes, HFCs, PFCs, and SF₆ 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.

In 2009, industrial processes generated emissions of 282.9 teragrams of CO₂ equivalent (Tg CO₂ Eq.), or 4 percent of total U.S. greenhouse gas emissions. CO₂ emissions from all industrial processes were 119.0 Tg CO₂ Eq. (119,010 Gg) in 2009, or 2 percent of total U.S. CO₂ emissions. CH₄ emissions from industrial processes resulted in emissions of approximately 1.2 Tg CO₂ Eq. (58 Gg) in 2009, which was less than 1 percent of U.S. CH₄ emissions. N₂O emissions from adipic acid and nitric acid production were 16.5 Tg CO₂ Eq. (53 Gg) in 2009, or 6 percent of total U.S. N₂O emissions. In 2009 combined emissions of HFCs, PFCs and SF₆ totaled 146.1 Tg CO₂ Eq. Despite the significant increase in HFC emissions associated with increased usage of ODSs, total emissions from industrial processes in 2009 were less than 1990 for the first time since 1994. This decrease is primarily due to significant reductions in emissions from iron and steel production, metallurgical coke production, ammonia production and urea consumption, adipic acid production, HCFC-22 production, aluminum production and cement production.

Table 4-1 summarizes emissions for the Industrial Processes chapter in Tg CO₂ Eq., while unweighted native gas emissions in Gg are 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 reporting format tables, corresponding generally to: mineral products, chemical production, metal production, and emissions from the uses of HFCs, PFCs, and SF₆.

Table 4-1: Emissions from Industrial Processes (Tg CO₂ Eq.)

Gas/Source	1990	2000	2005	2006	2007	2008	2009
CO₂	188.4	184.9	165.4	169.9	172.6	159.5	119.0
Iron and Steel Production and Metallurgical Coke Production	99.5	85.9	65.9	68.8	71.0	66.0	41.9
<i>Iron and Steel Production</i>	97.1	83.7	63.9	66.9	69.0	63.7	40.9
<i>Metallurgical Coke Production</i>	2.5	2.2	2.0	1.9	2.1	2.3	1.0
Cement Production	33.3	40.4	45.2	45.8	44.5	40.5	29.0
Ammonia Production & Urea Consumption	16.8	16.4	12.8	12.3	14.0	11.9	11.8

Lime Production	11.5	14.1	14.4	15.1	14.6	14.3	11.2
Limestone and Dolomite Use	5.1	5.1	6.8	8.0	7.7	6.3	7.6
Soda Ash Production and Consumption	4.1	4.2	4.2	4.2	4.1	4.1	4.3
Aluminum Production	6.8	6.1	4.1	3.8	4.3	4.5	3.0
Petrochemical Production	3.3	4.5	4.2	3.8	3.9	3.4	2.7
Carbon Dioxide Consumption	1.4	1.4	1.3	1.7	1.9	1.8	1.8
Titanium Dioxide Production	1.2	1.8	1.8	1.8	1.9	1.8	1.5
Ferroalloy Production	2.2	1.9	1.4	1.5	1.6	1.6	1.5
Phosphoric Acid Production	1.5	1.4	1.4	1.2	1.2	1.2	1.0
Zinc Production	0.7	1.0	1.1	1.1	1.1	1.2	1.0
Lead Production	0.5	0.6	0.6	0.6	0.6	0.6	0.5
Silicon Carbide Production and Consumption	0.4	0.2	0.2	0.2	0.2	0.2	0.1
CH₄	1.9	2.2	1.8	1.7	1.7	1.6	1.2
Petrochemical Production	0.9	1.2	1.1	1.0	1.0	0.9	0.8
Iron and Steel Production and Metallurgical Coke Production	1.0	0.9	0.7	0.7	0.7	0.6	0.4
<i>Iron and Steel Production</i>	<i>1.0</i>	<i>0.9</i>	<i>0.7</i>	<i>0.7</i>	<i>0.7</i>	<i>0.6</i>	<i>0.4</i>
<i>Metallurgical Coke Production</i>	+	+	+	+	+	+	+
Ferroalloy Production	+	+	+	+	+	+	+
Silicon Carbide Production and Consumption	+	+	+	+	+	+	+
N₂O	33.5	24.9	21.5	20.5	22.9	18.5	16.5
Nitric Acid Production	17.7	19.4	16.5	16.2	19.2	16.4	14.6
Adipic Acid Production	15.8	5.5	5.0	4.3	3.7	2.0	1.9
HFCs	36.9	103.2	120.2	123.5	129.5	129.4	125.7
Substitution of Ozone Depleting Substances ^a	0.3	74.3	104.2	109.4	112.3	115.5	120.0
HCFC-22 Production	36.4	28.6	15.8	13.8	17.0	13.6	5.4
Semiconductor Manufacturing HFCs	0.2	0.3	0.2	0.3	0.3	0.3	0.3
PFCs	20.8	13.5	6.2	6.0	7.5	6.7	5.6
Aluminum Production	18.5	8.6	3.0	2.5	3.8	2.7	1.6
Semiconductor Manufacturing PFCs	2.2	4.9	3.2	3.5	3.7	4.0	4.0
SF₆	34.4	20.1	19.0	17.9	16.7	16.1	14.8
Electrical Transmission and Distribution	28.4	16.0	15.1	14.1	13.2	13.3	12.8
Semiconductor Manufacturing SF ₆	0.5	1.1	1.0	1.0	0.8	0.9	1.0
Magnesium Production and Processing	5.4	3.0	2.9	2.9	2.6	1.9	1.1
Total	315.8	348.8	334.1	339.4	350.9	331.7	282.9

+ Does not exceed 0.05 Tg CO₂ Eq.

Note: Totals may not sum due to independent rounding.

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

Table 4-2: Emissions from Industrial Processes (Gg)

Gas/Source	1990	2000	2005	2006	2007	2008	2009
CO₂	188,431	184,919	165,384	169,870	172,592	159,470	119,010
Iron and Steel Production and Metallurgical Coke Production	99,528	85,935	65,925	68,772	71,045	66,015	41,871

<i>Iron and Steel</i>							
<i>Production</i>	97,058	83,740	63,882	66,852	68,991	63,682	40,914
<i>Metallurgical Coke</i>							
<i>Production</i>	2,470	2,195	2,043	1,919	2,054	2,334	956
Cement Production	33,278	40,405	45,197	45,792	44,538	40,531	29,018
Ammonia Production & Urea Consumption	16,831	16,402	12,849	12,300	14,038	11,949	11,797
Lime Production	11,533	14,088	14,379	15,100	14,595	14,330	11,223
Limestone and Dolomite Use	5,127	5,056	6,768	8,035	7,702	6,276	7,649
Soda Ash Production and Consumption	4,141	4,181	4,228	4,162	4,140	4,111	4,265
Aluminum Production	6,831	6,086	4,142	3,801	4,251	4,477	3,009
Petrochemical Production	3,311	4,479	4,181	3,837	3,931	3,449	2,735
Carbon Dioxide Consumption	1,416	1,421	1,321	1,709	1,867	1,780	1,763
Titanium Dioxide Production	1,195	1,752	1,755	1,836	1,930	1,809	1,541
Ferroalloy Production	2,152	1,893	1,392	1,505	1,552	1,599	1,469
Phosphoric Acid Production	1,529	1,382	1,386	1,167	1,166	1,187	1,035
Zinc Production	667	997	1,088	1,088	1,081	1,230	966
Lead Production	516	594	553	560	562	551	525
Silicon Carbide Production and Consumption	375	248	219	207	196	175	145
CH₄	88	104	86	83	82	75	58
Petrochemical Production	41	59	51	48	48	43	40
Iron and Steel Production and Metallurgical Coke Production	46	44	34	35	33	31	17
<i>Iron and Steel</i>							
<i>Production</i>	46	44	34	35	33	31	17
<i>Metallurgical Coke</i>							
<i>Production</i>	+	+	+	+	+	+	+
Ferroalloy Production	1	1	+	+	+	+	+
Silicon Carbide Production and Consumption	1	1	+	+	+	+	+
N₂O	108	80	69	66	74	60	53
Nitric Acid Production	57	63	53	52	62	53	47
Adipic Acid Production	51	18	16	14	12	7	6
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	2	1	1	1	1	+
Semiconductor Manufacturing HFCs	+	+	+	+	+	+	+
PFCs	M	M	M	M	M	M	M
Aluminum Production Semiconductor Manufacturing PFCs	M	M	M	M	M	M	M
SF₆	1	1	1	1	1	1	1
Electrical Transmission and Distribution	1	1	1	1	1	1	1
Semiconductor	+	+	+	+	+	+	+

Manufacturing SF ₆ Magnesium Production and Processing	+		+		+		+		+		+
<hr/>											
+ Does not exceed 0.5 Gg											
M (Mixture of gases)											
Note: Totals may not sum due to independent rounding.											
^a Small amounts of PFC emissions also result from this source.											

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

QA/QC and Verification Procedures

Tier 1 quality assurance and quality control procedures have been performed for all industrial process sources. For industrial process sources of CO₂ and CH₄ emissions, a detailed plan was developed and implemented. This plan was based on the overall U.S. strategy, 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 procedures and checks of the emission factors, activity data, and methodologies used for estimating emissions from the relevant industrial process 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.

The general method employed to estimate emissions for industrial processes, as recommended by the IPCC, involves multiplying production data (or activity data) for each process by an emission factor per unit of production. The uncertainty in the emission estimates is therefore generally a function of a combination of the uncertainties surrounding the production and emission factor variables. Uncertainty of activity data and the associated probability density functions for industrial processes CO₂ sources were estimated based on expert assessment of available qualitative and quantitative information. Uncertainty estimates and probability density functions for the emission factors used to calculate emissions from this source were devised based on IPCC recommendations.

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 plant-level production data and is influenced by the completeness of the survey response. The emission factors used were either 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 2009 inventory estimates from industrial processes 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.

4.1. Cement Production (IPCC Source Category 2A1)

Cement production is an energy- and raw-material-intensive process that results in the generation of CO₂ from both

the energy consumed in making the cement and the chemical process itself.¹⁰² Cement is produced in 36 states and Puerto Rico. CO₂ emitted from the chemical process of cement production is the second largest source of industrial CO₂ emissions in the United States.

During the cement production process, calcium carbonate (CaCO₃) is heated in a cement kiln at a temperature of about 1,450°C (2,400°F) to form lime (i.e., calcium oxide or CaO) and CO₂ in a process known as calcination or calcining. A very small amount of carbonates other than CaCO₃ and non-carbonates are also present in the raw material; however, for calculation purposes all of the raw material is assumed to be CaCO₃. Next, the lime is combined with silica-containing materials to produce clinker (an intermediate product), with the earlier by-product CO₂ 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), and used to make portland cement.¹⁰³

In 2009, U.S. clinker production—including Puerto Rico—totaled 56,116 thousand metric tons (USGS 2011). The resulting CO₂ emissions were estimated to be 29.0 Tg CO₂ Eq. (29,018 Gg) (see Table 4-3).

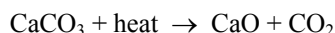
Table 4-3: CO₂ Emissions from Cement Production (Tg CO₂ Eq. and Gg)

Year	Tg CO ₂ Eq.	Gg
1990	33.3	33,278
2000	40.4	40,405
2005	45.2	45,197
2006	45.8	45,792
2007	44.5	44,538
2008	40.5	40,531
2009	29.0	29,018

Greenhouse gas emissions from cement production grew every year from 1991 through 2006, but have decreased since. Emissions since 1990 have decreased by 13 percent. Emissions decreased significantly between 2008 and 2009, due to the economic recession and associated decrease in demand for construction materials. Cement continues to be a critical component of the construction industry; therefore, the availability of public construction funding, as well as overall economic conditions, have considerable influence on cement production.

Methodology

CO₂ emissions from cement production are created by the chemical reaction of carbon-containing minerals (i.e., calcining limestone) in the cement kiln. While in the kiln, limestone is broken down into CO₂ and lime with the CO₂ released to the atmosphere. The quantity of CO₂ emitted during cement production is directly proportional to the lime content of the clinker. During calcination, each mole of CaCO₃ (i.e., limestone) heated in the clinker kiln forms one mole of lime (CaO) and one mole of CO₂:



CO₂ emissions were estimated by applying an emission factor, in tons of CO₂ released per ton of clinker produced, to the total amount of clinker produced. The emission factor used in this analysis is the product of the average lime fraction for clinker of 65 percent and a constant reflecting the mass of CO₂ released per unit of lime (van Oss 2008). This calculation yields an emission factor of 0.51 tons of CO₂ per ton of clinker produced, which was determined as follows:

¹⁰² The CO₂ emissions related to the consumption of energy for cement manufacture are accounted for under CO₂ from Fossil Fuel Combustion in the Energy chapter.

¹⁰³ Approximately three percent of total clinker production is used to produce masonry cement, which is produced using plasticizers (e.g., ground limestone, lime) and portland cement (USGS 2011). CO₂ emissions that result from the production of lime used to create masonry cement are included in the Lime Manufacture source category.

$$EF_{\text{Clinker}} = 0.6460 \text{ CaO} \times \left[\frac{44.01 \text{ g/mole CO}_2}{56.08 \text{ g/mole CaO}} \right] = 0.5070 \text{ tons CO}_2/\text{ton clinker}$$

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 CO₂ emissions should be estimated as two percent of the CO₂ emissions calculated from clinker production.¹⁰⁴ Total cement production emissions were calculated by adding the emissions from clinker production to the emissions assigned to CKD (IPCC 2006).¹⁰⁵

The 1990 through 2009 activity data for clinker production (see Table 4-4) were obtained from USGS (US Bureau of Mines 1990 through 1993, USGS 1995 through 2011). The data were compiled by USGS through questionnaires sent to domestic clinker and cement manufacturing plants.

Table 4-4: Clinker Production (Gg)

Year	Clinker
1990	64,355
2000	78,138
2005	87,405
2006	88,555
2007	86,130
2008	78,382
2009	56,116

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 CaCO₃, 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 2008). CKD loss can range from 1.5 to 8 percent depending upon plant specifications. Additionally, some amount of CO₂ 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 CO₂ 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 CO₂ reabsorbed is thought to be minimal, it was not estimated.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 4-5. 2009 CO₂ emissions from cement production were estimated to be between 25.3 and 33.0 Tg CO₂ Eq. at the 95 percent confidence level. This confidence level indicates a range of approximately 13 percent below and 14 percent above the emission estimate of 29.0 Tg CO₂ Eq.

Table 4-5: Tier 2 Quantitative Uncertainty Estimates for CO₂ Emissions from Cement Production (Tg CO₂ Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate ^a			
			(Tg CO ₂ Eq.)		(%)	
			Lower	Upper	Lower	Upper

¹⁰⁴ Default IPCC clinker and CKD emission factors were verified through expert consultation with the Portland Cement Association (PCA 2008) and van Oss (2008).

¹⁰⁵ The two percent CO₂ addition associated with CKD is included in the emission estimate for completeness. The cement emission estimate also includes an assumption that all raw material is limestone (CaCO₃) when in fact a small percentage is likely composed of non-carbonate materials. Together these assumptions may result in a small emission overestimate (van Oss 2008).

			Bound	Bound	Bound	Bound
Cement Production	CO ₂	29.0	25.3	33.0	-13%	+14%

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

Recalculations Discussion

Activity data for the time series was revised for the current Inventory. Specifically, clinker production data for 1995 through 2008 (excluding 2001) were revised to reflect published USGS data. In a given Inventory year, advance clinker data is typically used. This data is typically finalized several years later by USGS. The published time series was reviewed to ensure time series consistency. Published data generally differed from advance data by approximately 1,000 metric tons, or 1 percent of the total. Details on the emission trends through time are described in more detail in the Methodology section, above.

Planned Improvements

Future improvements to the cement source category involve evaluating facility level greenhouse gas emissions data as a basis for improving emissions calculations from cement production. Beginning in 2010, all U.S. cement production facilities are required to monitor, calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. Under the program, EPA will obtain data for 2010 emissions from facilities based on use of higher tier methods and in particular assess how this data could be used to improve the overall method for calculating emissions from the U.S. cement industry, including also improving emission factors for clinker production and CKD.

4.2. Lime Production (IPCC Source Category 2A2)

Lime is an important manufactured product with many industrial, chemical, and environmental applications. Its major uses are in steel making, flue gas desulfurization systems at coal-fired electric power plants, construction, and water purification. 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]).

Lime production involves three main processes: stone preparation, calcination, and hydration. CO₂ is generated during the calcination stage, when limestone—mostly calcium carbonate (CaCO₃)—is roasted at high temperatures in a kiln to produce CaO and CO₂. The CO₂ is given off as a gas and is normally emitted to the atmosphere. Some of the CO₂ generated during the production process, however, is recovered at some facilities for use in sugar refining and precipitated calcium carbonate (PCC) production.¹⁰⁶ In certain additional applications, lime reabsorbs CO₂ during use.

Lime production in the United States—including Puerto Rico—was reported to be 15,781 thousand metric tons in 2009 (USGS 2010). This production resulted in estimated CO₂ emissions of 11.2 Tg CO₂ Eq. (11,223 Gg) (see Table 4-6 and Table 4-7).

Table 4-6: CO₂ Emissions from Lime Production (Tg CO₂ Eq. and Gg)

Year	Tg CO₂ Eq.	Gg
1990	11.5	11,533
2000	14.1	14,088
2005	14.4	14,379
2006	15.1	15,100
2007	14.6	14,595
2008	14.3	14,330
2009	11.2	11,223

¹⁰⁶ PCC is obtained from the reaction of CO₂ with calcium hydroxide. It is used as a filler and/or coating in the paper, food, and plastic industries.

Table 4-7: Potential, Recovered, and Net CO₂ Emissions from Lime Production (Gg)

Year	Potential	Recovered*	Net Emissions
1990	12,004	471	11,533
2000	14,872	784	14,088
2005	15,131	752	14,379
2006	15,825	725	15,100
2007	15,264	669	14,595
2008	14,977	647	14,330
2009	11,913	690	11,223

* For sugar refining and PCC production.

Note: Totals may not sum due to rounding

Lime production in 2009 decreased by 21 percent compared to 2008, owing mostly to a significant downturn in major markets such as construction and steel. Because of this significant downturn, overall lime production in 2009 was approximately equal to production in 1990. The contemporary lime market is approximately distributed across five end-use categories as follows: environmental uses, 34 percent; metallurgical uses, 31 percent; chemical and industrial uses, 25 percent; construction uses, 9 percent; and refractory dolomite, 1 percent. In the construction sector, lime is used to improve durability in plaster, stucco, and mortars, as well as to stabilize soils. Consumption for metallurgical uses accounted for 57 percent of the overall decrease in lime consumption (USGS 2010).

Methodology

During the calcination stage of lime production, CO₂ is given off as a gas and normally exits the system with the stack gas. To calculate emissions, the amounts of high-calcium and dolomitic lime produced were multiplied by their respective emission factors. The emission factor is the product of a constant reflecting the mass of CO₂ released per unit of lime and the average calcium plus magnesium oxide (CaO + MgO) content for lime (95 percent for both types of 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:

$$[(88.02 \text{ g/mole CO}_2) \div (96.39 \text{ g/mole CaO})] \times (0.9500 \text{ CaO/lime}) = 0.8675 \text{ g CO}_2/\text{g lime}$$

Production was adjusted to remove the mass of chemically combined water found in hydrated lime, determined according to the molecular weight ratios of H₂O to (Ca(OH)₂ and [Ca(OH)₂•Mg(OH)₂]) (IPCC 2000). 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.

Lime emission estimates were multiplied by a factor of 1.02 to account for lime kiln dust (LKD), which is produced as a by-product during the production of lime (IPCC 2006).

Lime emission estimates were further adjusted to account for PCC producers and sugar refineries that recover CO₂ emitted by lime production facilities for use as an input into production or refining processes. For CO₂ recovery by sugar refineries, lime consumption estimates from USGS were multiplied by a CO₂ recovery factor to determine the total amount of CO₂ recovered from lime production facilities. According to industry surveys, sugar refineries use captured CO₂ for 100 percent of their CO₂ input (Lutter 2009). CO₂ recovery by PCC producers was determined by multiplying estimates for the percentage CO₂ of production weight for PCC production at lime plants by a CO₂ recovery factor based on the amount of purchased CO₂ by PCC manufacturers (Prillaman 2008 through 2010). As data were only available starting in 2007, CO₂ recovery for the period 1990 through 2006 was extrapolated by determining a ratio of PCC production at lime facilities to lime consumption for PCC (USGS 1992 through 2008).

Lime production data (high-calcium- and dolomitic-quicklime, high-calcium- and dolomitic-hydrated, and dead-burned dolomite) for 1990 through 2009 (see Table 4-8) were obtained from USGS (1992 through 2010). Natural

hydraulic lime, which is produced from CaO and hydraulic calcium silicates, is not produced in the United States (USGS 2009). 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 2000). 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) was 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 (Gg)

Year	High-Calcium Quicklime	Dolomitic Quicklime	High-Calcium Hydrated	Dolomitic Hydrated	Dead-Burned Dolomite
1990	11,166	2,234	1,781	319	342
2000	14,300	3,000	1,550	421	200
2005	14,100	2,990	2,220	474	200
2006	15,000	2,950	2,370	409	200
2007	14,700	2,700	2,240	352	200
2008	14,900	2,310	2,070	358	200
2009	11,800	1,830	1,690	261	200

Table 4-9: Adjusted Lime Production^a (Gg)

Year	High-Calcium	Dolomitic
1990	12,514	2,809
2000	15,473	3,506
2005	15,781	3,535
2006	16,794	3,448
2007	16,396	3,156
2008	16,467	2,771
2009	13,079	2,220

^a 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 these products and recovery rates for sugar refineries and PCC manufacturers located at lime plants. 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 CO₂ emitted during lime production will actually be reabsorbed when the lime is consumed. As noted above, lime has many different chemical, industrial, environmental, and construction applications. In many processes, CO₂ reacts with the lime to create calcium carbonate (e.g., water softening). CO₂ reabsorption rates vary, however, depending on the application. For example, 100 percent of the lime used to produce precipitated calcium carbonate reacts with CO₂; whereas most of the lime used in steel making reacts with impurities such as silica, sulfur, and aluminum compounds. A detailed accounting of lime use in the United States and further research into the associated processes are required to quantify the amount of CO₂ that is reabsorbed.¹⁰⁷

In some cases, lime is generated from calcium carbonate by-products at pulp mills and water treatment plants.¹⁰⁸

¹⁰⁷ Representatives of the National Lime Association estimate that CO₂ reabsorption that occurs from the use of lime may offset as much as a quarter of the CO₂ emissions from calcination (Males 2003).

¹⁰⁸ Some carbide producers may also regenerate lime from their calcium hydroxide by-products, which does not result in

The lime generated by these processes is not 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 CO₂—for reuse in the pulping process. Although this re-generation of lime could be considered a lime manufacturing process, the CO₂ 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 Chapter 7).

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.

Uncertainties also remain surrounding recovery rates used for sugar refining and PCC production. The recovery rate for sugar refineries is based on two sugar beet processing and refining facilities located in California that use 100 percent recovered CO₂ from lime plants (Lutter 2010). This analysis assumes that all sugar refineries located on-site at lime plants also use 100 percent recovered CO₂. The recovery rate for PCC producers located on-site at lime plants is based on the 2009 value for PCC manufactured at commercial lime plants, given by the National Lime Association (Prillaman 2010).

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 4-10. Lime CO₂ emissions were estimated to be between 10.4 and 12.3 Tg CO₂ Eq. at the 95 percent confidence level. This confidence level indicates a range of approximately 7 percent below and 10 percent above the emission estimate of 11.2 Tg CO₂ Eq.

Table 4-10: Tier 2 Quantitative Uncertainty Estimates for CO₂ Emissions from Lime Production (Tg CO₂ Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate ^a			
			(Tg CO ₂ Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Lime Production	CO ₂	11.2	10.4	12.3	-7%	+10%

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

No methodological or activity data changes to the time series were made to this source for the current Inventory. Details on the emission trends through time are described in more detail in the Methodology section, above.

Planned Improvements

Future improvements to the lime source category involve evaluating facility level greenhouse gas emissions data as a basis for improving emissions calculations from lime production. Beginning in 2010, all U.S. lime production facilities are required to monitor, calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. Under the program, EPA will obtain data for 2010 emissions from facilities based on use of higher tier methods and in particular assess how this data could be used to improve the overall method for calculating emissions from the U.S. lime industry, including improving emission factors for various lime types and LKD.

Future improvements to the lime source category will also involve continued research into CO₂ recovery associated with lime use during sugar refining and precipitate calcium carbonate (PCC) production. Currently, two sugar refining facilities in California have been identified to capture CO₂ produced in lime kilns located on the same site as the sugar refinery (Lutter 2010). Data on CO₂ production by these lime facilities is unavailable. Future work will

emissions of CO₂. 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) $[\text{CaC}_2 + 2\text{H}_2\text{O} \rightarrow \text{C}_2\text{H}_2 + \text{Ca}(\text{OH})_2]$, not calcium carbonate $[\text{CaCO}_3]$. Thus, the calcium hydroxide is heated in the kiln to simply expel the water $[\text{Ca}(\text{OH})_2 + \text{heat} \rightarrow \text{CaO} + \text{H}_2\text{O}]$ and no CO₂ is released.

include research to determine the number of sugar refineries that employ the carbonation technique, the percentage of these that use captured CO₂ from lime production facilities, and the amount of CO₂ recovered per unit of lime production. Future research will also aim to improve estimates of CO₂ recovered as part of the PCC production process using estimates of PCC production and CO₂ inputs rather than lime consumption by PCC facilities.

4.3. Limestone and Dolomite Use (IPCC Source Category 2A3)

Limestone (CaCO₃) and dolomite (CaCO₃MgCO₃)¹⁰⁹ are basic raw materials used by a wide variety of industries, including construction, agriculture, chemical, metallurgy, glass production, and environmental pollution control. 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. For some of these applications, limestone is heated sufficiently enough to calcine the material and generate CO₂ as a by-product. 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, or as a raw material in glass manufacturing and magnesium production.

In 2009, approximately 14,928 thousand metric tons of limestone and 3,020 thousand metric tons of dolomite were consumed for these emissive applications. Overall, usage of limestone and dolomite resulted in aggregate CO₂ emissions of 7.6 Tg CO₂ Eq. (7,649 Gg) (see Table 4-11 and Table 4-12). Overall, emissions have increased 49 percent from 1990 through 2009.

Table 4-11: CO₂ Emissions from Limestone & Dolomite Use (Tg CO₂ Eq.)

Year	Flux Stone	Glass Making	FGD	Magnesium Production	Other Miscellaneous Uses	Total
1990	2.6	0.2	1.4	0.1	0.8	5.1
2000	2.1	0.4	1.8	0.1	0.7	5.1
2005	2.7	0.4	3.0	0.0	0.7	6.8
2006	4.5	0.7	2.1	0.0	0.7	8.0
2007	2.0	0.3	3.2	0.0	2.2	7.7
2008	1.0	0.4	3.8	0.0	1.1	6.3
2009	1.8	0.1	5.4	0.0	0.4	7.6

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 4-12: CO₂ Emissions from Limestone & Dolomite Use (Gg)

Year	Flux Stone	Glass Making	FGD	Magnesium Production	Other Miscellaneous Uses	Total
1990	2,593	217	1,433	64	819	5,127
2000	2,104	371	1,787	73	722	5,056
2005	2,650	425	2,975	0	718	6,768
2006	4,492	747	2,061	0	735	8,035
2007	1,959	333	3,179	0	2,231	7,702
2008	974	387	3,801	0	1,114	6,276
2009	1,785	61	5,406	0	396	7,649

Methodology

CO₂ emissions were calculated by multiplying the quantity of limestone or dolomite consumed by the average C

¹⁰⁹ Limestone and dolomite are collectively referred to as limestone by the industry, and intermediate varieties are seldom distinguished.

content, 12.0 percent for limestone and 13.0 percent for dolomite (based on stoichiometry), and converting this value to CO₂. This methodology was used for flux stone, glass manufacturing, flue gas desulfurization systems, chemical stone, mine dusting or acid water treatment, acid neutralization, and sugar refining and then converting to CO₂ using a molecular weight ratio. Flux stone used during the production of iron and steel was deducted from the Limestone and Dolomite Use estimate and attributed to the Iron and Steel Production estimate.

Traditionally, the production of magnesium metal was the only other significant use of limestone and dolomite that produced CO₂ emissions. At the start of 2001, there were two magnesium production plants operating in the United States and they used different production methods. One plant produced magnesium metal using a dolomitic process that resulted in the release of CO₂ emissions, while the other plant produced magnesium from magnesium chloride using a CO₂-emissions-free process called electrolytic reduction. However, the plant utilizing the dolomitic process ceased its operations prior to the end of 2001, so beginning in 2002 there were no emissions from this particular sub-use.

Consumption data for 1990 through 2008 of limestone and dolomite used for flux stone, glass manufacturing, flue gas desulfurization systems, chemical stone, mine dusting or acid water treatment, acid neutralization, and sugar refining (see Table 4-13) were obtained from the USGS *Minerals Yearbook: Crushed Stone Annual Report* (1995 through 2010a) and the U.S. Bureau of Mines (1991 & 1993a). Consumption data for 2009 were obtained from personal communication with the USGS crushed stone commodity specialist (Willett 2010). The production capacity data for 1990 through 2009 of dolomitic magnesium metal also came from the USGS (1995 through 2010b) and the U.S. Bureau of Mines (1990 through 1993b). The last plant in the United States that used the dolomitic production process for magnesium metal closed in 2001. The USGS does not mention this process in the *Minerals Yearbook: Magnesium*; therefore, it is assumed that this process continues to be non-existent in the United States (USGS 2010b). 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 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 uses fraction of total consumption in that year.¹¹⁰

Table 4-13: Limestone and Dolomite Consumption (Thousand Metric Tons)

Activity	1990	2000	2005	2006	2007	2008	2009
Flux Stone	6,737	6,283	7,022	11,030	5,305	3,253	4,623
Limestone	5,804	4,151	3,165	5,208	3,477	1,970	1,631
Dolomite	933	2,132	3,857	5,822	1,827	1,283	2,992
Glass Making	489	843	962	1,693	757	879	139
Limestone	430	843	920	1,629	757	879	139
Dolomite	59	0	43	64	0	0	0
FGD	3,258	4,061	6,761	4,683	7,225	8,639	12,288
Other Miscellaneous Uses	1,835	1,640	1,632	1,671	5,057	2,531	898
Total	12,319	12,826	16,377	19,078	18,344	15,302	17,948

Notes: "Other miscellaneous uses" includes chemical stone, mine dusting or acid water treatment, acid neutralization, and sugar refining. Zero values for limestone and dolomite consumption for glass making result during years when the USGS reports that no limestone or dolomite are consumed for this use.

¹¹⁰This approach was recommended by USGS.

Uncertainty and Time Series Consistency

The uncertainty levels presented in this section arise 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. Similarly, the quality of the limestone used for glass manufacturing will depend on the type of glass being manufactured.

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 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. The uncertainty of the estimates for limestone 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.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 4-14. Limestone and Dolomite Use CO₂ emissions were estimated to be between 6.6 and 9.1 Tg CO₂ Eq. at the 95 percent confidence level. This indicates a range of approximately 13 percent below and 19 percent above the emission estimate of 7.6 Tg CO₂ Eq.

Table 4-14: Tier 2 Quantitative Uncertainty Estimates for CO₂ Emissions from Limestone and Dolomite Use (Tg CO₂ Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate ^a			
			(Tg CO ₂ Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Limestone and Dolomite Use	CO ₂	7.6	6.6	9.1	-13%	+19%

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

Planned Improvements

Future improvements to the limestone and dolomite source category involve research into the availability of limestone and dolomite end-use data, including from EPA’s new Greenhouse Gas Reporting Program. If sufficient data are available, limestone and dolomite used as process materials in source categories included in future inventories (e.g., glass production, other process use of carbonates) may be removed from this section and will be reported under the appropriate source categories. Additionally, future improvements include revisiting the methodology to distribute withheld data across emissive end-uses for all years to improve consistency of calculations.

4.4. Soda Ash Production and Consumption (IPCC Source Category 2A4)

Soda ash (sodium carbonate, Na₂CO₃) 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. It is used primarily as an alkali, either in glass manufacturing or simply as a material that reacts with and neutralizes acids or acidic substances. 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.

Only two states produce natural soda ash: Wyoming and California. Of these two states, only net emissions of CO₂

from Wyoming were calculated due to specifics regarding the production processes employed in the state.¹¹¹ During the production process used in Wyoming, trona ore is calcined to produce crude soda ash. CO₂ is generated as a by-product of this reaction, and is eventually emitted into the atmosphere. In addition, CO₂ may also be released when soda ash is consumed.

In 2009, CO₂ emissions from the production of soda ash from trona were approximately 1.7 Tg CO₂ Eq. (1,733 Gg). Soda ash consumption in the United States generated 2.5 Tg CO₂ Eq. (2,532 Gg) in 2009. Total emissions from soda ash production and consumption in 2009 were 4.3 Tg CO₂ Eq. (4,265 Gg) (see Table 4-15 and Table 4-16). Emissions have remained relatively constant with some fluctuations since 1990. These fluctuations were strongly related to the behavior of the export market and the U.S. economy. Emissions from the production of soda ash from trona in 2009 are currently proxied to emissions in 2008, due to lack of available data at time of publication. Emissions in 2009 increased by approximately 4 percent from emissions in 2008, and have also increased overall by 3 percent since 1990.

Table 4-15: CO₂ Emissions from Soda Ash Production and Consumption (Tg CO₂ Eq.)

Year	Production	Consumption	Total
1990	1.4	2.7	4.1
2000	1.5	2.7	4.2
2005	1.7	2.6	4.2
2006	1.6	2.5	4.2
2007	1.7	2.5	4.1
2008	1.7	2.4	4.1
2009	1.7	2.5	4.3

Note: Totals may not sum due to independent rounding.

Table 4-16: CO₂ Emissions from Soda Ash Production and Consumption (Gg)

Year	Production	Consumption	Total
1990	1,431	2,710	4,141
2000	1,529	2,652	4,181
2005	1,655	2,573	4,228
2006	1,626	2,536	4,162
2007	1,675	2,465	4,140
2008	1,733	2,378	4,111
2009	1,733	2,532	4,265

Note: Totals may not sum due to independent rounding.

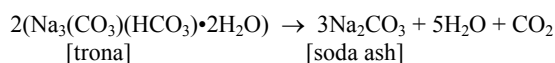
The United States represents about one-fourth of total world soda ash output. Based on final 2007 reported data, the estimated distribution of soda ash by end-use in 2008 was glass making, 49 percent; chemical production, 30 percent; soap and detergent manufacturing, 8 percent; distributors, 5 percent; flue gas desulfurization, 2 percent; water treatment, 2 percent; pulp and paper production, 2 percent; and miscellaneous, 3 percent (USGS 2009). The same distribution by end-use is currently assumed for 2009, due to lack of available data at time of publication.

¹¹¹ 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 CO₂ 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 CO₂ is generated as a by-product, the CO₂ 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, NaHCO₃ was produced using soda ash feedstocks mined in Wyoming and shipped to Colorado. Because the trona is 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.

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. While Chinese soda ash production appears to be stabilizing, U.S. competition in Asian markets is expected to continue. Despite this competition, U.S. soda ash production is expected to increase by about 0.5 percent annually (USGS 2008).

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. CO₂ and water are generated as by-products of the calcination process. CO₂ emissions from the calcination of trona can be estimated based on the following chemical reaction:



Based on this formula, approximately 10.27 metric tons of trona are required to generate one metric ton of CO₂, or an emission factor of 0.097 metric tons CO₂ per metric ton trona (IPCC 2006). Thus, the 17.8 million metric tons of trona mined in 2008 for soda ash production (USGS 2008) resulted in CO₂ emissions of approximately 1.7 Tg CO₂ Eq. (1,733 Gg). The same production and associated emissions estimates are assumed for 2009 due to lack of available data at time of publication.

Once produced, most soda ash is consumed in glass and chemical production, with minor amounts in soap and detergents, pulp and paper, flue gas desulfurization and water treatment. As soda ash is consumed for these purposes, additional CO₂ is usually emitted. In these applications, it is assumed that one mole of C is released for every mole of soda ash used. Thus, approximately 0.113 metric tons of C (or 0.415 metric tons of CO₂) are released for every metric ton of soda ash consumed.

The activity data for trona production and soda ash consumption (see Table 4-17) were taken from USGS (1994 through 2008). Data for soda ash consumption in 2009 was taken from USGS (2010) *Mineral Commodity Summary: Soda Ash*. Due to lack of 2009 trona production data at time of publication, the 2008 estimate is used as a proxy for 2009. Soda ash production and consumption data were collected by the USGS from voluntary surveys of the U.S. soda ash industry.

Table 4-17: Soda Ash Production and Consumption (Gg)

Year	Production*	Consumption
1990	14,700	6,530
2000	15,700	6,390
2005	17,000	6,200
2006	16,700	6,110
2007	17,200	5,940
2008	17,800	5,730
2009	17,800	6,100

* Soda ash produced from trona ore only.

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. 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 information characterizing the emissions from each end-use is limited. Therefore, there is uncertainty surrounding the emission factors from the consumption of soda ash.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 4-18. Soda Ash Production and Consumption CO₂ emissions were estimated to be between 4.0 and 4.6 Tg CO₂ Eq. at the 95 percent confidence level. This indicates a range of approximately 7 percent below and 7 percent above the emission estimate of 4.3 Tg CO₂ Eq.

Table 4-18: Tier 2 Quantitative Uncertainty Estimates for CO₂ Emissions from Soda Ash Production and Consumption (Tg CO₂ Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate ^a			
			(Tg CO ₂ Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Soda Ash Production and Consumption	CO ₂	4.3	4.0	4.6	-7%	+7%

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

Planned Improvements

Future inventories are anticipated to estimate emissions from glass production and other use of carbonates. These inventories will extract soda ash consumed for glass production and other use of carbonates from the current soda ash consumption emission estimates and include them under those sources.

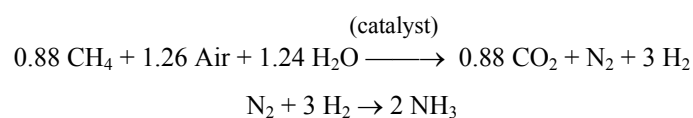
In addition, future improvements to the soda ash production category involve evaluating facility level greenhouse gas emissions data as a basis for improving emissions calculations from soda ash production. Beginning in 2010, all U.S. soda ash production facilities are required to monitor, calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. Under the program, EPA will obtain data for 2010 emissions from facilities based on use of higher tier methods and in particular assess how this data could be used to improve the overall method for calculating emissions from the U.S. soda ash production industry, including also improving emission factors associated with trona consumption.

4.5. Ammonia Production (IPCC Source Category 2B1) and Urea Consumption

Emissions of CO₂ occur during the production of synthetic ammonia, primarily through the use of natural gas as a feedstock. The natural gas-based, naphtha-based, and petroleum coke-based processes produce CO₂ and hydrogen (H₂), the latter of which is used in the production of ammonia. One N production plant located in Kansas is producing ammonia from petroleum coke feedstock. In some plants the CO₂ produced is captured and used to produce urea. The brine electrolysis process for production of ammonia does not lead to process-based CO₂ emissions.

There are five principal process steps in synthetic ammonia production from natural gas feedstock. The primary reforming step converts CH₄ to CO₂, carbon monoxide (CO), and H₂ in the presence of a catalyst. Only 30 to 40 percent of the CH₄ feedstock to the primary reformer is converted to CO and CO₂. The secondary reforming step converts the remaining CH₄ feedstock to CO and CO₂. The CO in the process gas from the secondary reforming step (representing approximately 15 percent of the process gas) is converted to CO₂ in the presence of a catalyst, water, and air in the shift conversion step. CO₂ is removed from the process gas by the shift conversion process, and the hydrogen gas is combined with the nitrogen (N₂) gas in the process gas during the ammonia synthesis step to produce ammonia. The CO₂ is included in a waste gas stream with other process impurities and is absorbed by a scrubber solution. In regenerating the scrubber solution, CO₂ is released.

The conversion process for conventional steam reforming of CH₄, including primary and secondary reforming and the shift conversion processes, is approximately as follows:



To produce synthetic ammonia from petroleum coke, the petroleum coke is gasified and converted to CO₂ and H₂. These gases are separated, and the H₂ is used as a feedstock to the ammonia production process, where it is reacted with N₂ to form ammonia.

Not all of the CO₂ produced in the production of ammonia is emitted directly to the atmosphere. Both ammonia and CO₂ are used as raw materials in the production of urea [CO(NH₂)₂], which is another type of nitrogenous fertilizer that contains C as well as N. The chemical reaction that produces urea is:



Urea is consumed for a variety of uses, including as a nitrogenous fertilizer, in urea-formaldehyde resins, and as a deicing agent (TIG 2002). The C in the consumed urea is assumed to be released into the environment as CO₂ during use. Therefore, the CO₂ produced by ammonia production that is subsequently used in the production of urea is still emitted during urea consumption. The majority of CO₂ emissions associated with urea consumption are those that result from its use as a fertilizer. These emissions are accounted for in the Cropland Remaining Cropland section of the Land Use, Land-Use Change, and Forestry chapter. CO₂ emissions associated with other uses of urea are accounted for in this chapter. Net emissions of CO₂ from ammonia production in 2009 were 11.8 Tg CO₂ Eq. (11,797 Gg), and are summarized in Table 4-19 and Table 4-20. Emissions of CO₂ from urea consumed for non-fertilizer purposes in 2009 totaled 3.9 Tg CO₂ Eq. (3,942 Gg), and are summarized in Table 4-19 and Table 4-20. The decrease in ammonia production in recent years is due to several factors, including market fluctuations and high natural gas prices. Ammonia production relies on natural gas as both a feedstock and a fuel, and as such, domestic producers are competing with imports from countries with lower gas prices. If natural gas prices remain high, it is likely that domestically produced ammonia will continue to decrease with increasing ammonia imports (EEA 2004).

Table 4-19: CO₂ Emissions from Ammonia Production and Urea Consumption (Tg CO₂ Eq.)

Source	1990	2000	2005	2006	2007	2008	2009
Ammonia Production	13.0	12.2	9.2	8.8	9.1	7.9	7.9
Urea Consumption ^a	3.8	4.2	3.7	3.5	5.0	4.1	3.9
Total	16.8	16.4	12.8	12.3	14.0	11.9	11.8

Note: Totals may not sum due to independent rounding.

^a Urea Consumption is for non-fertilizer purposes only. Urea consumed as a fertilizer is accounted for in the Land Use, Land-Use Change, and Forestry chapter.

Table 4-20: CO₂ Emissions from Ammonia Production and Urea Consumption (Gg)

Source	1990	2000	2005	2006	2007	2008	2009
Ammonia							
Production	13,047	12,172	9,196	8,781	9,074	7,883	7,855
Urea Consumption ^a	3,784	4,231	3,653	3,519	4,963	4,066	3,942
Total	16,831	16,402	12,849	12,300	14,038	11,949	11,797

^a Urea Consumption is for non-fertilizer purposes only. Urea consumed as a fertilizer is accounted for in the Land Use, Land-Use Change, and Forestry chapter.

Methodology

The calculation methodology for non-combustion CO₂ emissions from production of nitrogenous fertilizers from natural gas feedstock is based on a CO₂ emission factor published by the European Fertilizer Manufacturers Association (EFMA). The selected EFMA factor is based on ammonia production technologies that are similar to those employed in the United States. The CO₂ emission factor (1.2 metric tons CO₂/metric ton NH₃) is applied to the percent of total annual domestic ammonia production from natural gas feedstock. Emissions from fuels consumed for energy purposes during the production of ammonia are accounted for in the Energy chapter. Emissions of CO₂ from ammonia production are then adjusted to account for the use of some of the CO₂ produced from ammonia production as a raw material in the production of urea. For each ton of urea produced, 8.8 of every 12 tons of CO₂ are consumed and 6.8 of every 12 tons of ammonia are consumed (IPCC 2006, EFMA 2000). The CO₂ emissions reported for ammonia production are therefore reduced by a factor of 0.73 multiplied by total annual domestic urea production. Total CO₂ emissions resulting from nitrogenous fertilizer production do not change as a result of this calculation, but some of the CO₂ emissions are attributed to ammonia production and some of the CO₂ emissions are attributed to urea consumption. Those CO₂ emissions that result from the use of urea as a fertilizer are accounted for in the Land Use, Land-Use Change, and Forestry chapter.

The total amount of urea consumed for non-agricultural purposes 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 and is reported in Table 4-21, from total U.S. production. Total urea production is estimated based on the

amount of urea produced plus the sum of net urea imports and exports. CO₂ emissions associated with urea that is used for non-fertilizer purposes are estimated using a factor of 0.73 tons of CO₂ per ton of urea consumed.

All 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. The CO₂ emission factor for production of ammonia from petroleum coke is based on plant specific data, wherein all C contained in the petroleum coke feedstock that is not used for urea production is assumed to be emitted to the atmosphere as CO₂ (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 CO₂ emission factor (3.57 metric tons CO₂/metric ton NH₃) is applied to the percent of total annual domestic ammonia production from petroleum coke feedstock.

The emission factor of 1.2 metric ton CO₂/metric ton NH₃ for production of ammonia from natural gas feedstock was taken from the EFMA Best Available Techniques publication, Production of Ammonia (EFMA 1995). The EFMA reported an emission factor range of 1.15 to 1.30 metric ton CO₂/metric ton NH₃, with 1.2 metric ton CO₂/metric ton NH₃ as a typical value. Technologies (e.g., catalytic reforming process) associated with this factor are found to closely resemble those employed in the U.S. for use of natural gas as a feedstock. The EFMA reference also indicates that more than 99 percent of the CH₄ feedstock to the catalytic reforming process is ultimately converted to CO₂. The emission factor of 3.57 metric ton CO₂/metric ton NH₃ for production of ammonia from petroleum coke feedstock was developed from plant-specific ammonia production data and petroleum coke feedstock utilization data for the ammonia plant located in Kansas (Bark 2004). As noted earlier, emissions from fuels consumed for energy purposes during the production of ammonia are accounted for in the Energy chapter. Ammonia production data (see Table 4-21) was obtained from Coffeyville Resources (Coffeyville 2005, 2006, 2007a, 2007b, 2009, 2010) 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 was obtained from Coffeyville Resources (Coffeyville 2005, 2006, 2007a, 2007b, 2009, 2010). Urea production data for 1990 through 2008 were obtained from the Minerals Yearbook: Nitrogen (USGS 1994 through 2009). Urea production data for 2009 was obtained from the U.S. Bureau of the Census (2010). Import data for urea were obtained from the U.S. Census Bureau Current Industrial Reports Fertilizer Materials and Related Products annual and quarterly reports for 1997 through 2009 (U.S. Census Bureau 1998 through 2010), 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 4-21). Urea export data for 1990 through 2009 were taken from U.S. Fertilizer Import/Exports from USDA Economic Research Service Data Sets (U.S. Department of Agriculture 2010).

Table 4-21: Ammonia Production, Urea Production, Urea Net Imports, and Urea Exports (Gg)

Year	Ammonia Production	Urea Production	Urea Applied as Fertilizer	Urea Imports	Urea Exports
1990	15,425	7,450	3,296	1,860	854
2000	14,342	6,910	4,382	3,904	663
2005	10,143	5,270	4,779	5,026	536
2006	9,962	5,410	4,985	5,029	656
2007	10,393	5,590	5,097	6,546	271
2008	9,570	5,240	4,925	5,459	230
2009	9,372	5,084	4,295	5,505	289

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 natural gas feedstock consumption data for the U.S. ammonia industry as a whole, 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. It is also assumed that ammonia and urea are produced at collocated plants from the

same natural gas raw material.

Such recovery may or may not affect the overall estimate of CO₂ emissions depending upon the end use to which the recovered CO₂ is applied. Further research is required to determine whether byproduct CO₂ is being recovered from other ammonia production plants for application to end uses that are not accounted for elsewhere.

Additional uncertainty is associated with the estimate of urea consumed for non-fertilizer purposes. Emissions associated with this consumption are reported in this source category, while those associated with consumption as fertilizer are reported in Cropland Remaining Cropland section of the Land Use, Land-Use Change, and Forestry chapter. The amount of urea used for non-fertilizer purposes is estimated based on estimates of urea production, net urea imports, and the amount of urea used as fertilizer. There is uncertainty associated with the accuracy of these estimates as well as the fact that each estimate is obtained from a different data source.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 4-22. Ammonia Production and Urea Consumption CO₂ emissions were estimated to be between 10.9 and 12.7 Tg CO₂ Eq. at the 95 percent confidence level. This indicates a range of approximately 7 percent below and 8 percent above the emission estimate of 11.8 Tg CO₂ Eq.

Table 4-22: Tier 2 Quantitative Uncertainty Estimates for CO₂ Emissions from Ammonia Production and Urea Consumption (Tg CO₂ Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate ^a			
			(Tg CO ₂ Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Ammonia Production and Urea Consumption	CO ₂	11.8	10.9	12.7	-7%	+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 time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

Recalculations Discussion

The uncertainty range (-7 percent/+8 percent) has decreased by 7 percent compared to the uncertainty range in the previous Inventory (±11 percent), due to two stoichiometric variables being removed from the uncertainty analysis.

Planned Improvements

Future improvements to the ammonia production and urea consumption category involve evaluating facility level greenhouse gas emissions data as a basis for improving emissions calculations from ammonia production. Beginning in 2010, all U.S. ammonia production facilities are required to monitor, calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. Under the program, EPA will obtain data for 2010 emissions from facilities based on use of higher tier methods and in particular assess how this data could be used to improve the overall method for calculating emissions from U.S. ammonia production. Specifically, the planned improvements include assessing data to update the emission factors to include both fuel and feedstock CO₂ emissions and incorporate CO₂ 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. Additional efforts will be made to find consistent data sources for urea consumption and to report emissions from this consumption appropriately as defined.

4.6. Nitric Acid Production (IPCC Source Category 2B2)

Nitric acid (HNO₃) is 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 catalytic oxidation of ammonia (EPA 1997). During this reaction, N₂O is formed as a by-product and is released from reactor vents into the atmosphere.

Currently, the nitric acid industry controls for emissions of NO and NO₂ (i.e., NO_x). As such, the industry in the US 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 N₂O. However, NSCR units are generally not preferred in modern plants because of high energy costs and associated high gas temperatures. NSCRs were widely installed in nitric plants built between 1971 and 1977. Approximately 25 percent of nitric acid plants use NSCR and they represent 15.3 percent of estimated national production (EPA 2010a). The remaining 84.7 percent of production occurs using SCR or extended absorption, neither of which is known to reduce N₂O emissions.

N₂O emissions from this source were estimated to be 14.6 Tg CO₂ Eq. (47 Gg) in 2009 (see Table 4-23). Emissions from nitric acid production have decreased by 18 percent since 1990, with the trend in the time series closely tracking the changes in production. Emissions decreased 11.4 percent between 2008 and 2009. Emissions have decreased by 30.8 percent since 1997, the highest year of production in the time series.

Table 4-23: N₂O Emissions from Nitric Acid Production (Tg CO₂ Eq. and Gg)

Year	Tg CO ₂ Eq.	Gg
1990	17.7	57
2000	19.4	63
2005	16.5	53
2006	16.2	52
2007	19.2	62
2008	16.4	53
2009	14.6	47

Methodology

N₂O emissions were calculated by multiplying nitric acid production by the amount of N₂O emitted per unit of nitric acid produced. The emission factor was determined as a weighted average of two known emission factors: 2 kg N₂O/metric ton HNO₃ produced at plants using non-selective catalytic reduction (NSCR) systems and 9 kg N₂O/metric ton HNO₃ produced at plants not equipped with NSCR (IPCC 2006). In the process of destroying NO_x, NSCR systems destroy 80 to 90 percent of the N₂O, which is accounted for in the emission factor of 2 kg N₂O/metric ton HNO₃. Approximately 25 percent of HNO₃ plants in the United States are equipped with NSCR representing 15.3 percent of estimated national production (EPA 2010a). Hence, the emission factor is equal to $(9 \times 0.847) + (2 \times 0.153) = 7.9$ kg N₂O per metric ton HNO₃.

Nitric acid production data for 1990 through 2002 were obtained from the U.S. Census Bureau, Current Industrial Reports (2006). Production data for 2003 were obtained from the U.S. Census Bureau, Current Industrial Reports (2008). Production data for 2004 through 2009 were obtained from the U.S. Census Bureau, Current Industrial Reports (2010) (see Table 4-24).

Table 4-24: Nitric Acid Production (Gg)

Year	Gg
1990	7,195
2000	7,900
2005	6,711
2006	6,572
2007	7,827
2008	6,686
2009	5,924

Uncertainty and Time-Series Consistency

The overall uncertainty associated with the 2009 N₂O emissions estimate from nitric acid production was calculated using the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006) Tier 2 methodology.

Uncertainty associated with the parameters used to estimate N₂O emissions included that of production data, the share of U.S. nitric acid production attributable to each emission abatement technology over the time series, and the emission factors applied to each abatement technology type.

The results of this Tier 2 quantitative uncertainty analysis are summarized in Table 4-25. N₂O emissions from nitric acid production were estimated to be between 8.8 and 20.7 Tg CO₂ Eq. at the 95 percent confidence level. This indicates a range of approximately 40 percent below to 42 percent above the 2009 emissions estimate of 14.6 Tg CO₂ Eq.

Table 4-25: Tier 2 Quantitative Uncertainty Estimates for N₂O Emissions from Nitric Acid Production (Tg CO₂ Eq. and Percent)

Source	Gas	2009 Emission	Uncertainty Range Relative to Emission Estimate ^a			
		Estimate	(Tg CO ₂ Eq.)		(%)	
		(Tg CO ₂ Eq.)	Lower Bound	Upper Bound	Lower Bound	Upper Bound
Nitric Acid Production	N ₂ O	14.6	8.8	20.7	-40%	+42%

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

Planned Improvements

Future improvements to the nitric acid production category involve evaluating facility level greenhouse gas emissions data as a basis for improving emissions calculations from nitric acid production. Beginning in 2010, all U.S. nitric acid production facilities are required to monitor, calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. Under the program, EPA will obtain data for 2010 emissions from facilities based on use of higher tier methods and in particular assess how this data could be used to improve the overall method for calculating emissions from U.S. nitric acid production. Specifically, the planned improvements include assessing data to update the N₂O emission factors, abatement utilization and destruction factors, and the current share of nitric acid production attributable to various abatement technologies.

Recalculations Discussion

Historical estimates for N₂O emissions from nitric acid production have been revised relative to the previous Inventory based on updated information from EPA (2010) on abatement technologies in use and based on revised production data published by the U.S. Census Bureau (2010). The previous Inventory assumed that approximately 17 percent of facilities accounting for less than 8 percent of national production were equipped with NSCR systems (EPA 2010b). The current Inventory assumes that approximately 25 percent of facilities, accounting for roughly 15 percent of national production, were equipped with NSCR systems (EPA 2010a). This change resulted in a decrease in the weighted average emission factor of 0.6 kg N₂O/metric ton HNO₃ (6.3 percent). Additionally, national nitric acid production values for 1991, 1993-1995, 1997-1999, 2002, and 2008 have been updated relative to the previous Inventory (US Census Bureau 2009, 2010). Revised production in 2008 contributed to an overall decrease in emissions of 2.6 Tg CO₂ Eq. (13.6 percent) in that year; revised production in the other historical years had a negligible impact on emissions. Overall, changes relative to the previous Inventory resulted in an average annual decrease in emissions of 1.3 Tg CO₂ Eq. (6.7 percent) for the period 1990 through 2008.

4.7. Adipic Acid Production (IPCC Source Category 2B3)

Adipic acid production is an anthropogenic source of N₂O emissions. Worldwide, few adipic acid plants exist. The United States and Europe are the major producers. In 2009, the United States had two companies with a total of three adipic acid processes, two of which were operational (CW 2007; Desai 2010; VA DEQ 2009). 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.

84 percent of all adipic acid produced in the United States is used in the production of nylon 6,6; nine percent is used in the production of polyester polyols; four percent is used in the production of plasticizers; and the remaining four 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).

Adipic acid is produced through a two-stage process during which N₂O is generated in the second stage. 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. N₂O is generated as a by-product of the nitric acid oxidation stage and is emitted in the waste gas stream (Thiemens and Trogler 1991). 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 of the three major adipic acid-producing plants had N₂O abatement technologies in place and, as of 1998, the 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 N₂O (VA DEQ 2009; ICIS 2007; VA DEQ 2006).

N₂O emissions from adipic acid production were estimated to be 1.9 Tg CO₂ Eq. (6 Gg) in 2009 (see Table 4-26). National adipic acid production has increased by approximately 11 percent over the period of 1990 through 2009, to roughly 820,000 metric tons. Over the same period, emissions have been reduced by 88 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 (Desai 2010).

Table 4-26: N₂O Emissions from Adipic Acid Production (Tg CO₂ Eq. and Gg)

Year	Tg CO ₂ Eq.	Gg
1990	15.8	51
2000	5.5	18
2005	5.0	16
2006	4.3	14
2007	3.7	12
2008	2.0	7
2009	1.9	6

Methodology

Due to confidential business information, plant names are not provided in this section. The four adipic acid-producing plants will henceforth be referred to as Plants 1 through 4.

For 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 (Desai 2010). These estimates were based on continuous emissions monitoring equipment installed at the two facilities. In 2009, no Adipic acid production occurred at Plant 1. For Plants 3 and 4, N₂O emissions were calculated by multiplying adipic acid production by an emission factor (i.e., N₂O emitted per unit of adipic acid produced) and adjusting for the percentage of N₂O released as a result of plant-specific emission controls. On the basis of experiments, the overall reaction stoichiometry for N₂O production in the preparation of adipic acid was estimated at approximately 0.3 metric tons of N₂O per metric ton of product (IPCC 2006). Emissions are estimated using the following equation:

$$\text{N}_2\text{O emissions} = (\text{production of adipic acid [metric tons \{MT\} of adipic acid]}) \times (0.3 \text{ MT N}_2\text{O} / \text{MT adipic acid}) \times (1 - [\text{N}_2\text{O destruction factor} \times \text{abatement system utility factor}])$$

The “N₂O destruction factor” represents the percentage of N₂O 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. Overall, in the United States, two of the plants employ catalytic destruction (Plants 1 and 2), one plant employs thermal destruction (Plant 3), and the smallest plant used no N₂O abatement equipment (Plant 4). For Plant 3, which uses thermal destruction and for which no reported plant-specific emissions are available, the N₂O abatement system destruction factor is assumed to be 98.5 percent, and the abatement system utility factor is assumed to be 97 percent (IPCC 2006).

From 1990 to 2003, plant-specific production data were estimated for Plant 3 where direct emission measurements were not available. In order to calculate plant-specific production for this plant, national adipic acid production was allocated to the plant level using the ratio of known plant capacity to total national capacity for all U.S. plants. The estimated plant production for this plant was then used for calculating emissions as described above. For 2004 and 2006, actual plant production data were obtained and used for emission calculations (CW 2007; CW 2005). For 2005, interpolated national production was used for calculating emissions. Updated production data were not available for Plant 3 for 2007 through 2009; therefore, production values for 2007 through 2009 were proxied using 2006 data.

For Plant 4, which last operated in April 2006 (VA DEQ 2009), plant-specific production data were obtained across the time series from 1990 through 2008 (VA DEQ 2010). Since the plant has not operated since 2006, production in 2009 is assumed to be equal to the 2008 estimate, which was zero. The plant-specific production data were then used for calculating emissions as described above.

National adipic acid production data (see Table 4-27) from 1990 through 2009 were obtained from the American Chemistry Council (ACC 2010).

Plant capacities for 1990 through 1994 were obtained from Chemical and 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 2005, the plant capacities for three plants were kept the same as the year 2000 capacities. Plant capacity for 1999 to 2005 for the one remaining plant was kept the same as 1998. For 2004 to 2009, although some plant capacity data are available (CW 1999, CMR 2001, ICIS 2007), they are not used to calculate plant-specific production for these years because plant-specific production data for 2004 and 2006 are also available and are used in our calculations instead (CW 2005, CW 2007).

Table 4-27: Adipic Acid Production (Gg)

Year	Gg
1990	735
2000	925
2005	903
2006	964
2007	930
2008	869
2009	819

Uncertainty and Time-Series Consistency

The overall uncertainty associated with the 2009 N₂O emission estimate from adipic acid production was calculated using the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006) Tier 2 methodology. Uncertainty associated with the parameters used to estimate N₂O emissions included that of company specific production data, emission factors for abated and unabated emissions, and company-specific historical emission estimates.

The results of this Tier 2 quantitative uncertainty analysis are summarized in Table 4-28. N₂O emissions from adipic acid production were estimated to be between 1.2 and 2.8 Tg CO₂ Eq. at the 95 percent confidence level. This indicates a range of approximately 40 percent below to 42 percent above the 2009 emission estimate of 1.9 Tg CO₂ Eq.

Table 4-28: Tier 2 Quantitative Uncertainty Estimates for N₂O Emissions from Adipic Acid Production (Tg CO₂ Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate ^a (Tg CO ₂ Eq.)	(%)
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			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Adipic Acid Production	N ₂ O	1.9	1.2	2.8	-40%	+42%

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

Recalculations

The current Inventory uses national production data from the ACC (2010) across the full time series. Previous Inventories relied upon a variety of sources and linear interpolation for missing intervening years in the national production time series. This change resulted in an average annual decrease in the national production estimate of approximately 2 percent for the period 1990 through 2008 relative to the previous Inventory. Emissions decreased by less than 0.1 percent over the same time period relative to the previous Inventory.

Planned Improvements

Future improvements to the adipic acid production category involve evaluating facility level greenhouse gas emissions data as a basis for improving emissions calculations from adipic acid production. Beginning in 2010, all U.S. adipic acid production facilities are required to monitor, calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. Under the program, EPA will obtain data for 2010 emissions from facilities based on use of higher tier methods and in particular assess how this data could be used to improve the overall method for calculating emissions from U.S. adipic acid production. Specifically, the planned improvements include assessing data to update the N₂O emission factors and update abatement utility and destruction factors based on actual performance of the latest catalytic and thermal abatement equipment at plants with continuous process and emission monitoring equipment.

4.8. Silicon Carbide Production (IPCC Source Category 2B4) and Consumption

CO₂ and CH₄ are emitted from the production¹¹² of silicon carbide (SiC), a material used as an industrial abrasive. To make SiC, quartz (SiO₂) is reacted with C in the form of petroleum coke. A portion (about 35 percent) of the C contained in the petroleum coke is retained in the SiC. The remaining C is emitted as CO₂, CH₄, or CO.

CO₂ is also emitted from the consumption of SiC for metallurgical and other non-abrasive applications. 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 2006).

CO₂ from SiC production and consumption in 2009 were 0.1 Tg CO₂ Eq. (145 Gg) (USGS 2009). Approximately 63 percent of these emissions resulted from SiC production while the remainder results from SiC consumption. CH₄ emissions from SiC production in 2009 were 0.01 Tg CO₂ Eq. CH₄ (0.4 Gg) (see Table 4-29 and Table 4-30).

Table 4-29: CO₂ and CH₄ Emissions from Silicon Carbide Production and Consumption (Tg CO₂ Eq.)

Year	1990		2000		2005	2006	2007	2008	2009
CO ₂	0.4		0.2		0.2	0.2	0.2	0.2	0.1
CH ₄	+		+		+	+	+	+	+
Total	0.4		0.3		0.2	0.2	0.2	0.2	0.2

+ Does not exceed 0.05 Tg CO₂ Eq.

Note: Totals may not sum due to independent rounding.

Table 4-30: CO₂ and CH₄ Emissions from Silicon Carbide Production and Consumption (Gg)

Year	1990		2000		2005	2006	2007	2008	2009
-------------	-------------	--	-------------	--	-------------	-------------	-------------	-------------	-------------

¹¹² Silicon carbide is produced for both abrasive and metallurgical applications in the United States. Production for metallurgical applications is not available and therefore both CH₄ and CO₂ estimates are based solely upon production estimates of silicon carbide for abrasive applications.

CO ₂	375		248		219	207	196	175	145
CH ₄	1		1		+	+	+	+	+

+ Does not exceed 0.5 Gg.

Methodology

Emissions of CO₂ and CH₄ from the production of SiC were calculated by multiplying annual SiC production by the emission factors (2.62 metric tons CO₂/metric ton SiC for CO₂ and 11.6 kg CH₄/metric ton SiC for CH₄) provided by the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006).

Emissions of CO₂ from silicon carbide consumption were 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 2009). The total SiC consumed in metallurgical and other non-abrasive uses was multiplied by the C content of SiC (31.5 percent), which was determined according to the molecular weight ratio of SiC.

Production data for 1990 through 2008 were obtained from the Minerals Yearbook: Manufactured Abrasives (USGS 1991a through 2005a, 2007, and 2009). Production data for 2009 was taken from the Minerals Commodity Summary: Abrasives (Manufactured) (USGS 2010). Silicon carbide consumption by major end use was obtained from the Minerals Yearbook: Silicon (USGS 1991b through 2005b) (see Table 4-31) for years 1990 through 2004 and from the USGS Minerals Commodity Specialist for 2005 and 2006 (Corathers 2006, 2007). Silicon carbide consumption by major end use data for 2009 is proxied using 2008 data due to unavailability of data at time of publication. Net imports for the entire time series were obtained from the U.S. Census Bureau (2005 through 2010).

Table 4-31: Production and Consumption of Silicon Carbide (Metric Tons)

Year	Production	Consumption
1990	105,000	172,465
2000	45,000	225,070
2005	35,000	220,149
2006	35,000	199,937
2007	35,000	179,741
2008	35,000	144,928
2009	35,000	92,280

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 CH₄, there is also uncertainty associated with the hydrogen-containing volatile compounds in the petroleum coke (IPCC 2006). There is also some uncertainty associated with production, net imports, and consumption data as well as the percent of total consumption that is attributed to metallurgical and other non-abrasive uses.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 4-32. Silicon carbide production and consumption CO₂ emissions were estimated to be between 9 percent below and 9 percent above the emission estimate of 0.2 Tg CO₂ Eq. at the 95 percent confidence level. Silicon carbide production CH₄ emissions were estimated to be between 9 percent below and 9 percent above the emission estimate of 0.01 Tg CO₂ Eq. at the 95 percent confidence level.

Table 4-32: Tier 2 Quantitative Uncertainty Estimates for CH₄ and CO₂ Emissions from Silicon Carbide Production and Consumption (Tg CO₂ Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate ^a			
			(Tg CO ₂ Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Silicon Carbide Production	CO ₂	0.2	0.13	0.16	-9%	+9%

and Consumption							
Silicon Carbide Production	CH ₄	+	+	+	-9%	+9%	
^a Range of emission estimates predicted by Monte Carlo Stochastic Simulation for a 95 percent confidence interval.							
+ Does not exceed 0.05 Tg CO ₂ Eq. or 0.5 Gg.							

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

Planned Improvements

Future improvements to the silicon carbide production source category include evaluating facility level greenhouse gas emissions data as a basis for improving emissions calculations from silicon carbide production. Beginning in 2010, all U.S. silicon carbide production facilities are required to monitor, calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. Under the program, EPA will obtain data for 2010 emissions from facilities based on use of higher tier methods and in particular assess how this data could be used to improve the overall method for calculating emissions from the U.S. silicon carbide production industry. 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. Additionally, as future improvement to the silicon carbide uncertainty analysis, USGS Mineral Commodity Specialists will be contacted to verify the uncertainty range associated with silicon carbide emissive utilization.

4.9. Petrochemical Production (IPCC Source Category 2B5)

The production of some petrochemicals results in the release of small amounts of CH₄ and CO₂ emissions. Petrochemicals are chemicals isolated or derived from petroleum or natural gas. CH₄ emissions are presented here from the production of carbon black, ethylene, ethylene dichloride, and methanol, while CO₂ emissions are presented here for only carbon black production. The CO₂ emissions from petrochemical processes other than carbon black are currently included in the Carbon Stored in Products from Non-Energy Uses of Fossil Fuels Section of the Energy chapter. The CO₂ from carbon black production is included here to allow for the direct reporting of CO₂ emissions from the process and direct accounting of the feedstocks used in the process.

Carbon black is an intense black powder generated by the incomplete combustion of an aromatic petroleum or coal-based feedstock. 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. Ethylene 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. Ethylene dichloride is one of the first manufactured chlorinated hydrocarbons with reported production as early as 1795. In addition to being an important intermediate in the synthesis of chlorinated hydrocarbons, ethylene dichloride is used as an industrial solvent and as a fuel additive. Methanol is an alternative transportation fuel as well as a principle ingredient in windshield wiper fluid, paints, solvents, refrigerants, and disinfectants. In addition, methanol-based acetic acid is used in making PET plastics and polyester fibers.

Emissions of CO₂ and CH₄ from petrochemical production in 2009 were 2.7 Tg CO₂ Eq. (2,735 Gg) and 0.8 Tg CO₂ Eq. (40 Gg), respectively (see Table 4-33 and Table 4-34), totaling 3.6 Tg CO₂ Eq. There has been an overall decrease in CO₂ emissions from carbon black production of 17 percent since 1990. CH₄ emissions from petrochemical production decreased by approximately two percent since 1990.

Table 4-33: CO₂ and CH₄ Emissions from Petrochemical Production (Tg CO₂ Eq.)

Year	1990	2000	2005	2006	2007	2008	2009
CO ₂	3.3	4.5	4.2	3.8	3.9	3.4	2.7
CH ₄	0.9	1.2	1.1	1.0	1.0	0.9	0.8
Total	4.2	5.7	5.3	4.8	4.9	4.4	3.6

Note: Totals may not sum due to independent rounding.

Table 4-34: CO₂ and CH₄ Emissions from Petrochemical Production (Gg)

Year	1990	2000	2005	2006	2007	2008	2009
------	------	------	------	------	------	------	------

CO ₂	3,311	4,479	4,181	3,837	3,931	3,449	2,735
CH ₄	41	59	51	48	48	43	40

Methodology

Emissions of CH₄ were calculated by multiplying annual estimates of chemical production by the appropriate emission factor, as follows: 11 kg CH₄/metric ton carbon black, 1 kg CH₄/metric ton ethylene, 0.4 kg CH₄/metric ton ethylene dichloride,¹¹³ and 2 kg CH₄/metric ton methanol. Although the production of other chemicals may also result in CH₄ emissions, insufficient data were available to estimate their emissions.

Emission factors were taken from the Revised 1996 IPCC Guidelines (IPCC/UNEP/OECD/IEA 1997). Annual production data (see Table 4-35) were obtained from the American Chemistry Council's Guide to the Business of Chemistry (ACC 2002, 2003, 2005 through 2010) and the International Carbon Black Association (Johnson 2003, 2005 through 2010). Note that 2009 production data for Methanol was not available at time of publication, as such, 2008 methanol production is used as a proxy for 2009.

Table 4-35: Production of Selected Petrochemicals (Thousand Metric Tons)

Chemical	1990	2000	2005	2006	2007	2008	2009
Carbon Black	1,307	1,769	1,651	1,515	1,552	1,362	1,080
Ethylene	16,541	24,970	23,954	25,000	25,392	22,539	22,596
Ethylene Dichloride	6,282	9,866	11,260	9,736	9,566	8,981	8,131
Methanol	3,785	5,221	2,336	1,123	1,068	1,136	1,136

Almost all carbon black in the United States is produced from petroleum-based or coal-based feedstocks using the “furnace black” process (European IPPC Bureau 2004). The furnace black process is a partial combustion process in which a portion of the carbon black feedstock is combusted to provide energy to the process. Carbon black is also produced in the United States by the thermal cracking of acetylene-containing feedstocks (“acetylene black process”) and by the thermal cracking of other hydrocarbons (“thermal black process”). One U.S. carbon black plant produces carbon black using the thermal black process, and one U.S. carbon black plant produces carbon black using the acetylene black process (The Innovation Group 2004).

The furnace black process produces carbon black from “carbon black feedstock” (also referred to as “carbon black oil”), which is a heavy aromatic oil that may be derived as a byproduct of either the petroleum refining process or the metallurgical (coal) coke production process. For the production of both petroleum-derived and coal-derived carbon black, the “primary feedstock” (i.e., carbon black feedstock) is injected into a furnace that is heated by a “secondary feedstock” (generally natural gas). Both the natural gas secondary feedstock and a portion of the carbon black feedstock are oxidized to provide heat to the production process and pyrolyze the remaining Carbon black feedstock to carbon black. The “tail gas” from the furnace black process contains CO₂, carbon monoxide, sulfur compounds, CH₄, and non-CH₄ volatile organic compounds. A portion of the tail gas is generally burned for energy recovery to heat the downstream carbon black product dryers. The remaining tail gas may also be burned for energy recovery, flared, or vented uncontrolled to the atmosphere.

The calculation of the C lost during the production process is the basis for determining the amount of CO₂ released during the process. The C content of national carbon black production is subtracted from the total amount of C contained in primary and secondary carbon black feedstock to find the amount of C lost during the production process. It is assumed that the C lost in this process is emitted to the atmosphere as either CH₄ or CO₂. The C content of the CH₄ emissions, estimated as described above, is subtracted from the total C lost in the process to calculate the amount of C emitted as CO₂. The total amount of primary and secondary carbon black feedstock consumed in the process (see Table 4-36) is estimated using a primary feedstock consumption factor and a secondary feedstock consumption factor estimated from U.S. Census Bureau (1999, 2004, and 2007) data. The average carbon black feedstock consumption factor for U.S. carbon black production is 1.69 metric tons of carbon black feedstock consumed per metric ton of carbon black produced. The average natural gas consumption factor for

¹¹³ The emission factor obtained from IPCC/UNEP/OECD/IEA (1997), page 2.23 is assumed to have a misprint; the chemical identified should be ethylene dichloride (C₂H₄Cl₂) rather than dichloroethylene (C₂H₂Cl₂).

U.S. carbon black production is 321 normal cubic meters of natural gas consumed per metric ton of carbon black produced. The amount of C contained in the primary and secondary feedstocks is calculated by applying the respective C contents of the feedstocks to the respective levels of feedstock consumption (EIA 2003, 2004).

Table 4-36: Carbon Black Feedstock (Primary Feedstock) and Natural Gas Feedstock (Secondary Feedstock) Consumption (Thousand Metric Tons)

Activity	1990	2000	2005	2006	2007	2008	2009
Primary Feedstock	2,213	2,993	2,794	2,564	2,627	2,305	1,828
Secondary Feedstock	284	384	359	329	337	296	235

For the purposes of emissions estimation, 100 percent of the primary carbon black feedstock is assumed to be derived from petroleum refining byproducts. Carbon black feedstock derived from metallurgical (coal) coke production (e.g., creosote oil) is also used for carbon black production; however, no data are available concerning the annual consumption of coal-derived carbon black feedstock. Carbon black feedstock derived from petroleum refining byproducts is assumed to be 89 percent elemental C (Srivastava et al. 1999). It is assumed that 100 percent of the tail gas produced from the carbon black production process is combusted and that none of the tail gas is vented to the atmosphere uncontrolled. The furnace black process is assumed to be the only process used for the production of carbon black because of the lack of data concerning the relatively small amount of carbon black produced using the acetylene black and thermal black processes. The carbon black produced from the furnace black process is assumed to be 97 percent elemental C (Othmer et al. 1992).

Uncertainty and Time-Series Consistency

The CH₄ emission factors used for petrochemical production are based on a limited number of studies. Using plant-specific factors instead of average factors could increase the accuracy of the emission estimates; however, such data were not available. There may also be other significant sources of CH₄ arising from petrochemical production activities that have not been included in these estimates.

The results of the quantitative uncertainty analysis for the CO₂ emissions from carbon black production calculation are based on feedstock consumption, import and export data, and carbon black production data. The composition of carbon black feedstock varies depending upon the specific refinery production process, and therefore the assumption that carbon black feedstock is 89 percent C gives rise to uncertainty. Also, no data are available concerning the consumption of coal-derived carbon black feedstock, so CO₂ emissions from the utilization of coal-based feedstock are not included in the emission estimate. In addition, other data sources indicate that the amount of petroleum-based feedstock used in carbon black production may be underreported by the U.S. Census Bureau. Finally, the amount of carbon black produced from the thermal black process and acetylene black process, although estimated to be a small percentage of the total production, is not known. Therefore, there is some uncertainty associated with the assumption that all of the carbon black is produced using the furnace black process.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 4-37. Petrochemical production CO₂ emissions were estimated to be between 2.0 and 3.6 Tg CO₂ Eq. at the 95 percent confidence level. This indicates a range of approximately 27 percent below to 31 percent above the emission estimate of 2.7 Tg CO₂ Eq. Petrochemical production CH₄ emissions were estimated to be between 0.6 and 1.1 Tg CO₂ Eq. at the 95 percent confidence level. This indicates a range of approximately 26 percent below to 27 percent above the emission estimate of 0.8 Tg CO₂ Eq.

Table 4-37: Tier 2 Quantitative Uncertainty Estimates for CH₄ Emissions from Petrochemical Production and CO₂ Emissions from Carbon Black Production (Tg CO₂ Eq. and Percent)

Source	Gas	2009 Emission			
		Estimate (Tg CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate ^a		
			(Tg CO ₂ Eq.)	(%)	
			Lower Bound	Upper Bound	Lower Bound Upper Bound
Petrochemical Production	CO ₂	2.7	2.0	3.6	-27% +31%
Petrochemical Production	CH ₄	0.8	0.6	1.1	-26% +27%

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

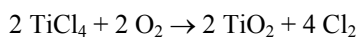
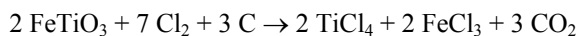
Planned Improvements

Future improvements to the petrochemicals source category involve updating the methodology to use CH₄ emission factors for petrochemical production from the IPCC 2006 guidelines rather than the IPCC 1996 guidelines. Further future improvements involve evaluating facility level greenhouse gas emissions data as a basis for improving emissions calculations from petrochemical production. Beginning in 2010, all U.S. petrochemical production facilities are required to monitor, calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. Under the program, EPA will obtain data for 2010 emissions from facilities based on use of higher tier methods and in particular assess how this data could be used to improve the overall method for calculating emissions from the U.S. petrochemical production industry, for example using a Tier 2 methodology to calculate emissions from the production of methanol, ethylene, propylene, ethylene dichloride, and ethylene oxide. In addition, the planned improvements include assessing the data EPA obtains to update data sources for acrylonitrile production in the United States.

4.10. Titanium Dioxide Production (IPCC Source Category 2B5)

Titanium dioxide (TiO₂) is a metal oxide manufactured from titanium ore, and is principally used as a pigment. Titanium dioxide is a principal ingredient in white paint, and is also used as a pigment in the manufacture of white paper, foods, and other products. There are two processes for making TiO₂: the chloride process and the sulfate process. The chloride process uses petroleum coke and chlorine as raw materials and emits process-related CO₂. The sulfate process does not use petroleum coke or other forms of C as a raw material and does not emit CO₂.

The chloride process is based on the following chemical reactions:



The C in the first chemical reaction is provided by petroleum coke, which is oxidized in the presence of the chlorine and FeTiO₃ (the Ti-containing ore) to form CO₂. The majority of U.S. TiO₂ was produced in the United States through the chloride process, and a special grade of “calcined” petroleum coke is manufactured specifically for this purpose.

Emissions of CO₂ in 2009 were 1.5 Tg CO₂ Eq. (1,541 Gg), which represents an increase of 29 percent since 1990 (see Table 4-38).

Table 4-38: CO₂ Emissions from Titanium Dioxide (Tg CO₂ Eq. and Gg)

Year	Tg CO ₂ Eq.	Gg
1990	1.2	1,195
2000	1.8	1,752
2005	1.8	1,755
2006	1.8	1,836
2007	1.9	1,930
2008	1.8	1,809
2009	1.5	1,541

Methodology

Emissions of CO₂ from TiO₂ production were calculated by multiplying annual TiO₂ production by chloride-process-specific emission factors.

Data were obtained for the total amount of TiO₂ produced each year. For years previous to 2004, it was assumed that TiO₂ 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

had closed; therefore, 100 percent of post-2004 production uses the chloride process (USGS 2005). An emission factor of 0.4 metric tons C/metric ton TiO₂ was applied to the estimated chloride-process production. It was assumed that all TiO₂ produced using the chloride process was produced using petroleum coke, although some TiO₂ may have been produced with graphite or other C inputs. The amount of petroleum coke consumed annually in TiO₂ production was calculated based on the assumption that the calcined petroleum coke used in the process is 98.4 percent C and 1.6 percent inert materials (Nelson 1969).

The emission factor for the TiO₂ chloride process was taken from the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006). Titanium dioxide production data and the percentage of total TiO₂ production capacity that is chloride process for 1990 through 2008 (see Table 4-39) were obtained through the Minerals Yearbook: Titanium Annual Report (USGS 1991 through 2008). Production data in 2009 was obtained from the Minerals Commodity Summary: Titanium and Titanium Dioxide (USGS 2010). Due to lack of available 2009 capacity data at the time of publication, the 2008 capacity estimate is used as a proxy for 2009. Percentage chloride-process data were not available for 1990 through 1993, and 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 plant remained online in the United States and this plant closed in 2004 (USGS 2005).

Table 4-39: Titanium Dioxide Production (Gg)

Year	Gg
1990	979
2000	1,400
2005	1,310
2006	1,370
2007	1,440
2008	1,350
2009	1,150

Uncertainty and Time-Series Consistency

Although some TiO₂ may be produced using graphite or other C inputs, information and data regarding these practices were not available. Titanium dioxide produced using graphite inputs, for example, may generate differing amounts of CO₂ per unit of TiO₂ 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 TiO₂ produced, sufficient data were not available to do so.

Also, annual TiO₂ is not reported by USGS by the type of production process used (chloride or sulfate). Only the percentage of total production capacity by process is reported. The percent of total TiO₂ production capacity that was attributed to the chloride process was multiplied by total TiO₂ production to estimate the amount of TiO₂ produced using the chloride process (since, as of 2004, the last remaining sulfate-process plant in the United States closed). This assumes that the chloride-process plants and sulfate-process plants operate at the same level of utilization. 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 TiO₂ production, literature data were used for petroleum coke composition. Certain grades of petroleum coke are manufactured specifically for use in the TiO₂ chloride process; however, this composition information was not available.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 4-40. Titanium dioxide consumption CO₂ emissions were estimated to be between 1.4 and 1.7 Tg CO₂ Eq. at the 95 percent confidence level. This indicates a range of approximately 13 percent below and 13 percent above the emission estimate of 1.5 Tg CO₂ Eq.

Table 4-40: Tier 2 Quantitative Uncertainty Estimates for CO₂ Emissions from Titanium Dioxide Production (Tg CO₂ Eq. and Percent)

Source	Gas	2009 Emission	Uncertainty Range Relative to Emission Estimate ^a			
		Estimate	Range		Relative to Emission Estimate ^a	
		(Tg CO ₂ Eq.)	(Tg CO ₂ Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Titanium Dioxide Production	CO ₂	1.5	1.3	1.7	-13%	+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 time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

Planned Improvements

Future improvements to the titanium dioxide production category involve evaluating facility level greenhouse gas emissions data as a basis for improving emissions calculations from titanium dioxide production. Beginning in 2010, all U.S. titanium dioxide production facilities using the chloride production process are required to monitor, calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. Under the program, EPA will obtain data for 2010 emissions from facilities based on use of higher tier methods and in particular assess how this data could be used to improve the overall method for calculating emissions from the U.S. titanium dioxide production industry, including improving the emission factors. In addition, the 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 estimates.

4.11. Carbon Dioxide Consumption (IPCC Source Category 2B5)

CO₂ 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). CO₂ 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, CO₂ used in non-EOR applications will eventually be released to the atmosphere, and for the purposes of this analysis CO₂ used in commercial applications other than EOR is assumed to be emitted to the atmosphere. CO₂ 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.

CO₂ is produced from naturally occurring CO₂ reservoirs, as a by-product from the energy and industrial production processes (e.g., ammonia production, fossil fuel combustion, ethanol production), and as a by-product from the production of crude oil and natural gas, which contain naturally occurring CO₂ as a component. Only CO₂ produced from naturally occurring CO₂ reservoirs and used in industrial applications other than EOR is included in this analysis. Neither by-product CO₂ generated from energy nor industrial production processes nor CO₂ separated from crude oil and natural gas are included in this analysis for a number of reasons. CO₂ captured from biogenic sources (e.g., ethanol production plants) is not included in the inventory. CO₂ captured from crude oil and gas production is used in EOR applications and is therefore reported in the Energy Chapter. Any CO₂ captured from industrial or energy production processes (e.g., ammonia plants, fossil fuel combustion) and used in non-EOR applications is assumed to be emitted to the atmosphere. The CO₂ emissions from such capture and use are

therefore accounted for under Ammonia Production, Fossil Fuel Combustion, or other appropriate source category.¹¹⁴

CO₂ is produced as a by-product of crude oil and natural gas production. This CO₂ 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 CO₂ used in EOR is described in the Energy Chapter under the text box titled “Carbon Dioxide Transport, Injection, and Geological Storage.” The only CO₂ consumption that is accounted for in this analysis is CO₂ produced from naturally-occurring CO₂ reservoirs that is used in commercial applications other than EOR.

There are currently two facilities, one in Mississippi and one in New Mexico, producing CO₂ from naturally occurring CO₂ reservoirs for use in both EOR and in other commercial applications (e.g., chemical manufacturing, food production). There are other naturally occurring CO₂ reservoirs, mostly located in the western United States. Facilities are producing CO₂ from these natural reservoirs, but they are only producing CO₂ for EOR applications, not for other commercial applications (Allis et al. 2000). CO₂ production from these facilities is discussed in the Energy Chapter.

In 2009, the amount of CO₂ produced by the Mississippi and New Mexico facilities for commercial applications and subsequently emitted to the atmosphere was 1.8 Tg CO₂ Eq. (1,763 Gg) (see Table 4-41). This amount represents a decrease of one percent from the previous year and an increase of 24 percent since 1990. This increase was due to an increase in production at the Mississippi facility, despite the decrease in the percent of the facility’s total reported production that was used for commercial applications.

Table 4-41: CO₂ Emissions from CO₂ Consumption (Tg CO₂ Eq. and Gg)

Year	Tg CO ₂ Eq.	Gg
1990	1.4	1,416
2000	1.4	1,421
2005	1.3	1,321
2006	1.7	1,709
2007	1.9	1,867
2008	1.8	1,780
2009	1.8	1,763

Methodology

CO₂ emission estimates for 1990 through 2009 were based on production data for the two facilities currently producing CO₂ from naturally-occurring CO₂ reservoirs for use in non-EOR applications. Some of the CO₂ 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 CO₂ production used in commercial applications other than EOR is eventually released into the atmosphere.

CO₂ production data for the Jackson Dome, Mississippi facility and the percentage of total production that was used for EOR and in non-EOR applications were obtained from the Advanced Resources Institute (ARI 2006, 2007) for 1990 to 2000 and from the Annual Reports for Denbury Resources (Denbury Resources 2002 through 2010) for 2001 to 2009 (see Table 4-42). Denbury Resources reported the average CO₂ production in units of MMCF CO₂ per day for 2001 through 2009 and reported the percentage of the total average annual production that was used for EOR. CO₂ production data for the Bravo Dome, New Mexico facility were obtained from the Advanced Resources International, Inc. (ARI 1990 through 2010). The percentage of total production that was used for EOR and in non-EOR applications were obtained from the New Mexico Bureau of Geology and Mineral Resources (Broadhead 2003 and New Mexico Bureau of Geology and Mineral Resources 2006).

Table 4-42: CO₂ Production (Gg CO₂) and the Percent Used for Non-EOR Applications for Jackson Dome and

¹¹⁴ There are currently four known electric power plants operating in the U.S. that capture CO₂ for use as food-grade CO₂ or other industrial processes; however, insufficient data prevents estimating emissions from these activities as part of Carbon Dioxide Consumption.

Bravo Dome

Year	Jackson Dome CO ₂ Production (Gg)	Jackson Dome % Used for Non-EOR	Bravo Dome CO ₂ Production (Gg)	Bravo Dome % Used for Non-EOR
1990	1,353	100%	6,301	1%
2000	1,353	100%	6,834	1%
2005	4,678	27%	5,799	1%
2006	6,610	25%	5,613	1%
2007	9,529	19%	5,605	1%
2008	12,312	14%	5,605	1%
2009	13,201	13%	4,639	1%

Uncertainty and Time-Series Consistency

Uncertainty is associated with the number of facilities that are currently producing CO₂ from naturally occurring CO₂ reservoirs for commercial uses other than EOR, and for which the CO₂ emissions are not accounted for elsewhere. Research indicates that there are only two such facilities, which are in New Mexico and Mississippi; however, additional facilities may exist that have not been identified. In addition, it is possible that CO₂ recovery exists in particular production and end-use sectors that are not accounted for elsewhere. Such recovery may or may not affect the overall estimate of CO₂ emissions from that sector depending upon the end use to which the recovered CO₂ is applied. Further research is required to determine whether CO₂ is being recovered from other facilities for application to end uses that are not accounted for elsewhere.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 4-43. CO₂ consumption CO₂ emissions were estimated to be between 1.3 and 2.3 Tg CO₂ Eq. at the 95 percent confidence level. This indicates a range of approximately 26 percent below to 30 percent above the emission estimate of 1.8 Tg CO₂ Eq.

Table 4-43: Tier 2 Quantitative Uncertainty Estimates for CO₂ Emissions from CO₂ Consumption (Tg CO₂ Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate ^a (%)			
			Lower Bound		Upper Bound	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
CO ₂ Consumption	CO ₂	1.8	1.3	2.3	-26%	+30%

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

Planned Improvements

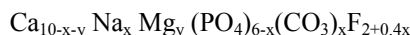
Future improvements to the Carbon Dioxide Consumption source category involve evaluating facility level greenhouse gas emissions data as a basis for improving emissions calculations from carbon dioxide consumption. Beginning in 2010, all U.S. CO₂ producers are required to monitor, calculate and report the quantity of CO₂ supplied to EPA through its Greenhouse Gas Reporting Program. Under the program, EPA will obtain data for 2010 on CO₂ supplied from facilities based on use of higher tier methods and in particular assess how this data could be used to improve the overall method for calculating emissions from consumption of CO₂.

4.12. Phosphoric Acid Production (IPCC Source Category 2B5)

Phosphoric acid (H₃PO₄) is a basic raw material in the production of phosphate-based fertilizers. Phosphate rock is mined in Florida, North Carolina, Idaho, Utah, and other areas of the United States and is used primarily as a raw material for phosphoric acid production. The production of phosphoric acid from phosphate rock produces byproduct gypsum (CaSO₄·2H₂O), referred to as phosphogypsum.

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 C in the form of calcium carbonate (limestone) and also may contain organic C. The chemical composition of phosphate rock (francolite) mined in Florida is:

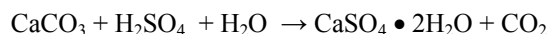


The calcium carbonate component of the phosphate rock is integral to the phosphate rock chemistry. Phosphate rock can also contain organic C that is physically incorporated into the mined rock but is not an integral component of the phosphate rock chemistry. Phosphoric acid production from natural phosphate rock is a source of CO₂ emissions, due to the chemical reaction of the inorganic C (calcium carbonate) component of the phosphate rock.

The phosphoric acid production process involves chemical reaction of the calcium phosphate (Ca₃(PO₄)₂) component of the phosphate rock with sulfuric acid (H₂SO₄) and recirculated phosphoric acid (H₃PO₄) (EFMA 2000). The primary chemical reactions for the production of phosphoric acid from phosphate rock are:



The limestone (CaCO₃) component of the phosphate rock reacts with the sulfuric acid in the phosphoric acid production process to produce calcium sulfate (phosphogypsum) and CO₂. The chemical reaction for the limestone-sulfuric acid reaction is:



Total marketable phosphate rock production in 2009 was 27.2 million metric tons (USGS 2010). Approximately 87 percent of domestic phosphate rock production was mined in Florida and North Carolina, while approximately 13 percent of production was mined in Idaho and Utah. Total imports of phosphate rock in 2009 were 1.8 million metric tons (USGS 2010). The vast majority, 99 percent, of imported phosphate rock is sourced from Morocco (USGS 2005). Marketable phosphate rock production, including domestic production and imports for consumption, decreased by 13.6 percent between 2008 and 2009. Over the 1990 to 2009 period, production has decreased by 34 percent. Total CO₂ emissions from phosphoric acid production were 1.0 Tg CO₂ Eq. (1,035 Gg) in 2009 (see Table 4-44). According to USGS 2010, the weak market conditions of phosphate rock in the U.S. in 2009 were a result of the global economic crisis that started in late 2008 and carried into 2009.

Table 4-44: CO₂ Emissions from Phosphoric Acid Production (Tg CO₂ Eq. and Gg)

Year	Tg CO2 Eq.	Gg
1990	1.5	1,529
2000	1.4	1,382
2005	1.4	1,386
2006	1.2	1,167
2007	1.2	1,166
2008	1.2	1,187
2009	1.0	1,035

Methodology

CO₂ emissions from production of phosphoric acid from phosphate rock are calculated by multiplying the average amount of calcium carbonate contained in the natural phosphate rock by the amount of phosphate rock that is used annually to produce phosphoric acid, accounting for domestic production and net imports for consumption.

The CO₂ emissions calculation methodology is based on the assumption that all of the inorganic C (calcium carbonate) content of the phosphate rock reacts to CO₂ in the phosphoric acid production process and is emitted with the stack gas. The methodology also assumes that none of the organic C content of the phosphate rock is converted to CO₂ and that all of the organic C 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 4-45). For the years 1990, 1991,

1992, 2005, 2006, and 2007 only nationally aggregated mining data was reported by USGS. For these years, the breakdown of phosphate rock mined in Florida and North Carolina, and the amount mined in Idaho and Utah, are approximated using 1993 to 2004 data. Data for domestic production of phosphate rock, exports of phosphate rock (primarily from Florida and North Carolina), and imports of phosphate rock for consumption for 1990 through 2008 were obtained from *USGS Minerals Yearbook: Phosphate Rock* (USGS 1994 through 2010). 2009 data were obtained from *USGS Minerals Commodity Summary: Phosphate Rock* (USGS 2010). From 2004 through 2009, the USGS reported no exports of phosphate rock from U.S. producers (USGS 2005 through 2010).

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 2003). Phosphate rock mined in Florida contains approximately 1 percent inorganic C, and phosphate rock imported from Morocco contains approximately 1.46 percent inorganic C. Calcined phosphate rock mined in North Carolina and Idaho contains approximately 0.41 percent and 0.27 percent inorganic C, respectively (see Table 4-46).

Carbonate content data for phosphate rock mined in Florida are used to calculate the CO₂ emissions from consumption of phosphate rock mined in Florida and North Carolina (87 percent of domestic production) and carbonate content data for phosphate rock mined in Morocco are used to calculate CO₂ emissions from consumption of imported phosphate rock. The CO₂ 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). Carbonate content data for uncalcined phosphate rock mined in Idaho and Utah (13 percent of domestic production) were not available, and carbonate content was therefore estimated from the carbonate content data for calcined phosphate rock mined in Idaho.

Table 4-45: Phosphate Rock Domestic Production, Exports, and Imports (Gg)

Location/Year	1990	2000	2005	2006	2007	2008	2009
U.S. Production ^a	49,800	37,370	36,100	30,100	29,700	30,200	27,200
FL & NC	42,494	31,900	31,227	26,037	25,691	26,123	23,528
ID & UT	7,306	5,470	4,874	4,064	4,010	4,077	3,672
Exports—FL & NC	6,240	299	-	-	-	-	-
Imports—Morocco	451	1,930	2,630	2,420	2,670	2,754	1,800
Total U.S.							
Consumption	44,011	39,001	38,730	32,520	32,370	32,954	29,000

^a USGS does not disaggregate production data regionally (FL & NC and ID & UT) for 1990, 2005, 2006, and 2007. Data for those years are estimated based on the remaining time series distribution.

- Assumed equal to zero.

Table 4-46: Chemical Composition of Phosphate Rock (percent by weight)

Composition	Central	North Carolina			
	Florida	North Florida	(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	-	0.10
Inorganic Carbon (as CO ₂)	3.67	3.43	1.50	1.00	5.00

Source: FIPR 2003

- Assumed equal to zero.

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 2009. For previous years in the time series, USGS provided the data disaggregated regionally; however, beginning in 2006 only total U.S. phosphate rock production were reported. Regional production for 2008 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 2008 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 CO₂ 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. Another source of uncertainty is the disposition of the organic C 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 2003a). Organic C is therefore not included in the calculation of CO₂ 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 CO₂. However, according to the USGS, only one producer in Idaho is currently calcining phosphate rock, and no data were available concerning the annual production of this single producer (USGS 2005). For available years, total production of phosphate rock in Utah and Idaho combined amounts to approximately 13 percent of total domestic production on average (USGS 1994 through 2005).

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 CO₂ in the elemental phosphorus production process. The calculation for CO₂ emissions is based on the assumption that phosphate rock consumption, for purposes other than phosphoric acid production, results in CO₂ emissions from 100 percent of the inorganic C content in phosphate rock, but none from the organic C content.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 4-47. Phosphoric acid production CO₂ emissions were estimated to be between 0.9 and 1.2 Tg CO₂ Eq. at the 95 percent confidence level. This indicates a range of approximately 18 percent below and 19 percent above the emission estimate of 1.0 Tg CO₂ Eq.

Table 4-47: Tier 2 Quantitative Uncertainty Estimates for CO₂ Emissions from Phosphoric Acid Production (Tg CO₂ Eq. and Percent)

Source	Gas	2009 Emission	Uncertainty Range Relative to Emission Estimate ^a			
		Estimate	Range		Relative to Emission Estimate ^a	
		(Tg CO ₂ Eq.)	(Tg CO ₂ Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Phosphoric Acid Production	CO ₂	1.0	0.9	1.2	-18%	+19%

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

Planned Improvements

Future improvements to the phosphoric acid production source category involve evaluating facility level greenhouse gas emissions data as a basis for improving emissions calculations from phosphoric acid production. Beginning in 2010, all U.S. phosphoric acid producers are required to monitor, calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. Under the program, EPA will obtain data for 2010 from facilities based on use of higher tier methods and assess how this data could be used to improve the method for calculating emissions from the U.S. phosphoric acid production industry. Currently, data sources for the carbonate content of the phosphate rock are limited. If additional data sources are found, this information will be incorporated into future estimates. Additionally, as future improvement to the phosphoric acid uncertainty analysis, USGS Mineral Commodity Specialists will be contacted to verify uncertainty ranges associated with phosphate rock

imports and exports.

4.13. Iron and Steel Production (IPCC Source Category 2C1) and Metallurgical Coke Production

The production of iron and steel is an energy-intensive activity that also generates process-related emissions of CO₂ and CH₄. Process emissions occur at each step of steel production from the production of raw materials to the refinement of iron to the making of crude steel. In the United States, steel is produced through both primary and secondary processes. Historically, primary production—using a basic oxygen furnace (BOF) with pig iron as the primary feedstock—has been the dominant method. But secondary production through the use scrap steel and electric arc furnaces (EAFs) has increased significantly in recent years due to the economic advantages of steel recycling, which has been driven by the increased availability of scrap steel. Total production of crude steel in the United States in the time period between 2001 and 2008 ranged from a low of 99,321,000 tons to a high of 109,879,000 tons (2001 and 2004, respectively). But due to the decrease in demand caused by the global economic downturn, crude steel production in the United States decreased to 65,460,000 tons in 2009 (AISI 2010).

Metallurgical coke is an important input in the production of iron and steel. Coke is used to produce iron or pig iron feedstock from raw iron ore. The production of metallurgical coke from coking coal occurs both on-site at “integrated” iron and steel plants and off-site at “merchant” coke plants. Metallurgical coke is produced by heating coking coal in a coke oven in a low-oxygen environment. The process drives off the volatile components of the coking coal and produces coal (metallurgical) coke. Carbon containing byproducts of the metallurgical coke manufacturing process include coke oven gas, coal tar, coke breeze (small-grade coke oven coke with particle size <5mm) and light oil. Coke oven gas is recovered and used for underfiring the coke ovens and within the iron and steel mill. Small amounts of coke oven gas are also sold as synthetic natural gas outside of iron and steel mills (and are accounted for in the Energy chapter). Coal tar is used as a raw material to produce anodes used for primary aluminum production, electric arc furnace (EAF) steel production, and other electrolytic processes, and also is used in the production of other coal tar products. Light oil is sold to petroleum refiners who use the material as an additive for gasoline. The metallurgical coke production process produces CO₂ emissions and fugitive CH₄ emissions.

Iron is produced by first reducing iron oxide (iron ore) with metallurgical coke in a blast furnace. Iron can be introduced into the blast furnace in the form of raw iron ore, taconite pellets (9-16mm iron-containing spheres), briquettes, or sinter. In addition to metallurgical coke and iron, other inputs to the blast furnace include natural gas, fuel oil, and coke oven gas. The carbon in the metallurgical coke used in the blast furnace combines with oxides in the iron ore in a reducing atmosphere to produce blast furnace gas containing carbon monoxide (CO) and CO₂. The CO is then converted and emitted as CO₂ when combusted to either pre-heat the blast air used in the blast furnace or for other purposes at the steel mill. This pig iron or crude iron that is produced from this process contains about 3 to 5 percent carbon by weight. The pig iron production process in a blast furnace produces CO₂ emissions and fugitive CH₄ emissions.

Iron can also be produced through the direct reduction process; wherein, iron ore is reduced to metallic iron in the solid state at process temperatures less than 1000°C. Direct reduced iron production results in process emissions of CO₂ and emissions of CH₄ through the consumption of natural gas used during the reduction process.

Sintering is a thermal process by which fine iron-bearing particles, such as air emission control system dust, are baked, which causes the material to agglomerate into roughly one-inch pellets that are then recharged into the blast furnace for pig iron production. Iron ore particles may also be formed into larger pellets or briquettes by mechanical means, and then agglomerated by heating. The agglomerate is then crushed and screened to produce an iron-bearing feed that is charged into the blast furnace. The sintering process produces CO₂ and fugitive CH₄ emissions through the consumption of carbonaceous inputs (e.g., coke breeze) during the sintering process.

Steel is produced from varying levels of pig iron and scrap steel in specialized BOF and EAF steel-making furnaces. Carbon inputs to BOF steel-making furnaces include pig iron and scrap steel as well as natural gas, fuel oil, and fluxes (e.g., limestone, dolomite). In a BOF, the carbon in iron and scrap steel combines with high-purity oxygen to reduce the carbon content of the metal to the amount desired for the specified grade of steel. EAFs use carbon electrodes, charge carbon and other materials (e.g., natural gas) to aid in melting metal inputs (primarily recycled scrap steel), which are refined and alloyed to produce the desired grade of steel. CO₂ emissions occur in BOFs through the reduction process. In EAFs, CO₂ emissions result primarily from the consumption of carbon electrodes

and also from the consumption of supplemental materials used to augment the melting process.

In addition to the production processes mentioned above, CO₂ is also generated at iron and steel mills through the consumption of process by-products (e.g., blast furnace gas, coke oven gas) used for various purposes including heating, annealing, and electricity generation. Process by-products sold for use as synthetic natural gas are deducted and reported in the Energy chapter (emissions associated with natural gas and fuel oil consumption for these purposes are reported in the Energy chapter).

The majority of CO₂ emissions from the iron and steel production process come from the use of metallurgical coke in the production of pig iron and from the consumption of other process by-products at the iron and steel mill, with lesser amounts emitted from the use of flux and from the removal of carbon from pig iron used to produce steel. Some carbon is also stored in the finished iron and steel products.

According to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (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 Guidelines suggest that emissions from the production of metallurgical coke should be reported separately in the Energy source, while emissions from coke consumption in iron and steel production should be reported in the industrial process source. However, the approaches and emission estimates for both metallurgical coke production and iron and steel production are both presented here because the activity data used to estimate emissions from metallurgical coke production have significant overlap with activity data used to estimate iron and steel production emissions. Further, some by-products (e.g., coke oven gas) of the metallurgical coke production process are consumed during iron and steel production, and some by-products of the iron and steel production process (e.g., blast furnace gas) are consumed during metallurgical coke production. Emissions associated with the consumption of these by-products are attributed to point of consumption. As an example, CO₂ emissions associated with the combustion of coke oven gas in the blast furnace during pig iron production are attributed to pig iron production. Emissions associated with the use of conventional fuels (e.g., natural gas and fuel oil) 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 CO₂ and CH₄ from metallurgical coke production in 2009 were 1.0 Tg CO₂ Eq. (956 Gg) and less than 0.002 Tg CO₂ Eq. (less than 0.00003 Gg), respectively (see Table 4-48 and Table 4-49), totaling 1.0 Tg CO₂ Eq. Emissions decreased in 2009, and have decreased overall since 1990. In 2009, domestic coke production decreased by 29 percent and has decreased overall since 1990. Coke production in 2009 was 46 percent lower than in 2000 and 60 percent below 1990. Overall, emissions from metallurgical coke production have declined by 61 percent (1.5 Tg CO₂ Eq.) from 1990 to 2009.

Table 4-48: CO₂ and CH₄ Emissions from Metallurgical Coke Production (Tg CO₂ Eq.)

Year	1990	2000	2005	2006	2007	2008	2009
CO ₂	2.5	2.2	2.0	1.9	2.1	2.3	1.0
CH ₄	+	+	+	+	+	+	+
Total	2.5	2.2	2.0	1.9	2.1	2.3	1.0

+ Does not exceed 0.05 Tg CO₂ Eq.

Table 4-49: CO₂ and CH₄ Emissions from Metallurgical Coke Production (Gg)

Year	1990	2000	2005	2006	2007	2008	2009
CO ₂	2,470	2,195	2,043	1,919	2,054	2,334	956
CH ₄	+	+	+	+	+	+	+

+ Does not exceed 0.5 Gg

Iron and Steel Production

Emissions of CO₂ and CH₄ from iron and steel production in 2009 were 40.9 Tg CO₂ Eq. (40,914 Gg) and 0.4 Tg CO₂ Eq. (17.4 Gg), respectively (see Table 4-50 through Table 4-53), totaling approximately 41 Tg CO₂ Eq. Emissions decreased in 2009—largely due to decreased steel production associated with the global economic downturn—and have decreased overall since 1990 due to restructuring of the industry, technological improvements, and increased scrap steel utilization. CO₂ 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 2009, domestic production of pig iron decreased by 44 percent. Overall, domestic pig iron production has declined since the 1990s. Pig iron production in 2009 was 60 percent lower than in 2000 and 62 percent below 1990. CO₂ emissions from steel production have declined by 15 percent (1.1 Tg CO₂ Eq.) since 1990, while overall CO₂ emissions from iron and steel production have declined by 58 percent (56.1 Tg CO₂ Eq.) from 1990 to 2009.

Table 4-50: CO₂ Emissions from Iron and Steel Production (Tg CO₂ Eq.)

Year	1990	2000	2005	2006	2007	2008	2009
Sinter Production	2.4	2.2	1.7	1.4	1.4	1.3	0.8
Iron Production	47.9	33.8	19.6	23.9	27.3	25.7	15.9
Steel Production	7.5	7.9	8.5	8.9	9.4	7.5	6.4
Other Activities ^a	39.3	39.9	34.2	32.6	31.0	29.1	17.8
Total	97.1	83.7	63.9	66.9	69.0	63.7	40.9

Note: Totals may not sum due to independent rounding.

^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.

Table 4-51: CO₂ Emissions from Iron and Steel Production (Gg)

Year	1990	2000	2005	2006	2007	2008	2009
Sinter Production	2,448	2,158	1,663	1,418	1,383	1,299	763
Iron Production	47,880	33,818	19,570	23,928	27,262	25,696	15,948
Steel Production	7,475	7,887	8,489	8,924	9,382	7,541	6,389
Other Activities ^a	39,256	39,877	34,160	32,583	30,964	29,146	17,815
Total	97,058	83,740	63,882	66,852	68,991	63,682	40,914

Note: Totals may not sum due to independent rounding.

^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.

Table 4-52: CH₄ Emissions from Iron and Steel Production (Tg CO₂ Eq.)

Year	1990	2000	2005	2006	2007	2008	2009
Sinter Production	+	+	+	+	+	+	+
Iron Production	0.9	0.9	0.7	0.7	0.7	0.6	0.4
Total	1.0	0.9	0.7	0.7	0.7	0.6	0.4

+ Does not exceed 0.05 Tg CO₂ Eq.

Note: Totals may not sum due to independent rounding.

Table 4-53: CH₄ Emissions from Iron and Steel Production (Gg)

Year	1990	2000	2005	2006	2007	2008	2009
Sinter Production	0.9	0.7	0.6	0.5	0.5	0.4	0.3
Iron Production	44.7	43.1	33.5	34.1	32.7	30.4	17.1
Total	45.6	43.8	34.1	34.6	33.2	30.8	17.4

Note: Totals may not sum due to independent rounding.

Methodology

Emission estimates presented in this chapter are based on the methodologies provided by the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006), which 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.

Metallurgical Coke Production

Coking coal is used to manufacture metallurgical (coal) 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 lead and zinc (see Lead

Production and Zinc Production in 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 emission from metallurgical coke production, a Tier 2 method provided by the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (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, 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 4-54). 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. 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 4-54: 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.

The production processes for metallurgical coke production results in fugitive emissions of CH₄, 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 (0.1 g CH₄ per metric ton) taken from the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006) for metallurgical coke production.

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 2004) and January through March (EIA 2010a) (see Table 4-55). 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 20010) and through personal communications with AISI (2008b) (see Table 4-56). The factor for the quantity of coal tar produced per ton of coking coal consumed was provided by AISI (2008b). 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 for National Greenhouse Gas Inventories (IPCC 2006). The C content for coke breeze was assumed to equal the C content of coke.

Table 4-55: Production and Consumption Data for the Calculation of CO₂ and CH₄ Emissions from Metallurgical Coke Production (Thousand Metric Tons)

Source/Activity Data	1990	2000	2005	2006	2007	2008	2009
Metallurgical Coke Production							
Coking Coal Consumption at Coke Plants	35,269	26,254	21,259	20,827	20,607	20,022	13,904
Coke Production at Coke Plants	25,054	18,877	15,167	14,882	14,698	14,194	10,109
Coal Breeze Production	2,645	1,969	1,594	1,562	1,546	1,502	1,043
Coal Tar Production	1,058	788	638	625	618	601	417

Table 4-56: Production and Consumption Data for the Calculation of CO₂ Emissions from Metallurgical Coke Production (million ft³)

Source/Activity Data	1990	2000	2005	2006	2007	2008	2009
Metallurgical Coke Production							
Coke Oven Gas Production ^a	250,767	149,477	114,213	114,386	109,912	103,191	66,155
Natural Gas Consumption	599	180	2,996	3,277	3,309	3,134	2,121
Blast Furnace Gas Consumption	24,602	26,075	4,460	5,505	5,144	4,829	2,435

^a Includes coke oven gas used for purposes other than coke oven underfiring only.

Iron and Steel Production

Emissions of CO₂ 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 CO₂ emission factors (see Table 4-57). Because estimates of sinter production and direct reduced iron production were not available, production was assumed to equal consumption.

Table 4-57: CO₂ 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 C contained in the produced pig iron and blast furnace gas were deducted from the amount of C contained in inputs (i.e., metallurgical coke, sinter, natural ore, pellets, natural gas, fuel oil, coke oven gas, direct coal injection). The C 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 4-58). Carbon in blast furnace gas used to pre-heat the blast furnace air is combusted to form CO₂ during this process.

Emissions from steel production in EAFs were estimated by deducting the C 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 C from direct reduced iron, pig iron, and flux additions to the EAFs were also included in the EAF calculation. For BOFs, estimates of C 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 C was calculated by multiplying material-specific carbon contents by each material type (see Table 4-58). 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 2008b)). The amount of flux (e.g., limestone and dolomite) used during steel manufacture was deducted from the Limestone and Dolomite Use source category to avoid double-counting.

CO₂ 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 C content (see Table 4-58).

CO₂ 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 CO₂ emissions from iron and steel production (see Table 4-50 and Table 4-51).

Table 4-58: 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 processes for sinter and pig iron result in fugitive emissions of CH₄, 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 for National Greenhouse Gas Inventories (IPCC 2006) for sinter production and the 1995 IPCC Guidelines (IPCC/UNEP/OECD/IEA 1995) (see Table 4-59) for pig iron production. The production of direct reduced iron also results in emissions of CH₄ through the consumption of fossil fuels (e.g., natural gas); however, these emissions estimates are excluded due to data limitations.

Table 4-59: CH₄ Emission Factors for Sinter and Pig Iron Production

Material Produced	Factor	Unit
Pig Iron	0.9	g CH ₄ /kg
Sinter	0.07	kg CH ₄ /metric ton

Source: Sinter (IPCC 2006, Table 4.2), Pig Iron (IPCC/UNEP/OECD/IEA 1995, Table 2.2)

Sinter consumption and direct reduced iron consumption data were obtained from AISI's Annual Statistical Report (AISI 2004 through 2010) and through personal communications with AISI (2008b) (see Table 4-60). Data on direct reduced iron consumed in EAFs were not available for the years 1990, 1991, 1999, 2006, 2007, 2008, and 2009. EAF direct reduced iron consumption in 1990 and 1991 were assumed to equal consumption in 1992, and consumption in 1999 was assumed to equal the average of 1998 and 2000. EAF consumption in 2006, 2007, 2008, and 2009 were calculated by multiplying the total DRI consumption for all furnaces as provided in the 2009 AISI Annual Statistical Report by the EAF share of total DRI consumption in 2005 (the most recent year that data was available for EAF vs. BOF consumption of DRI). Data on direct reduced iron consumed in BOFs were not available for the years 1990 through 1994, 1999, 2006, 2007, 2008, and 2009. BOF direct reduced iron consumption in 1990 through 1994 was assumed to equal consumption in 1995, and consumption in 1999 was assumed to equal the average of 1998 and 2000. BOF consumption in 2006, 2007, and 2008 were calculated by multiplying the total DRI consumption for all furnaces as provided in the 2009 AISI Annual Statistical Report by the BOF share of total DRI consumption in 2005 (the most recent year that data was available for EAF vs. BOF consumption of DRI). The Tier 1 CO₂ emission factors for sinter production and direct reduced iron production were obtained through the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006). 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 2010) and through personal communications with AISI (2008b) (see Table 4-61). Data for EAF steel production, flux, EAF charge carbon, direct reduced iron, pig iron, scrap steel, and natural gas consumption as well as EAF steel production were obtained from AISI's Annual Statistical Report (AISI 2004 through 2010) and through personal communications with AISI (2011). The factor for the quantity of EAF anode consumed per ton of EAF steel produced was provided by AISI (AISI 2008b). Data for BOF steel production, flux, direct reduced iron, pig iron, scrap steel, natural gas, natural ore, pellet sinter consumption as well as BOF steel production were obtained from AISI's Annual Statistical Report (AISI 2004 through 2010) and through personal communications with AISI (2008b). Because data on pig iron consumption and scrap steel consumption in BOFs and EAFs were not available for 2006, 2007, and 2009, values for these years were calculated by multiplying the total pig iron and scrap steel consumption for all furnaces as provided in the 2009 AISI Annual Statistical Report by the BOF and EAF shares of total pig iron and scrap consumption in 2005 (the most recent year that data was available for EAF vs. BOF consumption of pig iron and scrap steel). Because pig iron consumption in EAFs was also not available in 2003 and 2004, the average of 2002 and 2005 pig iron consumption data were used. 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 2010) and through personal communications with AISI (2008b). Data on blast furnace gas and coke oven gas sold for use as synthetic natural gas were obtained through EIA's *Natural Gas Annual 2009* (EIA 2010b). C contents for direct reduced iron, EAF carbon electrodes, EAF charge carbon, limestone, dolomite, pig iron, and steel were provided by

the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006). The C contents for natural gas, fuel oil, and direct injection coal as well as the heat contents for the same fuels were provided by EIA (1992, 2010c). Heat contents for coke oven gas and blast furnace gas were provided in Table 2-2 of the report *Energy and Environmental Profile of the U.S. Iron and Steel Industry* (DOE 2000).

Table 4-60: Production and Consumption Data for the Calculation of CO₂ and CH₄ Emissions from Iron and Steel Production (Thousand Metric Tons)

Source/Activity Data	1990	2000	2005	2006	2007	2008	2009
Sinter Production							
Sinter Production	12,239	10,788	8,315	7,088	6,914	6,497	3,814
Direct Reduced Iron Production							
Direct Reduced Iron Production	936	1,914	1,633	1,497	2,087	1,769	1,243
Pig Iron Production							
Coke Consumption	24,946	19,215	13,832	14,684	15,039	14,251	8,572
Pig Iron Production	49,669	47,888	37,222	37,904	36,337	33,730	19,019
Direct Injection Coal Consumption	1,485	3,012	2,573	2,526	2,734	2,578	1,674
EAF Steel Production							
EAF Anode and Charge							
Carbon Consumption	67	96	1,127	1,245	1,214	1,109	845
Scrap Steel Consumption	35,743	43,001	37,558	38,033	40,845	40,824	35,472
Flux Consumption	319	654	695	671	567	680	476
EAF Steel Production	33,511	47,860	52,194	56,071	57,004	52,791	36,700
BOF Steel Production							
Pig Iron Consumption	46,564	46,993	32,115	32,638	33,773	29,322	23,134
Scrap Steel Consumption	14,548	14,969	11,612	11,759	12,628	8,029	6,641
Flux Consumption	576	978	582	610	408	431	318
BOF Steel Production	43,973	53,965	42,705	42,119	41,099	39,105	22,659

Table 4-61: Production and Consumption Data for the Calculation of CO₂ Emissions from Iron and Steel Production (million ft³ unless otherwise specified)

Source/Activity Data	1990	2000	2005	2006	2007	2008	2009
Pig Iron Production							
Natural Gas Consumption	56,273	91,798	59,844	58,344	56,112	53,349	35,933
Fuel Oil Consumption (thousand gallons)	163,397	120,921	16,170	87,702	84,498	55,552	23,179
Coke Oven Gas Consumption	22,033	13,702	16,557	16,649	16,239	15,336	9,951
Blast Furnace Gas Production	1,439,380	1,524,891	1,299,980	1,236,526	1,173,588	1,104,674	672,486
EAF Steel Production							
Natural Gas Consumption	9,604	13,717	14,959	16,070	16,337	15,130	10,518
BOF Steel Production							
Natural Gas Consumption	6,301	6,143	5,026	5,827	11,740	-4,304 ^a	-2,670 ^a
Coke Oven Gas Consumption	3,851	640	524	559	525	528	373
Other Activities							
Coke Oven Gas Consumption	224,883	135,135	97,132	97,178	93,148	87,327	55,831
Blast Furnace Gas Consumption	1,414,778	1,498,816	1,295,520	1,231,021	1,168,444	1,099,845	670,051

^a EPA is continuing to work with AISI to investigate why this value is negative.

Uncertainty and Time-Series Consistency

The estimates of CO₂ and CH₄ 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 CO₂ 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 CO₂ emissions from iron and steel production are based on material production and consumption data and average C 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 C contents for pellets, sinter, and natural ore, which are assumed to equal the C contents of direct reduced iron. For EAF steel production there is uncertainty associated with the amount of EAF anode and charge C consumed due to inconsistent data throughout the time series. 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 (e.g., electricity and steam generation); therefore, all consumption is attributed to iron and steel production. These data and C contents produce a relatively accurate estimate of CO₂ emissions. However, there are uncertainties associated with each.

For the purposes of the CH₄ calculation from iron and steel production it is assumed that all of the CH₄ escapes as fugitive emissions and that none of the CH₄ is captured in stacks or vents. Additionally, the CO₂ emissions calculation is not corrected by subtracting the C content of the CH₄, which means there may be a slight double counting of C as both CO₂ and CH₄.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 4-62 for metallurgical coke production and iron and steel production. Total CO₂ emissions from metallurgical coke production and iron and steel production were estimated to be between 35.2 and 48.4 Tg CO₂ Eq. at the 95 percent confidence level. This indicates a range of approximately 16 percent below and 16 percent above the emission estimate of 41.9 Tg CO₂ Eq. Total CH₄ emissions from metallurgical coke production and iron and steel production were estimated to be 0.4 Tg CO₂ Eq. at the 95 percent confidence level. This indicates a range of approximately 21 percent below and 23 percent above the emission estimate of 0.4 Tg CO₂ Eq.

Table 4-62: Tier 2 Quantitative Uncertainty Estimates for CO₂ and CH₄ Emissions from Iron and Steel Production and Metallurgical Coke Production (Tg. CO₂ Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate ^a			
			(Tg CO ₂ Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Metallurgical Coke & Iron and Steel Production	CO ₂	41.9	35.2	48.4	-16%	+16%
Metallurgical Coke & Iron and Steel Production	CH ₄	0.4	0.3	0.4	-21%	+23%

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

Planned Improvements

Future improvements to the Iron and Steel production source category involve evaluating facility level greenhouse gas emissions data as a basis for improving emissions calculations from iron and steel production. Beginning in 2010, all U.S. iron and steel producing facilities that emit over 25,000 tons of greenhouse gases (CO₂ Eq.) are required to monitor, calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. Under the program, EPA will obtain data for 2010 from these facilities based on use of higher tier methods and assess how this data could be used to improve the method for calculating emissions from the U.S. iron and steel industry. Specifically, plans include attributing emissions 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. Additional 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 inputs for preparing Tier 2 estimates for sinter and direct reduced iron production, as well as identifying information to better characterize emissions from the use of process gases and fuels within the Energy and Industrial Processes chapters.

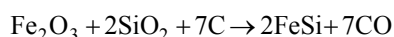
Recalculations Discussion

In the previous Inventory, coal tar production and coke breeze production were incorrectly estimated by multiplying the respective production factors by U.S. coke production at coke plants rather than U.S. coking coal consumption at coke plants (to which the coal tar and coke breeze production factors should be applied). This issue has been corrected and decreased the 1990 through 2008 emissions from metallurgical coke production by an average of 53 percent per year relative to the previous Inventory. The total 1990 through 2008 emissions for metallurgical coke and iron and steel production decreased by an average of 3 percent per year relative to the previous Inventory.

4.14. Ferroalloy Production (IPCC Source Category 2C2)

CO₂ and CH₄ are emitted from the production of several ferroalloys. Ferroalloys are composites of iron and other elements such as silicon, manganese, and chromium. When incorporated in alloy steels, ferroalloys are used to alter the material properties of the steel. Estimates from two types of ferrosilicon (25 to 55 percent and 56 to 95 percent silicon), silicon metal (about 98 percent silicon), and miscellaneous alloys (36 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. Subsequently, government information disclosure rules prevent the publication of production data for these production facilities.

Similar to emissions from the production of iron and steel, CO₂ 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 CO₂. A representative reaction equation for the production of 50 percent ferrosilicon is given below:



While most of the C contained in the process materials is released to the atmosphere as CO₂, a percentage is also released as CH₄ and other volatiles. The amount of CH₄ that is released is dependent on furnace efficiency, operation technique, and control technology.

Emissions of CO₂ from ferroalloy production in 2009 were 1.5 Tg CO₂ Eq. (1,469 Gg) (see Table 4-63 and Table 4-64), which is a 32 percent reduction since 1990. Emissions of CH₄ from ferroalloy production in 2009 were 0.01 Tg CO₂ Eq. (0.406 Gg), which is a 40 percent decrease since 1990.

Table 4-63: CO₂ and CH₄ Emissions from Ferroalloy Production (Tg CO₂ Eq.)

Year	1990		2000		2005	2006	2007	2008	2009
CO ₂	2.2		1.9		1.4	1.5	1.6	1.6	1.5
CH ₄	+		+		+	+	+	+	+
Total	2.2		1.9		1.4	1.5	1.6	1.6	1.6

+ Does not exceed 0.05 Tg CO₂ Eq.

Note: Totals may not sum due to independent rounding.

Table 4-64: CO₂ and CH₄ Emissions from Ferroalloy Production (Gg)

Year	1990	2000	2005	2006	2007	2008	2009
CO ₂	2,152	1,893	1,392	1,505	1,552	1,599	1,469
CH ₄	1	1	+	+	+	+	+

Methodology

Emissions of CO₂ and CH₄ from ferroalloy production were calculated by multiplying annual ferroalloy production by material-specific emission factors. Emission factors taken from the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006) were applied to ferroalloy production. For ferrosilicon alloys containing 25 to 55 percent silicon and miscellaneous alloys (including primarily magnesium-ferrosilicon, but also including other silicon alloys) containing 32 to 65 percent silicon, an emission factor for 45 percent silicon was applied for CO₂ (2.5 metric tons CO₂/metric ton of alloy produced) and an emission factor for 65 percent silicon was applied for CH₄ (1 kg CH₄/metric ton of alloy produced). Additionally, for ferrosilicon alloys containing 56 to 95 percent silicon, an emission factor for 75 percent silicon ferrosilicon was applied for both CO₂ and CH₄ (4 metric tons CO₂/metric ton alloy produced and 1 kg CH₄/metric ton of alloy produced, respectively). The emission factors for silicon metal equaled 5 metric tons CO₂/metric ton metal produced and 1.2 kg CH₄/metric ton metal produced. It was assumed that 100 percent of the ferroalloy production was produced using petroleum coke using an electric arc furnace process (IPCC 2006), although some ferroalloys may have been produced with coking coal, wood, other biomass, or graphite C 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.

Ferroalloy production data for 1990 through 2009 (see Table 4-65) were obtained from the USGS through personal communications with the USGS Silicon Commodity Specialist (Corathers 2011) and through the *Minerals Yearbook: Silicon Annual Report* (USGS 1991 through 2010). Because USGS does not provide estimates of silicon metal production for 2006-2009, 2005 production data are used. Until 1999, the USGS reported production of ferrosilicon containing 25 to 55 percent silicon separately from production of miscellaneous alloys containing 32 to 65 percent silicon; beginning in 1999, the USGS reported these as a single category (see Table 4-65). The composition data for petroleum coke was obtained from Onder and Bagdoyan (1993).

Table 4-65: 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
2000	229,000	100,000	184,000	NA
2005	123,000	86,100	148,000	NA
2006	164,000	88,700	148,000	NA
2007	180,000	90,600	148,000	NA
2008	193,000	94,000	148,000	NA
2009	123,932	104,855	148,000	NA

NA (Not Available)

Uncertainty and Time-Series Consistency

Although some ferroalloys may be produced using wood or other biomass as a C source, 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 C is of biogenic origin.¹¹⁵ 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 CO₂ 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.

¹¹⁵ Emissions and sinks of biogenic carbon are accounted for in the Land Use, Land-Use Change, and Forestry chapter.

Emissions of CH₄ 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 CH₄ emissions; however, specific furnace information was not available or included in the CH₄ emission estimates.

Also, annual ferroalloy production is now reported by the USGS in three broad categories: ferroalloys containing 25 to 55 percent silicon (including miscellaneous alloys), ferroalloys containing 56 to 95 percent silicon, and silicon metal. It was assumed that the IPCC emission factors apply to all of the ferroalloy production processes, including miscellaneous alloys. Finally, production data for silvery pig iron (alloys containing less than 25 percent silicon) are not reported by the USGS to avoid disclosing company proprietary data. Emissions from this production category, therefore, were not estimated.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 4-66. Ferroalloy production CO₂ emissions were estimated to be between 1.3 and 1.7 Tg CO₂ Eq. at the 95 percent confidence level. This indicates a range of approximately 12 percent below and 13 percent above the emission estimate of 1.5 Tg CO₂ Eq. Ferroalloy production CH₄ emissions were estimated to be between a range of approximately 12 percent below and 12 percent above the emission estimate of 0.01 Tg CO₂ Eq.

Table 4-66: Tier 2 Quantitative Uncertainty Estimates for CO₂ Emissions from Ferroalloy Production (Tg CO₂ Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate ^a			
			Range (Tg CO ₂ Eq.)		Range (%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Ferroalloy Production	CO ₂	1.5	1.3	1.7	-12%	+13%
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 Tg CO₂ Eq.

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

Planned Improvements

Future improvements to the ferroalloy production source category involve evaluating facility level greenhouse gas emissions data as a basis for improving emissions calculations from ferroalloy production. Beginning in 2010, all U.S. ferroalloy producing facilities that emit over 25,000 tons of greenhouse gases (CO₂ Eq.) are required to monitor, calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. Under the program, EPA will obtain data for 2010 from these facilities based on use of higher tier methods and assess how this data could be used to improve the methodology and emissions factors for calculating emissions from the U.S. ferroalloy industry, in particular, including emission estimates from production of ferroalloys other than ferrosilicon and silicon metal. If data are available, emissions will be estimated for those ferroalloys. Additionally, research will be conducted to determine whether data are available concerning raw material consumption (e.g., coal coke, limestone and dolomite flux, etc.) for inclusion in ferroalloy production emission estimates.

4.15. Aluminum Production (IPCC Source Category 2C3)

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 last reporting, the United States was the fourth largest producer of primary aluminum, with approximately seven percent of the world total (USGS 2009a). 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 CO₂ and two perfluorocarbons (PFCs): perfluoromethane (CF₄) and perfluoroethane (C₂F₆).

CO₂ is emitted during the aluminum smelting process when alumina (aluminum oxide, Al₂O₃) 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 carbon mass of paste, coke briquettes, or prebaked carbon blocks from petroleum coke. During reduction, most of this carbon is oxidized and released to the atmosphere as CO_2 .

Process emissions of CO_2 from aluminum production were estimated to be 3.0 Tg CO_2 Eq. (3,009 Gg) in 2009 (see Table 4-67). The carbon 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 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 4-67: CO_2 Emissions from Aluminum Production (Tg CO_2 Eq. and Gg)

Year	Tg CO_2 Eq.	Gg
1990	6.8	6,831
2000	6.1	6,086
2005	4.1	4,142
2006	3.8	3,801
2007	4.3	4,251
2008	4.5	4,477
2009	3.0	3,009

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 carbon 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 92 percent and 89 percent, respectively, to 1.3 Tg CO_2 Eq. of CF_4 (0.20 Gg) and 0.30 Tg CO_2 Eq. of C_2F_6 (0.032 Gg) in 2009, as shown in Table 4-68 and Table 4-69. 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. Since 1990, aluminum production has declined by 57 percent, while the combined CF_4 and C_2F_6 emission rate (per metric ton of aluminum produced) has been reduced by 80 percent.

Table 4-68: PFC Emissions from Aluminum Production (Tg CO_2 Eq.)

Year	CF_4	C_2F_6	Total
1990	15.9	2.7	18.5
2000	7.8	0.8	8.6
2005	2.5	0.4	3.0
2006	2.1	0.4	2.5
2007	3.2	0.6	3.8
2008	2.2	0.5	2.7
2009	1.3	0.3	1.6

Note: Totals may not sum due to independent rounding.

Table 4-69: PFC Emissions from Aluminum Production (Gg)

Year	CF_4	C_2F_6
1990	2.4	0.3
2000	1.2	0.1
2005	0.4	+

2006	0.3	+
2007	0.5	0.1
2008	0.3	0.1
2009	0.2	+

+ Does not exceed 0.05 Gg.

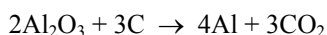
In 2009, U.S. primary aluminum production totaled approximately 1.7 million metric tons, a 35 percent decrease from 2008 production levels (USAA 2010). In 2009, six companies managed production at 13 operational primary aluminum smelters. Four smelters were closed the entire year, and demolition of one smelter that had been idle since 2000 was completed in 2009. Of the operating smelters, three were temporarily idled during some fraction of 2009, and parts of four others were temporarily closed in 2009 (USGS 2010a). During 2009, U.S. primary aluminum production was less for every month when compared to the corresponding month in 2008 (USGS 2009b, USGS 2010b).

For 2010, total production during January through September was approximately 1.28 million metric tons, compared to 1.32 million metric tons for the same period in 2009, only a 3 percent decrease (USGS 2010c). Based on the similarity in production, process CO₂ and PFC emissions are likely to be similar over this period in 2009 given no significant changes in process controls at operational facilities.

Methodology

CO₂ emissions released during aluminum production were estimated by combining individual partner reported data with process-specific emissions modeling. These estimates are based on information gathered by EPA's Voluntary Aluminum Industrial Partnership (VAIP) program.

Most of the CO₂ emissions released during aluminum production occur during the electrolysis reaction of the carbon anode, as described by the following reaction:



For prebake smelter technologies, CO₂ is also emitted during the anode baking process. These emissions can account for approximately 10 percent of total process CO₂ emissions from prebake smelters.

Depending on the availability of smelter-specific data, the CO₂ 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 CO₂ emission factors. The first approach tracks the consumption and C content of the anode, assuming that all C in the anode is converted to CO₂. Sulfur, ash, and other impurities in the anode are subtracted from the anode consumption to arrive at total C consumption. 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 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 CO₂ 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 Söderberg 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 CO₂ 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 CO₂ process data were not reported by these companies, estimates were developed through linear interpolation, and/or assuming industry default values.

In the absence of any previous 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), CO₂ emission estimates were estimated using Tier 1 Söderberg and/or Prebake emission factors (metric ton of CO₂ per metric ton of aluminum produced) from IPCC (2006).

Aluminum production data for 10 out of 13 operating smelters were reported under the VAIP in 2009. Between 1990 and 2008, production data were provided 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 (USAA 2010), with allocation to specific smelters based on reported production capacities (USGS 2009a).

PFC emissions from aluminum production were estimated using a per-unit production emission factor that is expressed as a function of operating parameters (anode effect frequency and duration), as follows:

$$\text{PFC (CF}_4 \text{ or C}_2\text{F}_6\text{) kg/metric ton Al} = S \times (\text{Anode Effect Minutes/Cell-Day})$$

where,

$$S = \text{Slope coefficient ((kg PFC/metric ton Al)/(Anode Effect Minutes/Cell-Day))}$$

$$\text{Anode Effect Minutes/Cell-Day} = \text{Anode Effect Frequency/Cell-Day} \times \text{Anode Effect Duration (minutes)}$$

This approach corresponds to either the Tier 3 or the Tier 2 approach in the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006), depending upon whether the slope-coefficient is smelter-specific (Tier 3) or technology-specific (Tier 2). 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 2000, 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, 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.

National primary aluminum production data for 2009 were obtained via the United States Aluminum Association (USAA 2010). For 1990 through 2001, and 2006 (see Table 4-70) 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 2008 national aluminum production data were obtained from the USAA's Primary Aluminum Statistics (USAA 2004, 2005, 2006, 2008, 2009).

Table 4-70: Production of Primary Aluminum (Gg)

Year	Gg
1990	4,048
2000	3,668
2005	2,478
2006	2,284
2007	2,560
2008	2,659
2009	1,727

Uncertainty and Time Series Consistency

The overall uncertainties associated with the 2009 CO₂, CF₄, and C₂F₆ emission estimates were calculated using Approach 2, as defined by IPCC (2006). For CO₂, uncertainty was assigned to each of the parameters used to estimate CO₂ emissions. Uncertainty surrounding reported production data was assumed to be 1 percent (IPCC 2006). For additional variables, such as net C consumption, and sulfur and ash content in baked anodes, estimates for uncertainties associated with reported and default data were obtained from IPCC (2006). A Monte Carlo analysis was applied to estimate the overall uncertainty of the CO₂ emission estimate for the U.S. aluminum industry as a whole, and the results are provided below.

To estimate the uncertainty associated with emissions of CF₄ and C₂F₆, the uncertainties associated with three variables were estimated for each smelter: (1) the quantity of aluminum produced, (2) the anode effect minutes per cell day (which may be reported directly or calculated as the product of anode effect frequency and anode effect duration), and, (3) the smelter- or technology-specific slope coefficient. A Monte Carlo analysis was then applied to estimate the overall uncertainty of the emission estimate for each smelter and for the U.S. aluminum industry as a whole.

The results of this quantitative uncertainty analysis are summarized in Table 4-71. Aluminum production-related CO₂ emissions were estimated to be between 2.90 and 3.12 Tg CO₂ Eq. at the 95 percent confidence level. This indicates a range of approximately 4 percent below to 4 percent above the emission estimate of 3.01 Tg CO₂ Eq. Also, production-related CF₄ emissions were estimated to be between 1.14 and 1.44 Tg CO₂ Eq. at the 95 percent confidence level. This indicates a range of approximately 12 percent below to 12 percent above the emission estimate of 1.29 Tg CO₂ Eq. Finally, aluminum production-related C₂F₆ emissions were estimated to be between 0.25 and 0.35 Tg CO₂ Eq. at the 95 percent confidence level. This indicates a range of approximately 17 percent below to 19 percent above the emission estimate of 0.30 Tg CO₂ Eq.

Table 4-71: Tier 2 Quantitative Uncertainty Estimates for CO₂ and PFC Emissions from Aluminum Production (Tg CO₂ Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO ₂ Eq.)	Uncertainty Range Relative to 2009 Emission Estimate ^a			
			(Tg CO ₂ Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Aluminum Production	CO ₂	3.0	2.9	3.1	-4%	+4%
Aluminum Production	CF ₄	1.3	1.1	1.4	-12%	+12%
Aluminum Production	C ₂ F ₆	0.3	0.2	0.4	-17%	+19%

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

The 2009 emission estimate was developed using either company-wide or site-specific PFC slope coefficients for all but 1 of the 14 operating smelters where default IPCC (2006) slope data was used. In some cases, where smelters are owned by one company, data have been reported on a company-wide basis as totals or weighted averages. Consequently, in the Monte Carlo analysis, uncertainties in anode effect minutes per cell-day, slope coefficients, and aluminum production have been applied to the company as a whole and not to each smelter. This probably overestimates the uncertainty associated with the cumulative emissions from these smelters, because errors that were in fact independent were treated as if they were correlated. It is therefore likely that the uncertainties calculated above for the total U.S. 2009 emission estimates for CF₄ and C₂F₆ are also overestimated.

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

Planned Improvements

Beginning in 2010, all primary U.S. aluminum producing facilities are required to monitor, calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. Under the program, EPA will obtain data for 2010 from these facilities based on use of higher tier methods and assess how this data could be used to improve the methodology and emissions factors for calculating emissions from the U.S. primary aluminum production industry.

4.16. Magnesium Production and Processing (IPCC Source Category 2C4)

The magnesium metal production and casting industry uses sulfur hexafluoride (SF₆) 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 twenty-five years. A dilute gaseous mixture of SF₆ with dry air and/or CO₂ is blown over molten magnesium metal to induce and stabilize the formation of a protective crust. A small portion of the SF₆ reacts with the magnesium to form a thin molecular film of mostly magnesium oxide and magnesium fluoride. The amount of SF₆ reacting in magnesium production and processing is considered to be negligible, and thus all SF₆ used is assumed to be emitted into the atmosphere. Although alternative cover gases, such as AM-cover™ (containing HFC-134a), Novec™ 612 and dilute SO₂ systems can be used, many facilities in the United States are still using traditional SF₆ cover gas systems.

The magnesium industry emitted 1.1 Tg CO₂ Eq. (0.04 Gg) of SF₆ in 2009, representing a decrease of approximately 45 percent from 2008 emissions (See Table 4-72). The decrease can be attributed to die casting facilities in the United States closing or halting production due to reduced demand from the American auto industry and other industrial sectors (USGS 2010a). Production associated with primary and secondary facilities also dropped in 2009. The significant reduction in emissions can also be attributed to industry efforts to switch to cover gas alternatives, such as sulfur dioxide, as part of the EPA's SF₆ Emission Reduction Partnership for the Magnesium Industry.

Table 4-72: SF₆ Emissions from Magnesium Production and Processing (Tg CO₂ Eq. and Gg)

Year	Tg CO ₂ Eq.	Gg
1990	5.4	0.2
2000	3.0	0.1
2005	2.9	0.1
2006	2.9	0.1
2007	2.6	0.1
2008	1.9	0.1
2009	1.1	0.04

Methodology

Emission estimates for the magnesium industry incorporate information provided by industry participants in EPA's SF₆ Emission Reduction Partnership for the Magnesium Industry. The Partnership started in 1999 and, currently, participating companies represent 100 percent of U.S. primary and secondary production and 90 percent of the casting sector production (i.e., die, sand, permanent mold, wrought, and anode casting). Absolute emissions for 1999 through 2009 from primary production, secondary production (i.e., recycling), and die casting were generally reported by Partnership participants. Partners reported their SF₆ consumption, which was assumed to be equivalent to emissions. When a partner did not report emissions, they were estimated based on the metal processed and emission rate reported by that partner in previous and (if available) subsequent years. Where data for subsequent years was not available, metal production and emissions rates were extrapolated based on the trend shown by partners reporting in the current and previous years. When it was determined a Partner is no longer in production, their metal production and emissions rates were set to zero if no activity information was available; in one case a partner that closed mid-year was estimated to have produced 50 percent of the metal from the prior year.

Emission factors for 2002 to 2006 for sand casting activities were also acquired through the Partnership. For 2007, 2008 and 2009, the sand casting partner did not report and the reported emission factor from 2005 was utilized as being representative of the industry. The 1999 through 2009 emissions from casting operations (other than die) were estimated by multiplying emission factors (kg SF₆ per metric ton of metal produced or processed) by the amount of metal produced or consumed. The emission factors for casting activities are provided below in Table 4-73. The emission factors for primary production, secondary production and sand casting are withheld 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 SF₆ 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. U.S. magnesium consumption (casting) data from 1990 through 2009 were available from the USGS (USGS 2002, 2003, 2005, 2006, 2007, 2008, 2010).

Table 4-73: SF₆ Emission Factors (kg SF₆ per metric ton of magnesium)

Year	Die Casting	Permanent Mold	Wrought	Anodes
1999	2.14 ^a	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	0.81	2	1	1
2005	0.79	2	1	1
2006	0.86	2	1	1
2007	0.67	2	1	1
2008	1.15 ^b	2	1	1
2009	1.77 ^b	2	1	1

^a This is a weighted average that includes an estimated emission factor of 5.2 kg SF₆ per metric ton of magnesium for die casters that did not participate in the Partnership in 1999. These die casters were assumed to be similar to partners that cast small parts. Due to process requirements, these casters consume larger quantities of SF₆ per metric ton of processed magnesium than casters that process large parts. In later years, die casters participating in the Partnership accounted for all U.S. die casting tracked by USGS.

^b The emission factor for die casting increased significantly between 2007 and 2008, and again between 2008 and 2009. These increases occurred for two reasons. First, one of the die casters with a significant share of U.S. production that had used SF₆ as a cover gas and that had maintained a relatively low emission rate began using an alternative cover gas in 2008. Since the SF₆ emission factor provided here is based only on die casting operations that use SF₆ as a cover gas, the removal of the low-emitting die caster from the SF₆-using group increased the weighted average emission rate of that group. Second, one SF₆-using die caster experienced a significant leak in its cover gas distribution system in 2009 that resulted in an abnormally high SF₆ emission rate.

To estimate emissions for 1990 through 1998, industry emission factors were multiplied by the corresponding metal production and consumption (casting) statistics from USGS. The primary production emission factors were 1.2 kg per metric ton for 1990 through 1993, and 1.1 kg per metric ton for 1994 through 1997. These factors were based on information provided by U.S. primary producers. For die casting, an emission factor of 4.1 kg per metric ton was used for the period 1990 through 1996. This factor was drawn from an international survey of die casters (Gjestland & Magers 1996). For 1996 through 1998, the emission factors for primary production and die casting were assumed to decline linearly to the level estimated based on partner reports in 1999. This assumption is consistent with the trend in SF₆ sales to the magnesium sector that is reported in the RAND survey of major SF₆ manufacturers, which shows a decline of 70 percent from 1996 to 1999 (RAND 2002). Sand casting emission factors for 2002 through 2009 were provided by the Magnesium Partnership participants, and 1990 through 2001 emission factors for this process were assumed to have been the same as the 2002 emission factor. The emission factor for secondary production from 1990 through 1998 was assumed to be constant at the 1999 average partner value. 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 4-73.

Uncertainty

To estimate the uncertainty surrounding the estimated 2009 SF₆ emissions from magnesium production and processing, the uncertainties associated with three variables were estimated (1) emissions reported by magnesium producers and processors that participate in the Magnesium Partnership, (2) emissions estimated for magnesium producers and processors that participate in the Partnership but did not report this year, and (3) emissions estimated for magnesium producers and processors that do not participate in the Partnership. An uncertainty of 5 percent was assigned to the data reported by each participant in the Partnership. If partners did not report emissions data during the current reporting year, SF₆ emissions data were estimated using available emission factor and production information reported in prior years; the extrapolation was based on the average trend for partners reporting in the current reporting year and the year prior. The uncertainty associated with the SF₆ usage estimate generated from the extrapolated emission factor and production information was estimated to be 30 percent for each year of extrapolation. The lone sand casting partner did not report in the past two reporting years and its activity and emission factor were held constant at 2005 levels due to a reporting anomaly in 2006 because of malfunctions at the facility. The uncertainty associated with the SF₆ usage for the sand casting partner was 52 percent. For those industry processes that are not represented in Partnership, such as permanent mold and wrought casting, SF₆ emissions were estimated using production and consumption statistics reported by USGS and estimated process-

specific emission factors (see Table 4-73). The uncertainties associated with the emission factors and USGS-reported statistics were assumed to be 75 percent and 25 percent, respectively. Emissions associated with sand casting activities utilized a partner-reported emission factor with an uncertainty of 75 percent. In general, where precise quantitative information was not available on the uncertainty of a parameter, a conservative (upper-bound) value was used.

Additional uncertainties exist in these estimates that are not addressed in this methodology, such as the basic assumption that SF₆ neither reacts nor decomposes during use. The melt surface reactions and high temperatures associated with molten magnesium could potentially cause some gas degradation. Recent measurement studies have identified SF₆ cover gas degradation in die casting applications on the order of 20 percent (Bartos et al. 2007). Sulfur hexafluoride may also be used as a cover gas for the casting of molten aluminum with high magnesium content; however, the extent to which this technique is used in the United States is unknown.

The results of this Tier 2 quantitative uncertainty analysis are summarized in Table 4-74. SF₆ emissions associated with magnesium production and processing were estimated to be between 1.01 and 1.10 Tg CO₂ Eq. at the 95 percent confidence level. This indicates a range of approximately 6 percent below to 5 percent above the 2008 emission estimate of 1.05 Tg CO₂ Eq.

Table 4-74: Tier 2 Quantitative Uncertainty Estimates for SF₆ Emissions from Magnesium Production and Processing (Tg CO₂ Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate ^a			
			(Tg CO ₂ Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Magnesium Production	SF ₆	1.05	1.01	1.10	-4%	+4%

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

Recalculations Discussion

The uncertainty estimates for 2009 are lower relative to the previous inventory uncertainty estimate for 2008 emissions, which is likely due to the fact that emission estimates for 2009 are based more on actual reported data than emission estimates for 2008 were in the 1990-2008 inventory, with two emission sources using projected (highly uncertain) estimates.

Planned Improvements

Cover gas research conducted by the EPA over the last decade has found that SF₆ used for magnesium melt protection can have degradation rates on the order of 20 percent in die casting applications (Bartos et al. 2007). Current emission estimates assume (per the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006)) that all SF₆ utilized is emitted to the atmosphere. Additional research may lead to a revision of IPCC Guidelines to reflect this phenomenon and until such time, developments in this sector will be monitored for possible application to the inventory methodology. Another issue that will be addressed in future inventories is the likely adoption of alternate cover gases by U.S. magnesium producers and processors. These cover gases, which include AM-cover™ (containing HFC-134a) and Novec™ 612, have lower GWPs than SF₆, and tend to quickly degrade during their exposure to the molten metal. Magnesium producers and processors have already begun using these cover gases for 2006 through 2009 in a limited fashion; because the amounts being used by companies on the whole are low enough that they have a minor effect on the overall emissions from the industry, these emissions are only being monitored and recorded at this time.

4.17. Zinc Production (IPCC Source Category 2C5)

Zinc production in the United States consists of both primary and secondary processes. Primary production in the United States is conducted through the electrolytic process while secondary techniques used in the United States include the electrothermic and Waelz kiln processes as well as a range of other metallurgical, hydrometallurgical, and pyrometallurgical processes. Worldwide primary zinc production also employs a pyrometallurgical process using the Imperial Smelting Furnace process; however, this process is not used in the United States (Sjardin 2003). Of the primary and secondary processes used in the United States, only the electrothermic and Waelz kiln secondary

processes result in non-energy CO₂ emissions (Viklund-White 2000).

During the electrothermic zinc production process, roasted zinc concentrate and secondary zinc products enter a sinter feed where they are burned to remove impurities before entering an electric retort furnace. Metallurgical coke added to the electric retort furnace reduces the zinc oxides and produces vaporized zinc, which is then captured in a vacuum condenser. This reduction process produces non-energy CO₂ emissions (Sjardin 2003).

In the Waelz kiln process, EAF dust, which is captured during the recycling of galvanized steel, enters a kiln along with a reducing agent—often metallurgical coke. When kiln temperatures reach approximately 1100–1200°C, zinc fumes are produced, which are combusted with air entering the kiln. This combustion forms zinc oxide, which is collected in a baghouse or electrostatic precipitator, and is then leached to remove chloride and fluoride. Through this process, approximately 0.33 metric ton of zinc is produced for every metric ton of EAF dust treated (Viklund-White 2000).

In 2009, U.S. primary and secondary zinc production was estimated to total 286,000 metric tons (USGS 2010). Since reported activity data for 2009 were not available for all necessary inputs in time for this publication, production values in 2009 were assumed to equal 2008 values in some cases. The resulting emissions of CO₂ from zinc production in 2009 were estimated to be 0.97 Tg CO₂ Eq. (966 Gg) (see Table 4-75). All 2009 CO₂ emissions resulted from secondary zinc production.

Table 4-75: CO₂ Emissions from Zinc Production (Tg CO₂ Eq. and Gg)

Year	Tg CO ₂ Eq.	Gg
1990	0.7	667
2000	1.0	997
2005	1.1	1088
2006	1.1	1088
2007	1.1	1081
2008	1.2	1230
2009	1.0	966

Emissions from zinc production in the U.S. have increased overall due to a gradual shift from non-emissive primary production to emissive secondary production. In 2009, emissions were estimated to be 45 percent higher than they were in 1990.

Methodology

Non-energy CO₂ emissions from zinc production result from the electrothermic and Waelz kiln secondary production processes, which both use metallurgical coke or other C-based materials as reductants. Sjardin (2003) provides an emission factor of 0.43 metric tons CO₂/metric ton zinc produced for emissive zinc production processes; however, this emission factor is based on the Imperial Smelting Furnace production process. Because the Imperial Smelting Furnace production process is not used in the United States, emission factors specific to electrothermic and Waelz kiln processes were needed. Due to the limited amount of information available for these electrothermic processes, only Waelz kiln process-specific emission factors were developed. These emission factors were applied to both the Waelz kiln and electrothermic secondary zinc production processes.

A Waelz kiln emission factor based on the amount of zinc produced was developed based on the amount of metallurgical coke consumed for non-energy purposes per ton of zinc produced, 1.19 metric tons coke/metric ton zinc produced (Viklund-White 2000), and the following equation:

$$EF_{\text{Waelz Kiln}} = \frac{1.19 \text{ metric tons coke}}{\text{metric tons zinc}} \times \frac{0.85 \text{ metric tons C}}{\text{metric tons coke}} \times \frac{3.67 \text{ metric tons CO}_2}{\text{metric tons C}} = \frac{3.70 \text{ metric tons CO}_2}{\text{metric tons zinc}}$$

In addition, a Waelz kiln emission factor based on the amount of EAF dust consumed was developed based on the amount of metallurgical coke consumed per ton of EAF dust consumed, 0.4 metric tons coke/metric ton EAF dust

consumed (Viklund-White 2000), and the following equation:¹¹⁶

$$EF_{\text{EAF Dust}} = \frac{0.4 \text{ metric tons coke}}{\text{metric tons EAF dust}} \times \frac{0.85 \text{ metric tons C}}{\text{metric tons coke}} \times \frac{3.67 \text{ metric tons CO}_2}{\text{metric tons C}} = \frac{1.24 \text{ metric tons CO}_2}{\text{metric tons EAF Dust}}$$

The only companies in the United States that use emissive technology to produce secondary zinc products are Horsehead Corp and Steel Dust Recycling. For Horsehead Corp, EAF dust is recycled in Waelz kilns at their Beaumont, TX; Calumet, IL; Palmerton, PA; and Rockwood, TN facilities (and soon to be performed at their new South Carolina facility). These Waelz kiln facilities produce intermediate zinc products (crude zinc oxide or calcine), most of which is transported to their Monaca, PA facility where the products are smelted into refined zinc using electrothermic technology. Some of Horsehead's intermediate zinc products that are not smelted at Monaca are instead exported to other countries around the world (Horsehead Corp 2010). Steel Dust Recycling recycles EAF dust into intermediate zinc products using Waelz kilns, and then sells the intermediate products to companies who smelt it into refined products.

The total amount of EAF dust consumed by Horsehead Corp at their Waelz kilns was available from Horsehead financial reports for years 2006 through 2009 (Horsehead 2010). Consumption levels for 1990 through 2005 were extrapolated using the percentage change in annual refined zinc production at secondary smelters in the United States as provided by USGS Minerals Yearbook: Zinc (USGS 1994 through 2010). The EAF dust consumption values for each year were then multiplied by the 1.24 metric tons CO₂/metric ton EAF dust consumed emission factor to develop CO₂ emission estimates for Horsehead's Waelz kiln facilities.

The amount of EAF dust consumed by the Steel Dust Recycling facility for 2008 and 2009 (the only two years it has been in operation) was not publically available. Therefore, these consumption values were estimated by calculating the 2008 and 2009 capacity utilization of Horsehead's Waelz kilns and multiplying this utilization ratio by the capacity of Steel Dust Recycling's facility, which were available from the company (Steel Dust Recycling LLC 2010). The 1.24 metric tons CO₂/metric ton EAF dust consumed emission factor was then applied to Steel Dust Recycling's estimated EAF dust consumption to develop CO₂ emission estimates for its Waelz kiln facility.

Refined zinc production levels for Horsehead's Monaca, PA facility (utilizing electrothermic technology) were available from the company for years 2005 through 2009 (Horsehead Corp 2010, Horsehead Corp 2008). Production levels for 1990 through 2004 were extrapolated using the percentage changes in annual refined zinc production at secondary smelters in the United States as provided by USGS Minerals Yearbook: Zinc (USGS 1994 through 2010). The 3.70 metric tons CO₂/metric ton zinc emission factor was then applied to the Monaca facility's production levels to estimate CO₂ emissions for the facility. The Waelz kiln production emission factor was applied in this case rather than the EAF dust consumption emission factor since Horsehead's Monaca facility did not consume EAF dust.

Table 4-76: Zinc Production (Metric Tons)

Year	Primary	Secondary
1990	262,704	95,708
2000	227,800	143,000
2005	191,120	156,000
2006	113,000	156,000
2007	121,000	157,000
2008	125,000	161,000
2009	125,000	161,000

¹¹⁶ For Waelz kiln based secondary zinc production, IPCC recommends the use of emission factors based on EAF dust consumption rather than the amount of zinc produced since the amount of reduction materials used is more directly dependent on the amount of EAF dust consumed (IPCC 2006).

Uncertainty and Time-Series Consistency

The uncertainties contained in these estimates are two-fold, relating to activity data and emission factors used.

First, there is uncertainty associated with the amount of EAF dust consumed in the United States to produce secondary zinc using emission-intensive Waelz kilns. The estimate for the total amount of EAF dust consumed in Waelz kilns is based on (1) an EAF dust consumption value reported annually by Horsehead Corporation as part of its financial reporting to the Securities and Exchange Commission (SEC), and (2) an estimate of the amount of EAF dust consumed at a Waelz kiln facility operated in Alabama by Steel Dust Recycling LLC. Since actual EAF dust consumption information is not available for the Steel Dust Recycling LLC facility, the amount is estimated by multiplying the EAF dust recycling capacity of the facility (available from the company's Web site) by the capacity utilization factor for Horsehead Corporation (which is available from Horsehead's financial reports). Therefore, there is uncertainty associated with the assumption that the capacity utilization of Steel Dust Recycling LLC's Waelz kiln facility is equal to the capacity utilization of Horsehead's Waelz kiln facility. Second, there are uncertainties associated with the emission factors used to estimate CO₂ emissions from secondary zinc production processes. The Waelz kiln emission factors are based on materials balances for metallurgical coke and EAF dust consumed as provided by Viklund-White (2000). Therefore, the accuracy of these emission factors depend upon the accuracy of these materials balances. Data limitations prevented the development of emission factors for the electrothermic process. Therefore, emission factors for the Waelz kiln process were applied to both electrothermic and Waelz kiln production processes. The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 4-77. Zinc production CO₂ emissions were estimated to be between 0.8 and 1.1 Tg CO₂ Eq. at the 95 percent confidence level. This indicates a range of approximately 17 percent below and 18 percent above the emission estimate of 1.0 Tg CO₂ Eq.

Table 4-77: Tier 2 Quantitative Uncertainty Estimates for CO₂ Emissions from Zinc Production (Tg CO₂ Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate ^a			
			(Tg CO ₂ Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Zinc Production	CO ₂	1.0	0.8	1.1	-17%	+18%

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

Planned Improvements

Future improvements to the zinc production source category involve evaluating facility level greenhouse gas emissions data as a basis for improving emissions calculations from zinc production. Beginning in 2010, all U.S. zinc producing facilities (both primary and secondary) that emit over 25,000 tons of greenhouse gases (CO₂ Eq.) are required to monitor, calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. Under the program, EPA will obtain data for 2010 from these facilities based on use of higher tier methods and assess how this data could be used to improve the methodology and emissions factors for calculating emissions from the U.S. zinc production industry.

Recalculations Discussion

The methodology for estimating CO₂ emissions from zinc production was revised for the current Inventory based on the availability of new data regarding secondary zinc production in the United States. The previous Inventory methodology assumed that two facilities had produced zinc in the United States using emissive processes since 1990: Horsehead Corporation's Monaca, PA facility (electrothermic) and Horsehead Corporation's Palmerton, PA facility (Waelz kiln). The 3.70 metric tons CO₂/metric ton zinc emission factor was applied to the estimated refined zinc production at the Monaca, PA electrothermic facility, and the 1.24 metric tons CO₂/metric ton EAF dust consumed emission factor was applied to the estimated EAF dust consumption at the Palmerton, PA Waelz kiln facility. The annual zinc production (for the Monaca facility) and EAF dust consumption (for the Palmerton

facility) were estimated using historic values that were published in articles for select years (extrapolation techniques were used for years in which published data was not available). The Monaca, PA facility was assumed to have closed in 2003 and not operated since.

New data for the industry showed that there were emissive zinc-producing facilities not being captured by the previous Inventory methodology. The facilities that were not captured included three Horsehead Corp Waelz kiln facilities in Beaumont, TX; Calumet, IL; and Rockwood, TN as well as a Waelz kiln facility commissioned in 2008 in Millport, AL by Steel Dust Recycling LLC. Also, research showed that the Monaca, PA facility only closed temporarily in 2003 and has been operating every year since (the Monaca, PA facility produces refined zinc from intermediary zinc products produced at Horsehead's other facilities). The updated methodology utilizes EAF dust consumption values and secondary zinc production values released annually by the main secondary zinc producer in the United States (Horsehead Corp.), and also includes the previously overlooked secondary zinc producing facilities in the emission estimates.

As a result of the revised methodology, historical emission estimates decreased by an average of 11 percent between 1990 and 2002, while emission estimates increased by an average of 140 percent between 2003 and 2009. The significant changes in emission estimates for years 2005 through 2008 were largely driven by Horsehead Corp's Monaca, PA facility being captured in the emission calculations for these years.

4.18. Lead Production (IPCC Source Category 2C5)

Lead production in the United States consists of both primary and secondary processes—both of which emit CO₂ (Sjardin 2003). Primary lead production, in the form of direct smelting, occurs at a just a single plant in Missouri. Secondary production largely involves the recycling of lead acid batteries at approximately 21 separate smelters in the United States. Fifteen of those secondary smelters have annual capacities of 15,000 tons or more and were collectively responsible for 99 percent of secondary lead production in 2009 (USGS 2010). Secondary lead production has increased in the United States over the past decade while primary lead production has decreased. In 2009, secondary lead production accounted for approximately 92 percent of total lead production (USGS 2011).

Primary production of lead through the direct smelting of lead concentrate produces CO₂ emissions as the lead concentrates are reduced in a furnace using metallurgical coke (Sjardin 2003). U.S. primary lead production decreased by 24 percent from 2008 to 2009, and has decreased by 75 percent since 1990 (USGS 2011, USGS 1995).

Similar to primary lead production, CO₂ emissions from secondary production result when a reducing agent, usually metallurgical coke, is added to the smelter to aid in the reduction process. CO₂ emissions from secondary production also occur through the treatment of secondary raw materials (Sjardin 2003). U.S. secondary lead production decreased from 2008 to 2009 by 3 percent, and has increased by 20 percent since 1990 (USGS 2011, USGS 1995).

At last reporting, the United States was the third largest mine producer of lead in the world, behind China and Australia, accounting for 11 percent of world production in 2009 (USGS 2011). In 2009, U.S. primary and secondary lead production totaled 1,213,000 metric tons (USGS 2011). The resulting emissions of CO₂ from 2009 production were estimated to be 0.5 Tg CO₂ Eq. (525 Gg) (see Table 4-78). The majority of 2009 lead production is from secondary processes, which accounted for 95 percent of total 2009 CO₂ emissions.

Table 4-78: CO₂ Emissions from Lead Production (Tg CO₂ Eq. and Gg)

Year	Tg CO₂ Eq.	Gg
1990	0.5	516
2000	0.6	594
2005	0.6	553
2006	0.6	560
2007	0.6	562
2008	0.6	551
2009	0.5	525

After a gradual decrease in total emissions from 1990 to 1995, total emissions have gradually increased since 1995

and emissions in 2009 were two percent greater than in 1990. Although primary production has decreased significantly (75 percent since 1990), secondary production has increased by about 20 percent over the same time period. Since secondary production is more emissions-intensive, the increase in secondary production since 1990 has resulted in a net increase in emissions despite the sharp decrease in primary production (USGS 2011, USGS 1994).

Methodology

Non-energy CO₂ emissions from lead production result from primary and secondary production processes that use metallurgical coke or other C-based materials as reductants. For primary lead production using direct smelting, Sjardin (2003) and the IPCC (2006) provide an emission factor of 0.25 metric tons CO₂/metric ton lead. For secondary lead production, Sjardin (2003) and IPCC (2006) provide an emission factor of 0.25 metric tons CO₂/metric ton lead for direct smelting as well as an emission factor of 0.2 metric tons CO₂/metric ton lead produced for the treatment of secondary raw materials (i.e., pretreatment of lead acid batteries). The direct smelting factor (0.25) and the sum of the direct smelting and pretreatment emission factors (0.45) are multiplied by total U.S. primary and secondary lead production, respectively, to estimate CO₂ emissions.

The 1990 through 2009 activity data for primary and secondary lead production (see Table 4-79) were obtained through the USGS Mineral Yearbook: Lead (USGS 1994 through 2011).

Table 4-79: Lead Production (Metric Tons)

Year	Primary	Secondary
1990	404,000	922,000
2000	341,000	1,130,000
2005	143,000	1,150,000
2006	153,000	1,160,000
2007	123,000	1,180,000
2008	135,000	1,150,000
2009	103,000	1,110,000

Uncertainty and Time-Series Consistency

Uncertainty associated with lead production relates to the emission factors and activity data used. The direct smelting emission factor used in primary production is taken from Sjardin (2003) who averages the values provided by three other studies (Dutrizac et al. 2000, Morris et al. 1983, Ullman 1997). For secondary production, Sjardin (2003) adds a CO₂ emission factor associated with battery treatment. The applicability of these emission factors to plants in the United States is uncertain. There is also a smaller level of uncertainty associated with the accuracy of primary and secondary production data provided by the USGS.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 4-80. Lead production CO₂ emissions were estimated to be between 0.5 and 0.6 Tg CO₂ Eq. at the 95 percent confidence level. This indicates a range of approximately 14 percent below and 15 percent above the emission estimate of 0.5 Tg CO₂ Eq.

Table 4-80: Tier 2 Quantitative Uncertainty Estimates for CO₂ Emissions from Lead Production (Tg CO₂ Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate ^a			
			(Tg CO ₂ Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Lead Production	CO ₂	0.5	0.5	0.6	-14%	+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 time-series consistency from 1990 through 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

Planned Improvements

Future improvements to the lead production source category involve evaluating facility level greenhouse gas emissions data as a basis for improving emission calculations from lead production. Beginning in 2010, all U.S. lead producing facilities (primary and secondary) that emit over 25,000 tons of greenhouse gases (CO₂ Eq.) are required to monitor, calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. Under the Program, EPA will obtain data for 2010 from these facilities based on use of higher tier methods and assess how this data could be used to improve the methodology and emissions factors for calculating emissions from the U.S. lead production industry.

Recalculations Discussion

In previous Inventory reports, CO₂ emissions from secondary lead production were estimated by multiplying secondary lead production values from USGS by an emission factor of 0.2 metric tons CO₂/metric ton lead produced. This emission factor is provided by Sjardin (2003) and IPCC (2006) for the treatment of secondary raw materials (i.e., pretreatment of lead acid batteries). Due to a misinterpretation of language in Sjardin (2003) and IPCC (2006), this was the only emission factor applied to secondary lead production even though an emission factor of 0.25 metric tons CO₂/metric ton lead for direct smelting should have been applied as well. This issue has been corrected for the current Inventory, and increased 1990 through 2008 emissions from lead production by an average of 95 percent per year relative to the previous Inventory.

4.19. HCFC-22 Production (IPCC Source Category 2E1)

Trifluoromethane (HFC-23 or CHF₃) is generated as a by-product 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. 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.¹¹⁷ Feedstock production, however, is permitted to continue indefinitely.

HCFC-22 is produced by the reaction of chloroform (CHCl₃) and hydrogen fluoride (HF) in the presence of a catalyst, SbCl₅. The reaction of the catalyst and HF produces SbCl_xF_y, (where x + y = 5), which reacts with 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 (CHCl₂F), HCFC-22 (CHClF₂), HFC-23 (CHF₃), 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.

Emissions of HFC-23 in 2009 were estimated to be 5.4 Tg CO₂ Eq. (0.5 Gg) (Table 4-81). This quantity represents a 60 percent decrease from 2008 emissions and a 85 percent decline from 1990 emissions. The decrease from 2008 emissions was caused by a 27 percent decrease in HCFC-22 production and a 46 percent decrease in the HFC-23 emission rate. The decline from 1990 emissions is due to a 34 percent decrease in HCFC-22 production and a 78 percent decrease in the HFC-23 emission rate since 1990. The decrease in the emission rate is primarily attributable to five 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, and (e) another plant began destroying HFC-23. All three HCFC-22 production plants operating in the United States in 2009 used thermal oxidation to significantly lower their HFC-23 emissions.

¹¹⁷ 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]

Table 4-81: HFC-23 Emissions from HCFC-22 Production (Tg CO₂ Eq. and Gg)

Year	Tg CO₂ Eq.	Gg
1990	36.4	3
2000	28.6	2
2005	15.8	1
2006	13.8	1
2007	17.0	1
2008	13.6	1
2009	5.4	0.46

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 for National Greenhouse Gas Inventories (IPCC 2006) were used. 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 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.

In most years, including 2010, an industry association aggregates and reports to EPA country-level estimates of HCFC-22 production and HFC-23 emissions (ARAP 1997, 1999, 2000, 2001, 2002, 2003, 2004, 2005, 2006, 2007, 2008, 2009, 2010). However, in 1997 and 2008, EPA (through a contractor) performed comprehensive reviews of plant-level estimates of HFC-23 emissions and HCFC-22 production (RTI 1997; RTI 2008). These reviews enabled EPA to review, update, and where necessary, correct U.S. totals, and also to perform plant-level uncertainty analyses (Monte-Carlo simulations) for 1990, 1995, 2000, 2005, and 2006. Estimates of annual U.S. HCFC-22 production are presented in Table 4-82.

Table 4-82: HCFC-22 Production (Gg)

Year	Gg
1990	139
2000	186
2005	156
2006	154
2007	162
2008	126
2009	91

Uncertainty and Time Series Consistency

The uncertainty analysis presented in this section was based on a plant-level Monte Carlo 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.

Because plant-level emissions data for 2009 were not available, the relative errors yielded by the Monte Carlo simulation for 2006 were applied to the U.S. emission estimate for 2009. The resulting estimates of absolute uncertainty are likely to be 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 2008 and 2009 (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 Tier 2 quantitative uncertainty analysis are summarized in Table 4-83. HFC-23 emissions from HCFC-22 production were estimated to be between 5.0 and 5.9 Tg CO₂ Eq. at the 95percent confidence level. This indicates a range of approximately 7 percent below and 10 percent above the emission estimate of 5.4 Tg CO₂ Eq.

Table 4-83: Quantitative Uncertainty Estimates for HFC-23 Emissions from HCFC-22 Production (Tg CO₂ Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate ^a (Tg CO ₂ Eq.)			
			Lower Bound	Upper Bound	Lower Bound (%)	Upper Bound (%)
HCFC-22 Production	HFC-23	5.4	5.0	5.9	-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 2009. Details on the emission trends through time are described in more detail in the Methodology section, above.

Planned Improvements

Beginning in 2010, all U.S. HCFC-22 production facilities are required to calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program. Data collected under this program will be used in future inventories to improve the calculation of national emissions from HCFC-22 production

4.20. Substitution of Ozone Depleting Substances (IPCC Source Category 2F)

Hydrofluorocarbons (HFCs) and perfluorocarbons (PFCs) are used as alternatives to several classes of ozone-depleting substances (ODSs) that are being phased out under the terms of the Montreal Protocol and the Clean Air Act Amendments of 1990.¹¹⁸ Ozone depleting substances—chlorofluorocarbons (CFCs), halons, carbon tetrachloride, methyl chloroform, and hydrochlorofluorocarbons (HCFCs)—are used in a variety of industrial applications including refrigeration and air conditioning equipment, solvent cleaning, foam production, sterilization, fire extinguishing, and aerosols. Although HFCs and PFCs are not harmful to the stratospheric ozone layer, they are potent greenhouse gases. Emission estimates for HFCs and PFCs used as substitutes for ODSs are provided in Table 4-84 and Table 4-85.

Table 4-84: Emissions of HFCs and PFCs from ODS Substitutes (Tg CO₂ Eq.)

Gas	1990	2000	2005	2006	2007	2008	2009
HFC-23	+	+	+	+	+	+	+
HFC-32	+	+	0.3	0.6	1.0	1.3	1.7
HFC-125	+	5.2	10.1	12.5	15.1	18.2	21.6
HFC-134a	+	60.4	75.1	75.0	72.3	69.3	66.7
HFC-143a	+	4.1	12.2	14.4	16.7	19.2	22.0
HFC-236fa	+	0.5	0.8	0.8	0.9	0.9	0.9

¹¹⁸ [42 U.S.C § 7671, CAA § 601]

CF ₄	+		+		+	+	+	+	+
Others*	0.3		4.0		5.6	6.0	6.3	6.7	7.0
Total	0.3		74.3		104.2	109.4	112.3	115.5	120.0

+ Does not exceed 0.05 Tg CO₂ Eq.

* Others include HFC-152a, HFC-227ea, HFC-245fa, HFC-4310mee, C₄F₁₀, and PFC/PFPEs, the latter being a proxy for a diverse collection of PFCs and perfluoropolyethers (PFPEs) employed for solvent applications. For estimating purposes, the GWP value used for PFC/PFPEs was based upon C₆F₁₄.

Note: Totals may not sum due to independent rounding.

Table 4-85: Emissions of HFCs and PFCs from ODS Substitution (Mg)

Gas	1990		2000		2005	2006	2007	2008	2009
HFC-23	+		1		1	1	1	2	2
HFC-32	+		26		505	971	1,465	1,977	2,540
HFC-125	+		1,855		3,619	4,453	5,393	6,486	7,730
HFC-134a	+		46,465		57,777	57,728	55,603	53,294	51,281
HFC-143a	+		1,089		3,200	3,782	4,402	5,044	5,798
HFC-236fa	+		85		125	131	136	141	144
CF ₄	+		1		2	2	2	2	2
Others*	M		M		M	M	M	M	M

M (Mixture of Gases)

+ Does not exceed 0.5 Mg

* Others include HFC-152a, HFC-227ea, HFC-245fa, HFC-4310mee, C₄F₁₀, and PFC/PFPEs, the latter being a proxy for a diverse collection of PFCs and perfluoropolyethers (PFPEs) employed for solvent applications.

In 1990 and 1991, the only significant emissions of HFCs and PFCs as substitutes to ODSs were relatively small amounts of HFC-152a—used as an aerosol propellant and also a component of the refrigerant blend R-500 used in chillers—and HFC-134a in refrigeration end-uses. Beginning in 1992, HFC-134a was used in growing amounts as a refrigerant in motor vehicle air-conditioners and in refrigerant blends such as R-404A.¹¹⁹ In 1993, the use of HFCs in foam production began, and in 1994 these compounds also found applications as solvents. In 1995, ODS substitutes for halons entered widespread use in the United States as halon production was phased-out.

The use and subsequent emissions of HFCs and PFCs as ODS substitutes has been increasing from small amounts in 1990 to 120.0 Tg CO₂ Eq. in 2009. 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 accelerate 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. Improvements in the technologies associated with the use of these gases and the introduction of alternative gases and technologies, however, may help to offset this anticipated increase in emissions.

Table 4-86 presents emissions of HFCs and PFCs as ODS substitutes by end-use sector for 1990 through 2009. The end-use sectors that contributed the most toward emissions of HFCs and PFCs as ODS substitutes in 2009 include refrigeration and air-conditioning (104.9 Tg CO₂ Eq., or approximately 87 percent), aerosols (9.1 Tg CO₂ Eq., or approximately 8 percent), and foams (3.9 Tg CO₂ Eq., or approximately 3 percent). Within the refrigeration and air-conditioning end-use sector, motor vehicle air-conditioning was the highest emitting end-use (45.9 Tg CO₂ Eq.), followed by refrigerated retail food and transport. Each of the end-use sectors is described in more detail below.

Table 4-86: Emissions of HFCs and PFCs from ODS Substitutes (Tg CO₂ Eq.) by Sector

Gas	1990		2000		2005	2006	2007	2008	2009
Refrigeration/Air Conditioning	+		61.6		93.1	97.6	99.8	102.3	104.9
Aerosols	0.3		10.1		7.3	7.7	8.2	8.6	9.1
Foams	+		0.3		1.9	2.1	2.3	2.5	3.9
Solvents	+		2.1		1.3	1.3	1.3	1.3	1.3
Fire Protection	+		0.2		0.5	0.6	0.7	0.7	0.8
Total	0.3		74.3		104.2	109.4	112.3	115.5	120.0

¹¹⁹ R-404A contains HFC-125, HFC-143a, and HFC-134a.

Refrigeration/Air Conditioning

The refrigeration and air-conditioning sector includes a wide variety of equipment types that have historically used CFCs or HCFCs. End-uses within this sector include motor vehicle air-conditioning, retail food refrigeration, refrigerated transport (e.g., ship holds, truck trailers, railway freight cars), household refrigeration, residential and small commercial air-conditioning/and heat pumps, chillers (large comfort cooling), cold storage facilities, and industrial process refrigeration (e.g., systems used in food processing, chemical, petrochemical, pharmaceutical, oil and gas, and metallurgical industries). As the ODS phaseout is taking effect, most equipment is being or will eventually be retrofitted or replaced to use HFC-based substitutes. Common HFCs in use today in refrigeration/air-conditioning equipment are HFC-134a, R-410A¹²⁰, R-404A, and R-507A¹²¹. These HFCs are emitted to the atmosphere during equipment manufacture and operation (as a result of component failure, leaks, and purges), as well as at servicing and disposal events.

Aerosols

Aerosol propellants are used in metered dose inhalers (MDIs) and a variety of personal care products and technical/specialty products (e.g., duster sprays and safety horns). Many pharmaceutical companies that produce MDIs—a type of inhaled therapy used to treat asthma and chronic obstructive pulmonary disease—have committed to replace the use of CFCs with HFC-propellant alternatives. The earliest ozone-friendly MDIs were produced with HFC-134a, but the industry has started to use HFC-227ea as well. Conversely, since the use of CFC propellants was banned in 1978, most consumer aerosol products have not transitioned to HFCs, but to “not-in-kind” technologies, such as solid roll-on deodorants and finger-pump sprays. The transition away from ODS in specialty aerosol products has also led to the introduction of non-fluorocarbon alternatives (e.g., hydrocarbon propellants) in certain applications, in addition to HFC-134a or HFC-152a. These propellants are released into the atmosphere as the aerosol products are used.

Foams

CFCs and HCFCs have traditionally been used as foam blowing agents to produce polyurethane (PU), polystyrene, polyolefin, and phenolic foams, which are used in a wide variety of products and applications. Since the Montreal Protocol, flexible PU foams as well as other types of foam, such as polystyrene sheet, polyolefin, and phenolic foam, have transitioned almost completely away from fluorocompounds, into alternatives such as CO₂, methylene chloride, and hydrocarbons. The majority of rigid PU foams have transitioned to HFCs—primarily HFC-134a and HFC-245fa. Today, these HFCs are used to produce polyurethane appliance, PU commercial refrigeration, PU spray, and PU panel foams—used in refrigerators, vending machines, roofing, wall insulation, garage doors, and cold storage applications. In addition, HFC-152a is used to produce polystyrene sheet/board foam, which is used in food packaging and building insulation. Emissions of blowing agents occur when the foam is manufactured as well as during the foam lifetime and at foam disposal, depending on the particular foam type.

Solvents

CFCs, methyl chloroform (1,1,1-trichloroethane or TCA), and to a lesser extent carbon tetrachloride (CCl₄) were historically used as solvents in a wide range of cleaning applications, including precision, electronics, and metal cleaning. Since their phaseout, metal cleaning end-use applications have primarily transitioned to non-fluorocarbon solvents and not-in-kind processes. The precision and electronics cleaning end-uses have transitioned in part to high-GWP gases, due to their high reliability, excellent compatibility, good stability, low toxicity, and selective solvency. These applications rely on HFC-4310mee, HFC-365mfc, HFC-245fa, and to a lesser extent, PFCs. Electronics cleaning involves removing flux residue that remains after a soldering operation for printed circuit boards and other contamination-sensitive electronics applications. Precision cleaning may apply to either electronic components or to metal surfaces, and is characterized by products, such as disk drives, gyroscopes, and optical components, that require a high level of cleanliness and generally have complex shapes, small clearances, and other cleaning

¹²⁰ R-410A contains HFC-32 and HFC-125.

¹²¹ R-507A, also called R-507, contains HFC-125 and HFC-143a.

challenges. The use of solvents yields fugitive emissions of these HFCs and PFCs.

Fire Protection

Fire protection applications include portable fire extinguishers (“streaming” applications) that originally used halon 1211, and total flooding applications that originally used halon 1301, as well as some halon 2402. Since the production and sale of halons were banned in the United States in 1994, the halon replacement agent of choice in the streaming sector has been dry chemical, although HFC-236ea is also used to a limited extent. In the total flooding sector, HFC-227ea has emerged as the primary replacement for halon 1301 in applications that require clean agents. Other HFCs, such as HFC-23, HFC-236fa, and HFC-125, are used in smaller amounts. The majority of HFC-227ea in total flooding systems is used to protect essential electronics, as well as in civil aviation, military mobile weapons systems, oil/gas/other process industries, and merchant shipping. As fire protection equipment is tested or deployed, emissions of these HFCs occur.

Methodology

A detailed Vintaging Model of ODS-containing equipment and products was used to estimate the actual—versus potential—emissions of various ODS substitutes, including HFCs and PFCs. The name of the model refers to the fact that it tracks the use and emissions of various compounds for the annual “vintages” of new equipment that enter service in each end-use. The Vintaging Model predicts ODS and ODS substitute use in the United States based on modeled estimates of the quantity of equipment or products sold each year containing these chemicals and the amount of the chemical required to manufacture and/or maintain equipment and products over time. Emissions for each end-use were estimated by applying annual leak rates and release profiles, which account for the lag in emissions from equipment as they leak over time. By aggregating the data for nearly 60 different end-uses, the model produces estimates of annual use and emissions of each compound. Further information on the Vintaging Model is contained in Annex 3.8.

Uncertainty

Given that emissions of ODS substitutes occur from thousands of different kinds of equipment and from millions of point and mobile sources throughout the United States, emission estimates must be made using analytical tools such as the Vintaging Model or the methods outlined in IPCC (2006). Though the model is more comprehensive than the IPCC default methodology, significant uncertainties still exist with regard to the levels of equipment sales, equipment characteristics, and end-use emissions profiles that were used to estimate annual emissions for the various compounds.

The Vintaging Model estimates emissions from nearly 60 end-uses. The uncertainty analysis, however, quantifies the level of uncertainty associated with the aggregate emissions resulting from the top 21 end-uses, comprising over 95 percent of the total emissions, and 5 other end-uses. These 26 end-uses comprise 97 percent of the total emissions. In an effort to improve the uncertainty analysis, additional end-uses are added annually, with the intention that over time uncertainty for all emissions from the Vintaging Model will be fully characterized. Any end-uses included in previous years’ uncertainty analysis were included in the current uncertainty analysis, whether or not those end-uses were included in the top 95 percent of emissions from ODS Substitutes.

In order to calculate uncertainty, functional forms were developed to simplify some of the complex “vintaging” aspects of some end-use sectors, especially with respect to refrigeration and air-conditioning, and to a lesser degree, fire extinguishing. These sectors calculate emissions based on the entire lifetime of equipment, not just equipment put into commission in the current year, thereby necessitating simplifying equations. The functional forms used variables that included growth rates, emission factors, transition from ODSs, change in charge size as a result of the transition, disposal quantities, disposal emission rates, and either stock for the current year or original ODS consumption. Uncertainty was estimated around each variable within the functional forms based on expert judgment, and a Monte Carlo analysis was performed. The most significant sources of uncertainty for this source category include the emission factors for retail food equipment and refrigerated transport, as well as the percent of non-MDI aerosol propellant that is HFC-152a.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 4-87. Substitution of ozone depleting substances HFC and PFC emissions were estimated to be between 111.8 and 129.3 Tg CO₂ Eq. at the 95 percent confidence level. This indicates a range of approximately 7 percent below to 8 percent above the emission

estimate of 120.0 Tg CO₂ Eq.

Table 4-87: Tier 2 Quantitative Uncertainty Estimates for HFC and PFC Emissions from ODS Substitutes (Tg CO₂ Eq. and Percent)

Source	Gases	2009 Emission Estimate (Tg CO ₂ Eq.) ^a	Uncertainty Range Relative to Emission Estimate ^b			
			(Tg CO ₂ Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Substitution of Ozone Depleting Substances	HFCs and PFCs	117.1	109.0	126.5	-7%	+8%

^a 2009 emission estimates and the uncertainty range presented in this table correspond to selected end-uses within the aerosols, foams, solvents, fire extinguishing agents, and refrigerants sectors, but not for other remaining categories. Therefore, because the uncertainty associated with emissions from “other” ODS substitutes was not estimated, they were excluded in the estimates reported in this table.

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

Recalculations Discussion

An extensive review of the MDI aerosol, unitary air-conditioning, and domestic refrigerator foams markets resulted in revisions to the Vintaging Model since the previous Inventory. For MDI aerosols, the charge size for both the CFC and HFC propellants was revised. Based on research on substitutes and growth in the market, the percent of the CFC market that transitions to HFCs over the time series and the overall size of the MDI market decreased. For unitary air-conditioning, a review of air conditioner sales data reduced the quantity of air-conditioning equipment introduced into the market for 1990 through 1993 and 2008, while increasing the quantity of equipment sold into the market for 1994 through 2009. A review of the domestic refrigerator foams market increased the quantity of blowing agent consumed in the foam and decreased the quantity of blowing agent emitted during the foam manufacturing process. Overall, these changes to the Vintaging Model increased greenhouse gas emissions on average by 0.5 percent across the time series.

4.21. Semiconductor Manufacture (IPCC Source Category 2F6)

The semiconductor industry uses multiple long-lived fluorinated gases in plasma etching and plasma enhanced chemical vapor deposition (PECVD) processes to produce semiconductor products. The gases most commonly employed are trifluoromethane (HFC-23 or CHF₃), perfluoromethane (CF₄), perfluoroethane (C₂F₆), nitrogen trifluoride (NF₃), and sulfur hexafluoride (SF₆), although other compounds such as perfluoropropane (C₃F₈) and perfluorocyclobutane (c-C₄F₈) are also used. The exact combination of compounds is specific to the process employed.

A single 300 mm silicon wafer that yields between 400 to 500 semiconductor products (devices or chips) may require as many as 100 distinct fluorinated-gas-using process steps, principally to deposit and pattern dielectric films. Plasma etching (or patterning) of dielectric films, such as silicon dioxide and silicon nitride, is performed to provide pathways for conducting material to connect individual circuit components in each device. The patterning process uses plasma-generated fluorine atoms, which chemically react with exposed dielectric film to selectively remove the desired portions of the film. The material removed as well as undissociated fluorinated gases flow into waste streams and, unless emission abatement systems are employed, into the atmosphere. PECVD chambers, used for depositing dielectric films, are cleaned periodically using fluorinated and other gases. During the cleaning cycle the gas is converted to fluorine atoms in plasma, which etches away residual material from chamber walls, electrodes, and chamber hardware. Undissociated fluorinated gases and other products pass from the chamber to waste streams and, unless abatement systems are employed, into the atmosphere. In addition to emissions of unreacted gases, some fluorinated compounds can also be transformed in the plasma processes into different fluorinated compounds which are then exhausted, unless abated, into the atmosphere. For example, when C₂F₆ is used in cleaning or etching, CF₄ is generated and emitted as a process by-product. Besides dielectric film etching and PECVD chamber cleaning, much smaller quantities of fluorinated gases are used to etch polysilicon films and

refractory metal films like tungsten.

For 2009, total weighted emissions of all fluorinated greenhouse gases by the U.S. semiconductor industry were estimated to be 5.3 Tg CO₂ Eq. Combined emissions of all fluorinated greenhouse gases are presented in Table 4-88 and Table 4-89 below for years 1990, 2000 and the period 2005 to 2009. The rapid growth of this industry and the increasing complexity (growing number of layers)¹²² of semiconductor products led to an increase in emissions of 148 percent between 1990 and 1999, when emissions peaked at 7.2 Tg CO₂ Eq. The emissions growth rate began to slow after 1998, and emissions declined by 26 percent between 1999 and 2009. Together, industrial growth and adoption of emissions reduction technologies, including but not limited to abatement technologies, resulted in a net increase in emissions of 83 percent between 1990 and 2009.

Table 4-88: PFC, HFC, and SF₆ Emissions from Semiconductor Manufacture (Tg CO₂ Eq.)

Year	1990	2000	2005	2006	2007	2008	2009
CF ₄	0.7	1.8	1.1	1.2	1.3	1.4	1.5
C ₂ F ₆	1.5	3.0	2.0	2.2	2.3	2.4	2.5
C ₃ F ₈	0.0	0.1	0.0	0.0	0.0	0.1	0.0
C ₄ F ₈	0.0	0.0	0.1	0.1	0.1	0.1	0.0
HFC-23	0.2	0.3	0.2	0.3	0.3	0.3	0.3
SF ₆	0.5	1.1	1.0	1.0	0.8	0.9	1.0
NF ₃ *	0.0	0.2	0.4	0.7	0.5	0.6	0.5
Total	2.9	6.2	4.4	4.7	4.8	5.1	5.3

Note: Totals may not sum due to independent rounding.

* NF₃ emissions are presented for informational purposes, using the AR4 GWP of 17,200, and are not included in totals.

Table 4-89: PFC, HFC, and SF₆ Emissions from Semiconductor Manufacture (Mg)

Year	1990	2000	2005	2006	2007	2008	2009
CF ₄	115	281	168	181	198	216	227
C ₂ F ₆	160	321	216	240	249	261	271
C ₃ F ₈	0	18	5	5	6	13	5
C ₄ F ₈	0	0	13	13	7	7	4
HFC-23	15	23	18	22	23	25	28
SF ₆	22	45	40	40	34	36	40
NF ₃	3	11	26	40	30	33	30

Methodology

Emissions are based on Partner reported emissions data received through the EPA's PFC Reduction/Climate Partnership and the EPA's PFC Emissions Vintage Model (PEVM), a model which estimates industry emissions in the absence of emission control strategies (Burton and Beizaie 2001).¹²³ The availability and applicability of Partner data differs across the 1990 through 2009 time series. Consequently, emissions from semiconductor manufacturing were estimated using four distinct methods, one each for the periods 1990 through 1994, 1995 through 1999, 2000 through 2006, and 2007 through 2009.

1990 through 1994

From 1990 through 1994, Partnership data was unavailable and emissions were modeled using the PEVM (Burton

¹²² Complexity is a term denoting the circuit required to connect the active circuit elements (transistors) on a chip. Increasing miniaturization, for the same chip size, leads to increasing transistor density, which, in turn, requires more complex interconnections between those transistors. This increasing complexity is manifested by increasing the levels (i.e., layers) of wiring, with each wiring layer requiring fluorinated gas usage for its manufacture.

¹²³ A Partner refers to a participant in the U.S. EPA PFC Reduction/Climate Partnership for the Semiconductor Industry. Through a Memorandum of Understanding (MoU) with the EPA, Partners voluntarily report their PFC emissions to the EPA by way of a third party, which aggregates the emissions.

and Beizaie 2001).¹²⁴ 1990 to 1994 emissions are assumed to be uncontrolled, since reduction strategies such as chemical substitution and abatement were yet to be developed.

PEVM is based on the recognition that PFC emissions from semiconductor manufacturing vary with: (1) the number of layers that comprise different kinds of semiconductor devices, including both silicon wafer and metal interconnect layers, and (2) silicon consumption (i.e., the area of semiconductors produced) for each kind of device. The product of these two quantities, Total Manufactured Layer Area (TMLA), constitutes the activity data for semiconductor manufacturing. PEVM also incorporates an emission factor that expresses emissions per unit of layer-area. Emissions are estimated by multiplying TMLA by this emission factor.

PEVM incorporates information on the two attributes of semiconductor devices that affect the number of layers: (1) linewidth technology (the smallest manufactured feature size),¹²⁵ and (2) product type (discrete, memory or logic).¹²⁶ For each linewidth technology, a weighted average number of layers is estimated using VLSI product-specific worldwide silicon demand data in conjunction with complexity factors (i.e., the number of layers per Integrated Circuit (IC)) specific to product type (Burton and Beizaie 2001, ITRS 2007). PEVM derives historical consumption of silicon (i.e., square inches) by linewidth technology from published data on annual wafer starts and average wafer size (VLSI Research, Inc. 2010).

The emission factor in PEVM is the average of four historical emission factors, each derived by dividing the total annual emissions reported by the Partners for each of the four years between 1996 and 1999 by the total TMLA estimated for the Partners in each of those years. Over this period, the emission factors varied relatively little (i.e., the relative standard deviation for the average was 5 percent). Since Partners are believed not to have applied significant emission reduction measures before 2000, the resulting average emission factor reflects uncontrolled emissions. The emission factor is used to estimate world uncontrolled emissions using publicly available data on world silicon consumption.

1995 through 1999

For 1995 through 1999, total U.S. emissions were extrapolated from the total annual emissions reported by the Partners (1995 through 1999). Partner-reported emissions are considered more representative (e.g., in terms of capacity utilization in a given year) than PEVM estimated emissions, and are used to generate total U.S. emissions when applicable. The emissions reported by the Partners were divided by the ratio of the total capacity of the plants operated by the Partners and the total capacity of all of the semiconductor plants in the United States; this ratio represents the share of capacity attributable to the Partnership. This method assumes that Partners and non-Partners have identical capacity utilizations and distributions of manufacturing technologies. Plant capacity data is contained in the World Fab Forecast (WFF) database and its predecessors, which is updated quarterly (Semiconductor Equipment and Materials Industry 2010).

2000 through 2006

The emission estimate for the years 2000 through 2006—the period during which Partners began the consequential application of PFC-reduction measures—was estimated using a combination of Partner reported emissions and PEVM modeled emissions. The emissions reported by Partners for each year were accepted as the quantity emitted from the share of the industry represented by those Partners. Remaining emissions, those from non-Partners, were

¹²⁴ Various versions of the PEVM exist to reflect changing industrial practices. From 1990 to 1994 emissions estimates are from PEVM v1.0, completed in September 1998. The emission factor used to estimate 1990 to 1994 emissions is an average of the 1995 and 1996 emissions factors, which were derived from Partner reported data for those years.

¹²⁵ By decreasing features of Integrated Circuit components, more components can be manufactured per device, which increases its functionality. However, as those individual components shrink it requires more layers to interconnect them to achieve the functionality. For example, a microprocessor manufactured with the smallest feature sizes (65 nm) might contain as many as 1 billion transistors and require as many as 11 layers of component interconnects to achieve functionality while a device manufactured with 130 nm feature size might contain a few hundred million transistors and require 8 layers of component interconnects (ITRS 2007).

¹²⁶ Memory devices manufactured with the same feature sizes as microprocessors (a logic device) require approximately one-half the number of interconnect layers, whereas discrete devices require only a silicon base layer and no interconnect layers (ITRS 2007). Since discrete devices did not start using PFCs appreciably until 2004, they are only accounted for in the PEVM emissions estimates from 2004 onwards.

estimated using PEVM and the method described above. This is because non-Partners are assumed not to have implemented any PFC-reduction measures, and PEVM models emissions without such measures. The portion of the U.S. total attributed to non-Partners is obtained by multiplying PEVM's total U.S. emissions figure by the non-Partner share of U. S. total silicon capacity for each year as described above.^{127,128} Annual updates to PEVM reflect published figures for actual silicon consumption from VLSI Research, Inc., revisions and additions to the world population of semiconductor manufacturing plants, and changes in IC fabrication practices within the semiconductor industry (see ITRS 2007 and Semiconductor Equipment and Materials Industry 2010).^{129,130,131}

2007 through 2009

For the years 2007 through 2009, emissions were also estimated using a combination of Partner reported emissions and PEVM modeled emissions; however, two improvements were made to the estimation method employed for the previous years in the time series. First, the 2007 through 2009 emission estimates account for the fact that Partners and non-Partners employ different distributions of manufacturing technologies, with the Partners using manufacturing technologies with greater transistor densities and therefore greater numbers of layers.¹³² Second, the scope of the 2007 through 2009 estimates is expanded relative to the estimates for the years 2000 through 2006 to include emissions from Research and Development (R&D) fabs. This was feasible through the use of more detailed data published in the World Fab Forecast. PEVM databases are updated annually as described above. The published world average capacity utilization for 2007 and 2008 was used for production fabs while in 2008 for R&D fabs a 20 percent figure was assumed (SIA 2009).

In addition, publicly available actual utilization data was used to account for differences in fab utilization for manufacturers of discrete and IC products for the emissions in 2009 for non-partners. PEVM estimates were adjusted using technology weighted capacity shares that reflect relative influence of different utilization.

¹²⁷ This approach assumes that the distribution of linewidth technologies is the same between Partners and non-Partners. As discussed in the description of the method used to estimate 2007 emissions, this is not always the case.

¹²⁸ Generally 5 percent or less of the fields needed to estimate TMLA shares are missing values in the World Fab Watch databases. In the 2007 World Fab Watch database used to generate the 2006 non-Partner TMLA capacity share, these missing values were replaced with the corresponding mean TMLA across fabs manufacturing similar classes of products. However, the impact of replacing missing values on the non-Partner TMLA capacity share was inconsequential.

¹²⁹ Special attention was given to the manufacturing capacity of plants that use wafers with 300 mm diameters because the actual capacity of these plants is ramped up to design capacity, typically over a 2–3 year period. To prevent overstating estimates of partner-capacity shares from plants using 300 mm wafers, *design* capacities contained in WFW were replaced with estimates of *actual installed* capacities for 2004 published by Citigroup Smith Barney (2005). Without this correction, the partner share of capacity would be overstated, by approximately 5 percent. For perspective, approximately 95 percent of all new capacity additions in 2004 used 300 mm wafers, and by year-end those plants, on average, could operate at approximately 70 percent of the design capacity. For 2005, actual installed capacities were estimated using an entry in the World Fab Watch database (April 2006 Edition) called “wafers/month, 8-inch equivalent,” which denoted the actual installed capacity instead of the fully-ramped capacity. For 2006, actual installed capacities of new fabs were estimated using an average monthly ramp rate of 1100 wafer starts per month (wspm) derived from various sources such as semiconductor fabtech, industry analysts, and articles in the trade press. The monthly ramp rate was applied from the first-quarter of silicon volume (FQSV) to determine the average design capacity over the 2006 period.

¹³⁰ In 2006, the industry trend in co-ownership of manufacturing facilities continued. Several manufacturers, who are Partners, now operate fabs with other manufacturers, who in some cases are also Partners and in other cases are not Partners. Special attention was given to this occurrence when estimating the Partner and non-Partner shares of U.S. manufacturing capacity.

¹³¹ Two versions of PEVM are used to model non-Partner emissions during this period. For the years 2000 to 2003 PEVM v3.2.0506.0507 was used to estimate non-Partner emissions. During this time, discrete devices did not use PFCs during manufacturing and therefore only memory and logic devices were modeled in the PEVM v3.2.0506.0507. From 2004 onwards, discrete device fabrication started to use PFCs, hence PEVM v4.0.0701.0701, the first version of PEVM to account for PFC emissions from discrete devices, was used to estimate non-Partner emissions for this time period.

¹³² EPA considered applying this change to years before 2007, but found that it would be difficult due to the large amount of data (i.e., technology-specific global and non-Partner TMLA) that would have to be examined and manipulated for each year. This effort did not appear to be justified given the relatively small impact of the improvement on the total estimate for 2007 and the fact that the impact of the improvement would likely be lower for earlier years because the estimated share of emissions accounted for by non-Partners is growing as Partners continue to implement emission-reduction efforts.

Gas-Specific Emissions

Two different approaches were also used to estimate the distribution of emissions of specific fluorinated gases. Before 1999, when there was no consequential adoption of fluorinated-gas-reducing measures, a fixed distribution of fluorinated-gas use was assumed to apply to the entire U.S. industry. This distribution was based upon the average fluorinated-gas purchases made by semiconductor manufacturers during this period and the application of IPCC default emission factors for each gas (Burton and Beizaie 2001). For the 2000 through 2009 period, the 1990 through 1999 distribution was assumed to apply to the non-Partners. Partners, however, began reporting gas-specific emissions during this period. Thus, gas-specific emissions for 2000 through 2009 were estimated by adding the emissions reported by the Partners to those estimated for the non-Partners.

Data Sources

Partners estimate their emissions using a range of methods. For 2009, it is assumed that most Partners used a method at least as accurate as the IPCC's Tier 2a Methodology, recommended in the 2006 IPCC Guidelines for National Greenhouse Inventories (IPCC 2006). Data used to develop emission estimates are attributed in part to estimates provided by the members of the Partnership, and in part from data obtained from PEVM estimates. Estimates of operating plant capacities and characteristics for Partners and non-Partners were derived from the Semiconductor Equipment and Materials Industry (SEMI) World Fab Forecast (formerly World Fab Watch) database (1996 through 2009) (e.g., Semiconductor Materials and Equipment Industry, 2010). Actual world capacity utilizations for 2009 were obtained from Semiconductor International Capacity Statistics (SICAS) (SIA, 2009). Estimates of silicon consumed by linewidth from 1990 through 2009 were derived from information from VLSI Research, Inc. (2010), and the number of layers per linewidth was obtained from International Technology Roadmap for Semiconductors: 2006 Update (Burton and Beizaie 2001, ITRS 2007, ITRS 2008).

Uncertainty and Time Series Consistency

A quantitative uncertainty analysis of this source category was performed using the IPCC-recommended Tier 2 uncertainty estimation methodology, the Monte Carlo Stochastic Simulation technique. The equation used to estimate uncertainty is:

$$\text{U.S. emissions} = \sum \text{Partnership gas-specific submittals} + [(\text{non-Partner share of World TMLA}) \times (\text{PEVM Emission Factor} \times \text{World TMLA})]$$

The Monte Carlo analysis results presented below relied on estimates of uncertainty attributed to the four quantities on the right side of the equation. Estimates of uncertainty for the four quantities were in turn developed using the estimated uncertainties associated with the individual inputs to each quantity, error propagation analysis, Monte Carlo simulation, and expert judgment. The relative uncertainty associated with World TMLA estimate in 2009 is about ± 10 percent, based on the uncertainty estimate obtained from discussions with VLSI, Inc. For the share of World layer-weighted silicon capacity accounted for by non-Partners, a relative uncertainty of ± 8 percent was estimated based on a separate Monte Carlo simulation to account for the random occurrence of missing data in the World Fab Watch database. For the aggregate PFC emissions data supplied to the partnership, a relative uncertainty of ± 50 percent was estimated for each gas-specific PFC emissions value reported by an individual Partner, and error propagation techniques were used to estimate uncertainty for total Partnership gas-specific submittals.¹³³ A relative uncertainty of approximately ± 10 percent was estimated for the PEVM emission factor, based on the standard deviation of the 1996 to 1999 emission factors.¹³⁴ All estimates of uncertainties are given at 95-percent confidence intervals.

In developing estimates of uncertainty, consideration was also given to the nature and magnitude of the potential bias that World activity data (i.e., World TMLA) might have in its estimates of the number of layers associated with devices manufactured at each technology node. The result of a brief analysis indicated that U.S. TMLA overstates the average number of layers across all product categories and all manufacturing technologies for 2004 by 0.12 layers or 2.9 percent. The same upward bias is assumed for World TMLA, and is represented in the uncertainty analysis by deducting the absolute bias value from the World activity estimate when it is incorporated into the

¹³³ Error propagation resulted in Partnership gas-specific uncertainties ranging from 17 to 27 percent

¹³⁴ The average of 1996 to 1999 emission factor is used to derive the PEVM emission factor.

Monte Carlo analysis.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 4-90. The emissions estimate for total U.S. PFC emissions from semiconductor manufacturing were estimated to be between 4.8 and 5.9 Tg CO₂ Eq. at a 95 percent confidence level. This range represents 10 percent below to 11 percent above the 2009 emission estimate of 5.3 Tg CO₂ Eq. This range and the associated percentages apply to the estimate of total emissions rather than those of individual gases. Uncertainties associated with individual gases will be somewhat higher than the aggregate, but were not explicitly modeled.

Table 4-90: Tier 2 Quantitative Uncertainty Estimates for HFC, PFC, and SF₆ Emissions from Semiconductor Manufacture (Tg CO₂ Eq. and Percent)

Source	Gas	2009 Emission Estimate ^a (Tg CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate ^b			
			(Tg CO ₂ Eq.)		(%)	
			Lower Bound ^c	Upper Bound ^c	Lower Bound	Upper Bound
Semiconductor Manufacture	HFC, PFC, and SF ₆	5.3	4.8	5.9	-10%	+11%

^a Because the uncertainty analysis covered all emissions (including NF₃), the emission estimate presented here does not match that shown in Table 4-88.

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

^c Absolute lower and upper bounds were calculated using the corresponding lower and upper bounds in percentages.

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

Planned Improvements

With the exception of possible future updates to emission factors, the method to estimate non-Partner related emissions (i.e., PEVM) is not expected to change. Future improvements to the national emission estimates will primarily be associated with determining the portion of national emissions to attribute to Partner report totals (about 80 percent in recent years) and improvements in estimates of non-Partner totals. As the nature of the Partner reports change through time and industry-wide reduction efforts increase, consideration will be given to what emission reduction efforts—if any—are likely to be occurring at non-Partner facilities. Currently, none are assumed to occur.

Another point of consideration for future national emissions estimates is the inclusion of PFC emissions from heat transfer fluid (HTF) loss to the atmosphere and the production of photovoltaic cells (PVs). Heat transfer fluids, of which some are liquid perfluorinated compounds, are used during testing of semiconductor devices and, increasingly, are used to manage heat during the manufacture of semiconductor devices. Evaporation of these fluids is a source of emissions (EPA 2006). PFCs are also used during manufacture of PV cells that use silicon technology, specifically, crystalline, polycrystalline, and amorphous silicon technologies. PV manufacture is growing in the United States, and therefore may be expected to constitute a growing share of U.S. PFC emissions from the electronics sector.

4.22. Electrical Transmission and Distribution (IPCC Source Category 2F7)

The largest use of SF₆, both in the United States and internationally, is as an electrical insulator and interrupter in equipment that transmits and distributes electricity (RAND 2004). The gas has been employed by the electric power industry in the United States since the 1950s because of its dielectric strength and arc-quenching characteristics. It is used in gas-insulated substations, circuit breakers, and other switchgear. Sulfur hexafluoride has replaced flammable insulating oils in many applications and allows for more compact substations in dense urban areas.

Fugitive emissions of SF₆ can escape from gas-insulated substations and switchgear through seals, especially from older equipment. The gas can also be released during equipment manufacturing, installation, servicing, and disposal. Emissions of SF₆ from equipment manufacturing and from electrical transmission and distribution systems were estimated to be 12.8 Tg CO₂ Eq. (0.5 Gg) in 2009. This quantity represents a 55 percent decrease from the estimate for 1990 (see Table 4-91 and Table 4-92). This decrease is believed to have two causes: a sharp increase in the price of SF₆ during the 1990s and a growing awareness of the environmental impact of SF₆ emissions through

programs such as EPA's SF₆ Emission Reduction Partnership for Electric Power Systems.

Table 4-91: SF₆ Emissions from Electric Power Systems and Electrical Equipment Manufacturers (Tg CO₂ Eq.)

Year	Electric Power Systems	Electrical Equipment Manufacturers	Total
1990	28.1	0.3	28.4
2000	15.4	0.7	16.0
2005	14.1	1.1	15.1
2006	13.1	1.0	14.1
2007	12.4	0.8	13.2
2008	12.1	1.3	13.3
2009	12.1	0.7	12.8

Note: Totals may not sum due to independent rounding.

Table 4-92: SF₆ Emissions from Electric Power Systems and Electrical Equipment Manufacturers (Gg)

Year	Emissions
1990	1.2
2000	0.7
2005	0.6
2006	0.6
2007	0.6
2008	0.6
2009	0.5

Methodology

The estimates of emissions from Electric Transmission and Distribution are comprised of emissions from electric power systems and emissions from the manufacture of electrical equipment. The methodologies for estimating both sets of emissions are described below.

1999 through 2009 Emissions from Electric Power Systems

Emissions from electric power systems from 1999 to 2009 were estimated based on: (1) reporting from utilities participating in EPA's SF₆ Emission Reduction Partnership for Electric Power Systems (Partners), which began in 1999; and, (2) the relationship between emissions and utilities' transmission miles as reported in the 2001, 2004, 2007, and 2010 Utility Data Institute (UDI) Directories of Electric Power Producers and Distributors (UDI 2001, 2004, 2007, 2010). (Transmission miles are defined as the miles of lines carrying voltages above 34.5 kV.) Over the period from 1999 to 2009, Partner utilities, which for inventory purposes are defined as utilities that either currently are or previously have been part of the Partnership, represented between 42 percent and 47 percent of total U.S. transmission miles. For each year, the emissions reported by or estimated for Partner utilities were added to the emissions estimated for utilities that have never participated in the Partnership (i.e., non-Partners).¹³⁵

Partner utilities estimated their emissions using a Tier 3 utility-level mass balance approach (IPCC 2006). If a Partner utility did not provide data for a particular year, emissions were interpolated between years for which data were available or extrapolated based on Partner-specific transmission mile growth rates. In 2009, non-reporting Partners accounted for approximately 8 percent of the total emissions attributed to Partner utilities.

Emissions from non-Partners in every year since 1999 were estimated using the results of a regression analysis that showed that the emissions from reporting utilities were most strongly correlated with their transmission miles. The results of this analysis are not surprising given that, in the United States, SF₆ is contained primarily in transmission

¹³⁵ Partners in EPA's SF₆ Emission Reduction Partnership reduced their emissions by approximately 61% from 1999 to 2008.

equipment rated above 34.5 kV. The equations were developed based on the 1999 SF₆ emissions reported by a subset of 42 Partner utilities (representing approximately 23 percent of U.S. transmission miles) and 2000 transmission mileage data obtained from the 2001 UDI Directory of Electric Power Producers and Distributors (UDI 2001). Two equations were developed, one for small and one for large utilities (i.e., with fewer or more than 10,000 transmission miles, respectively). The distinction between utility sizes was made because the regression analysis showed that the relationship between emissions and transmission miles differed for small and large transmission networks. The same equations were used to estimate non-Partner emissions in 1999 and every year thereafter because non-Partners were assumed not to have implemented any changes that would have resulted in reduced emissions since 1999.

The regression equations are:

Non-Partner small utilities (fewer than 10,000 transmission miles, in kilograms):

$$\text{Emissions (kg)} = 1.001 \times \text{Transmission Miles}$$

Non-Partner large utilities (more than 10,000 transmission miles, in kilograms):

$$\text{Emissions (kg)} = 0.58 \times \text{Transmission Miles}$$

Data on transmission miles for each non-Partner utility for the years 2000, 2003, 2006, and 2009 were obtained from the 2001, 2004, 2007, and 2010 UDI Directories of Electric Power Producers and Distributors, respectively (UDI 2001, 2004, 2007, 2010). The U.S. transmission system grew by over 25,000 miles between 2000 and 2003 and by over 52,000 miles between 2003 and 2006. These periodic increases are assumed to have occurred gradually. Therefore, transmission mileage was assumed to increase at an annual rate of 1.3 percent between 2000 and 2003 and 2.6 percent between 2003 and 2006. This growth rate slowed to 0.2% from 2006 to 2009 as transmission miles increased by just 4,400 miles (approximately).

As a final step, total electric power system emissions were determined for each year by summing the Partner reported and estimated emissions (reported data was available through the EPA's SF₆ Emission Reduction Partnership for Electric Power Systems) and the non-Partner emissions (determined using the 1999 regression equations).

1990 through 1998 Emissions from Electric Power Systems

Because most participating utilities reported emissions only for 1999 through 2009, modeling was used to estimate SF₆ emissions from electric power systems for the years 1990 through 1998. To perform this modeling, U.S. emissions were assumed to follow the same trajectory as global emissions from this source during the 1990 to 1999 period. To estimate global emissions, the RAND survey of global SF₆ sales were used, together with the following equation for estimating emissions, which is derived from the mass-balance equation for chemical emissions (Volume 3, Equation 7.3) in the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006).¹³⁶ (Although equation 7.3 of the IPCC Guidelines appears in the discussion of substitutes for ozone-depleting substances, it is applicable to emissions from any long-lived pressurized equipment that is periodically serviced during its lifetime.)

$$\text{Emissions (kilograms SF}_6\text{)} = \text{SF}_6 \text{ purchased to refill existing equipment (kilograms) + nameplate capacity of retiring equipment (kilograms)}^{137}$$

Note that the above equation holds whether the gas from retiring equipment is released or recaptured; if the gas is recaptured, it is used to refill existing equipment, thereby lowering the amount of SF₆ purchased by utilities for this purpose.

Gas purchases by utilities and equipment manufacturers from 1961 through 2003 are available from the RAND (2004) survey. To estimate the quantity of SF₆ released or recovered from retiring equipment, the nameplate capacity of retiring equipment in a given year was assumed to equal 81.2 percent of the amount of gas purchased by

¹³⁶ Ideally, sales to utilities in the U.S. between 1990 and 1999 would be used as a model. However, this information was not available. There were only two U.S. manufacturers of SF₆ during this time period, so it would not have been possible to conceal sensitive sales information by aggregation.

¹³⁷ Nameplate capacity is defined as the amount of SF₆ within fully charged electrical equipment.

electrical equipment manufacturers 40 years previous (e.g., in 2000, the nameplate capacity of retiring equipment was assumed to equal 81.2 percent of the gas purchased in 1960). The remaining 18.8 percent was assumed to have been emitted at the time of manufacture. The 18.8 percent emission factor is an average of IPCC default SF₆ emission rates for Europe and Japan for 1995 (IPCC 2006). The 40-year lifetime for electrical equipment is also based on IPCC (2006). The results of the two components of the above equation were then summed to yield estimates of global SF₆ emissions from 1990 through 1999.

U.S. emissions between 1990 and 1999 are assumed to follow the same trajectory as global emissions during this period. To estimate U.S. emissions, global emissions for each year from 1990 through 1998 were divided by the estimated global emissions from 1999. The result was a time series of factors that express each year's global emissions as a multiple of 1999 global emissions. Historical U.S. emissions were estimated by multiplying the factor for each respective year by the estimated U.S. emissions of SF₆ from electric power systems in 1999 (estimated to be 15.0 Tg CO₂ Eq.).

Two factors may affect the relationship between the RAND sales trends and actual global emission trends. One is utilities' inventories of SF₆ in storage containers. When SF₆ prices rise, utilities are likely to deplete internal inventories before purchasing new SF₆ at the higher price, in which case SF₆ sales will fall more quickly than emissions. On the other hand, when SF₆ prices fall, utilities are likely to purchase more SF₆ to rebuild inventories, in which case sales will rise more quickly than emissions. This effect was accounted for by applying 3-year smoothing to utility SF₆ sales data. The other factor that may affect the relationship between the RAND sales trends and actual global emissions is the level of imports from and exports to Russia and China. SF₆ production in these countries is not included in the RAND survey and is not accounted for in any another manner by RAND. However, atmospheric studies confirm that the downward trend in estimated global emissions between 1995 and 1998 was real (see the Uncertainty discussion below).

1990 through 2009 Emissions from Manufacture of Electrical Equipment

The 1990 to 2009 emission estimates for original equipment manufacturers (OEMs) were derived by assuming that manufacturing emissions equal 10 percent of the quantity of SF₆ provided with new equipment. The quantity of SF₆ provided with new equipment was estimated based on statistics compiled by the National Electrical Manufacturers Association (NEMA). These statistics were provided for 1990 to 2000; the quantities of SF₆ provided with new equipment for 2001 to 2009 were estimated using Partner reported data and the total industry SF₆ nameplate capacity estimate (137.4 Tg CO₂ Eq. in 2009). Specifically, the ratio of new nameplate capacity to total nameplate capacity of a subset of Partners for which new nameplate capacity data was available from 1999 to 2009 was calculated. This ratio was then multiplied by the total industry nameplate capacity estimate to derive the amount of SF₆ provided with new equipment for the entire industry. The 10 percent emission rate is the average of the "ideal" and "realistic" manufacturing emission rates (4 percent and 17 percent, respectively) identified in a paper prepared under the auspices of the International Council on Large Electric Systems (CIGRE) in February 2002 (O'Connell et al. 2002).

Uncertainty

To estimate the uncertainty associated with emissions of SF₆ from Electric Transmission and Distribution, uncertainties associated with three quantities were estimated: (1) emissions from Partners, (2) emissions from non-Partners, and (3) emissions from manufacturers of electrical equipment. A Monte Carlo analysis was then applied to estimate the overall uncertainty of the emissions estimate.

Total emissions from the SF₆ Emission Reduction Partnership include emissions from both reporting and non-reporting Partners. For reporting Partners, individual Partner-reported SF₆ data was assumed to have an uncertainty of 10 percent. Based on a Monte Carlo analysis, the cumulative uncertainty of all Partner reported data was estimated to be 5.3 percent. The uncertainty associated with extrapolated or interpolated emissions from non-reporting Partners was assumed to be 20 percent.

There are two sources of uncertainty associated with the regression equations used to estimate emissions in 2009 from non-Partners: (1) uncertainty in the coefficients (as defined by the regression standard error estimate), and (2) the uncertainty in total transmission miles for non-Partners. In addition, there is uncertainty associated with the assumption that the emission factor used for non-Partner utilities (which accounted for approximately 57 percent of U.S. transmission miles in 2009) will remain at levels defined by Partners who reported in 1999. However, the last

source of uncertainty was not modeled.

Uncertainties were also estimated regarding (1) the quantity of SF₆ supplied with equipment by equipment manufacturers, which is projected from Partner provided nameplate capacity data and industry SF₆ nameplate capacity estimates, and (2) the manufacturers' SF₆ emissions rate.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 4-93. Electrical Transmission and Distribution SF₆ emissions were estimated to be between 10.2 and 15.7 Tg CO₂ Eq. at the 95 percent confidence level. This indicates a range of approximately 21 percent below and 22 percent above the emission estimate of 12.8 Tg CO₂ Eq.

Table 4-93: Tier 2 Quantitative Uncertainty Estimates for SF₆ Emissions from Electrical Transmission and Distribution (Tg CO₂ Eq. and percent)

Source	Gas	2009 Emission Estimate (Tg CO ₂ Eq.)	Uncertainty Range Relative to 2009 Emission Estimate ^a			
			(Tg CO ₂ Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Electrical Transmission and Distribution	SF ₆	12.8	10.2	15.7	-21%	+22%

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

In addition to the uncertainty quantified above, there is uncertainty associated with using global SF₆ sales data to estimate U.S. emission trends from 1990 through 1999. However, the trend in global emissions implied by sales of SF₆ appears to reflect the trend in global emissions implied by changing SF₆ concentrations in the atmosphere. That is, emissions based on global sales declined by 29 percent between 1995 and 1998, and emissions based on atmospheric measurements declined by 27 percent over the same period.

Several pieces of evidence indicate that U.S. SF₆ emissions were reduced as global emissions were reduced. First, the decreases in sales and emissions coincided with a sharp increase in the price of SF₆ that occurred in the mid-1990s and that affected the United States as well as the rest of the world. A representative from DILO, a major manufacturer of SF₆ recycling equipment, stated that most U.S. utilities began recycling rather than venting SF₆ within two years of the price rise. Finally, the emissions reported by the one U.S. utility that reported 1990 through 1999 emissions to EPA showed a downward trend beginning in the mid-1990s.

Recalculations Discussion

SF₆ emission estimates for the period 1990 through 2008 were updated based on (1) new data from EPA's SF₆ Emission Reduction Partnership; (2) revisions to interpolated and extrapolated non-reported Partner data; and (3) a correction made to 2004 transmission mile data for a large Partnership utility that had been interpreted incorrectly from the UDI database in previous years. Updating the 2004 transmission mile data for the Partner changed the annual transmission mile growth rates used to extrapolate total U.S. transmission mile values for years in which a UDI database was not purchased (including 1999). This recalculation impacted emission estimates in two ways. First, the regression coefficients used to estimate emissions for non-Partners are based on 1999 transmission miles and emissions for Partners that reported emissions in 1999, so the change in 1999 transmission miles affected the regression coefficients. The result was that the regression coefficient for utilities with fewer than 10,000 transmission miles increased from 0.89 to 1.001 kg of emissions per transmission mile, while the regression coefficient for utilities with more than 10,000 transmission miles increased very slightly from 0.577 to 0.578 kg of emissions per transmission mile. The second impact of the updated annual transmission mile growth rates was that the total non-Partner transmission miles that the regression coefficients are applied to were also affected. Based on the revisions listed above, SF₆ emissions from electric transmission and distribution increased between 4 to 9 percent for each year from 1990 through 2008.

In addition, the method for estimating potential emissions from the sector was updated for the 1990-2009 Inventory. In previous years, potential emissions were assumed to equal total industry SF₆ purchases, which were developed from two components: (1) purchases by Partner utilities from bulk gas distributors, and (2) purchases by electrical equipment manufacturers from bulk gas distributors. This previous method led to concerns of double-counting since Partners sometimes were recording all SF₆ received in cylinders from any source (including equipment

manufacturers) as gas received from bulk distributors. Therefore, SF₆ that was purchased by a utility from an equipment manufacturer was sometimes counted as a purchase by both the equipment manufacturer and the utility. The new method still assumes that potential emissions are equal to industry purchases, but estimates total purchases for the industry by adding the total amount of gas purchased by all U.S. utilities from any source (bulk distributor or equipment manufacturer) to estimated emissions from equipment manufacturers. It is assumed that all SF₆ purchased by equipment manufacturers is either emitted or sent to utilities.

4.23. Industrial Sources of Indirect Greenhouse Gases

In addition to the main greenhouse gases addressed above, many industrial processes generate emissions of indirect greenhouse gases. Total emissions of nitrogen oxides (NO_x), carbon monoxide (CO), and non-CH₄ volatile organic compounds (NMVOCs) from non-energy industrial processes from 1990 to 2009 are reported in Table 4-94.

Table 4-94: NO_x, CO, and NMVOC Emissions from Industrial Processes (Gg)

Gas/Source	1990	1995	2000	2005	2006	2007	2008	2009
NO_x	591	607	626	569	553	537	520	568
Other Industrial Processes	343	362	435	437	418	398	379	436
Chemical & Allied Product								
Manufacturing	152	143	95	55	57	59	61	55
Metals Processing	88	89	81	60	61	62	62	60
Storage and Transport	3	5	14	15	15	16	16	15
Miscellaneous*	5	8	2	2	2	2	2	2
CO	4,125	3,959	2,216	1,555	1,597	1,640	1,682	1,549
Metals Processing	2,395	2,159	1,175	752	788	824	859	752
Other Industrial Processes	487	566	537	484	474	464	454	484
Chemical & Allied Product								
Manufacturing	1,073	1,110	327	189	206	223	240	187
Storage and Transport	69	23	153	97	100	103	104	97
Miscellaneous*	101	102	23	32	30	27	25	29
NMVOCs	2,422	2,642	1,773	1,997	1,933	1,869	1,804	1,322
Storage and Transport	1,352	1,499	1,067	1,308	1,266	1,224	1,182	662
Other Industrial Processes	364	408	412	415	398	383	367	395
Chemical & Allied Product								
Manufacturing	575	599	230	213	211	210	207	206
Metals Processing	111	113	61	44	44	43	42	44
Miscellaneous*	20	23	3	17	14	10	7	15

* Miscellaneous includes the following categories: catastrophic/accidental release, other combustion, health services, cooling towers, and fugitive dust. It does not include agricultural fires or slash/prescribed burning, which are accounted for under the Field Burning of Agricultural Residues source.

Note: Totals may not sum due to independent rounding.

Methodology

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

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

Uncertainty and Time-Series Consistency

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

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

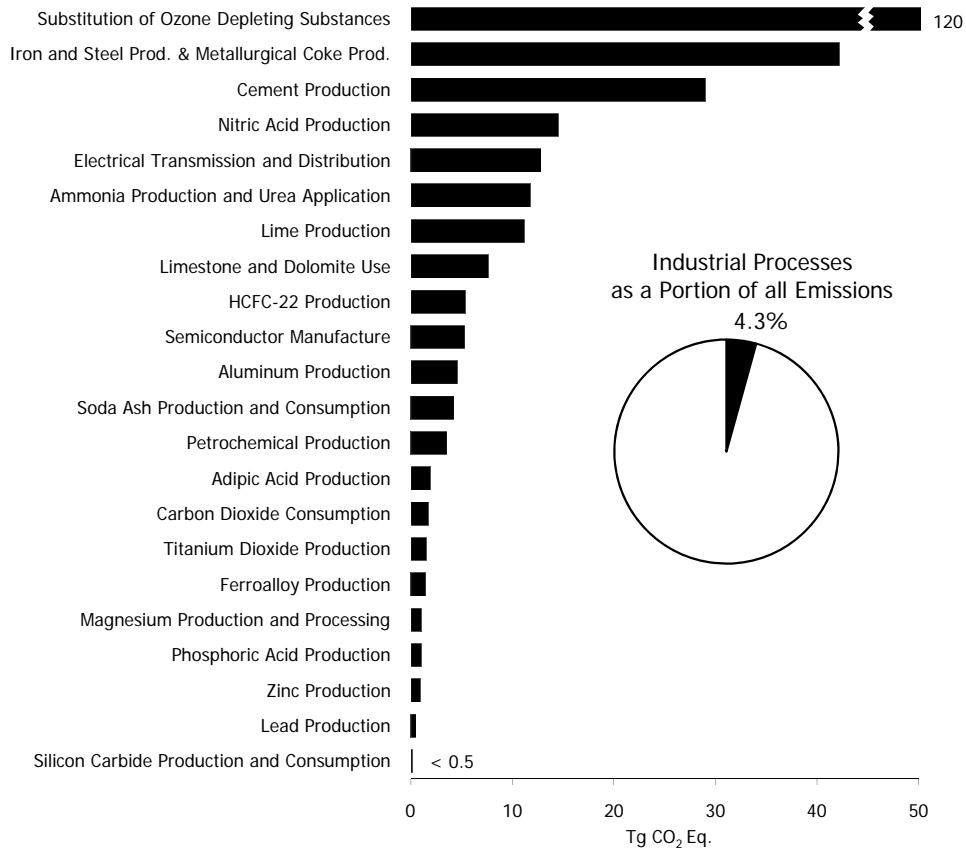


Figure 4-1: 2009 Industrial Processes Chapter Greenhouse Gas Sources

5. Solvent and Other Product Use

Greenhouse gas emissions are produced as a by-product of various solvent and other product uses. In the United States, emissions from Nitrous Oxide (N₂O) Product Uses, the only source of greenhouse gas emissions from this sector, accounted for less than 0.1 percent of total U.S. anthropogenic greenhouse gas emissions on a CO₂ equivalent basis in 2009 (see Table 5-1). Indirect greenhouse gas emissions also result from solvent and other product use, and are presented in Table 5-5 in gigagrams (Gg).

Table 5-1: N₂O Emissions from Solvent and Other Product Use (Tg CO₂ Eq. and Gg)

Gas/Source	1990	2000	2005	2006	2007	2008	2009
N ₂ O from Product Uses							
Tg CO ₂ Eq.	4.4	4.9	4.4	4.4	4.4	4.4	4.4
Gg	14	16	14	14	14	14	14

5.1. Nitrous Oxide from Product Uses (IPCC Source Category 3D)

N₂O is a clear, colorless, oxidizing liquefied gas, with a slightly sweet odor. Two companies operate a total of five N₂O production facilities in the United States (Airgas 2007; FTC 2001). N₂O is primarily used in carrier gases with oxygen to administer more potent inhalation anesthetics for general anesthesia, and as an anesthetic in various dental and veterinary applications. As such, it is used to treat short-term pain, for sedation in minor elective surgeries, and as an induction anesthetic. The second main use of N₂O is as a propellant in pressure and aerosol products, the largest application being pressure-packaged whipped cream. Small quantities of N₂O also are used in the following applications:

- Oxidizing agent and etchant used in semiconductor manufacturing;
- Oxidizing agent used, with acetylene, in atomic absorption spectrometry;
- Production of sodium azide, which is used to inflate airbags;
- Fuel oxidant in auto racing; and
- Oxidizing agent in blowtorches used by jewelers and others (Heydorn 1997).

Production of N₂O in 2009 was approximately 15 Gg (Table 5-2).

Table 5-2: N₂O Production (Gg)

Year	Gg
1990	16
2000	17
2005	15
2006	15
2007	15
2008	15
2009	15

N₂O emissions were 4.4 Tg CO₂ Eq. (14 Gg) in 2009 (Table 5-3). Production of N₂O stabilized during the 1990s because medical markets had found other substitutes for anesthetics, and more medical procedures were being performed on an outpatient basis using local anesthetics that do not require N₂O. The use of N₂O as a propellant for whipped cream has also stabilized due to the increased popularity of cream products packaged in reusable plastic tubs (Heydorn 1997).

Table 5-3: N₂O Emissions from N₂O Product Usage (Tg CO₂ Eq. and Gg)

Year	Tg CO ₂ Eq.	Gg
1990	4.4	14

2000	4.9	16
2005	4.4	14
2006	4.4	14
2007	4.4	14
2008	4.4	14
2009	4.4	14

Methodology

Emissions from N₂O product usage were calculated by first multiplying the total amount of N₂O produced in the United States by the share of the total quantity of N₂O attributed to each end use. This value was then multiplied by the associated emission rate for each end use. After the emissions were calculated for each end use, they were added together to obtain a total estimate of N₂O product usage emissions. Emissions were determined using the following equation:

$$\text{N}_2\text{O Product Usage Emissions} = \sum_i [\text{Total U.S. Production of N}_2\text{O}] \times [\text{Share of Total Quantity of N}_2\text{O Usage by Sector } i] \times [\text{Emissions Rate for Sector } i]$$

where,

i = Sector.

The share of total quantity of N₂O usage by end use represents the share of national N₂O produced that is used by the specific subcategory (i.e., anesthesia, food processing, etc.). In 2009, the medical/dental industry used an estimated 89.5 percent of total N₂O produced, followed by food processing propellants at 6.5 percent. All other categories combined used the remainder of the N₂O produced. This subcategory breakdown has changed only slightly over the past decade. For instance, the small share of N₂O usage in the production of sodium azide has declined significantly during the 1990s. Due to the lack of information on the specific time period of the phase-out in this market subcategory, most of the N₂O usage for sodium azide production is assumed to have ceased after 1996, with the majority of its small share of the market assigned to the larger medical/dental consumption subcategory (Heydorn 1997). The N₂O was allocated across the following categories: medical applications, food processing propellant, and sodium azide production (pre-1996). A usage emissions rate was then applied for each sector to estimate the amount of N₂O emitted.

Only the medical/dental and food propellant subcategories were estimated to release emissions into the atmosphere, and therefore these subcategories were the only usage subcategories with emission rates. For the medical/dental subcategory, due to the poor solubility of N₂O in blood and other tissues, none of the N₂O is assumed to be metabolized during anesthesia and quickly leaves the body in exhaled breath. Therefore, an emission factor of 100 percent was used for this subcategory (IPCC 2006). For N₂O used as a propellant in pressurized and aerosol food products, none of the N₂O is reacted during the process and all of the N₂O is emitted to the atmosphere, resulting in an emission factor of 100 percent for this subcategory (IPCC 2006). For the remaining subcategories, all of the N₂O is consumed/reacted during the process, and therefore the emission rate was considered to be zero percent (Tupman 2002).

The 1990 through 1992 N₂O production data were obtained from SRI Consulting's Nitrous Oxide, North America report (Heydorn 1997). N₂O production data for 1993 through 1995 were not available. Production data for 1996 was specified as a range in two data sources (Heydorn 1997, Tupman 2002). In particular, for 1996, Heydorn (1997) estimates N₂O production to range between 13.6 and 18.1 thousand metric tons. Tupman (2003) provided a narrower range (15.9 to 18.1 thousand metric tons) for 1996 that falls within the production bounds described by Heydorn (1997). Tupman (2003) data are considered more industry-specific and current. Therefore, the midpoint of the narrower production range was used to estimate N₂O emissions for years 1993 through 2001 (Tupman 2003). The 2002 and 2003 N₂O production data were obtained from the Compressed Gas Association Nitrous Oxide Fact Sheet and Nitrous Oxide Abuse Hotline (CGA 2002, 2003). These data were also provided as a range. For example, in 2003, CGA (2003) estimates N₂O production to range between 13.6 and 15.9 thousand metric tons. Due to unavailable data, production estimates for years 2004 through 2009 were held at the 2003 value.

The 1996 share of the total quantity of N₂O used by each subcategory was obtained from SRI Consulting's Nitrous

Oxide, North America report (Heydorn 1997). The 1990 through 1995 share of total quantity of N₂O used by each subcategory was kept the same as the 1996 number provided by SRI Consulting. The 1997 through 2001 share of total quantity of N₂O usage by sector was obtained from communication with a N₂O industry expert (Tupman 2002). The 2002 and 2003 share of total quantity of N₂O usage by sector was obtained from CGA (2002, 2003). Due to unavailable data, the share of total quantity of N₂O usage data for years 2004 through 2009 was assumed to equal the 2003 value. The emissions rate for the food processing propellant industry was obtained from SRI Consulting's Nitrous Oxide, North America report (Heydorn 1997), and confirmed by a N₂O industry expert (Tupman 2002). The emissions rate for all other subcategories was obtained from communication with a N₂O industry expert (Tupman 2002). The emissions rate for the medical/dental subcategory was obtained from the 2006 IPCC Guidelines.

Uncertainty and Time-Series Consistency

The overall uncertainty associated with the 2009 N₂O emission estimate from N₂O product usage was calculated using the IPCC Guidelines for National Greenhouse Gas Inventories (2006) Tier 2 methodology. Uncertainty associated with the parameters used to estimate N₂O emissions include production data, total market share of each end use, and the emission factors applied to each end use, respectively.

The results of this Tier 2 quantitative uncertainty analysis are summarized in Table 5-4. N₂O emissions from N₂O product usage were estimated to be between 4.1 and 4.7 Tg CO₂ Eq. at the 95 percent confidence level (or in 19 out of 20 Monte Carlo Stochastic Simulations). This indicates a range of approximately 8 percent below to 8 percent above the 2009 emissions estimate of 4.4 Tg CO₂ Eq.

Table 5-4: Tier 2 Quantitative Uncertainty Estimates for N₂O Emissions from N₂O Product Usage (Tg CO₂ Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate ^a			
			(Tg CO ₂ Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
N ₂ O Product Usage	N ₂ O	4.4	4.1	4.7	-8%	+8%

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

Note that this uncertainty range (±8 percent) has increased by 12 percent compared to the uncertainty range in last year's Inventory (±2 percent), due to a correction to the uncertainty input parameters. Furthermore, methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009. Details on the emission trends through time-series are described in more detail in the Methodology section, above.

Planned Improvements

Planned improvements include a continued evaluation of alternative production statistics for cross verification, a reassessment of N₂O product use subcategories to accurately represent trends, investigation of production and use cycles, and the potential need to incorporate a time lag between production and ultimate product use and resulting release of N₂O. Additionally, planned improvements include considering imports and exports of N₂O for product uses.

5.2. Indirect Greenhouse Gas Emissions from Solvent Use

The use of solvents and other chemical products can result in emissions of various ozone precursors (i.e., indirect greenhouse gases).¹³⁸ Non-CH₄ volatile organic compounds (NMVOCs), commonly referred to as "hydrocarbons," are the primary gases emitted from most processes employing organic or petroleum based solvents. As some of industrial applications also employ thermal incineration as a control technology, combustion by-products, such as carbon monoxide (CO) and nitrogen oxides (NO_x), are also reported with this source category. In the United States,

¹³⁸ Solvent usage in the United States also results in the emission of small amounts of hydrofluorocarbons (HFCs) and hydrofluoroethers (HFEs), which are included under Substitution of Ozone Depleting Substances in the Industrial Processes chapter.

emissions from solvents are primarily the result of solvent evaporation, whereby the lighter hydrocarbon molecules in the solvents escape into the atmosphere. The evaporation process varies depending on different solvent uses and solvent types. The major categories of solvent uses include: degreasing, graphic arts, surface coating, other industrial uses of solvents (i.e., electronics, etc.), dry cleaning, and non-industrial uses (i.e., uses of paint thinner, etc.).

Total emissions of NO_x, NMVOCs, and CO from 1990 to 2009 are reported in Table 5-5.

Table 5-5: Emissions of NO_x, CO, and NMVOC from Solvent Use (Gg)

Activity	1990	2000	2005	2006	2007	2008	2009
NO_x	1	3	3	4	4	4	3
Surface Coating	1	3	3	4	4	4	3
Graphic Arts	+	+	+	+	+	+	+
Degreasing	+	+	+	+	+	+	+
Dry Cleaning	+	+	+	+	+	+	+
Other Industrial Processes ^a	+	+	+	+	+	+	+
Non-Industrial Processes ^b	+	+	+	+	+	+	+
Other	NA	+	+	+	+	+	+
CO	5	45	2	2	2	2	2
Surface Coating	+	45	2	2	2	2	2
Other Industrial Processes ^a	4	+	+	+	+	+	+
Dry Cleaning	+	+	+	+	+	+	+
Degreasing	+	+	+	+	+	+	+
Graphic Arts	+	+	+	+	+	+	+
Non-Industrial Processes ^b	+	+	+	+	+	+	+
Other	NA	+	+	+	+	+	+
NMVOCs	5,216	4,384	3,851	3,846	3,839	3,834	2,583
Surface Coating	2,289	1,766	1,578	1,575	1,573	1,571	1,058
Non-Industrial Processes ^b	1,724	1,676	1,446	1,444	1,441	1,439	970
Degreasing	675	316	280	280	280	279	188
Dry Cleaning	195	265	230	230	229	229	154
Graphic Arts	249	222	194	193	193	193	130
Other Industrial Processes ^a	85	98	88	88	87	87	59
Other	+	40	36	36	36	36	24

^a Includes rubber and plastics manufacturing, and other miscellaneous applications.

^b Includes cutback asphalt, pesticide application adhesives, consumer solvents, and other miscellaneous applications.

Note: Totals may not sum due to independent rounding.

+ Does not exceed 0.5 Gg.

Methodology

Emissions were calculated by aggregating solvent use data based on information relating to solvent uses from different applications such as degreasing, graphic arts, etc. Emission factors for each consumption category were then applied to the data to estimate emissions. For example, emissions from surface coatings were mostly due to solvent evaporation as the coatings solidify. By applying the appropriate solvent-specific emission factors to the amount of solvents used for surface coatings, an estimate of emissions was obtained. Emissions of CO and NO_x result primarily from thermal and catalytic incineration of solvent-laden gas streams from painting booths, printing operations, and oven exhaust.

These emission estimates were obtained from preliminary data (EPA 2010, EPA 2009), and disaggregated based on EPA (2003), which, in its final iteration, will be published on the National Emission Inventory (NEI) Air Pollutant Emission Trends web site. Emissions were calculated either for individual categories or for many categories combined, using basic activity data (e.g., the amount of solvent purchased) 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 the reliability of correlations between activity data and actual emissions.

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

6. Agriculture

Agricultural activities contribute directly to emissions of greenhouse gases through a variety of processes. This chapter provides an assessment of non-carbon-dioxide emissions from the following source categories: enteric fermentation in domestic livestock, livestock manure management, rice cultivation, agricultural soil management, and field burning of agricultural residues (see Figure 6-1). Carbon dioxide (CO₂) emissions and removals from agriculture-related land-use activities, such as liming of agricultural soils and conversion of grassland to cultivated land, are presented in the Land Use, Land-Use Change, and Forestry chapter. Carbon dioxide emissions from on-farm energy use are accounted for in the Energy chapter.

Figure 6-1: 2009 Agriculture Chapter Greenhouse Gas Emission Sources

In 2009, the Agriculture sector was responsible for emissions of 419.3 teragrams of CO₂ equivalents (Tg CO₂ Eq.), or 6.3 percent of total U.S. greenhouse gas emissions. Methane (CH₄) and nitrous oxide (N₂O) were the primary greenhouse gases emitted by agricultural activities. Methane emissions from enteric fermentation and manure management represent about 20 percent and 7 percent of total CH₄ emissions from anthropogenic activities, respectively. Of all domestic animal types, beef and dairy cattle were by far the largest emitters of CH₄. Rice cultivation and field burning of agricultural residues were minor sources of CH₄. Agricultural soil management activities such as fertilizer application and other cropping practices were the largest source of U.S. N₂O emissions, accounting for 69 percent. Manure management and field burning of agricultural residues were also small sources of N₂O emissions.

Table 6-1 and Table 6-2 present emission estimates for the Agriculture sector. Between 1990 and 2009, CH₄ emissions from agricultural activities increased by 14.9 percent, while N₂O emissions fluctuated from year to year, but overall increased by 4.8 percent.

Table 6-1: Emissions from Agriculture (Tg CO₂ Eq.)

Gas/Source	1990	2000	2005	2006	2007	2008	2009
CH₄	171.2	186.7	190.1	191.7	198.2	197.5	196.8
Enteric Fermentation	132.1	136.5	136.5	138.8	141.0	140.6	139.8
Manure Management	31.7	42.4	46.6	46.7	50.7	49.4	49.5
Rice Cultivation	7.1	7.5	6.8	5.9	6.2	7.2	7.3
Field Burning of Agricultural Residues	0.3	0.3	0.2	0.2	0.2	0.3	0.2
N₂O	212.4	224.0	228.7	227.1	227.6	228.8	222.5
Agricultural Soil Management	197.8	206.8	211.3	208.9	209.4	210.7	204.6
Manure Management	14.5	17.1	17.3	18.0	18.1	17.9	17.9
Field Burning of Agricultural Residues	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	383.6	410.6	418.8	418.8	425.8	426.3	419.3

Note: Totals may not sum due to independent rounding.

Table 6-2: Emissions from Agriculture (Gg)

Gas/Source	1990	2000	2005	2006	2007	2008	2009
CH₄	8,153	8,890	9,052	9,129	9,437	9,405	9,372
Enteric Fermentation	6,290	6,502	6,500	6,611	6,715	6,696	6,655
Manure Management	1,511	2,019	2,217	2,226	2,416	2,353	2,356
Rice Cultivation	339	357	326	282	295	343	349
Field Burning of Agricultural Residues	13	12	9	11	11	13	12
N₂O	685	722	738	732	734	738	718
Agricultural Soil Management	638	667	682	674	675	680	660

Manure Management	47		55		56	58	58	58	58
Field Burning of Agricultural Residues	+		+		+	+	+	+	+

+ Less than 0.5 Gg.

Note: Totals may not sum due to independent rounding.

6.1. Enteric Fermentation (IPCC Source Category 4A)

Methane is produced as part of normal digestive processes in animals. During digestion, microbes resident in an animal's digestive system ferment food consumed by the animal. This microbial fermentation process, referred to as enteric fermentation, produces CH₄ as a byproduct, which can be exhaled or eructated by the animal. The amount of CH₄ produced and emitted by an individual animal depends primarily upon the animal's digestive system, and the amount and type of feed it consumes.

Ruminant animals (e.g., cattle, buffalo, sheep, goats, and camels) are the major emitters of CH₄ because of their unique digestive system. Ruminants possess a rumen, or large "fore-stomach," in which microbial fermentation breaks down the feed they consume into products that can be absorbed and metabolized. The microbial fermentation that occurs in the rumen enables them to digest coarse plant material that non-ruminant animals cannot. Ruminant animals, consequently, have the highest CH₄ emissions among all animal types.

Non-ruminant animals (e.g., swine, horses, and mules) also produce CH₄ emissions through enteric fermentation, although this microbial fermentation occurs in the large intestine. These non-ruminants emit significantly less CH₄ on a per-animal basis than ruminants because the capacity of the large intestine to produce CH₄ is lower.

In addition to the type of digestive system, an animal's feed quality and feed intake also affect CH₄ emissions. In general, lower feed quality and/or higher feed intake leads to higher CH₄ emissions. Feed intake is positively correlated to animal size, growth rate, and production (e.g., milk production, wool growth, pregnancy, or work). Therefore, feed intake varies among animal types as well as among different management practices for individual animal types (e.g., animals in feedlots or grazing on pasture).

Methane emission estimates from enteric fermentation are provided in Table 6-3 and Table 6-4. Total livestock CH₄ emissions in 2009 were 139.8 Tg CO₂ Eq. (6,655 Gg). Beef cattle remain the largest contributor of CH₄ emissions from enteric fermentation, accounting for 71 percent in 2009. Emissions from dairy cattle in 2009 accounted for 24 percent, and the remaining emissions were from horses, sheep, swine, and goats.

From 1990 to 2009, emissions from enteric fermentation have increased by 5.8 percent. Generally, emissions decreased from 1996 to 2003, though with a slight increase in 2002. This trend was mainly due to decreasing populations of both beef and dairy cattle and increased digestibility of feed for feedlot cattle. Emissions increased from 2004 through 2007, as both dairy and beef populations have undergone increases and the literature for dairy cow diets indicated a trend toward a decrease in feed digestibility for those years. Emissions decreased again in 2008 and 2009 as beef cattle populations again decreased. During the timeframe of this analysis, populations of sheep have decreased 49 percent while horse populations have increased over 87 percent, mostly since 1999. Goat and swine populations have increased 25 percent and 23 percent, respectively, during this timeframe.

Table 6-3: CH₄ Emissions from Enteric Fermentation (Tg CO₂ Eq.)

Livestock Type	1990	2000	2005	2006	2007	2008	2009
Beef Cattle	94.5	100.6	99.3	100.9	101.6	100.7	99.6
Dairy Cattle	31.8	30.7	30.4	31.1	32.4	32.9	33.2
Horses	1.9	2.0	3.5	3.6	3.6	3.6	3.6
Sheep	1.9	1.2	1.0	1.0	1.0	1.0	1.0
Swine	1.7	1.9	1.9	1.9	2.1	2.1	2.1
Goats	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Total	132.1	136.5	136.5	138.8	141.0	140.6	139.8

Note: Totals may not sum due to independent rounding.

Table 6-4: CH₄ Emissions from Enteric Fermentation (Gg)

Livestock Type	1990	2000	2005	2006	2007	2008	2009
Beef Cattle	4,502	4,790	4,731	4,803	4,837	4,796	4,742
Dairy Cattle	1,513	1,460	1,449	1,479	1,544	1,564	1,581

Horses	91		94		166	171	171	171	171
Sheep	91		56		49	50	49	48	46
Swine	81		88		92	93	98	101	99
Goats	13		12		14	15	16	16	16
Total	6,290		6,502		6,500	6,611	6,715	6,696	6,655

Note: Totals may not sum due to independent rounding.

Methodology

Livestock emission estimate methodologies fall into two categories: cattle and other domesticated animals. Cattle, due to their large population, large size, and particular digestive characteristics, account for the majority of CH₄ emissions from livestock in the United States. A more detailed methodology (i.e., IPCC Tier 2) was therefore applied to estimate emissions for all cattle except for bulls. Emission estimates for other domesticated animals (horses, sheep, swine, goats, and bulls) were handled using a less detailed approach (i.e., IPCC Tier 1).

While the large diversity of animal management practices cannot be precisely characterized and evaluated, significant scientific literature exists that provides the necessary data to estimate cattle emissions using the IPCC Tier 2 approach. The Cattle Enteric Fermentation Model (CEFM), developed by EPA and used to estimate cattle CH₄ emissions from enteric fermentation, incorporates this information and other analyses of livestock population, feeding practices, and production characteristics.

National cattle population statistics were disaggregated into the following cattle sub-populations:

- Dairy Cattle
 - Calves
 - Heifer Replacements
 - Cows
- Beef Cattle
 - Calves
 - Heifer Replacements
 - Heifer and Steer Stockers
 - Animals in Feedlots (Heifers and Steers)
 - Cows
 - Bulls

Calf birth rates, end-of-year population statistics, detailed feedlot placement information, and slaughter weight data were used to create a transition matrix that models cohorts of individual animal types and their specific emission profiles. The key variables tracked for each of the cattle population categories are described in Annex 3.9. These variables include performance factors such as pregnancy and lactation as well as average weights and weight gain. Annual cattle population data were obtained from the U.S. Department of Agriculture's (USDA) National Agricultural Statistics Service (NASS) QuickStats database (USDA 2010).

Diet characteristics were estimated by region for U.S. dairy, beef, and feedlot cattle. These estimates were used to calculate Digestible Energy (DE) values (expressed as the percent of gross energy intake digested by the animal) and CH₄ conversion rates (Y_m) (expressed as the fraction of gross energy converted to CH₄) for each population category. The IPCC recommends Y_m values of 3.0±1.0 percent for feedlot cattle and 6.5±1.0 percent for other well-fed cattle consuming temperate-climate feed types (IPCC 2006). Given the availability of detailed diet information for different regions and animal types in the United States, DE and Y_m values unique to the United States were developed, rather than using the recommended IPCC values. The diet characterizations and estimation of DE and Y_m values were based on information from state agricultural extension specialists, a review of published forage quality studies and scientific literature, expert opinion, and modeling of animal physiology. The diet characteristics for dairy cattle were based on Donovan (1999) and an extensive review of nearly 20 years of literature. Dairy replacement heifer diet assumptions were based on the observed relationship in the literature between dairy cow and

dairy heifer diet characteristics. The diet assumptions for beef cattle were derived from NRC (2000). For feedlot animals, the DE and Y_m values used for 1990 were recommended by Johnson (1999). Values for DE and Y_m for 1991 through 1999 were linearly extrapolated based on the 1990 and 2000 data. DE and Y_m values for 2000 onwards were based on survey data in Galyean and Gleghorn (2001) and Vasconcelos and Galyean (2007). For grazing beef cattle, DE values were based on diet information in NRC (2000) and Y_m values were based on Johnson (2002). Weight and weight gains for cattle were estimated from Holstein Association USA (2010), Enns (2008), Lippke et al. (2000), Pinchack et al., (2004), Platter et al. (2003), Skogerboe et al. (2000), and expert opinion. See Annex 3.9 for more details on the method used to characterize cattle diets and weights in the United States.

To estimate CH₄ emissions from all cattle types except bulls and calves younger than 7 months,¹³⁹ the population was divided into state, age, sub-type (i.e., dairy cows and replacements, beef cows and replacements, heifer and steer stockers, and heifers and steers in feedlots), and production (i.e., pregnant, lactating) groupings to more fully capture differences in CH₄ emissions from these animal types. The transition matrix was used to simulate the age and weight structure of each sub-type on a monthly basis, to more accurately reflect the fluctuations that occur throughout the year. Cattle diet characteristics were then used in conjunction with Tier 2 equations from IPCC (2006) to produce CH₄ emission factors for the following cattle types: dairy cows, beef cows, dairy replacements, beef replacements, steer stockers, heifer stockers, steer feedlot animals, and heifer feedlot animals. To estimate emissions from cattle, population data from the transition matrix were multiplied by the calculated emission factor for each cattle type. More details are provided in Annex 3.9.

Emission estimates for other animal types were based on average emission factors representative of entire populations of each animal type. Methane emissions from these animals accounted for a minor portion of total CH₄ emissions from livestock in the United States from 1990 through 2009. Also, the variability in emission factors for each of these other animal types (e.g., variability by age, production system, and feeding practice within each animal type) is less than that for cattle. Annual livestock population data for these other livestock types, except horses and goats, as well as feedlot placement information, were obtained for all years from USDA NASS (USDA 2010). Horse population data were obtained from the Food and Agriculture Organization of the United Nations (FAO) FAOSTAT database (FAO 2010), because USDA does not estimate U.S. horse populations annually. Goat population data were obtained for 1992, 1997, 2002, and 2007 (USDA 2010); these data were interpolated and extrapolated to derive estimates for the other years. Methane emissions from sheep, goats, swine, and horses were estimated by using emission factors utilized in Crutzen et al. (1986, cited in IPCC 2006). These emission factors are representative of typical animal sizes, feed intakes, and feed characteristics in developed countries. The methodology is the same as that recommended by IPCC (2006).

See Annex 3.9 for more detailed information on the methodology and data used to calculate CH₄ emissions from enteric fermentation.

Uncertainty and Time-Series Consistency

A quantitative uncertainty analysis for this source category was performed through the IPCC-recommended Tier 2 uncertainty estimation methodology, Monte Carlo Stochastic Simulation technique as described in ICF (2003). These uncertainty estimates were developed for the 1990 through 2001 Inventory report. No significant changes occurred in the method of data collection, data estimation methodology, or other factors that influence the uncertainty ranges around the 2009 activity data and emission factor input variables used in the current submission. Consequently, these uncertainty estimates were directly applied to the 2009 emission estimates.

A total of 185 primary input variables (177 for cattle and 8 for non-cattle) were identified as key input variables for the uncertainty analysis. A normal distribution was assumed for almost all activity- and emission factor-related input variables. Triangular distributions were assigned to three input variables (specifically, cow-birth ratios for the three most recent years included in the 2001 model run) to capture the fact that these variables cannot be negative. For some key input variables, the uncertainty ranges around their estimates (used for inventory estimation) were collected from published documents and other public sources; others were based on expert opinion and best estimates. In addition, both endogenous and exogenous correlations between selected primary input variables were

¹³⁹ Emissions from bulls are estimated using a Tier 1 approach because it is assumed there is minimal variation in population and diets. Because calves younger than 7 months consume mainly milk and the IPCC recommends the use of methane conversion factor of zero for all juveniles consuming only milk, this results in no methane emissions from this subcategory of cattle.

modeled. The exogenous correlation coefficients between the probability distributions of selected activity-related variables were developed through expert judgment.

The uncertainty ranges associated with the activity data-related input variables were plus or minus 10 percent or lower. However, for many emission factor-related input variables, the lower- and/or the upper-bound uncertainty estimates were over 20 percent. The results of the quantitative uncertainty analysis are summarized in Table 6-5. Enteric fermentation CH₄ emissions in 2009 were estimated to be between 124.4 and 165.0 Tg CO₂ Eq. at a 95 percent confidence level, which indicates a range of 11 percent below to 18 percent above the 2009 emission estimate of 139.8 Tg CO₂ Eq. Among the individual cattle sub-source categories, beef cattle account for the largest amount of CH₄ emissions as well as the largest degree of uncertainty in the inventory emission estimates. Among non-cattle, horses account for the largest degree of uncertainty in the inventory emission estimates because there is a higher degree of uncertainty among the FAO population estimates used for horses than for the USDA population estimates used for swine, goats, and sheep.

Table 6-5: Quantitative Uncertainty Estimates for CH₄ Emissions from Enteric Fermentation (Tg CO₂ Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate ^{a, b}			
			(Tg CO ₂ Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Enteric Fermentation	CH ₄	139.8	124.4	165.0	-11%	+18%

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

^b Note that the relative uncertainty range was estimated with respect to the 2001 emission estimates submitted in 2003 and applied to the 2009 estimates.

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

QA/QC and Verification

In order to ensure the quality of the emission estimates from enteric fermentation, the IPCC Tier 1 and Tier 2 Quality Assurance/Quality Control (QA/QC) procedures were implemented consistent with the U.S. QA/QC plan. Tier 2 QA procedures included independent peer review of emission estimates. Because there were no major modifications to the CEFM for 2009, QA/QC emphasis for the current Inventory was placed on cleaning up documentation and references within the model, and review of external data sources. For example, during the course of the QA/QC activities for this source category, it was noted that the U.S. total for 2009 Cattle On Feed data provided via USDA's Quickstats database did not match the total calculated from summing all individual states. The appropriate party was contacted at USDA, and it was determined that data for New Mexico and North Carolina were included individually, as well as within the "Other States" aggregate number, so they were being double counted in the U.S. total. This issue was quickly resolved.

In addition, over the past few years, particular importance has been placed on harmonizing the data exchange between the enteric fermentation and manure management source categories. The current inventory submission now utilizes the transition matrix from the CEFM for estimating cattle populations and weights for both source categories, and the CEFM is used to output volatile solids and nitrogen (N) excretion estimates using the diet assumptions in the model in conjunction with the energy balance equations from the IPCC (2006). This approach should complete the resolution of the discrepancies noted in previous reviews of these sectors, and facilitate the QA/QC process for both of these source categories.

Recalculations Discussion

There were several modifications to the estimates relative to the previous Inventory that had an effect on emission estimates, including the following:

- The average weight assumed for mature dairy cows has changed from the 1,550 pounds used in previous inventories to 1,500 pounds (Johnson 2010; Holstein Association 2010).
- The USDA published revised estimates in several categories that affected historical emissions estimated for

cattle and swine for 2008. Calves, beef replacements, and feedlot cattle all saw slight modifications to their 2008 populations, while swine population categories were modified so that the categories “<60 pounds” and “60-119 pounds” were replaced with “<50 pounds” and “50-119” pounds. Additionally, 2008 lactation estimates for Arkansas, Connecticut, Indiana, Nebraska, New Jersey, Oklahoma, South Carolina, and Vermont were updated by USDA.

- For the 1990 through 2009 inventory, goat population data were taken from the 2007 *Census of Agriculture*. For 2007 population values, the Census’s 2007 “Total Goat” population for each state was used. Using the 2002 and 2007 data points, the population for the intervening years was interpolated, and the population for 2008 and 2009 were set equal to the population for 2007. The updated Census data resulted in a change in population values from 2003 through 2008 as populations for these years were previously set equal to the 2002 population.

As a result of these changes, dairy cattle emissions decreased an average of 11.5 Gg (0.8 percent) per year and beef cattle emissions decreased an average of 0.13 Gg (less than 0.01 percent) per year over the entire time series relative to the previous Inventory. Historical emission estimates for 2008 increased by 1.3 percent for goats as a result of the USDA population revisions described above.

Planned Improvements

Continued research and regular updates are necessary to maintain a current model of cattle diet characterization, feedlot placement data, rates of weight gain and calving, among other data inputs. Ongoing revisions could include some of the following options:

- Reviewing and updating the diet assumptions for foraging beef cattle;
- Estimating bull emissions using the IPCC Tier 2 approach;
- Updating input variables that are from older data sources, such as beef births by month and beef cow lactation rates;
- The possible breakout of other animal types (i.e., sheep, swine, goats, horses) from national estimates to state-level estimates; and
- Including bison in the estimates for other domesticated animals.

In addition, recent changes that have been implemented to the CEFM warrant an assessment of the current uncertainty analysis; therefore, a revision of the quantitative uncertainty surrounding emission estimates from this source category will be initiated.

6.2. Manure Management (IPCC Source Category 4B)

The management of livestock manure can produce anthropogenic CH₄ and N₂O emissions. Methane is produced by the anaerobic decomposition of manure. Direct N₂O emissions are produced as part of the N cycle through the nitrification and denitrification of the organic N in livestock dung and urine.¹⁴⁰ Indirect N₂O emissions are produced as result of the volatilization of N as NH₃ and NO_x and runoff and leaching of N during treatment, storage and transportation.

When livestock or poultry manure are stored or treated in systems that promote anaerobic conditions (e.g., as a liquid/slurry in lagoons, ponds, tanks, or pits), the decomposition of materials in the manure tends to produce CH₄. When manure is handled as a solid (e.g., in stacks or drylots) or deposited on pasture, range, or paddock lands, it tends to decompose aerobically and produce little or no CH₄. Ambient temperature, moisture, and manure storage or residency time affect the amount of CH₄ produced because they influence the growth of the bacteria responsible for CH₄ formation. For non-liquid-based manure systems, moist conditions (which are a function of rainfall and

¹⁴⁰ Direct and indirect N₂O emissions from dung and urine spread onto fields either directly as daily spread or after it is removed from manure management systems (e.g., lagoon, pit, etc.) and from livestock dung and urine deposited on pasture, range, or paddock lands are accounted for and discussed in the Agricultural Soil Management source category within the Agriculture sector.

humidity) can promote CH₄ production. Manure composition, which varies by animal diet, growth rate, and type, including the animal's digestive system, also affects the amount of CH₄ produced. In general, the greater the energy content of the feed, the greater the potential for CH₄ emissions. However, some higher-energy feeds also are more digestible than lower quality forages, which can result in less overall waste excreted from the animal.

The production of direct N₂O emissions from livestock manure depends on the composition of the manure and urine, the type of bacteria involved in the process, and the amount of oxygen and liquid in the manure system. For direct N₂O emissions to occur, the manure must first be handled aerobically where ammonia (NH₃) or organic N is converted to nitrates and nitrites (nitrification), and then handled anaerobically where the nitrates and nitrites are reduced to dinitrogen gas (N₂), with intermediate production of N₂O and nitric oxide (NO) (denitrification) (Groffman et al. 2000). These emissions are most likely to occur in dry manure handling systems that have aerobic conditions, but that also contain pockets of anaerobic conditions due to saturation. A very small portion of the total N excreted is expected to convert to N₂O in the waste management system (WMS). Indirect N₂O emissions are produced when nitrogen is lost from the system through volatilization (as NH₃ or NO_x) or through runoff and leaching. The vast majority of volatilization losses from these operations are NH₃. Although there are also some small losses of NO_x, there are no quantified estimates available for use, so losses due to volatilization are only based on NH₃ loss factors. Runoff losses would be expected from operations that house animals or store manure in a manner that is exposed to weather. Runoff losses are also specific to the type of animal housed on the operation due to differences in manure characteristics. Little information is known about leaching from manure management systems as most research focuses on leaching from land application systems. Since leaching losses are expected to be minimal, leaching losses are coupled with runoff losses and the runoff/leaching estimate does not include any leaching losses.

Estimates of CH₄ emissions in 2009 were 49.5 Tg CO₂ Eq. (2,356 Gg), 56 percent higher than in 1990. Emissions increased on average by 0.9 Tg CO₂ Eq. (2.5 percent) annually over this period. The majority of this increase was from swine and dairy cow manure, where emissions increased 45 and 95 percent, respectively. Although the majority of manure in the United States is handled as a solid, producing little CH₄, the general trend in manure management, particularly for dairy and swine (which are both shifting towards larger facilities), is one of increasing use of 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. Although national dairy animal populations have been generally decreasing, some states have seen increases in their dairy populations as the industry becomes more concentrated in certain areas of the country. These areas of concentration, such as California, New Mexico, and Idaho, tend to utilize more liquid-based systems to manage (flush or scrape) and store manure. Thus the shift toward larger facilities is translated into an increasing use of liquid manure management systems, which have higher potential CH₄ emissions than dry systems. This shift was accounted for by incorporating state and WMS-specific CH₄ conversion factor (MCF) values in combination with the 1992, 1997, and 2002 farm-size distribution data reported in the *Census of Agriculture* (USDA 2009a). Methane emissions from sheep have decreased significantly since 1990 (a 54 percent decrease from 1990 to 2009); however, this is mainly due to population changes. Overall, sheep contribute less than one percent of CH₄ emissions from animal manure management. From 2008 to 2009, there was a less than 1 percent increase in total CH₄ emissions, due to minor shifts in the animal populations and the resultant effects on manure management system allocations.

In 2009, total N₂O emissions were estimated to be 17.9 Tg CO₂ Eq. (58 Gg); in 1990, emissions were 14.5 Tg CO₂ Eq. (47 Gg). These values include both direct and indirect N₂O emissions from manure management. Nitrous oxide emissions have remained fairly steady since 1990. Small changes in N₂O emissions from individual animal groups exhibit the same trends as the animal group populations, with the overall net effect that N₂O emissions showed a 23 percent increase from 1990 to 2009 and a less than 1 percent decrease from 2008 through 2009.

Table 6-6 and Table 6-7 provide estimates of CH₄ and N₂O emissions from manure management by animal category.

Table 6-6: CH₄ and N₂O Emissions from Manure Management (Tg CO₂ Eq.)

Gas/Animal Type	1990	2000	2005	2006	2007	2008	2009
CH₄^a	31.7	42.4	46.6	46.7	50.7	49.4	49.5
Dairy Cattle	12.6	18.9	21.4	21.7	24.2	24.1	24.5
Beef Cattle	2.7	2.8	2.8	2.9	2.9	2.8	2.7
Swine	13.1	17.5	19.0	18.7	20.3	19.3	19.0
Sheep	0.1	0.1	0.1	0.1	0.1	0.1	0.1

Goats	+	+	+	+	+	+	+
Poultry	2.8	2.7	2.7	2.7	2.8	2.7	2.7
Horses	0.5	0.4	0.6	0.6	0.6	0.5	0.5
N₂O^b	14.5	17.1	17.3	18.0	18.1	17.9	17.9
Dairy Cattle	5.3	5.6	5.6	5.8	5.8	5.7	5.8
Beef Cattle	6.1	7.8	7.5	8.0	7.9	7.8	7.8
Swine	1.2	1.6	1.8	1.8	1.9	2.0	2.0
Sheep	0.1	0.3	0.4	0.4	0.4	0.4	0.3
Goats	+	+	+	+	+	+	+
Poultry	1.5	1.6	1.7	1.7	1.7	1.7	1.6
Horses	0.2	0.2	0.3	0.3	0.3	0.3	0.3
Total	46.2	59.5	63.8	64.8	68.9	67.3	67.3

+ Less than 0.05 Tg CO₂ Eq.

^aAccounts for CH₄ reductions due to capture and destruction of CH₄ at facilities using anaerobic digesters.

^bIncludes both direct and indirect N₂O emissions.

Note: Totals may not sum due to independent rounding.

Table 6-7: CH₄ and N₂O Emissions from Manure Management (Gg)

Gas/Animal Type	1990	2000	2005	2006	2007	2008	2009
CH₄^a	1,511	2,019	2,217	2,226	2,416	2,353	2,356
Dairy Cattle	599	900	1,018	1,034	1,151	1,147	1,168
Beef Cattle	128	133	132	139	136	131	130
Swine	624	834	905	889	965	918	903
Sheep	7	4	3	3	3	3	3
Goats	1	1	1	1	1	1	1
Poultry	131	127	129	131	134	129	127
Horses	22	20	28	28	27	24	24
N₂O^b	47	55	56	58	58	58	58
Dairy Cattle	17	18	18	19	19	18	19
Beef Cattle	20	25	24	26	26	25	25
Swine	4	5	6	6	6	6	6
Sheep	+	1	1	1	1	1	1
Goats	+	+	+	+	+	+	+
Poultry	5	5	5	5	5	5	5
Horses	1	1	1	1	1	1	1

+ Less than 0.5 Gg.

^aAccounts for CH₄ reductions due to capture and destruction of CH₄ at facilities using anaerobic digesters.

^bIncludes both direct and indirect N₂O emissions.

Note: Totals may not sum due to independent rounding.

Methodology

The methodologies presented in IPCC (2006) form the basis of the CH₄ and N₂O emission estimates for each animal type. This section presents a summary of the methodologies used to estimate CH₄ and N₂O emissions from manure management for this Inventory. See Annex 3.10 for more detailed information on the methodology and data used to calculate CH₄ and N₂O emissions from manure management.

Methane Calculation Methods

The following inputs were used in the calculation of CH₄ emissions:

- Animal population data (by animal type and state);
- Typical animal mass (TAM) data (by animal type);
- Portion of manure managed in each waste management system (WMS), by state and animal type;
- Volatile solids (VS) production rate (by animal type and state or United States);
- Methane producing potential (B₀) of the volatile solids (by animal type); and

- Methane conversion factors (MCF), the extent to which the CH₄ producing potential is realized for each type of WMS (by state and manure management system, including the impacts of any biogas collection efforts).

Methane emissions were estimated by first determining activity data, including animal population, TAM, WMS usage, and waste characteristics. The activity data sources are described below:

- Annual animal population data for 1990 through 2009 for all livestock types, except horses and goats were obtained from USDA NASS. For cattle, the USDA populations were utilized in conjunction with birth rates, detailed feedlot placement information, and slaughter weight data to create the transition matrix in the CEFM that models cohorts of individual animal types and their specific emission profiles. The key variables tracked for each of the cattle population categories are described in Section 6.1 and in more detail in Annex 3.9. Horse population data were obtained from the FAOSTAT database (FAO 2010). Goat population data for 1992, 1997, 2002, and 2007 were obtained from the *Census of Agriculture* (USDA 2009a).
- The TAM is an annual average weight which was obtained for animal types other than cattle from information in USDA's *Agricultural Waste Management Field Handbook* (USDA 1996a), the American Society of Agricultural Engineers, Standard D384.1 (ASAE 1999) and others (EPA 1992, Safley 2000, ERG 2010a). For a description of the TAM used for cattle, please see section 6.1, Enteric Fermentation.
- WMS usage was estimated for swine and dairy cattle for different farm size categories using data from USDA (USDA 1996b, 1998b, 2000a) and EPA (ERG 2000a, EPA 2002a, 2002b). For beef cattle and poultry, manure management system usage data were not tied to farm size but were based on other data sources (ERG 2000a, USDA 2000b, UEP 1999). For other animal types, manure management system usage was based on previous estimates (EPA 1992).
- VS production rates for all cattle except for bulls and calves were calculated by head for each state and animal type in the CEFM. VS production rates by animal mass for all other animals were determined using data from USDA's *Agricultural Waste Management Field Handbook* (USDA 1996a, 2008) and data from the American Society of Agricultural Engineers, Standard D384.1 (ASAE 1998).
- The maximum CH₄ producing capacity of the VS (B₀) was determined for each animal type based on literature values (Morris 1976, Bryant et al, 1976, Hashimoto 1981, Hashimoto 1984, EPA 1992, Hill 1982, and Hill 1984).
- MCFs for dry systems were set equal to default IPCC factors based on state climate for each year (IPCC 2006). MCFs for liquid/slurry, anaerobic lagoon, and deep pit systems were calculated based on the forecast performance of biological systems relative to temperature changes as predicted in the van't Hoff-Arrhenius equation which is consistent with IPCC (2006) Tier 2 methodology.
- Anaerobic digestion system data were obtained from the EPA AgSTAR Program, including information presented in the *AgSTAR Digest* (EPA 2000, 2003, 2006). Anaerobic digester emissions were calculated based on estimated methane production and collection and destruction efficiency assumptions (ERG 2008).

To estimate CH₄ emissions for cattle, the estimated amount of VS (kg per animal-year) managed in each WMS for each animal type, state, and year were taken from the CEFM. For animals other than cattle, the annual amount of VS (kg per year) from manure excreted in each WMS was calculated for each animal type, state, and year. This calculation multiplied the animal population (head) by the VS excretion rate (kg VS per 1,000 kg animal mass per day), the TAM (kg animal mass per head) divided by 1,000, the WMS distribution (percent), and the number of days per year (365.25).

The estimated amount of VS managed in each WMS was used to estimate the CH₄ emissions (kg CH₄ per year) from each WMS. The amount of VS (kg per year) were multiplied by the maximum CH₄ producing capacity of the VS (B₀) (m³ CH₄ per kg VS), the MCF for that WMS (percent), and the density of CH₄ (kg CH₄ per m³ CH₄). The CH₄ emissions for each WMS, state, and animal type were summed to determine the total U.S. CH₄ emissions.

Nitrous Oxide Calculation Methods

The following inputs were used in the calculation of direct and indirect N₂O emissions:

- Animal population data (by animal type and state);

- TAM data (by animal type);
- Portion of manure managed in each WMS (by state and animal type);
- Total Kjeldahl N excretion rate (N_{ex});
- Direct N_2O emission factor (EF_{WMS});
- Indirect N_2O emission factor for volatilization ($EF_{volatilization}$);
- Indirect N_2O emission factor for runoff and leaching ($EF_{runoff/leach}$);
- Fraction of nitrogen loss from volatilization of NH_3 and NO_x ($Frac_{gas}$); and
- Fraction of nitrogen loss from runoff and leaching ($Frac_{runoff/leach}$).

N_2O emissions were estimated by first determining activity data, including animal population, TAM, WMS usage, and waste characteristics. The activity data sources (except for population, TAM, and WMS, which were described above) are described below:

- N_{ex} rates for all cattle except for bulls and calves were calculated by head for each state and animal type in the CEFM. N_{ex} rates by animal mass for all other animals were determined using data from USDA's *Agricultural Waste Management Field Handbook* (USDA 1996a, 2008) and data from the American Society of Agricultural Engineers, Standard D384.1 (ASAE 1998).
- All N_2O emission factors (direct and indirect) were taken from IPCC (2006).
- Country-specific estimates for the fraction of N loss from volatilization ($Frac_{gas}$) and runoff and leaching ($Frac_{runoff/leach}$) were developed. $Frac_{gas}$ values were based on WMS-specific volatilization values as estimated from EPA's *National Emission Inventory - Ammonia Emissions from Animal Agriculture Operations* (EPA 2005). $Frac_{runoff/leaching}$ values were based on regional cattle runoff data from EPA's Office of Water (EPA 2002b; see Annex 3.1).

To estimate N_2O emissions for cattle, the estimated amount of N excreted (kg per animal-year) managed in each WMS for each animal type, state, and year were taken from the CEFM. For animals other than cattle, the amount of N excreted (kg per year) in manure in each WMS for each animal type, state, and year was calculated. The population (head) for each state and animal was multiplied by TAM (kg animal mass per head) divided by 1,000, the nitrogen excretion rate (N_{ex} , in kg N per 1000 kg animal mass per day), WMS distribution (percent), and the number of days per year.

Direct N_2O emissions were calculated by multiplying the amount of N excreted (kg per year) in each WMS by the N_2O direct emission factor for that WMS (EF_{WMS} , in kg N_2O -N per kg N) and the conversion factor of N_2O -N to N_2O . These emissions were summed over state, animal, and WMS to determine the total direct N_2O emissions (kg of N_2O per year).

Next, indirect N_2O emissions from volatilization (kg N_2O per year) were calculated by multiplying the amount of N excreted (kg per year) in each WMS by the fraction of N lost through volatilization ($Frac_{tas}$) divided by 100, and the emission factor for volatilization ($EF_{volatilization}$, in kg N_2O per kg N), and the conversion factor of N_2O -N to N_2O . Indirect N_2O emissions from runoff and leaching (kg N_2O per year) were then calculated by multiplying the amount of N excreted (kg per year) in each WMS by the fraction of N lost through runoff and leaching ($Frac_{runoff/leach}$) divided by 100, and the emission factor for runoff and leaching ($EF_{runoff/leach}$, in kg N_2O per kg N), and the conversion factor of N_2O -N to N_2O . The indirect N_2O emissions from volatilization and runoff and leaching were summed to determine the total indirect N_2O emissions.

The direct and indirect N_2O emissions were summed to determine total N_2O emissions (kg N_2O per year).

Uncertainty and Time-Series Consistency

An analysis (ERG 2003) was conducted for the manure management emission estimates presented in the 1990 through 2001 Inventory report to determine the uncertainty associated with estimating CH_4 and N_2O emissions from livestock manure management. The quantitative uncertainty analysis for this source category was performed in 2002 through the IPCC-recommended Tier 2 uncertainty estimation methodology, the Monte Carlo Stochastic Simulation technique. The uncertainty analysis was developed based on the methods used to estimate CH_4 and N_2O emissions from manure management systems. A normal probability distribution was assumed for each source data category. The series of equations used were condensed into a single equation for each animal type and state. The equations for each animal group contained four to five variables around which the uncertainty analysis was

performed for each state. These uncertainty estimates were directly applied to the 2009 emission estimates.

The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 6-8. Manure management CH₄ emissions in 2009 were estimated to be between 40.6 and 59.4 Tg CO₂ Eq. at a 95 percent confidence level, which indicates a range of 18 percent below to 20 percent above the actual 2009 emission estimate of 49.5 Tg CO₂ Eq. At the 95 percent confidence level, N₂O emissions were estimated to be between 15.0 and 22.1 Tg CO₂ Eq. (or approximately 16 percent below and 24 percent above the actual 2009 emission estimate of 17.9 Tg CO₂ Eq.).

Table 6-8: Tier 2 Quantitative Uncertainty Estimates for CH₄ and N₂O (Direct and Indirect) Emissions from Manure Management (Tg CO₂ Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate ^a			
			(Tg CO ₂ Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Manure Management	CH ₄	49.5	40.6	59.4	-18%	+20%
Manure Management	N ₂ O	17.9	15.0	22.1	-16%	+24%

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

QA/QC and Verification

Tier 1 and Tier 2 QA/QC activities were conducted consistent with the U.S. QA/QC plan. Tier 2 activities focused on comparing estimates for the previous and current inventories for N₂O emissions from managed systems and CH₄ emissions from livestock manure. All errors identified were corrected. Order of magnitude checks were also conducted, and corrections made where needed. Manure N data were checked by comparing state-level data with bottom up estimates derived at the county level and summed to the state level. Similarly, a comparison was made by animal and WMS type for the full time series, between national level estimates for nitrogen excreted and the sum of county estimates for the full time series.

Recalculations Discussion

The CEFM produces VS and Nex data for cattle that are used in the manure management inventory. As a result, all changes to the CEFM described in Section 6.1 Enteric Fermentation contributed to changes in the VS and Nex data utilized for calculating CH₄ and N₂O emissions from manure management. In addition, to standardize the estimates of TAM between the CEFM and the manure management source category, the total VS and Nex estimates in units of kg per head per year from the CEFM were used in the manure management calculations in the current Inventory. With these changes, CH₄ and N₂O emission estimates from manure management systems are higher than reported in the previous Inventory for both beef and dairy cattle. Methane emissions from beef and dairy cattle were higher by 7 and 24 percent, respectively, while N₂O emissions were higher by 1 and 5 percent for beef and dairy cattle, respectively, averaged over the 1990 to 2008 time series.

In addition to changes in cattle Nex and VS data, the VS and Nex for other animal types were updated using data from USDA's updated *Agricultural Waste Management Field Handbook* (USDA 2008). Data from both the previous *Handbook* and the updated the *Handbook* were used to create a time series of VS and Nex data across all inventory years for all animals (ERG 2010b). The VS and Nex updates for all animals contributed to an average emission increase of 9.5 percent for CH₄ and 2.7 percent for N₂O across the time series.

For the current Inventory, USDA population data were used that included updated market swine categories. USDA changed the "market swine under 60 lbs." category to "market swine under 50 lbs." for years 2008 and 2009. In addition, USDA changed the "market swine from 60-119 lbs." to "market swine from 50-119 lbs." for the same years. This update resulted in a change in TAM estimates for those two swine categories which contributed to an overall decrease in CH₄ emissions from swine of 1.6 percent and an overall increase in N₂O emissions from swine of 20.9 percent in 2008.

The goat population was updated to reflect the USDA 2007 Census of Agriculture. This change resulted in an increase in both CH₄ and N₂O emissions for goats from the years 2003 through 2008 by 13 percent and 16 percent on average, respectively.

Planned Improvements

A recent journal article (Lory et al., 2010) criticized the IPCC and EPA methodology used to estimate greenhouse gas emissions from manure management. After review of the methodologies, EPA does not feel that any changes to the IPCC inventory methodologies are required as a result of this article; for more specific information, please see EPA's detailed response to the article (Bartram et al., 2010). EPA will continue to investigate any new or additional data sources identified that contain updated information that can be used to improve the inventory emission estimates. Also, EPA will continue to seek empirical data to compare inventory estimates to specific systems, in order to improve the methodology used to estimate greenhouse gas emissions from manure management.

USDA's 2007 *Census of Agriculture* data are finalized and available. These data will be incorporated into the county-level population estimates used for the Agricultural Soils source category and the estimates of MCF and utilize it to update the WMS distributions for swine and dairy animals.

Due to time constraints, the temperature data used to estimate MCFs were not updated for the current Inventory. Updated temperature data will be obtained and applied for subsequent Inventory reports.

The uncertainty analysis will be updated in the future to more accurately assess uncertainty of emission calculations. This update is necessary due to the extensive changes in emission calculation methodology that was made in the 1990 through 2006 Inventory, including estimation of emissions at the WMS level and the use of new calculations and variables for indirect N₂O emissions.

6.3. Rice Cultivation (IPCC Source Category 4C)

Most of the world's rice, and all rice in the United States, is grown on flooded fields. When fields are flooded, aerobic decomposition of organic material gradually depletes most of the oxygen present in the soil, causing anaerobic soil conditions. Once the environment becomes anaerobic, CH₄ is produced through anaerobic decomposition of soil organic matter by methanogenic bacteria. As much as 60 to 90 percent of the CH₄ produced is oxidized by aerobic methanotrophic bacteria in the soil (some oxygen remains at the interfaces of soil and water, and soil and root system) (Holzapfel-Pschorn et al. 1985, Sass et al. 1990). Some of the CH₄ is also leached away as dissolved CH₄ in floodwater that percolates from the field. The remaining un-oxidized CH₄ is transported from the submerged soil to the atmosphere primarily by diffusive transport through the rice plants. Minor amounts of CH₄ also escape from the soil via diffusion and bubbling through floodwaters.

The water management system under which rice is grown is one of the most important factors affecting CH₄ emissions. Upland rice fields are not flooded, and therefore are not believed to produce CH₄. In deepwater rice fields (i.e., fields with flooding depths greater than one meter), the lower stems and roots of the rice plants are dead, so the primary CH₄ transport pathway to the atmosphere is blocked. The quantities of CH₄ released from deepwater fields, therefore, are believed to be significantly less than the quantities released from areas with shallower flooding depths. Some flooded fields are drained periodically during the growing season, either intentionally or accidentally. If water is drained and soils are allowed to dry sufficiently, CH₄ emissions decrease or stop entirely. This is due to soil aeration, which not only causes existing soil CH₄ to oxidize but also inhibits further CH₄ production in soils. All rice in the United States is grown under continuously flooded conditions; none is grown under deepwater conditions. Mid-season drainage does not occur except by accident (e.g., due to levee breach).

Other factors that influence CH₄ emissions from flooded rice fields include fertilization practices (especially the use of organic fertilizers), soil temperature, soil type, rice variety, and cultivation practices (e.g., tillage, seeding, and weeding practices). The factors that determine the amount of organic material available to decompose (i.e., organic fertilizer use, soil type, rice variety,¹⁴¹ and cultivation practices) are the most important variables influencing the amount of CH₄ emitted over the growing season; the total amount of CH₄ released depends primarily on the amount of organic substrate available. Soil temperature is known to be an important factor regulating the activity of methanogenic bacteria, and therefore the rate of CH₄ production. However, although temperature controls the amount of time it takes to convert a given amount of organic material to CH₄, that time is short relative to a growing season, so the dependence of total emissions over an entire growing season on soil temperature is weak. The application of synthetic fertilizers has also been found to influence CH₄ emissions; in particular, both nitrate and

¹⁴¹ The roots of rice plants shed organic material, which is referred to as "root exudate." The amount of root exudate produced by a rice plant over a growing season varies among rice varieties.

sulfate fertilizers (e.g., ammonium nitrate and ammonium sulfate) appear to inhibit CH₄ formation.

Rice is cultivated in eight states: Arkansas, California, Florida, Louisiana, Mississippi, Missouri, Oklahoma, and Texas.¹⁴² Soil types, rice varieties, and cultivation practices for rice vary from state to state, and even from farm to farm. However, most rice farmers apply organic fertilizers in the form of residue from the previous rice crop, which is left standing, disked, or rolled into the fields. Most farmers also apply synthetic fertilizer to their fields, usually urea. Nitrate and sulfate fertilizers are not commonly used in rice cultivation in the United States. In addition, the climatic conditions of southwest Louisiana, Texas, and Florida often allow for a second, or ratoon, rice crop. Ratoon crops are much less common or non-existent in Arkansas, California, Mississippi, Missouri, Oklahoma, and northern areas of Louisiana. Methane emissions from ratoon crops have been found to be considerably higher than those from the primary crop. This second rice crop is produced from regrowth of the stubble after the first crop has been harvested. Because the first crop's stubble is left behind in ratooned fields, and there is no time delay between cropping seasons (which would allow the stubble to decay aerobically), the amount of organic material that is available for anaerobic decomposition is considerably higher than with the first (i.e., primary) crop.

Rice cultivation is a small source of CH₄ in the United States (Table 6-9 and Table 6-10). In 2009, CH₄ emissions from rice cultivation were 7.3 Tg CO₂ Eq. (349 Gg). Annual emissions fluctuated unevenly between the years 1990 and 2009, ranging from an annual decrease of 14 percent to an annual increase of 17 percent. There was an overall decrease of 17 percent between 1990 and 2006, due to an overall decrease in primary crop area.¹⁴³ However, emission levels increased again by 24 percent between 2006 and 2009 due to a slight increase in rice crop area in all states. The factors that affect the rice acreage in any year vary from state to state, although the price of rice relative to competing crops is the primary controlling variable in most states.

Table 6-9: CH₄ Emissions from Rice Cultivation (Tg CO₂ Eq.)

State	1990	2000	2005	2006	2007	2008	2009
Primary	5.1	5.5	6.0	5.1	4.9	5.3	5.6
Arkansas	2.1	2.5	2.9	2.5	2.4	2.5	2.6
California	0.7	1.0	0.9	0.9	1.0	0.9	1.0
Florida	+	+	+	+	+	+	+
Louisiana	1.0	0.9	0.9	0.6	0.7	0.8	0.8
Mississippi	0.4	0.4	0.5	0.3	0.3	0.4	0.4
Missouri	0.1	0.3	0.4	0.4	0.3	0.4	0.4
Oklahoma	+	+	+	+	0.0	0.0	0.0
Texas	0.6	0.4	0.4	0.3	0.3	0.3	0.3
Ratoon	2.1	2.0	0.8	0.9	1.3	1.9	1.8
Arkansas	+	+	+	+	+	+	+
Florida	+	0.1	+	+	+	+	+
Louisiana	1.1	1.3	0.5	0.5	0.9	1.2	1.1
Texas	0.9	0.7	0.4	0.4	0.3	0.6	0.7
Total	7.1	7.5	6.8	5.9	6.2	7.2	7.3

+ Less than 0.05 Tg CO₂ Eq.

Note: Totals may not sum due to independent rounding.

Table 6-10: CH₄ Emissions from Rice Cultivation (Gg)

State	1990	2000	2005	2006	2007	2008	2009
Primary	241	260	287	241	235	254	265
Arkansas	102	120	139	119	113	119	125
California	34	47	45	44	45	44	47
Florida	1	2	1	1	1	1	1
Louisiana	46	41	45	29	32	39	39

¹⁴² A very small amount of rice is grown on about 20 acres in South Carolina; however, this amount was determined to be too insignificant to warrant inclusion in national emission estimates.

¹⁴³ The 14 percent decrease occurred between 2005 and 2006; the 17 percent increase happened between 1993 and 1994.

Mississippi	21		19		22	16	16	19	21
Missouri	7		14		18	18	15	17	17
Oklahoma	+		+		+	+	0	+	+
Texas	30		18		17	13	12	15	14
Ratoon	98		97		39	41	60	89	84
Arkansas	+		+		1	+	+	+	+
Florida	2		2		+	1	1	1	2
Louisiana	52		61		22	22	42	59	51
Texas	45		34		17	18	16	29	31
Total	339		357		326	282	295	343	349

+ Less than 0.5 Gg

Note: Totals may not sum due to independent rounding.

Methodology

IPCC (2006) recommends using harvested rice areas, area-based daily emission factors (i.e., amount of CH₄ emitted per day per unit harvested area), and length of growing season to estimate annual CH₄ emissions from rice cultivation. This Inventory uses the recommended methodology and employs Tier 2 U.S.-specific emission factors derived from rice field measurements. State-specific and daily emission factors were not available, however, so average U.S. seasonal emission factors were used. Seasonal emissions have been found to be much higher for ratooned crops than for primary crops, so emissions from ratooned and primary areas are estimated separately using emission factors that are representative of the particular growing season. This approach is consistent with IPCC (2006).

The harvested rice areas for the primary and ratoon crops in each state are presented in Table 6-11, and the area of ratoon crop area as a percent of primary crop area is shown in Table 6-12. Primary crop areas for 1990 through 2009 for all states except Florida and Oklahoma were taken from U.S. Department of Agriculture's Field Crops Final Estimates 1987–1992 (USDA 1994), Field Crops Final Estimates 1992–1997 (USDA 1998), Field Crops Final Estimates 1997–2002 (USDA 2003), and Crop Production Summary (USDA 2005 through 2010). Source data for non-USDA sources of primary and ratoon harvest areas are shown in Table 6-13. California, Mississippi, Missouri, and Oklahoma have not ratooned rice over the period 1990 through 2009 (Guethle 1999 through 2010; Lee 2003 through 2007; Mutters 2002 through 2005; Street 1999 through 2003; Walker 2005, 2007 through 2008; Buehring 2009 through 2010).

Table 6-11: Rice Areas Harvested (Hectares)

State/Crop	1990	2000	2005	2006	2007	2008	2009
Arkansas							
Primary	485,633	570,619	661,675	566,572	536,220	564,549	594,901
Ratoon ^a	-	-	662	6	5	6	6
California	159,854	221,773	212,869	211,655	215,702	209,227	225,010
Florida							
Primary	4,978	7,801	4,565	4,575	6,242	5,463	5,664
Ratoon	2,489	3,193	0	1,295	1,873	1,639	2,266
Louisiana							
Primary	220,558	194,253	212,465	139,620	152,975	187,778	187,778
Ratoon	66,168	77,701	27,620	27,924	53,541	75,111	65,722
Mississippi	101,174	88,223	106,435	76,487	76,487	92,675	98,341
Missouri	32,376	68,393	86,605	86,605	72,036	80,534	80,939
Oklahoma	617	283	271	17	0	77	0
Texas							
Primary	142,857	86,605	81,344	60,704	58,681	69,607	68,798
Ratoon	57,143	43,302	21,963	23,675	21,125	36,892	39,903
Total Primary	1,148,047	1,237,951	1,366,228	1,146,235	1,118,343	1,209,911	1,261,431

Total Ratoon	125,799	124,197	50,245	52,899	76,544	113,648	107,897
Total	1,273,847	1,362,148	1,416,473	1,199,135	1,194,887	1,323,559	1,369,328

^a Arkansas ratooning occurred only in 1998, 1999, and 2005 through 2009.

Note: Totals may not sum due to independent rounding.

Table 6-12: Ratooned Area as Percent of Primary Growth Area

State	1990	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Arkansas	0%		+	+			0%			0.1%	+	+	+	+
Florida		50%		65%	41%	60%	54%	100%	77%	0%	28%	30%	30%	40%
Louisiana			30%		40%	30%	15%	35%	30%	13%	20%	35%	40%	35%
Texas		40%			50%	40%	37%	38%	35%	27%	39%	36%	53%	58%

+ Indicates ratooning rate less than 0.1 percent.

Table 6-13: Non-USDA Data Sources for Rice Harvest Information

State/Crop	1990	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Arkansas											
Ratoon	Wilson (2002 – 2007, 2009 – 2010)										
Florida											
Primary	Scheuneman (1999 – 2001)	Deren (2002)	Kirstein (2003, 2006)				Gonzales (2006 – 2010)				
Ratoon	Scheuneman (1999)	Deren (2002)	Kirstein (2003-2004)	Cantens (2005)	Gonzales (2006 – 2010)						
Louisiana											
Ratoon	Bollich (2000)	Linscombe (1999, 2001 – 2010)									
Oklahoma											
Primary	Lee (2003-2007)								Anderson (2008 – 2010)		
Texas											
Ratoon	Klosterboer (1999 – 2003)				Stansel (2004 – 2005)		Texas Ag Experiment Station (2006 – 2010)				

To determine what CH₄ emission factors should be used for the primary and ratoon crops, CH₄ flux information from rice field measurements in the United States was collected. Experiments that involved atypical or nonrepresentative management practices (e.g., the application of nitrate or sulfate fertilizers, or other substances believed to suppress CH₄ formation), as well as experiments in which measurements were not made over an entire flooding season or floodwaters were drained mid-season, were excluded from the analysis. The remaining experimental results¹⁴⁴ were then sorted by season (i.e., primary and ratoon) and type of fertilizer amendment (i.e., no fertilizer added, organic fertilizer added, and synthetic and organic fertilizer added). The experimental results from primary crops with added synthetic and organic fertilizer (Bossio et al. 1999; Cicerone et al. 1992; Sass et al. 1991a, 1991b) were averaged to derive an emission factor for the primary crop, and the experimental results from ratoon crops with added synthetic fertilizer (Lindau and Bollich 1993, Lindau et al. 1995) were averaged to derive an emission factor for the ratoon crop. The resultant emission factor for the primary crop is 210 kg CH₄/hectare-season, and the resultant emission factor for the ratoon crop is 780 kg CH₄/hectare-season.

Uncertainty and Time-Series Consistency

The largest uncertainty in the calculation of CH₄ emissions from rice cultivation is associated with the emission factors. Seasonal emissions, derived from field measurements in the United States, vary by more than one order of

¹⁴⁴ In some of these remaining experiments, measurements from individual plots were excluded from the analysis because of the aforementioned reasons. In addition, one measurement from the ratooned fields (i.e., the flux of 1,490 kg CH₄/hectare-season in Lindau and Bollich 1993) was excluded, because this emission rate is unusually high compared to other flux measurements in the United States, as well as IPCC (2006) default emission factors.

magnitude. This inherent variability is due to differences in cultivation practices, particularly fertilizer type, amount, and mode of application; differences in cultivar type; and differences in soil and climatic conditions. A portion of this variability is accounted for by separating primary from ratooned areas. However, even within a cropping season or a given management regime, measured emissions may vary significantly. Of the experiments used to derive the emission factors applied here, primary emissions ranged from 22 to 479 kg CH₄/hectare-season and ratoon emissions ranged from 481 to 1,490 kg CH₄/hectare-season. The uncertainty distributions around the primary and ratoon emission factors were derived using the distributions of the relevant primary or ratoon emission factors available in the literature and described above. Variability about the rice emission factor means was not normally distributed for either primary or ratooned crops, but rather skewed, with a tail trailing to the right of the mean. A lognormal statistical distribution was, therefore, applied in the Tier 2 Monte Carlo analysis.

Other sources of uncertainty include the primary rice-cropped area for each state, percent of rice-cropped area that is ratooned, and the extent to which flooding outside of the normal rice season is practiced. Expert judgment was used to estimate the uncertainty associated with primary rice-cropped area for each state at 1 to 5 percent, and a normal distribution was assumed. Uncertainties were applied to ratooned area by state, based on the level of reporting performed by the state. No uncertainties were calculated for the practice of flooding outside of the normal rice season because CH₄ flux measurements have not been undertaken over a sufficient geographic range or under a broad enough range of representative conditions to account for this source in the emission estimates or its associated uncertainty.

To quantify the uncertainties for emissions from rice cultivation, a Monte Carlo (Tier 2) uncertainty analysis was performed using the information provided above. The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 6-14. Rice cultivation CH₄ emissions in 2009 were estimated to be between 2.5 and 18.0 Tg CO₂ Eq. at a 95 percent confidence level, which indicates a range of 65 percent below to 146 percent above the actual 2009 emission estimate of 7.3 Tg CO₂ Eq.

Table 6-14: Tier 2 Quantitative Uncertainty Estimates for CH₄ Emissions from Rice Cultivation (Tg CO₂ Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate ^a			
			(Tg CO ₂ Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Rice Cultivation	CH ₄	7.3	2.5	18.0	-65%	+146%

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

QA/QC and Verification

A source-specific QA/QC plan for rice cultivation was developed and implemented. This effort included a Tier 1 analysis, as well as portions of a Tier 2 analysis. The Tier 2 procedures focused on comparing trends across years, states, and cropping seasons to attempt to identify any outliers or inconsistencies. No problems were found.

Planned Improvements

A possible future improvement is to create region-specific emission factors for rice cultivation. The current methodology uses a nationwide average emission factor, derived from several studies done in a number of states. The prospective improvement would take the same studies and average them by region, presumably resulting in more spatially specific emission factors.

6.4. Agricultural Soil Management (IPCC Source Category 4D)

Nitrous oxide is produced naturally in soils through the microbial processes of nitrification and denitrification.¹⁴⁵ A number of agricultural activities increase mineral N availability in soils, thereby increasing the amount available for nitrification and denitrification, and ultimately the amount of N₂O emitted. These activities increase soil mineral N either directly or indirectly (see Figure 6-2). Direct increases occur through a variety of management practices that add or lead to greater release of mineral N to the soil, including fertilization; application of managed livestock manure and other organic materials such as sewage sludge; deposition of manure on soils by domesticated animals in pastures, rangelands, and paddocks (PRP) (i.e., by grazing animals and other animals whose manure is not managed); production of N-fixing crops and forages; retention of crop residues; and drainage and cultivation of organic cropland soils (i.e., soils with a high organic matter content, otherwise known as histosols).¹⁴⁶ Other agricultural soil management activities, including irrigation, drainage, tillage practices, and fallowing of land, can influence N mineralization in soils and thereby affect direct emissions. Mineral N is also made available in soils through decomposition of soil organic matter and plant litter, as well as asymbiotic fixation of N from the atmosphere,¹⁴⁷ and these processes are influenced by agricultural management through impacts on moisture and temperature regimes in soils. These additional sources of mineral N are included at the recommendation of IPCC (2006) for complete accounting of management impacts on greenhouse gas emissions, as discussed in the Methodology section. Indirect emissions of N₂O occur through two pathways: (1) volatilization and subsequent atmospheric deposition of applied/mineralized N,¹⁴⁸ and (2) surface runoff and leaching of applied/mineralized N into groundwater and surface water. Direct emissions from agricultural lands (i.e., cropland and grassland) are included in this section, while direct emissions from forest lands and settlements are presented in the Land Use, Land-Use Change, and Forestry chapter. However, indirect N₂O emissions from all land-uses (cropland, grassland, forest lands, and settlements) are reported in this section.

Figure 6-2: Sources and Pathways of N that Result in N₂O Emissions from Agricultural Soil Management

Agricultural soils produce the majority of N₂O emissions in the United States. Estimated emissions from this source in 2009 were 204.6 Tg CO₂ Eq. (660 Gg N₂O) (see Table 6-15 and Table 6-16). Annual N₂O emissions from agricultural soils fluctuated between 1990 and 2009, although overall emissions were 3 percent higher in 2009 than in 1990. Year-to-year fluctuations are largely a reflection of annual variation in weather patterns, synthetic fertilizer use, and crop production. On average, cropland accounted for approximately 70 percent of total direct emissions, while grassland accounted for approximately 30 percent. These percentages are about the same for indirect emissions since forest lands and settlements account for such a small percentage of total indirect emissions. Estimated direct and indirect N₂O emissions by sub-source category are shown in Table 6-17 and Table 6-18.

Table 6-15: N₂O Emissions from Agricultural Soils (Tg CO₂ Eq.)

Activity	1990	2000	2005	2006	2007	2008	2009
Direct	153.8	162.6	167.5	163.7	165.1	166.6	160.2
Cropland	102.9	115.6	118.1	115.6	117.8	117.9	112.0
Grassland	50.9	47.1	49.4	48.1	47.3	48.7	48.2
Indirect (All Land-Use Types)	44.0	44.1	43.9	45.2	44.3	44.1	44.4

¹⁴⁵ Nitrification and denitrification are driven by the activity of microorganisms in soils. Nitrification is the aerobic microbial oxidation of ammonium (NH₄⁺) to nitrate (NO₃⁻), and denitrification is the anaerobic microbial reduction of nitrate to N₂. Nitrous oxide is a gaseous intermediate product in the reaction sequence of denitrification, which leaks from microbial cells into the soil and then into the atmosphere. Nitrous oxide is also produced during nitrification, although by a less well-understood mechanism (Nevison 2000).

¹⁴⁶ Drainage and cultivation of organic soils in former wetlands enhances mineralization of N-rich organic matter, thereby increasing N₂O emissions from these soils.

¹⁴⁷ Asymbiotic N fixation is the fixation of atmospheric N₂ by bacteria living in soils that do not have a direct relationship with plants.

¹⁴⁸ These processes entail volatilization of applied or mineralized N as NH₃ and NO_x, transformation of these gases within the atmosphere (or upon deposition), and deposition of the N primarily in the form of particulate NH₄⁺, nitric acid (HNO₃), and NO_x.

Cropland	37.5		37.7		36.8	38.6	37.6	37.5	37.5
Grassland	6.1		5.8		6.3	5.9	5.9	5.9	6.2
Forest Land	+		0.1		0.1	0.1	0.1	0.1	0.1
Settlements	0.3		0.4		0.6	0.6	0.6	0.6	0.6
Total	197.8		206.8		211.3	208.9	209.4	210.7	204.6

+ Less than 0.05 Tg CO₂ Eq.

Table 6-16: N₂O Emissions from Agricultural Soils (Gg)

Activity	1990		2000		2005	2006	2007	2008	2009
Direct	496		525		540	528	533	538	517
Cropland	332		373		381	373	380	380	361
Grassland	164		152		159	155	152	157	155
Indirect (All Land-Use Types)	142		142		142	146	143	142	143
Cropland	121		122		119	125	121	121	121
Grassland	20		19		20	19	19	19	20
Forest Land	0		+		+	+	+	+	+
Settlements	1		1		2	2	2	2	2
Total	638		667		682	674	675	680	660

+ Less than 0.5 Gg N₂O

Table 6-17: Direct N₂O Emissions from Agricultural Soils by Land Use Type and N Input Type (Tg CO₂ Eq.)

Activity	1990		2000		2005	2006	2007	2008	2009
Cropland	102.9		115.6		118.1	115.6	117.8	117.9	112.0
Mineral Soils	100.1		112.7		115.2	112.7	114.9	115.0	109.1
<i>Mineralization and Asymbiotic Fixation</i>	44.6		50.6		50.5	49.7	50.9	50.9	47.1
<i>Synthetic Fertilizer</i>	32.3		36.0		38.6	36.7	37.4	37.3	36.9
<i>Residue N^a</i>	12.4		14.3		13.7	13.8	13.9	14.3	13.1
<i>Organic Amendments^b</i>	10.8		11.8		12.3	12.5	12.8	12.5	12.1
Organic Soils	2.9		2.9		2.9	2.9	2.9	2.9	2.9
Grassland	50.9		47.1		49.4	48.1	47.3	48.7	48.2
Residue N ^c	15.6		13.8		14.6	14.2	13.9	14.4	14.1
PRP Manure	8.1		7.9		8.2	8.1	8.0	8.2	7.9
Synthetic Fertilizer	3.9		3.9		4.1	4.0	3.9	4.0	3.9
Managed Manure ^d	1.5		1.6		1.6	1.6	1.6	1.6	1.6
Sewage Sludge	0.3		0.4		0.5	0.5	0.5	0.5	0.5
Mineralization and Asymbiotic Fixation	21.5		19.5		20.4	19.7	19.3	20.0	20.1
Total	153.8		162.6		167.5	163.7	165.1	166.6	160.2

^a Cropland residue N inputs include N in unharvested legumes as well as crop residue N.

^b Organic amendment inputs include managed manure amendments, daily spread manure amendments, and commercial organic fertilizers (i.e., dried blood, dried manure, tankage, compost, and other).

^c Grassland residue N inputs include N in ungrazed legumes as well as ungrazed grass residue N

^d Accounts for managed manure and daily spread manure amendments that are applied to grassland soils.

Table 6-18: Indirect N₂O Emissions from all Land-Use Types (Tg CO₂ Eq.)

Activity	1990		2000		2005	2006	2007	2008	2009
Cropland	37.5		37.7		36.8	38.6	37.6	37.5	37.5
Volatilization & Atm. Deposition	11.6		12.7		13.1	14.2	12.8	12.9	13.4
Surface Leaching & Run-Off	25.8		25.0		23.7	24.4	24.9	24.5	24.1
Grassland	6.1		5.8		6.3	5.9	5.9	5.9	6.2
Volatilization & Atm. Deposition	5.1		4.7		4.8	4.8	4.7	4.7	4.7

Surface Leaching & Run-Off	1.0	1.2	1.5	1.1	1.2	1.2	1.5
Forest Land	+	0.1	0.1	0.1	0.1	0.1	0.1
Volatilization & Atm. Deposition	+	+	+	+	+	+	+
Surface Leaching & Run-Off	+	0.1	0.1	0.1	0.1	0.1	0.1
Settlements	0.3	0.4	0.6	0.6	0.6	0.6	0.6
Volatilization & Atm. Deposition	0.1	0.1	0.2	0.2	0.2	0.2	0.2
Surface Leaching & Run-Off	0.2	0.3	0.4	0.4	0.4	0.4	0.4
Total	44.0	44.1	43.9	45.2	44.3	44.1	44.4

+ Less than 0.05 Tg CO₂ Eq.

Figure 6-3 through Figure 6-6 show regional patterns in direct N₂O emissions, and also show N losses from volatilization, leaching, and runoff that lead to indirect N₂O emissions. Average annual emissions and N losses are shown for croplands that produce major crops and from grasslands in each state. Direct N₂O emissions from croplands tend to be high in the Corn Belt (Illinois, Iowa, Indiana, Ohio, southern Minnesota, southern Wisconsin, and eastern Nebraska), where a large portion of the land is used for growing highly fertilized corn and N-fixing soybean crops. Direct emissions are also high in Missouri, Kansas, and Texas, primarily from irrigated cropping in western Texas, dryland wheat in Kansas, and hay cropping in eastern Texas and Missouri. Direct emissions are low in many parts of the eastern United States because a small portion of land is cultivated, and also low in many western states where rainfall and access to irrigation water are limited.

Direct emissions (Tg CO₂ Eq./state/year) from grasslands are highest in the central and western United States (Figure 6-4) where a high proportion of the land is used for cattle grazing. Some areas in the Great Lake states, the Northeast, and Southeast have moderate to low emissions even though emissions from these areas tend to be high on a per unit area basis, because the total amount of grassland is much lower than in the central and western United States.

Indirect emissions from croplands and grasslands (Figure 6-5 and Figure 6-6) show patterns similar to direct emissions, because the factors that control direct emissions (N inputs, weather, soil type) also influence indirect emissions. However, there are some exceptions, because the processes that contribute to indirect emissions (NO₃⁻ leaching, N volatilization) do not respond in exactly the same manner as the processes that control direct emissions (nitrification and denitrification). For example, coarser-textured soils facilitate relatively high indirect emissions in Florida grasslands due to high rates of N volatilization and NO₃⁻ leaching, even though they have only moderate rates of direct N₂O emissions.

Figure 6-3: Major Crops, Average Annual Direct N₂O Emissions Estimated Using the DAYCENT Model, 1990-2009 (Tg CO₂ Eq./year)

[Figure will be provided in public review]

Figure 6-4: Grasslands, Average Annual Direct N₂O Emissions Estimated Using the DAYCENT Model, 1990-2009 (Tg CO₂ Eq./year)

[Figure will be provided in public review]

Figure 6-5: Major Crops, Average Annual N Losses Leading to Indirect N₂O Emissions Estimated Using the DAYCENT Model, 1990-2009 (Gg N/year)

[Figure will be provided in public review]

Figure 6-6: Grasslands, Average Annual N Losses Leading to Indirect N₂O Emissions Estimated Using the DAYCENT Model, 1990-2009 (Gg N/year)

[Figure will be provided in public review]

Methodology

The 2006 IPCC Guidelines (IPCC 2006) divide the Agricultural Soil Management source category into four components: (1) direct emissions due to N additions to cropland and grassland mineral soils, including synthetic

fertilizers, sewage sludge applications, crop residues, organic amendments, and biological N fixation associated with planting of legumes on cropland and grassland soils; (2) direct emissions from drainage and cultivation of organic cropland soils; (3) direct emissions from soils due to the deposition of manure by livestock on PRP grasslands; and (4) indirect emissions from soils and water due to N additions and manure deposition to soils that lead to volatilization, leaching, or runoff of N and subsequent conversion to N₂O.

The United States has adopted recommendations from IPCC (2006) on methods for agricultural soil management. These recommendations include (1) estimating the contribution of N from crop residues to indirect soil N₂O emissions; (2) adopting a revised emission factor for direct N₂O emissions to the extent that Tier 1 methods are used in the Inventory (described later in this section); (3) removing double counting of emissions from N-fixing crops associated with the biological N fixation and crop residue N input categories; (4) using revised crop residue statistics to compute N inputs to soils based on harvest yield data to the extent that Tier 1 methods are used in the Inventory; (5) accounting for indirect as well as direct emissions from N made available via mineralization of soil organic matter and litter, in addition to asymbiotic fixation¹⁴⁹ (i.e., computing total emissions from managed land); and (6) reporting all emissions from managed lands, largely because management affects all processes leading to soil N₂O emissions. One recommendation from IPCC (2006) that has not been adopted is the accounting of emissions from pasture renewal, which involves occasional plowing to improve forage production. This practice is not common in the United States, and is not estimated.

The methodology used to estimate emissions from agricultural soil management in the United States is based on a combination of IPCC Tier 1 and 3 approaches. A Tier 3, process-based model (DAYCENT) was used to estimate direct emissions from major crops on mineral (i.e., non-organic) soils; as well as most of the direct emissions from grasslands. The Tier 3 approach has been specifically designed and tested to estimate N₂O emissions in the United States, accounting for more of the environmental and management influences on soil N₂O emissions than the IPCC Tier 1 method (see Box 6-1 for further elaboration). The Tier 1 IPCC (2006) methodology was used to estimate (1) direct emissions from non-major crops on mineral soils (e.g., barley, oats, vegetables, and other crops); (2) the portion of the grassland direct emissions that were not estimated with the Tier 3 DAYCENT model (i.e., federal grasslands); and (3) direct emissions from drainage and cultivation of organic cropland soils. Indirect emissions were also estimated with a combination of DAYCENT and the IPCC Tier 1 method.

In past Inventories, attempts were made to subtract “background” emissions that would presumably occur if the lands were not managed. However, this approach is likely to be inaccurate for estimating the anthropogenic influence on soil N₂O emissions. Moreover, if background emissions could be measured or modeled based on processes unaffected by anthropogenic activity, they would be a very small portion of the total emissions, due to the high inputs of N to agricultural soils from fertilization and legume cropping. Given the recommendation from IPCC (2006) and the influence of management on all processes leading to N₂O emissions from soils in agricultural systems, the decision was made to report total emissions from managed lands for this source category. Annex 3.11 provides more detailed information on the methodologies and data used to calculate N₂O emissions from each component.

[BEGIN BOX]

Box 6-1. Tier 1 vs. Tier 3 Approach for Estimating N₂O Emissions

The IPCC (2006) Tier 1 approach is based on multiplying activity data on different N inputs (e.g., synthetic fertilizer, manure, N fixation, etc.) by the appropriate default IPCC emission factors to estimate N₂O emissions on an input-by-input basis. The Tier 1 approach requires a minimal amount of activity data, readily available in most countries (e.g., total N applied to crops); calculations are simple; and the methodology is highly transparent. In contrast, the Tier 3 approach developed for this Inventory employs a process-based model (i.e., DAYCENT) that represents the interaction of N inputs and the environmental conditions at specific locations. Consequently, the Tier

¹⁴⁹ N inputs from asymbiotic N fixation are not directly addressed in *2006 IPCC Guidelines*, but are a component of the total emissions from managed lands and are included in the Tier 3 approach developed for this source.

3 approach is likely to produce more accurate estimates; it accounts more comprehensively for land-use and management impacts and their interaction with environmental factors (i.e., weather patterns and soil characteristics), which will enhance or dampen anthropogenic influences. However, the Tier 3 approach requires more detailed activity data (e.g., crop-specific N amendment rates), additional data inputs (e.g., daily weather, soil types, etc.), and considerable computational resources and programming expertise. The Tier 3 methodology is less transparent, and thus it is critical to evaluate the output of Tier 3 methods against measured data in order to demonstrate the adequacy of the method for estimating emissions (IPCC 2006). Another important difference between the Tier 1 and Tier 3 approaches relates to assumptions regarding N cycling. Tier 1 assumes that N added to a system is subject to N₂O emissions only during that year and cannot be stored in soils and contribute to N₂O emissions in subsequent years. This is a simplifying assumption that is likely to create bias in estimated N₂O emissions for a specific year. In contrast, the process-based model used in the Tier 3 approach includes such legacy effects when N added to soils is re-mineralized from soil organic matter and emitted as N₂O during subsequent years.

[END BOX]

Direct N₂O Emissions from Cropland Soils

Major Crop Types on Mineral Cropland Soils

The DAYCENT ecosystem model (Del Grosso et al. 2001, Parton et al. 1998) was used to estimate direct N₂O emissions from mineral cropland soils that are managed for production of major crops—specifically corn, soybeans, wheat, alfalfa hay, other hay, sorghum, and cotton—representing approximately 90 percent of total croplands in the United States. For these croplands, DAYCENT was used to simulate crop growth, soil organic matter decomposition, greenhouse gas fluxes, and key biogeochemical processes affecting N₂O emissions, and the simulations were driven by model input data generated from daily weather records (Thornton et al. 1997, 2000; Thornton and Running 1999), land management surveys (see citations below), and soil physical properties determined from national soil surveys (Soil Survey Staff 2005). Note that the influence of land-use change on soil N₂O emissions was not addressed in this analysis, but is a planned improvement.

DAYCENT simulations were conducted for each major crop at the county scale in the United States. Simulating N₂O emissions at the county scale was facilitated by soil and weather data that were available for every county with more than 100 acres of agricultural land, and by land management data (e.g., timing of planting, harvesting, and intensity of cultivation) that were available at the agricultural-region level as defined by the Agricultural Sector Model (McCarl et al. 1993). ASM has 63 agricultural regions in the contiguous United States. Most regions correspond to one state, except for those states with greater heterogeneity in agricultural practices; in such cases, more than one region is assigned to a state. While cropping systems were simulated for each county, the results best represent emissions at regional (i.e., state) and national levels due to the regional scale of management data, which include model parameters that determined the influence of management activities on soil N₂O emissions (e.g., when crops were planted/harvested).

Nitrous oxide emissions from managed agricultural lands are the result of interactions among anthropogenic activities (e.g., N fertilization, manure application, tillage) and other driving variables, such as weather and soil characteristics. These factors influence key processes associated with N dynamics in the soil profile, including immobilization of N by soil microbial organisms, decomposition of organic matter, plant uptake, leaching, runoff, and volatilization, as well as the processes leading to N₂O production (nitrification and denitrification). It is not possible to partition N₂O emissions into each anthropogenic activity directly from model outputs due to the complexity of the interactions (e.g., N₂O emissions from synthetic fertilizer applications cannot be distinguished from those resulting from manure applications). To approximate emissions by activity, the amount of mineral N added to the soil for each of these sources was determined and then divided by the total amount of mineral N that was made available in the soil according to the DAYCENT model. The percentages were then multiplied by the total of direct N₂O emissions in order to approximate the portion attributed to key practices. This approach is only an approximation because it assumes that all N made available in soil has an equal probability of being released as N₂O, regardless of its source, which is unlikely to be the case (Delgado et al., 2009). However, this approach allows for further disaggregation of emissions by source of N, which is valuable for reporting purposes and is analogous to the reporting associated with the IPCC (2006) Tier 1 method, in that it associates portions of the total soil N₂O

emissions with individual sources of N.

DAYCENT was used to estimate direct N₂O emissions due to mineral N available from: (1) the application of synthetic fertilizers; (2) the application of livestock manure; (3) the retention of crop residues (i.e., leaving residues in the field after harvest instead of burning or collecting residues); and (4) mineralization of soil organic matter and litter, in addition to asymbiotic fixation. Note that commercial organic fertilizers are addressed with the Tier 1 method because county-level application data would be needed to simulate applications in DAYCENT, and currently data are only available at the national scale. The third and fourth sources are generated internally by the DAYCENT model. For the first two practices, annual changes in soil mineral N due to anthropogenic activity were obtained or derived from the following sources:

- Crop-specific N-fertilization rates: Data sources for fertilization rates include Alexander and Smith (1990), Anonymous (1924), Battaglin and Goolsby (1994), Engle and Makela (1947), ERS (1994, 2003), Fraps and Asbury (1931), Ibach and Adams (1967), Ibach et al. (1964), NFA (1946), NRIAI (2003), Ross and Mehrling (1938), Skinner (1931), Smalley et al. (1939), Taylor (1994), and USDA (1966, 1957, 1954, 1946). Information on fertilizer use and rates by crop type for different regions of the United States were obtained primarily from the USDA *Economic Research Service Cropping Practices Survey* (ERS 1997) with additional data from other sources, including the National Agricultural Statistics Service (NASS 1992, 1999, 2004).
- Managed manure production and application to croplands and grasslands: Manure N amendments and daily spread manure N amendments applied to croplands and grasslands (not including PRP manure) were determined using USDA Manure N Management Databases for 1997 (Kellogg et al. 2000; Edmonds et al. 2003). Amendment data for 1997 were scaled to estimate values for other years based on the availability of managed manure N for application to soils in 1997 relative to other years. The amount of available N from managed manure for each livestock type was calculated as described in the Manure Management section (Section 6.2) and Annex 3.10.
- Retention of crop residue, N mineralization from soil organic matter, and asymbiotic N fixation from the atmosphere: The IPCC approach considers crop residue N and N mineralized from soil organic matter as activity data. However, they are not treated as activity data in DAYCENT simulations because residue production, N fixation, mineralization of N from soil organic matter, and asymbiotic fixation are internally generated by the model as part of the simulation. In other words, DAYCENT accounts for the influence of N fixation, mineralization of N from soil organic matter, and retention of crop residue on N₂O emissions, but these are not model inputs. The DAYCENT simulations also accounted for the approximately 3 percent of grain crop residues that were assumed to be burned based on state inventory data (ILENR 1993, Oregon Department of Energy 1995, Noller 1996, Wisconsin Department of Natural Resources 1993, and Cibrowski 1996), and therefore did not contribute to soil N₂O emissions.
- Historical and modern crop rotation and management information (e.g., timing and type of cultivation, timing of planting/harvest, etc.): These activity data were derived from Hurd (1930, 1929), Latta (1938), Iowa State College Staff Members (1946), Bogue (1963), Hurt (1994), USDA (2000a) as extracted by Eve (2001) and revised by Ogle (2002), CTIC (1998), Piper et al. (1924), Hardies and Hume (1927), Holmes (1902, 1929), Spillman (1902, 1905, 1907, 1908), Chilcott (1910), Smith (1911), Kezer (ca. 1917), Hargreaves (1993), ERS (2002), Warren (1911), Langston et al. (1922), Russell et al. (1922), Elliott and Tapp (1928), Elliott (1933), Ellsworth (1929), Garey (1929), Hodges et al. (1930), Bonnen and Elliott (1931), Brenner et al. (2002, 2001), and Smith et al. (2002).

DAYCENT simulations produced per-area estimates of N₂O emissions (g N₂O-N/m²) for major crops in each county, which were multiplied by the cropland areas in each county to obtain county-scale emission estimates. Cropland area data were from NASS (USDA 2010a, 2010b). The emission estimates by reported crop areas in the county were scaled to the regions (and states for mapping purposes when there was more than one region in a state), and the national estimate was calculated by summing results across all regions. DAYCENT is sensitive to interannual variability in weather patterns and other controlling variables, so emissions associated with individual activities vary through time even if the management practices remain the same (e.g., if N fertilization remains the same for two years). In contrast, Tier 1 methods do not capture this variability and rather have a linear, monotonic response that depends solely on management practices. DAYCENT's ability to capture these interactions between management and environmental conditions produces more accurate estimates of N₂O emissions than the Tier 1 method.

Non-Major Crop Types on Mineral Cropland Soils

The IPCC (2006) Tier 1 methodology was used to estimate direct N₂O emissions for mineral cropland soils that are managed for production of non-major crop types, including barley, oats, tobacco, sugarcane, sugar beets, sunflowers, millet, rice, peanuts, and other crops that were not included in the DAYCENT simulations. Estimates of direct N₂O emissions from N applications to non-major crop types were based on mineral soil N that was made available from the following practices: (1) the application of synthetic commercial fertilizers; (2) application of managed manure and non-manure commercial organic fertilizers;¹⁵⁰ and (3) the retention of above- and below-ground crop residues in agricultural fields (i.e., crop biomass that is not harvested). Non-manure organic amendments were not included in the DAYCENT simulations because county-level data were not available. Consequently, non-manure organic amendments, as well as additional manure that was not added to major crops in the DAYCENT simulations, were included in the Tier 1 analysis. The influence of land-use change on soil N₂O emissions from non-major crops has not been addressed in this analysis, but is a planned improvement. The following sources were used to derive activity data:

- A process-of-elimination approach was used to estimate synthetic N fertilizer additions for non-major crops, because little information exists on their fertilizer application rates. The total amount of fertilizer used on farms has been estimated by the USGS from sales records (Ruddy et al. 2006), and these data were aggregated to obtain state-level N additions to farms. After subtracting the portion of fertilizer applied to major crops and grasslands (see sections on Major Crops and Grasslands for information on data sources), the remainder of the total fertilizer used on farms was assumed to be applied to non-major crops.
- A process-of-elimination approach was used to estimate manure N additions for non-major crops, because little information exists on application rates for these crops. The amount of manure N applied to major crops and grasslands was subtracted from total manure N available for land application (see sections on Major Crops and Grasslands for information on data sources), and this difference was assumed to be applied to non-major crops.
- Non-manure, non-sewage-sludge commercial organic fertilizer additions were based on organic fertilizer consumption statistics, which were converted to units of N using average organic fertilizer N content (TVA 1991 through 1994; AAPFCO 1995 through 2010). Manure and sewage sludge components were subtracted from total commercial organic fertilizers to avoid double counting.
- Crop residue N was derived by combining amounts of above- and below-ground biomass, which were determined based on crop production yield statistics (USDA 1994, 1998, 2003, 2005, 2006, 2008, 2009, 2010a), dry matter fractions (IPCC 2006), linear equations to estimate above-ground biomass given dry matter crop yields from harvest (IPCC 2006), ratios of below-to-above-ground biomass (IPCC 2006), and N contents of the residues (IPCC 2006). Approximately 3 percent of the crop residues were burned and therefore did not contribute to soil N₂O emissions, based on state inventory data (ILENR 1993, Oregon Department of Energy 1995, Noller 1996, Wisconsin Department of Natural Resources 1993, and Cibrowski 1996).

The total increase in soil mineral N from applied fertilizers and crop residues was multiplied by the IPCC (2006) default emission factor to derive an estimate of direct N₂O emissions from non-major crop types.

Drainage and Cultivation of Organic Cropland Soils

The IPCC (2006) Tier 1 methods were used to estimate direct N₂O emissions due to drainage and cultivation of organic soils at a state scale. State-scale estimates of the total area of drained and cultivated organic soils were obtained from the *National Resources Inventory* (NRI) (USDA 2000a, as extracted by Eve 2001 and amended by Ogle 2002). Temperature data from Daly et al. (1994, 1998) were used to subdivide areas into temperate and sub-tropical climates using the climate classification from IPCC (2006). Data were available for 1982, 1992 and 1997. To estimate annual emissions, the total temperate area was multiplied by the IPCC default emission factor for temperate regions, and the total sub-tropical area was multiplied by the average of the IPCC default emission factors for temperate and tropical regions (IPCC 2006).

¹⁵⁰ Commercial organic fertilizers include dried blood, tankage, compost, and other; dried manure and sewage sludge that are used as commercial fertilizer have been excluded to avoid double counting. The dried manure N is counted with the non-commercial manure applications, and sewage sludge is assumed to be applied only to grasslands.

Direct N₂O Emissions from Grassland Soils

As with N₂O from croplands, the Tier 3 process-based DAYCENT model and Tier 1 method described in IPCC (2006) were combined to estimate emissions from grasslands. Grasslands include pastures and rangelands used for grass forage production, where the primary use is livestock grazing. Rangelands are typically extensive areas of native grasslands that are not intensively managed, while pastures are often seeded grasslands, possibly following tree removal, which may or may not be improved with practices such as irrigation and interseeding legumes.

DAYCENT was used to simulate county-scale N₂O emissions from non-federal grasslands resulting from manure deposited by livestock directly onto pastures and rangelands (i.e., PRP manure), N fixation from legume seeding, managed manure amendments (i.e., manure other than PRP manure), and synthetic fertilizer application. Other N inputs were simulated within the DAYCENT framework, including N input from mineralization due to decomposition of soil organic matter and N inputs from senesced grass litter, as well as asymbiotic fixation of N from the atmosphere. The simulations used the same weather, soil, and synthetic N fertilizer data as discussed under the section for Major Crop Types on Mineral Cropland Soils. Managed manure N amendments to grasslands were estimated from Edmonds et al. (2003) and adjusted for annual variation using data on the availability of managed manure N for application to soils, according to methods described in the Manure Management section (Section 6.2) and Annex 3.10. Biological N fixation is simulated within DAYCENT and therefore was not an input to the model.

Manure N deposition from grazing animals (i.e., PRP manure) is another key input of N to grasslands. The amounts of PRP manure N applied on non-federal and federal grasslands in each county were based on the proportion of non-federal to federal grassland area (See below for more information on area data). The amount of PRP manure applied on non-federal grasslands was an input to the DAYCENT model (see Annex 3.10), and included approximately 91 percent of total PRP manure. The remainder of the PRP manure N excretions in each county was assumed to be excreted on federal grasslands (i.e., DAYCENT simulations were only conducted for non-federal grasslands), and the N₂O emissions were estimated using the IPCC (2006) Tier 1 method with IPCC default emission factors. Sewage sludge was assumed to be applied on grasslands because of the heavy metal content and other pollutants in human waste that limit its use as an amendment to croplands. Sewage sludge application was estimated from data compiled by EPA (1993, 1999, 2003), McFarland (2001), and NEBRA (2007). Sewage sludge data on soil amendments to agricultural lands were only available at the national scale, and it was not possible to associate application with specific soil conditions and weather at the county scale. Therefore, DAYCENT could not be used to simulate the influence of sewage sludge amendments on N₂O emissions from grassland soils, and consequently, emissions from sewage sludge were estimated using the IPCC (2006) Tier 1 method.

Grassland area data were consistent with the Land Representation reported in Section 7.1. Data were obtained from the U.S. Department of Agriculture *National Resources Inventory* (USDA 2000a, Nusser and Goebel 1997, <http://www.ncgc.nrcs.usda.gov/products/nri/index.htm>) and the U.S. Geological Survey (USGS) National Land Cover Dataset (NLCD, Vogelmann et al. 2001, <http://www.mrlc.gov>), which were reconciled with the Forest Inventory and Analysis Data (<http://fia.fs.us/tools-data/data>). The area data for pastures and rangeland were aggregated to the county level to estimate non-federal and federal grassland areas.

DAYCENT simulations produced per-area estimates of N₂O emissions (g N₂O-N/m²) for pasture and rangelands, which were multiplied by the non-federal grassland areas in each county. The county-scale N₂O emission estimates for non-federal grasslands were scaled to the 63 agricultural regions (and to the state level for mapping purposes if there was more than one region in a state), and the national estimate was calculated by summing results across all regions. Tier 1 estimates of N₂O emissions for the PRP manure N deposited on federal grasslands and applied sewage sludge N were produced by multiplying the N input by the appropriate emission factor. Tier 1 estimates for emissions from manure N were calculated at the state level and aggregated to the entire country but emission from sewage sludge N were calculated exclusively at the national scale.

Total Direct N₂O Emissions from Cropland and Grassland Soils

Annual direct emissions from major and non-major crops on mineral cropland soils, from drainage and cultivation of organic cropland soils, and from grassland soils were summed to obtain the total direct N₂O emissions from agricultural soil management (see Table 6-15 and Table 6-16).

Indirect N₂O Emissions from Managed Soils of all Land-Use Types

This section describes the methods used for estimating indirect soil N₂O emissions from all land-use types (i.e.,

croplands, grasslands, forest lands, and settlements). Indirect N₂O emissions occur when mineral N made available through anthropogenic activity is transported from the soil either in gaseous or aqueous forms and later converted into N₂O. There are two pathways leading to indirect emissions. The first pathway results from volatilization of N as NO_x and NH₃ following application of synthetic fertilizer, organic amendments (e.g., manure, sewage sludge), and deposition of PRP manure. N made available from mineralization of soil organic matter and asymbiotic fixation also contributes to volatilized N emissions. Volatilized N can be returned to soils through atmospheric deposition, and a portion of the deposited N is emitted to the atmosphere as N₂O. The second pathway occurs via leaching and runoff of soil N (primarily in the form of NO₃⁻) that was made available through anthropogenic activity on managed lands, mineralization of soil organic matter, and asymbiotic fixation. The NO₃⁻ is subject to denitrification in water bodies, which leads to N₂O emissions. Regardless of the eventual location of the indirect N₂O emissions, the emissions are assigned to the original source of the N for reporting purposes, which here includes croplands, grasslands, forest lands, and settlements.

Indirect N₂O Emissions from Atmospheric Deposition of Volatilized N from Managed Soils

As in the direct emissions calculation, the Tier 3 DAYCENT model and IPCC (2006) Tier 1 methods were combined to estimate the amount of N that was volatilized and eventually emitted as N₂O. DAYCENT was used to estimate N volatilization for land areas whose direct emissions were simulated with DAYCENT (i.e., major croplands and most grasslands). The N inputs included are the same as described for direct N₂O emissions in the sections on major crops and grasslands. Nitrogen volatilization for all other areas was estimated using the Tier 1 method and default IPCC fractions for N subject to volatilization (i.e., N inputs on non-major croplands, PRP manure N excretion on federal grasslands, sewage sludge application on grasslands). The Tier 1 method and default fractions were also used to estimate N subject to volatilization from N inputs on settlements and forest lands (see the Land Use, Land-Use Change, and Forestry chapter). For the volatilization data generated from both the DAYCENT and Tier 1 approaches, the IPCC (2006) default emission factor was used to estimate indirect N₂O emissions occurring due to re-deposition of the volatilized N (Table 6-18).

Indirect N₂O Emissions from Leaching/Runoff

As with the calculations of indirect emissions from volatilized N, the Tier 3 DAYCENT model and IPCC (2006) Tier 1 method were combined to estimate the amount of N that was subject to leaching and surface runoff into water bodies, and eventually emitted as N₂O. DAYCENT was used to simulate the amount of N transported from lands used to produce major crops and most grasslands. N transport from all other areas was estimated using the Tier 1 method and the IPCC (2006) default factor for the proportion of N subject to leaching and runoff. This N transport estimate includes N applications on croplands that produce non-major crops, sewage sludge amendments on grasslands, PRP manure N excreted on federal grasslands, and N inputs on settlements and forest lands. For both the DAYCENT and IPCC (2006) Tier 1 methods, nitrate leaching was assumed to be an insignificant source of indirect N₂O in cropland and grassland systems in arid regions as discussed in IPCC (2006). In the United States, the threshold for significant nitrate leaching is based on the potential evapotranspiration (PET) and rainfall amount, similar to IPCC (2006), and is assumed to be negligible in regions where the amount of precipitation plus irrigation does not exceed 80 percent of PET. For leaching and runoff data estimated by the DAYCENT and Tier 1 approaches, the IPCC (2006) default emission factor was used to estimate indirect N₂O emissions that occur in groundwater and waterways (Table 6-18).

Uncertainty and Time-Series Consistency

Uncertainty was estimated for each of the following five components of N₂O emissions from agricultural soil management: (1) direct emissions calculated by DAYCENT; (2) the components of indirect emissions (N volatilized and leached or runoff) calculated by DAYCENT; (3) direct emissions calculated with the IPCC (2006) Tier 1 method; (4) the components of indirect emissions (N volatilized and leached or runoff) calculated with the IPCC (2006) Tier 1 method; and (5) indirect emissions calculated with the IPCC (2006) Tier 1 method. Uncertainty in direct emissions, which account for the majority of N₂O emissions from agricultural management, as well as the components of indirect emissions calculated by DAYCENT were estimated with a Monte Carlo Analysis, addressing uncertainties in model inputs and structure (i.e., algorithms and parameterization) (Del Grosso et al., 2010). Uncertainties in direct emissions calculated with the IPCC (2006) Tier 1 method, the proportion of volatilization and leaching or runoff estimated with the IPCC (2006) Tier 1 method, and indirect N₂O emissions were estimated with a simple error propagation approach (IPCC 2006). Additional details on the uncertainty

methods are provided in Annex 3.11.

Uncertainties from the Tier 1 and Tier 3 (i.e., DAYCENT) estimates were combined using simple error propagation (IPCC 2006), and the results are summarized in Table 6-19. Agricultural direct soil N₂O emissions in 2009 were estimated to be between 118.3 and 250.6 Tg CO₂ Eq. at a 95 percent confidence level. This indicates a range of 26 percent below and 56 percent above the 2009 emission estimate of 160.2 Tg CO₂ Eq. The indirect soil N₂O emissions in 2009 were estimated to range from 22.4 to 111.6 Tg CO₂ Eq. at a 95 percent confidence level, indicating an uncertainty of 50 percent below and 151 percent above the 2009 emission estimate of 44.4 Tg CO₂ Eq.

Table 6-19: Quantitative Uncertainty Estimates of N₂O Emissions from Agricultural Soil Management in 2009 (Tg CO₂ Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate			
			(Tg CO ₂ Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Direct Soil N ₂ O Emissions	N ₂ O	160.2	118.3	250.6	-26%	+56%
Indirect Soil N ₂ O Emissions	N ₂ O	44.4	22.4	111.6	-50%	+151%

Note: Due to lack of data, uncertainties in areas for major crops, managed manure N production, PRP manure N production, other organic fertilizer amendments, indirect losses of N in the DAYCENT simulations, and sewage sludge amendments to soils are currently treated as certain; these sources of uncertainty will be included in future Inventories.

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

QA/QC and Verification

For quality control, DAYCENT results for N₂O emissions and NO₃⁻ leaching were compared with field data representing various cropland and grassland systems, soil types, and climate patterns (Del Grosso et al. 2005, Del Grosso et al. 2008), and further evaluated by comparing to emission estimates produced using the IPCC (2006) Tier 1 method for the same sites. Nitrous oxide measurement data were available for 11 sites in the United States and one in Canada, representing 30 different combinations of fertilizer treatments and cultivation practices. DAYCENT estimates of N₂O emissions were closer to measured values at all sites compared to the IPCC Tier 1 estimate, except for Colorado dryland cropping (Figure 6-7). In general, IPCC Tier 1 methodology tends to over-estimate emissions when observed values are low and under-estimate emissions when observed values are high, while DAYCENT estimates are less biased. This is not surprising because DAYCENT accounts for site-level factors (weather, soil type) that influence N₂O emissions. Nitrate leaching data were available for three sites in the United States representing nine different combinations of fertilizer amendments. Linear regressions of simulated vs. observed emission and leaching data yielded correlation coefficients of 0.89 and 0.94 for annual N₂O emissions and NO₃⁻ leaching, respectively. This comparison demonstrates that DAYCENT provides relatively high predictive capability for N₂O emissions and NO₃⁻ leaching, and is an improvement over the IPCC Tier 1 method (see additional information in Annex 3.11).

Figure 6-7: Comparison of Measured Emissions at Field Sites and Modeled Emissions Using the DAYCENT Simulation Model

Spreadsheets containing input data and probability distribution functions required for DAYCENT simulations of major croplands and grasslands and unit conversion factors were checked, as were the program scripts that were used to run the Monte Carlo uncertainty analysis. Several errors were identified following re-organization of the calculation spreadsheets, and corrective actions have been taken. In particular, some of the links between spreadsheets were missing or needed to be modified. Spreadsheets containing input data, emission factors, and calculations required for the Tier 1 approach were checked and no errors were found.

Recalculations Discussion

Two major revisions were made in the Agricultural Soil Management section for the current Inventory.

First, the methodology used to estimate grassland areas was updated and revised to be consistent with the Land Representation used in the Land Use, Land Use Change and Forestry sector (see Section 7.1). This led to an overall decrease in grassland area, and lower emissions than reported in the prior Inventory. Second, the methodology used to calculate livestock manure N was changed such that total manure N added to soils increased by approximately 11 percent (see Section 6.2 for details).

The recalculations had opposite impacts on the emissions, with less grassland area tending to decrease emissions and higher manure N inputs tending to increase emissions. In some years emissions were higher overall, but on average, these changes led to a lower amount of N₂O emissions from agricultural soil management by about 1.5 percent over the time series relative to the previous Inventory.

Planned Improvements

A key improvement is underway for Agricultural Soil Management to incorporate more land-use survey data from the NRI (USDA 2000a) into the DAYCENT simulation analysis, beyond the area estimates for rangeland and pasture that are currently used to estimate emissions from grasslands. NRI has a record of land-use activities since 1979 for all U.S. agricultural land, which is estimated at about 386 Mha. NASS is used as the basis for land-use records in the current Inventory, and there are three major disadvantages to this dataset. First, most crops are grown in rotation with other crops (e.g., corn-soybean), but NASS data provide no information regarding rotation histories. In contrast, NRI is designed to track rotation histories, which is important because emissions from any particular year can be influenced by the crop that was grown the previous year. Second, NASS does not conduct a complete survey of cropland area each year, leading to gaps in the land base. NRI provides a complete history of cropland areas for four out of every five years from 1979 to 1997, and then every year after 1998. Third, the current inventory based on NASS does not quantify the influence of land-use change on emissions, which can be addressed using the NRI survey records. NRI also provides additional information on pasture land management that can be incorporated into the analysis (particularly the use of irrigation). Using NRI data will also make the Agricultural Soil Management methods more consistent with the methods used to estimate C stock changes for agricultural soils. The structure of model input files that contain land management data are currently being extensively revised to facilitate use of the annualized NRI data. This improvement is planned for completion by the next Inventory.

Another improvement is to reconcile the amount of crop residues burned with the Field Burning of Agricultural Residues source category (Section 6.5). This year the methodology for Field Burning of Agricultural Residues was significantly updated, but the changes were implemented too late for the new estimates of crop residues burned to be incorporated into the DAYCENT runs for the Agricultural Soil Management source. Next year the estimates will be reconciled; meanwhile the estimates presented in this section use the previous year's methodology for determining crop residues burned.

Other planned improvements are minor but will lead to more accurate estimates, including updating DAYMET weather data for more recent years following the release of new data, and using a rice-crop-specific emission factor for N amendments to rice areas.

6.5. Field Burning of Agricultural Residues (IPCC Source Category 4F)

Farming activities produce large quantities of agricultural crop residues, and farmers use or dispose of these residues in a variety of ways. For example, agricultural residues can be left on or plowed into the field; composted and then applied to soils; landfilled; or burned in the field. Alternatively, they can be collected and used as fuel, animal bedding material, supplemental animal feed, or construction material. Field burning of crop residues is not considered a net source of CO₂, because the C released to the atmosphere as CO₂ during burning is assumed to be reabsorbed during the next growing season. Crop residue burning is, however, a net source of CH₄, N₂O, CO, and NO_x, which are released during combustion.

Field burning is not a common method of agricultural residue disposal in the United States. The primary crop types whose residues are typically burned in the United States are corn, cotton, lentils, rice, soybeans, sugarcane, and wheat (McCarty 2009). In 2009, CH₄ and N₂O emissions from field burning were 0.2 Tg CO₂ Eq. (12 Gg) and 0.1 Tg CO₂ Eq. (0.3 Gg), respectively. Annual emissions from this source over the period 1990 to 2009 have remained

relatively constant, averaging approximately 0.2 Tg CO₂ Eq. (1 Gg) of CH₄ and 0.1 Tg CO₂ Eq. (0.3 Gg) of N₂O (see Table 6-20 and Table 6-21).

Table 6-20: CH₄ and N₂O Emissions from Field Burning of Agricultural Residues (Tg CO₂ Eq.)

Gas/Crop Type	1990	2000	2005	2006	2007	2008	2009
CH₄	0.3	0.3	0.2	0.2	0.2	0.3	0.2
Corn	+	+	+	+	+	+	+
Cotton	+	+	+	+	+	+	+
Lentils	+	+	+	+	+	+	+
Rice	+	+	+	+	0.1	+	+
Soybeans	+	+	+	+	+	+	+
Sugarcane	0.1	0.1	+	0.1	+	+	+
Wheat	0.1	0.1	0.1	0.1	0.1	0.1	0.1
N₂O	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Corn	+	+	+	+	+	+	+
Cotton	+	+	+	+	+	+	+
Lentils	+	+	+	+	+	+	+
Rice	+	+	+	+	+	+	+
Soybeans	+	+	+	+	+	+	+
Sugarcane	+	+	+	+	+	+	+
Wheat	+	+	+	+	+	+	+
Total	0.4	0.4	0.3	0.3	0.3	0.4	0.4

+ Less than 0.05 Tg CO₂ Eq.

Note: Totals may not sum due to independent rounding.

Table 6-21: CH₄, N₂O, CO, and NO_x Emissions from Field Burning of Agricultural Residues (Gg)

Gas/Crop Type	1990	2000	2005	2006	2007	2008	2009
CH₄	13	12	9	11	11	13	12
Corn	1	1	1	2	1	1	2
Cotton	+	+	+	+	+	+	+
Lentils	+	+	+	+	+	+	+
Rice	2	2	2	2	3	2	2
Soybeans	1	1	1	1	1	1	1
Sugarcane	3	2	1	3	1	2	2
Wheat	6	6	4	4	5	6	5
N₂O	+	+	+	+	+	+	+
Corn	+	+	+	+	+	+	+
Cotton	+	+	+	+	+	+	+
Lentils	+	+	+	+	+	+	+
Rice	+	+	+	+	+	+	+
Soybeans	+	+	+	+	+	+	+
Sugarcane	+	+	+	+	+	+	+
Wheat	+	+	+	+	+	+	+
CO	268	259	184	233	237	270	247
NO_x	8	8	6	7	8	8	8

+ Less than 0.5 Gg

Note: Totals may not sum due to independent rounding.

Methodology

The Tier 2 methodology used for estimating greenhouse gas emissions from field burning of agricultural residues in the United States is consistent with IPCC (2006) (for more details, see Box 6-2). In order to estimate the amounts of C and N released during burning, the following equation was used:

$$\text{C or N released} = \sum \text{over all crop types and states (Area Burned} \div \text{Crop Area Harvested} \times \text{Crop Production} \times$$

$$\text{Residue/Crop Ratio} \times \text{Dry Matter Fraction} \times \text{Burning Efficiency} \times \text{Combustion Efficiency} \times \text{Fraction of C or N}$$

where,

Area Burned	= Total area of crop burned, by state
Crop Area Harvested	= Total area of crop harvested, by state
Crop Production	= Annual production of crop in Gg, by state
Residue/Crop Ratio	= Amount of residue produced per unit of crop production, by state
Dry Matter Fraction	= Amount of dry matter per unit of biomass for a crop
Fraction of C or N	= Amount of C or N per unit of dry matter for a crop
Burning Efficiency	= The proportion of prefire fuel biomass consumed ¹⁵¹
Combustion Efficiency	= The proportion of C or N released with respect to the total amount of C or N available in the burned material, respectively ¹⁵¹

Crop production and area harvested were available by state and year from USDA (2010) for all crops (except rice in Florida and Oklahoma, as detailed below). The amount C or N released was used in the following equation to determine the CH₄, CO, N₂O and NO_x emissions from the field burning of agricultural residues:

$$\text{CH}_4 \text{ and CO, or N}_2\text{O and NO}_x \text{ Emissions from Field Burning of Agricultural Residues} = (\text{C or N Released}) \times (\text{Emissions Ratio for C or N}) \times (\text{Conversion Factor})$$

where,

Emissions Ratio	= g CH ₄ -C or CO-C/g C released, or g N ₂ O-N or NO _x -N/g N released
Conversion Factor	= conversion, by molecular weight ratio, of CH ₄ -C to C (16/12), or CO-C to C (28/12), or N ₂ O-N to N (44/28), or NO _x -N to N (30/14)

[BEGIN BOX]

Box 6-2: Comparison of Tier 2 U.S. Inventory Approach and IPCC (2006) Default Approach

This Inventory calculates emissions from Burning of Agricultural Residues using a Tier 2 methodology that is based on IPCC/UNEP/OECD/IEA (1997) and incorporates crop- and country-specific emission factors and variables. The equation used in this Inventory varies slightly in form from the one presented in the IPCC (2006) guidelines, but both equations rely on the same underlying variables. The IPCC (2006) equation was developed to be broadly applicable to all types of biomass burning, and, thus, is not specific to agricultural residues. IPCC (2006) default factors are provided only for four crops (wheat, corn, rice, and sugarcane), while this Inventory analyzes emissions from seven crops. A comparison of the methods and factors used in (1) the current Inventory and (2) the default IPCC (2006) approach was undertaken to determine the magnitude of the difference in overall estimates resulting from the two approaches. The IPCC (2006) approach was not used because crop-specific emission factors for N₂O were not available for all crops. In order to maintain consistency of methodology, the IPCC/UNEP/OECD/IEA (1997) approach presented in the Methodology section was used.

The IPCC (2006) default approach resulted in 12 percent higher emissions of CH₄ and 25 percent higher emissions of N₂O than the current estimates in this Inventory. It is reasonable to maintain the current methodology, since the IPCC (2006) defaults are only available for four crops and are worldwide average estimates, while current inventory estimates are based on U.S.-specific, crop-specific, published data.

[END BOX]

¹⁵¹ In IPCC/UNEP/OECD/IEA (1997), the equation for C or N released contains the variable ‘fraction oxidized in burning.’ This variable is equivalent to (burning efficiency × combustion efficiency).

Crop production data for all crops except rice in Florida and Oklahoma were taken from USDA's QuickStats service (USDA 2010). Rice production and area data for Florida and Oklahoma, which are not collected by USDA, were estimated separately. Average primary and ratoon crop yields for Florida (Schueneman and Deren 2002) were applied to Florida acreages (Schueneman 1999, 2001; Deren 2002; Kirstein 2003, 2004; Cantens 2004, 2005; Gonzalez 2007 through 2010), and crop yields for Arkansas (USDA 2010) were applied to Oklahoma acreages¹⁵² (Lee 2003 through 2006; Anderson 2008 through 2010). The production data for the crop types whose residues are burned are presented in Table 6-22. Crop weight by bushel was obtained from Murphy (1993).

The fraction of crop area burned was calculated using data on area burned by crop type and state¹⁵³ from McCarty (2010) for corn, cotton, lentils, rice, soybeans, sugarcane, and wheat.¹⁵⁴ McCarty (2010) used remote sensing data from Moderate Resolution Imaging Spectroradiometer (MODIS) to estimate area burned by crop. For the inventory analysis, the state-level area burned data were divided by state-level crop area harvested data to estimate the percent of crop area burned by crop and by state. The average fraction of area burned by crop across all states is shown in Table 6-23. All crop area harvested data were from USDA (2010), except for rice acreage in Florida and Oklahoma, which is not measured by USDA (Schueneman 1999, 2001; Deren 2002; Kirstein 2003, 2004; Cantens 2004, 2005; Gonzalez 2007 through 2010; Lee 2003 through 2006; Anderson 2008 through 2010). Data on crop area burned were only available from McCarty (2010) for the years 2003 through 2007. For other years in the time series, the percent area burned was assumed to be equal to the average percent area burned from the 5 years for which data were available. This average was taken at the crop and state level. Table 6-23 shows these percent area estimates aggregated for the United States as a whole, at the crop level.

All residue/crop product mass ratios except sugarcane and cotton were obtained from Strehler and Stützel (1987). The datum for sugarcane is from Kinoshita (1988) and that of cotton from Huang et al. (2007). The residue/crop ratio for lentils was assumed to be equal to the average of the values for peas and beans. Residue dry matter fractions for all crops except soybeans, lentils, and cotton were obtained from Turn et al. (1997). Soybean and lentil dry matter fractions were obtained from Strehler and Stützel (1987); the value for lentil residue was assumed to equal the value for bean straw. The cotton dry matter fraction was taken from Huang et al. (2007). The residue C contents and N contents for all crops except soybeans and cotton are from Turn et al. (1997). The residue C content for soybeans is the IPCC default (IPCC/UNEP/OECD/IEA 1997). The N content of soybeans is from Barnard and Kristoferson (1985). The C and N contents of lentils were assumed to equal those of soybeans. The C and N contents of cotton are from Lachnicht et al. (2004). These data are listed in Table 6-24. The burning efficiency was assumed to be 93 percent, and the combustion efficiency was assumed to be 88 percent, for all crop types, except sugarcane (EPA 1994). For sugarcane, the burning efficiency was assumed to be 81 percent (Kinoshita 1988) and the combustion efficiency was assumed to be 68 percent (Turn et al. 1997). Emission ratios and conversion factors for all gases (see Table 6-25) were taken from the *Revised 1996 IPCC Guidelines* (IPCC/UNEP/OECD/IEA 1997).

Table 6-22: Agricultural Crop Production (Gg of Product)

Crop	1990	2000	2005	2006	2007	2008	2009
Corn ^a	201,534	251,854	282,263	267,503	331,177	307,142	333,011
Cotton	3,376	3,742	5,201	4,700	4,182	2,790	2,654
Lentils	40	137	238	147	166	109	266
Rice	7,114	8,705	10,132	8,843	9,033	9,272	9,972
Soybeans	52,416	75,055	83,507	87,001	72,859	80,749	91,417
Sugarcane	25,525	32,763	24,137	26,820	27,188	25,041	27,608
Wheat	74,292	60,641	57,243	49,217	55,821	68,016	60,366

^a Corn for grain (i.e., excludes corn for silage).

¹⁵² Rice production yield data are not available for Oklahoma, so the Arkansas values are used as a proxy.

¹⁵³ Alaska and Hawaii were excluded.

¹⁵⁴ McCarty (2009) also examined emissions from burning of Kentucky bluegrass and a general "other crops/fallow" category, but USDA crop area and production data were insufficient to estimate emissions from these crops using the methodology employed in the Inventory. McCarty (2009) estimates that approximately 18 percent of crop residue emissions result from burning of the Kentucky bluegrass and "other" categories.

Table 6-23: U.S. Average Percent Crop Area Burned by Crop (Percent)

State	1990	2000	2005	2006	2007	2008	2009
Corn	+	+	+	+	+	+	+
Cotton	1	1	1	1	1	2	1
Lentils	3	2	+	2	1	1	1
Rice	10	10	6	8	12	9	9
Soybeans	+	+	+	+	+	+	+
Sugarcane	59	40	26	56	26	39	37
Wheat	3	3	2	3	3	3	3

+ Less than 0.5 percent

Table 6-24: Key Assumptions for Estimating Emissions from Field Burning of Agricultural Residues

Crop	Residue/Crop Ratio	Dry Matter Fraction	C Fraction	N Fraction	Burning Efficiency (Fraction)	Combustion Efficiency (Fraction)
Corn	1.0	0.91	0.448	0.006	0.93	0.88
Cotton	1.6	0.90	0.445	0.012	0.93	0.88
Lentils	2.0	0.85	0.450	0.023	0.93	0.88
Rice	1.4	0.91	0.381	0.007	0.93	0.88
Soybeans	2.1	0.87	0.450	0.023	0.93	0.88
Sugarcane	0.2	0.62	0.424	0.004	0.81	0.68
Wheat	1.3	0.93	0.443	0.006	0.93	0.88

Table 6-25: Greenhouse Gas Emission Ratios and Conversion Factors

Gas	Emission Ratio	Conversion Factor
CH ₄ :C	0.005 ^a	16/12
CO:C	0.060 ^a	28/12
N ₂ O:N	0.007 ^b	44/28
NO _x :N	0.121 ^b	30/14

^a Mass of C compound released (units of C) relative to mass of total C released from burning (units of C).^b Mass of N compound released (units of N) relative to mass of total N released from burning (units of N).

Uncertainty and Time-Series Consistency

Due to data and time limitations, uncertainty resulting from the fact that emissions from burning of Kentucky bluegrass and “other” residues are not included in the emissions estimates was not incorporated into the uncertainty analysis. The results of the Tier 2 Monte Carlo uncertainty analysis are summarized in Table 6-26. Methane emissions from field burning of agricultural residues in 2009 were estimated to be between 0.15 and 0.35 Tg CO₂ Eq. at a 95 percent confidence level. This indicates a range of 40 percent below and 42 percent above the 2009 emission estimate of 0.25 Tg CO₂ Eq. Also at the 95 percent confidence level, N₂O emissions were estimated to be between 0.07 and 0.14 Tg CO₂ Eq. (or approximately 30 percent below and 31 percent above the 2009 emission estimate of 0.10 Tg CO₂ Eq.).

Table 6-26: Tier 2 Quantitative Uncertainty Estimates for CH₄ and N₂O Emissions from Field Burning of Agricultural Residues (Tg CO₂ Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate ^a (%)			
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Field Burning of Agricultural Residues	CH ₄	0.25	0.15	0.35	-40%	+42%
Field Burning of Agricultural Residues	N ₂ O	0.10	0.07	0.14	-30%	+31%

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

QA/QC and Verification

A source-specific QA/QC plan for field burning of agricultural residues was implemented. This effort included a Tier 1 analysis, as well as portions of a Tier 2 analysis. The Tier 2 procedures focused on comparing trends across years, states, and crops to attempt to identify any outliers or inconsistencies. For some crops and years in Florida and Oklahoma, the total area burned as measured by McCarty (2010) was greater than the area estimated for that crop, year, and state by USDA (2010), leading to a percent area burned estimate of greater than 100 percent. In such cases, it was assumed that the percent crop area burned for that state was 100 percent.

Recalculations Discussion

The methodology over the entire time series was revised relative to the previous Inventory to incorporate state- and crop-level data on area burned from McCarty (2010). (1) Cotton and lentils were added as crops; peanuts and barley were removed, because McCarty (2009) indicated that their residues are not burned in significant quantities in the United States; (2) fraction of residue burned was calculated at the state and crop level based on McCarty (2010) and USDA (2010) data, rather than a blanket application of 3 percent burned for all crops except rice and sugarcane, as was used in the previous Inventory; (3) since data from McCarty (2010) were only available for 5 years, the percent area burned for those 5 years was averaged by crop and state and used as an estimate for the remaining years in the time series. Because the percent area burned was lower than previously assumed for almost all crops, these recalculations have resulted in an average decrease in CH₄ emissions of 71 percent and an average decrease in N₂O emissions of 79 percent across the time series, relative to the previous Inventory.

Planned Improvements

Further investigation will be made into inconsistent data from Florida and Oklahoma as mentioned in the QA/QC and verification section, and attempts will be made to revise or further justify the assumption of 100 percent of area burned for those crops and years where the estimated percent area burned exceeded 100 percent. The availability of useable area harvested and other data for bluegrass and the “other crops” category in McCarty (2010) will also be investigated, in order to try to incorporate these emissions into the Inventory.

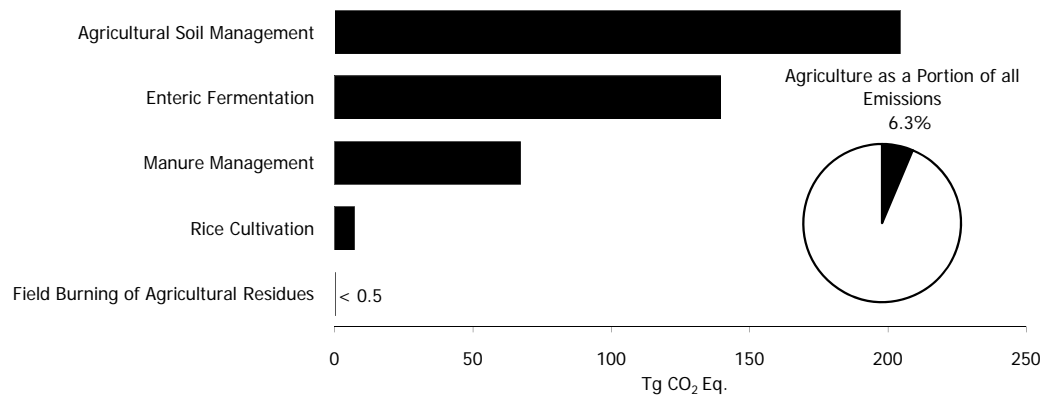


Figure 6-1: 2009 Agriculture Chapter Greenhouse Gas Sources

Figure 6-2



This graphic illustrates the sources and pathways of nitrogen that result in direct and indirect N₂O emissions from soils using the methodologies described in this Inventory. Emission pathways are shown with arrows. On the lower right-hand side is a cut-away view of a representative section of a managed soil; histosol cultivation is represented here.

Figure 6-3

**Major Crops, Average Annual Direct N₂O Emissions Estimated Using the DAYCENT Model, 1990-2009
(Tg CO₂ Eq/year)**

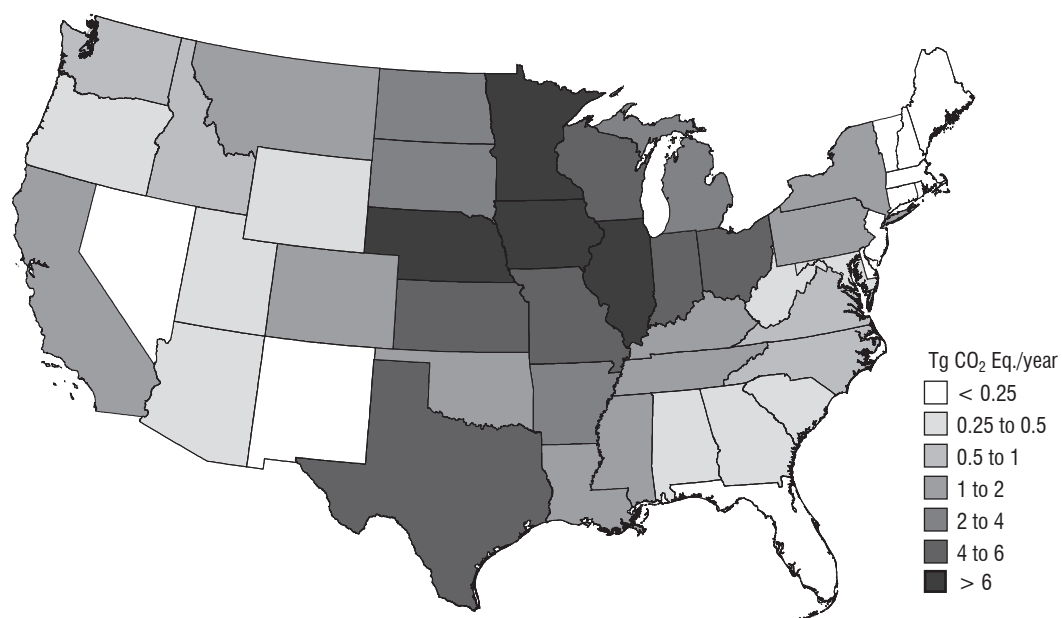


Figure 6-4

**Grasslands, Average Annual Direct N₂O Emissions Estimated Using the DAYCENT Model, 1990-2009
(Tg CO₂ Eq./year)**

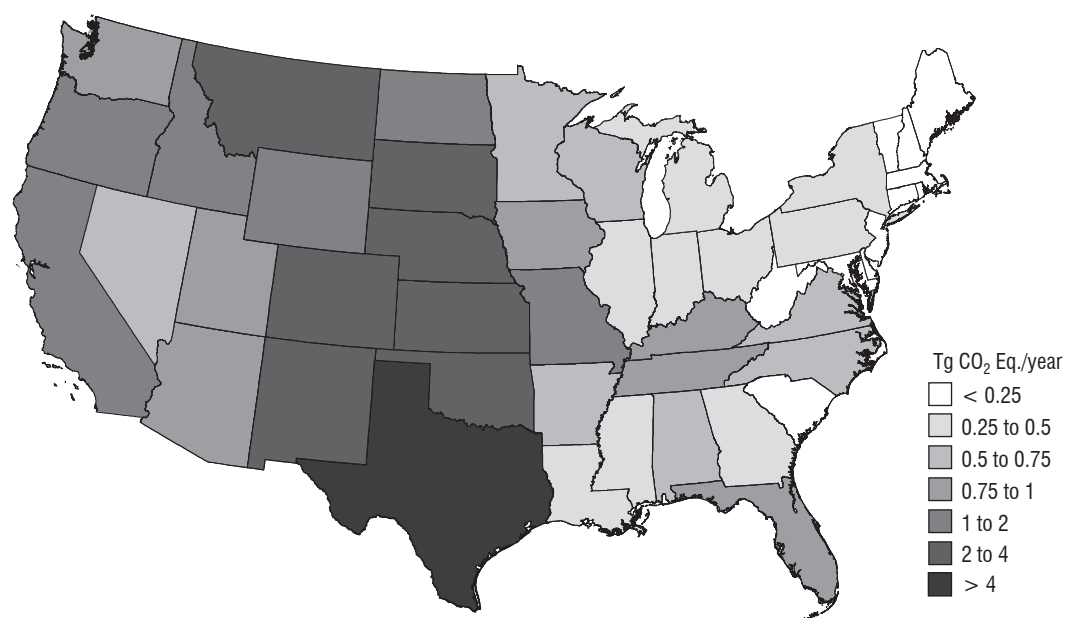


Figure 6-5

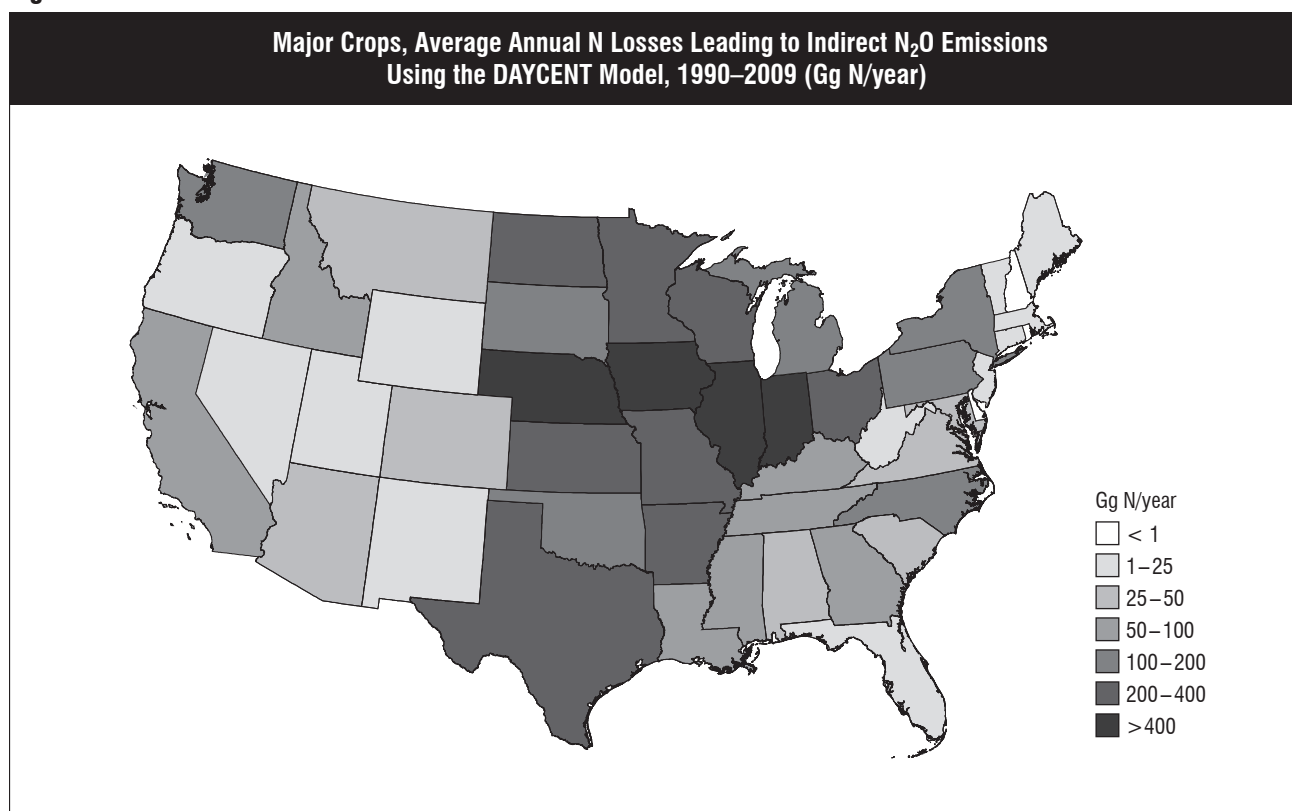


Figure 6-6

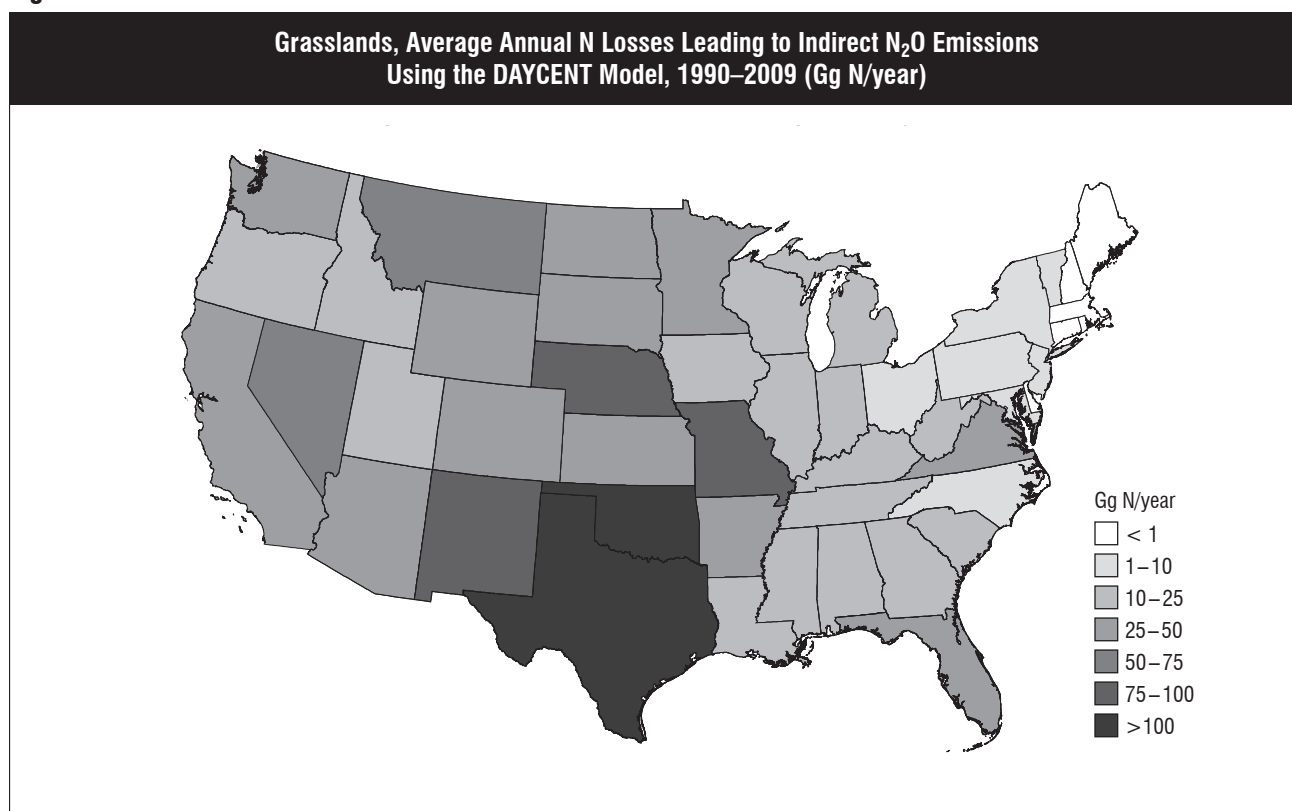
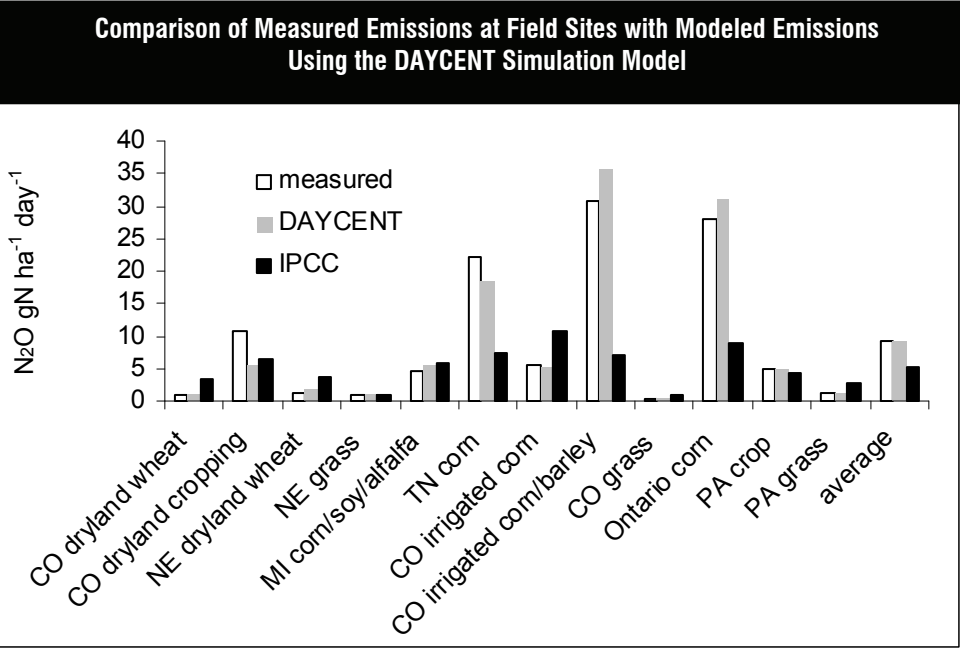


Figure 6-7



7. Land Use, Land-Use Change, and Forestry

This chapter provides an assessment of the net greenhouse gas flux¹⁵⁵ resulting from the uses and changes in land types and forests in the United States. The Intergovernmental Panel on Climate Change 2006 *Guidelines for National Greenhouse Gas Inventories* (IPCC 2006) recommends reporting fluxes according to changes within and conversions between certain land-use types termed forest land, cropland, grassland, and settlements (as well as wetlands). The greenhouse gas flux from *Forest Land Remaining Forest Land* is reported using estimates of changes in forest carbon (C) stocks, non-carbon dioxide (CO₂) emissions from forest fires, and the application of synthetic fertilizers to forest soils. The greenhouse gas flux reported in this chapter from agricultural lands (i.e., cropland and grassland) includes changes in organic C stocks in mineral and organic soils due to land use and management, and emissions of CO₂ due to the application of crushed limestone and dolomite to managed land (i.e., soil liming) and urea fertilization. Fluxes are reported for four agricultural land use/land-use change categories: *Cropland Remaining Cropland*, *Land Converted to Cropland*, *Grassland Remaining Grassland*, and *Land Converted to Grassland*. Fluxes resulting from *Settlements Remaining Settlements* include those from urban trees and soil fertilization. Landfilled yard trimmings and food scraps are accounted for separately under *Other*.

The estimates in this chapter, with the exception of CO₂ fluxes from wood products and urban trees, and CO₂ emissions from liming and urea fertilization, are based on activity data collected at multiple-year intervals, which are in the form of forest, land-use, and municipal solid waste surveys. CO₂ fluxes from forest C stocks (except the wood product components) and from agricultural soils (except the liming component) are calculated on an average annual basis from data collected in intervals ranging from 1 to 10 years. The resulting annual averages are applied to years between surveys. Calculations of non-CO₂ emissions from forest fires are based on forest CO₂ flux data. For the landfilled yard trimmings and food scraps source, periodic solid waste survey data were interpolated so that annual storage estimates could be derived. This flux has been applied to the entire time series, and periodic U.S. census data on changes in urban area have been used to develop annual estimates of CO₂ flux.

Land use, land-use change, and forestry activities in 2009 resulted in a net C sequestration of 1,015.1 Tg CO₂ Eq. (276.8 Tg C) (Table 7-1 and Table 7-2). This represents an offset of approximately 15.3 percent of total U.S. CO₂ emissions. Total land use, land-use change, and forestry net C sequestration¹⁵⁶ increased by approximately 17.8 percent between 1990 and 2009. This increase was primarily due to an increase in the rate of net C accumulation in forest C stocks. Net C accumulation in *Forest Land Remaining Forest Land*, *Land Converted to Grassland*, and *Settlements Remaining Settlements* increased, while net C accumulation in *Cropland Remaining Cropland*, *Grassland Remaining Grassland*, and landfilled yard trimmings and food scraps slowed over this period. Emissions from *Land Converted to Cropland* increased between 1990 and 2009.

Table 7-1: Net CO₂ Flux from Carbon Stock Changes in Land Use, Land-Use Change, and Forestry (Tg CO₂ Eq.)

Sink Category	1990	2000	2005	2006	2007	2008	2009
Forest Land Remaining Forest Land ¹	(681.1)	(378.3)	(911.5)	(917.5)	(911.9)	(891.0)	(863.1)
Cropland Remaining Cropland	(29.4)	(30.2)	(18.3)	(19.1)	(19.7)	(18.1)	(17.4)
Land Converted to Cropland	2.2	2.4	5.9	5.9	5.9	5.9	5.9
Grassland Remaining Grassland							
Grassland	(52.2)	(52.6)	(8.9)	(8.8)	(8.6)	(8.5)	(8.3)
Land Converted to Grassland	(19.8)	(27.2)	(24.4)	(24.2)	(24.0)	(23.8)	(23.6)
Settlements Remaining Settlements ²	(57.1)	(77.5)	(87.8)	(89.8)	(91.9)	(93.9)	(95.9)
Other (Landfilled Yard Trimmings and Food Scraps)	(24.2)	(13.2)	(11.5)	(11.0)	(10.9)	(11.2)	(12.6)
Total	(861.5)	(576.6)	(1,056.5)	(1,064.3)	(1,060.9)	(1,040.5)	(1,015.1)

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

¹⁵⁵ The term “flux” is used here to encompass both emissions of greenhouse gases to the atmosphere, and removal of C from the atmosphere. Removal of C from the atmosphere is also referred to as “carbon sequestration.”

¹⁵⁶ Carbon sequestration estimates are net figures. The C stock in a given pool fluctuates due to both gains and losses. When losses exceed gains, the C stock decreases, and the pool acts as a source. When gains exceed losses, the C stock increases, and the pool acts as a sink. This is also referred to as net C sequestration.

¹ Estimates include C stock changes on both *Forest Land Remaining Forest Land* and *Land Converted to Forest Land*.

² Estimates include C stock changes on both *Settlements Remaining Settlements* and *Land Converted to Settlements*.

Table 7-2: Net CO₂ Flux from Carbon Stock Changes in Land Use, Land-Use Change, and Forestry (Tg C)

Sink Category	1990	2000	2005	2006	2007	2008	2009
Forest Land Remaining Forest Land ¹	(185.7)	(103.2)	(248.6)	(250.2)	(248.7)	(243.0)	(235.4)
Cropland Remaining Cropland	(8.0)	(8.2)	(5.0)	(5.2)	(5.4)	(4.9)	(4.7)
Land Converted to Cropland	0.6	0.6	1.6	1.6	1.6	1.6	1.6
Grassland Remaining							
Grassland	(14.2)	(14.3)	(2.4)	(2.4)	(2.3)	(2.3)	(2.3)
Land Converted to Grassland	(5.4)	(7.4)	(6.7)	(6.6)	(6.5)	(6.5)	(6.4)
Settlements Remaining							
Settlements ²	(15.6)	(21.1)	(23.9)	(24.5)	(25.1)	(25.6)	(26.2)
Other (Landfilled Yard Trimmings and Food Scraps)	(6.6)	(3.6)	(3.1)	(3.0)	(3.0)	(3.1)	(3.4)
Total	(235.0)	(157.3)	(288.1)	(290.3)	(289.3)	(283.8)	(276.8)

Note: 1 Tg C = 1 teragram C = 1 million metric tons C. Parentheses indicate net sequestration. Totals may not sum due to independent rounding.

¹ Estimates include C stock changes on both *Forest Land Remaining Forest Land* and *Land Converted to Forest Land*.

² Estimates include C stock changes on both *Settlements Remaining Settlements* and *Land Converted to Settlements*.

Emissions from Land Use, Land-Use Change, and Forestry are shown in Table 7-3 and Table 7-4. Liming of agricultural soils and urea fertilization in 2009 resulted in CO₂ emissions of 4.2 Tg CO₂ Eq. (4,221 Gg) and 3.6 Tg CO₂ Eq. (3,612 Gg), respectively. Lands undergoing peat extraction (i.e., *Peatlands Remaining Peatlands*) resulted in CO₂ emissions of 1.1 Tg CO₂ Eq. (1,090 Gg), and nitrous oxide (N₂O) emissions of less than 0.05 Tg CO₂ Eq. The application of synthetic fertilizers to forest soils in 2009 resulted in direct N₂O emissions of 0.4 Tg CO₂ Eq. (1 Gg). Direct N₂O 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, direct N₂O emissions from fertilizer application to settlement soils in 2009 accounted for 1.5 Tg CO₂ Eq. (5 Gg) in 2009. This represents an increase of 55 percent since 1990. Forest fires in 2009 resulted in methane (CH₄) emissions of 7.8 Tg CO₂ Eq. (372 Gg), and in N₂O emissions of 6.4 Tg CO₂ Eq. (21 Gg).

Table 7-3: Emissions from Land Use, Land-Use Change, and Forestry (Tg CO₂ Eq.)

Source Category	1990	2000	2005	2006	2007	2008	2009
CO₂	8.1	8.8	8.9	8.8	9.2	9.6	8.9
Cropland Remaining Cropland:							
Liming of Agricultural Soils	4.7	4.3	4.3	4.2	4.5	5.0	4.2
Urea Fertilization	2.4	3.2	3.5	3.7	3.7	3.6	3.6
Wetlands Remaining Wetlands:							
Peatlands Remaining Peatlands	1.0	1.2	1.1	0.9	1.0	1.0	1.1
CH₄	3.2	14.3	9.8	21.6	20.0	11.9	7.8
Forest Land Remaining Forest							
Land: Forest Fires	3.2	14.3	9.8	21.6	20.0	11.9	7.8
N₂O	3.7	13.2	9.8	19.5	18.3	11.6	8.3
Forest Land Remaining Forest							
Land: Forest Fires	2.6	11.7	8.0	17.6	16.3	9.8	6.4
Forest Land Remaining Forest							
Land: Forest Soils ¹	0.1	0.4	0.4	0.4	0.4	0.4	0.4
Settlements Remaining							
Settlements: Settlement Soils ²	1.0	1.1	1.5	1.5	1.6	1.5	1.5
Wetlands Remaining Wetlands:							
Peatlands Remaining Peatlands	+	+	+	+	+	+	+
Total	15.0	36.3	28.6	49.8	47.5	33.2	25.0

+ Less than 0.05 Tg CO₂ Eq.

Note: These estimates include direct emissions only. Indirect N₂O emissions are reported in the Agriculture chapter. Totals may

not sum due to independent rounding.

¹ 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.

² Estimates include emissions from N fertilizer additions on both *Settlements Remaining Settlements*, and *Land Converted to Settlements*, but not from land-use conversion.

Table 7-4: Emissions from Land Use, Land-Use Change, and Forestry (Gg)

Source Category	1990	2000	2005	2006	2007	2008	2009
CO₂	8,117	8,768	8,933	8,754	9,214	9,646	8,922
Cropland Remaining Cropland:							
Liming of Agricultural Soils	4,667	4,328	4,349	4,220	4,464	5,042	4,221
Urea Fertilization	2,417	3,214	3,504	3,656	3,738	3,612	3,612
Wetlands Remaining Wetlands:							
Peatlands Remaining Peatlands	1,033	1,227	1,079	879	1,012	992	1,090
CH₄	152	682	467	1,027	953	569	372
Forest Land Remaining Forest							
Land: Forest Fires	152	682	467	1,027	953	569	372
N₂O	12	43	32	63	59	37	27
Forest Land Remaining Forest							
Land: Forest Fires	8	38	26	57	53	31	21
Forest Land Remaining Forest							
Land: Forest Soils ¹	+	1	1	1	1	1	1
Settlements Remaining							
Settlements: Settlement Soils ²	3	4	5	5	5	5	5
Wetlands Remaining Wetlands:							
Peatlands Remaining Peatlands	+	+	+	+	+	+	+

+ Less than 0.5 Gg

Note: These estimates include direct emissions only. Indirect N₂O emissions are reported in the Agriculture chapter. Totals may not sum due to independent rounding.

¹ 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.

² Estimates include emissions from N fertilizer additions on both *Settlements Remaining Settlements*, and *Land Converted to Settlements*, but not from land-use conversion.

[BEGIN BOX]

Box 7-1: 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 Intergovernmental Panel on Climate Change (IPCC).¹⁵⁷ Additionally, the calculated emissions and sinks in a given year for the U.S. are presented in a common manner in line with the UNFCCC reporting guidelines for the reporting of inventories under this international agreement.¹⁵⁸ 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 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.

[END BOX]

¹⁵⁷ See <http://www.ipcc-nggip.iges.or.jp/public/index.html>.

¹⁵⁸ See http://unfccc.int/national_reports/annex_i_ghg_inventories/national_inventories_submissions/items/5270.php.

7.1. Representation of the U.S. Land Base

A national land-use categorization system that is consistent and complete both temporally and spatially is needed in order to assess land use and land-use change status and the associated greenhouse gas fluxes over the inventory time series. This system should be consistent with IPCC (2006), such that all countries reporting on national greenhouse gas fluxes to the UNFCCC should (1) describe the methods and definitions used to determine areas of managed and unmanaged lands in the country, (2) describe and apply a consistent set of definitions for land-use categories over the entire national land base and time series associated with the greenhouse gas inventory, such that increases in the land areas within particular land-use categories are balanced by decreases in the land areas of other categories, and (3) account for greenhouse gas fluxes on all managed lands. The implementation of such a system helps to ensure that estimates of greenhouse gas fluxes are as accurate as possible. This section of the Inventory has been developed in order to comply with this guidance.

Multiple databases are used to track land management in the United States, which are also used as the basis to classify U.S. land area into the six IPCC land-use categories (i.e., *Forest Land Remaining Forest Land*, *Cropland Remaining Cropland*, *Grassland Remaining Grassland*, *Wetlands Remaining Wetlands*, *Settlements Remaining Settlements* and *Other Land Remaining Other Land*) and thirty land-use change categories (e.g., *Cropland Converted to Forest Land*, *Grassland Converted to Forest Land*, *Wetlands Converted to Forest Land*, *Settlements Converted to Forest Land*, *Other Land Converted to Forest Lands*)¹⁵⁹ (IPCC 2006). The primary databases are the U.S. Department of Agriculture (USDA) National Resources Inventory (NRI)¹⁶⁰ and the USDA Forest Service (USFS) Forest Inventory and Analysis (FIA)¹⁶¹ Database. The U.S. Geological Survey (USGS) National Land Cover Dataset (NLCD)¹⁶² is also used to identify land uses in regions that were not included in the NRI or FIA. The total land area included in the U.S. Inventory is 786 million hectares, and this entire land base is considered managed.¹⁶³ In 2009, the United States had a total of 274 million hectares of Forest Land (a 4 percent increase since 1990), 163 million hectares of Cropland (down 4.4 percent since 1990), 258 million hectares of Grassland (down 4.2 percent since 1990), 26 million hectares of Wetlands (down 4.9 percent since 1990), 49 million hectares of Settlements (up 24.5 percent since 1990), and 14 million hectares of Other Land. It is important to note that the land base formally classified for the Inventory (see Table 7-5) is considered managed. Alaska is not formally included in the current land representation, but there is a planned improvement underway to include this portion of the United States in future inventories. In addition, wetlands are not differentiated between managed and unmanaged, although some wetlands would be unmanaged according to the U.S. definition (see definition later in this section). Future improvements will include a differentiation between managed and unmanaged wetlands. In addition, carbon stock changes are not currently estimated for the entire land base, which leads to discrepancies between the area data presented here and in the subsequent sections of the NIR. Planned improvements are underway or in development phases to conduct an inventory of carbon stock changes on all managed land (e.g., federal grasslands).

Dominant land uses vary by region, largely due to climate patterns, soil types, geology, proximity to coastal regions, and historical settlement patterns, although all land-uses occur within each of the fifty states (Figure 7-1). Forest Land tends to be more common in the eastern states, mountainous regions of the western United States, and Alaska. Cropland is concentrated in the mid-continent region of the United States, and Grassland is more common in the western United States. Wetlands are fairly ubiquitous throughout the United States, though they are more common in the upper Midwest and eastern portions of the country. Settlements are more concentrated along the coastal margins and in the eastern states.

¹⁵⁹ Land-use category definitions are provided in the Methodology section.

¹⁶⁰ NRI data is available at <<http://www.nrcg.nrcs.usda.gov/products/nri/index.html>>.

¹⁶¹ FIA data is available at <<http://fia.fs.fed.us/tools-data/data/>>.

¹⁶² NLCD data is available at <<http://www.mrlc.gov/>>.

¹⁶³ The current land representation does not include areas from Alaska or U.S. territories, but there are planned improvements to include these regions in future reports.

Table 7-5: Size of Land Use and Land-Use Change Categories on Managed Land Area by Land Use and Land Use Change Categories (thousands of hectares)

Land Use & Land-Use Change Categories^a	1990	2000	2005	2006	2007	2008	2009
Total Forest Land	263,878	268,790	271,322	272,107	272,891	273,677	274,462
FF	257,180	253,080	255,444	256,181	256,917	257,655	258,392
CF	1,266	2,793	2,976	2,983	2,991	2,998	3,006
GF	4,879	11,347	11,122	11,157	11,193	11,229	11,264
WF	63	201	205	205	206	207	207
SF	101	268	303	304	305	306	307
OF	389	1,102	1,273	1,276	1,279	1,282	1,285
Total Cropland	170,632	164,401	163,192	163,178	163,164	163,151	163,137
CC	155,433	144,004	145,531	145,518	145,506	145,493	145,481
FC	1,105	1,101	805	804	803	802	802
GC	13,298	17,834	15,513	15,513	15,513	15,512	15,512
WC	163	264	234	234	234	234	234
SC	470	886	825	825	825	825	825
OC	162	311	283	283	283	283	283
Total Grassland	269,643	263,092	260,565	260,012	259,458	258,904	258,350
GG	260,064	245,460	243,839	243,395	242,951	242,506	242,061
FG	1,463	3,048	2,787	2,773	2,759	2,745	2,730
CG	7,502	13,303	12,632	12,541	12,451	12,360	12,270
WG	230	373	339	338	338	337	336
SG	129	255	255	253	252	250	249
OG	255	653	714	712	709	706	704
Total Wetlands	27,788	27,560	27,173	26,983	26,793	26,603	26,412
WW	27,179	26,155	25,701	25,519	25,338	25,157	24,976
FW	138	378	401	398	395	393	390
CW	134	348	351	348	344	341	338
GW	286	633	675	672	670	668	665
SW	<1	3	3	3	3	3	3
OW	51	43	43	42	42	42	42
Total Settlements	39,518	47,558	49,247	49,238	49,229	49,220	49,212
SS	34,742	34,055	34,975	34,966	34,958	34,949	34,941
FS	1,842	5,480	5,872	5,872	5,872	5,871	5,871
CS	1,373	3,599	3,673	3,672	3,672	3,672	3,672
GS	1,498	4,183	4,479	4,479	4,479	4,479	4,479
WS	3	29	32	32	32	32	32
OS	60	212	217	217	217	217	217
Total Other Land	14,385	14,443	14,346	14,327	14,309	14,290	14,272
OO	13,397	12,286	12,104	12,087	12,069	12,051	12,033
FO	193	506	559	559	559	559	559
CO	279	440	499	499	499	499	499
GO	458	1,085	1,058	1,057	1,057	1,056	1,056
WO	55	115	114	114	114	114	113
SO	3	11	12	12	12	12	12
Grand Total	785,845	785,845	785,845	785,845	785,845	785,845	785,845

^aThe abbreviations are “F” for Forest Land, “C” for Cropland, “G” for Grassland, “W” for Wetlands, “S” for Settlements, and “O” for Other Lands. Lands remaining in the same land use category are identified with the land use abbreviation given twice (e.g., “FF” is Forest Land Remaining Forest Land), and land use change categories are identified with the previous land use abbreviation followed by the new land use abbreviation (e.g., “CF” is Cropland Converted to Forest Land).

Notes: All land areas reported in this table are considered managed. A planned improvement is underway to deal with an exception for wetlands which includes both managed and unmanaged lands based on the definitions for the current U.S. Land Representation Assessment. In addition, U.S. Territories have not been classified into land uses and are not included in the U.S. Land Representation Assessment. See Planned Improvements for discussion on plans to include Alaska and territories in future Inventories.

Figure 7-1. Percent of Total Land Area in the General Land-Use Categories for 2009

Methodology

IPCC Approaches for Representing Land Areas

IPCC (2006) describes three approaches for representing land areas. Approach 1 provides data on the total area for each individual land-use category, but does not provide detailed information on changes of area between categories and is not spatially explicit other than at the national or regional level. With Approach 1, total net conversions between categories can be detected, but not the individual changes between the land-use categories that led to those net changes. Approach 2 introduces tracking of individual land-use changes between the categories (e.g., Forest Land to Cropland, Cropland to Forest Land, Grassland to Cropland, etc.), using surveys or other forms of data that do not provide location data on specific parcels of land. Approach 3 extends Approach 2 by providing location data on specific parcels of land, such as maps, along with the land-use history. The three approaches are not presented as hierarchical tiers and are not mutually exclusive.

According to IPCC (2006), the approach or mix of approaches selected by an inventory agency should reflect calculation needs and national circumstances. For this analysis, the NRI, FIA, and the NLCD have been combined to provide a complete representation of land use for managed lands. These data sources are described in more detail later in this section. All of these datasets have a spatially-explicit time series of land-use data, and therefore Approach 3 is used to provide a full representation of land use in the U.S. Inventory. Lands are treated as remaining in the same category (e.g., *Cropland Remaining Cropland*) if a land-use change has not occurred in the last 20 years. Otherwise, the land is classified in a land-use-change category based on the current use and most recent use before conversion to the current use (e.g., *Cropland Converted to Forest Land*).

Definitions of Land Use in the United States

Managed and Unmanaged Land

The U.S. definitions of managed and unmanaged lands are similar to the basic IPCC (2006) definition of managed land, but with some additional elaboration to reflect national circumstances. Based on the following definitions, most lands in the United States are classified as managed:

- *Managed Land*: Land is considered managed if direct human intervention has influenced its condition. Direct intervention includes altering or maintaining the condition of the land to produce commercial or non-commercial products or services; to serve as transportation corridors or locations for buildings, landfills, or other developed areas for commercial or non-commercial purposes; to extract resources or facilitate acquisition of resources; or to provide social functions for personal, community or societal objectives. Managed land also includes legal protection of lands (e.g., wilderness, preserves, parks, etc.) for conservation purposes (i.e., meets societal objectives).¹⁶⁴
- *Unmanaged Land*: All other land is considered unmanaged. Unmanaged land is largely comprised of areas inaccessible to human intervention due to the remoteness of the locations, or lands with essentially no development interest or protection due to limited personal, commercial or social value. Though these lands may be influenced indirectly by human actions such as atmospheric deposition of chemical species

¹⁶⁴ Wetlands are an exception to this general definition, because these lands, as specified by IPCC (2006), are only considered managed if they are created through human activity, such as dam construction, or the water level is artificially altered by human activity. Distinguishing between managed and unmanaged wetlands is difficult, however, due to limited data availability. Wetlands are not characterized by use within the NRI. Therefore, unless wetlands are managed for cropland or grassland, it is not possible to know if they are artificially created or if the water table is managed based on the use of NRI data. See the Planned Improvements section of the Inventory for work being done to refine the Wetland area estimates.

produced in industry, they are not influenced by a direct human intervention.¹⁶⁵

Land-Use Categories

As with the definition of managed lands, IPCC (2006) provides general non-prescriptive definitions for the six main land-use categories: Forest Land, Cropland, Grassland, Wetlands, Settlements and Other Land. In order to reflect U.S. circumstances, country-specific definitions have been developed, based predominantly on criteria used in the land-use surveys for the United States. Specifically, the definition of Forest Land is based on the FIA definition of forest,¹⁶⁶ while definitions of Cropland, Grassland, and Settlements are based on the NRI.¹⁶⁷ The definitions for Other Land and Wetlands are based on the IPCC (2006) definitions for these categories.

- *Forest Land*: A land-use category that includes areas at least 36.6 m wide and 0.4 ha in size with at least 10 percent cover (or equivalent stocking) by live trees of any size, including land that formerly had such tree cover and that will be naturally or artificially regenerated. Forest land includes transition zones, such as areas between forest and non-forest lands that have at least 10 percent cover (or equivalent stocking) with live trees and forest areas adjacent to urban and built-up lands. Roadside, streamside, and shelterbelt strips of trees must have a crown width of at least 36.6 m and continuous length of at least 110.6 m to qualify as forest land. Unimproved roads and trails, streams, and clearings in forest areas are classified as forest if they are less than 36.6 m wide or 0.4 ha in size, otherwise they are excluded from Forest Land and classified as Settlements. Tree-covered areas in agricultural production settings, such as fruit orchards, or tree-covered areas in urban settings, such as city parks, are not considered forest land (Smith et al. 2009). NOTE: This definition applies to all U.S. lands and territories. However, at this time, data availability is limited for remote or inaccessible areas such as interior Alaska
- *Cropland*: A land-use category that includes areas used for the production of adapted crops for harvest; this category includes both cultivated and non-cultivated lands.¹⁶⁸ Cultivated crops include row crops or close-grown crops and also hay or pasture in rotation with cultivated crops. Non-cultivated cropland includes continuous hay, perennial crops (e.g., orchards) and horticultural cropland. Cropland also includes land with alley cropping and windbreaks,¹⁶⁹ as well as lands in temporary fallow or enrolled in conservation reserve programs (i.e., set-asides¹⁷⁰). Roads through Cropland, including interstate highways, state highways, other paved roads, gravel roads, dirt roads, and railroads are excluded from Cropland area estimates and are, instead, classified as Settlements.
- *Grassland*: A land-use category on which the plant cover is composed principally of grasses, grass-like plants, forbs, or shrubs suitable for grazing and browsing, and includes both pastures and native rangelands.¹⁷¹ This includes areas where practices such as clearing, burning, chaining, and/or chemicals are applied to maintain the grass vegetation. Savannas, some wetlands and deserts, in addition to tundra are considered Grassland.¹⁷² Woody plant communities of low forbs and shrubs, such as mesquite, chaparral, mountain shrub, and pinyon-juniper, are also classified as Grassland if they do not meet the criteria for Forest Land. Grassland includes land managed with agroforestry practices such as silvopasture and windbreaks, assuming the stand or woodlot does not meet the criteria for Forest Land. Roads through

¹⁶⁵ There will be some areas that qualify as Forest Land or Grassland according to the land use criteria, but are classified as unmanaged land due to the remoteness of their location.

¹⁶⁶ See <http://socrates.lv-hrc.nevada.edu/fia/ab/issues/pending/glossary/Glossary_5_30_06.pdf>.

¹⁶⁷ See <<http://www.nrcs.usda.gov/technical/land/nri01/glossary.html>>.

¹⁶⁸ A minor portion of Cropland occurs on federal lands, and is not currently included in the C stock change inventory. A planned improvement is underway to include these areas in future C inventories.

¹⁶⁹ Currently, there is no data source to account for biomass C stock change associated with woody plant growth and losses in alley cropping systems and windbreaks in cropping systems, although these areas are included in the cropland land base.

¹⁷⁰ A set-aside is cropland that has been taken out of active cropping and converted to some type of vegetative cover, including, for example, native grasses or trees.

¹⁷¹ Grasslands on federal lands are included in the managed land base, but C stock changes are not estimated on these lands. Federal grassland areas have been assumed to have negligible changes in C due to limited land use and management change, but planned improvements are underway to further investigate this issue and include these areas in future C inventories.

¹⁷² IPCC (2006) guidelines do not include provisions to separate desert and tundra as land categories.

Grassland, including interstate highways, state highways, other paved roads, gravel roads, dirt roads, and railroads are excluded from Grassland area estimates and are, instead, classified as Settlements.

- *Wetlands*: A land-use category that includes land covered or saturated by water for all or part of the year. Managed Wetlands are those where the water level is artificially changed, or were created by human activity. Certain areas that fall under the managed Wetlands definition are covered in other areas of the IPCC guidance and/or the inventory, including Cropland (e.g., rice cultivation), Grassland, and Forest Land (including drained or undrained forested wetlands).
- *Settlements*: A land-use category representing developed areas consisting of units of 0.25 acres (0.1 ha) or more that includes residential, industrial, commercial, and institutional land; construction sites; public administrative sites; railroad yards; cemeteries; airports; golf courses; sanitary landfills; sewage treatment plants; water control structures and spillways; parks within urban and built-up areas; and highways, railroads, and other transportation facilities. Also included are tracts of less than 10 acres (4.05 ha) that may meet the definitions for Forest Land, Cropland, Grassland, or Other Land but are completely surrounded by urban or built-up land, and so are included in the settlement category. Rural transportation corridors located within other land uses (e.g., Forest Land, Cropland) are also included in Settlements.
- *Other Land*: A land-use category that includes bare soil, rock, ice, non-settlement transportation corridors, and all land areas that do not fall into any of the other five land-use categories. It allows the total of identified land areas to match the managed national area.

Land-Use Data Sources: Description and Application to U.S. Land Area Classification

U.S. Land-Use Data Sources

The three main data sources for land area and use data in the United States are the NRI, FIA, and the NLCD. For the Inventory, the NRI is the official source of data on all land uses on non-federal lands (except forest land), and is also used as the resource to determine the total land base for the conterminous United States and Hawaii. The NRI is conducted by the USDA Natural Resources Conservation Service and is designed to assess soil, water, and related environmental resources on non-federal lands. The NRI has a stratified multi-stage sampling design, where primary sample units are stratified on the basis of county and township boundaries defined by the U.S. Public Land Survey (Nusser and Goebel 1997). Within a primary sample unit (typically a 160-acre [64.75 ha] square quarter-section), three sample points are selected according to a restricted randomization procedure. Each point in the survey is assigned an area weight (expansion factor) based on other known areas and land-use information (Nusser and Goebel 1997). The NRI survey utilizes data derived from remote sensing imagery and site visits in order to provide detailed information on land use and management, particularly for croplands and grasslands, and is used as the basis to account for C stock changes in agricultural lands (except federal Grasslands). The NRI survey was conducted every 5 years between 1982 and 1997, but shifted to annualized data collection in 1998. This Inventory incorporates data through 2003 from the NRI.

The FIA program, conducted by the USFS, is the official source of data on Forest Land area and management data for the Inventory. FIA engages in a hierarchical system of sampling, with sampling categorized as Phases 1 through 3, in which sample points for phases are subsets of the previous phase. Phase 1 refers to collection of remotely-sensed data (either aerial photographs or satellite imagery) primarily to classify land into forest or non-forest and to identify landscape patterns like fragmentation and urbanization. Phase 2 is the collection of field data on a network of ground plots that enable classification and summarization of area, tree, and other attributes associated with forest land uses. Phase 3 plots are a subset of Phase 2 plots where data on indicators of forest health are measured. Data from all three phases are also used to estimate C stock changes for forest land. Historically, FIA inventory surveys had been conducted periodically, with all plots in a state being measured at a frequency of every 5 to 14 years. A new national plot design and annual sampling design was introduced by FIA about ten years ago. Most states, though, have only recently been brought into this system. Annualized sampling means that a portion of plots throughout each state is sampled each year, with the goal of measuring all plots once every 5 years. See Annex 3.12 to see the specific survey data available by state. The most recent year of available data varies state by state (2002 through 2009).

Though NRI provides land-area data for both federal and non-federal lands, it only includes land-use data on non-federal lands, and FIA only records data for forest land.¹⁷³ Consequently, major gaps exist when the datasets are combined, such as federal grassland operated by the Bureau of Land Management (BLM), USDA, and National Park Service, as well as most of Alaska.¹⁷⁴ The NLCD is used as a supplementary database to account for land use on federal lands that are not included in the NRI and FIA databases. The NLCD land-cover classification scheme, available for 1992 and 2001, has been applied over the conterminous United States (Homer et al. 2007). The 2001 product also provides land use data that has been used for Hawaii federal lands. For this analysis, the NLCD Retrofit Land Cover Change Product was used in order to represent both land use and land-use change for federal lands in the conterminous U.S. (Homer et al. 2007). It is based primarily on Landsat Thematic Mapper imagery. The NLCD contains 21 categories of land-cover information, which have been aggregated into the IPCC land-use categories, and the data are available at a spatial resolution of 30 meters. The federal land portion of the NLCD was extracted from the dataset using the federal land area boundary map from the National Atlas (2005). This map represents federal land boundaries in 2005, so as part of the analysis, the federal land area was adjusted annually based on the NRI federal land area estimates (i.e., land is periodically transferred between federal and non-federal ownership). Consequently, the portion of the land base categorized with NLCD data varied from year to year, corresponding to an increase or decrease in the federal land base. The NLCD is strictly a source of land-cover information, however, and does not provide the necessary site conditions, crop types, and management information from which to estimate C stock changes on those lands.

Another step in the analysis is to address gaps as well as overlaps in the representation of the U.S. land base between the Agricultural Carbon Stock Inventory (*Cropland Remaining Cropland, Land Converted to Cropland, Grassland Remaining Grassland, Land Converted to Grassland*) and Forest Land Carbon Stock Inventory (*Forest Land Remaining Forest Land and Land Converted to Forest Land*), which are based on the NRI and FIA databases, respectively. NRI and FIA have different criteria for classifying forest land and sampling designs, leading to discrepancies in the resulting estimates of Forest Land area on non-federal land. Similarly, there are discrepancies between the NLCD and FIA data for defining and classifying Forest Land on federal lands. Moreover, dependence exists between the Forest Land area and the amount of land designated as other land uses in both the NRI and the NLCD, such as the amount of Grassland, Cropland, and Wetlands, relative to the Forest Land area. This results in inconsistencies among the three databases for estimated Forest Land area, as well as for the area estimates for other land-use categories. FIA is the main database for forest statistics, and consequently, the NRI and NLCD were adjusted to achieve consistency with FIA estimates of Forest Land. The adjustments were made at a state-scale, and it was assumed that the majority of the discrepancy in forest area was associated with an under- or over-prediction of Grassland and Wetland area in the NRI and NLCD due to differences in Forest Land definitions. Specifically, the Forest Land area for a given state according to the NRI and NLCD was adjusted to match the FIA estimates of Forest Land for non-federal and federal land, respectively. In a second step, corresponding increases or decreases were made in the area estimates of Grassland and Wetland from the NRI and NLCD, in order to balance the change in forest area, and therefore not change the overall amount of managed land within an individual state. The adjustments were based on the proportion of land within each of these land-use categories at the state-level. (i.e., a higher proportion of Grassland led to a larger adjustment in Grassland area).

As part of Quality Assurance /Quality Control (QA/QC), the land base derived from the NRI, FIA and NLCD was compared to the Topologically Integrated Geographic Encoding and Referencing (TIGER) survey (U.S. Census Bureau 2010). The U.S. Census Bureau gathers data on the U.S. population and economy, and has a database of land areas for the country. The land area estimates from the U.S. Census Bureau differ from those provided by the land-use surveys used in the Inventory because of discrepancies in the reporting approach for the census and the methods used in the NRI, FIA, and NLCD. The area estimates of land-use categories, based on NRI, FIA, and NLCD, are derived from remote sensing data instead of the land survey approach used by the U.S. Census Survey. More importantly, the U.S. Census Survey does not provide a time series of land-use change data or land management information, which is critical for conducting emission inventories and is provided from the NRI and FIA surveys. Consequently, the U.S. Census Survey was not adopted as the official land area estimate for the Inventory. Rather, the NRI data were adopted because this database provides full coverage of land area and land use

¹⁷³ FIA does collect some data on non-forest land use, but these are held in regional databases versus the national database. The status of these data is being investigated.

¹⁷⁴ The survey programs also do not include U.S. Territories with the exception of non-federal lands in Puerto Rico, which are included in the NRI survey. Furthermore, NLCD does not include coverage for U.S. Territories.

for the conterminous United States and Hawaii. Regardless, the total difference between the U.S. Census Survey and the data sources used in the Inventory is about 25 million hectares for the total land base of about 786 million hectares currently included in the Inventory, or a 3.1 percent difference. Much of this difference is associated with open waters in coastal regions and the Great Lakes. NRI does not include as much of the area of open waters in these regions as the U.S. Census Survey.

Approach for Combining Data Sources

The managed land base in the United States has been classified into the six IPCC land-use categories using definitions¹⁷⁵ developed to meet national circumstances, while adhering to IPCC (2006). In practice, the land was initially classified into a variety of land-use categories using the NRI, FIA and NLCD, and then aggregated into the thirty-six broad land use and land-use-change categories identified in IPCC (2006). Details on the approach used to combine data sources for each land use are described below as are the gaps that will be reconciled as part of ongoing planned improvements:

- *Forest Land*: Both non-federal and federal forest lands in both the continental United States and coastal Alaska are covered by FIA. FIA is used as the basis for both Forest Land area data as well as to estimate C stocks and fluxes on Forest Land. Interior Alaska is not currently surveyed by FIA, but NLCD has a new product for Alaska that will be incorporated into the assessment as a planned improvement for future reports. Forest Lands in U.S. territories are currently excluded from the analysis, but FIA surveys are currently being conducted on U.S. territories and will become available in the future. NRI is being used in the current report to provide Forest Land areas on non-federal lands in Hawaii. Currently, federal forest land in Hawaii is evaluated with the 2001 NLCD, but FIA data will be collected in Hawaii in the future.
- *Cropland*: Cropland is classified using the NRI, which covers all non-federal lands within 49 states (excluding Alaska), including state and local government-owned land as well as tribal lands. NRI is used as the basis for both Cropland area data as well as to estimate C stocks and fluxes on Cropland. Croplands in U.S. territories are excluded from both NRI data collection and the NLCD. NLCD has a new product for Alaska that will be incorporated into the assessment as a planned improvement for future reports.
- *Grassland*: Grassland on non-federal lands is classified using the NRI within 49 states (excluding Alaska), including state and local government-owned land as well as tribal lands. NRI is used as the basis for both Grassland area data as well as to estimate C stocks and fluxes on Grassland. U.S. territories are excluded from both NRI data collection and the current release of the NLCD product. Grassland on federal Bureau of Land Management lands, Department of Defense lands, National Parks and within USFS lands are covered by the NLCD. In addition, federal and non-federal grasslands in Alaska are currently excluded from the analysis, but NLCD has a new product for Alaska that will be incorporated into the assessment for future reports.
- *Wetlands*: NRI captures wetlands on non-federal lands within 49 states (excluding Alaska), while federal wetlands are covered by the NLCD. Alaska and U.S. territories are excluded. This currently includes both managed and unmanaged wetlands as no database has yet been applied to make this distinction. See Planned Improvements for details.
- *Settlements*: The NRI captures non-federal settlement area in 49 states (excluding Alaska). If areas of Forest Land or Grassland under 10 acres (4.05 ha) are contained within settlements or urban areas, they are classified as Settlements (urban) in the NRI database. If these parcels exceed the 10 acre (4.05 ha) threshold and are Grassland, they will be classified as such by NRI. Regardless of size, a forested area is classified as non-forest by FIA if it is located within an urban area. Settlements on federal lands are covered by NLCD. Settlements in U.S. territories are currently excluded from NRI and NLCD. NLCD has a new product for Alaska that will be incorporated into the assessment as a planned improvement for future reports.
- *Other Land*: Any land not falling into the other five land categories and, therefore, categorized as Other Land is classified using the NRI for non-federal areas in the 49 states (excluding Alaska) and NLCD for the federal lands. Other land in U.S. territories is excluded from the NLCD. NLCD has a new product for

¹⁷⁵ Definitions are provided in the previous section.

Alaska that will be incorporated into the assessment as a planned improvement for future reports.

Some lands can be classified into one or more categories due to multiple uses that meet the criteria of more than one definition. However, a ranking has been developed for assignment priority in these cases. The ranking process is initiated by distinguishing between managed and unmanaged lands. The managed lands are then assigned, from highest to lowest priority, in the following manner:

Settlements > Cropland > Forest Land > Grassland > Wetlands > Other Land

Settlements are given the highest assignment priority because they are extremely heterogeneous with a mosaic of patches that include buildings, infrastructure and travel corridors, but also open grass areas, forest patches, riparian areas, and gardens. The latter examples could be classified as Grassland, Forest Land, Wetlands, and Cropland, respectively, but when located in close proximity to settlement areas they tend to be managed in a unique manner compared to non-settlement areas. Consequently, these areas are assigned to the Settlements land-use category. Cropland is given the second assignment priority, because cropping practices tend to dominate management activities on areas used to produce food, forage or fiber. The consequence of this ranking is that crops in rotation with grass will be classified as Cropland, and land with woody plant cover that is used to produce crops (e.g., orchards) is classified as Cropland, even though these areas may meet the definitions of Grassland or Forest Land, respectively. Similarly, Wetlands are considered Croplands if they are used for crop production, such as rice or cranberries. Forest Land occurs next in the priority assignment because traditional forestry practices tend to be the focus of the management activity in areas with woody plant cover that are not croplands (e.g., orchards) or settlements (e.g., housing subdivisions with significant tree cover). Grassland occurs next in the ranking, while Wetlands and Other Land complete the list.

The assignment priority does not reflect the level of importance for reporting greenhouse gas emissions and removals on managed land, but is intended to classify all areas into a single land use. Currently, the IPCC does not make provisions in the guidelines for assigning land to multiple uses. For example, a Wetland is classified as Forest Land if the area has sufficient tree cover to meet the stocking and stand size requirements. Similarly, Wetlands are classified as Cropland if they are used for crop production, such as rice or cranberries. In either case, emissions from Wetlands are included in the Inventory if human interventions are influencing emissions from Wetlands, in accordance with the guidance provided in IPCC (2006).

Recalculations Discussion

No major revisions were made to the time series for the current Inventory. However, new data were incorporated from FIA on forestland areas, which was used to make minor adjustments to the time series. FIA conducts a survey of plots annually so that each plot is visited every 5 years (Note: some states have not initiated the annual sampling regime, as discussed previously). Consequently, the time series is updated each year as new data are collected over the 5 year cycles.

Planned Improvements

Area data by land-use category are not estimated for major portions of Alaska or any of the U.S. territories. A key planned improvement is to incorporate land-use data from these areas into the Inventory. For Alaska, a new NLCD 2001 data product will be used to cover those land areas presently omitted. Fortunately, most of the managed land in the United States is included in the current land-use statistics, but a complete accounting is a key goal for the near future. Data sources will also be evaluated for representing land use on federal and non-federal lands in U.S. territories.

Additional work will be conducted to reconcile differences in Forest Land estimates between the NRI and FIA, evaluating the assumption that the majority of discrepancies in Forest Land areas are associated with an over- or under-estimation of Grassland and Wetland area. In some regions of the United States, a discrepancy in Forest Land areas between NRI and FIA may be associated with an over- or under-prediction of other land uses, and an analysis is planned to develop region-specific adjustments.

There are also other databases that may need to be reconciled with the NRI and NLCD datasets, particularly for Settlements and Wetlands. Urban area estimates, used to produce C stock and flux estimates from urban trees, are currently based on population data (1990 and 2000 U.S. Census data). Using the population statistics, “urban clusters” are defined as areas with more than 500 people per square mile. The USFS is currently moving ahead with

an urban forest inventory program so that urban forest area estimates will be consistent with FIA forest area estimates outside of urban areas, which would be expected to reduce omissions and overlap of forest area estimates along urban boundary areas.

7.2. Forest Land Remaining Forest Land

Changes in Forest Carbon Stocks (IPCC Source Category 5A1)

For estimating C stocks or stock change (flux), C in forest ecosystems can be divided into the following five storage pools (IPCC 2003):

- Aboveground biomass, which includes all living biomass above the soil including stem, stump, branches, bark, seeds, and foliage. This category includes live understory.
- Belowground biomass, which includes all living biomass of coarse living roots greater than 2 mm diameter.
- Dead wood, which includes all non-living woody biomass either standing, lying on the ground (but not including litter), or in the soil.
- Litter, which includes the litter, fomic, and humic layers, and all non-living biomass with a diameter less than 7.5 cm at transect intersection, lying on the ground.
- Soil organic C (SOC), including all organic material in soil to a depth of 1 meter but excluding the coarse roots of the aboveground pools.

In addition, there are two harvested wood pools necessary for estimating C flux:

- Harvested wood products (HWP) in use.
- HWP in solid waste disposal sites (SWDS).

C is continuously cycled among these storage pools and between forest ecosystems and the atmosphere as a result of biological processes in forests (e.g., photosynthesis, respiration, growth, mortality, decomposition, and disturbances such as fires or pest outbreaks) and anthropogenic activities (e.g., harvesting, thinning, clearing, and replanting). As trees photosynthesize and grow, C is removed from the atmosphere and stored in living tree biomass. As trees die and otherwise deposit litter and debris on the forest floor, C is released to the atmosphere or transferred to the soil by organisms that facilitate decomposition.

The net change in forest C is not equivalent to the net flux between forests and the atmosphere because timber harvests do not cause an immediate flux of C of all vegetation C to the atmosphere. Instead, harvesting transfers a portion of the C stored in wood to a "product pool." Once in a product pool, the C is emitted over time as CO₂ when the wood product combusts or decays. The rate of emission varies considerably among different product pools. For example, if timber is harvested to produce energy, combustion releases C immediately. Conversely, if timber is harvested and used as lumber in a house, it may be many decades or even centuries before the lumber decays and C is released to the atmosphere. If wood products are disposed of in SWDS, the C contained in the wood may be released many years or decades later, or may be stored almost permanently in the SWDS.

This section quantifies the net changes in C stocks in the five forest C pools and two harvested wood pools. The net change in stocks for each pool is estimated, and then the changes in stocks are summed over all pools to estimate total net flux. The focus on C implies that all C-based greenhouse gases are included, and the focus on stock change suggests that specific ecosystem fluxes do not need to be separately itemized in this report. Disturbances from forest fires and pest outbreaks are implicitly included in the net changes. For instance, an inventory conducted after fire counts only the trees that are left. The change between inventories thus accounts for the C changes due to fires; however, it may not be possible to attribute the changes to the disturbance specifically. The IPCC (2003) recommends reporting C stocks according to several land-use types and conversions, specifically *Forest Land Remaining Forest Land* and *Land Converted to Forest Land*. Currently, consistent datasets are just becoming available for the conterminous United States to allow forest land conversions and forest land remaining forest land to be identified, and research is ongoing to properly use that information based on research results. Thus, net changes in all forest-related land, including non-forest land converted to forest and forests converted to non-forest, are reported here.

Forest C storage pools, and the flows between them via emissions, sequestration, and transfers, are shown in Figure 7-2. In the figure, boxes represent forest C storage pools and arrows represent flows between storage pools or between storage pools and the atmosphere. Note that the boxes are not identical to the storage pools identified in this chapter. The storage pools identified in this chapter have been refined in this graphic to better illustrate the processes that result in transfers of C from one pool to another, and emissions to as well as uptake from the atmosphere.

Figure 7-2: Forest Sector Carbon Pools and Flows

Approximately 33 percent (304 million hectares) of the U.S. land area is forested (Smith et al. 2009). The current forest carbon inventory includes 271 million hectares in the conterminous 48 states (USDA Forest Service 2010a, 2010b) that are considered managed and are included in this inventory. An additional 6.1 million hectares of southeast and south central Alaskan forest are inventoried and are included here. Three notable differences exist in forest land defined in Smith et al. (2009) and the forest land included in this report, which is based on USDA Forest Service (2010b). Survey data are not yet available from Hawaii and a large portion of interior Alaska, but estimates of these areas are included in Smith et al. (2009). Alternately, survey data for west Texas has only recently become available, and these forests contribute to overall carbon stock reported below. While Hawaii and U.S. territories have relatively small areas of forest land and will thus probably not influence the overall C budget substantially, these regions will be added to the C budget as sufficient data become available. Agroforestry systems are also not currently accounted for in the inventory, since they are not explicitly inventoried by either the Forest Inventory and Analysis (FIA) program of the U.S. Department of Agriculture (USDA) Forest Service or the National Resources Inventory (NRI) of the USDA Natural Resources Conservation Service (Perry et al. 2005).

Sixty-eight percent of U.S. forests (208 million hectares) are classified as timberland, meaning they meet minimum levels of productivity. Nine percent of Alaska forests overall and 81 percent of forests in the conterminous United States are classified as timberlands. Of the remaining nontimberland forests, 30 million hectares are reserved forest lands (withdrawn by law from management for production of wood products) and 66 million hectares are lower productivity forest lands (Smith et al. 2009). Historically, the timberlands in the conterminous 48 states have been more frequently or intensively surveyed than other forest lands.

Forest land area declined by approximately 10 million hectares over the period from the early 1960s to the late 1980s. Since then, forest area has increased by about 12 million hectares. Current trends in forest area represent average annual change of less than 0.2 percent. Given the low rate of change in U.S. forest land area, the major influences on the current net C flux from forest land are management activities and the ongoing impacts of previous land-use changes. These activities affect the net flux of C by altering the amount of C stored in forest ecosystems. For example, intensified management of forests that leads to an increased rate of growth increases the eventual biomass density of the forest, thereby increasing the uptake of C.¹⁷⁶ Though harvesting forests removes much of the aboveground C, on average the volume of annual net growth nationwide is about 72 percent higher than the volume of annual removals on timberlands (Smith et al. 2009). The reversion of cropland to forest land increases C storage in biomass, forest floor, and soils. The net effects of forest management and the effects of land-use change involving forest land are captured in the estimates of C stocks and fluxes presented in this chapter.

In the United States, improved forest management practices, the regeneration of previously cleared forest areas, and timber harvesting and use have resulted in net uptake (i.e., net sequestration) of C each year from 1990 through 2009. The rate of forest clearing begun in the 17th century following European settlement had slowed by the late 19th century. Through the later part of the 20th century many areas of previously forested land in the United States were allowed to revert to forests or were actively reforested. The impacts of these land-use changes still influence C fluxes from these forest lands. More recently, the 1970s and 1980s saw a resurgence of federally-sponsored forest management programs (e.g., the Forestry Incentive Program) and soil conservation programs (e.g., the Conservation Reserve Program), which have focused on tree planting, improving timber management activities, combating soil erosion, and converting marginal cropland to forests. In addition to forest regeneration and management, forest

¹⁷⁶ The term “biomass density” refers to the mass of live vegetation per unit area. It is usually measured on a dry-weight basis. Dry biomass is 50 percent C by weight.

harvests have also affected net C fluxes. Because most of the timber harvested from U.S. forests is used in wood products, and many discarded wood products are disposed of in SWDS rather than by incineration, significant quantities of C in harvested wood are transferred to long-term storage pools rather than being released rapidly to the atmosphere (Skog and Nicholson 1998, Skog 2008). The size of these long-term C storage pools has increased during the last century.

Changes in C stocks in U.S. forests and harvested wood were estimated to account for net sequestration of 863 Tg CO₂ Eq. (235 Tg C) in 2009 (Table 7-6, Table 7-7, and Table 7-8). In addition to the net accumulation of C in harvested wood pools, sequestration is a reflection of net forest growth and increasing forest area over this period. Overall, average C in forest ecosystem biomass (aboveground and belowground) increased from 67 to 73 Mg C/ha between 1990 and 2010 (see Annex 3-12 for average C densities by specific regions and forest types). Continuous, regular annual surveys are not available over the period for each state; therefore, estimates for non-survey years were derived by interpolation between known data points. Survey years vary from state to state, and national estimates are a composite of individual state surveys. Therefore, changes in sequestration over the interval 1990 to 2009 are the result of the sequences of new inventories for each state. C in forest ecosystem biomass had the greatest effect on total change through increases in C density and total forest land. Management practices that increase C stocks on forest land, as well as afforestation and reforestation efforts, influence the trends of increased C densities in forests and increased forest land in the United States.

The decline in net additions to HWP carbon stocks continued through 2009 from the recent high point in 2006. This is due to sharp declines in U.S. production of solidwood and paper products in 2009 primarily due to the decline in housing construction. The low level of gross additions to solidwood and paper products in use in 2009 was exceeded by discards from uses. The result is a net reduction in the amount of HWP carbon that is held in products in use during 2009. For 2009, additions to landfills still exceeded emissions from landfills and the net additions to landfills have remained relatively stable. Overall, there were net carbon additions to HWP in use and in landfills combined in 2009.

Table 7-6: Net Annual Changes in C Stocks (Tg CO₂/yr) in Forest and Harvested Wood Pools

Carbon Pool	1990	2000	2005	2006	2007	2008	2009
Forest	(549.3)	(265.4)	(806.1)	(808.9)	(808.9)	(808.9)	(808.9)
Aboveground							
Biomass	(360.0)	(287.0)	(447.9)	(447.9)	(447.9)	(447.9)	(447.9)
Belowground							
Biomass	(70.9)	(57.5)	(88.4)	(88.4)	(88.4)	(88.4)	(88.4)
Dead Wood	(31.6)	(12.9)	(30.8)	(33.5)	(33.5)	(33.5)	(33.5)
Litter	(32.2)	27.5	(41.9)	(41.9)	(41.9)	(41.9)	(41.9)
Soil Organic							
Carbon	(54.7)	64.6	(197.2)	(197.2)	(197.2)	(197.2)	(197.2)
Harvested Wood	(131.8)	(112.9)	(105.4)	(108.6)	(103.0)	(82.1)	(54.3)
Products in Use	(64.8)	(47.0)	(45.4)	(45.1)	(39.1)	(19.1)	6.8
SWDS	(67.0)	(65.9)	(59.9)	(63.4)	(63.8)	(63.0)	(61.1)
Total Net Flux	(681.1)	(378.3)	(911.5)	(917.5)	(911.9)	(891.0)	(863.1)

Note: Forest C stocks do not include forest stocks in U.S. territories, Hawaii, a portion of managed forests in Alaska, or trees on non-forest land (e.g., urban trees, agroforestry systems). Parentheses indicate net C sequestration (i.e., a net removal of C from the atmosphere). Total net flux is an estimate of the actual net flux between the total forest C pool and the atmosphere. Forest area estimates are based on interpolation and extrapolation of inventory data as described in the text and in Annex 3.12. Harvested wood estimates are based on results from annual surveys and models. Totals may not sum due to independent rounding.

Table 7-7: Net Annual Changes in C Stocks (Tg C/yr) in Forest and Harvested Wood Pools

Carbon Pool	1990	2000	2005	2006	2007	2008	2009
Forest	(149.8)	(72.4)	(219.9)	(220.6)	(220.6)	(220.6)	(220.6)
Aboveground							
Biomass	(98.2)	(78.3)	(122.1)	(122.1)	(122.1)	(122.1)	(122.1)
Belowground							
Biomass	(19.3)	(15.7)	(24.1)	(24.1)	(24.1)	(24.1)	(24.1)
Dead Wood	(8.6)	(3.5)	(8.4)	(9.1)	(9.1)	(9.1)	(9.1)

Litter	(8.8)	7.5	(11.4)	(11.4)	(11.4)	(11.4)	(11.4)
Soil Organic C	(14.9)	17.6	(53.8)	(53.8)	(53.8)	(53.8)	(53.8)
Harvested Wood	(35.9)	(30.8)	(28.7)	(29.6)	(28.1)	(22.4)	(14.8)
Products in Use	(17.7)	(12.8)	(12.4)	(12.3)	(10.7)	(5.2)	1.9
SWDS	(18.3)	(18.0)	(16.3)	(17.3)	(17.4)	(17.2)	(16.7)
Total Net Flux	(185.7)	(103.2)	(248.6)	(250.2)	(248.7)	(243.0)	(235.4)

Note: Forest C stocks do not include forest stocks in U.S. territories, Hawaii, a portion of managed lands in Alaska, or trees on non-forest land (e.g., urban trees, agroforestry systems). Parentheses indicate net C sequestration (i.e., a net removal of C from the atmosphere). Total net flux is an estimate of the actual net flux between the total forest C pool and the atmosphere. Harvested wood estimates are based on results from annual surveys and models. Totals may not sum due to independent rounding.

Stock estimates for forest and harvested wood C storage pools are presented in Table 7-8. Together, the aboveground live and forest soil pools account for a large proportion of total forest C stocks. C stocks in all non-soil pools increased over time. Therefore, C sequestration was greater than C emissions from forests, as discussed above. Figure 7-4 shows county-average C densities for live trees on forest land, including both above- and belowground biomass.

Table 7-8: Forest area (1000 ha) and C Stocks (Tg C) in Forest and Harvested Wood Pools

	1990	2000	2005	2006	2007	2008	2009	2010
Forest Area (1000 ha)	269,137	274,183	276,769	277,561	278,354	279,147	279,939	280,732
Carbon Pools (Tg C)								
Forest	42,783	44,108	44,886	45,105	45,326	45,547	45,767	45,988
Aboveground								
Biomass	15,072	16,024	16,536	16,658	16,780	16,902	17,024	17,147
Belowground								
Biomass	2,995	3,183	3,285	3,309	3,333	3,357	3,381	3,405
Dead Wood	2,960	3,031	3,060	3,068	3,077	3,086	3,096	3,105
Litter	4,791	4,845	4,862	4,873	4,885	4,896	4,908	4,919
Soil Organic C	16,96	17,025	17,143	17,197	17,251	17,304	17,358	17,412
Harvested								
Wood	1,859	2,187	2,325	2,354	2,383	2,412	2,434	2,449
Products in Use	1,231	1,382	1,436	1,448	1,460	1,471	1,476	1,474
SWDS	628	805	890	906	923	941	958	974
Total C Stock	44,643	46,296	47,211	47,459	47,710	47,958	48,201	48,437

Note: Forest area estimates include portions of managed forests in Alaska for which survey data are available. Forest C stocks do not include forest stocks in U.S. territories, Hawaii, a large portion of Alaska, or trees on non-forest land (e.g., urban trees, agroforestry systems). Wood product stocks include exports, even if the logs are processed in other countries, and exclude imports. Forest area estimates are based on interpolation and extrapolation of inventory data as described in Smith et al. (2010) and in Annex 3.12. Harvested wood estimates are based on results from annual surveys and models. Totals may not sum due to independent rounding. Inventories are assumed to represent stocks as of January 1 of the inventory year. Flux is the net annual change in stock. Thus, an estimate of flux for 2006 requires estimates of C stocks for 2006 and 2007.

Figure 7-3: Estimates of Net Annual Changes in C Stocks for Major C Pools

Figure 7-4: Average C Density in the Forest Tree Pool in the Conterminous United States, 2009

[BEGIN BOX]

Box 7-2: CO₂ Emissions from Forest Fires

As stated previously, the forest inventory approach implicitly accounts for emissions due to disturbances such as forest fires, because only C remaining in the forest is estimated. Net C stock change is estimated by subtracting consecutive C stock estimates. A disturbance removes C from the forest. The inventory data on which net C stock estimates are based already reflect this C loss. Therefore, estimates of net annual changes in C stocks for U.S. forestland already account for CO₂ emissions from forest fires occurring in the lower 48 states as well as in the proportion of Alaska's managed forest land captured in this inventory. Because it is of interest to quantify the magnitude of CO₂ emissions from fire disturbance, these estimates are being highlighted here, using the full extent of available data. Non-CO₂ greenhouse gas emissions from forest fires are also quantified in a separate section below.

The IPCC (2003) methodology and IPCC (2006) default combustion factor for wildfire were employed to estimate CO₂ emissions from forest fires. CO₂ emissions from wildfires and prescribed fires in the lower 48 states and wildfires in Alaska in 2009 were estimated to be 124.3 Tg CO₂/yr. This amount is masked in the estimate of net annual forest carbon stock change for 2009, however, because this net estimate accounts for the amount sequestered minus any emissions.

Table 7-9: Estimates of CO₂ (Tg/yr) emissions for the lower 48 states and Alaska¹

Year	CO₂ emitted from Wildfires in Lower 48 States (Tg/yr)	CO₂ emitted from Prescribed Fires in Lower 48 States (Tg/yr)	CO₂ emitted from Wildfires in Alaska (Tg/yr)	Total CO₂ emitted (Tg/yr)
1990	42.1	8.5	+	50.7
2000	225.1	2.1	+	227.3
2005	131.0	24.8	+	155.9
2006	313.6	29.3	+	342.9
2007	284.1	34.0	+	318.1
2008	169.0	20.8	+	189.8
2009	97.1	27.3	+	124.3

+ Does not exceed 0.05 Tg CO₂ Eq.

¹ Note that these emissions have already been accounted for in the estimates of net annual changes in C stocks, which account for the amount sequestered minus any emissions.

[END BOX]

Methodology and Data Sources

The methodology described herein is consistent with IPCC (2003, 2006) and IPCC/UNEP/OECD/IEA (1997). Forest ecosystem C stocks and net annual C stock change are determined according to stock-difference methods, which involve applying C estimation factors to forest inventory data and interpolating between successive inventory-based estimates of C stocks. Harvested wood C estimates are based on factors such as the allocation of wood to various primary and end-use products as well as half-life (the time at which half of amount placed in use will have been discarded from use) and expected disposition (e.g., product pool, SWDS, combustion). An overview of the different methodologies and data sources used to estimate the C in forest ecosystems or harvested wood products is provided here. See Annex 3.12 for details and additional information related to the methods and data.

Forest Ecosystem Carbon from Forest Inventory

Forest ecosystem stock and flux estimates are based on the stock-difference method and calculations for all estimates are in units of C. Separate estimates are made for the five IPCC C storage pools described above. All estimates are based on data collected from the extensive array of permanent forest inventory plots in the United States as well as models employed to fill gaps in field data. Carbon conversion factors are applied at the disaggregated level of each inventory plot and then appropriately expanded to population estimates. A combination

of tiers as outlined by IPCC (2006) is used. The Tier 3 biomass C values are from forest inventory tree-level data. The Tier 2 dead organic and soil C pools are based on empirical or process models from the inventory data. All carbon conversion factors are specific to regions or individual states within the U.S., which are further classified according to characteristic forest types within each region.

The first step in developing forest ecosystem estimates is to identify useful inventory data and resolve any inconsistencies among datasets. Forest inventory data were obtained from the USDA Forest Service FIA program (Frayner and Furnival 1999, USDA Forest Service 2010b). Inventories include data collected on permanent inventory plots on forest lands¹⁷⁷ and are organized as a number of separate datasets, each representing a complete inventory, or survey, of an individual state at a specified time. Some of the more recent annual inventories reported for some states include “moving window” averages, which means that a portion—but not all—of the previous year’s inventory is updated each year (USDA Forest Service 2010d). Forest C calculations are organized according to these state surveys, and the frequency of surveys varies by state. All available data sets are identified for each state starting with pre-1990 data, and all unique surveys are identified for stock and change calculations. Since C stock change is based on differences between successive surveys within each state, accurate estimates of net C flux thus depend on consistent representation of forest land between these successive inventories. In order to achieve this consistency from 1990 to the present, states are sometimes subdivided into sub-state areas where the sum of sub-state inventories produces the best whole-state representation of C change as discussed in Smith et al. (2010).

The principal FIA datasets employed are freely available for download at USDA Forest Service (2010b) as the Forest Inventory and Analysis Database (FIADB) Version 4.0. However, to achieve consistent representation (spatial and temporal), two other general sources of past FIA data are included as necessary. First, older FIA plot- and tree-level data—not in the current FIADB format—are used if available. Second, Resources Planning Act Assessment (RPA) databases, which are periodic, plot-level only, summaries of state inventories, are used mostly to provide the data at or before 1990. An additional forest inventory data source is the Integrated Database (IDB), which is a compilation of periodic forest inventory data from the 1990s for California, Oregon, and Washington (Waddell and Hiserote 2005). These data were identified by Heath et al. (submitted) as the most appropriate non-FIADB sources for these states and are included in this inventory. See USDA Forest Service (2010a) for information on current and older data as well as additional FIA Program features. A detailed list of the specific forest inventory data used in this inventory is in Annex 3.12.

Forest C stocks are estimated from inventory data by a collection of conversion factors and models (Birdsey and Heath 1995, Birdsey and Heath 2001, Heath et al. 2003, Smith et al. 2004, Smith et al. 2006), which have been formalized in an FIADB-to-carbon calculator (Smith et al. 2010). The conversion factors and model coefficients are categorized by region and forest type, and forest C stock estimates are calculated from application of these factors at the scale of FIA inventory plots. The results are estimates of C density (Mg C per hectare) for six forest ecosystem pools: live trees, standing dead trees, understory vegetation, down dead wood, forest floor, and soil organic matter. The six carbon pools used in the FIADB-to-carbon calculator are aggregated to the 5 carbon pools defined by IPCC (2006): aboveground biomass, belowground biomass, dead wood, litter, and soil organic matter. All non-soil pools except forest floor are separated into aboveground and belowground components. The live tree and understory C pools are pooled as biomass, and standing dead trees and down dead wood are pooled as dead wood, in accordance with IPCC (2006).

Once plot-level C stocks are calculated as C densities on *Forest Land Remaining Forest Land* for the five IPCC (2006) reporting pools, the stocks are expanded to population estimates according to methods appropriate to the respective inventory data (for example, see Bechtold and Patterson (2005)). These expanded C stock estimates are summed to state or sub-state total C stocks. Annualized estimates of C stocks are developed by using available FIA inventory data and interpolating or extrapolating to assign a C stock to each year in the 1990 through 2010 time series. Flux, or net annual stock change, is estimated by calculating the difference between two successive years and applying the appropriate sign convention; net increases in ecosystem C are identified as negative flux. By convention, inventories are assigned to represent stocks as of January 1 of the inventory year; an estimate of flux for 1996 requires estimates of C stocks for 1996 and 1997, for example. Additional discussion of the use of FIA inventory data and the C conversion process is in Annex 3.12.

¹⁷⁷ Forest land in the United States includes land that is at least 10 percent stocked with trees of any size. Timberland is the most productive type of forest land, which is on unreserved land and is producing or capable of producing crops of industrial wood.

Carbon in Biomass

Live tree C pools include aboveground and belowground (coarse root) biomass of live trees with diameter at diameter breast height (d.b.h.) of at least 2.54 cm at 1.37 m above the forest floor. Separate estimates are made for full-tree and aboveground-only biomass in order to estimate the belowground component. If inventory plots include data on individual trees, tree C is based on Jenkins et al. (2003) and is a function of species and diameter. Some inventory data do not provide measurements of individual trees; tree C in these plots is estimated from plot-level volume of merchantable wood, or growing-stock volume, of live trees, which is calculated from updates of Smith et al. (2003). These biomass conversion and expansion factors (BCEFs) are applied to about 3 percent of the inventory records, all of which are pre-1998 data. Some inventory data, particularly some of the older datasets, may not include sufficient information to calculate tree C because of incomplete or missing tree or volume data; C estimates for these plots are based on averages from similar, but more complete, inventory data. This applies to an additional 2 percent of inventory records, which represent older (pre-1998) non-timberlands.

Understory vegetation is a minor component of biomass, which is defined as all biomass of undergrowth plants in a forest, including woody shrubs and trees less than 2.54 cm d.b.h. In the current inventory, it is assumed that 10 percent of total understory C mass is belowground. Estimates of C density are based on information in Birdsey (1996). Understory frequently represents over 1 percent of C in biomass, but its contribution rarely exceeds 2 percent of the total.

Carbon in Dead Organic Matter

Dead organic matter is initially calculated as three separate pools with C stocks modeled from inventory data. Estimates are specific to regions and forest types within each region, and stratification of forest land for dead organic matter calculations is identical to that used for biomass through the state and sub-state use of FIA data as discussed above. The two components of dead wood—standing dead trees and down dead wood—are estimated separately. The standing dead tree C pools include aboveground and belowground (coarse root) mass and include trees of at least 2.54 cm d.b.h. Calculations are BCEF-like factors based on updates of Smith et al. (2003). Down dead wood is defined as pieces of dead wood greater than 7.5 cm diameter, at transect intersection, that are not attached to live or standing dead trees. Down dead wood includes stumps and roots of harvested trees. Ratios of down dead wood to live tree are used to estimate this quantity. Litter C is the pool of organic C (also known as duff, humus, and fine woody debris) above the mineral soil and includes woody fragments with diameters of up to 7.5 cm. Estimates are based on equations of Smith and Heath (2002).

Carbon in Forest Soil

Soil organic C (SOC) includes all organic material in soil to a depth of 1 meter but excludes the coarse roots of the biomass or dead wood pools. Estimates of SOC are based on the national STATSGO spatial database (USDA 1991), which includes region and soil type information. SOC determination is based on the general approach described by Amichev and Galbraith (2004). Links to FIA inventory data were developed with the assistance of the USDA Forest Service FIA Geospatial Service Center by overlaying FIA forest inventory plots on the soil C map. This method produced mean SOC densities stratified by region and forest type group. It did not provide separate estimates for mineral or organic soils but instead weighted their contribution to the overall average based on the relative amount of each within forest land. Thus, forest SOC is a function of species and location, and net change also depends on these two factors as total forest area changes. In this respect, SOC provides a country-specific reference stock for 1990-present, but it does not reflect effects of past land use.

Harvested Wood Carbon

Estimates of the HWP contribution to forest C sinks and emissions (hereafter called “HWP Contribution”) are based on methods described in Skog (2008) using the WOODCARB II model. These methods are based on IPCC (2006) guidance for estimating HWP C. IPCC (2006) provides methods that allow Parties to report HWP Contribution using one of several different accounting approaches: production, stock change and atmospheric flow, as well as a default method that assumes there is no change in HWP C stocks (see Annex 3.12 for more details about each approach). The United States uses the production accounting approach to report HWP Contribution. Under the production approach, C in exported wood is estimated as if it remains in the United States, and C in imported wood is not included in inventory estimates. Though reported U.S. HWP estimates are based on the production approach, estimates resulting from use of the two alternative approaches, the stock change and atmospheric flow approaches,

are also presented for comparison (see Annex 3.12). Annual estimates of change are calculated by tracking the additions to and removals from the pool of products held in end uses (i.e., products in use such as housing or publications) and the pool of products held in solid waste disposal sites (SWDS).

Solidwood products added to pools include lumber and panels. End-use categories for solidwood include single and multifamily housing, alteration and repair of housing, and other end-uses. There is one product category and one end-use category for paper. Additions to and removals from pools are tracked beginning in 1900, with the exception that additions of softwood lumber to housing begins in 1800. Solidwood and paper product production and trade data are from USDA Forest Service and other sources (Hair and Ulrich 1963; Hair 1958; USDC Bureau of Census; 1976; Ulrich, 1985, 1989; Steer 1948; AF&PA 2006a 2006b; Howard 2003, 2007). Estimates for disposal of products reflect the change over time in the fraction of products discarded to SWDS (as opposed to burning or recycling) and the fraction of SWDS that are in sanitary landfills versus dumps.

There are five annual HWP variables that are used in varying combinations to estimate HWP Contribution using any one of the three main approaches listed above. These are:

- (1A) annual change of C in wood and paper products in use in the United States,
- (1B) annual change of C in wood and paper products in SWDS in the United States,
- (2A) annual change of C in wood and paper products in use in the United States and other countries where the wood came from trees harvested in the United States,
- (2B) annual change of C in wood and paper products in SWDS in the United States and other countries where the wood came from trees harvested in the United States,
- (3) C in imports of wood, pulp, and paper to the United States,
- (4) C in exports of wood, pulp and paper from the United States, and
- (5) C in annual harvest of wood from forests in the United States.

The sum of variables 2A and 2B yields the estimate for HWP Contribution under the production accounting approach. A key assumption for estimating these variables is that products exported from the United States and held in pools in other countries have the same half lives for products in use, the same percentage of discarded products going to SWDS, and the same decay rates in SWDS as they would in the United States.

Uncertainty and Time Series Consistency

A quantitative uncertainty analysis placed bounds on current flux for forest ecosystems as well as C in harvested wood products through Monte Carlo simulation of the Methods described above and probabilistic sampling of C conversion factors and inventory data. See Annex 3.12 for additional information. The 2009 flux estimate for forest C stocks is estimated to be between -1,014 and -714 Tg CO₂ Eq. at a 95 percent confidence level. This includes a range of -662 to -959 Tg CO₂ Eq. in forest ecosystems and -69 to -41 Tg CO₂ Eq. for HWP.

Table 7-10: Tier 2 Quantitative Uncertainty Estimates for Net CO₂ Flux from Forest Land Remaining Forest Land: Changes in Forest C Stocks (Tg CO₂ Eq. and Percent)

Source	Gas	2009 Flux Estimate (Tg CO ₂ Eq.)	Uncertainty Range Relative to Flux Estimate ^a			
			(Tg CO ₂ Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Forest Ecosystem	CO ₂	(808.9)	(959.4)	(661.7)	-19%	-18%
Harvested Wood Products	CO ₂	(54.3)	(68.6)	(41.0)	-27%	-24%
Total Forest	CO₂	(863.1)	(1,014.4)	(713.9)	-18%	-17%

Note: Parentheses indicate negative values or net sequestration.

^aRange of flux 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 2009. Details on the emission trends through time are described in more detail in the Methodology section,

above.

QA/QC and Verification

As discussed above, the FIA program has conducted consistent forest surveys based on extensive statistically-based sampling of most of the forest land in the conterminous United States, dating back to 1952. The main purpose of the FIA program has been to estimate areas, volume of growing stock, and timber products output and utilization factors. The FIA program includes numerous quality assurance and quality control (QA/QC) procedures, including calibration among field crews, duplicate surveys of some plots, and systematic checking of recorded data. Because of the statistically-based sampling, the large number of survey plots, and the quality of the data, the survey databases developed by the FIA program form a strong foundation for C stock estimates. Field sampling protocols, summary data, and detailed inventory databases are archived and are publicly available on the Internet (USDA Forest Service 2010d).

Many key calculations for estimating current forest C stocks based on FIA data were developed to fill data gaps in assessing forest carbon and have been in use for many years to produce national assessments of forest C stocks and stock changes (see additional discussion and citations in the Methodology section above and in Annex 3.12). General quality control procedures were used in performing calculations to estimate C stocks based on survey data. For example, the derived C datasets, which include inventory variables such as areas and volumes, were compared to standard inventory summaries such as the forest resource statistics of Smith et al. (2009) or selected population estimates generated from FIADB 4.0, which are available at an FIA internet site (USDA Forest Service 2009b). Agreement between the C datasets and the original inventories is important to verify accuracy of the data used. Finally, C stock estimates were compared with previous inventory report estimates to ensure that any differences could be explained by either new data or revised calculation methods (see the “Recalculations” discussion, below).

Estimates of the HWP variables and the HWP contribution under the production accounting approach use data from U.S. Census and USDA Forest Service surveys of production and trade. Factors to convert wood and paper to units C are based on estimates by industry and Forest Service published sources. The WOODCARB II model uses estimation methods suggested by IPCC (2006). Estimates of annual C change in solidwood and paper products in use were calibrated to meet two independent criteria. The first criterion is that the WOODCARB II model estimate of C in houses standing in 2001 needs to match an independent estimate of C in housing based on U.S. Census and USDA Forest Service survey data. Meeting the first criterion resulted in an estimated half life of about 80 years for single family housing built in the 1920s, which is confirmed by other U.S. Census data on housing. The second criterion is that the WOODCARB II model estimate of wood and paper being discarded to SWDS needs to match EPA estimates of discards each year over the period 1990 to 2000 (EPA 2006). These criteria help reduce uncertainty in estimates of annual change in C in products in use in the United States and, to a lesser degree, reduce uncertainty in estimates of annual change in C in products made from wood harvested in the United States. In addition, WOODCARB II landfill decay rates have been validated by ensuring that estimates of CH₄ emissions from landfills based on EPA (2006) data are reasonable in comparison with CH₄ estimates based on WOODCARB II landfill decay rates.

Recalculations Discussion

The basic models used to estimate forest ecosystem and HWP C stocks and change are unchanged from the previous Inventory (Smith et al. 2010, Skog 2008). Many of the state-level estimates for 1990 through the present are relatively similar to the values previously reported (EPA 2010). Recent forest inventory additions to the FIADB include newer annual inventory data for most states including Oklahoma, which had the effect of increasing overall net sequestration estimated for the interval from 2000 through 2008. An additional change to the FIADB was the addition of some older periodic inventories for some southern states; these were incorporated into the calculations but did not appreciably affect national trends. The addition of the IDB forest inventories for a part of the series for California, Oregon, and Washington did affect recalculations for those states and the United States as a whole; it tended to decrease net sequestration throughout the 1990 to 2008 interval. However, the decreased sequestration associated with the use of the IDB was offset by the increased sequestration associated with newer annual inventory data for the post-2000 interval.

Planned Improvements

The ongoing annual surveys by the FIA Program will improve precision of forest C estimates as new state surveys

become available (USDA Forest Service 2010b), particularly in western states. The annual surveys will eventually include all states. To date, three states are not yet reporting any data from the annualized sampling design of FIA: Hawaii, New Mexico and Wyoming. Estimates for these states are currently based on older, periodic data. Hawaii and U.S. territories will also be included when appropriate forest C data are available. In addition, the more intensive sampling of down dead wood, litter, and soil organic C on some of the permanent FIA plots continues and will substantially improve resolution of C pools at the plot level for all U.S. forest land as this information becomes available (Woodall et al. in press). Improved resolution, incorporating more of Alaska's forests, and using annualized sampling data as it becomes available for those states currently not reporting are planned for future reporting.

As more information becomes available about historical land use, the ongoing effects of changes in land use and forest management will be better accounted for in estimates of soil C (Birdsey and Lewis 2003, Woodbury et al. 2006, Woodbury et al. 2007). Currently, soil C estimates are based on the assumption that soil C density depends only on broad forest type group, not on land-use history, but long-term residual effects on soil and forest floor C stocks are likely after land-use change. Estimates of such effects depend on identifying past land use changes associated with forest lands.

Similarly, agroforestry practices, such as windbreaks or riparian forest buffers along waterways, are not currently accounted for in the inventory. In order to properly account for the C stocks and fluxes associated with agroforestry, research will be needed that provides the basis and tools for including these plantings in a nation-wide inventory, as well as the means for entity-level reporting.

Non-CO₂ Emissions from Forest Fires

Emissions of non-CO₂ gases from forest fires were estimated using the default IPCC (2003) methodology incorporating default IPCC (2006) emissions factors and combustion factor for wildfires. Emissions from this source in 2009 were estimated to be 7.8 Tg CO₂ Eq. of CH₄ and 6.4 Tg CO₂ Eq. of N₂O, as shown in Table 7-11 and Table 7-12. The estimates of non-CO₂ emissions from forest fires account for wildfires in the lower 48 states and Alaska as well as prescribed fires in the lower 48 states.

Table 7-11: Estimated Non-CO₂ Emissions from Forest Fires (Tg CO₂ Eq.) for U.S. Forests¹

Gas	1990	2000	2005	2006	2007	2008	2009
CH ₄	3.2	14.3	9.8	21.6	20.0	11.9	7.8
N ₂ O	2.6	11.7	8.0	17.6	16.3	9.8	6.4
Total	5.8	26.0	17.8	39.2	36.3	21.7	14.2

¹ Calculated based on C emission estimates in *Changes in Forest Carbon Stocks* and default factors in IPCC (2003, 2006).

Table 7-12: Estimated Non-CO₂ Emissions from Forest Fires (Gg Gas) for U.S. Forests¹

Gas	1990	2000	2005	2006	2007	2008	2009
CH ₄	152	682	467	1,027	953	569	372
N ₂ O	8	38	26	57	53	31	21

¹ Calculated based on C emission estimates in *Changes in Forest Carbon Stocks* and default factors in IPCC (2003, 2006).

Methodology

The IPCC (2003) Tier 2 default methodology was used to calculate non-CO₂ emissions from forest fires. However, more up-to-date default emission factors from IPCC (2006) were converted into gas-specific emission ratios and incorporated into the methodology. Estimates of CH₄ and N₂O emissions were calculated by multiplying the total estimated CO₂ emitted from forest burned by the gas-specific emissions ratios. CO₂ emissions were estimated by multiplying total C emitted (Table 7-13) by the C to CO₂ conversion factor of 44/12 and by 92.8 percent, which is the estimated proportion of C emitted as CO₂ (Smith 2008a). The equations used were:

$$\text{CH}_4 \text{ Emissions} = (\text{C released}) \times 92.8\% \times (44/12) \times (\text{CH}_4 \text{ to CO}_2 \text{ emission ratio})$$

$$\text{N}_2\text{O Emissions} = (\text{C released}) \times 92.8\% \times (44/12) \times (\text{N}_2\text{O to CO}_2 \text{ emission ratio})$$

Estimates for C emitted from forest fires are the same estimates used to generate estimates of CO₂ presented earlier in Box 7-1. Estimates for C emitted include emissions from wildfires in both Alaska and the lower 48 states as well

as emissions from prescribed fires in the lower 48 states only (based on expert judgment that prescribed fires only occur in the lower 48 states) (Smith 2008a). The IPCC (2006) default combustion factor of 0.45 for “all ‘other’ temperate forests” was applied in estimating C emitted from both wildfires and prescribed fires. See the explanation in Annex 3.12 for more details on the methodology used to estimate C emitted from forest fires.

Table 7-13: Estimated Carbon Released from Forest Fires for U.S. Forests

Year	C Emitted (Tg/yr)
1990	14.9
2000	66.8
2005	45.8
2006	100.8
2007	93.5
2008	55.8
2009	36.5

Uncertainty and Time-Series Consistency

Non-CO₂ gases emitted from forest fires depend on several variables, including: forest area for Alaska and the lower 48 states; average C densities for wildfires in Alaska, wildfires in the lower 48 states, and prescribed fires in the lower 48 states; emission ratios; and combustion factor values (proportion of biomass consumed by fire). To quantify the uncertainties for emissions from forest fires, a Monte Carlo (Tier 2) uncertainty analysis was performed using information about the uncertainty surrounding each of these variables. The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 7-14.

Table 7-14: Tier 2 Quantitative Uncertainty Estimates of Non-CO₂ Emissions from Forest Fires in Forest Land Remaining Forest Land (Tg CO₂ Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate			
			(Tg CO ₂ Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Non-CO ₂ Emissions from Forest Fires	CH ₄	7.8	2.2	19.2	-72%	+145%
Non-CO ₂ Emissions from Forest Fires	N ₂ O	6.4	1.8	15.7	-72%	+145%

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

QA/QC and Verification

Tier 1 and Tier 2 QA/QC activities were conducted consistent with the U.S. QA/QC plan. Source-specific quality control measures for forest fires 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

This is the second year in which non-CO₂ emissions were calculated using the 2006 IPCC default emission factors for CH₄ and N₂O instead of the 2003 IPCC default emission factors. These default emission factors were converted to CH₄ to CO₂ and N₂O to CO₂ emission ratios and then multiplied by CO₂ emissions to estimate CH₄ and N₂O emissions. The previous 2003 IPCC methodology provides emission ratios that are multiplied by total carbon emitted.

Planned Improvements

The default combustion factor of 0.45 from IPCC (2006) was applied in estimating C emitted from both wildfires and prescribed fires. Additional research into the availability of a combustion factor specific to prescribed fires is

being conducted.

Direct N₂O Fluxes from Forest Soils (IPCC Source Category 5A1)

Of the synthetic N fertilizers applied to soils in the United States, no more than one percent is applied to forest soils. Application rates are similar to those occurring on cropped soils, but in any given year, only a small proportion of total forested land receives N fertilizer. This is because forests are typically fertilized only twice during their approximately 40-year growth cycle (once at planting and once approximately 20 years later). Thus, while the rate of N fertilizer application for the area of forests that receives N fertilizer in any given year is relatively high, the average annual application is quite low as inferred by dividing all forest land that may undergo N fertilization at some point during its growing cycle by the amount of N fertilizer added to these forests in a given year. Direct N₂O emissions from forest soils in 2009 were 0.4 Tg CO₂ Eq. (1 Gg). Emissions have increased by 455 percent from 1990 to 2009 as a result of an increase in the area of N fertilized pine plantations in the southeastern United States and Douglas-fir timberland in western Washington and Oregon. Total forest soil N₂O emissions are summarized in Table 7-15.

Table 7-15: Direct N₂O Fluxes from Soils in *Forest Land Remaining Forest Land* (Tg CO₂ Eq. and Gg N₂O)

Year	Tg CO ₂ Eq.	Gg
1990	0.1	0.2
2000	0.4	1.3
2005	0.4	1.2
2006	0.4	1.2
2007	0.4	1.2
2008	0.4	1.2
2009	0.4	1.2

Note: These estimates include direct N₂O emissions from N fertilizer additions only. Indirect N₂O emissions from fertilizer additions are reported in the Agriculture chapter. These estimates include emissions from both *Forest Land Remaining Forest Land* and from *Land Converted to Forest Land*.

Methodology

The IPCC Tier 1 approach was used to estimate N₂O from soils within *Forest Land Remaining Forest Land*. According to U.S. Forest Service statistics for 1996 (USDA Forest Service 2001), approximately 75 percent of trees planted were for timber, and about 60 percent of national total harvested forest area is in the southeastern United States. Although southeastern pine plantations represent the majority of fertilized forests in the United States, this Inventory also accounted for N fertilizer application to commercial Douglas-fir stands in western Oregon and Washington. For the Southeast, estimates of direct N₂O emissions from fertilizer applications to forests were based on the area of pine plantations receiving fertilizer in the southeastern United States and estimated application rates (Albaugh et al. 2007). Not accounting for fertilizer applied to non-pine plantations is justified because fertilization is routine for pine forests but rare for hardwoods (Binkley et al. 1995). For each year, the area of pine receiving N fertilizer was multiplied by the weighted average of the reported range of N fertilization rates (121 lbs. N per acre). Area data for pine plantations receiving fertilizer in the Southeast were not available for 2005, 2006, 2007 and 2008, so data from 2004 were used for these years. For commercial forests in Oregon and Washington, only fertilizer applied to Douglas-fir was accounted for, because the vast majority (~95 percent) of the total fertilizer applied to forests in this region is applied to Douglas-fir (Briggs 2007). Estimates of total Douglas-fir area and the portion of fertilized area were multiplied to obtain annual area estimates of fertilized Douglas-fir stands. The annual area estimates were multiplied by the typical rate used in this region (200 lbs. N per acre) to estimate total N applied (Briggs 2007), and the total N applied to forests was multiplied by the IPCC (2006) default emission factor of 1 percent to estimate direct N₂O emissions. The volatilization and leaching/runoff N fractions for forest land, calculated according to the IPCC default factors of 10 percent and 30 percent, respectively, were included with the indirect emissions in the Agricultural Soil Management source category (consistent with reporting guidance that all indirect emissions are included in the Agricultural Soil Management source category).

Uncertainty and Time-Series Consistency

The amount of N₂O emitted from forests depends not only on N inputs and fertilized area, but also on a large number of variables, including organic C availability, oxygen gas partial pressure, soil moisture content, pH, temperature, and tree planting/harvesting cycles. The effect of the combined interaction of these variables on N₂O flux is complex and highly uncertain. IPCC (2006) does not incorporate any of these variables into the default methodology, except variation in estimated fertilizer application rates and estimated areas of forested land receiving N fertilizer. All forest soils are treated equivalently under this methodology. Furthermore, only synthetic N fertilizers are captured, so applications of organic N fertilizers are not estimated. However, the total quantity of organic N inputs to soils is included in the Agricultural Soil Management and *Settlements Remaining Settlements* sections.

Uncertainties exist in the fertilization rates, annual area of forest lands receiving fertilizer, and the emission factors. Fertilization rates were assigned a default level¹⁷⁸ of uncertainty at ±50 percent, and area receiving fertilizer was assigned a ±20 percent according to expert knowledge (Binkley 2004). IPCC (2006) provided estimates for the uncertainty associated with direct N₂O emission factor for synthetic N fertilizer application to soils. Quantitative uncertainty of this source category was estimated through the IPCC-recommended Tier 2 uncertainty estimation methodology. The uncertainty ranges around the 2005 activity data and emission factor input variables were directly applied to the 2009 emissions estimates. The results of the quantitative uncertainty analysis are summarized in Table 7-16. N₂O fluxes from soils were estimated to be between 0.1 and 1.1 Tg CO₂ Eq. at a 95 percent confidence level. This indicates a range of 59 percent below and 211 percent above the 2009 emission estimate of 0.4 Tg CO₂ Eq.

Table 7-16: Quantitative Uncertainty Estimates of N₂O Fluxes from Soils in *Forest Land Remaining Forest Land* (Tg CO₂ Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate			
			(Tg CO ₂ Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Forest Land Remaining Forest Land:						
N ₂ O Fluxes from Soils	N ₂ O	0.4	0.1	1.1	-59%	+211%

Note: This estimate includes direct N₂O emissions from N fertilizer additions to both *Forest Land Remaining Forest Land* and *Land Converted to Forest Land*.

Planned Improvements

State-level area data will be acquired for southeastern pine plantations and northwestern Douglas-fir forests receiving fertilizer to estimate soil N₂O emission by state and provide information about regional variation in emission patterns.

7.3. Land Converted to Forest Land (IPCC Source Category 5A2)

Land-use change is constantly occurring, and areas under a number of differing land-use types are converted to forest each year, just as forest land is converted to other uses. However, the magnitude of these changes is not currently known. Given the paucity of available land-use information relevant to this particular IPCC source category, it is not possible to separate CO₂ or N₂O fluxes on *Land Converted to Forest Land* from fluxes on *Forest Land Remaining Forest Land* at this time.

7.4. Cropland Remaining Cropland (IPCC Source Category 5B1)

Mineral and Organic Soil Carbon Stock Changes

Soils contain both organic and inorganic forms of C, but soil organic C (SOC) stocks are the main source and sink for atmospheric CO₂ in most soils. Changes in inorganic C stocks are typically minor. In addition, soil organic C is

¹⁷⁸ Uncertainty is unknown for the fertilization rates so a conservative value of ±50% was used in the analysis.

the dominant organic C pool in cropland ecosystems, because biomass and dead organic matter have considerably less C and those pools are relatively ephemeral. IPCC (2006) recommends reporting changes in soil organic C stocks due to agricultural land-use and management activities on mineral and organic soils.¹⁷⁹

Typical well-drained mineral soils contain from 1 to 6 percent organic C by weight, although mineral soils that are saturated with water for substantial periods during the year may contain significantly more C (NRCS 1999). Conversion of mineral soils from their native state to agricultural uses can cause as much as half of the SOC to be decomposed and the C lost to the atmosphere. The rate and ultimate magnitude of C loss will depend on pre-conversion conditions, conversion method and subsequent management practices, climate, and soil type. In the tropics, 40 to 60 percent of the C loss generally occurs within the first 10 years following conversion; C stocks continue to decline in subsequent decades but at a much slower rate. In temperate regions, C loss can continue for several decades, reducing stocks by 20 to 40 percent of native C levels. Eventually, the soil can reach a new equilibrium that reflects a balance between C inputs (e.g., decayed plant matter, roots, and organic amendments such as manure and crop residues) and C loss through microbial decomposition of organic matter. However, land use, management, and other conditions may change before the new equilibrium is reached. The quantity and quality of organic matter inputs and their rate of decomposition are determined by the combined interaction of climate, soil properties, and land use. Land use and agricultural practices such as clearing, drainage, tillage, planting, grazing, crop residue management, fertilization, and flooding can modify both organic matter inputs and decomposition, and thereby result in a net flux of C to or from the pool of soil C.

Organic soils, also referred to as histosols, include all soils with more than 12 to 20 percent organic C by weight, depending on clay content (NRCS 1999, Brady and Weil 1999). The organic layer of these soils can be very deep (i.e., several meters), forming under inundated conditions in which minimal decomposition of plant residue occurs. When organic soils are prepared for crop production, they are drained and tilled, leading to aeration of the soil, which accelerates the rate of decomposition and CO₂ emissions. Because of the depth and richness of the organic layers, C loss from drained organic soils can continue over long periods of time. The rate of CO₂ emissions varies depending on climate and composition (i.e., decomposability) of the organic matter. Also, the use of organic soils for annual crop production leads to higher C loss rates than drainage of organic soils in grassland or forests, due to deeper drainage and more intensive management practices in cropland (Armentano and Verhoeven 1990, as cited in IPCC/UNEP/OECD/IEA 1997). Carbon losses are estimated from drained organic soils under both grassland and cropland management in this Inventory.

Cropland Remaining Cropland includes all cropland in an inventory year that had been cropland for the last 20 years¹⁸⁰ according to the USDA NRI land-use survey (USDA-NRCS 2000). The Inventory includes all privately-owned croplands in the conterminous United States and Hawaii, but there is a minor amount of cropland on federal lands that is not currently included in the estimation of C stock changes, leading to a discrepancy between the total amount of managed area in *Cropland Remaining Cropland* (see Section 7.1) and the cropland area included in the Inventory. It is important to note that plans are being made to include federal croplands in future C inventories.

The area of *Cropland Remaining Cropland* changes through time as land is converted to or from cropland management. CO₂ emissions and removals¹⁸¹ due to changes in mineral soil C stocks are estimated using a Tier 3 approach for the majority of annual crops. A Tier 2 IPCC method is used for the remaining crops (vegetables, tobacco, perennial/horticultural crops, and rice) not included in the Tier 3 method. In addition, a Tier 2 method is used for very gravelly, cobbly, or shaley soils (i.e., classified as soils that have greater than 35 percent of soil volume comprised of gravel, cobbles, or shale) and for additional changes in mineral soil C stocks that were not addressed with the Tier 3 approach (i.e., change in C stocks after 2003 due to Conservation Reserve Program enrollment). Emissions from organic soils are estimated using a Tier 2 IPCC method.

Of the two sub-source categories, land-use and land management of mineral soils was the most important component of total net C stock change between 1990 and 2009 (see Table 7-17 and Table 7-18). In 2009, mineral soils were estimated to remove 45.1 Tg CO₂ Eq. (12.3 Tg C). This rate of C storage in mineral soils represented about a 20 percent decrease in the rate since the initial reporting year of 1990. Emissions from organic soils were

¹⁷⁹ CO₂ emissions associated with liming are also estimated but are included in a separate section of the report.

¹⁸⁰ NRI points were classified according to land-use history records starting in 1982 when the NRI survey began, and consequently the classifications were based on less than 20 years from 1990 to 2001.

¹⁸¹ Note that removals occur through crop and forage uptake of CO₂ into biomass C that is later incorporated into soil pools.

27.7 Tg CO₂ Eq. (7.5 Tg C) in 2009. In total, U.S. agricultural soils in *Cropland Remaining Cropland* removed approximately 17.4 Tg CO₂ Eq. (4.7 Tg C) in 2009.

Table 7-17: Net CO₂ Flux from Soil C Stock Changes in *Cropland Remaining Cropland* (Tg CO₂ Eq.)

Soil Type	1990	2000	2005	2006	2007	2008	2009
Mineral Soils	(56.8)	(57.9)	(45.9)	(46.8)	(47.3)	(45.7)	(45.1)
Organic Soils	27.4	27.7	27.7	27.7	27.7	27.7	27.7
Total Net Flux	(29.4)	(30.2)	(18.3)	(19.1)	(19.7)	(18.1)	(17.4)

Note: Parentheses indicate net sequestration. Shaded areas indicate values based on a combination of historical data and projections. All other values are based on historical data only. Totals may not sum due to independent rounding.

Table 7-18: Net CO₂ Flux from Soil C Stock Changes in *Cropland Remaining Cropland* (Tg C)

Soil Type	1990	2000	2005	2006	2007	2008	2009
Mineral Soils	(15.5)	(15.8)	(12.5)	(12.8)	(12.9)	(12.5)	(12.3)
Organic Soils	7.5	7.5	7.5	7.5	7.5	7.5	7.5
Total Net Flux	(8.0)	(8.2)	(5.0)	(5.2)	(5.4)	(4.9)	(4.7)

Note: Parentheses indicate net sequestration. Shaded areas indicate values based on a combination of historical data and projections. All other values are based on historical data only. Totals may not sum due to independent rounding.

The net reduction in soil C accumulation over the time series (39 percent from 1990 to 2009) was largely due to the declining influence of annual cropland enrolled in the Conservation Reserve Program, which began in the late 1980s. However, there were still positive increases in C stocks from land enrolled in the reserve program, as well as intensification of crop production by limiting the use of bare-summer fallow in semi-arid regions, increased hay production, and adoption of conservation tillage (i.e., reduced- and no-till practices).

The spatial variability in annual CO₂ flux associated with C stock changes in mineral and organic soils is displayed in Figure 7-5 and Figure 7-6. The highest rates of net C accumulation in mineral soils occurred in the Midwest, which is the area with the largest amounts of cropland managed with conservation tillage. Rates were also high in the Great Plains due to enrollment in the Conservation Reserve Program. Emission rates from drained organic soils were highest along the southeastern coastal region, in the northeast central United States surrounding the Great Lakes, and along the central and northern portions of the West Coast.

Figure 7-5: Total Net Annual CO₂ Flux for Mineral Soils under Agricultural Management within States, 2009, *Cropland Remaining Cropland*

Figure 7-6: Total Net Annual CO₂ Flux for Organic Soils under Agricultural Management within States, 2009, *Cropland Remaining Cropland*

Methodology

The following section includes a description of the methodology used to estimate changes in soil C stocks due to: (1) agricultural land-use and management activities on mineral soils; and (2) agricultural land-use and management activities on organic soils for *Cropland Remaining Cropland*.

Soil C stock changes were estimated for *Cropland Remaining Cropland* (as well as agricultural land falling into the IPCC categories *Land Converted to Cropland*, *Grassland Remaining Grassland*, and *Land Converted to Grassland*) according to land-use histories recorded in the USDA National Resources Inventory (NRI) survey (USDA-NRCS 2000). The NRI is a statistically-based sample of all non-federal land, and includes approximately 260,000 points in agricultural land for the conterminous United States and Hawaii.¹⁸² Each point is associated with an “expansion factor” that allows scaling of C stock changes from NRI points to the entire country (i.e., each expansion factor represents the amount of area with the same land-use/management history as the sample point). Land-use and some

¹⁸² NRI points were classified as agricultural if under grassland or cropland management between 1990 and 2003.

management information (e.g., crop type, soil attributes, and irrigation) were originally collected for each NRI point on a 5-year cycle beginning in 1982. For cropland, data were collected for 4 out of 5 years in the cycle (i.e., 1979-1982, 1984-1987, 1989-1992, and 1994-1997). However, the NRI program began collecting annual data in 1998, and data are currently available through 2003. NRI points were classified as *Cropland Remaining Cropland* in a given year between 1990 and 2009 if the land use had been cropland for 20 years.¹⁸³ Cropland includes all land used to produce food and fiber, or forage that is harvested and used as feed (e.g., hay and silage).

Mineral Soil Carbon Stock Changes

An IPCC Tier 3 model-based approach was applied to estimate C stock changes for mineral soils used to produce a majority of annual crops in the United States (Ogle et al. 2010). The remaining crops on mineral soils were estimated using an IPCC Tier 2 method (Ogle et al. 2003), including vegetables, tobacco, perennial/horticultural crops, rice, and crops rotated with these crops. The Tier 2 method was also used for very gravelly, cobbly, or shaley soils (greater than 35 percent by volume). Mineral SOC stocks were estimated using a Tier 2 method for these areas because the Century model, which is used for the Tier 3 method, has not been fully tested to address its adequacy for estimating C stock changes associated with certain crops and rotations, as well as cobbly, gravelly, or shaley soils. An additional stock change calculation was made for mineral soils using Tier 2 emission factors, accounting for enrollment patterns in the Conservation Reserve Program after 2003, which was not addressed by the Tier 3 methods.

Further elaboration on the methodology and data used to estimate stock changes from mineral soils are described below and in Annex 3.13.

Tier 3 Approach

Mineral SOC stocks and stock changes were estimated using the Century biogeochemical model (Parton et al. 1987, 1988, 1994; Metherell et al. 1993), which simulates the dynamics of C and other elements in cropland, grassland, forest, and savanna ecosystems. It uses monthly weather data as an input, along with information about soil physical properties. Input data on land use and management are specified at monthly resolution and include land-use type, crop/forage type, and management activities (e.g., planting, harvesting, fertilization, manure amendments, tillage, irrigation, residue removal, grazing, and fire). The model computes net primary productivity and C additions to soil, soil temperature, and water dynamics, in addition to turnover, stabilization, and mineralization of soil organic matter C and nutrient (N, K, S) elements. This method is more accurate than the Tier 1 and 2 approaches provided by the IPCC, because the simulation model treats changes as continuous over time rather than the simplified discrete changes represented in the default method (see Box 7-3 for additional information). National estimates were obtained by simulating historical land-use and management patterns as recorded in the USDA National Resources Inventory (NRI) survey.

[BEGIN BOX]

Box 7-3: Tier 3 Approach for Soil C Stocks Compared to Tier 1 or 2 Approaches

A Tier 3 model-based approach is used to inventory soil C stock changes on the majority of agricultural land with mineral soils. This approach entails several fundamental differences compared to the IPCC Tier 1 or 2 methods, which are based on a classification of land areas into a number of discrete classes based on a highly aggregated classification of climate, soil, and management (i.e., only six climate regions, seven soil types and eleven management systems occur in U.S. agricultural land under the IPCC classification). Input variables to the Tier 3 model, including climate, soils, and management activities (e.g., fertilization, crop species, tillage, etc.), are represented in considerably more detail both temporally and spatially, and exhibit multi-dimensional interactions through the more complex model structure compared with the IPCC Tier 1 or 2 approach. The spatial resolution of

¹⁸³ NRI points were classified according to land-use history records starting in 1982 when the NRI survey began. Therefore, the classification prior to 2002 was based on less than 20 years of recorded land-use history for the time series.

the analysis is also finer in the Tier 3 method compared to the lower tier methods as implemented in the United States for previous Inventories (e.g., 3,037 counties versus 181 Major Land Resource Areas (MLRAs), respectively).

In the Century model, soil C dynamics (and CO₂ emissions and uptake) are treated as continuous variables, which change on a monthly time step. Carbon emissions and removals are an outcome of plant production and decomposition processes, which are simulated in the model structure. Thus, changes in soil C stocks are influenced by not only changes in land use and management but also inter-annual climate variability and secondary feedbacks between management activities, climate, and soils as they affect primary production and decomposition. This latter characteristic constitutes one of the greatest differences between the methods, and forms the basis for a more complete accounting of soil C stock changes in the Tier 3 approach compared with Tier 2 methodology.

Because the Tier 3 model simulates a continuous time period rather than the equilibrium step change used in the IPCC methodology (Tier 1 and 2), the Tier 3 model addresses the delayed response of soils to management and land-use changes. Delayed responses can occur due to variable weather patterns and other environmental constraints that interact with land use and management and affect the time frame over which stock changes occur. Moreover, the Tier 3 method also accounts for the overall effect of increasing yields and, hence, C input to soils that have taken place across management systems and crop types within the United States. Productivity has increased by 1 to 2 percent annually over the past 4 to 5 decades for most major crops in the United States (Reilly and Fuglie 1998), which is believed to have led to increases in cropland soil C stocks (e.g., Allmaras et al. 2000). This is a major difference from the IPCC-based Tier 1 and 2 approaches, in which trends in soil C stocks only capture discrete changes in management and/or land use, rather than a longer term trend such as gradual increases in crop productivity.

[END BOX]

Additional sources of activity data were used to supplement the land-use information from NRI. The Conservation Technology Information Center (CTIC 1998) provided annual data on tillage activity at the county level since 1989, with adjustments for long-term adoption of no-till agriculture (Towery 2001). Information on fertilizer use and rates by crop type for different regions of the United States were obtained primarily from the USDA Economic Research Service Cropping Practices Survey (ERS 1997) with additional data from other sources, including the National Agricultural Statistics Service (NASS 1992, 1999, 2004). Frequency and rates of manure application to cropland during 1997 were estimated from data compiled by the USDA Natural Resources Conservation Service (Edmonds et al. 2003), and then adjusted using county-level estimates of manure available for application in other years. Specifically, county-scale ratios of manure available for application to soils in other years relative to 1997 were used to adjust the area amended with manure (see Annex 3.13 for further details). Greater availability of managed manure N relative to 1997 was, thus, assumed to increase the area amended with manure, while reduced availability of manure N relative to 1997 was assumed to reduce the amended area. The amount of manure produced by each livestock type was calculated for managed and unmanaged waste management systems based on methods described in the Manure Management section (Section 6.2) and annex (Annex 3.10).

Manure amendments were an input to the Century Model based on manure N available for application from all managed or unmanaged systems except Pasture/Range/Paddock.¹⁸⁴ Data on the county-level N available for application were estimated for managed systems based on the total amount of N excreted in manure minus N losses during storage and transport, and including the addition of N from bedding materials. Nitrogen losses include direct nitrous oxide emissions, volatilization of ammonia and NO_x, runoff and leaching, and poultry manure used as a feed supplement. More information on these losses is available in the description of the Manure Management source category. For unmanaged systems, it is assumed that no N losses or additions occur prior to the application of manure to the soil.

Monthly weather data were used as an input in the model simulations, based on an aggregation of gridded weather data to the county scale from the Parameter-elevation Regressions on Independent Slopes Model (PRISM) database

¹⁸⁴ Pasture/Range/Paddock manure additions to soils are addressed in the *Grassland Remaining Grassland* and *Land Converted to Grassland* categories.

(Daly et al. 1994). Soil attributes, which were obtained from an NRI database, were assigned based on field visits and soil series descriptions. Each NRI point was run 100 times as part of the uncertainty assessment, yielding a total of over 18 million simulation runs for the analysis. Carbon stock estimates from Century were adjusted using a structural uncertainty estimator accounting for uncertainty in model algorithms and parameter values (Ogle et al. 2007, 2010). C stocks and 95 percent confidence intervals were estimated for each year between 1990 and 2003, but C stock changes from 2004 to 2009 were assumed to be similar to 2003 because no additional activity data are currently available from the NRI for the latter years.

Tier 2 Approach

In the IPCC Tier 2 method, data on climate, soil types, land-use, and land management activity were used to classify land area to apply appropriate stock change factors. MLRAs formed the base spatial unit for mapping climate regions in the United States; each MLRA represents a geographic unit with relatively similar soils, climate, water resources, and land uses (NRCS 1981). MLRAs were classified into climate regions according to the IPCC categories using the PRISM climate database of Daly et al. (1994).

Reference C stocks were estimated using the National Soil Survey Characterization Database (NRCS 1997) with cultivated cropland as the reference condition, rather than native vegetation as used in IPCC (2003, 2006). Changing the reference condition was necessary because soil measurements under agricultural management are much more common and easily identified in the National Soil Survey Characterization Database (NRCS 1997) than those that are not considered cultivated cropland.

U.S.-specific stock change factors were derived from published literature to determine the impact of management practices on SOC storage, including changes in tillage, cropping rotations and intensification, and land-use change between cultivated and uncultivated conditions (Ogle et al. 2003, Ogle et al. 2006). U.S. factors associated with organic matter amendments were not estimated because there were an insufficient number of studies to analyze those impacts. Instead, factors from IPCC (2003) were used to estimate the effect of those activities. Euliss and Gleason (2002) provided the data for computing the change in SOC storage resulting from restoration of wetland enrolled in the Conservation Reserve Program.

Activity data were primarily based on the historical land-use/management patterns recorded in the NRI. Each NRI point was classified by land use, soil type, climate region (using PRISM data, Daly et al. 1994) and management condition. Classification of cropland area by tillage practice was based on data from the Conservation Tillage Information Center (CTIC 1998, Towery 2001) as described above. Activity data on wetland restoration of Conservation Reserve Program land were obtained from Euliss and Gleason (2002). Manure N amendments over the inventory time period were based on application rates and areas amended with manure N from Edmonds et al. (2003), in addition to the managed manure production data discussed in the previous methodology subsection on the Tier 3 analysis for mineral soils.

Combining information from these data sources, SOC stocks for mineral soils were estimated 50,000 times for 1982, 1992, and 1997, using a Monte Carlo simulation approach and the probability distribution functions for U.S.-specific stock change factors, reference C stocks, and land-use activity data (Ogle et al. 2002, Ogle et al. 2003). The annual C flux for 1990 through 1992 was determined by calculating the average annual change in stocks between 1982 and 1992; annual C flux for 1993 through 2009 was determined by calculating the average annual change in stocks between 1992 and 1997.

Additional Mineral C Stock Change

Annual C flux estimates for mineral soils between 1990 and 2009 were adjusted to account for additional C stock changes associated with gains or losses in soil C after 2003 due to changes in Conservation Reserve Program enrollment. The change in enrollment acreage relative to 2003 was based on data from USDA-FSA (2009) for 2004 through 2009, and the differences in mineral soil areas were multiplied by 0.5 metric tons C per hectare per year to estimate the net effect on soil C stocks. The stock change rate is based on estimations using the IPCC method (see Annex 3.13 for further discussion).

Organic Soil Carbon Stock Changes

Annual C emissions from drained organic soils in *Cropland Remaining Cropland* were estimated using the Tier 2 method provided in IPCC (2003, 2006), with U.S.-specific C loss rates (Ogle et al. 2003) rather than default IPCC

rates. The final estimates included a measure of uncertainty as determined from the Monte Carlo simulation with 50,000 iterations. Emissions were based on the 1992 and 1997 *Cropland Remaining Cropland* areas from the 1997 *National Resources Inventory* (USDA-NRCS 2000). The annual flux estimated for 1992 was applied to 1990 through 1992, and the annual flux estimated for 1997 was applied to 1993 through 2009.

Uncertainty and Time-Series Consistency

Uncertainty associated with the *Cropland Remaining Cropland* land-use category was addressed for changes in agricultural soil C stocks (including both mineral and organic soils). Uncertainty estimates are presented in Table 7-19 for mineral soil C stocks and organic soil C stocks disaggregated to the level of the inventory methodology employed (i.e., Tier 2 and Tier 3). Uncertainty for the portions of the Inventory estimated with Tier 2 and 3 approaches was derived using a Monte Carlo approach (see Annex 3.13 for further discussion). A combined uncertainty estimate for changes in soil C stocks is also included. Uncertainty estimates from each component were combined using the error propagation equation in accordance with IPCC (2006). The combined uncertainty was calculated by taking the square root of the sum of the squares of the standard deviations of the uncertain quantities. More details on how the individual uncertainties were developed are in Annex 3.13. The combined uncertainty for soil C stocks in *Cropland Remaining Cropland* ranged from 172 percent below to 167 percent above the 2009 stock change estimate of -17.4 Tg CO₂ Eq.

Table 7-19: Tier 2 Quantitative Uncertainty Estimates for Soil C Stock Changes occurring within *Cropland Remaining Cropland* (Tg CO₂ Eq. and Percent)

Source	2009 Flux Estimate (Tg CO ₂ Eq.)	Uncertainty Range Relative to Flux Estimate			
		(Tg CO ₂ Eq.)		(%)	
		Lower Bound	Upper Bound	Lower Bound	Upper Bound
Mineral Soil C Stocks: Cropland Remaining Cropland, Tier 3 Inventory Methodology	(42.3)	(69.6)	(15.1)	-64%	+64%
Mineral Soil C Stocks: Cropland Remaining Cropland, Tier 2 Inventory Methodology	(3.0)	(6.9)	0.8	-127%	+128%
Mineral Soil C Stocks: Cropland Remaining Cropland (Change in CRP enrollment relative to 2003)	(0.3)	(0.1)	(0.4)	-50%	+50%
Organic Soil C Stocks: Cropland Remaining Cropland, Tier 2 Inventory Methodology	27.7	15.8	36.9	-43%	+33%
Combined Uncertainty for Flux associated with Agricultural Soil Carbon Stock Change in Cropland Remaining Cropland	(17.4)	(47.3)	11.6	-172%	+167%

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

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

QA/QC and Verification

Quality control measures included checking input data, model scripts, and results to ensure data were properly handled throughout the inventory process. As discussed in the uncertainty section, results were compared to field measurements, and a statistical relationship was developed to assess uncertainties in the model's predictive capability. The comparisons included over 40 long-term experiments, representing about 800 combinations of management treatments across all of the sites (Ogle et al. 2007). Inventory reporting forms and text were reviewed and revised as needed to correct transcription errors.

Planned Improvements

The first improvement is to update the Tier 2 inventory analysis with the latest annual National Resources Inventory (NRI) data. While the land base for the Tier 3 approach uses the latest available data from the NRI, the Tier 2 portion of the Inventory has not updated and is based on the Revised 1997 NRI data product (USDA-NRCS 2000).

This improvement will extend the time series of the land use data from 1997 through 2003 for the Tier 2 portion of the Inventory.

The second improvement is to incorporate remote sensing in the analysis for estimation of crop and forage production, and conduct the Tier 3 assessment of soil C stock changes and soil nitrous oxide emissions in a single analysis. Specifically, the Enhanced Vegetation Index (EVI) product that is derived from MODIS satellite imagery is being used to refine the production estimation for the Tier 3 assessment framework based on the DAYCENT simulation model. EVI reflects changes in plant “greenness” over the growing season and can be used to compute production based on the light use efficiency of the crop or forage (Potter et al. 1993). In the current framework, production is simulated based on the weather data, soil characteristics, and the genetic potential of the crop. While this method produces reasonable results, remote sensing can be used to refine the productivity estimates and reduce biases in crop production and subsequent C input to soil systems. It is anticipated that precision in the Tier 3 assessment framework will be increased by 25 percent or more with the new method. In addition, DAYCENT is currently used for estimating soil nitrous oxide emissions in the Inventory, and can also be used to estimate soil organic C stock changes using the same algorithms in the CENTURY model. Simulating both soil C stock changes and nitrous oxide emissions in a single analysis will ensure consistency in the treatment of these sources, which are coupled through the N and C cycles in agricultural systems.

CO₂ Emissions from Agricultural Liming

IPCC (2006) recommends reporting CO₂ emissions from lime additions (in the form of crushed limestone (CaCO₃) and dolomite (CaMg(CO₃)₂) to agricultural soils. Limestone and dolomite are added by land managers to ameliorate acidification. When these compounds come in contact with acid soils, they degrade, thereby generating CO₂. The rate and ultimate magnitude of degradation of applied limestone and dolomite depends on the soil conditions, climate regime, and the type of mineral applied. Emissions from liming have fluctuated over the past nineteen years, ranging from 3.8 Tg CO₂ Eq. to 5.0 Tg CO₂ Eq. In 2009, liming of agricultural soils in the United States resulted in emissions of 4.2 Tg CO₂ Eq. (1.2 Tg C), representing about a 10 percent decrease in emissions since 1990 (see Table 7-20 and Table 7-21). The trend is driven entirely by the amount of lime and dolomite estimated to have been applied to soils over the time period.

Table 7-20: Emissions from Liming of Agricultural Soils (Tg CO₂ Eq.)

Source	1990		2000		2005	2006	2007	2008	2009
Liming of Soils ¹	4.7		4.3		4.3	4.2	4.5	5.0	4.2

Note: Shaded areas indicate values based on a combination of data and projections. All other values are based on data only.

¹ Also includes emissions from liming on *Land Converted to Cropland, Grassland Remaining Grassland, Land Converted to Grassland, and Settlements Remaining Settlements*.

Table 7-21: Emissions from Liming of Agricultural Soils (Tg C)

Source	1990		2000		2005	2006	2007	2008	2009
Liming of Soils ¹	1.3		1.2		1.2	1.2	1.2	1.4	1.2

Note: Shaded areas indicate values based on a combination of data and projections. All other values are based on data only.

¹ Also includes emissions from liming on *Land Converted to Cropland, Grassland Remaining Grassland, Land Converted to Grassland, and Settlements Remaining Settlements*.

Methodology

CO₂ emissions from degradation of limestone and dolomite applied to agricultural soils were estimated using a Tier 2 methodology consistent with IPCC (2006). The annual amounts of limestone and dolomite applied (see Table 7-22) were multiplied by CO₂ emission factors from West and McBride (2005). These emission factors (0.059 metric ton C/metric ton limestone, 0.064 metric ton C/metric ton dolomite) are lower than the IPCC default emission factors because they account for the portion of agricultural lime that may leach through the soil and travel by rivers to the ocean (West and McBride 2005). This analysis of lime dissolution is based on liming occurring in the Mississippi River basin, where the vast majority of all U.S. liming takes place (West 2008). U.S. liming that does not occur in the Mississippi River basin tends to occur under similar soil and rainfall regimes, and, thus, the emission factor is appropriate for use across the United States (West 2008). The annual application rates of limestone and dolomite were derived from estimates and industry statistics provided in the *Minerals Yearbook* and *Mineral Industry Surveys* (Tepordei 1993 through 2006; Willett 2007a, b, 2009 through 2010; USGS 2008 through

2010). To develop these data, the U.S. Geological Survey (USGS; U.S. Bureau of Mines prior to 1997) obtained production and use information by surveying crushed stone manufacturers. Because some manufacturers were reluctant to provide information, the estimates of total crushed limestone and dolomite production and use were divided into three components: (1) production by end-use, as reported by manufacturers (i.e., “specified” production); (2) production reported by manufacturers without end-uses specified (i.e., “unspecified” production); and (3) estimated additional production by manufacturers who did not respond to the survey (i.e., “estimated” production).

The “unspecified” and “estimated” amounts of crushed limestone and dolomite applied to agricultural soils were calculated by multiplying the percentage of total “specified” limestone and dolomite production applied to agricultural soils by the total amounts of “unspecified” and “estimated” limestone and dolomite production. In other words, the proportion of total “unspecified” and “estimated” crushed limestone and dolomite that was applied to agricultural soils (as opposed to other uses of the stone) was assumed to be proportionate to the amount of “specified” crushed limestone and dolomite that was applied to agricultural soils. In addition, data were not available for 1990, 1992, and 2009 on the fractions of total crushed stone production that were limestone and dolomite, and on the fractions of limestone and dolomite production that were applied to soils. To estimate the 1990 and 1992 data, a set of average fractions were calculated using the 1991 and 1993 data. These average fractions were applied to the quantity of “total crushed stone produced or used” reported for 1990 and 1992 in the 1994 *Minerals Yearbook* (Tepordei 1996). To estimate 2009 data, the previous year’s fractions were applied to a 2009 estimate of total crushed stone presented in the USGS *Mineral Industry Surveys: Crushed Stone and Sand and Gravel in the First Quarter of 2010* (USGS 2010); thus, the 2009 data in Table 7-20 through Table 7-22 are shaded to indicate that they are based on a combination of data and projections.

The primary source for limestone and dolomite activity data is the *Minerals Yearbook*, published by the Bureau of Mines through 1994 and by the USGS from 1995 to the present. In 1994, the “Crushed Stone” chapter in the *Minerals Yearbook* began rounding (to the nearest thousand metric tons) quantities for total crushed stone produced or used. It then reported revised (rounded) quantities for each of the years from 1990 to 1993. In order to minimize the inconsistencies in the activity data, these revised production numbers have been used in all of the subsequent calculations. Since limestone and dolomite activity data are also available at the state level, the national-level estimates reported here were broken out by state, although state-level estimates are not reported here.

Table 7-22: Applied Minerals (Million Metric Tons)

Mineral	1990		2000		2005	2006	2007	2008	2009
Limestone	19.01		15.86		18.09	16.54	17.46	20.55	17.20
Dolomite	2.36		3.81		1.85	2.73	2.92	2.54	2.13

Note: These numbers represent amounts applied to *Cropland Remaining Cropland, Land Converted to Cropland, Grassland Remaining Grassland, Land Converted to Grassland, and Settlements Remaining Settlements*. Shaded areas indicate values based on a combination of data and projections. All other values are based on data only.

Uncertainty and Time-Series Consistency

Uncertainty regarding limestone and dolomite activity data inputs was estimated at ± 15 percent and assumed to be uniformly distributed around the inventory estimate (Tepordei 2003b). Analysis of the uncertainty associated with the emission factors included the following: the fraction of agricultural lime dissolved by nitric acid versus the fraction that reacts with carbonic acid, and the portion of bicarbonate that leaches through the soil and is transported to the ocean. Uncertainty regarding the time associated with leaching and transport was not accounted for, but should not change the uncertainty associated with CO₂ emissions (West 2005). The uncertainties associated with the fraction of agricultural lime dissolved by nitric acid and the portion of bicarbonate that leaches through the soil were each modeled as a smoothed triangular distribution between ranges of zero percent to 100 percent. The uncertainty surrounding these two components largely drives the overall uncertainty estimates reported below. More information on the uncertainty estimates for Liming of Agricultural Soils is contained within the Uncertainty Annex.

A Monte Carlo (Tier 2) uncertainty analysis was applied to estimate the uncertainty of CO₂ emissions from liming. The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 7-23. CO₂ emissions from Liming of Agricultural Soils in 2008 were estimated to be between 0.1 and 8.4 Tg CO₂ Eq. at the 95 percent confidence level. This indicates a range of 97 percent below to 99 percent above the 2009 emission estimate of 4.2 Tg CO₂ Eq.

Table 7-23: Tier 2 Quantitative Uncertainty Estimates for CO₂ Emissions from Liming of Agricultural Soils (Tg CO₂ Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO ₂ Eq.)	Uncertainty Range Relative to Emissions Estimate ^a			
			(Tg CO ₂ Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Liming of Agricultural Soils ¹	CO ₂	4.2	0.1	8.4	-97%	+99%

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

¹ Also includes emissions from liming on *Land Converted to Cropland*, *Grassland Remaining Grassland*, *Land Converted to Grassland*, and *Settlements Remaining Settlements*.

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

QA/QC and Verification

A QA/QC analysis was performed for data gathering and input, documentation, and calculation. The QA/QC analysis did not reveal any inaccuracies or incorrect input values.

Recalculations Discussion

Several adjustments were made in the current Inventory to improve the results. The quantity of applied minerals reported in the previous Inventory for 2007 has been revised; the updated activity data for 2007 are approximately 1,480 thousand metric tons greater than the data used for the previous Inventory, consequently, the reported emissions resulting from liming in 2007 increased by about 8.4 percent. In the previous Inventory, to estimate 2008 data, the previous year's fractions were applied to a 2008 estimate of total crushed stone presented in the USGS *Mineral Industry Surveys: Crushed Stone and Sand and Gravel in the First Quarter of 2009* (USGS 2009). Since publication of the previous Inventory, the *Minerals Yearbook* has published actual quantities of crushed stone sold or used by producers in the United States in 2008. These values have replaced those used in the previous Inventory to calculate the quantity of minerals applied to soil and the emissions from liming. The updated activity data for 2008 are approximately 5,460 thousand metric tons greater than the data used in the previous Inventory. As a result, the reported emissions from liming in 2008 increased by about 36 percent.

CO₂ Emissions from Urea Fertilization

The use of urea (CO(NH₂)₂) as fertilizer leads to emissions of CO₂ that was fixed during the industrial production process. Urea in the presence of water and urease enzymes is converted into ammonium (NH₄⁺), hydroxyl ion (OH⁻), and bicarbonate (HCO₃⁻). The bicarbonate then evolves into CO₂ and water. Emissions from urea fertilization in the United States totaled 3.6 Tg CO₂ Eq. (1.0 Tg C) in 2009 (Table 7-24 and Table 7-25). Emissions from urea fertilization have grown 49 percent between 1990 and 2009, due to an increase in the use of urea as fertilizer.

Table 7-24: CO₂ Emissions from Urea Fertilization in *Cropland Remaining Cropland* (Tg CO₂ Eq.)

Source	1990	2000	2005	2006	2007	2008	2009
Urea Fertilization ¹	2.4	3.2	3.5	3.7	3.7	3.6	3.6

Note: Shaded areas indicate values based on a combination of data and projections. All other values are based on data only.

¹ Also includes emissions from urea fertilization on *Land Converted to Cropland*, *Grassland Remaining Grassland*, *Land Converted to Grassland*, *Settlements Remaining Settlements*, and *Forest Land Remaining Forest Land*.

Table 7-25: CO₂ Emissions from Urea Fertilization in *Cropland Remaining Cropland* (Tg C)

Source	1990	2000	2005	2006	2007	2008	2009
Urea Fertilization ¹	0.7	0.9	1.0	1.0	1.0	1.0	1.0

Note: Shaded areas indicate values based on a combination of data and projections. All other values are based on data only.

¹ Also includes emissions from urea fertilization on *Land Converted to Cropland*, *Grassland Remaining Grassland*, *Land Converted to Grassland*, *Settlements Remaining Settlements*, and *Forest Land Remaining Forest Land*.

Methodology

Carbon dioxide emissions from the application of urea to agricultural soils were estimated using the IPCC (2006) Tier 1 methodology. The annual amounts of urea fertilizer applied (see Table 7-26) were derived from state-level fertilizer sales data provided in *Commercial Fertilizers* (TVA 1991, 1992, 1993, 1994; AAPFCO 1995 through 2010) and were multiplied by the default IPCC (2006) emission factor of 0.20, which is equal to the C content of urea on an atomic weight basis. Because fertilizer sales data are reported in fertilizer years (July through June), a calculation was performed to convert the data to calendar years (January through December). According to historic monthly fertilizer use data (TVA 1992b), 65 percent of total fertilizer used in any fertilizer year is applied between January and June of that calendar year, and 35 percent of total fertilizer used in any fertilizer year is applied between July and December of the previous calendar year. Fertilizer sales data for the 2009 fertilizer year were not available in time for publication. Accordingly, urea application in the 2009 fertilizer year was assumed to be equal to that of the 2008 fertilizer year. Since 2010 fertilizer year data were not available, July through December 2009 fertilizer consumption was assumed to be equal to July through December 2008 fertilizer consumption; thus, the 2009 data in Table 7-24 through Table 7-26 are shaded to indicate that they are based on a combination of data and projections. State-level estimates of CO₂ emissions from the application of urea to agricultural soils were summed to estimate total emissions for the entire United States.

Table 7-26: Applied Urea (Million Metric Tons)

	1990	2000	2005	2006	2007	2008	2009
Urea Fertilizer ¹	3.30	4.38	4.78	4.98	5.10	4.92	4.92

Note: Shaded areas indicate values based on a combination of data and projections. All other values are based on data only.

¹These numbers represent amounts applied to all agricultural land, including *Land Converted to Cropland*, *Grassland Remaining Grassland*, *Land Converted to Grassland*, *Settlements Remaining Settlements*, and *Forest Land Remaining Forest Land*.

Uncertainty and Time-Series Consistency

Uncertainty estimates are presented in Table 7-27 for Urea Fertilization. A Tier 2 Monte Carlo analysis was completed. The largest source of uncertainty was the default emission factor, which assumes that 100 percent of the C applied to soils is ultimately emitted into the environment as CO₂. This factor does not incorporate the possibility that some of the C may be retained in the soil. The emission estimate is, thus, likely to be high. In addition, each urea consumption data point has an associated uncertainty. Urea for non-fertilizer use, such as aircraft deicing, may be included in consumption totals; it was determined through personal communication with Fertilizer Regulatory Program Coordinator David L. Terry (2007), however, that this amount is most likely very small. Research into aircraft deicing practices also confirmed that urea is used minimally in the industry; a 1992 survey found a known annual usage of approximately 2,000 tons of urea for deicing; this would constitute 0.06 percent of the 1992 consumption of urea (EPA 2000). Similarly, surveys conducted from 2002 to 2005 indicate that total urea use for deicing at U.S. airports is estimated to be 3,740 MT per year, or less than 0.07 percent of the fertilizer total for 2007 (Itle 2009). Lastly, there is uncertainty surrounding the assumptions behind the calculation that converts fertilizer years to calendar years. CO₂ emissions from urea fertilization of agricultural soils in 2009 were estimated to be between 2.1 and 3.7 Tg CO₂ Eq. at the 95 percent confidence level. This indicates a range of 43 percent below to 3 percent above the 2009 emission estimate of 3.6 Tg CO₂ Eq.

Table 7-27: Quantitative Uncertainty Estimates for CO₂ Emissions from Urea Fertilization (Tg CO₂ Eq. and Percent)

Source	Gas	2009 Emission	Uncertainty Range Relative to Emissions Estimate ^a			
		Estimate (Tg CO ₂ Eq.)	(Tg CO ₂ Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Urea Fertilization	CO ₂	3.6	2.1	3.7	-43%	+3%

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

Note: These numbers represent amounts applied to all agricultural land, including *Land Converted to Cropland*, *Grassland Remaining Grassland*, *Land Converted to Grassland*, *Settlements Remaining Settlements*, and *Forest Land Remaining Forest Land*.

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

QA/QC and Verification

A QA/QC analysis was performed for data gathering and input, documentation, and calculation. Inventory reporting forms and text were reviewed. No errors were found.

Recalculations Discussion

July to December 2007 urea application data were updated with assumptions for fertilizer year 2008, and the 2007 emission estimate was revised accordingly. The activity data decreased about 800,000 metric tons for 2007 and this change resulted in an approximately 3 percent decrease in emissions in 2007 relative to the previous Inventory. In the previous Inventory, the application for this period was calculated based on application during July to December 2006. January to June 2008 data were also used to update 2008 emission estimates. The activity data decreased about 270,000 metric tons for 2008, resulting in an approximately 5 percent decrease in emissions in 2008 relative to the previous Inventory.

Planned Improvements

The primary planned improvement is to investigate using a Tier 2 or Tier 3 approach, which would utilize country-specific information to estimate a more precise emission factor.

7.5. Land Converted to Cropland (IPCC Source Category 5B2)

Land Converted to Cropland includes all cropland in an inventory year that had been another land use at any point during the previous 20 years¹⁸⁵ according to the USDA NRI land-use survey (USDA-NRCS 2000). Consequently, lands are retained in this category for 20 years as recommended by the IPCC guidelines (IPCC 2006) unless there is another land-use change. The Inventory includes all privately-owned croplands in the conterminous United States and Hawaii, but there is a minor amount of cropland on federal lands that is not currently included in the estimation of C stock changes, leading to a discrepancy between the total amount of managed area in *Land Converted to Cropland* (see Section 7.1) and the cropland area included in the Inventory. It is important to note that plans are being made to include these areas in future C inventories.

Background on agricultural C stock changes is provided in *Cropland Remaining Cropland* and will only be summarized here for *Land Converted to Cropland*. Soils are the largest pool of C in agricultural land, and also have the greatest potential for storage or release of C, because biomass and dead organic matter C pools are relatively small and ephemeral compared with soils. The IPCC (2006) recommends reporting changes in soil organic C stocks due to: (1) agricultural land-use and management activities on mineral soils, and (2) agricultural land-use and management activities on organic soils.¹⁸⁶

Land-use and management of mineral soils in *Land Converted to Cropland* generally led to relatively small increases in soil C during the 1990s but the pattern changed to small losses of C through the latter part of the time series (Table 7-28 and Table 7-29). The total rate of change in soil C stocks was 5.9 Tg CO₂ Eq. (1.6 Tg C) in 2009. Mineral soils were estimated to lose 3.3 Tg CO₂ Eq. (0.9 Tg C) in 2009, while drainage and cultivation of organic soils led to annual losses of 2.6 Tg CO₂ Eq. (0.7 Tg C) in 2009.

Table 7-28: Net CO₂ Flux from Soil C Stock Changes in *Land Converted to Cropland* (Tg CO₂ Eq.)

Soil Type	1990		2000		2005	2006	2007	2008	2009
Mineral Soils	(0.3)		(0.3)		3.3	3.3	3.3	3.3	3.3
Organic Soils	2.4		2.6		2.6	2.6	2.6	2.6	2.6
Total Net Flux	2.2		2.4		5.9	5.9	5.9	5.9	5.9

Note: Parentheses indicate net sequestration. Shaded areas indicate values based on a combination of historical data and projections. All other values are based on historical data only. Totals may not sum due to independent rounding.

Table 7-29: Net CO₂ Flux from Soil C Stock Changes in *Land Converted to Cropland* (Tg C)

¹⁸⁵ NRI points were classified according to land-use history records starting in 1982 when the NRI survey began, and consequently the classifications were based on less than 20 years from 1990 to 2001.

¹⁸⁶ CO₂ emissions associated with liming are also estimated but included in a separate section of the report.

Soil Type	1990		2000		2005	2006	2007	2008	2009
Mineral Soils	(0.1)		(0.1)		0.9	0.9	0.9	0.9	0.9
Organic Soils	0.7		0.7		0.7	0.7	0.7	0.7	0.7
Total Net Flux	0.6		0.6		1.6	1.6	1.6	1.6	1.6

Note: Parentheses indicate net sequestration. Shaded areas indicate values based on a combination of historical data and projections. All other values are based on historical data only. Totals may not sum due to independent rounding.

The spatial variability in annual CO₂ flux associated with C stock changes in mineral and organic soils for *Land Converted to Cropland* is displayed in Figure 7-7 and Figure 7-8. While a large portion of the United States had net losses of soil C for *Land Converted to Cropland*, there were some notable areas with net C accumulation in the Great Plains, Midwest, mid-Atlantic states. These areas were gaining C following conversion, because the land had been brought into hay production, including grass and legume hay, leading to enhanced plant production relative to the previous land use, and thus higher C input to the soil. Emissions from organic soils were largest in California, Florida, and the upper Midwest, which coincided with largest concentrations of cultivated organic soils in the United States.

Figure 7-7: Total Net Annual CO₂ Flux for Mineral Soils under Agricultural Management within States, 2009, *Land Converted to Cropland*

Figure 7-8: Total Net Annual CO₂ Flux for Organic Soils under Agricultural Management within States, 2009, *Land Converted to Cropland*

Methodology

The following section includes a brief description of the methodology used to estimate changes in soil C stocks due to agricultural land-use and management activities on mineral and organic soils for *Land Converted to Cropland*. Further elaboration on the methodologies and data used to estimate stock changes for mineral and organic soils are provided in the *Cropland Remaining Cropland* section and Annex 3.13.

Soil C stock changes were estimated for *Land Converted to Cropland* according to land-use histories recorded in the USDA NRI survey (USDA-NRCS 2000). Land-use and some management information (e.g., crop type, soil attributes, and irrigation) were originally collected for each NRI point on a 5-year cycle beginning in 1982. However, the NRI program initiated annual data collection in 1998, and the annual data are currently available through 2003. NRI points were classified as *Land Converted to Cropland* in a given year between 1990 and 2009 if the land use was cropland but had been another use during the previous 20 years. Cropland includes all land used to produce food or fiber, or forage that is harvested and used as feed (e.g., hay and silage).

Mineral Soil Carbon Stock Changes

A Tier 3 model-based approach was applied to estimate C stock changes for soils on *Land Converted to Cropland* used to produce a majority of all crops (Ogle et al. 2010). Soil C stock changes on the remaining soils were estimated with the IPCC Tier 2 method (Ogle et al. 2003), including land used to produce vegetable, tobacco, perennial/horticultural crops, and rice; land on very gravelly, cobbly, or shaley soils (greater than 35 percent by volume); and land converted from forest or federal ownership.¹⁸⁷

Tier 3 Approach

Mineral SOC stocks and stock changes were estimated using the Century biogeochemical model for the Tier 3

¹⁸⁷ Federal land is not a land use, but rather an ownership designation that is treated as forest or nominal grassland for purposes of these calculations. The specific use for federal lands is not identified in the NRI survey (USDA-NRCS 2000).

methods. National estimates were obtained by using the model to simulate historical land-use change patterns as recorded in the USDA National Resources Inventory (USDA-NRCS 2000). The methods used for *Land Converted to Cropland* are the same as those described in the Tier 3 portion of *Cropland Remaining Cropland* section for mineral soils (see *Cropland Remaining Cropland* Tier 3 methods section and Annex 3.13 for additional information).

Tier 2 Approach

For the mineral soils not included in the Tier 3 analysis, SOC stock changes were estimated using a Tier 2 Approach for *Land Converted to Cropland* as described in the Tier 2 portion of *Cropland Remaining Cropland* section for mineral soils (see *Cropland Remaining Cropland* Tier 2 methods section for additional information).

Organic Soil Carbon Stock Changes

Annual C emissions from drained organic soils in *Land Converted to Cropland* were estimated using the Tier 2 method provided in IPCC (2003, 2006), with U.S.-specific C loss rates (Ogle et al. 2003) rather than default IPCC rates. The final estimates included a measure of uncertainty as determined from the Monte Carlo simulation with 50,000 iterations. Emissions were based on the 1992 and 1997 *Land Converted to Cropland* areas from the 1997 *National Resources Inventory* (USDA-NRCS 2000). The annual flux estimated for 1992 was applied to 1990 through 1992, and the annual flux estimated for 1997 was applied to 1993 through 2009.

Uncertainty and Time-Series Consistency

Uncertainty analysis for mineral soil C stock changes using the Tier 3 and Tier 2 approaches were based on the same method described for *Cropland Remaining Cropland*, except that the uncertainty inherent in the structure of the Century model was not addressed. The uncertainty for annual C emission estimates from drained organic soils in *Land Converted to Cropland* was estimated using the Tier 2 approach, as described in the *Cropland Remaining Cropland* section.

Uncertainty estimates are presented in Table 7-30 for each subsource (i.e., mineral soil C stocks and organic soil C stocks) disaggregated to the level of the inventory methodology employed (i.e., Tier 2 and Tier 3). Uncertainty for the portions of the Inventory estimated with Tier 2 and 3 approaches was derived using a Monte Carlo approach (see Annex 3.13 for further discussion). A combined uncertainty estimate for changes in agricultural soil C stocks is also included. Uncertainty estimates from each component were combined using the error propagation equation in accordance with IPCC (2006), i.e., by taking the square root of the sum of the squares of the standard deviations of the uncertain quantities. The combined uncertainty for soil C stocks in *Land Converted to Cropland* was estimated to be 40 percent below and 36 percent above the inventory estimate of 5.9 Tg CO₂ Eq.

Table 7-30: Tier 2 Quantitative Uncertainty Estimates for Soil C Stock Changes occurring within *Land Converted to Cropland* (Tg CO₂ Eq. and Percent)

Source	2009 Flux Estimate (Tg CO ₂ Eq.)	Uncertainty Range Relative to Flux Estimate			
		(Tg CO ₂ Eq.)		(%)	
		Lower Bound	Upper Bound	Lower Bound	Upper Bound
Mineral Soil C Stocks: Land Converted to Cropland, Tier 3 Inventory Methodology	(0.8)	(1.5)	(0.1)	-84%	+84%
Mineral Soil C Stocks: Land Converted to Cropland, Tier 2 Inventory Methodology	4.1	2.3	5.8	-44%	+41%
Organic Soil C Stocks: Land Converted to Cropland, Tier 2 Inventory Methodology	2.6	1.2	3.7	-53%	+41%
Combined Uncertainty for Flux associated with Soil Carbon Stock Change in Land Converted to Cropland	5.9	3.5	8.1	-40%	+36%

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

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

above.

QA/QC and Verification

See QA/QC and Verification section under *Cropland Remaining Cropland*.

Planned Improvements

The empirically-based uncertainty estimator described in the *Cropland Remaining Cropland* section for the Tier 3 approach has not been developed to estimate uncertainties related to the structure of the Century model for *Land Converted to Cropland*, but this is a planned improvement. This improvement will produce a more rigorous assessment of uncertainty. See Planned Improvements section under *Cropland Remaining Cropland* for additional planned improvements.

7.6. Grassland Remaining Grassland (IPCC Source Category 5C1)

Grassland Remaining Grassland includes all grassland in an inventory year that had been grassland for the previous 20 years¹⁸⁸ according to the USDA NRI land use survey (USDA-NRCS 2000). The Inventory includes all privately-owned grasslands in the conterminous United States and Hawaii, but does not address changes in C stocks for grasslands on federal lands, leading to a discrepancy between the total amount of managed area in *Grassland Remaining Grassland* (see Section 7.1) and the grassland area included in the Inventory. While federal grasslands probably have minimal changes in land management and C stocks, plans are being made to further evaluate and potentially include these areas in future C inventories.

Background on agricultural C stock changes is provided in the *Cropland Remaining Cropland* section and will only be summarized here for *Grassland Remaining Grassland*. Soils are the largest pool of C in agricultural land, and also have the greatest potential for storage or release of C, because biomass and dead organic matter C pools are relatively small and ephemeral compared to soils. IPCC (2006) recommends reporting changes in soil organic C stocks due to: (1) agricultural land-use and management activities on mineral soils, and (2) agricultural land-use and management activities on organic soils.¹⁸⁹

Land-use and management of mineral soils in *Grassland Remaining Grassland* increased soil C, while organic soils lost relatively small amounts of C in each year 1990 through 2009. Due to the pattern for mineral soils, the overall trend was a gain in soil C over the time series although the rates varied from year to year, with a net removal of 8.3 Tg CO₂ Eq. (2.3 Tg C) in 2009. There was considerable variation over the time series driven by variability in weather patterns and associated interaction with land management activity. The change rates on per hectare basis were small, however, even in the years with larger total changes in stocks. Overall, flux rates declined by 43.8 Tg CO₂ Eq. (12.0 Tg C) when comparing the net change in soil C from 1990 and 2009.

Table 7-31: Net CO₂ Flux from Soil C Stock Changes in *Grassland Remaining Grassland* (Tg CO₂ Eq.)

Soil Type	1990	2000	2005	2006	2007	2008	2009
Mineral Soils	(56.0)	(56.3)	(12.6)	(12.4)	(12.3)	(12.2)	(12.0)
Organic Soils	3.9	3.7	3.7	3.7	3.7	3.7	3.7
Total Net Flux	(52.2)	(52.6)	(8.9)	(8.8)	(8.6)	(8.5)	(8.3)

Note: Parentheses indicate net sequestration. Shaded areas indicate values based on a combination of historical data and projections. All other values are based on historical data only. Totals may not sum due to independent rounding.

Table 7-32: Net CO₂ Flux from Soil C Stock Changes in *Grassland Remaining Grassland* (Tg C)

Soil Type	1990	2000	2005	2006	2007	2008	2009
Mineral Soils	(15.3)	(15.3)	(3.4)	(3.4)	(3.4)	(3.3)	(3.3)
Organic Soils	1.1	1.0	1.0	1.0	1.0	1.0	1.0
Total Net Flux	(14.2)	(14.3)	(2.4)	(2.4)	(2.3)	(2.3)	(2.3)

¹⁸⁸ NRI points were classified according to land-use history records starting in 1982 when the NRI survey began, and consequently the classifications were based on less than 20 years from 1990 to 2001.

¹⁸⁹ CO₂ emissions associated with liming are also estimated but included in a separate section of the report.

Note: Parentheses indicate net sequestration. Shaded areas indicate values based on a combination of historical data and projections. All other values are based on historical data only. Totals may not sum due to independent rounding.

The spatial variability in annual CO₂ flux associated with C stock changes in mineral and organic soils is displayed in Figure 7-9 and Figure 7-10. Grassland gained soil organic C in several regions during 2009, including the Northeast, Midwest, Southwest and far western states; although these were relatively small increases in C on a per-hectare basis. Emission rates from drained organic soils were highest along the southeastern coastal region, in the northeast central United States surrounding the Great Lakes, and along the central and northern portions of the West Coast.

Figure 7-9: Total Net Annual CO₂ Flux for Mineral Soils under Agricultural Management within States, 2009, *Grassland Remaining Grassland*

Figure 7-10: Total Net Annual CO₂ Flux for Organic Soils under Agricultural Management within States, 2009, *Grassland Remaining Grassland*

Methodology

The following section includes a brief description of the methodology used to estimate changes in soil C stocks due to agricultural land-use and management activities on mineral and organic soils for *Grassland Remaining Grassland*. Further elaboration on the methodologies and data used to estimate stock changes from mineral and organic soils are provided in the *Cropland Remaining Cropland* section and Annex 3.13.

Soil C stock changes were estimated for *Grassland Remaining Grassland* according to land-use histories recorded in the USDA NRI survey (USDA-NRCS 2000). Land-use and some management information (e.g., crop type, soil attributes, and irrigation) were originally collected for each NRI point on a 5-year cycle beginning in 1982. However, the NRI program initiated annual data collection in 1998, and the annual data are currently available through 2003. NRI points were classified as *Grassland Remaining Grassland* in a given year between 1990 and 2009 if the land use had been grassland for 20 years. Grassland includes pasture and rangeland used for grass forage production, where the primary use is livestock grazing. Rangelands are typically extensive areas of native grassland that are not intensively managed, while pastures are often seeded grassland, possibly following tree removal, that may or may not be improved with practices such as irrigation and interseeding legumes.

Mineral Soil Carbon Stock Changes

An IPCC Tier 3 model-based approach was applied to estimate C stock changes for most mineral soils in *Grassland Remaining Grassland*. The C stock changes for the remaining soils were estimated with an IPCC Tier 2 method (Ogle et al. 2003), including gravelly, cobbly, or shaley soils (greater than 35 percent by volume) and additional stock changes associated with sewage sludge amendments.

Tier 3 Approach

Mineral soil organic C stocks and stock changes for *Grassland Remaining Grassland* were estimated using the Century biogeochemical model, as described in *Cropland Remaining Cropland*. Historical land-use and management patterns were used in the Century simulations as recorded in the USDA National Resources Inventory (NRI) survey, with supplemental information on fertilizer use and rates from the USDA Economic Research Service Cropping Practices Survey (ERS 1997) and National Agricultural Statistics Service (NASS 1992, 1999, 2004). Frequency and rates of manure application to grassland during 1997 were estimated from data compiled by the USDA Natural Resources Conservation Service (Edmonds, et al. 2003), and then adjusted using county-level estimates of manure available for application in other years. Specifically, county-scale ratios of manure available for application to soils in other years relative to 1997 were used to adjust the area amended with manure (see Annex 3.13 for further details). Greater availability of managed manure N relative to 1997 was, thus, assumed to increase the area amended with manure, while reduced availability of manure N relative to 1997 was assumed to reduce the

amended area.

The amount of manure produced by each livestock type was calculated for managed and unmanaged waste management systems based on methods described in the Manure Management Section (Section 6.2) and Annex (Annex 3.10). In contrast to manure amendments, Pasture/Range/Paddock (PRP) manure N deposition was estimated internally in the Century model, as part of the grassland system simulations (i.e., PRP manure deposition was not an external input into the model). See the Tier 3 methods in *Cropland Remaining Cropland* section for additional discussion on the Tier 3 methodology for mineral soils.

Tier 2 Approach

The Tier 2 approach is based on the same methods described in the Tier 2 portion of *Cropland Remaining Cropland* section for mineral soils (see *Cropland Remaining Cropland* Tier 2 methods section and Annex 3.13 for additional information).

Additional Mineral C Stock Change Calculations

Annual C flux estimates for mineral soils between 1990 and 2009 were adjusted to account for additional C stock changes associated with sewage sludge amendments using a Tier 2 method. Estimates of the amounts of sewage sludge N applied to agricultural land were derived from national data on sewage sludge generation, disposition, and N content. Total sewage sludge generation data for 1988, 1996, and 1998, in dry mass units, were obtained from an EPA report (EPA 1999) and estimates for 2004 were obtained from an independent national biosolids survey (NEBRA 2007). These values were linearly interpolated to estimate values for the intervening years. N application rates from Kellogg et al. (2000) were used to determine the amount of area receiving sludge amendments. Although sewage sludge can be added to land managed for other land uses, it was assumed that agricultural amendments occur in grassland. Cropland is assumed to rarely be amended with sewage sludge due to the high metal content and other pollutants in human waste. The soil C storage rate was estimated at 0.38 metric tons C per hectare per year for sewage sludge amendments to grassland. The stock change rate is based on country-specific factors and the IPCC default method (see Annex 3.13 for further discussion).

Organic Soil Carbon Stock Changes

Annual C emissions from drained organic soils in *Grassland Remaining Grassland* were estimated using the Tier 2 method provided in IPCC (2003, 2006), which utilizes U.S.-specific C loss rates (Ogle et al. 2003) rather than default IPCC rates. Emissions were based on the 1992 and 1997 *Grassland Remaining Grassland* areas from the *1997 National Resources Inventory* (USDA-NRCS 2000). The annual flux estimated for 1992 was applied to 1990 through 1992, and the annual flux estimated for 1997 was applied to 1993 through 2009.

Uncertainty and Time-Series Consistency

Uncertainty estimates are presented in Table 7-33 for each subsource (i.e., mineral soil C stocks and organic soil C stocks) disaggregated to the level of the inventory methodology employed (i.e., Tier 2 and Tier 3). Uncertainty for the portions of the Inventory estimated with Tier 2 and 3 approaches was derived using a Monte Carlo approach (see Annex 3.13 for further discussion). A combined uncertainty estimate for changes in agricultural soil C stocks is also included. Uncertainty estimates from each component were combined using the error propagation equation in accordance with IPCC (2006), i.e., by taking the square root of the sum of the squares of the standard deviations of the uncertain quantities. The combined uncertainty for soil C stocks in *Grassland Remaining Grassland* was estimated to be 32 percent below and 25 percent above the inventory estimate of -8.3 Tg CO₂ Eq.

Table 7-33: Tier 2 Quantitative Uncertainty Estimates for C Stock Changes occurring within *Grassland Remaining Grassland* (Tg CO₂ Eq. and Percent)

Source	2009 Flux Estimate (Tg CO ₂ Eq.)	Uncertainty Range Relative to Flux Estimate			
		(Tg CO ₂ Eq.)		(%)	
		Lower Bound	Upper Bound	Lower Bound	Upper Bound
Mineral Soil C Stocks Grassland Remaining Grassland, Tier 3 Methodology	(10.6)	(11.4)	(9.8)	-7%	+7%

Mineral Soil C Stocks: Grassland Remaining Grassland, Tier 2 Methodology	(0.2)	(0.3)	0.0	-89%	+127%
Mineral Soil C Stocks: Grassland Remaining Grassland, Tier 2 Methodology (Change in Soil C due to Sewage Sludge Amendments)	(1.2)	(1.9)	(0.6)	-50%	+50%
Organic Soil C Stocks: Grassland Remaining Grassland, Tier 2 Methodology	3.7	1.2	5.5	-66%	+49%
Combined Uncertainty for Flux Associated with Agricultural Soil Carbon Stock Change in Grassland Remaining Grassland	(8.3)	(11.0)	(6.3)	-32%	+25%

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

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

Uncertainties in Mineral Soil Carbon Stock Changes

The uncertainty analysis for *Grassland Remaining Grassland* using the Tier 3 approach and Tier 2 approach were based on the same method described for *Cropland Remaining Cropland*, except that the uncertainty inherent in the structure of the Century model was not addressed. See the Tier 3 approach for mineral soils under the *Cropland Remaining Cropland* section for additional discussion.

A ± 50 percent uncertainty was assumed for additional adjustments to the soil C stocks between 1990 and 2009 to account for additional C stock changes associated with amending grassland soils with sewage sludge.

Uncertainties in Soil Carbon Stock Changes for Organic Soils

Uncertainty in C emissions from organic soils was estimated using country-specific factors and a Monte Carlo analysis. Probability distribution functions for emission factors were derived from a synthesis of 10 studies, and combined with uncertainties in the NRI land use and management data for organic soils in the Monte Carlo analysis. See the Tier 2 section under mineral soils of *Cropland Remaining Cropland* for additional discussion.

QA/QC and Verification

Quality control measures included checking input data, model scripts, and results to ensure data were properly handled through the inventory process. A minor error was found in the post-processing results to compute the final totals, which was corrected. No additional errors were found.

Recalculations Discussion

There were minor changes in the estimated area of grasslands associated with reconciling the forestland areas from the Forest Inventory and Analysis (FIA) survey with the data from the National Resources Inventory (NRI) (see section 7.1 for more information). The revised areas led to small changes in the soil C stock changes for *Grassland Remaining Grassland*.

Planned Improvements

The main planned improvement for the next Inventory is to integrate the assessments of soil C stock changes and soil N₂O emissions into a single analysis. This improvement will ensure that the N and C cycles are treated consistently in the Inventory, which is important because the cycles of these elements are linked through plant and soil processes in agricultural lands. This improvement will include the development of an empirically-based uncertainty analysis, which will provide a more rigorous assessment of uncertainty. See Planned Improvements section under *Cropland Remaining Cropland* for additional planned improvements.

7.7. Land Converted to Grassland (IPCC Source Category 5C2)

Land Converted to Grassland includes all grassland in an inventory year that had been in another land use at any point during the previous 20 years¹⁹⁰ according to the USDA NRI land-use survey (USDA-NRCS 2000).

Consequently, lands are retained in this category for 20 years as recommended by IPCC (2006) unless there is another land use change. The Inventory includes all privately-owned grasslands in the conterminous United States and Hawaii, but does not address changes in C stocks for grasslands on federal lands, leading to a discrepancy between the total amount of managed area for *Land Converted to Grassland* (see Section 7.1) and the grassland area included in the Inventory. It is important to note that plans are being made to include these areas in future C inventories.

Background on agricultural C stock changes is provided in *Cropland Remaining Cropland* and will only be summarized here for *Land Converted to Grassland*. Soils are the largest pool of C in agricultural land, and also have the greatest potential for storage or release of C, because biomass and dead organic matter C pools are relatively small and ephemeral compared with soils. IPCC (2006) recommend reporting changes in soil organic C stocks due to: (1) agricultural land-use and management activities on mineral soils, and (2) agricultural land-use and management activities on organic soils.¹⁹¹

Land-use and management of mineral soils in *Land Converted to Grassland* led to an increase in soil C stocks from 1990 through 2009, which was largely due to annual cropland conversion to pasture (see Table 7-34 and Table 7-35). For example, the stock change rates were estimated to remove 20.3 Tg CO₂ Eq./yr (5.5 Tg C) and 24.5 Tg CO₂ Eq./yr (6.7 Tg C) from mineral soils in 1990 and 2009, respectively. Drainage of organic soils for grazing management led to losses varying from 0.5 to 0.9 Tg CO₂ Eq./yr (0.1 to 0.2 Tg C).

Table 7-34: Net CO₂ Flux from Soil C Stock Changes for *Land Converted to Grassland* (Tg CO₂ Eq.)

Soil Type	1990	2000	2005	2006	2007	2008	2009
Mineral Soils ^a	(20.3)	(28.1)	(25.3)	(25.1)	(24.9)	(24.7)	(24.5)
Organic Soils	0.5	0.9	0.9	0.9	0.9	0.9	0.9
Total Net Flux	(19.8)	(27.2)	(24.4)	(24.2)	(24.0)	(23.8)	(23.6)

Note: Parentheses indicate net sequestration. Shaded areas indicate values based on a combination of historical data and projections. All other values are based on historical data only. Totals may not sum due to independent rounding.

^a Stock changes due to application of sewage sludge are reported in *Grassland Remaining Grassland*.

Table 7-35: Net CO₂ Flux from Soil C Stock Changes for *Land Converted to Grassland* (Tg C)

Soil Type	1990	2000	2005	2006	2007	2008	2009
Mineral Soils ^a	(5.5)	(7.7)	(6.9)	(6.8)	(6.8)	(6.7)	(6.7)
Organic Soils	0.1	0.2	0.2	0.2	0.2	0.2	0.2
Total Net Flux	(5.4)	(7.4)	(6.7)	(6.6)	(6.5)	(6.5)	(6.4)

Note: Parentheses indicate net sequestration. Shaded areas indicate values based on a combination of historical data and projections. All other values are based on historical data only. Totals may not sum due to independent rounding.

^a Stock changes due to application of sewage sludge in *Land Converted to Grassland* are reported in *Grassland Remaining Grassland*.

The spatial variability in annual CO₂ flux associated with C stock changes in mineral soils is displayed in Figure 7-11 and Figure 7-12. Soil C stock increased in most states for *Land Converted to Grassland*. The largest gains were in the South-Central region, Midwest, and northern Great Plains. The patterns were driven by conversion of annual cropland into continuous pasture. Emissions from organic soils were largest in California, Florida, and the upper Midwest, coinciding with largest concentrations of organic soils in the United States that are used for agricultural production.

Figure 7-11: Total Net Annual CO₂ Flux for Mineral Soils under Agricultural Management within States, 2009,

¹⁹⁰ NRI points were classified according to land-use history records starting in 1982 when the NRI survey began, and consequently the classifications were based on less than 20 years from 1990 to 2001.

¹⁹¹ CO₂ emissions associated with liming are also estimated but included in a separate section of the report.

Figure 7-12: Total Net Annual CO₂ Flux for Organic Soils under Agricultural Management within States, 2009, *Land Converted to Grassland*

Methodology

This section includes a brief description of the methodology used to estimate changes in soil C stocks due to agricultural land-use and management activities on mineral soils for *Land Converted to Grassland*. Biomass C stock changes are not explicitly included in this category but losses of associated with conversion of forest to grassland are included in the *Forest Land Remaining Forest Land* section. Further elaboration on the methodologies and data used to estimate stock changes from mineral and organic soils are provided in the *Cropland Remaining Cropland* section and Annex 3.13.

Soil C stock changes were estimated for *Land Converted to Grassland* according to land-use histories recorded in the USDA NRI survey (USDA-NRCS 2000). Land-use and some management information (e.g., crop type, soil attributes, and irrigation) were originally collected for each NRI point on a 5-year cycle beginning in 1982. However, the NRI program initiated annual data collection in 1998, and the annual data are currently available through 2003. NRI points were classified as *Land Converted to Grassland* in a given year between 1990 and 2009 if the land use was grassland, but had been another use in the previous 20 years. Grassland includes pasture and rangeland used for grass forage production, where the primary use is livestock grazing. Rangeland typically includes extensive areas of native grassland that are not intensively managed, while pastures are often seeded grassland, possibly following tree removal, that may or may not be improved with practices such as irrigation and interseeding legumes.

Mineral Soil Carbon Stock Changes

An IPCC Tier 3 model-based approach was applied to estimate C stock changes for *Land Converted to Grassland* on most mineral soils. C stock changes on the remaining soils were estimated with an IPCC Tier 2 approach (Ogle et al. 2003), including prior cropland used to produce vegetables, tobacco, perennial/horticultural crops, and rice; land areas with very gravelly, cobbly, or shaley soils (greater than 35 percent by volume); and land converted from forest or federal ownership.¹⁹² A Tier 2 approach was also used to estimate additional changes in mineral soil C stocks due to sewage sludge amendments. However, stock changes associated with sewage sludge amendments are reported in the *Grassland Remaining Grassland* section.

Tier 3 Approach

Mineral SOC stocks and stock changes were estimated using the Century biogeochemical model as described for *Grassland Remaining Grassland*. Historical land-use and management patterns were used in the Century simulations as recorded in the NRI survey, with supplemental information on fertilizer use and rates from the USDA Economic Research Service Cropping Practices Survey (ERS 1997) and the National Agricultural Statistics Service (NASS 1992, 1999, 2004) (see *Grassland Remaining Grassland* Tier 3 methods section for additional information).

Tier 2 Approach

The Tier 2 approach used for *Land Converted to Grassland* on mineral soils is the same as described for *Cropland Remaining Cropland* (See *Cropland Remaining Cropland* Tier 2 Approach and Annex 3.13 for additional information).

¹⁹² Federal land is not a land use, but rather an ownership designation that is treated as forest or nominal grassland for purposes of these calculations. The specific use for federal lands is not identified in the NRI survey (USDA-NRCS 2000).

Organic Soil Carbon Stock Changes

Annual C emissions from drained organic soils in *Land Converted to Grassland* were estimated using the Tier 2 method provided in IPCC (2003, 2006), which utilizes U.S.-specific C loss rates (Ogle et al. 2003) rather than default IPCC rates. Emissions were based on the 1992 and 1997 *Land Converted to Grassland* areas from the 1997 *National Resources Inventory* (USDA-NRCS 2000). The annual flux estimated for 1992 was applied to 1990 through 1992, and the annual flux estimated for 1997 was applied to 1993 through 2009.

Uncertainty and Time-Series Consistency

Uncertainty analysis for mineral soil C stock changes using the Tier 3 and Tier 2 approaches were based on the same method described in *Cropland Remaining Cropland*, except that the uncertainty inherent in the structure of the Century model was not addressed. The uncertainty or annual C emission estimates from drained organic soils in *Land Converted to Grassland* was estimated using the Tier 2 approach, as described in the *Cropland Remaining Cropland* section.

Uncertainty estimates are presented in Table 7-36 for each subsource (i.e., mineral soil C stocks and organic soil C stocks), disaggregated to the level of the inventory methodology employed (i.e., Tier 2 and Tier 3). Uncertainty for the portions of the Inventory estimated with Tier 2 and 3 approaches was derived using a Monte Carlo approach (see Annex 3.13 for further discussion). A combined uncertainty estimate for changes in agricultural soil C stocks is also included. Uncertainty estimates from each component were combined using the error propagation equation in accordance with IPCC (2006) (i.e., by taking the square root of the sum of the squares of the standard deviations of the uncertain quantities). The combined uncertainty for soil C stocks in *Land Converted to Grassland* ranged from 15 percent below to 15 percent above the 2009 estimate of -23.6 Tg CO₂ Eq.

Table 7-36: Tier 2 Quantitative Uncertainty Estimates for Soil C Stock Changes occurring within *Land Converted to Grassland* (Tg CO₂ Eq. and Percent)

Source	2009 Flux Estimate (Tg CO ₂ Eq.)	Uncertainty Range Relative to Flux Estimate			
		(Tg CO ₂ Eq.)		(%)	
		Lower Bound	Upper Bound	Lower Bound	Upper Bound
Mineral Soil C Stocks: Land Converted to Grassland, Tier 3 Inventory Methodology	(19.5)	(22.2)	(16.7)	-14%	+14%
Mineral Soil C Stocks: Land Converted to Grassland, Tier 2 Inventory Methodology	(5.0)	(7.0)	(2.8)	-39%	+43%
Organic Soil C Stocks: Land Converted to Grassland, Tier 2 Inventory Methodology	0.9	0.2	1.8	-76%	+104%
Combined Uncertainty for Flux associated with Agricultural Soil Carbon Stocks in Land Converted to Grassland					
	(23.6)	(27.0)	(20.0)	-15%	+15%

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

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

QA/QC and Verification

See the QA/QC and Verification section under *Grassland Remaining Grassland*.

Recalculations Discussion

There were minor changes in the current Inventory relative to the previous version in the estimated area of grasslands associated with reconciling the forestland areas from the Forest Inventory and Analysis (FIA) survey with the data from the National Resources Inventory (NRI) (see section 7.1 for more information). The revised areas led to small changes in the soil C stock changes for *Land Converted to Grassland*.

Planned Improvements

The main planned improvement for the next Inventory is to integrate the assessments of soil C stock changes and soil nitrous oxide emissions into a single analysis. This improvement will ensure that the nitrogen and carbon cycles are treated consistently in the national inventory, which is important because the cycles of these elements are linked through plant and soil processes in agricultural lands. This improvement will include the development of an empirically-based uncertainty analysis, which will provide a more rigorous assessment of uncertainty. See Planned Improvements section under *Cropland Remaining Cropland* for additional planned improvements.

7.8. Wetlands Remaining Wetlands

Peatlands Remaining Peatlands

Emissions from Managed Peatlands

Managed peatlands are peatlands which have been cleared and drained for the production of peat. The production cycle of a managed peatland has three phases: land conversion in preparation for peat extraction (e.g., draining, and clearing surface biomass), extraction (which results in the emissions reported under *Peatlands Remaining Peatlands*), and abandonment, restoration or conversion of the land to another use.

CO₂ emissions from the removal of biomass and the decay of drained peat constitute the major greenhouse gas flux from managed peatlands. Managed peatlands may also emit CH₄ and N₂O. The natural production of CH₄ is largely reduced but not entirely shut down when peatlands are drained in preparation for peat extraction (Strack et al., 2004 as cited in IPCC 2006); however, CH₄ emissions are assumed to be insignificant under Tier 1 (IPCC, 2006). N₂O emissions from managed peatlands depend on site fertility. In addition, abandoned and restored peatlands continue to release greenhouse gas emissions, and at present no methodology is provided by IPCC (2006) to estimate greenhouse gas emissions or removals from restored peatlands. This inventory estimates both CO₂ and N₂O emissions from *Peatlands Remaining Peatlands* in accordance with Tier 1 IPCC (2006) guidelines.

CO₂ and N₂O Emissions from *Peatlands Remaining Peatlands*

IPCC (2006) recommends reporting CO₂ and N₂O emissions from lands undergoing active peat extraction (i.e., *Peatlands Remaining Peatlands*) as part of the estimate for emissions from managed wetlands. Peatlands occur in wetland areas where plant biomass has sunk to the bottom of water bodies and water-logged areas and exhausted the oxygen supply below the water surface during the course of decay. Due to these anaerobic conditions, much of the plant matter does not decompose but instead forms layers of peat over decades and centuries. In the United States, peat is extracted for horticulture and landscaping growing media, and for a wide variety of industrial, personal care, and other products. It has not been used for fuel in the United States for many decades. Peat is harvested from two types of peat deposits in the United States: sphagnum bogs in northern states and wetlands in states further south. The peat from sphagnum bogs in northern states, which is nutrient poor, is generally corrected for acidity and mixed with fertilizer. Production from more southerly states is relatively coarse (i.e., fibrous) but nutrient rich.

IPCC (2006) recommends considering both on-site and off-site emissions when estimating CO₂ emissions from *Peatlands Remaining Peatlands* using the Tier 1 approach. Current methodologies estimate only on-site N₂O emissions, since off-site N₂O estimates are complicated by the risk of double-counting emissions from nitrogen fertilizers added to horticultural peat. On-site emissions from managed peatlands occur as the land is cleared of vegetation and the underlying peat is exposed to sun and weather. As this occurs, some peat deposit is lost and CO₂ is emitted from the oxidation of the peat. On-site N₂O is emitted during draining depending on site fertility and if the deposit contains significant amounts of organic nitrogen in inactive form. Draining land in preparation for peat extraction allows bacteria to convert the nitrogen into nitrates which leach to the surface where they are reduced to N₂O.

Off-site CO₂ emissions from managed peatlands occur from the horticultural and landscaping use of peat. CO₂ emissions occur as the nutrient-poor (but now fertilizer-enriched) peat is used in bedding plants, other greenhouse and plant nursery production, and by consumers, and as nutrient-rich (but relatively coarse) peat is used directly in landscaping, athletic fields, golf courses, and plant nurseries. Most of the CO₂ emissions from peat occur off-site, as the peat is processed and sold to firms which, in the United States, use it predominately for horticultural purposes. The magnitude of the CO₂ emitted from peat depends on whether the peat has been extracted from nutrient-rich or

nutrient-poor peat deposits.

Total emissions from *Peatlands Remaining Peatlands* were estimated to be 1.095 Tg CO₂ Eq. in 2009 (see Table 7-37) comprising 1.090 Tg CO₂ Eq. (1,090 Gg) of CO₂ and 0.005 Tg CO₂ Eq. (0.016 Gg) of N₂O. Total emissions in 2009 were about 10 percent larger than total emissions in 2008, with the increase due to the higher peat production reported in Alaska in 2009.

Total emissions from *Peatlands Remaining Peatlands* have fluctuated between 0.88 and 1.23 Tg CO₂ Eq. across the time series with a decreasing trend from 1990 until 1994 followed by an increasing trend through 2000. Since 2000, total emissions show a decreasing trend until 2006 followed by an increasing trend in recent years. CO₂ emissions from *Peatlands Remaining Peatlands* have fluctuated between 0.88 and 1.23 Tg CO₂ across the time series and drive the trends in total emissions. N₂O emissions remained close to zero across the time series, with a decreasing trend from 1990 until 1995 followed by an increasing trend through 2000. N₂O emissions decreased between 2000 and 2008, followed by a leveling off in 2009.

Table 7-37: Emissions from *Peatlands Remaining Peatlands* (Tg CO₂ Eq.)

Gas	1990		2000		2005	2006	2007	2008	2009
CO ₂	1.0		1.2		1.1	0.9	1.0	1.0	1.1
N ₂ O	+		+		+	+	+	+	+
Total	1.0		1.2		1.1	0.9	1.0	1.0	1.1

+ Less than 0.01 Tg CO₂ Eq.

Note: These numbers are based on U.S. production data in accordance with Tier 1 guidelines, which does not take into account imports, exports and stockpiles (i.e., apparent consumption).

Table 7-38: Emissions from *Peatlands Remaining Peatlands* (Gg)

Gas	1990		2000		2005	2006	2007	2008	2009
CO ₂	1,033		1,227		1,079	879	1,012	992	1,090
N ₂ O	+		+		+	+	+	+	+

+ Less than 0.05 Gg

Note: These numbers are based on U.S. production data in accordance with Tier 1 guidelines, which does not take into account imports, exports and stockpiles (i.e., apparent consumption).

Methodology

Off-Site CO₂ Emissions

CO₂ emissions from domestic peat production were estimated using a Tier 1 methodology consistent with IPCC (2006). Off-site CO₂ emissions from *Peatlands Remaining Peatlands* were calculated by apportioning the annual weight of peat produced in the United States (Table 7-39) into peat extracted from nutrient-rich deposits and peat extracted from nutrient-poor deposits using annual percentage by weight figures. These nutrient-rich and nutrient-poor production values were then multiplied by the appropriate default carbon fraction conversion factor taken from IPCC (2006) in order to obtain off-site emission estimates. For the lower 48 states, both annual percentages of peat type by weight and domestic peat production data were sourced from estimates and industry statistics provided in the *Minerals Yearbook* and *Mineral Commodity Summaries* from the U.S. Geological Survey (USGS 1991–2010). To develop these data, the U.S. Geological Survey (USGS; U.S. Bureau of Mines prior to 1997) obtained production and use information by surveying domestic peat producers. The USGS often receives a response to the survey from most of the smaller peat producers, but fewer of the larger ones. For example, of the four active operations producing 23,000 or more metric tons per year, two did not respond to the survey in 2007. As a result, the USGS estimates production from the non-respondent peat producers based on responses to previous surveys (responses from 2004 and 2005, in the case above) or other sources.

The Alaska estimates rely on reported peat production from Alaska's annual Mineral Industry Reports (Szumigala et al. 2010). Similar to the U.S. Geological Survey, Alaska's Mineral Industry Report methodology solicits voluntary reporting of peat production from producers. However, the report does not estimate production for the non-reporting producers, resulting in larger inter-annual variation in reported peat production from Alaska depending on the number of producers who report in a given year (Szumigala 2011). In addition, in both the lower 48 states and Alaska, large variations in peat production can also result from variations in precipitation and the subsequent

moisture conditions, since unusually wet years can hamper peat production (USGS 2010). The methodology estimates Alaska emissions separately from lower 48 emissions because the state conducts its own mineral survey and reports peat production by volume, rather than by weight (Table 7-40). However, volume production data was used to calculate off-site CO₂ emissions from Alaska applying the same methodology but with volume-specific carbon fraction conversion factors from IPCC (2006).¹⁹³

The *apparent consumption* of peat, which includes production plus imports minus exports plus the decrease in stockpiles, in the United States is over two-and-a-half times the amount of domestic peat production. Therefore, off-site CO₂ emissions from the use of all horticultural peat within the United States are not accounted for using the Tier 1 approach. The United States has increasingly imported peat from Canada for horticultural purposes; from 2005 to 2008, imports of sphagnum moss (nutrient-poor) peat from Canada represented 97 percent of total U.S. peat imports (USGS 2010). Most peat produced in the United States is reed-sedge peat, generally from southern states, which is classified as nutrient rich by IPCC (2006). Higher-tier calculations of CO₂ emissions from apparent consumption would involve consideration of the percentages of peat types stockpiled (nutrient rich versus nutrient poor) as well as the percentages of peat types imported and exported.

Table 7-39: Peat Production of Lower 48 States (in thousands of Metric Tons)

Type of Deposit	1990		2000		2005	2006	2007	2008	2009
Nutrient-Rich	595.1		728.6		657.6	529.0	581.0	559.7	554.2
Nutrient-Poor	55.4		63.4		27.4	22.0	54.0	55.4	54.8
Total Production	692.0		792.0		685.0	551.0	635.0	615.0	609.0

Sources: *Minerals Yearbook: Peat* (1990–2008 Reports), *Mineral Commodity Summaries: Peat* (1996–2009 Reports), and Apodaca (2010). United States Geological Survey.

Table 7-40: Peat Production of Alaska (in thousands of Cubic Meters)

	1990		2000		2005	2006	2007	2008	2009
Total Production	49.7		27.2		47.8	50.8	52.3	64.1	183.9

Sources: *Alaska's Mineral Industry* (1992–2009) Reports. Division of Geological & Geophysical Surveys, Alaska Department of Natural Resources.

On-site CO₂ Emissions

IPCC (2006) suggests basing the calculation of on-site emissions estimates on the area of peatlands managed for peat extraction differentiated by the nutrient type of the deposit (rich versus poor). Information on the area of land managed for peat extraction is currently not available for the United States, but in accordance with IPCC (2006), an average production rate for the industry was applied to derive an area estimate. In a mature industrialized peat industry, such as exists in the United States and Canada, the vacuum method¹⁹⁴ can extract up to 100 metric ton per hectare per year (Cleary et al. 2005 as cited in IPCC 2006). The area of land managed for peat extraction in the United States was estimated using nutrient-rich and nutrient-poor production data and the assumption that 100 metric tons of peat are extracted from a single hectare in a single year. The annual land area estimates were then multiplied by the appropriate nutrient-rich or nutrient-poor IPCC (2006) default emission factor in order to calculate on-site CO₂ emission estimates. Production data are not available by weight for Alaska. In order to calculate on-site emissions resulting from *Peatlands Remaining Peatlands* in Alaska, the production data by volume were converted to weight using annual average bulk peat density values, and then converted to land area estimates using the same assumption that a single hectare yields 100 metric tons. The IPCC (2006) on-site emissions equation also includes a term which accounts for emissions resulting from the change in carbon stocks that occurs during the clearing of vegetation prior to peat extraction. Area data on land undergoing conversion to peatlands for peat extraction is also unavailable for the United States. However, USGS records show that the number of active operations in the United

¹⁹³ Peat produced from Alaska was assumed to be nutrient poor; as is the case in Canada, “where deposits of high-quality [but nutrient poor] sphagnum moss are extensive” (USGS 2008).

¹⁹⁴ The vacuum method is one type of extraction that annually “mills” or breaks up the surface of the peat into particles, which then dry during the summer months. The air-dried peat particles are then collected by vacuum harvesters and transported from the area to stockpiles (IPCC 2006).

States has been declining since 1990; therefore it seems reasonable to assume that no new areas are being cleared of vegetation for managed peat extraction. Other changes in carbon stocks in living biomass on managed peatlands are also assumed to be zero under the Tier 1 methodology (IPCC 2006).

On-site N₂O Emissions

IPCC (2006) suggests basing the calculation of on-site N₂O emissions estimates on the area of nutrient-rich peatlands managed for peat extraction. These area data are not available directly for the United States, but the on-site CO₂ emissions methodology above details the calculation of area data from production data. In order to estimate N₂O emissions, the area of nutrient rich *Peatlands Remaining Peatlands* was multiplied by the appropriate default emission factor taken from IPCC (2006).

Uncertainty

The uncertainty associated with peat production data was estimated to be ± 25 percent (Apodaca 2008) and assumed to be normally distributed. The uncertainty associated with peat production data stems from the fact that the USGS receives data from the smaller peat producers but estimates production from some larger peat distributors. This same uncertainty and distribution was assumed for the peat type production percentages. The uncertainty associated with the Alaskan reported production data was assumed to be the same as the lower 48 states, or ± 25 percent with a normal distribution. It should be noted that the Alaskan Department of Natural Resources estimate that around half of producers do not respond to their survey with peat production data; therefore, the production numbers reported are likely to underestimate Alaska peat production (Szumigala 2008). The uncertainty associated with the average bulk density values was estimated to be ± 25 percent with a normal distribution (Apodaca 2008). IPCC (2006) gives uncertainty values for the emissions factors for the area of peat deposits managed for peat extraction based on the range of underlying data used to determine the emissions factors. The uncertainty associated with the emission factors was assumed to be triangularly distributed. The uncertainty values surrounding the carbon fractions were based on IPCC (2006) and the uncertainty was assumed to be uniformly distributed. Based on these values and distributions, a Monte Carlo (Tier 2) uncertainty analysis was applied to estimate the uncertainty of CO₂ and N₂O emissions from *Peatlands Remaining Peatlands*. The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 7-41. CO₂ emissions from *Peatlands Remaining Peatlands* in 2009 were estimated to be between 0.8 and 1.5 Tg CO₂ Eq. at the 95 percent confidence level. This indicates a range of 30 percent below to 34 percent above the 2009 emission estimate of 1.1 Tg CO₂ Eq. N₂O emissions from *Peatlands Remaining Peatlands* in 2009 were estimated to be between 0.001 and 0.007 Tg CO₂ Eq. at the 95 percent confidence level. This indicates a range of 74 percent below to 41 percent above the 2009 emission estimate of 0.005 Tg CO₂ Eq.

Table 7-41: Tier-2 Quantitative Uncertainty Estimates for CO₂ Emissions from *Peatlands Remaining Peatlands*

Source	Gas	2009 Emissions Estimate (Tg CO ₂ Eq.)	Uncertainty Range Relative to Emissions Estimate ^a			
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
<i>Peatlands Remaining Peatlands</i>	CO ₂	1.1	0.8	1.5	-30%	34%
	N ₂ O	+	+	+	-74%	41%

+ Does not exceed 0.01 Tg CO₂ Eq. or 0.5 Gg.

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

QA/QC and Verification

A QA/QC analysis was performed for data gathering and input, documentation, and calculation. The QA/QC analysis did not reveal any inaccuracies or incorrect input values.

Recalculations Discussion

The current Inventory represents the third Inventory report in which emissions from *Peatlands Remaining Peatlands* are included. A revised 2008 estimate of peat production by volume for Alaska was reported in 2010 (Szumigala et

al. 2010). Updating the 2008 production data with this revised estimate led to a 5 percent increase over the previous 2008 emission estimate.

Planned Improvements

In order to further improve estimates of CO₂ and N₂O emissions from *Peatlands Remaining Peatlands*, future efforts will consider options for obtaining better data on the quantity of peat harvested per hectare and the total area undergoing peat extraction.

7.9. Settlements Remaining Settlements

Changes in Carbon Stocks in Urban Trees (IPCC Source Category 5E1)

Urban forests constitute a significant portion of the total U.S. tree canopy cover (Dwyer et al. 2000). Urban areas (cities, towns, and villages) are estimated to cover over 4 percent of the United States (Nowak et al. 2005). With an average tree canopy cover of 27 percent, urban areas account for approximately 3 percent of total tree cover in the continental United States (Nowak et al. 2001). Trees in urban areas of the United States were estimated to account for an average annual net sequestration of 76.5 Tg CO₂ Eq. (20.9 Tg C) over the period from 1990 through 2009. Net C flux from urban trees in 2009 was estimated to be -95.9 Tg CO₂ Eq. (-26.2 Tg C). Annual estimates of CO₂ flux (Table 7-42) were developed based on periodic (1990 and 2000) U.S. Census data on urbanized area. This estimated urban area is smaller than the area categorized as *Settlements* in the Representation of the U.S. Land Base developed for this report, by an average of 21 percent over the 1990 through 2009 time series—i.e., the Census urban area is a subset of the *Settlements* area. Census area data are preferentially used to develop C flux estimates for this source category since these data are more applicable for use with the available peer-reviewed data on urban tree canopy cover and urban tree C sequestration. Annual sequestration increased by 68 percent between 1990 and 2009 due to increases in urban land area. Data on C storage and urban tree coverage were collected since the early 1990s and have been applied to the entire time series in this report.

Net C flux from urban trees is proportionately greater on an area basis than that of forests. This trend is primarily the result of different net growth rates in urban areas versus forests—urban trees often grow faster than forest trees because of the relatively open structure of the urban forest (Nowak and Crane 2002). However, areas in each case are accounted for differently. Because urban areas contain less tree coverage than forest areas, the C storage per hectare of land is in fact smaller for urban areas. However, urban tree reporting occurs on a basis of C sequestered per unit area of tree cover, rather than C sequestered per total land area. Areas covered by urban trees, therefore, appear to have a greater C density than do forested areas (Nowak and Crane 2002).

Table 7-42: Net C Flux from Urban Trees (Tg CO₂ Eq. and Tg C)

Year	Tg CO ₂ Eq.	Tg C
1990	(57.1)	(15.6)
2000	(77.5)	(21.1)
2005	(87.8)	(23.9)
2006	(89.8)	(24.5)
2007	(91.9)	(25.1)
2008	(93.9)	(25.6)
2009	(95.9)	(26.2)

Note: Parentheses indicate net sequestration.

Methodology

Methods for quantifying urban tree biomass, C sequestration, and C emissions from tree mortality and decomposition were taken directly from Nowak and Crane (2002) and Nowak (1994). In general, the methodology used by Nowak and Crane (2002) to estimate net C sequestration in urban trees followed three steps. First, field data from 14 cities were used to generate allometric estimates of biomass from measured tree dimensions. Second, estimates of tree growth and biomass increment were generated from published literature and adjusted for tree condition and land-use class to generate estimates of gross C sequestration in urban trees. Third, estimates of C emissions due to mortality and decomposition were subtracted from gross C sequestration values to derive estimates

of net C sequestration. Sequestration estimates for these cities, in units of carbon sequestered per unit area of tree cover, were then used to estimate urban forest C sequestration in the U.S. by using urban area estimates from U.S. Census data and urban tree cover estimates from remote sensing data, an approach consistent with Nowak and Crane (2002).

This approach is also consistent with the default IPCC methodology in IPCC (2006), although sufficient data are not yet available to separately determine interannual gains and losses in C stocks in the living biomass of urban trees. Annual changes in net C flux from urban trees are based solely on changes in total urban area in the United States.

In order to generate the allometric relationships between tree dimensions and tree biomass, Nowak and Crane (2002) and Nowak (1994, 2007c, 2009) collected field measurements in a number of U.S. cities between 1989 and 2002. For a sample of trees in each of the cities in Table 7-43, data including tree measurements of stem diameter, tree height, crown height and crown width, and information on location, species, and canopy condition were collected. The data for each tree were converted into C storage by applying allometric equations to estimate aboveground biomass, a root-to-shoot ratio to convert aboveground biomass estimates to whole tree biomass, moisture content, a C content of 50 percent (dry weight basis), and an adjustment factor of 0.8 to account for urban trees having less aboveground biomass for a given stem diameter than predicted by allometric equations based on forest trees (Nowak 1994). C storage estimates for deciduous trees include only carbon stored in wood. These calculations were then used to develop an allometric equation relating tree dimensions to C storage for each species of tree, encompassing a range of diameters.

Tree growth was estimated using annual height growth and diameter growth rates for specific land uses and diameter classes. Growth calculations were adjusted by a factor to account for tree condition (fair to excellent, poor, critical, dying, or dead). For each tree, the difference in C storage estimates between year 1 and year ($x + 1$) represents the gross amount of C sequestered. These annual gross C sequestration rates for each species (or genus), diameter class, and land-use condition (e.g., parks, transportation, vacant, golf courses) were then scaled up to city estimates using tree population information. The area of assessment for each city was defined by its political boundaries; parks and other forested urban areas were thus included in sequestration estimates (Nowak 2011).

Most of the field data used to develop the methodology of Nowak et al. were analyzed using the U.S. Forest Service's Urban Forest Effects (UFORE) model. UFORE is a computer model that uses standardized field data from random plots in each city and local air pollution and meteorological data to quantify urban forest structure, values of the urban forest, and environmental effects, including total C stored and annual C sequestration. UFORE was used with field data from a stratified random sample of plots in each city to quantify the characteristics of the urban forest. (Nowak et al. 2007a).

Gross C emissions result from tree death and removals. Estimates of gross C emissions from urban trees were derived by applying estimates of annual mortality and condition, and assumptions about whether dead trees were removed from the site to the total C stock estimate for each city. Estimates of annual mortality rates by diameter class and condition class were derived from a study of street-tree mortality (Nowak 1986). Different decomposition rates were applied to dead trees left standing compared with those removed from the site. For removed trees, different rates were applied to the removed/aboveground biomass in contrast to the belowground biomass. The estimated annual gross C emission rates for each species (or genus), diameter class, and condition class were then scaled up to city estimates using tree population information.

The field data for 13 of the 14 cities are described in Nowak and Crane (2002), Nowak et al. (2007a), and references cited therein. Data for the remaining city, Chicago, were taken from unpublished results (Nowak 2009). The allometric equations applied to the field data for each tree were taken from the scientific literature (see Nowak 1994, Nowak et al. 2002), but if no allometric equation could be found for the particular species, the average result for the genus was used. The adjustment (0.8) to account for less live tree biomass in urban trees was based on information in Nowak (1994). A root-to-shoot ratio of 0.26 was taken from Cairns et al. (1997), and species- or genus-specific moisture contents were taken from various literature sources (see Nowak 1994). Tree growth rates were taken from existing literature. Average diameter growth was based on the following sources: estimates for trees in forest stands came from Smith and Shifley (1984); estimates for trees on land uses with a park-like structure came from deVries (1987); and estimates for more open-grown trees came from Nowak (1994). Formulas from Fleming (1988) formed the basis for average height growth calculations. As described above, growth rates were adjusted to account for tree condition. Growth factors for Atlanta, Boston, Freehold, Jersey City, Moorestown, New York, Philadelphia, and Woodbridge were adjusted based on the typical growth conditions of different land-use categories (e.g., forest stands, park-like stands). Growth factors for the more recent studies in Baltimore, Chicago, Minneapolis, San

Francisco, Syracuse, and Washington were adjusted using an updated methodology based on the condition of each individual tree, which is determined using tree competition factors (depending on whether it is open grown or suppressed) (Nowak 2007b). Assumptions for which dead trees would be removed versus left standing were developed specific to each land use and were based on expert judgment of the authors. Decomposition rates were based on literature estimates (Nowak and Crane 2002).

Estimates of gross and net sequestration rates for each of the 14 cities (Table 7-43) were compiled in units of C sequestration per unit area of tree canopy cover. These rates were used in conjunction with estimates of national urban area and urban tree cover data to calculate national annual net C sequestration by urban trees for the United States. This method was described in Nowak and Crane (2002) and has been modified to incorporate U.S. Census data.

Specifically, urban area estimates were based on 1990 and 2000 U.S. Census data. The 1990 U.S. Census defined urban land as “urbanized areas,” which included land with a population density greater than 1,000 people per square mile, and adjacent “urban places,” which had predefined political boundaries and a population total greater than 2,500. In 2000, the U.S. Census replaced the “urban places” category with a new category of urban land called an “urban cluster,” which included areas with more than 500 people per square mile. Urban land area increased by approximately 36 percent from 1990 to 2000; Nowak et al. (2005) estimate that the changes in the definition of urban land are responsible for approximately 20 percent of the total reported increase in urban land area from 1990 to 2000. Under both 1990 and 2000 definitions, the urban category encompasses most cities, towns, and villages (i.e., it includes both urban and suburban areas).

Settlements area, as assessed in the Representation of the U.S. Land Base developed for this report, encompassed all developed parcels greater than 0.1 hectares in size, including rural transportation corridors, and as previously mentioned represent a larger area than the Census-derived urban area estimates. However, the Census-derived urban area estimates were deemed to be more suitable for estimating national urban tree cover given the data available in the peer-reviewed literature. Specifically, tree canopy cover of U.S. urban areas was estimated by Nowak et al. (2001) to be 27 percent, assessed across Census-delineated urbanized areas, urban places, and places containing urbanized area. This canopy cover percentage is multiplied by the urban area estimated for each year to produce an estimate of national urban tree cover area.

Net annual C sequestration estimates were derived for the 14 cities by subtracting the gross annual emission estimates from the gross annual sequestration estimates. The gross and net annual C sequestration values for each city were divided by each city’s area of tree cover to determine the average annual sequestration rates per unit of tree area for each city. The median value for gross sequestration per unit area of tree cover (0.29 kg C/m²-yr) was then multiplied by the estimate of national urban tree cover area to estimate national annual gross sequestration, per the methods of Nowak and Crane (2002). To estimate national annual net sequestration, the estimate of national annual gross sequestration was multiplied by the average of the ratios of net to gross sequestration (0.72) for those cities that had both estimates. The urban tree cover estimates for each of the 14 cities and the United States were obtained from Dwyer et al. (2000), Nowak et al. (2002), Nowak (2007a), and Nowak (2009). The urban area estimates were taken from Nowak et al. (2005).

Table 7-43: C Stocks (Metric Tons C), Annual C Sequestration (Metric Tons C/yr), Tree Cover (Percent), and Annual C Sequestration per Area of Tree Cover (kg C/m²-yr) for 14 U.S. Cities

City	Carbon Stocks	Gross Annual Sequestration	Net Annual Sequestration	Tree Cover	Gross Annual Sequestration per Area of Tree Cover	Net Annual Sequestration per Area of Tree Cover	Net:Gross Annual Sequestration Ratio
Atlanta, GA	1,219,256	42,093	32,169	36.7%	0.34	0.26	0.76
Baltimore, MD	541,589	14,696	9,261	21.0%	0.35	0.22	0.63
Boston, MA	289,392	9,525	6,966	22.3%	0.30	0.22	0.73
Chicago, IL	649,000	22,800	16,100	17.2%	0.22	0.16	0.71
Freehold, NJ	18,144	494	318	34.4%	0.28	0.18	0.64
Jersey City, NJ	19,051	807	577	11.5%	0.18	0.13	0.71
Minneapolis, MN	226,796	8,074	4,265	26.4%	0.20	0.11	0.53
Moorestown, NJ	106,141	3,411	2,577	28.0%	0.32	0.24	0.76
New York, NY	1,224,699	38,374	20,786	20.9%	0.23	0.12	0.54
Philadelphia, PA	480,808	14,606	10,530	15.7%	0.27	0.20	0.72

San Francisco, CA	175,994	4,627	4,152	11.9%	0.33	0.29	0.90
Syracuse, NY	156,943	4,917	4,270	23.1%	0.33	0.29	0.87
Washington, DC	477,179	14,696	11,661	28.6%	0.32	0.26	0.79
Woodbridge, NJ	145,150	5,044	3,663	29.5%	0.28	0.21	0.73
Median: 0.29						Mean: 0.72	

NA = not analyzed.

Sources: Nowak and Crane (2002), Nowak (2007a,c), and Nowak (2009).

Uncertainty and Time-Series Consistency

Uncertainty associated with changes in C stocks in urban trees includes the uncertainty associated with urban area, percent urban tree coverage, and estimates of gross and net C sequestration for each of the 14 U.S. cities. A 10 percent uncertainty was associated with urban area estimates while a 5 percent uncertainty was associated with percent urban tree coverage. Both of these uncertainty estimates were based on expert judgment. Uncertainty associated with estimates of gross and net C sequestration for each of the 14 U.S. cities was based on standard error estimates for each of the city-level sequestration estimates reported by Nowak (2007c) and Nowak (2009). These estimates are based on field data collected in each of the 14 U.S. cities, and uncertainty in these estimates increases as they are scaled up to the national level.

Additional uncertainty is associated with the biomass equations, conversion factors, and decomposition assumptions used to calculate C sequestration and emission estimates (Nowak et al. 2002). These results also exclude changes in soil C stocks, and there may be some overlap between the urban tree C estimates and the forest tree C estimates. Due to data limitations, urban soil flux is not quantified as part of this analysis, while reconciliation of urban tree and forest tree estimates will be addressed through the land-representation effort described in the Planned Improvements section of this chapter.

A Monte Carlo (Tier 2) uncertainty analysis was applied to estimate the overall uncertainty of the sequestration estimate. The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 7-44. The net C flux from changes in C stocks in urban trees in 2009 was estimated to be between -116.8 and -77.7 Tg CO₂ Eq. at a 95 percent confidence level. This indicates a range of 22 percent below and 19 percent above the 2009 flux estimate of -95.9 Tg CO₂ Eq.

Table 7-44: Tier 2 Quantitative Uncertainty Estimates for Net C Flux from Changes in C Stocks in Urban Trees (Tg CO₂ Eq. and Percent)

Source	Gas	2009 Flux Estimate (Tg CO ₂ Eq.)	Uncertainty Range Relative to Flux Estimate (Tg CO ₂ Eq.) (%)			
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Changes in C Stocks in Urban Trees	CO ₂	(95.9)	(116.8)	(77.7)	-22%	+19%

Note: Parentheses indicate negative values or net sequestration.

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

QA/QC and Verification

The net C flux resulting from urban trees was predominately calculated using estimates of gross and net C sequestration estimates for urban trees and urban tree coverage area published in the literature. The validity of these data for their use in this section of the inventory was evaluated through correspondence established with an author of the papers. Through this correspondence, the methods used to collect the urban tree sequestration and area data were further clarified and the use of these data in the inventory was reviewed and validated (Nowak 2002a, 2007b, 2011).

Planned Improvements

A consistent representation of the managed land base in the United States is being developed. A component of this effort, which is discussed at the beginning of the Land Use, Land-Use Change, and Forestry chapter, will involve reconciling the overlap between urban forest and non-urban forest greenhouse gas inventories. It is highly likely

that urban forest inventories are including areas also defined as forest land under the Forest Inventory and Analysis (FIA) program of the USDA Forest Service, resulting in “double-counting” of these land areas in estimates of C stocks and fluxes for the inventory. The Forest Service is currently conducting research that will define urban area boundaries and make it possible to distinguish forest from forested urban areas. Once those data become available, they will be incorporated into estimates of net C flux resulting from urban trees.

Urban forest data for additional cities are expected in the near future, as are updated data for cities currently included in the estimates. The use of these data will further refine the estimated median sequestration value. It may also be possible to report C losses and gains separately in the future. It is currently not possible, since existing studies estimate rather than measure natality or mortality; net sequestration estimates are based on assumptions about whether dead trees are being removed, burned, or chipped. There is an effort underway to assess urban tree loss to mortality and removals, which would allow for direct calculation of C losses and gains from observed rather than estimated natality and mortality of trees.

Data from the 2010 U.S. Census is expected to provide updated U.S. urbanized area, which would allow for refinement of the urban area time series. Revisions to urban area time series will result in revisions to prior years’ C flux estimates.

A revised average tree canopy cover percentage for U.S. urban areas is anticipated to become available in the peer-reviewed literature in the near future, which would allow for updated C flux estimates. Furthermore, urban tree cover data specific to each state is also expected in the near future. It may be possible to develop a set of state-specific sequestration rates for more granular and regionally precise C flux estimates by coupling these data with adjusted growth rates for each U.S. state. Future research may also enable more complete coverage of changes in the C stock in urban trees for all *Settlements* land. To provide estimates for all *Settlements*, research would need to establish the extent of overlap between *Settlements* and Census-defined urban areas, and would have to characterize sequestration on non-urban *Settlements* land.

Direct N₂O Fluxes from Settlement Soils (IPCC Source Category 5E1)

Of the synthetic N fertilizers applied to soils in the United States, approximately 2.5 percent are currently applied to lawns, golf courses, and other landscaping occurring within settlement areas. Application rates are lower than those occurring on cropped soils, and, therefore, account for a smaller proportion of total U.S. soil N₂O emissions per unit area. In addition to synthetic N fertilizers, a portion of surface applied sewage sludge is applied to settlement areas. In 2009, N₂O emissions from this source were 1.5 Tg CO₂ Eq. (4.9 Gg). There was an overall increase of 55 percent over the period from 1990 through 2009 due to a general increase in the application of synthetic N fertilizers to an expanding settlement area. Interannual variability in these emissions is directly attributable to interannual variability in total synthetic fertilizer consumption and sewage sludge applications in the United States. Emissions from this source are summarized in Table 7-45.

Table 7-45: Direct N₂O Fluxes from Soils in *Settlements Remaining Settlements* (Tg CO₂ Eq. and Gg N₂O)

Year	Tg CO ₂ Eq.	Gg
1990	1.0	3.2
2000	1.1	3.7
2005	1.5	4.7
2006	1.5	4.8
2007	1.6	5.1
2008	1.5	4.9
2009	1.5	4.9

Note: These estimates include direct N₂O emissions from N fertilizer additions only. Indirect N₂O emissions from fertilizer additions are reported in the Agriculture chapter. These estimates include emissions from both *Settlements Remaining Settlements* and from *Land Converted to Settlements*.

Methodology

For soils within *Settlements Remaining Settlements*, the IPCC Tier 1 approach was used to estimate soil N₂O emissions from synthetic N fertilizer and sewage sludge additions. Estimates of direct N₂O emissions from soils in settlements were based on the amount of N in synthetic commercial fertilizers applied to settlement soils, and the

amount of N in sewage sludge applied to non-agricultural land and surface disposal of sewage sludge (see Annex 3.11 for a detailed discussion of the methodology for estimating sewage sludge application).

Nitrogen applications to settlement soils are estimated using data compiled by the USGS (Ruddy et al. 2006). The USGS estimated on-farm and non-farm fertilizer use is based on sales records at the county level from 1982 through 2001 (Ruddy et al. 2006). Non-farm N fertilizer was assumed to be applied to settlements and forest lands; values for 2002 through 2008 were based on 2001 values adjusted for annual total N fertilizer sales in the United States because there is no new activity data on application after 2001. Settlement application was calculated by subtracting forest application from total non-farm fertilizer use. Sewage sludge applications were derived from national data on sewage sludge generation, disposition, and N content (see Annex 3.11 for further detail). The total amount of N resulting from these sources was multiplied by the IPCC default emission factor for applied N (1 percent) to estimate direct N₂O emissions (IPCC 2006). The volatilized and leached/runoff N fractions for settlements, calculated with the IPCC default volatilization factors (10 or 20 percent, respectively, for synthetic or organic N fertilizers) and leaching/runoff factor for wet areas (30 percent), were included with indirect emissions, as reported in the N₂O Emissions from Agricultural Soil Management source category of the Agriculture chapter (consistent with reporting guidance that all indirect emissions are included in the Agricultural Soil Management source category).

Uncertainty and Time-Series Consistency

The amount of N₂O emitted from settlements depends not only on N inputs and fertilized area, but also on a large number of variables, including organic C availability, oxygen gas partial pressure, soil moisture content, pH, temperature, and irrigation/watering practices. The effect of the combined interaction of these variables on N₂O flux is complex and highly uncertain. The IPCC default methodology does not explicitly incorporate any of these variables, except variations in fertilizer N and sewage sludge application rates. All settlement soils are treated equivalently under this methodology.

Uncertainties exist in both the fertilizer N and sewage sludge application rates in addition to the emission factors. Uncertainty in fertilizer N application was assigned a default level¹⁹⁵ of ±50 percent. Uncertainty in the amounts of sewage sludge applied to non-agricultural lands and used in surface disposal was derived from variability in several factors, including: (1) N content of sewage sludge; (2) total sludge applied in 2000; (3) wastewater existing flow in 1996 and 2000; and (4) the sewage sludge disposal practice distributions to non-agricultural land application and surface disposal. Uncertainty in the emission factors was provided by the IPCC (2006).

Quantitative uncertainty of this source category was estimated through the IPCC-recommended Tier 2 uncertainty estimation methodology. The uncertainty ranges around the 2005 activity data and emission factor input variables were directly applied to the 2009 emission estimates. The results of the quantitative uncertainty analysis are summarized in Table 7-46. N₂O emissions from soils in Settlements Remaining Settlements in 2009 were estimated to be between 0.8 and 4.0 Tg CO₂ Eq. at a 95 percent confidence level. This indicates a range of 49 percent below to 163 percent above the 2009 emission estimate of 1.5 Tg CO₂ Eq.

Table 7-46: Quantitative Uncertainty Estimates of N₂O Emissions from Soils in *Settlements Remaining Settlements* (Tg CO₂ Eq. and Percent)

Source	Gas	2009 Emissions (Tg CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate			
			(Tg CO ₂ Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Settlements Remaining Settlements:						
N ₂ O Fluxes from Soils	N ₂ O	1.5	0.8	4.0	-49%	163%

Note: This estimate includes direct N₂O emissions from N fertilizer additions to both *Settlements Remaining Settlements* and from *Land Converted to Settlements*.

¹⁹⁵ No uncertainty is provided with the USGS application data (Ruddy et al. 2006) so a conservative ±50% was used in the analysis.

Planned Improvements

A minor improvement is planned to update the uncertainty analysis for direct emissions from settlements to be consistent with the most recent activity data for this source.

7.10. Land Converted to Settlements (Source Category 5E2)

Land-use change is constantly occurring, and land under a number of uses undergoes urbanization in the United States each year. However, data on the amount of land converted to settlements is currently lacking. Given the lack of available information relevant to this particular IPCC source category, it is not possible to separate CO₂ or N₂O fluxes on *Land Converted to Settlements* from fluxes on *Settlements Remaining Settlements* at this time.

7.11. Other (IPCC Source Category 5G)

Changes in Yard Trimming and Food Scrap Carbon Stocks in Landfills

In the United States, a significant change in C stocks results from the removal of yard trimmings (i.e., grass clippings, leaves, and branches) and food scraps from settlements to be disposed in landfills. Yard trimmings and food scraps account for a significant portion of the municipal waste stream, and a large fraction of the collected yard trimmings and food scraps are discarded in landfills. C contained in landfilled yard trimmings and food scraps can be stored for very long periods.

Carbon storage estimates are associated with particular land uses. For example, harvested wood products are accounted for under *Forest Land Remaining Forest Land* because these wood products are a component of the forest ecosystem. The wood products serve as reservoirs to which C resulting from photosynthesis in trees is transferred, but the removals in this case occur in the forest. C stock changes in yard trimmings and food scraps are associated with settlements, but removals in this case do not occur within settlements. To address this complexity, yard trimming and food scrap C storage is therefore reported under the “Other” source category.

Both the amount of yard trimmings collected annually and the fraction that is landfilled have declined over the last decade. In 1990, over 53 million metric tons (wet weight) of yard trimmings and food scraps were generated (i.e., put at the curb for collection to be taken to disposal sites or to composting facilities) (EPA 2011; Schneider 2007, 2008). Since then, programs banning or discouraging yard trimmings disposal have led to an increase in backyard composting and the use of mulching mowers, and a consequent 5 percent decrease in the tonnage generated (i.e., collected for composting or disposal). At the same time, an increase in the number of municipal composting facilities has reduced the proportion of collected yard trimmings that are discarded in landfills—from 72 percent in 1990 to 33 percent in 2009. The net effect of the reduction in generation and the increase in composting is a 57 percent decrease in the quantity of yard trimmings disposed in landfills since 1990.

Food scraps generation has grown by 44 percent since 1990, and though the proportion of food scraps discarded in landfills has decreased slightly from 82 percent in 1990 to 80 percent in 2009, the tonnage disposed in landfills has increased considerably (by 40 percent). Overall, the decrease in the yard trimmings landfill disposal rate has more than compensated for the increase in food scrap disposal in landfills, and the net result is a decrease in annual landfill carbon storage from 24.2 Tg CO₂ Eq. in 1990 to 12.6 Tg CO₂ Eq. in 2009 (Table 7-47 and Table 7-48).

Table 7-47: Net Changes in Yard Trimming and Food Scrap Stocks in Landfills (Tg CO₂ Eq.)

Carbon Pool	1990		2000		2005	2006	2007	2008	2009
Yard Trimmings	(21.0)		(8.8)		(7.3)	(7.5)	(7.0)	(7.3)	(8.5)
Grass	(1.8)		(0.7)		(0.6)	(0.6)	(0.6)	(0.7)	(0.8)
Leaves	(9.0)		(3.9)		(3.3)	(3.4)	(3.2)	(3.4)	(3.9)
Branches	(10.2)		(4.2)		(3.3)	(3.4)	(3.2)	(3.3)	(3.8)
Food Scraps	(3.2)		(4.4)		(4.3)	(3.5)	(3.9)	(3.9)	(4.1)
Total Net Flux	(24.2)		(13.2)		(11.5)	(11.0)	(10.9)	(11.2)	(12.6)

Note: Totals may not sum due to independent rounding.

Table 7-48: Net Changes in Yard Trimming and Food Scrap Stocks in Landfills (Tg C)

Carbon Pool	1990		2000		2005	2006	2007	2008	2009
Yard Trimmings	(5.7)		(2.4)		(2.0)	(2.0)	(1.9)	(2.0)	(2.3)
Grass	(0.5)		(0.2)		(0.2)	(0.2)	(0.2)	(0.2)	(0.2)
Leaves	(2.5)		(1.1)		(0.9)	(0.9)	(0.9)	(0.9)	(1.1)
Branches	(2.8)		(1.2)		(0.9)	(0.9)	(0.9)	(0.9)	(1.0)
Food Scraps	(0.9)		(1.2)		(1.2)	(1.0)	(1.1)	(1.1)	(1.1)
Total Net Flux	(6.6)		(3.6)		(3.1)	(3.0)	(3.0)	(3.1)	(3.4)

Note: Totals may not sum due to independent rounding.

Methodology

When wastes of biogenic origin (such as yard trimmings and food scraps) are landfilled and do not completely decompose, the C that remains is effectively removed from the global C cycle. Empirical evidence indicates that yard trimmings and food scraps do not completely decompose in landfills (Barlaz 1998, 2005, 2008; De la Cruz and Barlaz 2010), and thus the stock of carbon in landfills can increase, with the net effect being a net atmospheric removal of carbon. Estimates of net C flux resulting from landfilled yard trimmings and food scraps were developed by estimating the change in landfilled C stocks between inventory years, based on methodologies presented for the Land Use, Land-Use Change, and Forestry sector in IPCC (2003). C stock estimates were calculated by determining the mass of landfilled C resulting from yard trimmings or food scraps discarded in a given year; adding the accumulated landfilled C from previous years; and subtracting the mass of C landfilled in previous years that decomposed.

To determine the total landfilled C stocks for a given year, the following were estimated: (1) the composition of the yard trimmings; (2) the mass of yard trimmings and food scraps discarded in landfills; (3) the C storage factor of the landfilled yard trimmings and food scraps; and (4) the rate of decomposition of the degradable C. The composition of yard trimmings was assumed to be 30 percent grass clippings, 40 percent leaves, and 30 percent branches on a wet weight basis (Oshins and Block 2000). The yard trimmings were subdivided, because each component has its own unique adjusted C storage factor and rate of decomposition. The mass of yard trimmings and food scraps disposed of in landfills was estimated by multiplying the quantity of yard trimmings and food scraps discarded by the proportion of discards managed in landfills. Data on discards (i.e., the amount generated minus the amount diverted to centralized composting facilities) for both yard trimmings and food scraps were taken primarily from *Municipal Solid Waste Generation, Recycling, and Disposal in the United States: Facts and Figures for 2009* (EPA 2011), which provides data for 1960, 1970, 1980, 1990, 2000, and 2005 through 2009. To provide data for some of the missing years, detailed backup data were obtained from Schneider (2007, 2008). Remaining years in the time series for which data were not provided were estimated using linear interpolation. The EPA (2011) report does not subdivide discards of individual materials into volumes landfilled and combusted, although it provides an estimate of the proportion of overall waste stream discards managed in landfills¹⁹⁶ and combustors with energy recovery (i.e., ranging from 100 percent and 0 percent, respectively, in 1960 to 81 percent and 19 percent in 2000); it is assumed that the proportion of each individual material (food scraps, grass, leaves, branches) that is landfilled is the same as the proportion across the overall waste stream.

The amount of C disposed of in landfills each year, starting in 1960, was estimated by converting the discarded landfilled yard trimmings and food scraps from a wet weight to a dry weight basis, and then multiplying by the initial (i.e., pre-decomposition) C content (as a fraction of dry weight). The dry weight of landfilled material was calculated using dry weight to wet weight ratios (Tchobanoglous et al. 1993, cited by Barlaz 1998) and the initial C contents and the C storage factors were determined by Barlaz (1998, 2005, 2008) (Table 7-49).

The amount of C remaining in the landfill for each subsequent year was tracked based on a simple model of C fate. As demonstrated by Barlaz (1998, 2005, 2008), a portion of the initial C resists decomposition and is essentially persistent in the landfill environment. Barlaz (1998, 2005, 2008) conducted a series of experiments designed to

¹⁹⁶ EPA (2011) reports discards in two categories: “combustion with energy recovery” and “landfill, other disposal,” which includes combustion without energy recovery. For years in which there is data from previous EPA reports on combustion without energy recovery, EPA assumes these estimates are still applicable. For 2000 to present, EPA assumes that any combustion of MSW that occurs includes energy recovery, so all discards to “landfill, other disposal” are assumed to go to landfills.

measure biodegradation of yard trimmings, food scraps, and other materials, in conditions designed to promote decomposition (i.e., by providing ample moisture and nutrients). After measuring the initial C content, the materials were placed in sealed containers along with a “seed” containing methanogenic microbes from a landfill. Once decomposition was complete, the yard trimmings and food scraps were re-analyzed for C content; the C remaining in the solid sample can be expressed as a proportion of initial C (shown in the row labeled “CS” in Table 7-49).

The modeling approach applied to simulate U.S. landfill C flows builds on the findings of Barlaz (1998, 2005, 2008). The proportion of C stored is assumed to persist in landfills. The remaining portion is assumed to degrade, resulting in emissions of CH₄ and CO₂ (the CH₄ emissions resulting from decomposition of yard trimmings and food scraps are accounted for in the “Waste” chapter). The degradable portion of the C is assumed to decay according to first-order kinetics.

The first-order decay rates, k , for each component were derived from De la Cruz and Barlaz (2010). De la Cruz and Barlaz (2010) calculate first-order decay rates using laboratory data published in Eleazer et al. (1997), and a correction factor, f , is found so that the weighted average decay rate for all components is equal to the AP-42 default decay rate (0.04) for mixed MSW for regions that receive more than 25 inches of rain annually. Because AP-42 values were developed using landfill data from approximately 1990, 1990 waste composition for the United States from EPA’s *Characterization of Municipal Solid Waste in the United States: 1990 Update* was used to calculate f . This correction factor is then multiplied by the Eleazer et al. (1997) decay rates of each waste component to develop field-scale first-order decay rates.

De la Cruz and Barlaz (2010) also use other assumed initial decay rates for mixed MSW in place of the AP-42 default value based on different types of environments in which landfills in the United States are found, including dry conditions (less than 25 inches of rain annually, $k=0.02$) and bioreactor landfill conditions (moisture is controlled for rapid decomposition, $k=0.12$). The *Landfills* section of the Inventory (which estimates CH₄ emissions) estimates the overall MSW decay rate by partitioning the U.S. landfill population into three categories, based on annual precipitation ranges of (1) less than 20 inches of rain per year, (2) 20 to 40 inches of rain per year, and (3) greater than 40 inches of rain per year. These correspond to overall MSW decay rates of 0.020, 0.038, and 0.057 yr⁻¹, respectively.

De la Cruz and Barlaz (2010) calculate component-specific decay rates corresponding to the first value (0.020 yr⁻¹), but not for the other two overall MSW decay rates. To maintain consistency between landfill methodologies across the Inventory, the correction factors (f) were developed for decay rates of 0.038 and 0.057 yr⁻¹ through linear interpolation. A weighted national average component-specific decay rate was calculated by assuming that waste generation is proportional to population (the same assumption used in the landfill methane emission estimate), based on population data from the 2000 U.S. Census. The component-specific decay rates are shown in Table 7-49.

For each of the four materials (grass, leaves, branches, food scraps), the stock of C in landfills for any given year is calculated according to the following formula:

$$LFC_{i,t} = \sum_n^t W_{i,n} \times (1 - MC_i) \times ICC_i \times \{ [CS_i \times ICC_i] + [(1 - (CS_i \times ICC_i)) \times e^{-k(t-n)}] \}$$

where,

t	=	Year for which C stocks are being estimated (year),
i	=	Waste type for which C stocks are being estimated (grass, leaves, branches, food scraps),
$LFC_{i,t}$	=	Stock of C in landfills in year t , for waste i (metric tons),
$W_{i,n}$	=	Mass of waste i disposed in landfills in year n (metric tons, wet weight),
n	=	Year in which the waste was disposed (year, where 1960 < n < t),
MC_i	=	Moisture content of waste i (percent of water),
CS_i	=	Proportion of initial C that is stored for waste i (percent),
ICC_i	=	Initial C content of waste i (percent),
e	=	Natural logarithm, and
k	=	First-order decay rate for waste i , (year ⁻¹).

For a given year t , the total stock of C in landfills ($TLFC_t$) is the sum of stocks across all four materials (grass, leaves, branches, food scraps). The annual flux of C in landfills (F_t) for year t is calculated as the change in stock compared to the preceding year:

$$F_t = TLFC_t - TLFC_{(t-1)}$$

Thus, the C placed in a landfill in year n is tracked for each year t through the end of the inventory period (2009). For example, disposal of food scraps in 1960 resulted in depositing about 1,135,000 metric tons of C. Of this amount, 16 percent (179,000 metric tons) is persistent; the remaining 84 percent (956,000 metric tons) is degradable. By 1965, more than half of the degradable portion (518,000 metric tons) decomposes, leaving a total of 617,000 metric tons (the persistent portion, plus the remainder of the degradable portion).

Continuing the example, by 2009, the total food scraps C originally disposed in 1960 had declined to 179,000 metric tons (i.e., virtually all degradable C had decomposed). By summing the C remaining from 1960 with the C remaining from food scraps disposed in subsequent years (1961 through 2009), the total landfill C from food scraps in 2009 was 35.9 million metric tons. This value is then added to the C stock from grass, leaves, and branches to calculate the total landfill C stock in 2009, yielding a value of 247.1 million metric tons (as shown in Table 7-50). In exactly the same way total net flux is calculated for forest C and harvested wood products, the total net flux of landfill C for yard trimmings and food scraps for a given year (Table 7-48) is the difference in the landfill C stock for that year and the stock in the preceding year. For example, the net change in 2009 shown in Table 7-48 (3.4 Tg C) is equal to the stock in 2009 (247.1 Tg C) minus the stock in 2008 (243.7 Tg C).

The C stocks calculated through this procedure are shown in Table 7-50.

Table 7-49: Moisture Content (%), C Storage Factor, Proportion of Initial C Sequestered (%), Initial C Content (%), and Decay Rate (year⁻¹) for Landfilled Yard Trimmings and Food Scraps in Landfills

Variable	Yard Trimmings			Food Scraps
	Grass	Leaves	Branches	
Moisture Content (% H ₂ O)	70	30	10	70
CS, proportion of initial C stored (%)	53	85	77	16
Initial C Content (%)	45	46	49	51
Decay Rate (year ⁻¹)	0.323	0.185	0.016	0.156

Table 7-50: C Stocks in Yard Trimmings and Food Scraps in Landfills (Tg C)

Carbon Pool	1990	2000	2005	2006	2007	2008	2009
Yard Trimmings	155.8	191.9	202.9	205.0	206.9	208.9	211.2
Branches	74.6	92.4	97.5	98.5	99.3	100.2	101.3
Leaves	66.7	82.4	87.3	88.3	89.1	90.1	91.1
Grass	14.5	17.2	18.1	18.2	18.4	18.6	18.8
Food Scraps	21.3	27.0	31.7	32.7	33.7	34.8	35.9
Total Carbon Stocks	177.2	218.9	234.6	237.6	240.6	243.7	247.1

Note: Totals may not sum due to independent rounding.

Uncertainty and Time-Series Consistency

The uncertainty analysis for landfilled yard trimmings and food scraps includes an evaluation of the effects of uncertainty for the following data and factors: disposal in landfills per year (tons of C), initial C content, moisture content, decay rate, and proportion of C stored. The C storage landfill estimates are also a function of the composition of the yard trimmings (i.e., the proportions of grass, leaves and branches in the yard trimmings mixture). There are respective uncertainties associated with each of these factors.

A Monte Carlo (Tier 2) uncertainty analysis was applied to estimate the overall uncertainty of the sequestration estimate. The results of the Tier 2 quantitative uncertainty analysis are summarized in Table 7-51. Total yard trimmings and food scraps CO₂ flux in 2009 was estimated to be between -21.2 and -6.2 Tg CO₂ Eq. at a 95 percent confidence level (or 19 of 20 Monte Carlo stochastic simulations). This indicates a range of 68 percent below to 51 percent above the 2009 flux estimate of -12.6 Tg CO₂ Eq. More information on the uncertainty estimates for Yard Trimmings and Food Scraps in Landfills is contained within the Uncertainty Annex.

Table 7-51: Tier 2 Quantitative Uncertainty Estimates for CO₂ Flux from Yard Trimmings and Food Scraps in Landfills (Tg CO₂ Eq. and Percent)

Source	Gas	2009 Flux Estimate (Tg CO ₂ Eq.)	Uncertainty Range Relative to Flux Estimate ^a			
			(Tg CO ₂ Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Yard Trimmings and Food Scraps	CO ₂	(12.6)	(21.2)	(6.2)	-68%	+51%

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

Note: Parentheses indicate negative values or net C sequestration.

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

QA/QC and Verification

A QA/QC analysis was performed for data gathering and input, documentation, and calculation and did not reveal any systematic inaccuracies or incorrect input values.

Recalculations Discussion

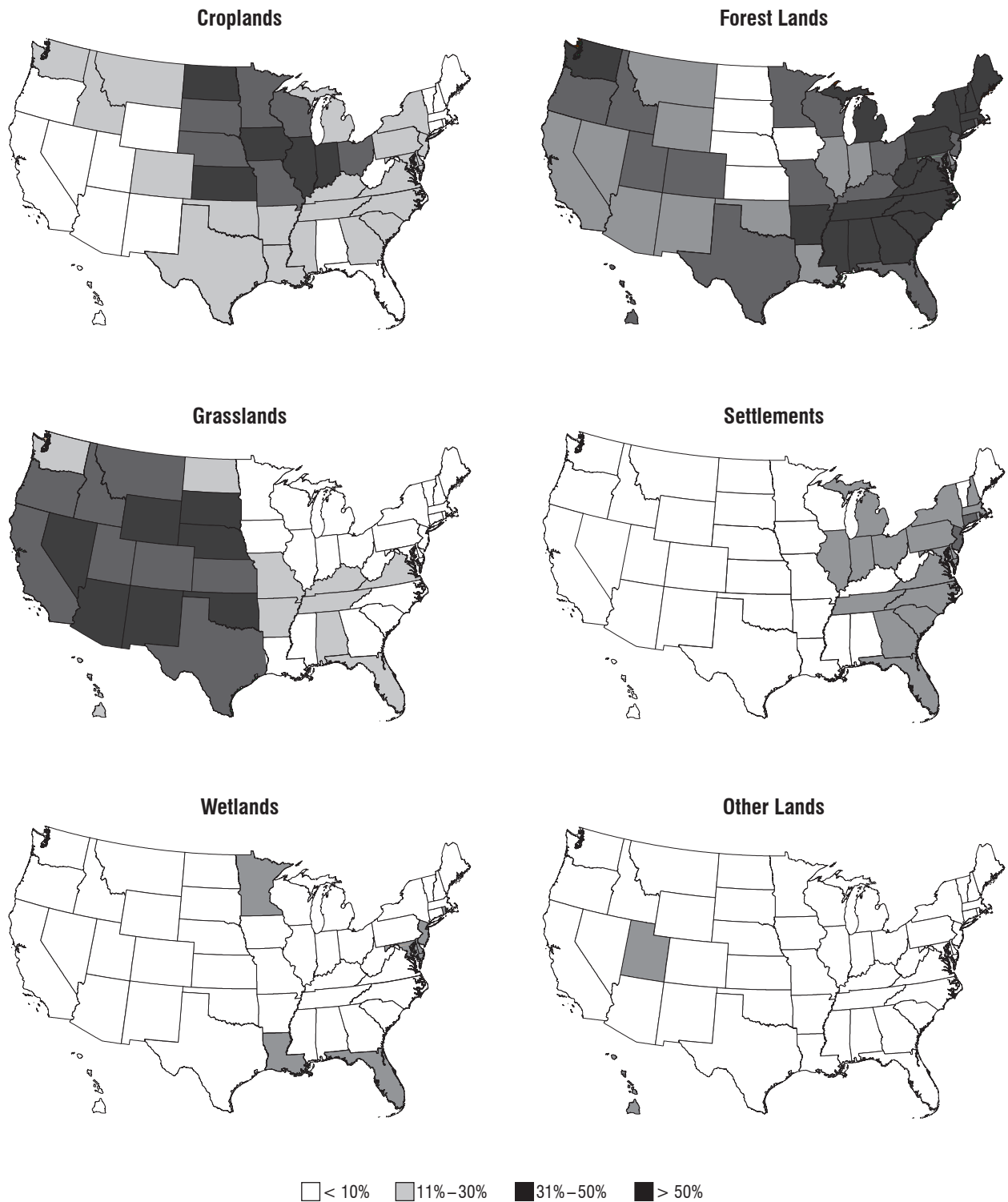
First-order decay rate constants were updated based on De la Cruz and Barlaz (2010), as described in the methodology section. Input data were updated for the years: 1990, 2000, 2005, and 2007 through 2009 based on the updated values reported in *Municipal Solid Waste Generation, Recycling, and Disposal in the United States: Facts and Figures for 2009* (EPA 2011). As a result, C storage estimates for those years were revised relative to the previous Inventory. While data inputs for intervening years in the timeseries were not revised, overall C storage in any given year is dependent on the previous year's storage (as shown in the second equation above), and so C storage estimates for those years were also revised. These revisions resulted in an annual average increase in C stored in landfills of 4.2 percent across the timeseries.

Planned Improvements

Future work is planned to evaluate the potential contribution of inorganic C, primarily in the form of carbonates, to landfill sequestration, as well as the consistency between the estimates of C storage described in this chapter and the estimates of landfill CH₄ emissions described in the Waste chapter.

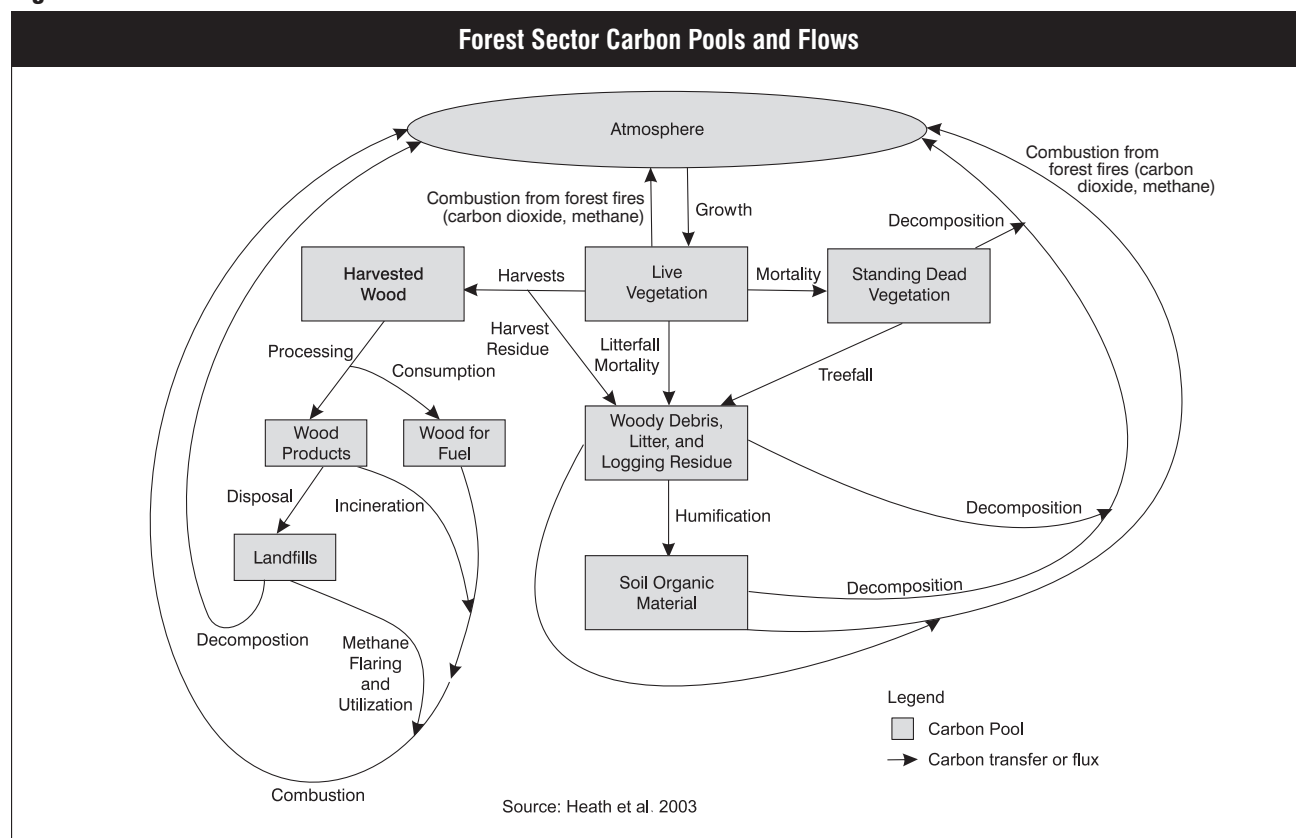
Figure 7-1

Percent of Total Land Area in the General Land Use Categories for 2009



Note: Land use/land-use change categories were aggregated into the 6 general land-use categories based on the current use in 2009.

Figure 7-2



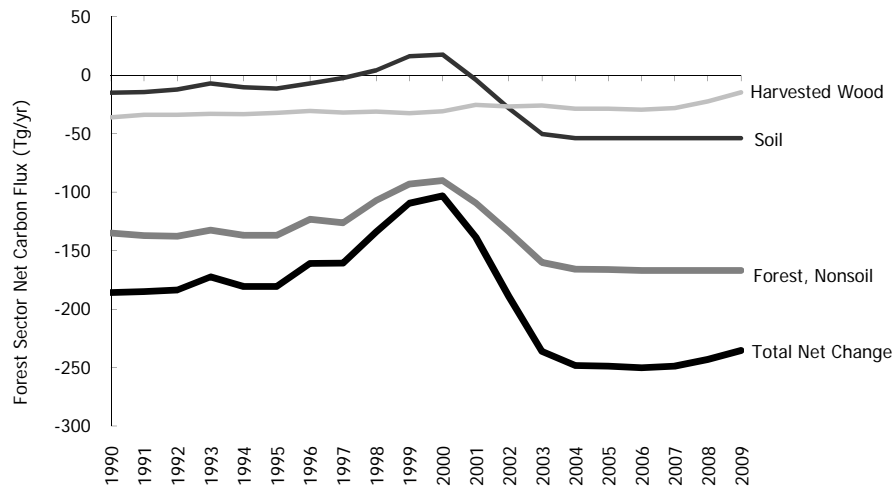


Figure 7-3: Estimates of Net Annual Changes in C Stocks for Major C Pools

Figure 7-4

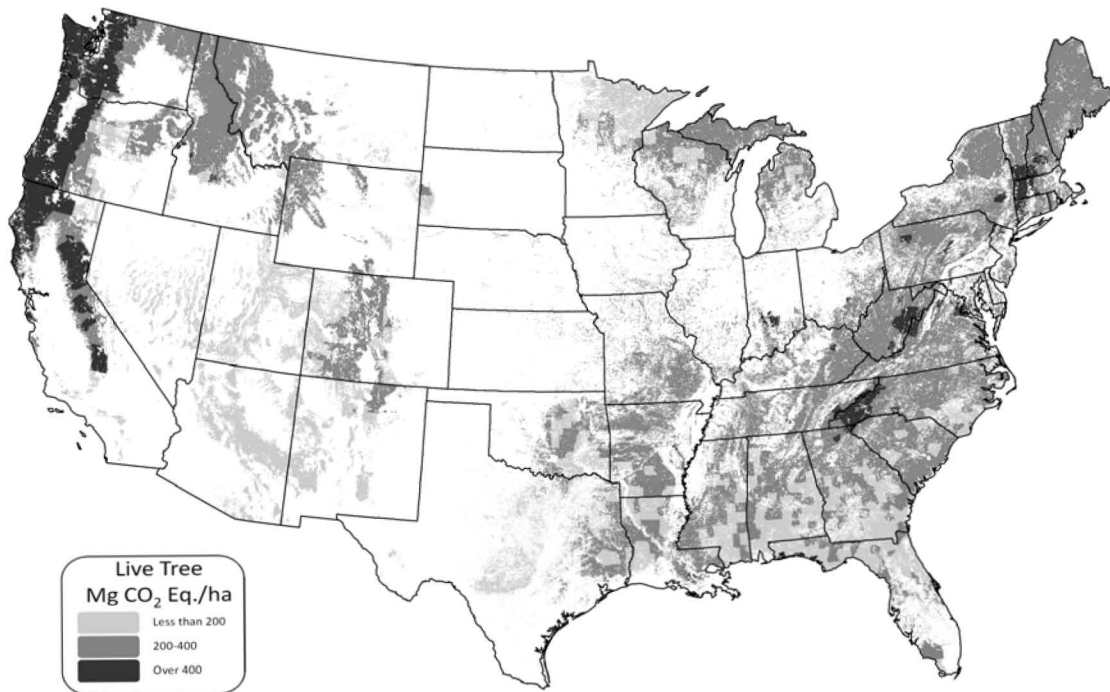
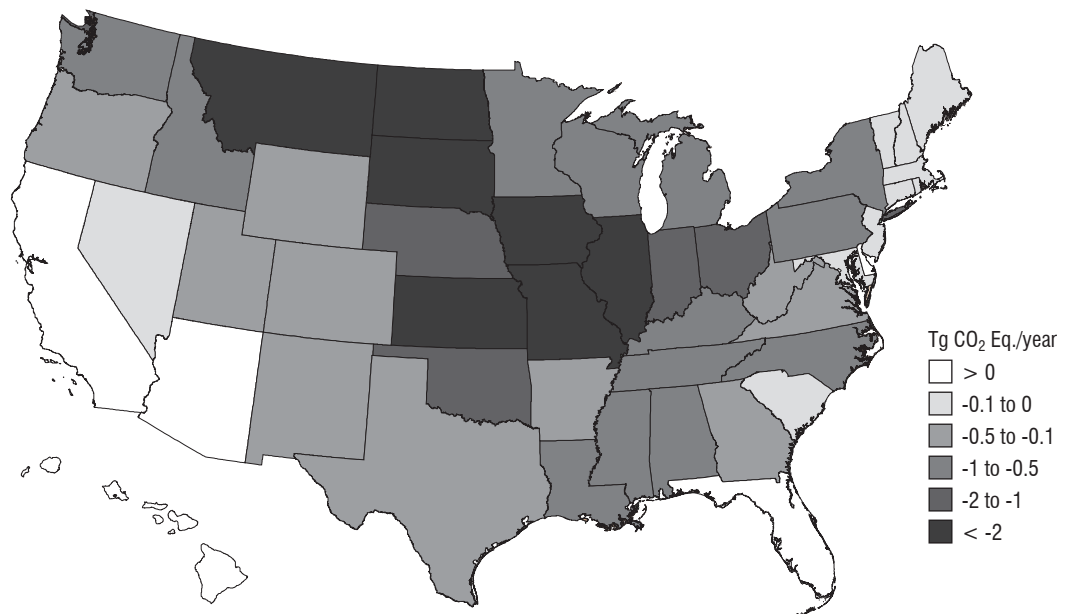


Figure 7-5

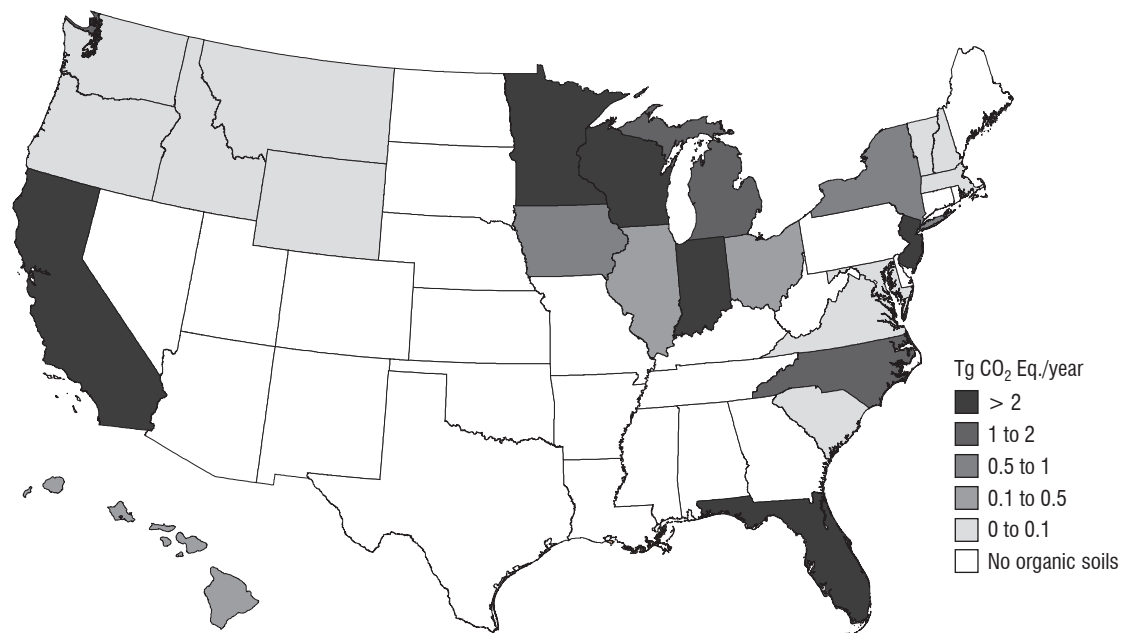
**Total Net Annual CO₂ Flux for Mineral Soils Under Agricultural Management within States,
2009, Cropland Remaining Cropland**



Note: Values greater than zero represent emissions, and values less than zero represent sequestration. Map accounts for fluxes associated with the Tier 2 and 3 Inventory computations. See Methodology for additional details.

Figure 7-6

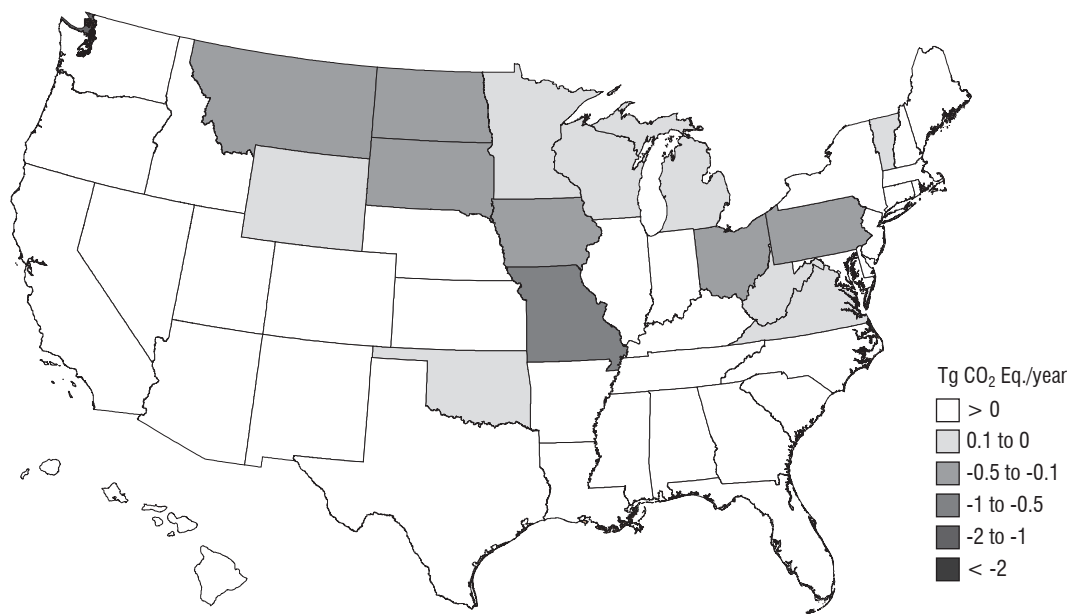
**Total Net Annual CO₂ Flux for Organic Soils Under Agricultural Management within States,
2009, Cropland Remaining Cropland**



Note: Values greater than zero represent emissions.

Figure 7-7

**Total Net Annual CO₂ Flux for Mineral Soils Under Agricultural Management within States,
2009, Land Converted to Cropland**



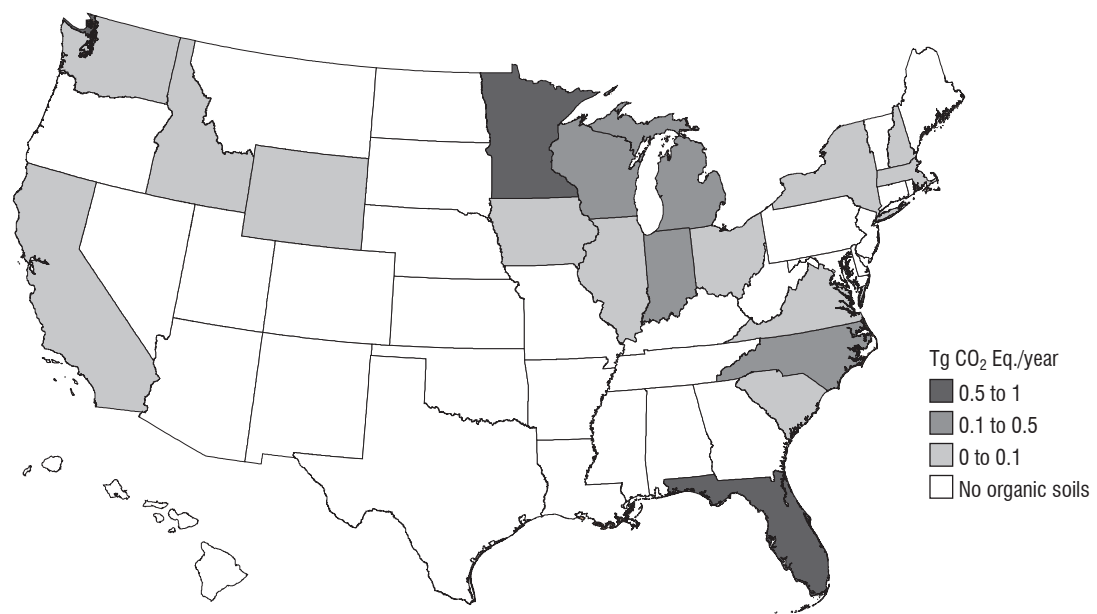
Note: Values greater than zero represent emissions, and values less than zero represent sequestration. Map accounts for fluxes associated with the Tier 2 and 3 Inventory computations. See Methodology for additional details.

Total Net Annual CO₂ Flux for Organic Soils Under Agricultural Management within States, 2009, Land Converted to Cropland

Tg CO₂ Eq./year

- 0.5 to 1
- 0.1 to 0.5
- 0 to 0.1
- No organic soils

Note: Values greater than zero represent emissions.



Total Net Annual CO₂ Flux for Mineral Soils Under Agricultural Management within States, 2009, Grassland Remaining Grassland

Tg CO₂ Eq./year

- > 0
- 0.1 to 0
- 0.5 to -0.1
- 1 to -0.5
- 2 to -1
- < -2

Note: Values greater than zero represent emissions, and values less than zero represent sequestration. Map accounts for fluxes associated with the Tier 2 and 3 Inventory computations. See Methodology for additional details.

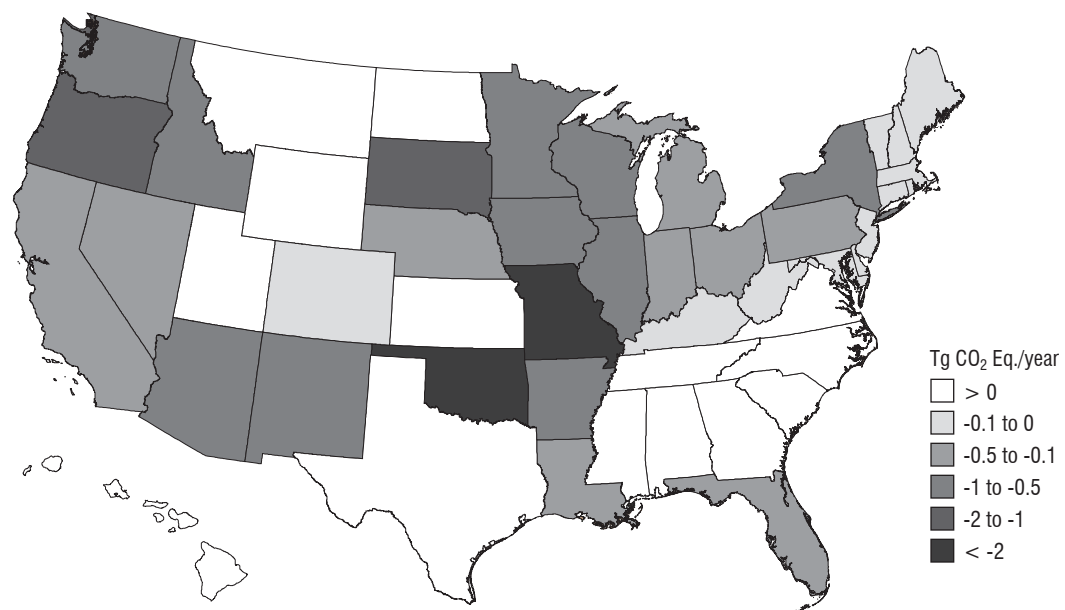
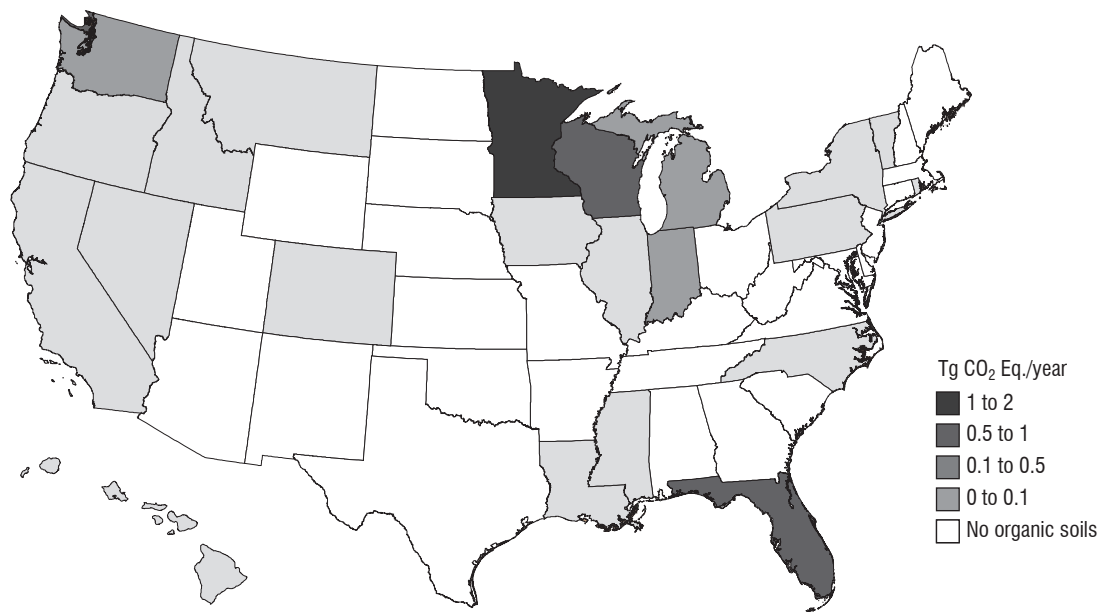


Figure 7-10

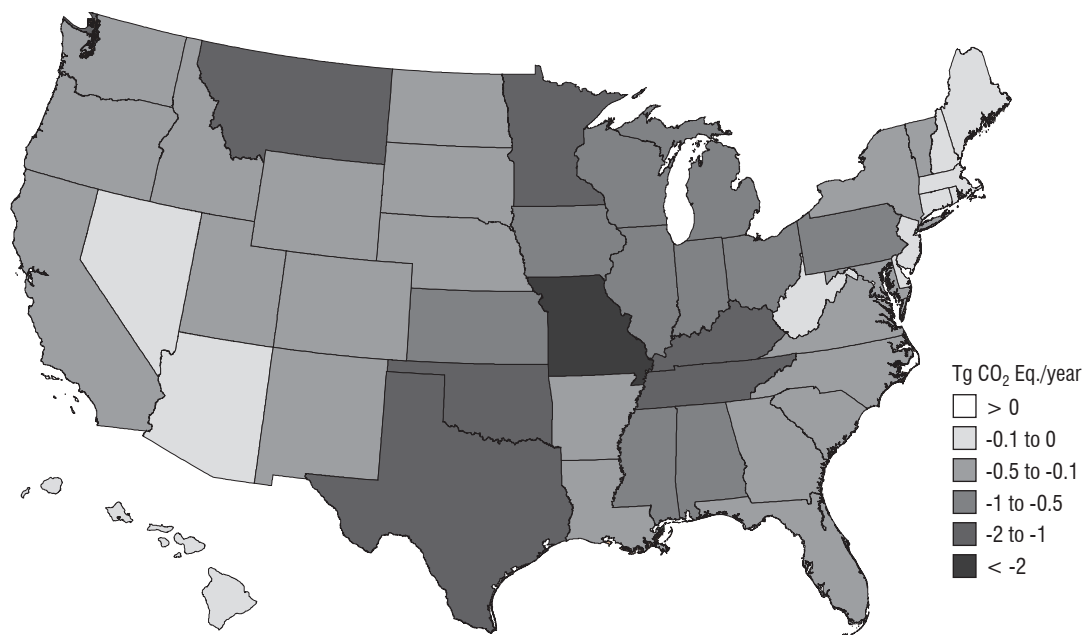
**Total Net Annual CO₂ Flux for Organic Soils Under Agricultural Management within States,
2009, Grassland Remaining Grassland**



Note: Values greater than zero represent emissions.

Figure 7-11

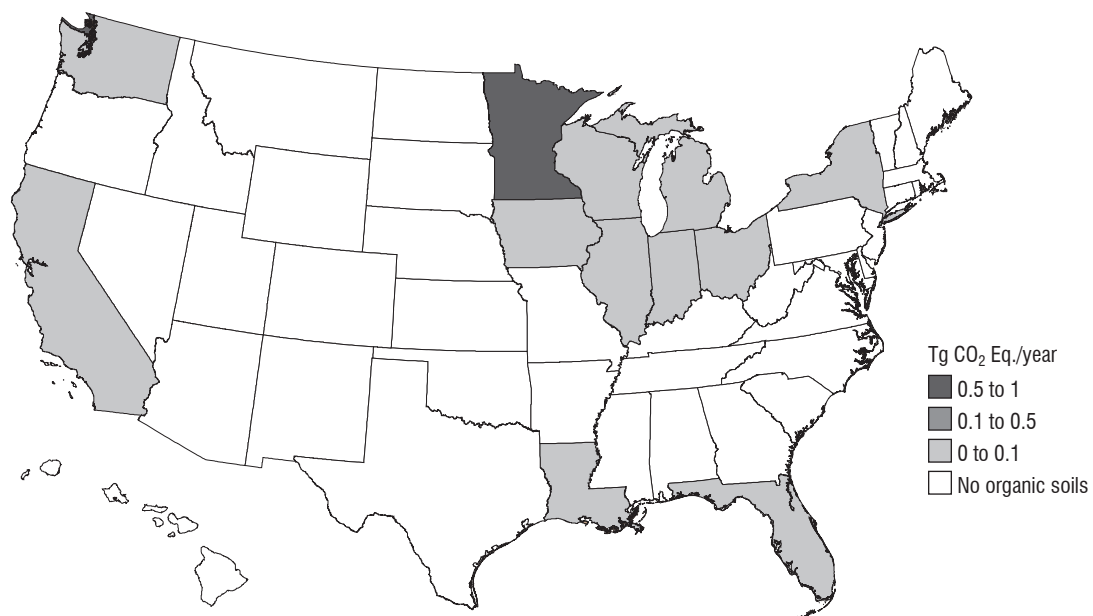
**Total Net Annual CO₂ Flux for Mineral Soils Under Agricultural Management within States,
2009, Land Converted to Grassland**



Note: Values greater than zero represent emissions, and values less than zero represent sequestration. Map accounts for fluxes associated with the Tier 2 and 3 Inventory computations. See Methodology for additional details.

Figure 7-12

**Total Net Annual CO₂ Flux for Organic Soils Under Agricultural Management within States,
2009, Land Converted to Grassland**



Note: Values greater than zero represent emissions.

8. Waste

Waste management and treatment activities are sources of greenhouse gas emissions (see Figure 8-1). Landfills accounted for approximately 17 percent of total U.S. anthropogenic methane (CH₄) emissions in 2009, the third largest contribution of any CH₄ source in the United States. Additionally, wastewater treatment and composting of organic waste accounted for approximately 4 percent and less than 1 percent of U.S. CH₄ emissions, respectively. Nitrous oxide (N₂O) emissions from the discharge of wastewater treatment effluents into aquatic environments were estimated, as were N₂O emissions from the treatment process itself. N₂O emissions from composting were also estimated. Together, these waste activities account for less than 3 percent of total U.S. N₂O emissions. Nitrogen oxides (NO_x), carbon monoxide (CO), and non-CH₄ volatile organic compounds (NMVOCs) are emitted by waste activities, and are addressed separately at the end of this chapter. A summary of greenhouse gas emissions from the Waste chapter is presented in Table 8-1 and Table 8-2.

CO₂, N₂O, and CH₄ emissions from the incineration of waste are accounted for in the Energy sector rather than in the Waste sector because almost all incineration of municipal solid waste (MSW) in the United States occurs at waste-to-energy facilities where useful energy is recovered. Similarly, the Energy sector also includes an estimate of emissions from burning waste tires because virtually all of the combustion occurs in industrial and utility boilers that recover energy. The incineration of waste in the United States in 2009 resulted in 12.7 Tg CO₂ Eq. emissions, nearly half of which is attributable to the combustion of plastics. For more details on emissions from the incineration of waste, see Section 3.3.

Figure 8-1: 2009 Waste Chapter Greenhouse Gas Sources

[BEGIN BOX]

Box 8-1: 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, 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).¹⁹⁷ Additionally, the calculated emissions and sinks in a given year for the U.S. are presented in a common manner in line with the UNFCCC reporting guidelines for the reporting of inventories under this international agreement.¹⁹⁸ 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,¹⁹⁹ 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.

[END BOX]

Overall, in 2009, waste activities generated emissions of 150.5 Tg CO₂ Eq., or just over 2 percent of total U.S. greenhouse gas emissions.

Table 8-1. Emissions from Waste (Tg CO₂ Eq.)

Gas/Source	1990	2000	2005	2006	2007	2008	2009
CH₄	171.2	138.1	138.4	137.8	137.4	142.1	143.6
Landfills	147.4	111.7	112.5	111.7	111.3	115.9	117.5

¹⁹⁷ See <http://www.ipcc-nggip.iges.or.jp/public/index.html>.

¹⁹⁸ See http://unfccc.int/national_reports/annex_i_ghg_inventories/national_inventories_submissions/items/5270.php.

¹⁹⁹ For example, see <http://www.epa.gov/aboutepa/oswer.html>.

Wastewater Treatment	23.5	25.2	24.3	24.5	24.4	24.5	24.5
Composting	0.3	1.3	1.6	1.6	1.7	1.7	1.7
N₂O	4.0	5.9	6.5	6.6	6.7	6.8	6.9
Domestic Wastewater Treatment	3.7	4.5	4.8	4.8	4.9	5.0	5.0
Composting	0.4	1.4	1.7	1.8	1.8	1.9	1.8
Total	175.2	143.9	144.9	144.4	144.1	149.0	150.5

Note: Totals may not sum due to independent rounding.

Table 8-2. Emissions from Waste (Gg)

Gas/Source	1990	2000	2005	2006	2007	2008	2009
CH₄	8,152	6,576	6,591	6,563	6,541	6,769	6,840
Landfills	7,018	5,317	5,358	5,321	5,299	5,520	5,593
Wastewater Treatment	1,118	1,199	1,159	1,167	1,163	1,168	1,167
Composting	15	60	75	75	79	80	79
N₂O	13	19	21	21	22	22	22
Domestic Wastewater Treatment	12	14	15	16	16	16	16
Composting	1	4	6	6	6	6	6

Note: Totals may not sum due to independent rounding.

8.1. Landfills (IPCC Source Category 6A1)

In 2009, landfill CH₄ emissions were approximately 117.5 Tg CO₂ Eq. (5,593 Gg of CH₄), representing the third largest source of CH₄ emissions in the United States, behind natural gas systems and enteric fermentation. Emissions from municipal solid waste (MSW) landfills, which received about 64.5 percent of the total solid waste generated in the United States, accounted for about 94 percent of total landfill emissions, while industrial landfills accounted for the remainder. Approximately 1,800 operational landfills exist in the United States, with the largest landfills receiving most of the waste and generating the majority of the CH₄ (*BioCycle* 2006, adjusted to include missing data from five states).

After being placed in a landfill, waste (such as paper, food scraps, and yard trimmings) is initially decomposed by aerobic bacteria. After the oxygen has been depleted, the remaining waste is available for consumption by anaerobic bacteria, which break down organic matter into substances such as cellulose, amino acids, and sugars. These substances are further broken down through fermentation into gases and short-chain organic compounds that form the substrates for the growth of methanogenic bacteria. These CH₄-producing anaerobic bacteria convert the fermentation products into stabilized organic materials and biogas consisting of approximately 50 percent carbon dioxide (CO₂) and 50 percent CH₄, by volume. Significant CH₄ production typically begins one or two years after waste disposal in a landfill and continues for 10 to 60 years or longer.

Methane emissions from landfills are a function of several factors, including: (1) the total amount of waste in MSW landfills, which is related to total waste landfilled annually; (2) the characteristics of landfills receiving waste (i.e., composition of waste-in-place, size, climate); (3) the amount of CH₄ that is recovered and either flared or used for energy purposes; and (4) the amount of CH₄ oxidized in landfills instead of being released into the atmosphere. From 1990 to 2009, net CH₄ emissions from landfills decreased by approximately 20 percent (see Table 8-3 and Table 8-4). This net CH₄ emissions decrease can be attributed to many factors, including changes in waste composition, an increase in the amount of landfill gas collected and combusted, a higher frequency of composting, and increased rates of recovery for degradable materials (e.g, paper and paperboard).

The estimated annual quantity of waste placed in MSW landfills increased from about 209 Tg in 1990 to 297 Tg in 2009, an increase of 42 percent (see Annex 3.14). Despite increased waste disposal, the amount of decomposable materials (i.e., paper and paperboard, food scraps, and yard trimmings) discarded in MSW landfills have decreased by approximately 21 percent from 1990 to 2008 (EPA, 2009b). In addition, the amount of landfill gas collected and combusted has increased. In 1990, for example, approximately 970 Gg of CH₄ were recovered and combusted (i.e., used for energy or flared) from landfills, while in 2009, 7,208 Gg CH₄ was combusted, which represents a 3 percent increase in the quantity of CH₄ recovered and combusted from 2008 levels. In 2009, an estimated 49 new landfill gas-to-energy (LFGTE) projects and 32 new flares began operation.

Over the past 9 years, however, the net CH₄ emissions have fluctuated from year to year, but a slowly increasing trend has been observed. While the amount of landfill gas collected and combusted continues to increase every year, the rate of increase in collection and combustion no longer exceeds the rate of additional CH₄ generation from the amount of organic MSW landfilled as the U.S. population grows.

Over the next several years, the total amount of municipal solid waste generated is expected to increase as the U.S. population continues to grow. The percentage of waste landfilled, however, may decline due to increased recycling and composting practices. In addition, the quantity of CH₄ that is recovered and either flared or used for energy purposes is expected to continue to increase as a result of 1996 federal regulations that require large municipal solid waste landfills to collect and combust landfill gas (see 40 CFR Part 60, Subpart Cc 2005 and 40 CFR Part 60, Subpart WWW 2005), voluntary programs that encourage CH₄ recovery and use such as EPA's Landfill Methane Outreach Program (LMOP), and federal and state incentives that promote renewable energy (e.g., tax credits, low interest loans, and Renewable Portfolio Standards).

Table 8-3. CH₄ Emissions from Landfills (Tg CO₂ Eq.)

Activity	1990	2000	2005	2006	2007	2008	2009
MSW Landfills	172.6	206.9	241.2	248.1	254.2	260.3	266.3
Industrial Landfills	11.5	14.3	15.2	15.3	15.4	15.5	15.6
Recovered							
Gas-to-Energy	(13.6)	(49.4)	(56.5)	(59.0)	(63.7)	(67.0)	(72.0)
Flared	(6.7)	(47.8)	(74.9)	(80.2)	(82.3)	(80.0)	(79.4)
Oxidized ^a	(16.4)	(12.4)	(12.5)	(12.4)	(12.4)	(12.9)	(13.1)
Total	147.4	111.7	112.5	111.7	111.3	115.9	117.5

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

^a Includes oxidation at both municipal and industrial landfills.

Table 8-4. CH₄ Emissions from Landfills (Gg)

Activity	1990	2000	2005	2006	2007	2008	2009
MSW Landfills	8,219	9,854	11,486	11,813	12,107	12,395	12,679
Industrial Landfills	549	682	724	727	732	738	744
Recovered							
Gas-to-Energy	(649)	(2,352)	(2,691)	(2,807)	(3,033)	(3,189)	(3,429)
Flared	(321)	(2,276)	(3,566)	(3,820)	(3,918)	(3,810)	(3,779)
Oxidized ^a	(780)	(591)	(596)	(592)	(589)	(614)	(622)
Total	7,018	5,317	5,358	5,321	5,299	5,520	5,593

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

^a Includes oxidation at municipal and industrial landfills.

Methodology

A detailed description of the methodology used to estimate CH₄ emissions from landfills can be found in Annex 3.14.

CH₄ emissions from landfills were estimated as the CH₄ produced from municipal solid waste landfills, plus the CH₄ produced by industrial landfills, minus the CH₄ recovered and combusted, minus the CH₄ oxidized before being released into the atmosphere:

$$\text{CH}_{4,\text{Solid Waste}} = [\text{CH}_{4,\text{MSW}} + \text{CH}_{4,\text{Ind}} - \text{R}] - \text{Ox}$$

where,

- CH_{4,Solid Waste} = CH₄ emissions from solid waste
- CH_{4,MSW} = CH₄ generation from municipal solid waste landfills,
- CH_{4,Ind} = CH₄ generation from industrial landfills,
- R = CH₄ recovered and combusted, and
- Ox = CH₄ oxidized from MSW and industrial landfills before release to the atmosphere.

The methodology for estimating CH₄ emissions from municipal solid waste landfills is based on the first order decay model described by the Intergovernmental Panel on Climate Change (IPCC 2006). Values for the CH₄ generation

potential (L_0) and rate constant (k) were obtained from an analysis of CH_4 recovery rates for a database of 52 landfills and from published studies of other landfills (RTI 2004; EPA 1998; SWANA 1998; Peer, Thorneloe, and Epperson 1993). The rate constant was found to increase with average annual rainfall; consequently, values of k were developed for 3 ranges of rainfall. The annual quantity of waste placed in landfills was apportioned to the 3 ranges of rainfall based on the percent of the U.S. population in each of the 3 ranges, and historical census data were used to account for the shift in population to more arid areas over time. For further information, see Annex 3.14.

National landfill waste generation and disposal data for 2007, 2008, and 2009 were extrapolated based on *BioCycle* data and the U.S. Census population from 2009. Data for 1989 through 2006 were obtained from *BioCycle* (2008). Because *BioCycle* does not account for waste generated in U.S. territories, waste generation for the territories was estimated using population data obtained from the U.S. Census Bureau (2010) and national per capita solid waste generation from *BioCycle* (2008). Estimates of the annual quantity of waste landfilled for 1960 through 1988 were obtained from EPA's *Anthropogenic Methane Emissions in the United States, Estimates for 1990: Report to Congress* (EPA 1993) and an extensive landfill survey by the EPA's Office of Solid Waste in 1986 (EPA 1988). Although waste placed in landfills in the 1940s and 1950s contributes very little to current CH_4 generation, estimates for those years were included in the first order decay model for completeness in accounting for CH_4 generation rates and are based on the population in those years and the per capita rate for land disposal for the 1960s. For calculations in this inventory, wastes landfilled prior to 1980 were broken into two groups: wastes disposed in landfills (Methane Conversion Factor, MCF, of 1) and those disposed in dumps (MCF of 0.6). Please see Annex 3.14 for more details.

The estimated landfill gas recovered per year was based on updated data collected from vendors of flaring equipment, a database of landfill gas-to-energy (LFGTE) projects compiled by LMOP (EPA 2009a), and a database maintained by the Energy Information Administration (EIA) for the voluntary reporting of greenhouse gases (EIA 2007). As the EIA database only included data through 2006; 2007 to 2009 recovery for projects included in the EIA database were assumed to be the same as in 2006. The three databases were carefully compared to identify landfills that were in two or all three of the databases to avoid double counting reductions. Based on the information provided by the EIA and flare vendor databases, the CH_4 combusted by flares in operation from 1990 to 2009 was estimated. This quantity likely underestimates flaring because these databases do not have information on all flares in operation. Additionally, the EIA and LMOP databases provided data on landfill gas flow and energy generation for landfills with LFGTE projects. If a landfill in the EIA database was also in the LMOP and/or the flare vendor database, the emissions avoided were based on the EIA data because landfill owners or operators reported the amount recovered based on measurements of gas flow and concentration, and the reporting accounted for changes over time. If both flare data and LMOP recovery data were available for any of the remaining landfills (i.e., not in the EIA database), then the emissions recovery was based on the LMOP data, which provides reported landfill-specific data on gas flow for direct use projects and project capacity (i.e., megawatts) for electricity projects. The flare data, on the other hand, only provided a range of landfill gas flow for a given flare size. Given that each LFGTE project is likely to also have a flare, double counting reductions from flares and LFGTE projects in the LMOP database was avoided by subtracting emission reductions associated with LFGTE projects for which a flare had not been identified from the emission reductions associated with flares. A further explanation of the improvements made to estimate the landfill gas recovered for the current Inventory can be found in Annex 3.14.

A destruction efficiency of 99 percent was applied to CH_4 recovered to estimate CH_4 emissions avoided. The value for efficiency was selected based on the range of efficiencies (98 to 100 percent) recommended for flares in EPA's AP-42 Compilation of Air Pollutant Emission Factors, Chapter 2.4 (EPA 1998), efficiencies used to establish new source performance standards (NSPS) for landfills, and in recommendations for closed flares used in LMOP.

Emissions from industrial landfills were estimated from activity data for industrial production (ERG 2010), waste disposal factors, and the first order decay model. As over 99 percent of the organic waste placed in industrial landfills originated from the food processing (meat, vegetables, fruits) and pulp and paper industries, estimates of industrial landfill emissions focused on these two sectors (EPA 1993). The amount of CH_4 oxidized by the landfill cover at both municipal and industrial landfills was assumed to be ten percent of the CH_4 generated that is not recovered (IPCC 2006, Mancinelli and McKay 1985, Czepiel et al. 1996). To calculate net CH_4 emissions, both CH_4 recovered and CH_4 oxidized were subtracted from CH_4 generated at municipal and industrial landfills.

Uncertainty and Time-Series Consistency

Several types of uncertainty are associated with the estimates of CH_4 emissions from landfills. The primary

uncertainty concerns the characterization of landfills. Information is not available on two fundamental factors affecting CH₄ production: the amount and composition of waste placed in every landfill for each year of its operation. The approach used here assumes that the CH₄ generation potential and the rate of decay that produces CH₄, as determined from several studies of CH₄ recovery at landfills, are representative of U.S. landfills.

Additionally, the approach used to estimate the contribution of industrial wastes to total CH₄ generation introduces uncertainty. Aside from uncertainty in estimating CH₄ generation potential, uncertainty exists in the estimates of oxidation by cover soils. There is also uncertainty in the estimates of CH₄ that is recovered by flaring and energy projects. The IPCC default value of 10 percent for uncertainty in recovery estimates was used in the uncertainty analysis when metering was in place (for about 64 percent of the CH₄ estimated to be recovered). For flaring without metered recovery data (approximately 34 percent of the CH₄ estimated to be recovered), a much higher uncertainty of approximately 50 percent was used (e.g., when recovery was estimated as 50 percent of the flare's design capacity).

N₂O emissions from the application of sewage sludge on landfills are not explicitly modeled as part of greenhouse gas emissions from landfills. N₂O emissions from sewage sludge applied to landfills would be relatively small because the microbial environment in landfills is not very conducive to the nitrification and denitrification processes that result in N₂O emissions. Furthermore, the 2006 IPCC Guidelines (IPCC 2006) did not include a methodology for estimating N₂O emissions from solid waste disposal sites "because they are not significant." Therefore, any uncertainty or bias caused by not including N₂O emissions from landfills is expected to be minimal.

The results of the IPCC Good Practice Guidance Tier 2 quantitative uncertainty analysis are summarized in Table 8-5. Landfill CH₄ emissions in 2009 were estimated to be between 61.1 and 164.5 Tg CO₂ Eq., which indicates a range of 48 percent below to 40 percent above the 2009 emission estimate of 117.5 Tg CO₂ Eq.

Table 8-5. Tier 2 Quantitative Uncertainty Estimates for CH₄ Emissions from Landfills (Tg CO₂ Eq. and Percent)

Source	Gas	2009 Emission	Uncertainty Range Relative to Emission Estimate ^a			
		Estimate	(Tg CO ₂ Eq.)		(%)	
		(Tg CO ₂ Eq.)	Lower Bound	Upper Bound	Lower Bound	Upper Bound
Landfills	CH₄	117.5	61.1	164.5	-48%	+40%
MSW	CH ₄	103.4	61.0	167.5	-41%	+62%
Industrial	CH ₄	14.1	10.2	17.1	-28%	+21%

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

QA/QC and Verification

A QA/QC analysis was performed for data gathering and input, documentation, and calculation. A primary focus of the QA/QC checks was to ensure that CH₄ recovery estimates were not double-counted. Both manual and electronic checks were made to ensure that emission avoidance from each landfill was calculated in only one of the three databases. The primary calculation spreadsheet is tailored from the IPCC waste model and has been verified previously using the original, peer-reviewed IPCC waste model. All model input values were verified by secondary QA/QC review.

Recalculations Discussion

In developing the current Inventory, a separate Monte Carlo analysis was conducted for MSW and industrial landfills to better characterize the greater amount of uncertainty surrounding industrial waste data. Additional steps were also taken to better characterize the food waste decay rate and the methodology for the flare correction factor. A weighted component-specific decay rate for food waste of 0.156 yr⁻¹ was used in the current Inventory as recommended by ICF International (2009). This replaced the previous Inventory's default food waste decay rate of 0.185 yr⁻¹ and resulted in a decrease of landfill emissions of less than 1 percent. The majority of changes in CH₄ emissions from landfills over the time series resulted from improvements made to the flare correction factor to better associate flares in the flare vendor database with a landfill and/or Landfill Gas to Energy (LFGTE) project in the

EIA and LMOP databases.

The flare correction factor for the 1990 through 2008 Inventory report consisted of approximately 512 cases where flares were not directly associated with a landfill and/or LFGTE project in the EIA and/or LMOP databases. For these projects, CH₄ avoided would be overestimated as both the CH₄ avoided from flaring and the LFGTE project would be counted. To abstain from overestimating emissions avoided from flaring, the CH₄ avoided from flares with no identified landfill or LFGTE project were determined and the flaring estimate from the flare vendor database was reduced by this quantity (referred to as a flare correction factor) on a state-by-state basis.

If comprehensive data on flares were available, the majority of LFGTE projects in the EIA and LMOP databases would have an identified flare because it is assumed that most LFGTE projects have flares. However, given that the flare vendor data only covers approximately 50 to 75 percent of the flare population, an associated flare was not identified for all LFGTE projects. These LFGTE projects likely have flares; however, flares were unable to be identified due to one of two reasons: (1) inadequate identifier information provided by the flare vendor; or (2) a lack of the flare in the flare vendor database.

Additional effort was undertaken to improve the methodology behind the flare correction factor for the current Inventory to reduce the overall number of flares that were not matched (512) to landfills and/or LFGTE projects in the EIA and LMOP databases. Each flare in the flare vendor database not associated with a LFGTE project in the EIA or LMOP databases was investigated to determine if it could be matched to either a landfill in the EIA database or a LFGTE project in the LMOP database. For some unmatched flares, the location information was missing or incorrectly transferred to the flare vendor database. In other instances, the landfill names were slightly different between what the flare vendor provided and the actual landfill name as listed in the EIA and/or LMOP databases.

It was found that a large majority of the unidentified flares are associated with landfills in LMOP that are currently flaring, but are also considering LFGTE. These landfill projects considering a LFGTE project are labeled as candidate, potential, or construction in the LMOP database. The flare vendor database was improved to match flares with operational, shutdown as well as candidate, potential, and construction LFGTE projects, thereby reducing the total number of unidentified flares in the flare vendor database, all of which are used in the flare correction factor. The results of this effort significantly decreased the number of flares used in the flare correction factor from 512 to 27, impacted emission estimates for the entire time series, and resulted in an average annual decrease of 8.2 Tg CO₂ Eq. (6.5 percent) in CH₄ emissions from the Landfills source category for the period 1990 through 2008.

Planned Improvements

Beginning in 2010, all MSW landfills that accepted waste on or after January 1, 1980 and generate CH₄ in amounts equivalent to 25,000 metric tons or more of carbon dioxide equivalent (CO₂ Eq.) will be required to calculate and report their greenhouse gas emissions to EPA through its Greenhouse Gas Reporting Program (GHGRP). This consists of the landfill, landfill gas collection systems, and landfill gas destruction devices, including flares. In addition to reporting greenhouse gas information to EPA, landfill-specific characteristics such as annual waste disposal quantity, waste composition data, surface area, and cover type must also be reported. The data collected from the GHGRP will be used in future inventories to revise the parameters used in the CH₄ generation calculations, including degradable organic carbon (DOC), the flare correction factor, the methane correction factor (MCF), fraction of DOC dissimilated (DOC_F), the destruction efficiency of flares, the oxidation factor (Ox), and the rate constant (k). The addition of this higher tier data will improve the emission calculations to provide a more accurate representation of greenhouse gas emissions from MSW landfills.

[Begin Text Box]

Box 8-1: Biogenic Wastes in Landfills

Regarding the depositing of wastes of biogenic origin in landfills, empirical evidence shows that some of these wastes degrade very slowly in landfills, and the C they contain is effectively sequestered in landfills over a period of time (Barlaz 1998, 2006). Estimates of C removals from landfilling of forest products, yard trimmings, and food scraps are further described in the Land Use, Land-Use Change, and Forestry chapter, based on methods presented in IPCC (2003) and IPCC (2006).

[End Box]

8.2. Wastewater Treatment (IPCC Source Category 6B)

Wastewater treatment processes can produce anthropogenic CH₄ and N₂O emissions. Wastewater from domestic²⁰⁰ and industrial sources is treated to remove soluble organic matter, suspended solids, pathogenic organisms, and chemical contaminants. Treatment may either occur on site, most commonly through septic systems or package plants, or off site at centralized treatment systems. Centralized wastewater treatment systems may include a variety of processes, ranging from lagooning to advanced tertiary treatment technology for removing nutrients. In the United States, approximately 20 percent of domestic wastewater is treated in septic systems or other on-site systems, while the rest is collected and treated centrally (U.S. Census Bureau 2009).

Soluble organic matter is generally removed using biological processes in which microorganisms consume the organic matter for maintenance and growth. The resulting biomass (sludge) is removed from the effluent prior to discharge to the receiving stream. Microorganisms can biodegrade soluble organic material in wastewater under aerobic or anaerobic conditions, where the latter condition produces CH₄. During collection and treatment, wastewater may be accidentally or deliberately managed under anaerobic conditions. In addition, the sludge may be further biodegraded under aerobic or anaerobic conditions. The generation of N₂O may also result from the treatment of domestic wastewater during both nitrification and denitrification of the N present, usually in the form of urea, ammonia, and proteins. These compounds are converted to nitrate (NO₃) through the aerobic process of nitrification. Denitrification occurs under anoxic conditions (without free oxygen), and involves the biological conversion of nitrate into dinitrogen gas (N₂). N₂O can be an intermediate product of both processes, but is more often associated with denitrification.

The principal factor in determining the CH₄ generation potential of wastewater is the amount of degradable organic material in the wastewater. Common parameters used to measure the organic component of the wastewater are the Biochemical Oxygen Demand (BOD) and Chemical Oxygen Demand (COD). Under the same conditions, wastewater with higher COD (or BOD) concentrations will generally yield more CH₄ than wastewater with lower COD (or BOD) concentrations. BOD represents the amount of oxygen that would be required to completely consume the organic matter contained in the wastewater through aerobic decomposition processes, while COD measures the total material available for chemical oxidation (both biodegradable and non-biodegradable). Because BOD is an aerobic parameter, it is preferable to use COD to estimate CH₄ production. The principal factor in determining the N₂O generation potential of wastewater is the amount of N in the wastewater.

In 2009, CH₄ emissions from domestic wastewater treatment were 16.0 Tg CO₂ Eq. (760 Gg). Emissions gradually increased from 1990 through 1997, but have decreased since that time due to decreasing percentages of wastewater being treated in anaerobic systems, including reduced use of on-site septic systems and central anaerobic treatment systems. In 2009, CH₄ emissions from industrial wastewater treatment were estimated to be 8.5 Tg CO₂ Eq. (407 Gg). Industrial emission sources have increased across the time series through 1999 and then fluctuated up and down with production changes associated with the treatment of wastewater from the pulp and paper manufacturing, meat and poultry processing, fruit and vegetable processing, starch-based ethanol production, and petroleum refining industries. Table 8-6 and Table 8-7 provide CH₄ and N₂O emission estimates from domestic and industrial wastewater treatment.

With respect to N₂O, the United States identifies two distinct sources for N₂O emissions from domestic wastewater: emissions from centralized wastewater treatment processes, and emissions from effluent from centralized treatment systems that has been discharged into aquatic environments. The 2009 emissions of N₂O from centralized wastewater treatment processes and from effluent were estimated to be 0.3 Tg CO₂ Eq. (1 Gg) and 4.7 Tg CO₂ Eq. (15.2 Gg), respectively. Total N₂O emissions from domestic wastewater were estimated to be 5.0 Tg CO₂ Eq. (16.2 Gg). N₂O emissions from wastewater treatment processes gradually increased across the time series as a result of increasing U.S. population and protein consumption.

Table 8-6. CH₄ and N₂O Emissions from Domestic and Industrial Wastewater Treatment (Tg CO₂ Eq.)

Activity	1990	2000	2005	2006	2007	2008	2009
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²⁰⁰ Throughout the inventory, emissions from domestic wastewater also include any commercial and industrial wastewater collected and co-treated with domestic wastewater.

CH₄	23.5		25.2		24.3	24.5	24.4	24.5	24.5
Domestic	16.4		16.8		16.2	16.0	15.9	15.8	16.0
Industrial*	7.1		8.4		8.2	8.5	8.5	8.6	8.5
N₂O	3.7		4.5		4.8	4.8	4.9	5.0	5.0
Domestic	3.7		4.5		4.8	4.8	4.9	5.0	5.0
Total	27.2		29.6		29.1	29.3	29.3	29.5	29.5

* Industrial activity includes the pulp and paper manufacturing, meat and poultry processing, fruit and vegetable processing, starch-based ethanol production, and petroleum refining industries.

Note: Totals may not sum due to independent rounding.

Table 8-7. CH₄ and N₂O Emissions from Domestic and Industrial Wastewater Treatment (Gg)

Activity	1990		2000		2005	2006	2007	2008	2009
CH₄	1,118		1,199		1,159	1,167	1,163	1,168	1,167
Domestic	780		801		770	764	758	759	760
Industrial*	338		398		389	403	405	409	407
N₂O	12		14		15	16	16	16	16
Domestic	12		14		15	16	16	16	16

* Industrial activity includes the pulp and paper manufacturing, meat and poultry processing, fruit and vegetable processing, starch-based ethanol production, and petroleum refining industries.

Note: Totals may not sum due to independent rounding.

Methodology

Domestic Wastewater CH₄ Emission Estimates

Domestic wastewater CH₄ emissions originate from both septic systems and from centralized treatment systems, such as publicly owned treatment works (POTWs). Within these centralized systems, CH₄ emissions can arise from aerobic systems that are not well managed or that are designed to have periods of anaerobic activity (e.g., constructed wetlands), anaerobic systems (anaerobic lagoons and facultative lagoons), and from anaerobic digesters when the captured biogas is not completely combusted. CH₄ emissions from septic systems were estimated by multiplying the total 5-day BOD (BOD₅) produced in the United States by the percent of wastewater treated in septic systems (20 percent), the maximum CH₄ producing capacity for domestic wastewater (0.60 kg CH₄/kg BOD), and the CH₄ correction factor (MCF) for septic systems (0.5). CH₄ emissions from POTWs were estimated by multiplying the total BOD₅ produced in the United States by the percent of wastewater treated centrally (80 percent), the relative percentage of wastewater treated by aerobic and anaerobic systems, the relative percentage of wastewater facilities with primary treatment, the percentage of BOD₅ treated after primary treatment (67.5 percent), the maximum CH₄-producing capacity of domestic wastewater (0.6), and the relative MCFs for aerobic (zero or 0.3) and anaerobic (0.8) systems with all aerobic systems assumed to be well-managed. CH₄ emissions from anaerobic digesters were estimated by multiplying the amount of biogas generated by wastewater sludge treated in anaerobic digesters by the proportion of CH₄ in digester biogas (0.65), the density of CH₄ (662 g CH₄/m³ CH₄), and the destruction efficiency associated with burning the biogas in an energy/thermal device (0.99). The methodological equations are:

$$\begin{aligned} \text{Emissions from Septic Systems} &= A \\ &= (\% \text{ onsite}) \times (\text{total BOD}_5 \text{ produced}) \times (B_o) \times (\text{MCF-septic}) \times 1/10^6 \end{aligned}$$

$$\begin{aligned} \text{Emissions from Centrally Treated Aerobic Systems} &= B \\ &= [(\% \text{ collected}) \times (\text{total BOD}_5 \text{ produced}) \times (\% \text{ aerobic}) \times (\% \text{ aerobic w/out primary}) + (\% \text{ collected}) \times (\text{total BOD}_5 \text{ produced}) \times (\% \text{ aerobic}) \times (\% \text{ aerobic w/primary}) \times (1 - \% \text{ BOD removed in prim. treat.})] \times (\% \text{ operations not well managed}) \times (B_o) \times (\text{MCF-aerobic_not_well_man}) \times 1/10^6 \end{aligned}$$

$$\begin{aligned} \text{Emissions from Centrally Treated Anaerobic Systems} &= C \\ &= [(\% \text{ collected}) \times (\text{total BOD}_5 \text{ produced}) \times (\% \text{ anaerobic}) \times (\% \text{ anaerobic w/out primary}) + (\% \text{ collected}) \times (\text{total BOD}_5 \text{ produced}) \times (\% \text{ anaerobic}) \times (\% \text{ anaerobic w/primary}) \times (1 - \% \text{ BOD removed in prim. treat.})] \times (B_o) \times (\text{MCF-anaerobic}) \times 1/10^6 \end{aligned}$$

$$\text{Emissions from Anaerobic Digesters} = D$$

$$= [(POTW_flow_AD) \times (\text{digester gas}) / (\text{per capita flow})] \times \text{conversion to m}^3 \times (FRAC_CH_4) \times (365.25) \times (\text{density of CH}_4) \times (1-DE) \times 1/10^9$$

$$\text{Total CH}_4 \text{ Emissions (Gg)} = A + B + C + D$$

Where:

% onsite	= Flow to septic systems / total flow
% collected	= Flow to POTWs / total flow
% aerobic	= Flow to aerobic systems / total flow to POTWs
% anaerobic	= Flow to anaerobic systems / total flow to POTWs
% aerobic w/out primary	= Percent of aerobic systems that do not employ primary treatment
% aerobic w/primary	= Percent of aerobic systems that employ primary treatment
% BOD removed in prim. treat.	= 32.5%
% operations not well managed	= Percent of aerobic systems that are not well managed and in which some anaerobic degradation occurs
% anaerobic w/out primary	= Percent of anaerobic systems that do not employ primary treatment
% anaerobic w/primary	= Percent of anaerobic systems that employ primary treatment
Total BOD ₅ produced	= kg BOD/capita/day × U.S. population × 365.25 days/yr
B ₀	= Maximum CH ₄ -producing capacity for domestic wastewater (0.60 kg CH ₄ /kg BOD)
MCF-septic	= CH ₄ correction factor for septic systems (0.5)
1/10 ⁶	= Conversion factor, kg to Gg
MCF-aerobic_not_well_man.	= CH ₄ correction factor for aerobic systems that are not well managed (0.3)
MCF-anaerobic	= CH ₄ correction factor for anaerobic systems (0.8)
DE	= CH ₄ destruction efficiency from flaring or burning in engine (0.99 for enclosed flares)
POTW_flow_AD	= Wastewater influent flow to POTWs that have anaerobic digesters (gal)
digester gas	= Cubic feet of digester gas produced per person per day (1.0 ft ³ /person/day) (Metcalf and Eddy 1991)
per capita flow	= Wastewater flow to POTW per person per day (100 gal/person/day)
conversion to m ³	= Conversion factor, ft ³ to m ³ (0.0283)
FRAC_CH ₄	= Proportion CH ₄ in biogas (0.65)
density of CH ₄	= 662 (g CH ₄ /m ³ CH ₄)
1/10 ⁹	= Conversion factor, g to Gg

U.S. population data were taken from the U.S. Census Bureau International Database (U.S. Census 2010) and include the populations of the United States, American Samoa, Guam, Northern Mariana Islands, Puerto Rico, and the Virgin Islands. Table 8-8 presents U.S. population and total BOD₅ produced for 1990 through 2009, while Table 8-9 presents domestic wastewater CH₄ emissions for both septic and centralized systems in 2009. The proportions of domestic wastewater treated onsite versus at centralized treatment plants were based on data from the 1989, 1991, 1993, 1995, 1997, 1999, 2001, 2003, 2005, 2007, and 2009 American Housing Surveys conducted by the U.S. Census Bureau (U.S. Census 2009), with data for intervening years obtained by linear interpolation. The percent of wastewater flow to aerobic and anaerobic systems, the percent of aerobic and anaerobic systems that do and do not employ primary treatment, and the wastewater flow to POTWs that have anaerobic digesters were obtained from the 1992, 1996, 2000, and 2004 Clean Watershed Needs Survey (EPA 1992, 1996, 2000, and 2004a). Data for intervening years were obtained by linear interpolation and the years 2004 through 2009 were forecasted from the rest of the time series. The BOD₅ production rate (0.09 kg/capita/day) and the percent BOD₅ removed by primary treatment for domestic wastewater were obtained from Metcalf and Eddy (1991 and 2003). The CH₄ emission factor (0.6 kg CH₄/kg BOD₅) and the MCFs were taken from IPCC (2006). The CH₄ destruction efficiency for methane recovered from sludge digestion operations, 99 percent, was selected based on the range of efficiencies (98 to 100 percent) recommended for flares in AP-42 Compilation of Air Pollutant Emission Factors, Chapter 2.4 (EPA 1998), efficiencies used to establish new source performance standards (NSPS) for landfills, and in recommendations for closed flares used by the Landfill Methane Outreach Program (LMOP). The cubic feet of digester gas produced per person per day (1.0 ft³/person/day) and the proportion of CH₄ in biogas (0.65) come from

Metcalf and Eddy (1991). The wastewater flow to a POTW (100 gal/person/day) was taken from the Great Lakes-Upper Mississippi River Board of State and Provincial Public Health and Environmental Managers, "Recommended Standards for Wastewater Facilities (Ten-State Standards)" (2004).

Table 8-8. U.S. Population (Millions) and Domestic Wastewater BOD₅ Produced (Gg)

Year	Population	BOD ₅
1990	254	8,333
2000	286	9,414
2005	300	9,864
2006	303	9,958
2007	306	10,057
2008	309	10,149
2009	311	10,236

Source: U.S. Census Bureau (2010); Metcalf & Eddy 1991 and 2003.

Table 8-9. Domestic Wastewater CH₄ Emissions from Septic and Centralized Systems (2009)

	CH ₄ emissions (Tg CO ₂ Eq.)	% of Domestic Wastewater CH ₄
Septic Systems	13.2	82.5%
Centralized Systems	2.8	17.5%
Total	16.0	100%

Note: Totals may not sum due to independent rounding.

Industrial Wastewater CH₄ Emission Estimates

CH₄ emissions estimates from industrial wastewater were developed according to the methodology described in IPCC (2006). Industry categories that are likely to produce significant CH₄ emissions from wastewater treatment were identified. High volumes of wastewater generated and a high organic wastewater load were the main criteria. The top five industries that meet these criteria are pulp and paper manufacturing; meat and poultry processing; vegetables, fruits, and juices processing; starch-based ethanol production; and petroleum refining. Wastewater treatment emissions for these sectors for 2009 are displayed in Table 8-10 below. Table 8-11 contains production data for these industries.

Table 8-10. Industrial Wastewater CH₄ Emissions by Sector (2009)

	CH ₄ emissions (Tg CO ₂ Eq.)	% of Industrial Wastewater CH ₄
Pulp & Paper	4.1	48%
Meat & Poultry	3.6	42%
Petroleum Refineries	0.6	7%
Fruit & Vegetables	0.1	1%
Ethanol Refineries	0.1	1%
Total	8.5	100%

Note: Totals may not sum due to independent rounding.

Table 8-11. U.S. Pulp and Paper, Meat, Poultry, Vegetables, Fruits and Juices, Ethanol, and Petroleum Refining Production (Tg)

Year	Pulp and Paper	Meat (Live Weight Killed)	Poultry (Live Weight Killed)	Vegetables, Fruits and Juices	Ethanol	Petroleum Refining
1990	128.9	27.3	14.6	38.7	2.7	702.4
2000	142.8	32.1	22.2	50.9	4.9	795.2
2005	131.4	31.4	25.1	42.9	11.7	818.6
2006	137.4	32.5	25.5	42.9	14.5	826.7
2007	135.9	33.4	26.0	44.7	19.4	827.6
2008	134.5	34.4	26.6	45.1	26.9	836.8

2009	137.0	33.8	25.2	47.0	31.7	822.4
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CH₄ emissions from these categories were estimated by multiplying the annual product output by the average outflow, the organics loading (in COD) in the outflow, the percentage of organic loading assumed to degrade anaerobically, and the emission factor. Ratios of BOD:COD in various industrial wastewaters were obtained from EPA (1997a) and used to estimate COD loadings. The B₀ value used for all industries is the IPCC default value of 0.25 kg CH₄/kg COD (IPCC 2006).

For each industry, the percent of plants in the industry that treat wastewater on site, the percent of plants that have a primary treatment step prior to biological treatment, and the percent of plants that treat wastewater anaerobically were defined. The percent of wastewater treated anaerobically onsite (TA) was estimated for both primary treatment and secondary treatment. For plants that have primary treatment in place, an estimate of COD that is removed prior to wastewater treatment in the anaerobic treatment units was incorporated.

The methodological equations are:

$$\text{CH}_4 (\text{industrial wastewater}) = P \times W \times \text{COD} \times \%TA \times B_0 \times \text{MCF}$$

$$\%TA_p = [\%Plants_o \times \%WW_{a,p} \times \%COD_p]$$

$$\%TA_s = [\%Plants_a \times \%WW_{a,s} \times \%COD_s] + [\%Plants_t \times \%WW_{a,t} \times \%COD_s]$$

Where:

CH ₄ (industrial wastewater)	= Total CH ₄ emissions from industrial wastewater (kg/year)
P	= Industry output (metric tons/year)
W	= Wastewater generated (m ³ /metric ton of product)
COD	= Organics loading in wastewater (kg/m ³)
%TA	= Percent of wastewater treated anaerobically on site
%TA _p	= Percent of wastewater treated anaerobically on site in primary treatment
%TA _s	= Percent of wastewater treated anaerobically on site in secondary treatment
%Plants _o	= Percent of plants with onsite treatment
%WW _{a,p}	= Percent of wastewater treated anaerobically in primary treatment
%COD _p	= Percent of COD entering primary treatment
%Plants _a	= Percent of plants with anaerobic secondary treatment
%Plants _t	= Percent of plants with other secondary treatment
%WW _{a,s}	= Percent of wastewater treated anaerobically in anaerobic secondary treatment
%WW _{a,t}	= percent of wastewater treated anaerobically in other secondary treatment
%COD _s	= percent of COD entering secondary treatment
B ₀	= Maximum CH ₄ producing potential of industrial wastewater (default value of 0.25 kg CH ₄ /kg COD)
MCF	= CH ₄ correction factor, indicating the extent to which the organic content (measured as COD) degrades anaerobically

As described below, the values presented in Table 8-12 were used in the emission calculations.

Table 8-12. Variables Used to Calculate Percent Wastewater Treated Anaerobically by Industry (%)

Variable	Industry						
	Pulp and Paper	Meat Processing	Poultry Processing	Fruit/Vegetable Processing	Ethanol Production – Wet Mill	Ethanol Production – Dry Mill	Petroleum Refining
%TA _p	0	0	0	0	0	0	0
%TA _s	10.5	33	25	4.2	33.3	75	100
%Plants _o	60	100	100	11	100	100	100
%Plants _a	25	33	25	5.5	33.3	75	100
%Plants _t	35	67	75	5.5	66.7	25	0
%WW _{a,p}	0	0	0	0	0	0	0
%WW _{a,s}	100	100	100	100	100	100	100
%WW _{a,t}	0	0	0	0	0	0	0

%COD _p	100	100	100	100	100	100	100
%COD _s	42	100	100	77	100	100	100

Pulp and Paper. Wastewater treatment for the pulp and paper industry typically includes neutralization, screening, sedimentation, and flotation/hydrocycloning to remove solids (World Bank 1999, Nemerow and Dasgupta 1991). Secondary treatment (storage, settling, and biological treatment) mainly consists of lagooning. In determining the percent that degrades anaerobically, both primary and secondary treatment were considered. In the United States, primary treatment is focused on solids removal, equalization, neutralization, and color reduction (EPA 1993). The vast majority of pulp and paper mills with on-site treatment systems use mechanical clarifiers to remove suspended solids from the wastewater. About 10 percent of pulp and paper mills with treatment systems use settling ponds for primary treatment and these are more likely to be located at mills that do not perform secondary treatment (EPA 1993). However, because the vast majority of primary treatment operations at U.S. pulp and paper mills use mechanical clarifiers, and less than 10 percent of pulp and paper wastewater is managed in primary settling ponds that are not expected to have anaerobic conditions, negligible emissions are assumed to occur during primary treatment.

Approximately 42 percent of the BOD passes on to secondary treatment, which consists of activated sludge, aerated stabilization basins, or non-aerated stabilization basins. No anaerobic activity is assumed to occur in activated sludge systems or aerated stabilization basins (note: although IPCC recognizes that some CH₄ can be emitted from anaerobic pockets, they recommend an MCF of zero). However, about 25 percent of the wastewater treatment systems used in the United States are non-aerated stabilization basins. These basins are typically 10 to 25 feet deep. These systems are classified as anaerobic deep lagoons (MCF = 0.8).

A time series of CH₄ emissions for 1990 through 2001 was developed based on production figures reported in the Lockwood-Post Directory (Lockwood-Post 2002). Published data from the American Forest and Paper Association, data published by Paper Loop, and other published statistics were used to estimate production for 2002 through 2009 (Pulp and Paper 2005, 2006, and monthly reports from 2003 through 2008; Paper 360° 2007). The overall wastewater outflow was estimated to be 85 m³/metric ton, and the average BOD concentrations in raw wastewater was estimated to be 0.4 gram BOD/liter (EPA 1997b, EPA 1993, World Bank 1999).

Meat and Poultry Processing. The meat and poultry processing industry makes extensive use of anaerobic lagoons in sequence with screening, fat traps and dissolved air flotation when treating wastewater on site. About 33 percent of meat processing operations (EPA 2002) and 25 percent of poultry processing operations (U.S. Poultry 2006) perform on-site treatment in anaerobic lagoons. The IPCC default B₀ of 0.25 kg CH₄/kg COD and default MCF of 0.8 for anaerobic lagoons were used to estimate the CH₄ produced from these on-site treatment systems. Production data, in carcass weight and live weight killed for the meat and poultry industry, were obtained from the USDA Agricultural Statistics Database and the Agricultural Statistics Annual Reports (USDA 2010). Data collected by EPA's Office of Water provided estimates for wastewater flows into anaerobic lagoons: 5.3 and 12.5 m³/metric ton for meat and poultry production (live weight killed), respectively (EPA 2002). The loadings are 2.8 and 1.5 g BOD/liter for meat and poultry, respectively.

Vegetables, Fruits, and Juices Processing. Treatment of wastewater from fruits, vegetables, and juices processing includes screening, coagulation/settling, and biological treatment (lagooning). The flows are frequently seasonal, and robust treatment systems are preferred for on-site treatment. Effluent is suitable for discharge to the sewer. This industry is likely to use lagoons intended for aerobic operation, but the large seasonal loadings may develop limited anaerobic zones. In addition, some anaerobic lagoons may also be used (Nemerow and Dasgupta 1991). Consequently, 4.2 percent of these wastewater organics are assumed to degrade anaerobically. The IPCC default B₀ of 0.25 kg CH₄/kg COD and default MCF of 0.8 for anaerobic treatment were used to estimate the CH₄ produced from these on-site treatment systems. The USDA National Agricultural Statistics Service (USDA 2010) provided production data for potatoes, other vegetables, citrus fruit, non-citrus fruit, and grapes processed for wine. Outflow and BOD data, presented in Table 8-13, were obtained from EPA (1974) for potato, citrus fruit, and apple processing, and from EPA (1975) for all other sectors.

Table 8-13. Wastewater Flow (m³/ton) and BOD Production (g/L) for U.S. Vegetables, Fruits, and Juices Production

Commodity	Wastewater Outflow (m ³ /ton)	BOD (g/L)
Vegetables		
Potatoes	10.27	1.765
Other Vegetables	8.74	0.801

Fruit		
Apples	3.66	1.371
Citrus	10.11	0.317
Non-citrus	12.42	1.204
Grapes (for wine)	2.78	1.831

Ethanol Production. Ethanol, or ethyl alcohol, is produced primarily for use as a fuel component, but is also used in industrial applications and in the manufacture of beverage alcohol. Ethanol can be produced from the fermentation of sugar-based feedstocks (e.g., molasses and beets), starch- or grain-based feedstocks (e.g., corn, sorghum, and beverage waste), and cellulosic biomass feedstocks (e.g., agricultural wastes, wood, and bagasse). Ethanol can also be produced synthetically from ethylene or hydrogen and carbon monoxide. However, synthetic ethanol comprises only about 2 percent of ethanol production, and although the Department of Energy predicts cellulosic ethanol to greatly increase in the coming years, currently it is only in an experimental stage in the United States. According to the Renewable Fuels Association, 82 percent of ethanol production facilities use corn as the sole feedstock and 7 percent of facilities use a combination of corn and another starch-based feedstock. The fermentation of corn is the principal ethanol production process in the United States and is expected to increase through 2012, and potentially more; therefore, emissions associated with wastewater treatment at starch-based ethanol production facilities were estimated (ERG 2006).

Ethanol is produced from corn (or other starch-based feedstocks) primarily by two methods: wet milling and dry milling. Historically, the majority of ethanol was produced by the wet milling process, but now the majority is produced by the dry milling process. The wastewater generated at ethanol production facilities is handled in a variety of ways. Dry milling facilities often combine the resulting evaporator condensate with other process wastewaters, such as equipment wash water, scrubber water, and boiler blowdown and anaerobically treat this wastewater using various types of digesters. Wet milling facilities often treat their steepwater condensate in anaerobic systems followed by aerobic polishing systems. Wet milling facilities may treat the stillage (or processed stillage) from the ethanol fermentation/distillation process separately or together with steepwater and/or wash water. CH₄ generated in anaerobic digesters is commonly collected and either flared or used as fuel in the ethanol production process (ERG 2006).

Available information was compiled from the industry on wastewater generation rates, which ranged from 1.25 gallons per gallon ethanol produced (for dry milling) to 10 gallons per gallon ethanol produced (for wet milling) (Ruocco 2006a,b; Merrick 1998; Donovan 1996; and NRBP 2001). COD concentrations were also found to be about 3 g/L (Ruocco 2006a; Merrick 1998; White and Johnson 2003). The amount of wastewater treated anaerobically was estimated, along with how much of the CH₄ is recovered through the use of biomethanators (ERG 2006). CH₄ emissions were then estimated as follows:

$$\text{Methane} = [\text{Production} \times \text{Flow} \times \text{COD} \times 3.785 \times ([\% \text{Plants}_o \times \% \text{WW}_{a,p} \times \% \text{COD}_p] + [\% \text{Plants}_a \times \% \text{WW}_{a,s} \times \% \text{COD}_s] + [\% \text{Plants}_t \times \% \text{WW}_{a,t} \times \% \text{COD}_s]) \times B_o \times \text{MCF} \times \% \text{Not Recovered}] + [\text{Production} \times \text{Flow} \times 3.785 \times \text{COD} \times ([\% \text{Plants}_o \times \% \text{WW}_{a,p} \times \% \text{COD}_p] + [\% \text{Plants}_a \times \% \text{WW}_{a,s} \times \% \text{COD}_s] + [\% \text{Plants}_t \times \% \text{WW}_{a,t} \times \% \text{COD}_s]) \times B_o \times \text{MCF} \times (\% \text{Recovered}) \times (1 - \text{DE})] \times 1/10^9$$

Where:

Production	= gallons ethanol produced (wet milling or dry milling)
Flow	= gallons wastewater generated per gallon ethanol produced (1.25 dry milling, 10 wet milling)
COD	= COD concentration in influent (3 g/l)
3.785	= conversion, gallons to liters
%Plants _o	= percent of plants with onsite treatment (100%)
%WW _{a,p}	= percent of wastewater treated anaerobically in primary treatment (0%)
%COD _p	= percent of COD entering primary treatment (100%)
%Plants _a	= percent of plants with anaerobic secondary treatment (33.3% wet, 75% dry)
%Plants _t	= percent of plants with other secondary treatment (66.7% wet, 25% dry)
%WW _{a,s}	= percent of wastewater treated anaerobically in anaerobic secondary treatment (100%)
%WW _{a,t}	= percent of wastewater treated anaerobically in other secondary treatment (0%)
%COD _s	= percent of COD entering secondary treatment (100%)

B_o	= maximum methane producing capacity (0.25 g CH ₄ /g COD)
MCF	= methane conversion factor (0.8 for anaerobic systems)
% Recovered	= percent of wastewater treated in system with emission recovery
% Not Recovered	= 1 - percent of wastewater treated in system with emission recovery
DE	= destruction efficiency of recovery system (99%)
$1/10^9$	= conversion factor, g to Gg

A time series of CH₄ emissions for 1990 through 2009 was developed based on production data from the Renewable Fuels Association (RFA 2010).

Petroleum Refining. Petroleum refining wastewater treatment operations produce CH₄ emissions from anaerobic wastewater treatment. The wastewater inventory section includes CH₄ emissions from petroleum refining wastewater treated on site under intended or unintended anaerobic conditions. Most facilities use aerated biological systems, such as trickling filters or rotating biological contactors; these systems can also exhibit anaerobic conditions that can result in the production of CH₄. Oil/water separators are used as a primary treatment method; however, it is unlikely that any COD is removed in this step.

Available information from the industry was compiled. The wastewater generation rate, from CARB (2007) and Timm (1985), was determined to be 35 gallons per barrel of finished product. An average COD value in the wastewater was estimated at 0.45 kg/m³ (Benyahia et al. 2006).

The equation used to calculate CH₄ generation at petroleum refining wastewater treatment systems is presented below:

$$\text{Methane} = \text{Flow} \times \text{COD} \times B_o \times \text{MCF}$$

Where:

Flow	= Annual flow treated through anaerobic treatment system (m ³ /year)
COD	= COD loading in wastewater entering anaerobic treatment system (kg/m ³)
B_o	= maximum methane producing potential of industrial wastewater (default value of 0.25 kg CH ₄ /kg COD)
MCF	= methane conversion factor (0.3)

A time series of CH₄ emissions for 1990 through 2009 was developed based on production data from the Energy Information Association (EIA 2010).

Domestic Wastewater N₂O Emission Estimates

N₂O emissions from domestic wastewater (wastewater treatment) were estimated using the IPCC (2006) methodology, including calculations that take into account N removal with sewage sludge, non-consumption and industrial wastewater N, and emissions from advanced centralized wastewater treatment plants:

- In the United States, a certain amount of N is removed with sewage sludge, which is applied to land, incinerated, or landfilled (N_{SLUDGE}). The N disposal into aquatic environments is reduced to account for the sewage sludge application.
- The IPCC methodology uses annual, per capita protein consumption (kg protein/[person-year]). For this inventory, the amount of protein available to be consumed is estimated based on per capita annual food availability data and its protein content, and then adjusts that data using a factor to account for the fraction of protein actually consumed.
- Small amounts of gaseous nitrogen oxides are formed as by-products in the conversion of nitrate to N gas in anoxic biological treatment systems. Approximately 7 grams N₂O is generated per capita per year if wastewater treatment includes intentional nitrification and denitrification (Scheehle and Doorn 2001). Analysis of the 2004 CWNS shows that plants with denitrification as one of their unit operations serve a population of 2.4 million people. Based on an emission factor of 7 grams per capita per year, approximately 21.2 metric tons of additional N₂O may have been emitted via denitrification in 2004. Similar analyses were completed for each year in the Inventory using data from CWNS on the amount of wastewater in centralized systems treated in denitrification units. Plants without intentional nitrification/denitrification are assumed to generate 3.2 grams N₂O per capita

per year.

N₂O emissions from domestic wastewater were estimated using the following methodology:

$$\begin{aligned}
 N_2O_{TOTAL} &= N_2O_{PLANT} + N_2O_{EFFLUENT} \\
 N_2O_{PLANT} &= N_2O_{NIT/DENIT} + N_2O_{WOUT\ NIT/DENIT} \\
 N_2O_{NIT/DENIT} &= [(US_{POPND}) \times EF_2 \times F_{IND-COM}] \times 1/10^9 \\
 N_2O_{WOUT\ NIT/DENIT} &= \{[(US_{POP} \times WWTP) - US_{POPND}] \times F_{IND-COM} \times EF_1\} \times 1/10^9 \\
 N_2O_{EFFLUENT} &= \{[(US_{POP} - (0.9 \times US_{POPND})) \times Protein \times F_{NPR} \times F_{NON-CON} \times F_{IND-COM}) - N_{SLUDGE}] \times EF_3 \times 44/28\} \times 1/10^6
 \end{aligned}$$

where,

N ₂ O _{TOTAL}	= Annual emissions of N ₂ O (Gg)
N ₂ O _{PLANT}	= N ₂ O emissions from centralized wastewater treatment plants (Gg)
N ₂ O _{NIT/DENIT}	= N ₂ O emissions from centralized wastewater treatment plants with nitrification/denitrification (Gg)
N ₂ O _{WOUT NIT/DENIT}	= N ₂ O emissions from centralized wastewater treatment plants without nitrification/denitrification (Gg)
N ₂ O _{EFFLUENT}	= N ₂ O emissions from wastewater effluent discharged to aquatic environments (Gg)
US _{POP}	= U.S. population
US _{POPND}	= U.S. population that is served by biological denitrification (from CWNS)
WWTP	= Fraction of population using WWTP (as opposed to septic systems)
EF ₁	= Emission factor (3.2 g N ₂ O/person-year) – plant with no intentional denitrification
EF ₂	= Emission factor (7 g N ₂ O/person-year) – plant with intentional denitrification
Protein	= Annual per capita protein consumption (kg/person/year)
F _{NPR}	= Fraction of N in protein, default = 0.16 (kg N/kg protein)
F _{NON-CON}	= Factor for non-consumed protein added to wastewater (1.4)
F _{IND-COM}	= Factor for industrial and commercial co-discharged protein into the sewer system (1.25)
N _{SLUDGE}	= N removed with sludge, kg N/yr
EF ₃	= Emission factor (0.005 kg N ₂ O -N/kg sewage-N produced) – from effluent
0.9	= Amount of nitrogen removed by denitrification systems
44/28	= Molecular weight ratio of N ₂ O to N ₂

U.S. population data were taken from the U.S. Census Bureau International Database (U.S. Census 2010) and include the populations of the United States, American Samoa, Guam, Northern Mariana Islands, Puerto Rico, and the Virgin Islands. The fraction of the U.S. population using wastewater treatment plants is based on data from the 1989, 1991, 1993, 1995, 1997, 1999, 2001, 2003, 2005, 2007, and 2009 American Housing Survey (U.S. Census 2009). Data for intervening years were obtained by linear interpolation. The emission factor (EF₁) used to estimate emissions from wastewater treatment was taken from IPCC (2006). Data on annual per capita protein intake were provided by U.S. Department of Agriculture Economic Research Service (USDA 2009). Protein consumption data for 2005 through 2009 were extrapolated from data for 1990 through 2004. Table 8-14 presents the data for U.S. population and average protein intake. An emission factor to estimate emissions from effluent (EF₃) has not been specifically estimated for the United States, thus the default IPCC value (0.005 kg N₂O-N/kg sewage-N produced) was applied. The fraction of N in protein (0.16 kg N/kg protein) was also obtained from IPCC (2006). The factor for non-consumed protein and the factor for industrial and commercial co-discharged protein were obtained from IPCC (2006). Sludge generation was obtained from EPA (1999) for 1988, 1996, and 1998 and from Beecher et al. (2007) for 2004. Intervening years were interpolated, and estimates for 2005 through 2009 were forecasted from the rest of the time series. An estimate for the N removed as sludge (N_{SLUDGE}) was obtained by determining the amount of sludge disposed by incineration, by land application (agriculture or other), through surface disposal, in landfills, or through ocean dumping. In 2009, 271 Gg N was removed with sludge.

Table 8-14. U.S. Population (Millions), Available Protein (kg/person-year), and Protein Consumed (kg/person-year)

Year	Population	Available Protein	Protein Consumed
1990	254	38.7	29.6

2000	286	41.3	31.6
2005	300	41.7	32.1
2006	303	41.9	32.1
2007	306	42.1	32.2
2008	309	42.2	32.4
2009	311	42.4	32.5

Source: U.S. Census Bureau 2010, USDA 2009.

Uncertainty and Time-Series Consistency

The overall uncertainty associated with both the 2009 CH₄ and N₂O emission estimates from wastewater treatment and discharge was calculated using the IPCC Good Practice Guidance Tier 2 methodology (2000). Uncertainty associated with the parameters used to estimate CH₄ emissions include that of numerous input variables used to model emissions from domestic wastewater, and wastewater from pulp and paper manufacture, meat and poultry processing, fruits and vegetable processing, ethanol production, and petroleum refining. Uncertainty associated with the parameters used to estimate N₂O emissions include that of sewage sludge disposal, total U.S. population, average protein consumed per person, fraction of N in protein, non-consumption nitrogen factor, emission factors per capita and per mass of sewage-N, and for the percentage of total population using centralized wastewater treatment plants.

The results of this Tier 2 quantitative uncertainty analysis are summarized in Table 8-15. CH₄ emissions from wastewater treatment were estimated to be between 15.3 and 35.9 Tg CO₂ Eq. at the 95 percent confidence level (or in 19 out of 20 Monte Carlo Stochastic Simulations). This indicates a range of approximately 37 percent below to 47 percent above the 2009 emissions estimate of 24.5 Tg CO₂ Eq. N₂O emissions from wastewater treatment were estimated to be between 1.2 and 9.7 Tg CO₂ Eq., which indicates a range of approximately 76 percent below to 93 percent above the actual 2009 emissions estimate of 5.0 Tg CO₂ Eq.

Table 8-15. Tier 2 Quantitative Uncertainty Estimates for CH₄ Emissions from Wastewater Treatment (Tg CO₂ Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate ^a			
			(Tg CO ₂ Eq.)		(%)	
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Wastewater Treatment	CH₄	24.5	15.3	35.9	-37%	+47%
Domestic	CH ₄	16.0	7.6	26.6	-52%	+66%
Industrial	CH ₄	8.5	5.1	13.1	-41%	+54%
Wastewater Treatment	N₂O	5.0	1.2	9.7	-76%	+93%

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

QA/QC and Verification

A QA/QC analysis was performed on activity data, documentation, and emission calculations. This effort included a Tier 1 analysis, including the following checks:

- Checked for transcription errors in data input;
- Ensured references were specified for all activity data used in the calculations;
- Checked a sample of each emission calculation used for the source category;
- Checked that parameter and emission units were correctly recorded and that appropriate conversion factors were used;
- Checked for temporal consistency in time series input data for each portion of the source category;
- Confirmed that estimates were calculated and reported for all portions of the source category and for all years;
- Investigated data gaps that affected emissions estimates trends; and

- Compared estimates to previous estimates to identify significant changes.

All transcription errors identified were corrected. The QA/QC analysis did not reveal any systemic inaccuracies or incorrect input values.

Planned Improvements Discussion

The methodology to estimate CH₄ emissions from domestic wastewater treatment currently utilizes estimates for the percentage of centrally treated wastewater that is treated by aerobic systems and anaerobic systems. These data come from the 1992, 1996, 2000, and 2004 CWNS. The question of whether activity data for wastewater treatment systems are sufficient across the timeseries to further differentiate aerobic systems with the potential to generate small amounts of CH₄ (aerobic lagoons) versus other types of aerobic systems, and to differentiate between anaerobic systems to allow for the use of different MCFs for different types of anaerobic treatment systems, continues to be explored. Recently available CWNS data for 2008 also is being evaluated for incorporation into the inventory. Due to significant changes in format, this dataset was unable to be included in the domestic wastewater calculations for the current Inventory. However, EPA continues to evaluate ways to incorporate the updated data into future years of the Inventory.

Currently, it is assumed that all aerobic systems are well managed and produce no CH₄ and that all anaerobic systems have an MCF of 0.8. Efforts to obtain better data reflecting emissions from various types of municipal treatment systems are currently being pursued.

A review of other industrial wastewater treatment sources for those industries believed to discharge significant loads of BOD and COD has been ongoing. Food processing industries have the highest potential for CH₄ generation due to the waste characteristics generated, and the greater likelihood to treat the wastes anaerobically. However, in all cases there is dated information available on U.S. treatment operations for these industries. A review of the organic chemicals industry was conducted in April 2010, during which only 1987 data was readily identified. It was concluded that current industry-level treatment system information is very difficult to obtain, as is time series data. Based on the 1987 data, emissions from this source are small and are not a likely industry category for significant CH₄ emissions. Therefore, this industry has not been included in the Inventory and there are no near future plans to do so. Similarly, the seafood processing industry was reviewed to estimate its potential to generate CH₄. Due to minimal anaerobic wastewater treatment operations at processing facilities, this industry was not selected for inclusion in the Inventory. Other industries will be reviewed as necessary for inclusion in future years of the Inventory.

Available data will be reviewed regarding anaerobic treatment at petroleum refineries. If necessary, the %TA for this industry will be revised accordingly. Currently, all petroleum plants are assumed to have anaerobic treatment.

With respect to estimating N₂O emissions, the default emission factor for indirect N₂O from wastewater effluent and direct N₂O from centralized wastewater treatment facilities has a high uncertainty. Current research is being conducted by the Water Environment Research Foundation (WERF) to measure N₂O emissions from municipal treatment systems. Such data will be reviewed as they are available to determine if a country-specific N₂O emission factor can or should be developed, or if alternate emission factors should be used. EPA expects WERF to publish a final N₂O generation report by the end of 2011. In addition, WERF recently conducted a study of greenhouse gas emissions from septic systems located in California. This study concluded that the emission rate for methane and nitrous oxide were 10.7 and 0.20 g/capita-d, respectively. EPA is currently reviewing the results of this study to determine if the systems evaluated are representative of U.S. operations and if a country-specific factor for septic systems can be introduced into the inventory. The effect would be to lower current estimates of CH₄ emissions by about half, and to include N₂O emission estimates where previously none were calculated. In addition, more investigation of new study results will be used to evaluate the method used to calculate N₂O emissions associated with effluent and whether septic systems are appropriately included in the calculation.

In addition, the estimate of N entering municipal treatment systems is under review. The factor that accounts for non-sewage N in wastewater (bath, laundry, kitchen, industrial components) also has a high uncertainty. Obtaining data on the changes in average influent N concentrations to centralized treatment systems over the time series would improve the estimate of total N entering the system, which would reduce or eliminate the need for other factors for non-consumed protein or industrial flow. The dataset previously provided by the National Association of Clean Water Agencies (NACWA) was reviewed to determine if it was representative of the larger population of centralized treatment plants for potential inclusion into the inventory. However, this limited dataset was not

representative of the number of systems by state or the service populations served in the United States, and therefore could not be incorporated into the inventory methodology. Additional data sources will continue to be researched with the goal of improving the uncertainty of the estimate of N entering municipal treatment systems.

8.3. Composting (IPCC Source Category 6D)

Composting of organic waste, such as food waste, garden (yard) and park waste, and sludge, is common in the United States. Advantages of composting include reduced volume in the waste material, stabilization of the waste, and destruction of pathogens in the waste material. The end products of composting, depending on its quality, can be recycled as fertilizer and soil amendment, or be disposed in a landfill.

Composting is an aerobic process and a large fraction of the degradable organic carbon in the waste material is converted into carbon dioxide (CO₂). Methane (CH₄) is formed in anaerobic sections of the compost, but it is oxidized to a large extent in the aerobic sections of the compost. Anaerobic sections are created in composting piles when there is excessive moisture or inadequate aeration (or mixing) of the compost pile. The estimated CH₄ released into the atmosphere ranges from less than 1 percent to a few percent of the initial C content in the material (IPCC 2006). Composting can also produce nitrous oxide (N₂O) emissions. The range of the estimated emissions varies from less than 0.5 percent to 5 percent of the initial nitrogen content of the material (IPCC 2006).

From 1990 to 2009, the amount of material composted in the United States has increased from 3,810 Gg to 19,857 Gg, an increase of approximately 421 percent. From 2000 to 2009, the amount of material composted in the United States has increased by approximately 33 percent. Emissions of CH₄ and N₂O from composting have increased by the same percentage (see Table 8-16 and Table 8-17). In 2009, CH₄ emissions from composting were 1.7 Tg CO₂ Eq. (79 Gg), and N₂O emissions from composting were 1.8 Tg CO₂ Eq. (6 Gg). The wastes that are composted include primarily yard trimmings (grass, leaves, and tree and brush trimmings) and food scraps from residences and commercial establishments (such as grocery stores, restaurants, and school and factory cafeterias). The composting waste quantities reported here do not include backyard composting. The growth in composting is attributable primarily to two factors: (1) steady growth in population and residential housing, and (2) state and local governments started enacting legislation that discouraged the disposal of yard trimmings in landfills. In 1992, 11 states and the District of Columbia had legislation in effect that banned or discouraged disposal of yard trimmings in landfills. In 2005, 21 states and the District of Columbia, representing about 50 percent of the nation's population, had enacted such legislation (EPA 2008).

Table 8-16. CH₄ and N₂O Emissions from Composting (Tg CO₂ Eq.)

Activity	1990	2000	2005	2006	2007	2008	2009
CH ₄	0.3	1.3	1.6	1.6	1.7	1.7	1.7
N ₂ O	0.4	1.4	1.7	1.8	1.8	1.9	1.8
Total	0.7	2.7	3.3	3.3	3.5	3.5	3.5

Table 8-17. CH₄ and N₂O Emissions from Composting (Gg)

Activity	1990	2000	2005	2006	2007	2008	2009
CH ₄	15	60	75	75	79	80	79
N ₂ O	1	4	6	6	6	6	6

Methodology

CH₄ and N₂O emissions from composting depend on factors such as the type of waste composted, the amount and type of supporting material (such as wood chips and peat) used, temperature, moisture content and aeration during the process.

The emissions shown in Table 8-16 and Table 8-17 were estimated using the IPCC default (Tier 1) methodology (IPCC 2006), which is the product of an emission factor and the mass of organic waste composted (note: no CH₄ recovery is expected to occur at composting operations):

$$E_i = M \times EF_i$$

where,

E_i	= CH ₄ or N ₂ O emissions from composting, Gg CH ₄ or N ₂ O,
M	= mass of organic waste composted in Gg,
EF_i	= emission factor for composting, 4 g CH ₄ /kg of waste treated (wet basis) and 0.3 g N ₂ O/kg of waste treated (wet basis), and
i	= designates either CH ₄ or N ₂ O.

Estimates of the quantity of waste composted (M) are presented in Table 8-18. Estimates of the quantity composted for 1990 and 1995 were taken from the *Characterization of Municipal Solid Waste in the United States: 1996 Update* (Franklin Associates 1997); estimates of the quantity composted for 2000, 2005, 2006, 2007, and 2008 were taken from EPA's *Municipal Solid Waste In The United States: 2008 Facts and Figures* (EPA 2009); estimates of the quantity composted for 2009 were calculated using the 2008 quantity composted.

Table 8-18: U.S. Waste Composted (Gg)

Activity	1990	2000	2005	2006	2007	2008	2009
Waste Composted	3,810	14,923	18,643	18,852	19,695	20,049	19,857

Source: Franklin Associates 1997 and EPA 2009.

Uncertainty and Time-Series Consistency

The estimated uncertainty from the 2006 IPCC Guidelines is ± 50 percent for the Tier 1 methodology. Emissions from composting in 2009 were estimated to be between 1.8 and 5.3 Tg CO₂ Eq., which indicates a range of 50 percent below to 50 percent above the actual 2009 emission estimate of 3.5 Tg CO₂ Eq. (see Table 8-19).

Table 8-19 : Tier 1 Quantitative Uncertainty Estimates for Emissions from Composting (Tg CO₂ Eq. and Percent)

Source	Gas	2009 Emission Estimate (Tg CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate (Tg CO ₂ Eq.) (%)			
			Lower Bound	Upper Bound	Lower Bound	Upper Bound
Composting	CH ₄ , N ₂ O	3.5	1.8	5.3	-50%	+50%

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

Planned Improvements

For future Inventories, additional efforts will be made to improve the estimates of CH₄ and N₂O emissions from composting. For example, a literature search may be conducted to determine if emission factors specific to various composting systems and composted materials are available.

8.4. Waste Sources of Indirect Greenhouse Gases

In addition to the main greenhouse gases addressed above, waste generating and handling processes are also sources of indirect greenhouse gas emissions. Total emissions of NO_x, CO, and NMVOCs from waste sources for the years 1990 through 2009 are provided in Table 8-20.

Table 8-20: Emissions of NO_x, CO, and NMVOC from Waste (Gg)

Gas/Source	1990	2000	2005	2006	2007	2008	2009
NO_x	+	2	2	2	2	2	2
Landfills	+	2	2	2	2	2	2
Wastewater Treatment	+	+	+	+	+	+	+
Miscellaneous ^a	+	+	+	+	+	+	0
CO	1	8	7	7	7	7	7
Landfills	1	7	6	6	6	6	6
Wastewater Treatment	+	1	+	+	+	+	+
Miscellaneous ^a	+	+	+	+	+	+	+
NMVOCs	673	119	114	113	111	109	76
Wastewater Treatment	57	51	49	49	48	47	33
Miscellaneous ^a	557	46	43	43	42	41	29
Landfills	58	22	22	21	21	21	14

^a Miscellaneous includes TSDFs (Treatment, Storage, and Disposal Facilities under the Resource Conservation and Recovery Act [42 U.S.C. § 6924, SWDA § 3004]) and other waste categories.

Note: Totals may not sum due to independent rounding.

+ Does not exceed 0.5 Gg.

Methodology

These emission estimates were obtained from preliminary data (EPA 2010, EPA 2009), and disaggregated based on EPA (2003), which, in its final iteration, will be published on the National Emission Inventory (NEI) Air Pollutant Emission Trends web site. Emission estimates of these gases were provided by sector, using a “top down” estimating procedure—emissions were calculated either for individual sources or for many sources 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 source categories from various agencies. Depending on the source category, these basic activity data may include data on production, fuel deliveries, raw material processed, etc.

Uncertainty and Time-Series Consistency

No quantitative estimates of uncertainty were calculated for this source category. Methodological recalculations were applied to the entire time-series to ensure time-series consistency from 1990 through 2009.

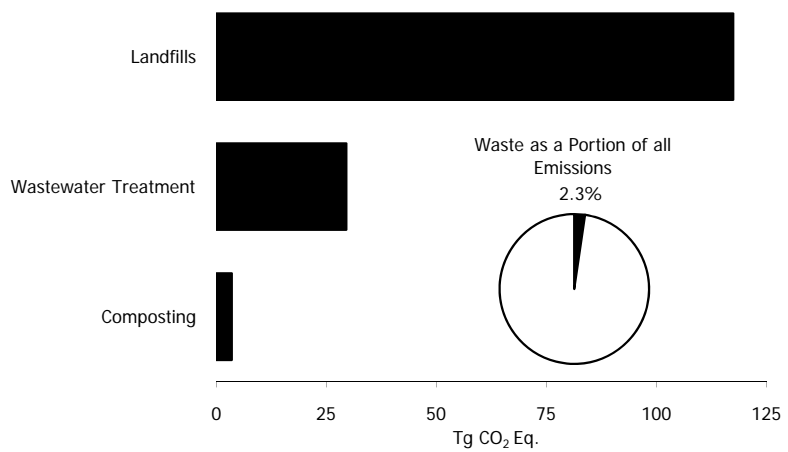


Figure 8-1: 2009 Waste Chapter Greenhouse Gas Sources

9. Other

The United States does not report any greenhouse gas emissions under the Intergovernmental Panel on Climate Change (IPCC) “Other” sector.

10. Recalculations and Improvements

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.”

The results of all methodological changes and historical data updates are presented in this section; detailed descriptions of each recalculation are contained within each source’s description found in this report, if applicable. Table 10-1 summarizes the quantitative effect of these changes on U.S. greenhouse gas emissions and Table 10-2 summarizes the quantitative effect on net CO₂ flux to the atmosphere, both relative to the previously published U.S. Inventory (i.e., the 1990 through 2008 report). These tables present the magnitude of these changes in units of teragrams of carbon dioxide equivalent (Tg CO₂ Eq.).

The Recalculations Discussion section of each source presents the details of each recalculation. In general, when methodological changes have been implemented, the entire time series (i.e., 1990 through 2008) has been recalculated to reflect the change, per IPCC (2006). Changes in historical data are generally the result of changes in statistical data supplied by other agencies.

The following emission sources, which are listed in descending order of absolute average annual change in emissions between 1990 and 2008, underwent some of the most important methodological and historical data changes. A brief summary of the recalculations and/or improvements undertaken is provided for each emission source.

- *Natural Gas Systems (CH₄)*. For the current Inventory, methodologies for gas well cleanups and condensate storage tanks were revised, and new data sources for centrifugal compressors with wet seals, unconventional gas well completions, and unconventional gas well workovers were used, relative to the previous Inventory. The net effect of these changes was an increase in total CH₄ emissions from natural gas systems of between 46.5 and 119.7 percent each year between 1990 and 2008, resulting in an overall annual average increase of 79.3 Tg CO₂ Eq. (66.4 percent). The natural gas production segment accounted for the largest increases, largely due to the methodological changes to gas well cleanups and the addition of unconventional gas well completions and workovers.
- *Landfills (CH₄)*. Changes in CH₄ emissions from Landfills relative to the previous Inventory resulted from improvements made to better associate flares with the correct landfills or Landfill Gas to Energy projects across the nation. In addition, steps were also taken to further characterize the food waste decay rate. A weighted component-specific decay rate for food waste of 0.156 yr⁻¹ was used in the current Inventory, replacing the previous Inventory’s default food waste decay rate of 0.185 yr⁻¹. These revisions impacted emission estimates for the entire time series and resulted in an average annual decrease of 8.3 Tg CO₂ Eq. (6.5 percent) in CH₄ emissions from Landfills for the period 1990 through 2008.
- *Manure Management (CH₄)*. Changes in CH₄ emissions from Manure Management relative to the previous Inventory resulted from several updates. Volatile solid production rates for all animal types were updated based on data from the USDA and EPA’s Cattle Enteric Fermentation Model. In addition, USDA data on swine were re-categorized, which changed the typical animal mass for two categories. These changes impacted emission estimates for the entire time series and resulted in an average annual increase of 3.5 Tg CO₂ Eq. (9.4 percent) in CH₄ emissions from Manure Management across the entire time series relative to the previous Inventory.
- *Agricultural Soil Management (N₂O)*. Changes in N₂O emissions from Agricultural Soil Management relative to the previous Inventory resulted from methodological changes for estimating grassland areas and livestock manure nitrogen. These recalculations have opposing effects on emissions; grassland area was reduced, resulting in lower emissions, and livestock manure nitrogen increased, resulting in higher emissions. These changes affected the entire time series, resulting in an average annual reduction in N₂O emissions of 3.2 Tg CO₂ Eq. (1.5 percent) for the period 1990 through 2008 relative to the previous Inventory.

- *Iron and Steel Production & Metallurgical Coke Production (CO₂)*. A calculation error in the previous Inventory regarding coal tar production and coke breeze production estimates was corrected for the current Inventory, resulting in an average annual decrease in CO₂ emissions from Iron and Steel Production & Metallurgical Coke Production of 2.2 Tg CO₂ Eq. (2.7 percent) for the period 1990 through 2008.
- *Non-Energy Uses of Fossil Fuels (CO₂)*. Updates to the EIA Manufacturer's Energy Consumption Survey (MECS) for 2006 resulted in changes to CO₂ emissions from Non-Energy Uses of Fossil Fuels for 2003 through 2008 relative to the previous Inventory. Adjustments were made to the entire MECS time series to remove scrap tire consumption for use as a fuel, which is associated with the Waste Incineration chapter. In addition, emissions from synthetic rubber were revised across the entire time series. These changes impacted emission estimates from 1990 through 2008 resulting in an average annual decrease in CO₂ emissions of 1.4 Tg CO₂ Eq. (1.0 percent) across the entire time series.
- *Petroleum Systems (CH₄)*. Well completion venting, well drilling, and offshore platform activity factors were updated relative to the previous Inventory from existing data sources from 1990 onward, and the emission factor for venting from fixed roof storage tanks in the crude oil production segment was increased to reflect the occurrence of gas venting through storage tanks. These changes affected the entire time series from Petroleum Systems, resulting in an average annual increase in CH₄ emissions of 1.3 Tg CO₂ Eq. (4.3 percent) for the period 1990 through 2008 relative to the previous report.
- *Nitric Acid Production (N₂O)*. Changes in N₂O emission from Nitric Acid Production relative to the previous Inventory resulted from updated information on abatement technologies in use at production facilities and revised production data from the U.S. Census Bureau. These changes resulted in an average annual decrease in N₂O emissions of 1.3 Tg CO₂ Eq. (6.7 percent) across the entire time series relative to the previous report.
- *Electrical Transmission and Distribution (SF₆)*. SF₆ emission estimates for the period 1990 through 2008 were updated relative to the previous Inventory based on (1) new data from EPA's SF₆ Emission Reduction Partnership; (2) revisions to interpolated and extrapolated non-reported Partner data; and (3) a correction made to 2004 transmission mile data for a large Partnership utility that had been interpreted incorrectly from the UDI database in previous years. In addition, the method for estimating potential emissions from the sector was updated for the current Inventory to assume that all SF₆ purchased by equipment manufacturers is either emitted or sent to utilities. These changes affected the entire time series, resulting in an average annual increase of 1.2 Tg CO₂ Eq. (6.6 percent) for the period 1990 through 2008 relative to the previous report.
- *Forestland Remaining Forestland (C Sink)*. Changes to the estimated carbon stored in Forestland Remaining Forestland stemmed from recent additions to the Forest Inventory and Analysis Database (FIADB). Newer annual inventory data for most states including Oklahoma, California, Oregon, and Washington were added. Some older periodic inventories for some southern states were also updated. These changes resulted in an average annual increase in carbon stored in forestland of 6.8 Tg CO₂ Eq. (2.4 percent) for the period 1990 through 2008 relative to the previous inventory report.

Table 10-1: Revisions to U.S. Greenhouse Gas Emissions (Tg CO₂ Eq.)

Gas/Source	1990	2000	2005	2006	2007	2008
CO₂	(1.1)	(2.2)	5.3	3.9	(0.2)	0.2
Fossil Fuel Combustion	2.7	1.5	(0.1)	0.3	(0.3)	(6.8)
Electricity Generation	+	+	+	NC	+	(2.6)
Transportation	0.2	+	1.3	1.4	0.2	4.7
Industrial	1.0	(1.1)	(2.5)	(2.5)	(0.2)	(16.4)
Residential	(0.8)	(0.5)	(0.5)	(0.5)	0.7	5.5
Commercial	2.3	3.2	2.3	2.6	2.0	4.7
U.S. Territories	NC	NC	(0.7)	(0.7)	(3.0)	(2.7)
Non-Energy Use of Fuels	(1.0)	(1.2)	6.9	4.2	1.9	6.8
Iron and Steel Production & Metallurgical						
Coke Production	(3.0)	(2.2)	(1.8)	(1.8)	(1.8)	(3.0)
Natural Gas Systems	0.3	0.5	0.4	1.2	0.2	2.9
Cement Production	NC	(0.8)	(0.7)	(0.8)	(0.7)	(0.6)
Incineration of Waste	(0.1)	(0.2)	(0.2)	(0.2)	(0.6)	(1.0)

Ammonia Production and Urea Consumption	NC	NC	NC	NC	0.1	0.2
Lime Production	NC	NC	NC	NC	NC	NC
Cropland Remaining Cropland	NC	NC	NC	NC	(0.1)	1.0
Limestone and Dolomite Use	NC	NC	NC	NC	NC	(0.3)
Soda Ash Production and Consumption	NC	NC	NC	NC	NC	NC
Aluminum Production	NC	NC	NC	NC	NC	NC
Petrochemical Production	NC	NC	NC	NC	NC	NC
Carbon Dioxide Consumption	NC	NC	NC	+	NC	NC
Titanium Dioxide Production	NC	NC	NC	NC	NC	NC
Ferroalloy Production	NC	NC	NC	NC	NC	NC
Wetlands Remaining Wetlands	NC	NC	NC	NC	NC	0.1
Phosphoric Acid Production	NC	NC	NC	NC	NC	+
Zinc Production	(0.3)	(0.1)	0.6	0.6	0.7	0.8
Lead Production	0.2	0.3	0.3	0.3	0.3	0.3
Petroleum Systems	+	+	+	+	+	+
Silicon Carbide Production and Consumption	NC	NC	NC	NC	NC	NC
<i>Land Use, Land-Use Change, and Forestry</i>						
<i>(Sink)^a</i>	47.9	87.7	(106.1)	(105.2)	(105.5)	(100.1)
<i>Biomass - Wood^a</i>	NC	NC	NC	(4.0)	(4.1)	(0.1)
<i>International Bunker Fuels^a</i>	+	+	(0.8)	(0.7)	0.6	(1.5)
<i>Biomass - Ethanol^a</i>	0.1	0.2	0.4	0.5	0.7	1.4
CH₄	61.5	73.9	78.3	103.9	95.4	109.1
Natural Gas Systems	60.3	78.6	86.8	114.6	105.7	115.4
Enteric Fermentation	(0.3)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)
Landfills	(1.9)	(9.0)	(13.1)	(15.3)	(15.2)	(10.4)
Coal Mining	NC	NC	NC	+	(0.2)	(0.5)
Manure Management	2.4	3.8	4.3	4.4	4.9	4.4
Petroleum Systems	1.5	1.3	1.1	1.1	1.2	1.1
Wastewater Treatment	+	+	+	+	+	0.2
Forest Land Remaining Forest Land	+	+	+	+	+	+
Rice Cultivation	NC	NC	NC	NC	NC	NC
Stationary Combustion	+	+	+	+	+	(0.2)
Abandoned Underground Coal Mines	NC	NC	+	(0.1)	(0.1)	+
Mobile Combustion	+	+	+	+	+	+
Composting	NC	NC	NC	NC	NC	+
Petrochemical Production	NC	NC	NC	NC	NC	NC
Iron and Steel Production & Metallurgical						
Coke Production	NC	NC	NC	NC	NC	NC
Field Burning of Agricultural Residues	(0.5)	(0.6)	(0.7)	(0.7)	(0.7)	(0.7)
Ferroalloy Production	NC	NC	NC	NC	NC	NC
Silicon Carbide Production and Consumption	NC	NC	NC	NC	NC	NC
Incineration of Waste	NC	NC	NC	NC	+	+
<i>International Bunker Fuels^a</i>	+	+	+	+	+	+
N₂O	(7.1)	(4.5)	(5.4)	(3.1)	(2.6)	(7.4)
Agricultural Soil Management	(5.7)	(3.3)	(4.5)	(2.3)	(1.6)	(5.1)
Mobile Combustion	+	+	+	+	+	+
Manure Management	0.1	0.4	0.6	0.7	0.8	0.8
Nitric Acid Production	(1.2)	(1.3)	(1.1)	(1.1)	(1.3)	(2.6)
Stationary Combustion	+	+	+	(0.1)	(0.1)	+
Forest Land Remaining Forest Land	+	+	+	+	+	+
Wastewater Treatment	+	+	+	+	+	+
N ₂ O from Product Uses	NC	NC	NC	NC	NC	NC
Adipic Acid Production	+	+	NC	NC	NC	NC
Composting	NC	NC	NC	NC	NC	+
Settlements Remaining Settlements	NC	NC	NC	NC	+	(0.1)
Incineration of Waste	NC	NC	NC	NC	+	+

Field Burning of Agricultural Residues	(0.3)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)
Wetlands Remaining Wetlands	NC	NC	NC	NC	NC	+
<i>International Bunker Fuels^a</i>	+	+	+	+	+	+
HFCs	NC	+	1.0	1.6	2.1	2.5
Substitution of Ozone Depleting Substances	NC	+	1.0	1.6	2.1	2.5
HCFC-22 Production	NC	NC	NC	NC	NC	NC
Semiconductor Manufacture	NC	NC	NC	NC	+	+
PFCs	NC	NC	NC	NC	+	+
Semiconductor Manufacture	NC	NC	NC	NC	+	+
Aluminum Production	NC	NC	NC	NC	NC	NC
SF₆	1.8	1.0	1.2	0.9	0.5	+
Electrical Transmission and Distribution	1.8	1.0	1.2	0.9	0.5	0.3
Magnesium Production and Processing	NC	NC	+	+	+	(0.1)
Semiconductor Manufacture	NC	NC	NC	NC	+	(0.2)
Net Change in Total Emissions^b	55.0	68.2	80.3	107.1	95.3	104.4
Percent Change	0.9%	1.0%	1.1%	1.5%	1.3%	1.5%

+ Absolute value does not exceed 0.05 Tg CO₂ Eq. or 0.05 percent.

Parentheses indicate negative values

NC (No Change)

^a Not included in emissions total.

^b Excludes net CO₂ flux from Land Use, Land-Use Change, and Forestry, and emissions from International Bunker Fuels.

Note: Totals may not sum due to independent rounding.

Table 10-2: Revisions to Net Flux of CO₂ to the Atmosphere from Land Use, Land-Use Change, and Forestry (Tg CO₂ Eq.)

Component: Net CO₂ Flux From Land Use, Land-Use Change, and Forestry	1990	2000	2005	2006	2007	2008
Forest Land Remaining Forest Land	48.8	89.4	(105.0)	(105.0)	(105.0)	(99.1)
Cropland Remaining Cropland	NC	NC	NC	NC	NC	NC
Land Converted to Cropland	NC	NC	NC	NC	NC	NC
Grassland Remaining Grassland	(0.1)	+	0.1	0.1	0.2	0.2
Land Converted to Grassland	+	+	0.2	0.3	0.3	0.4
Settlements Remaining Settlements	NC	NC	NC	NC	NC	NC
Other	(0.7)	(1.9)	(1.4)	(0.6)	(1.1)	(1.7)
Net Change in Total Flux	47.9	87.7	(106.1)	(105.2)	(105.5)	(100.1)
Percent Change	5.3%	13.2%	(11.2%)	(11.0%)	(11.0%)	(10.6%)

NC (No Change)

Note: Numbers in parentheses indicate a decrease in estimated net flux of CO₂ to the atmosphere, or an increase in net sequestration.

Note: Totals may not sum due to independent rounding.

+ Absolute value does not exceed 0.05 Tg CO₂ Eq. or 0.05 percent.

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Annexes

The following seven annexes provide additional information related to the material presented in the main body of this report as directed in the *UNFCCC Guidelines on Reporting and Review* (GE.03-60887). Annex 1 contains an analysis of the key categories of emissions discussed in this report and a review of the methodology used to identify those key categories. Annex 2 describes the methodologies used to estimate CO₂ emissions from fossil fuel combustion, the carbon content of fossil fuels, and the amount of carbon stored in products from non-energy uses of fossil fuels. Annex 3 discusses the methodologies used for a number of individual source categories in greater detail than was presented in the main body of the report and includes explicit activity data and emission factor tables. Annex 4 presents the IPCC reference approach for estimating CO₂ emissions from fossil fuel combustion. Annex 5 addresses the criteria for the inclusion of an emission source category and discusses some of the sources that are excluded from U.S. estimates. Annex 6 provides a range of additional information that is relevant to the contents of this report. Finally, Annex 7 provides data on the uncertainty of the emission estimates included in this report.

ANNEX 1 Key Category Analysis	3
ANNEX 2 Methodology and Data for Estimating CO ₂ Emissions from Fossil Fuel Combustion	21
2.1. Methodology for Estimating Emissions of CO ₂ from Fossil Fuel Combustion	21
2.2. Methodology for Estimating the Carbon Content of Fossil Fuels	48
2.3. Methodology for Estimating Carbon Emitted from Non-Energy Uses of Fossil Fuels	84
ANNEX 3 Methodological Descriptions for Additional Source or Sink Categories	109
3.1. Methodology for Estimating Emissions of CH ₄ , N ₂ O, and Indirect Greenhouse Gases from Stationary Combustion	109
3.2. Methodology for Estimating Emissions of CH ₄ , N ₂ O, and Indirect Greenhouse Gases from Mobile Combustion and Methodology for and Supplemental Information on Transportation-Related GHG Emissions	116
3.3. Methodology for Estimating CH ₄ Emissions from Coal Mining	139
3.4. Methodology for Estimating CH ₄ and CO ₂ Emissions from Natural Gas Systems	147
3.5. Methodology for Estimating CH ₄ and CO ₂ Emissions from Petroleum Systems	165
3.6. Methodology for Estimating CO ₂ , N ₂ O and CH ₄ Emissions from the Incineration of Waste	170
3.7. Methodology for Estimating Emissions from International Bunker Fuels used by the U.S. Military	176
3.8. Methodology for Estimating HFC and PFC Emissions from Substitution of Ozone Depleting Substances	181
3.9. Methodology for Estimating CH ₄ Emissions from Enteric Fermentation	199
3.10. Methodology for Estimating CH ₄ and N ₂ O Emissions from Manure Management	211
3.11. Methodology for Estimating N ₂ O Emissions from Agricultural Soil Management	235
3.12. Methodology for Estimating Net Carbon Stock Changes in Forest Lands Remaining Forest Lands	254
3.13. Methodology for Estimating Net Changes in Carbon Stocks in Mineral and Organic Soils on Cropland and Grassland	285
3.14. Methodology for Estimating CH ₄ Emissions from Landfills	304
ANNEX 4 IPCC Reference Approach for Estimating CO ₂ Emissions from Fossil Fuel Combustion	313
ANNEX 5 Assessment of the Sources and Sinks of Greenhouse Gas Emissions Not Included	323
ANNEX 6 Additional Information	325
6.1. Global Warming Potential Values	325
6.2. Ozone Depleting Substance Emissions	333
6.3. Sulfur Dioxide Emissions	335
6.4. Complete List of Source Categories	337
6.5. Constants, Units, and Conversions	338
6.6. Abbreviations	341
6.7. Chemical Formulas	345
ANNEX 7 Uncertainty	349
7.1. Overview	349
7.2. Methodology and Results	349
7.3. Planned Improvements	355
7.4. Additional Information on Uncertainty Analyses by Source	358

ANNEX 1 Key Category Analysis

The United States has identified national key categories based on the estimates presented in this report. The IPCC's *Good Practice Guidance* (IPCC 2000) describes 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 direct greenhouse gases in terms of the absolute level of emissions, the trend in emissions, or both.”¹ 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 determination of key categories must also account for the influence of the trends of individual categories. Therefore, a trend assessment is conducted to identify source and sink categories for which significant uncertainty in the estimate would have considerable effects on overall emission trends. 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, but can be considered key because of the unique country-specific estimation methods.

The methodology for conducting a key category analysis, as defined by IPCC's *Good Practice Guidance* (IPCC 2000), IPCC's *Good Practice Guidance for Land Use, Land-Use Change, and Forestry* (IPCC 2003), and IPCC's *2006 Guidelines for National Greenhouse Gas Inventories* (IPCC 2006); includes:

- Tier 1 approach (including both level and trend assessments);
- Tier 2 approach (including both level and trend assessments, and incorporating uncertainty analysis); and
- Qualitative approach.

This Annex presents an analysis of key categories, both for sources only and also for sources and sinks (i.e., including LULUCF); discusses Tier 1, Tier 2, and qualitative approaches to identifying key categories; provides level and trend assessment equations; and provides a brief statistical evaluation of IPCC's quantitative methodologies for defining key categories. Table A- 1 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 2009. The table also indicates the criteria used in identifying these categories (i.e., level, trend, Tier 1, Tier 2, and/or qualitative assessments).

Table A- 1: Key Source Categories for the United States (1990-2009)

IPCC Source Categories	Gas	Tier 1				Tier 2				Qual ^a	2009 Emissions (Tg 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	CO ₂	•		•	•	•		•	•		1,841.0
CO ₂ Emissions from Mobile Combustion: Road	CO ₂	•	•	•	•	•	•	•	•		1,475.6
CO ₂ Emissions from Stationary Combustion - Gas	CO ₂	•	•	•	•	•	•	•	•		1,164.6
CO ₂ Emissions from Stationary Combustion - Oil	CO ₂	•	•	•	•	•	•	•	•		483.3
CO ₂ Emissions from Mobile Combustion: Aviation	CO ₂	•	•	•	•	•	•	•	•		140.7
CO ₂ Emissions from Non-Energy Use of Fuels	CO ₂	•		•	•	•		•			123.4
CO ₂ Emissions from Mobile Combustion: Other	CO ₂	•	•	•	•						73.5
CO ₂ Emissions from Natural Gas Systems	CO ₂	•	•	•	•	•	•	•	•		32.2
CO ₂ Emissions from Mobile Combustion: Marine	CO ₂	•	•	•	•						30.0
Fugitive Emissions from Natural Gas Systems	CH ₄	•	•	•	•	•	•	•	•		221.2
Fugitive Emissions from Coal Mining	CH ₄	•	•	•	•	•	•	•	•		71.0
Fugitive Emissions from Petroleum Systems	CH ₄	•	•	•	•	•	•	•	•		30.9
Non-CO ₂ Emissions from Stationary Combustion	CH ₄						•		•		6.2
N ₂ O Emissions from Mobile Combustion: Road	N ₂ O	•	•	•	•		•		•		20.3
Non-CO ₂ Emissions from Stationary Combustion	N ₂ O					•		•			12.8
International Bunker Fuels ^b	Several									•	124.4
Industrial Processes											
CO ₂ Emissions from Iron and Steel Production & Metallurgical Coke Production	CO ₂	•	•	•	•	•	•	•	•		41.9
CO ₂ Emissions from Cement Production	CO ₂		•	•	•						29.0
CO ₂ Emissions from Ammonia Production and Urea Consumption	CO ₂		•		•						11.8
CO ₂ Emissions from Aluminum Production	CO ₂										3.0
N ₂ O Emissions from Nitric Acid Production	N ₂ O				•		•				14.6
N ₂ O Emissions from Adipic Acid Production	N ₂ O		•		•		•		•		1.9
Emissions from Substitutes for Ozone Depleting Substances	HiGWP	•	•	•	•		•	•	•		120.0
SF ₆ Emissions from Electrical Transmission and Distribution	HiGWP		•		•		•		•		12.8
HFC-23 Emissions from HCFC-22 Production	HiGWP	•	•	•	•		•		•		5.4
PFC Emissions from Aluminum Production	HiGWP		•		•		•				1.6
SF ₆ Emissions from Magnesium Production and Processing	HiGWP		•		•						1.1
Agriculture											
CH ₄ Emissions from Enteric Fermentation	CH ₄	•		•		•		•			139.8
CH ₄ Emissions from Manure Management	CH ₄	•	•	•	•		•		•		49.5
CH ₄ Emissions from Rice Cultivation	CH ₄					•		•			7.3
Direct N ₂ O Emissions from Agricultural Soil Management	N ₂ O	•	•	•	•	•	•	•	•		160.2
Indirect N ₂ O Emissions from Applied Nitrogen	N ₂ O	•		•		•	•	•	•		44.4
Waste											

IPCC Source Categories	Gas	Tier 1				Tier 2				Qual ^a	2009 Emissions (Tg 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		
CH ₄ Emissions from Landfills	CH ₄	•	•	•	•	•	•	•	•		117.5
CH ₄ Emissions from Wastewater Treatment	CH ₄					•		•			24.5
Land Use, Land Use Change, and Forestry											
CO ₂ Emissions from Changes in Forest Carbon Stocks	CO ₂			•	•			•	•		(863.1)
CO ₂ Emissions from Urban Trees	CO ₂			•	•			•	•		(95.9)
CO ₂ Emissions from Cropland Remaining Cropland	CO ₂				•			•	•		(17.4)
CO ₂ Emissions from Landfilled Yard Trimmings and Food Scraps	CO ₂				•			•	•		(12.6)
CO ₂ Emissions from Grassland Remaining Grassland	CO ₂			•	•			•	•		(8.3)
CH ₄ Emissions from Forest Fires	CH ₄							•	•		7.8
N ₂ O Emissions from Forest Fires	N ₂ O								•		6.4
Subtotal Without LULUCF											6,512.7
Total Emissions Without LULUCF											6,608.2
Percent of Total Without LULUCF											99%
Subtotal With LULUCF											5,529.5
Total Emissions With LULUCF											5,618.2
Percent of Total With LULUCF											98%

^aQualitative criteria.

^bEmissions from this source not included in totals.

Note: Parentheses indicate negative values (or sequestration). Table A-2 provides a complete listing of source categories by IPCC sector, along with notations on the criteria used in identifying key categories, without LULUCF sources and sinks. Similarly, Table A-3 provides a complete listing of source and sink categories by IPCC sector, along with notations on the criteria used in identifying key categories, including LULUCF sources and sinks. The notations refer specifically to the year(s) in the inventory time series (i.e., 1990 to 2009) in which each source category reached the threshold for being a key category based on either a Tier 1 or Tier 2 level assessment.

In addition to conducting Tier 1 and 2 level and trend assessments, a qualitative assessment of the source categories, as described in the IPCC's *Good Practice Guidance* (IPCC 2000), was conducted to capture any key categories that were not identified by any 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 with IPCC guidelines. If these emissions were included in the totals, bunker fuels would qualify as a key category according to the Tier 1 approach. The amount of uncertainty associated with estimation of emissions from international bunker fuels also supports the qualification of this source category as key, which would qualify it as a key category according to the Tier 2 approach.

Table A-2: U.S Greenhouse Gas Inventory Source Categories without LULUCF

IPCC Source Categories	Direct GHG	2009 Emissions (Tg CO ₂ Eq.)	Key Category?	ID Criteria ^a	Level in which year(s)? ^b
Energy					
CO ₂ Emissions from Stationary Combustion - Coal	CO ₂	1,841.0	•	L ₁ L ₂	1990, 2009
CO ₂ Emissions from Mobile Combustion: Road	CO ₂	1,475.6	•	L ₁ T ₁ L ₂ T ₂	1990, 2009
CO ₂ Emissions from Stationary Combustion - Gas	CO ₂	1,164.6	•	L ₁ T ₁ L ₂ T ₂	1990, 2009
CO ₂ Emissions from Stationary Combustion - Oil	CO ₂	483.3	•	L ₁ T ₁ L ₂ T ₂	1990, 2009
CO ₂ Emissions from Mobile Combustion: Aviation	CO ₂	140.7	•	L ₁ T ₁ L ₂ T ₂	1990, 2009
CO ₂ Emissions from Non-Energy Use of Fuels	CO ₂	123.4	•	L ₁ L ₂	1990, 2009
CO ₂ Emissions from Mobile Combustion: Other	CO ₂	73.5	•	L ₁ T ₁	1990, 2009
CO ₂ Emissions from Natural Gas Systems	CO ₂	32.2	•	L ₁ T ₁ L ₂ T ₂	1990, 2009 ₁
CO ₂ Emissions from Mobile Combustion: Marine	CO ₂	30.0	•	L ₁ T ₁	1990
CO ₂ Emissions from Incineration of Waste	CO ₂	12.3			
CO ₂ Emissions from Petroleum Systems	CO ₂	0.5			
CO ₂ Emissions from Stationary Combustion - Geothermal					
Energy	CO ₂	0.4			
Fugitive Emissions from Natural Gas Systems	CH ₄	221.2	•	L ₁ T ₁ L ₂ T ₂	1990, 2009
Fugitive Emissions from Coal Mining	CH ₄	71.0	•	L ₁ T ₁ L ₂ T ₂	1990, 2009
Fugitive Emissions from Petroleum Systems	CH ₄	30.9	•	L ₁ T ₁ L ₂ T ₂	1990 ₁ , 2009
Non-CO ₂ Emissions from Stationary Combustion	CH ₄	6.2	•	T ₂	
Fugitive Emissions from Abandoned Underground Coal					
Mines	CH ₄	5.5			
CH ₄ Emissions from Mobile Combustion: Road	CH ₄	1.4			
CH ₄ Emissions from Mobile Combustion: Other	CH ₄	0.4			
CH ₄ Emissions from Mobile Combustion: Aviation	CH ₄	0.1			
CH ₄ Emissions from Mobile Combustion: Marine	CH ₄	+			
CH ₄ Emissions from Incineration of Waste	CH ₄	+			
N ₂ O Emissions from Mobile Combustion: Road	N ₂ O	20.3	•	L ₁ T ₁ T ₂	1990
Non-CO ₂ Emissions from Stationary Combustion	N ₂ O	12.8	•	L ₂	1990, 2009
N ₂ O Emissions from Mobile Combustion: Other	N ₂ O	1.8			
N ₂ O Emissions from Mobile Combustion: Aviation	N ₂ O	1.3			
N ₂ O Emissions from Mobile Combustion: Marine	N ₂ O	0.4			
N ₂ O Emissions from Incineration of Waste	N ₂ O	0.4			
International Bunker Fuels ^c	Several	124.4	•	Q	
Industrial Processes					
CO ₂ Emissions from Iron and Steel Production & Metallurgical Coke Production	CO ₂	41.9	•	L ₁ T ₁ L ₂ T ₂	1990 ₂ , 2009
CO ₂ Emissions from Cement Production	CO ₂	29.0	•	T ₁	
CO ₂ Emissions from Ammonia Production and Urea Consumption	CO ₂	11.8	•	T ₁	
CO ₂ Emissions from Lime Production	CO ₂	11.2			
CO ₂ Emissions from Limestone and Dolomite Use	CO ₂	7.6			
CO ₂ Emissions from Soda Ash Production and Consumption	CO ₂	4.3			
CO ₂ Emissions from Aluminum Production	CO ₂	3.0			
CO ₂ Emissions from Petrochemical Production	CO ₂	2.7			
CO ₂ Emissions from Carbon Dioxide Consumption	CO ₂	1.8			
CO ₂ Emissions from Titanium Dioxide Production	CO ₂	1.5			
CO ₂ Emissions from Ferroalloy Production	CO ₂	1.5			
CO ₂ Emissions from Phosphoric Acid Production	CO ₂	1.0			

IPCC Source Categories	Direct GHG	2009 Emissions (Tg CO ₂ Eq.)	Key Category?	ID Criteria ^a	Level in which year(s)? ^b
		Eq.			
CO ₂ Emissions from Zinc Production	CO ₂	1.0			
CO ₂ Emissions from Lead Production	CO ₂	0.5			
CO ₂ Emissions from Silicon Carbide Production and Consumption	CO ₂	0.1			
CH ₄ Emissions from Petrochemical Production	CH ₄	0.8			
CH ₄ Emissions from Iron and Steel Production & Metallurgical Coke Production	CH ₄	0.4			
CH ₄ Emissions from Ferroalloy Production	CH ₄	+			
CH ₄ Emissions from Silicon Carbide Production and Consumption	CH ₄	+			
N ₂ O Emissions from Nitric Acid Production	N ₂ O	14.6	•	T ₂	
N ₂ O Emissions from Product Uses	N ₂ O	4.4			
N ₂ O Emissions from Adipic Acid Production	N ₂ O	1.9	•	T ₁ T ₂	
Emissions from Substitutes for Ozone Depleting Substances	HiGWP	120.0	•	L ₁ T ₁ T ₂	2009
SF ₆ Emissions from Electrical Transmission and Distribution	HiGWP	12.8	•	T ₁ T ₂	
HFC-23 Emissions from HCFC-22 Production	HiGWP	5.4	•	L ₁ T ₁ T ₂	1990
PFC, HFC, and SF ₆ Emissions from Semiconductor Manufacture	HiGWP	5.3			
PFC Emissions from Aluminum Production	HiGWP	1.6	•	T ₁ T ₂	
SF ₆ Emissions from Magnesium Production and Processing	HiGWP	1.1	•	T ₁	
Agriculture					
CH ₄ Emissions from Enteric Fermentation	CH ₄	139.8	•	L ₁ L ₂	1990, 2009
CH ₄ Emissions from Manure Management	CH ₄	49.5	•	L ₁ T ₁ T ₂	2009
CH ₄ Emissions from Rice Cultivation	CH ₄	7.3	•	L ₂	2009
CH ₄ Emissions from Field Burning of Agricultural Residues	CH ₄	0.2			
Direct N ₂ O Emissions from Agricultural Soil Management	N ₂ O	160.2	•	L ₁ T ₁ L ₂ T ₂	1990, 2009
Indirect N ₂ O Emissions from Applied Nitrogen	N ₂ O	44.4	•	L ₁ L ₂ T ₂	1990, 2009
N ₂ O Emissions from Manure Management	N ₂ O	17.9			
N ₂ O Emissions from Field Burning of Agricultural Residues	N ₂ O	0.1			
Waste					
CH ₄ Emissions from Landfills	CH ₄	117.5	•	L ₁ T ₁ L ₂ T ₂	1990, 2009
CH ₄ Emissions from Wastewater Treatment	CH ₄	24.5	•	L ₂	1990, 2009
CH ₄ Emissions from Composting	CH ₄	1.7			
N ₂ O Emissions from Wastewater Treatment	N ₂ O	5.0			
N ₂ O Emissions from Composting	N ₂ O	1.8			

^a For the ID criteria, L refers to a key category identified through a level assessment; T refers to a key category identified through a trend assessment and the subscripted number refers to either a Tier 1 or Tier 2 assessment (e.g., L₂ designates a source is a key category for a Tier 2 level assessment).

^b If the source is a key category for both L₁ and L₂ (as designated in the ID criteria column), it is a key category for both assessments in the years provided unless noted by a subscript, in which case it is a key category for that assessment in that year only (e.g., 1990₂ designates a source is a key category for the Tier 2 assessment only in 1990).

^c Emissions from these sources not included in totals.

+ Does not exceed 0.05 Tg CO₂ Eq.

Note: LULUCF sources and sinks are not included in this analysis.

Table A-3: U.S Greenhouse Gas Inventory Source Categories with LULUCF

IPCC Source Categories	Gas	2009 Emissions (Tg CO ₂ Eq.)	Key Category?	ID Criteria ^a	Level in which year(s)? ^b
Energy					
CO ₂ Emissions from Stationary Combustion - Coal	CO ₂	1,841.0	•	L ₁ T ₁ L ₂ T ₂	1990, 2009
CO ₂ Emissions from Mobile Combustion: Road	CO ₂	1,475.6	•	L ₁ T ₁ L ₂ T ₂	1990, 2009
CO ₂ Emissions from Stationary Combustion - Gas	CO ₂	1,164.6	•	L ₁ T ₁ L ₂ T ₂	1990, 2009
CO ₂ Emissions from Stationary Combustion - Oil	CO ₂	483.3	•	L ₁ T ₁ L ₂ T ₂	1990, 2009
CO ₂ Emissions from Mobile Combustion: Aviation	CO ₂	140.7	•	L ₁ T ₁ L ₂ T ₂	1990, 2009
CO ₂ Emissions from Non-Energy Use of Fuels	CO ₂	123.4	•	L ₁ T ₁ L ₂	1990, 2009
CO ₂ Emissions from Mobile Combustion: Other	CO ₂	73.5	•	L ₁ T ₁	1990, 2009

IPCC Source Categories	Gas	2009	Key Category?	ID Criteria ^a	Level in which year(s)? ^b
		Emissions (Tg CO ₂ Eq.)			
CO ₂ Emissions from Natural Gas Systems	CO ₂	32.2	•	L ₁ T ₁ L ₂ T ₂	1990 ₂ , 2009
CO ₂ Emissions from Mobile Combustion: Marine	CO ₂	30.0	•	L ₁ T ₁	1990
CO ₂ Emissions from Incineration of Waste	CO ₂	12.3			
CO ₂ Emissions from Petroleum Systems	CO ₂	0.5			
CO ₂ Emissions from Stationary Combustion - Geothermal Energy	CO ₂	0.4			
Fugitive Emissions from Natural Gas Systems	CH ₄	221.2	•	L ₁ T ₁ L ₂ T ₂	1990, 2009
Fugitive Emissions from Coal Mining	CH ₄	71.0	•	L ₁ T ₁ L ₂ T ₂	1990, 2009
Fugitive Emissions from Petroleum Systems	CH ₄	30.9	•	L ₁ T ₁ L ₂ T ₂	1990, 2009
Non-CO ₂ Emissions from Stationary Combustion	CH ₄	6.2	•	T ₂	
Fugitive Emissions from Abandoned Underground Coal Mines	CH ₄	5.5			
CH ₄ Emissions from Mobile Combustion: Road	CH ₄	1.4			
CH ₄ Emissions from Mobile Combustion: Other	CH ₄	0.4			
CH ₄ Emissions from Mobile Combustion: Aviation	CH ₄	0.1			
CH ₄ Emissions from Mobile Combustion: Marine	CH ₄	+			
CH ₄ Emissions from Incineration of Waste	CH ₄	+			
N ₂ O Emissions from Mobile Combustion: Road	N ₂ O	20.3	•	L ₁ T ₁ T ₂	1990
Non-CO ₂ Emissions from Stationary Combustion	N ₂ O	12.8	•	L ₂	1990, 2009
N ₂ O Emissions from Mobile Combustion: Other	N ₂ O	1.8			
N ₂ O Emissions from Mobile Combustion: Aviation	N ₂ O	1.3			
N ₂ O Emissions from Mobile Combustion: Marine	N ₂ O	0.4			
N ₂ O Emissions from Incineration of Waste	N ₂ O	0.4			
International Bunker Fuels ^c	Several	124.4	•	Q	
Industrial Processes					
CO ₂ Emissions from Iron and Steel Production & Metallurgical Coke Production	CO ₂	41.9	•	L ₁ T ₁ L ₂ T ₂	1990 ₂ , 2009
CO ₂ Emissions from Cement Production	CO ₂	29.0	•	L ₁ T ₁	1990
CO ₂ Emissions from Ammonia Production and Urea Consumption	CO ₂	11.8	•	T ₁	
CO ₂ Emissions from Lime Production	CO ₂	11.2			
CO ₂ Emissions from Limestone and Dolomite Use	CO ₂	7.6			
CO ₂ Emissions from Soda Ash Production and Consumption	CO ₂	4.3			
CO ₂ Emissions from Aluminum Production	CO ₂	3.0			
CO ₂ Emissions from Petrochemical Production	CO ₂	2.7			
CO ₂ Emissions from Carbon Dioxide Consumption	CO ₂	1.8			
CO ₂ Emissions from Titanium Dioxide Production	CO ₂	1.5			
CO ₂ Emissions from Ferroalloy Production	CO ₂	1.5			
CO ₂ Emissions from Phosphoric Acid Production	CO ₂	1.0			
CO ₂ Emissions from Zinc Production	CO ₂	1.0			
CO ₂ Emissions from Lead Production	CO ₂	0.5			
CO ₂ Emissions from Silicon Carbide Production and Consumption	CO ₂	0.1			
CH ₄ Emissions from Petrochemical Production	CH ₄	0.8			
CH ₄ Emissions from Iron and Steel Production & Metallurgical Coke Production	CH ₄	0.4			
CH ₄ Emissions from Ferroalloy Production	CH ₄	+			
CH ₄ Emissions from Silicon Carbide Production and Consumption	CH ₄	+			
N ₂ O Emissions from Nitric Acid Production	N ₂ O	14.6	•	T ₁	
N ₂ O Emissions from Product Uses	N ₂ O	4.4			
N ₂ O Emissions from Adipic Acid Production	N ₂ O	1.9	•	T ₁ T ₂	
Emissions from Substitutes for Ozone Depleting Substances	HiGWP	120.0	•	L ₁ T ₁ L ₂ T ₂	2009
SF ₆ Emissions from Electrical Transmission and Distribution	HiGWP	12.8	•	T ₁ T ₂	
HFC-23 Emissions from HCFC-22 Production	HiGWP	5.4	•	L ₁ T ₁ T ₂	1990

A-8 Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009

IPCC Source Categories	Gas	2009	Key Category?	ID Criteria ^a	Level in which year(s)? ^b
		Emissions (Tg CO ₂ Eq.)			
PFC, HFC, and SF ₆ Emissions from Semiconductor Manufacture	HiGWP	5.3			
PFC Emissions from Aluminum Production	HiGWP	1.6	•	T ₁	
SF ₆ Emissions from Magnesium Production and Processing	HiGWP	1.1	•	T ₁	
Agriculture					
CH ₄ Emissions from Enteric Fermentation	CH ₄	139.8	•	L ₁ L ₂	1990, 2009
CH ₄ Emissions from Manure Management	CH ₄	49.5	•	L ₁ T ₁ T ₂	1990, 2009
CH ₄ Emissions from Rice Cultivation	CH ₄	7.3	•	L ₂	2009
CH ₄ Emissions from Field Burning of Agricultural Residues	CH ₄	0.2			
Direct N ₂ O Emissions from Agricultural Soil Management	N ₂ O	160.2	•	L ₁ T ₁ L ₂ T ₂	1990, 2009
Indirect N ₂ O Emissions from Applied Nitrogen	N ₂ O	44.4	•	L ₁ L ₂ T ₂	1990, 2009
N ₂ O Emissions from Manure Management	N ₂ O	17.9			
N ₂ O Emissions from Field Burning of Agricultural Residues	N ₂ O	0.1			
Waste					
CH ₄ Emissions from Landfills	CH ₄	117.5	•	L ₁ T ₁ L ₂ T ₂	1990, 2009
CH ₄ Emissions from Wastewater Treatment	CH ₄	24.5	•	L ₂	1990, 2009
CH ₄ Emissions from Composting	CH ₄	1.7			
N ₂ O Emissions from Wastewater Treatment	N ₂ O	5.0			
N ₂ O Emissions from Composting	N ₂ O	1.8			
Land Use, Land Use Change, and Forestry					
CO ₂ Emissions from Changes in Forest Carbon Stocks	CO ₂	(863.1)	•	L ₁ T ₁ L ₂ T ₂	
CO ₂ Emissions from Urban Trees	CO ₂	(95.9)	•	L ₁ T ₁ L ₂ T ₂	
CO ₂ Emissions from Land Converted to Grassland	CO ₂	(23.6)			
CO ₂ Emissions from Cropland Remaining Cropland	CO ₂	(17.4)	•	L ₂ T ₁ T ₂	1990, 2009
CO ₂ Emissions from Landfilled Yard Trimmings and Food Scraps	CO ₂	(12.6)	•	L ₂ T ₁ T ₂	1990
CO ₂ Emissions from Grassland Remaining Grassland	CO ₂	(8.3)	•	L ₁ T ₁ L ₂ T ₂	1990
CO ₂ Emissions from Land Converted to Cropland	CO ₂	5.9			
CO ₂ Emissions from Liming of Agricultural Soils	CO ₂	4.2			
CO ₂ Emissions from Urea Fertilization	CO ₂	3.6			
CO ₂ Emissions from Wetlands Remaining Wetlands	CO ₂	1.1			
CH ₄ Emissions from Forest Fires	CH ₄	7.8	•	L ₂ T ₂	2009
N ₂ O Emissions from Forest Fires	N ₂ O	6.4	•	T ₂	
N ₂ O Emissions from Settlement Soils	N ₂ O	1.5			
N ₂ O Emissions from Forest Soils	N ₂ O	0.4			
N ₂ O Emissions from Wetlands Remaining Wetlands	N ₂ O	+			

^aFor the ID criteria, L refers to a key category identified through a level assessment; T refers to a key category identified through a trend assessment and the subscripted number refers to either a Tier 1 or Tier 2 assessment (e.g., L₂ designates a source is a key category for a Tier 2 level assessment).

^bIf the source is a key category for both L₁ and L₂ (as designated in the ID criteria column), it is a key category for both assessments in the years provided unless noted by a subscript, in which case it is a key category only for that assessment in only that year (e.g., 1990₂ designates a source is a key category for the Tier 2 assessment only in 1990).

^cEmissions from these sources not included in totals.

+ Does not exceed 0.05 Tg CO₂ Eq.

Note: Parentheses indicate negative values (or sequestration).

Evaluation of Key Categories

Level Assessment

When using a Tier 1 approach for the level assessment, a predetermined cumulative emissions threshold is used to identify key categories. When source and sink categories are sorted in order of decreasing absolute emissions, those that fall at the top of the list and cumulatively account for 95 percent of emissions are considered key categories. The 95 percent threshold in the IPCC *Good Practice Guidance* (IPCC 2000) was designed to establish a general level where the key category analysis covers approximately 75 to 92 percent of inventory uncertainty.

Including the Tier 2 approach provides additional insight into why certain source categories are considered key, and how to prioritize inventory improvements. In the Tier 2 approach, the level assessment for each category from the Tier 1 approach is multiplied by its percent relative uncertainty. If the uncertainty reported is asymmetrical, the absolute value

of the larger uncertainty is used. Uncertainty is not estimated for the following sources: CO₂ emissions from stationary combustion – geothermal energy; CO₂ emissions from mobile combustion by mode of transportation; CH₄ and N₂O emissions from mobile combustion by mode of off-road transportation; and CH₄ from the incineration of waste. While CO₂ emissions from geothermal energy are included in the overall emissions estimate, they are not an official IPCC source category. As a result, there are no guidelines to associate uncertainty with the emissions estimate; therefore, an uncertainty analysis was not conducted. The uncertainty associated with CO₂ from mobile combustion is applied to each mode's emissions estimate, and the uncertainty associated with off-road vehicle CH₄ and N₂O emissions are applied to both CH₄ and N₂O emissions from aviation, marine, and other sources. No uncertainty was associated with CH₄ emissions from waste incineration because emissions are less than 0.05 Gg CH₄ and an uncertainty analysis was not conducted. When source and sink categories are sorted in decreasing order of this calculation, those that fall at the top of the list and cumulatively account for 90 percent of emissions are considered key categories. The key categories identified by the Tier 2 level assessment may differ from those identified by the Tier 1 assessment. The final set of key categories includes all source and sink categories identified as key by either the Tier 1 or the Tier 2 assessment, keeping in mind that the two assessments are not mutually exclusive.

It is important to note that a key category analysis can be sensitive to the definitions of the source and sink categories. If a large source category is split into many subcategories, then the subcategories may have contributions to the total inventory that are too small for those source categories to be considered key. Similarly, a collection of small, non-key source categories adding up to less than 5 percent of total emissions could become key source categories if those source categories were aggregated into a single source category. The United States has attempted to define source and sink categories by the conventions which would allow comparison with other international key categories, while still maintaining the category definitions that constitute how the emissions estimates were calculated for this report. As such, some of the category names used in the key category analysis may differ from the names used in the main body of the report. Additionally, the United States accounts for some source categories, including fossil fuel feedstocks, international bunkers, and emissions from U.S. territories, that are derived from unique data sources using country-specific methodologies.

Table A- 4 through Table A- 7 contain the 1990 and 2009 level assessments for both with and without LULUCF sources and sinks, and contain further detail on where each source falls within the analysis. Tier 1 key categories are shaded dark gray. Additional key categories identified by the Tier 2 assessment are shaded light gray.

Trend Assessment

The Tier 1 approach for trend assessment is defined as the product of the source or sink category level assessment and the absolute difference between the source or sink category trend and the total trend. In turn, the source or sink category trend is defined as the change in emissions from the base year to the current year, as a percentage of current year emissions from that source or sink category. The total trend is the percentage change in total inventory emissions from the base year to the current year.

Thus, the source or sink category trend assessment will be large if the source or sink category represents a large percentage of emissions and/or has a trend that is quite different from the overall inventory trend. To determine key categories, the trend assessments are sorted in decreasing order, so that the source or sink categories with the highest trend assessments appear first. The trend assessments are summed until the threshold of 95 percent is reached; all categories that fall within that cumulative 95 percent are considered key categories.

For the Tier 2 approach, the trend assessment for each category from the Tier 1 approach is multiplied by its percent relative uncertainty. If the uncertainty reported is asymmetrical, the larger uncertainty is used. When source and sink categories are sorted in decreasing order of this calculation, those that fall at the top of the list and cumulatively account for 90 percent of emissions are considered key categories. The key categories identified by the Tier 2 trend assessment may differ from those identified by the Tier 1 assessment. The final set of key categories includes all source and sink categories identified as key by either the Tier 1 or the Tier 2 assessment, keeping in mind that the two assessments are not mutually exclusive.

Table A- 8 and Table A- 9 contain the 1990 through 2009 trend assessment for both with and without LULUCF sources and sinks, and contain further detail on where each source falls within the analysis. Tier 1 key categories are shaded dark gray. Additional key categories identified by the Tier 2 assessment are shaded light gray.

Table A- 4: 1990 Key Source Category Tier 1 and Tier 2 Analysis—Level Assessment, without LULUCF

IPCC Source Categories	Direct GHG	1990 Estimate	Tier 1 Level Assessment	Cumulative Total	Uncertainty ^a	Tier 2 Level Assessment
		(Tg CO ₂ Eq.)				
CO ₂ Emissions from Stationary Combustion - Coal	CO ₂	1,718.4	0.28	0.28	9%	0.026
CO ₂ Emissions from Mobile Combustion: Road	CO ₂	1,188.9	0.19	0.47	8%	0.016
CO ₂ Emissions from Stationary Combustion - Gas	CO ₂	964.5	0.16	0.63	6%	0.010
CO ₂ Emissions from Stationary Combustion - Oil	CO ₂	569.1	0.09	0.72	7%	0.007
Fugitive Emissions from Natural Gas Systems	CH ₄	189.8	0.03	0.75	30%	0.009
CO ₂ Emissions from Mobile Combustion: Aviation	CO ₂	179.3	0.03	0.78	8%	0.002
Direct N ₂ O Emissions from Agricultural Soil Management	N ₂ O	153.8	0.02	0.80	56%	0.014
CH ₄ Emissions from Landfills	CH ₄	147.4	0.02	0.83	48%	0.012
CH ₄ Emissions from Enteric Fermentation	CH ₄	132.1	0.02	0.85	18%	0.004
CO ₂ Emissions from Non-Energy Use of Fuels	CO ₂	118.6	0.02	0.87	21%	0.004
CO ₂ Emissions from Iron and Steel Production & Metallurgical Coke Production	CO ₂	99.5	0.02	0.89	16%	0.003
Fugitive Emissions from Coal Mining	CH ₄	84.1	0.01	0.90	16%	0.002
CO ₂ Emissions from Mobile Combustion: Other	CO ₂	73.3	0.01	0.91	8%	0.001
CO ₂ Emissions from Mobile Combustion: Marine	CO ₂	44.5	0.01	0.92	8%	0.001
Indirect N ₂ O Emissions from Applied Nitrogen	N ₂ O	44.0	0.01	0.93	151%	0.011
N ₂ O Emissions from Mobile Combustion: Road	N ₂ O	40.3	0.01	0.93	17%	0.001
CO ₂ Emissions from Natural Gas Systems	CO ₂	37.6	0.01	0.94	30%	0.002
HFC-23 Emissions from HCFC-22 Production	HFCs	36.4	0.01	0.94	10%	0.001
Fugitive Emissions from Petroleum Systems	CH ₄	35.4	0.01	0.95	149%	0.009
CO ₂ Emissions from Cement Production	CO ₂	33.3	0.01	0.96	14%	0.001
CH ₄ Emissions from Manure Management	CH ₄	31.7	0.01	0.96	20%	0.001
SF ₆ Emissions from Electrical Transmission and Distribution	SF ₆	28.4	<0.01	0.96	22%	0.001
CH ₄ Emissions from Wastewater Treatment	CH ₄	23.5	<0.01	0.97	47%	0.002
PFC Emissions from Aluminum Production	PFCs	18.5	<0.01	0.97	11%	<0.001
N ₂ O Emissions from Nitric Acid Production	N ₂ O	17.7	<0.01	0.97	42%	0.001
CO ₂ Emissions from Ammonia Production and Urea Consumption	CO ₂	16.8	<0.01	0.98	8%	<0.001
N ₂ O Emissions from Adipic Acid Production	N ₂ O	15.8	<0.01	0.98	42%	0.001
N ₂ O Emissions from Manure Management	N ₂ O	14.5	<0.01	0.98	24%	0.001
Non-CO ₂ Emissions from Stationary Combustion	N ₂ O	12.8	<0.01	0.98	187%	0.004
CO ₂ Emissions from Lime Production	CO ₂	11.5	<0.01	0.99	10%	<0.001
CO ₂ Emissions from Incineration of Waste	CO ₂	8.0	<0.01	0.99	24%	<0.001
Non-CO ₂ Emissions from Stationary Combustion	CH ₄	7.4	<0.01	0.99	127%	0.002
CH ₄ Emissions from Rice Cultivation	CH ₄	7.1	<0.01	0.99	146%	0.002
CO ₂ Emissions from Aluminum Production	CO ₂	6.8	<0.01	0.99	4%	<0.001
Fugitive Emissions from Abandoned Underground Coal Mines	CH ₄	6.0	<0.01	0.99	32%	<0.001
SF ₆ Emissions from Magnesium Production and Processing	SF ₆	5.4	<0.01	0.99	4%	<0.001
CO ₂ Emissions from Limestone and Dolomite Use	CO ₂	5.1	<0.01	0.99	19%	<0.001
N ₂ O Emissions from Product Uses	N ₂ O	4.4	<0.01	0.99	8%	<0.001
CH ₄ Emissions from Mobile Combustion: Road	CH ₄	4.2	<0.01	1.00	15%	<0.001
CO ₂ Emissions from Soda Ash Production and Consumption	CO ₂	4.1	<0.01	1.00	7%	<0.001
N ₂ O Emissions from Wastewater Treatment	N ₂ O	3.7	<0.01	1.00	93%	0.001
CO ₂ Emissions from Petrochemical Production	CO ₂	3.3	<0.01	1.00	31%	<0.001
PFC, HFC, and SF ₆ Emissions from Semiconductor Manufacture	Several	2.9	<0.01	1.00	11%	<0.001
CO ₂ Emissions from Ferroalloy Production	CO ₂	2.2	<0.01	1.00	13%	<0.001
N ₂ O Emissions from Mobile Combustion: Aviation	N ₂ O	1.7	<0.01	1.00	68%	<0.001
CO ₂ Emissions from Phosphoric Acid Production	CO ₂	1.5	<0.01	1.00	19%	<0.001
CO ₂ Emissions from Carbon Dioxide Consumption	CO ₂	1.4	<0.01	1.00	30%	<0.001
N ₂ O Emissions from Mobile Combustion: Other	N ₂ O	1.3	<0.01	1.00	47%	<0.001
CO ₂ Emissions from Titanium Dioxide Production	CO ₂	1.2	<0.01	1.00	13%	<0.001
CH ₄ Emissions from Iron and Steel Production & Metallurgical Coke Production	CH ₄	1.0	<0.01	1.00	23%	<0.001
CH ₄ Emissions from Petrochemical Production	CH ₄	0.9	<0.01	1.00	27%	<0.001
CO ₂ Emissions from Zinc Production	CO ₂	0.7	<0.01	1.00	18%	<0.001
N ₂ O Emissions from Mobile Combustion: Marine	N ₂ O	0.6	<0.01	1.00	57%	<0.001
CO ₂ Emissions from Petroleum Systems	CO ₂	0.6	<0.01	1.00	149%	<0.001
CO ₂ Emissions from Lead Production	CO ₂	0.5	<0.01	1.00	15%	<0.001
N ₂ O Emissions from Incineration of Waste	N ₂ O	0.5	<0.01	1.00	320%	<0.001
CO ₂ Emissions from Stationary Combustion - Geothermal	CO ₂	0.4	<0.01	1.00	NE	<0.001

IPCC Source Categories	Direct GHG	1990	Tier 1 Level Assessment	Cumulative Total	Uncertainty ^a	Tier 2 Level Assessment
		Estimate (Tg CO ₂ Eq.)				
Energy						
CO ₂ Emissions from Silicon Carbide Production and Consumption	CO ₂	0.4	<0.01	1.00	9%	<0.001
N ₂ O Emissions from Composting	N ₂ O	0.4	<0.01	1.00	50%	<0.001
Emissions from Substitutes for Ozone Depleting Substances	Several	0.3	<0.01	1.00	8%	<0.001
CH ₄ Emissions from Composting	CH ₄	0.3	<0.01	1.00	50%	<0.001
CH ₄ Emissions from Mobile Combustion: Other	CH ₄	0.3	<0.01	1.00	47%	<0.001
CH ₄ Emissions from Field Burning of Agricultural Residues	CH ₄	0.3	<0.01	1.00	42%	<0.001
CH ₄ Emissions from Mobile Combustion: Aviation	CH ₄	0.2	<0.01	1.00	61%	<0.001
N ₂ O Emissions from Field Burning of Agricultural Residues	N ₂ O	0.1	<0.01	1.00	31%	<0.001
CH ₄ Emissions from Silicon Carbide Production and Consumption	CH ₄	+	<0.01	1.00	9%	<0.001
CH ₄ Emissions from Mobile Combustion: Marine	CH ₄	+	<0.01	1.00	73%	<0.001
CH ₄ Emissions from Ferroalloy Production	CH ₄	+	<0.01	1.00	12%	<0.001
CH ₄ Emissions from Incineration of Waste	CH ₄	+	<0.01	1.00	NE	<0.001

Note: LULUCF sources and sinks are not included in this analysis.

^a Percent relative uncertainty. If the corresponding uncertainty is asymmetrical, the uncertainty given here is the larger and always positive.

NE Uncertainty not estimated.

+ Does not exceed 0.05 Tg CO₂ Eq.

Table A- 5: 1990 Key Source Category Tier 1 and Tier 2 Analysis—Level Assessment, with LULUCF

IPCC Source Categories	Direct GHG	1990	Tier 1 Level Assessment	Cumulative Total	Uncertainty ^a	Tier 2 Level Assessment
		Estimate (Tg CO ₂ Eq.)				
CO ₂ Emissions from Stationary Combustion - Coal	CO ₂	1,718.4	0.24	0.24	9%	0.023
CO ₂ Emissions from Mobile Combustion: Road	CO ₂	1,188.9	0.17	0.41	8%	0.014
CO ₂ Emissions from Stationary Combustion - Gas	CO ₂	964.5	0.14	0.55	6%	0.009
CO ₂ Emissions from Changes in Forest Carbon Stocks	CO ₂	681.1	0.10	0.65	18%	0.017
CO ₂ Emissions from Stationary Combustion - Oil	CO ₂	569.1	0.08	0.73	7%	0.006
Fugitive Emissions from Natural Gas Systems	CH ₄	189.8	0.03	0.75	30%	0.008
CO ₂ Emissions from Mobile Combustion: Aviation	CO ₂	179.3	0.03	0.78	8%	0.002
Direct N ₂ O Emissions from Agricultural Soil Management	N ₂ O	153.8	0.02	0.80	56%	0.012
CH ₄ Emissions from Landfills	CH ₄	147.4	0.02	0.82	48%	0.010
CH ₄ Emissions from Enteric Fermentation	CH ₄	132.1	0.02	0.84	18%	0.003
CO ₂ Emissions from Non-Energy Use of Fuels	CO ₂	118.6	0.02	0.86	21%	0.004
CO ₂ Emissions from Iron and Steel Production & Metallurgical Coke Production	CO ₂	99.5	0.01	0.87	16%	0.002
Fugitive Emissions from Coal Mining	CH ₄	84.1	0.01	0.88	16%	0.002
CO ₂ Emissions from Mobile Combustion: Other	CO ₂	73.3	0.01	0.89	8%	0.001
CO ₂ Emissions from Urban Trees	CO ₂	57.1	0.01	0.90	22%	0.002
CO ₂ Emissions from Grassland Remaining Grassland	CO ₂	52.2	0.01	0.91	32%	0.002
CO ₂ Emissions from Mobile Combustion: Marine	CO ₂	44.5	0.01	0.92	8%	0.001
Indirect N ₂ O Emissions from Applied Nitrogen	N ₂ O	44.0	0.01	0.92	151%	0.009
N ₂ O Emissions from Mobile Combustion: Road	N ₂ O	40.3	0.01	0.93	17%	0.001
CO ₂ Emissions from Natural Gas Systems	CO ₂	37.6	0.01	0.93	30%	0.002
HFC-23 Emissions from HCFC-22 Production	HFCs	36.4	0.01	0.94	10%	0.001
Fugitive Emissions from Petroleum Systems	CH ₄	35.4	0.01	0.94	149%	0.007
CO ₂ Emissions from Cement Production	CO ₂	33.3	<0.01	0.95	14%	0.001
CH ₄ Emissions from Manure Management	CH ₄	31.7	<0.01	0.95	20%	0.001
CO ₂ Emissions from Cropland Remaining Cropland	CO ₂	29.4	<0.01	0.96	172%	0.007
SF ₆ Emissions from Electrical Transmission and Distribution	SF ₆	28.4	<0.01	0.96	22%	0.001
CO ₂ Emissions from Landfilled Yard Trimmings and Food Scraps	CO ₂	24.2	<0.01	0.96	68%	0.002
CH ₄ Emissions from Wastewater Treatment	CH ₄	23.5	<0.01	0.97	47%	0.002
CO ₂ Emissions from Land Converted to Grassland	CO ₂	19.8	<0.01	0.97	15%	<0.001
PFC Emissions from Aluminum Production	PFCs	18.5	<0.01	0.97	11%	<0.001
N ₂ O Emissions from Nitric Acid Production	N ₂ O	17.7	<0.01	0.98	42%	0.001
CO ₂ Emissions from Ammonia Production and Urea Consumption	CO ₂	16.8	<0.01	0.98	8%	<0.001

IPCC Source Categories	1990 Estimate		Tier 1 Level Assessment	Cumulative Total	Uncertainty ^a	Tier 2 Level Assessment
	Direct GHG	(Tg CO ₂ Eq.)				
N ₂ O Emissions from Adipic Acid Production	N ₂ O	15.8	<0.01	0.98	42%	0.001
N ₂ O Emissions from Manure Management	N ₂ O	14.5	<0.01	0.98	24%	<0.001
Non-CO ₂ Emissions from Stationary Combustion	N ₂ O	12.8	<0.01	0.98	187%	0.003
CO ₂ Emissions from Lime Production	CO ₂	11.5	<0.01	0.99	10%	<0.001
CO ₂ Emissions from Incineration of Waste	CO ₂	8.0	<0.01	0.99	24%	<0.001
Non-CO ₂ Emissions from Stationary Combustion	CH ₄	7.4	<0.01	0.99	127%	0.001
CH ₄ Emissions from Rice Cultivation	CH ₄	7.1	<0.01	0.99	146%	0.001
CO ₂ Emissions from Aluminum Production	CO ₂	6.8	<0.01	0.99	4%	<0.001
Fugitive Emissions from Abandoned Underground Coal Mines	CH ₄	6.0	<0.01	0.99	32%	<0.001
SF ₆ Emissions from Magnesium Production and Processing	SF ₆	5.4	<0.01	0.99	4%	<0.001
CO ₂ Emissions from Limestone and Dolomite Use	CO ₂	5.1	<0.01	0.99	19%	<0.001
CO ₂ Emissions from Liming of Agricultural Soils	CO ₂	4.7	<0.01	0.99	99%	0.001
N ₂ O Emissions from Product Uses	N ₂ O	4.4	<0.01	0.99	8%	<0.001
CH ₄ Emissions from Mobile Combustion: Road	CH ₄	4.2	<0.01	0.99	15%	<0.001
CO ₂ Emissions from Soda Ash Production and Consumption	CO ₂	4.1	<0.01	0.99	7%	<0.001
N ₂ O Emissions from Wastewater Treatment	N ₂ O	3.7	<0.01	0.99	93%	<0.001
CO ₂ Emissions from Petrochemical Production	CO ₂	3.3	<0.01	1.00	31%	<0.001
CH ₄ Emissions from Forest Fires	CH ₄	3.2	<0.01	1.00	145%	0.001
PFC, HFC, and SF ₆ Emissions from Semiconductor Manufacture	Several	2.9	<0.01	1.00	11%	<0.001
N ₂ O Emissions from Forest Fires	N ₂ O	2.6	<0.01	1.00	145%	0.001
CO ₂ Emissions from Urea Fertilization	CO ₂	2.4	<0.01	1.00	43%	<0.001
CO ₂ Emissions from Ferroalloy Production	CO ₂	2.2	<0.01	1.00	13%	<0.001
CO ₂ Emissions from Land Converted to Cropland	CO ₂	2.2	<0.01	1.00	40%	<0.001
N ₂ O Emissions from Mobile Combustion: Aviation	N ₂ O	1.7	<0.01	1.00	68%	<0.001
CO ₂ Emissions from Phosphoric Acid Production	CO ₂	1.5	<0.01	1.00	19%	<0.001
CO ₂ Emissions from Carbon Dioxide Consumption	CO ₂	1.4	<0.01	1.00	30%	<0.001
N ₂ O Emissions from Mobile Combustion: Other	N ₂ O	1.3	<0.01	1.00	47%	<0.001
CO ₂ Emissions from Titanium Dioxide Production	CO ₂	1.2	<0.01	1.00	13%	<0.001
CO ₂ Emissions from Wetlands Remaining Wetlands	CO ₂	1.0	<0.01	1.00	34%	<0.001
N ₂ O Emissions from Settlement Soils	N ₂ O	1.0	<0.01	1.00	163%	<0.001
CH ₄ Emissions from Iron and Steel Production & Metallurgical Coke Production	CH ₄	1.0	<0.01	1.00	23%	<0.001
CH ₄ Emissions from Petrochemical Production	CH ₄	0.9	<0.01	1.00	27%	<0.001
CO ₂ Emissions from Zinc Production	CO ₂	0.7	<0.01	1.00	18%	<0.001
N ₂ O Emissions from Mobile Combustion: Marine	N ₂ O	0.6	<0.01	1.00	57%	<0.001
CO ₂ Emissions from Petroleum Systems	CO ₂	0.6	<0.01	1.00	149%	<0.001
CO ₂ Emissions from Lead Production	CO ₂	0.5	<0.01	1.00	15%	<0.001
N ₂ O Emissions from Incineration of Waste	N ₂ O	0.5	<0.01	1.00	320%	<0.001
CO ₂ Emissions from Stationary Combustion - Geothermal Energy	CO ₂	0.4	<0.01	1.00	NE	<0.001
CO ₂ Emissions from Silicon Carbide Production and Consumption	CO ₂	0.4	<0.01	1.00	9%	<0.001
N ₂ O Emissions from Composting	N ₂ O	0.4	<0.01	1.00	50%	<0.001
Emissions from Substitutes for Ozone Depleting Substances	Several	0.3	<0.01	1.00	8%	<0.001
CH ₄ Emissions from Composting	CH ₄	0.3	<0.01	1.00	50%	<0.001
CH ₄ Emissions from Mobile Combustion: Other	CH ₄	0.3	<0.01	1.00	47%	<0.001
CH ₄ Emissions from Field Burning of Agricultural Residues	CH ₄	0.3	<0.01	1.00	42%	<0.001
CH ₄ Emissions from Mobile Combustion: Aviation	CH ₄	0.2	<0.01	1.00	61%	<0.001
N ₂ O Emissions from Field Burning of Agricultural Residues	N ₂ O	0.1	<0.01	1.00	31%	<0.001
N ₂ O Emissions from Forest Soils	N ₂ O	0.1	<0.01	1.00	211%	<0.001
CH ₄ Emissions from Silicon Carbide Production and Consumption	CH ₄	+	<0.01	1.00	9%	<0.001
CH ₄ Emissions from Mobile Combustion: Marine	CH ₄	+	<0.01	1.00	73%	<0.001
CH ₄ Emissions from Ferroalloy Production	CH ₄	+	<0.01	1.00	12%	<0.001
N ₂ O Emissions from Wetlands Remaining Wetlands	N ₂ O	+	<0.01	1.00	74%	<0.001
CH ₄ Emissions from Incineration of Waste	CH ₄	+	<0.01	1.00	NE	<0.001

^a Percent relative uncertainty. If the corresponding uncertainty is asymmetrical, the uncertainty given here is the larger and always positive.

NE Uncertainty not estimated.

+ Does not exceed 0.05 Tg CO₂ Eq.

Table A- 6: 2009 Key Source Category Tier 1 and Tier 2 Analysis—Level Assessment, without LULUCF

IPCC Source Categories	Direct GHG	2009 Estimate	Tier 1 Level Assessment	Cumulative Total	Uncertainty ^a	Tier 2 Level Assessment
		(Tg CO ₂ Eq.)				
CO ₂ Emissions from Stationary Combustion - Coal	CO ₂	1,841.0	0.28	0.28	9%	0.026
CO ₂ Emissions from Mobile Combustion: Road	CO ₂	1,475.6	0.22	0.50	8%	0.019
CO ₂ Emissions from Stationary Combustion - Gas	CO ₂	1,164.6	0.18	0.68	6%	0.011
CO ₂ Emissions from Stationary Combustion - Oil	CO ₂	483.3	0.07	0.75	7%	0.005
Fugitive Emissions from Natural Gas Systems	CH ₄	221.2	0.03	0.78	30%	0.010
Direct N ₂ O Emissions from Agricultural Soil Management	N ₂ O	160.2	0.02	0.81	56%	0.014
CO ₂ Emissions from Mobile Combustion: Aviation	CO ₂	140.7	0.02	0.83	8%	0.002
CH ₄ Emissions from Enteric Fermentation	CH ₄	139.8	0.02	0.85	18%	0.004
CO ₂ Emissions from Non-Energy Use of Fuels	CO ₂	123.4	0.02	0.87	21%	0.004
Emissions from Substitutes for Ozone Depleting Substances	Several	120.0	0.02	0.89	8%	0.002
CH ₄ Emissions from Landfills	CH ₄	117.5	0.02	0.91	48%	0.009
CO ₂ Emissions from Mobile Combustion: Other	CO ₂	73.5	0.01	0.92	8%	0.001
Fugitive Emissions from Coal Mining	CH ₄	71.0	0.01	0.93	16%	0.002
CH ₄ Emissions from Manure Management	CH ₄	49.5	0.01	0.94	20%	0.001
Indirect N ₂ O Emissions from Applied Nitrogen	N ₂ O	44.4	0.01	0.94	151%	0.010
CO ₂ Emissions from Iron and Steel Production & Metallurgical Coke Production	CO ₂	41.9	0.01	0.95	16%	0.001
CO ₂ Emissions from Natural Gas Systems	CO ₂	32.2	<0.01	0.95	30%	0.001
Fugitive Emissions from Petroleum Systems	CH ₄	30.9	<0.01	0.96	149%	0.007
CO ₂ Emissions from Mobile Combustion: Marine	CO ₂	30.0	<0.01	0.96	8%	<0.001
CO ₂ Emissions from Cement Production	CO ₂	29.0	<0.01	0.97	14%	0.001
CH ₄ Emissions from Wastewater Treatment	CH ₄	24.5	<0.01	0.97	47%	0.002
N ₂ O Emissions from Mobile Combustion: Road	N ₂ O	20.3	<0.01	0.97	17%	0.001
N ₂ O Emissions from Manure Management	N ₂ O	17.9	<0.01	0.98	24%	0.001
N ₂ O Emissions from Nitric Acid Production	N ₂ O	14.6	<0.01	0.98	42%	0.001
SF ₆ Emissions from Electrical Transmission and Distribution	SF ₆	12.8	<0.01	0.98	22%	<0.001
Non-CO ₂ Emissions from Stationary Combustion	N ₂ O	12.8	<0.01	0.98	187%	0.004
CO ₂ Emissions from Incineration of Waste	CO ₂	12.3	<0.01	0.98	24%	<0.001
CO ₂ Emissions from Ammonia Production and Urea Consumption	CO ₂	11.8	<0.01	0.99	8%	<0.001
CO ₂ Emissions from Lime Production	CO ₂	11.2	<0.01	0.99	10%	<0.001
CO ₂ Emissions from Limestone and Dolomite Use	CO ₂	7.6	<0.01	0.99	19%	<0.001
CH ₄ Emissions from Rice Cultivation	CH ₄	7.3	<0.01	0.99	146%	0.002
Non-CO ₂ Emissions from Stationary Combustion	CH ₄	6.2	<0.01	0.99	127%	0.001
Fugitive Emissions from Abandoned Underground Coal Mines	CH ₄	5.5	<0.01	0.99	32%	<0.001
HFC-23 Emissions from HCFC-22 Production	HFCs	5.4	<0.01	0.99	10%	<0.001
PFC, HFC, and SF ₆ Emissions from Semiconductor Manufacture	Several	5.3	<0.01	0.99	11%	<0.001
N ₂ O Emissions from Wastewater Treatment	N ₂ O	5.0	<0.01	0.99	93%	0.001
N ₂ O Emissions from Product Uses	N ₂ O	4.4	<0.01	0.99	8%	<0.001
CO ₂ Emissions from Soda Ash Production and Consumption	CO ₂	4.3	<0.01	1.00	7%	<0.001
CO ₂ Emissions from Aluminum Production	CO ₂	3.0	<0.01	1.00	4%	<0.001
CO ₂ Emissions from Petrochemical Production	CO ₂	2.7	<0.01	1.00	31%	<0.001
N ₂ O Emissions from Adipic Acid Production	N ₂ O	1.9	<0.01	1.00	42%	<0.001
N ₂ O Emissions from Composting	N ₂ O	1.8	<0.01	1.00	50%	<0.001
N ₂ O Emissions from Mobile Combustion: Other	N ₂ O	1.8	<0.01	1.00	47%	<0.001
CO ₂ Emissions from Carbon Dioxide Consumption	CO ₂	1.8	<0.01	1.00	30%	<0.001
CH ₄ Emissions from Composting	CH ₄	1.7	<0.01	1.00	50%	<0.001
PFC Emissions from Aluminum Production	PFCs	1.6	<0.01	1.00	11%	<0.001
CO ₂ Emissions from Titanium Dioxide Production	CO ₂	1.5	<0.01	1.00	13%	<0.001
CO ₂ Emissions from Ferroalloy Production	CO ₂	1.5	<0.01	1.00	13%	<0.001
CH ₄ Emissions from Mobile Combustion: Road	CH ₄	1.4	<0.01	1.00	15%	<0.001
N ₂ O Emissions from Mobile Combustion: Aviation	N ₂ O	1.3	<0.01	1.00	68%	<0.001
SF ₆ Emissions from Magnesium Production and Processing	SF ₆	1.1	<0.01	1.00	4%	<0.001
CO ₂ Emissions from Phosphoric Acid Production	CO ₂	1.0	<0.01	1.00	19%	<0.001
CO ₂ Emissions from Zinc Production	CO ₂	1.0	<0.01	1.00	18%	<0.001
CH ₄ Emissions from Petrochemical Production	CH ₄	0.8	<0.01	1.00	27%	<0.001
CO ₂ Emissions from Lead Production	CO ₂	0.5	<0.01	1.00	15%	<0.001

IPCC Source Categories	Direct GHG	2009	Tier 1 Level Assessment	Cumulative Total	Uncertainty ^a	Tier 2 Level Assessment
		Estimate (Tg CO ₂ Eq.)				
CO ₂ Emissions from Petroleum Systems	CO ₂	0.5	<0.01	1.00	149%	<0.001
N ₂ O Emissions from Mobile Combustion: Marine	N ₂ O	0.4	<0.01	1.00	57%	<0.001
CH ₄ Emissions from Mobile Combustion: Other	CH ₄	0.4	<0.01	1.00	47%	<0.001
CO ₂ Emissions from Stationary Combustion - Geothermal Energy	CO ₂	0.4	<0.01	1.00	NE	<0.001
N ₂ O Emissions from Incineration of Waste	N ₂ O	0.4	<0.01	1.00	320%	<0.001
CH ₄ Emissions from Iron and Steel Production & Metallurgical Coke Production	CH ₄	0.4	<0.01	1.00	23%	<0.001
CH ₄ Emissions from Field Burning of Agricultural Residues	CH ₄	0.2	<0.01	1.00	42%	<0.001
CO ₂ Emissions from Silicon Carbide Production and Consumption	CO ₂	0.1	<0.01	1.00	9%	<0.001
CH ₄ Emissions from Mobile Combustion: Aviation	CH ₄	0.1	<0.01	1.00	61%	<0.001
N ₂ O Emissions from Field Burning of Agricultural Residues	N ₂ O	0.1	<0.01	1.00	31%	<0.001
CH ₄ Emissions from Mobile Combustion: Marine	CH ₄	+	<0.01	1.00	73%	<0.001
CH ₄ Emissions from Ferroalloy Production	CH ₄	+	<0.01	1.00	12%	<0.001
CH ₄ Emissions from Silicon Carbide Production and Consumption	CH ₄	+	<0.01	1.00	9%	<0.001
CH ₄ Emissions from Incineration of Waste	CH ₄	+	<0.01	1.00	NE	<0.001

Note: LULUCF sources and sinks are not included in this analysis.

^a Percent relative uncertainty. If the corresponding uncertainty is asymmetrical, the uncertainty given here is the larger and always positive.

NE Uncertainty not estimated.

+ Does not exceed 0.05 Tg CO₂ Eq.

Table A- 7: 2009 Key Source Category Tier 1 and Tier 2 Analysis—Level Assessment with LULUCF

IPCC Source Categories	Direct GHG	2009	Tier 1 Level Assessment	Cumulative Total	Uncertainty ^a	Tier 2 Level Assessment
		Estimate (Tg CO ₂ Eq.)				
CO ₂ Emissions from Stationary Combustion - Coal	CO ₂	1,841.0	0.24	0.24	9%	0.023
CO ₂ Emissions from Mobile Combustion: Road	CO ₂	1,475.6	0.19	0.43	8%	0.016
CO ₂ Emissions from Stationary Combustion - Gas	CO ₂	1,164.6	0.15	0.58	6%	0.010
CO ₂ Emissions from Changes in Forest Carbon Stocks	CO ₂	863.1	0.11	0.70	18%	0.020
CO ₂ Emissions from Stationary Combustion - Oil	CO ₂	483.3	0.06	0.76	7%	0.005
Fugitive Emissions from Natural Gas Systems	CH ₄	221.2	0.03	0.79	30%	0.009
Direct N ₂ O Emissions from Agricultural Soil Management	N ₂ O	160.2	0.02	0.81	56%	0.012
CO ₂ Emissions from Mobile Combustion: Aviation	CO ₂	140.7	0.02	0.83	8%	0.002
CH ₄ Emissions from Enteric Fermentation	CH ₄	139.8	0.02	0.85	18%	0.003
CO ₂ Emissions from Non-Energy Use of Fuels	CO ₂	123.4	0.02	0.86	21%	0.003
Emissions from Substitutes for Ozone Depleting Substances	Several	120.0	0.02	0.88	8%	0.001
CH ₄ Emissions from Landfills	CH ₄	117.5	0.02	0.89	48%	0.007
CO ₂ Emissions from Urban Trees	CO ₂	95.9	0.01	0.91	22%	0.003
CO ₂ Emissions from Mobile Combustion: Other	CO ₂	73.5	0.01	0.92	8%	0.001
Fugitive Emissions from Coal Mining	CH ₄	71.0	0.01	0.93	16%	0.001
CH ₄ Emissions from Manure Management	CH ₄	49.5	0.01	0.93	20%	0.001
Indirect N ₂ O Emissions from Applied Nitrogen	N ₂ O	44.4	0.01	0.94	151%	0.009
CO ₂ Emissions from Iron and Steel Production & Metallurgical Coke Production	CO ₂	41.9	0.01	0.94	16%	0.001
CO ₂ Emissions from Natural Gas Systems	CO ₂	32.2	<0.01	0.95	30%	0.001
Fugitive Emissions from Petroleum Systems	CH ₄	30.9	<0.01	0.95	149%	0.006
CO ₂ Emissions from Mobile Combustion: Marine	CO ₂	30.0	<0.01	0.96	8%	<0.001
CO ₂ Emissions from Cement Production	CO ₂	29.0	<0.01	0.96	14%	0.001
CH ₄ Emissions from Wastewater Treatment	CH ₄	24.5	<0.01	0.96	47%	0.001
CO ₂ Emissions from Land Converted to Grassland	CO ₂	23.6	<0.01	0.97	15%	<0.001
N ₂ O Emissions from Mobile Combustion: Road	N ₂ O	20.3	<0.01	0.97	17%	<0.001
N ₂ O Emissions from Manure Management	N ₂ O	17.9	<0.01	0.97	24%	0.001
CO ₂ Emissions from Cropland Remaining Cropland	CO ₂	17.4	<0.01	0.97	172%	0.004
N ₂ O Emissions from Nitric Acid Production	N ₂ O	14.6	<0.01	0.97	42%	0.001
SF ₆ Emissions from Electrical Transmission and Distribution	SF ₆	12.8	<0.01	0.98	22%	<0.001
Non-CO ₂ Emissions from Stationary Combustion	N ₂ O	12.8	<0.01	0.98	187%	0.003
CO ₂ Emissions from Landfilled Yard Trimmings and Food Scraps	CO ₂	12.6	<0.01	0.98	68%	0.001
CO ₂ Emissions from Incineration of Waste	CO ₂	12.3	<0.01	0.98	24%	<0.001

CO ₂ Emissions from Ammonia Production and Urea Consumption	CO ₂	11.8	<0.01	0.98	8%	<0.001
CO ₂ Emissions from Lime Production	CO ₂	11.2	<0.01	0.98	10%	<0.001
CO ₂ Emissions from Grassland Remaining Grassland	CO ₂	8.3	<0.01	0.99	32%	<0.001
CH ₄ Emissions from Forest Fires	CH ₄	7.8	<0.01	0.99	145%	0.001
CO ₂ Emissions from Limestone and Dolomite Use	CO ₂	7.6	<0.01	0.99	19%	<0.001
CH ₄ Emissions from Rice Cultivation	CH ₄	7.3	<0.01	0.99	146%	0.001
N ₂ O Emissions from Forest Fires	N ₂ O	6.4	<0.01	0.99	145%	0.001
Non-CO ₂ Emissions from Stationary Combustion	CH ₄	6.2	<0.01	0.99	127%	0.001
CO ₂ Emissions from Land Converted to Cropland	CO ₂	5.9	<0.01	0.99	40%	<0.001
Fugitive Emissions from Abandoned Underground Coal Mines	CH ₄	5.5	<0.01	0.99	32%	<0.001
HFC-23 Emissions from HCFC-22 Production	HFCs	5.4	<0.01	0.99	10%	<0.001
PFC, HFC, and SF ₆ Emissions from Semiconductor Manufacture	Several	5.3	<0.01	0.99	11%	<0.001
N ₂ O Emissions from Wastewater Treatment	N ₂ O	5.0	<0.01	0.99	93%	0.001
N ₂ O Emissions from Product Uses	N ₂ O	4.4	<0.01	0.99	8%	<0.001
CO ₂ Emissions from Soda Ash Production and Consumption	CO ₂	4.3	<0.01	0.99	7%	<0.001
CO ₂ Emissions from Liming of Agricultural Soils	CO ₂	4.2	<0.01	1.00	99%	0.001
CO ₂ Emissions from Urea Fertilization	CO ₂	3.6	<0.01	1.00	43%	<0.001
CO ₂ Emissions from Aluminum Production	CO ₂	3.0	<0.01	1.00	4%	<0.001
CO ₂ Emissions from Petrochemical Production	CO ₂	2.7	<0.01	1.00	31%	<0.001
N ₂ O Emissions from Adipic Acid Production	N ₂ O	1.9	<0.01	1.00	42%	<0.001
N ₂ O Emissions from Composting	N ₂ O	1.8	<0.01	1.00	50%	<0.001
N ₂ O Emissions from Mobile Combustion: Other	N ₂ O	1.8	<0.01	1.00	47%	<0.001
CO ₂ Emissions from Carbon Dioxide Consumption	CO ₂	1.8	<0.01	1.00	30%	<0.001
CH ₄ Emissions from Composting	CH ₄	1.7	<0.01	1.00	50%	<0.001
PFC Emissions from Aluminum Production	PFCs	1.6	<0.01	1.00	11%	<0.001
CO ₂ Emissions from Titanium Dioxide Production	CO ₂	1.5	<0.01	1.00	13%	<0.001
N ₂ O Emissions from Settlement Soils	N ₂ O	1.5	<0.01	1.00	163%	<0.001
CO ₂ Emissions from Ferroalloy Production	CO ₂	1.5	<0.01	1.00	13%	<0.001
CH ₄ Emissions from Mobile Combustion: Road	CH ₄	1.4	<0.01	1.00	15%	<0.001
N ₂ O Emissions from Mobile Combustion: Aviation	N ₂ O	1.3	<0.01	1.00	68%	<0.001
CO ₂ Emissions from Wetlands Remaining Wetlands	CO ₂	1.1	<0.01	1.00	34%	<0.001
SF ₆ Emissions from Magnesium Production and Processing	SF ₆	1.1	<0.01	1.00	4%	<0.001
CO ₂ Emissions from Phosphoric Acid Production	CO ₂	1.0	<0.01	1.00	19%	<0.001
CO ₂ Emissions from Zinc Production	CO ₂	1.0	<0.01	1.00	18%	<0.001
CH ₄ Emissions from Petrochemical Production	CH ₄	0.8	<0.01	1.00	27%	<0.001
CO ₂ Emissions from Lead Production	CO ₂	0.5	<0.01	1.00	15%	<0.001
CO ₂ Emissions from Petroleum Systems	CO ₂	0.5	<0.01	1.00	149%	<0.001
N ₂ O Emissions from Mobile Combustion: Marine	N ₂ O	0.4	<0.01	1.00	57%	<0.001
CH ₄ Emissions from Mobile Combustion: Other	CH ₄	0.4	<0.01	1.00	47%	<0.001
CO ₂ Emissions from Stationary Combustion - Geothermal Energy	CO ₂	0.4	<0.01	1.00	NE	<0.001
N ₂ O Emissions from Incineration of Waste	N ₂ O	0.4	<0.01	1.00	320%	<0.001
CH ₄ Emissions from Iron and Steel Production & Metallurgical Coke Production	CH ₄	0.4	<0.01	1.00	23%	<0.001
N ₂ O Emissions from Forest Soils	N ₂ O	0.4	<0.01	1.00	211%	<0.001
CH ₄ Emissions from Field Burning of Agricultural Residues	CH ₄	0.2	<0.01	1.00	42%	<0.001
CO ₂ Emissions from Silicon Carbide Production and Consumption	CO ₂	0.1	<0.01	1.00	9%	<0.001
CH ₄ Emissions from Mobile Combustion: Aviation	CH ₄	0.1	<0.01	1.00	61%	<0.001
N ₂ O Emissions from Field Burning of Agricultural Residues	N ₂ O	0.1	<0.01	1.00	31%	<0.001
CH ₄ Emissions from Mobile Combustion: Marine	CH ₄	+	<0.01	1.00	73%	<0.001
CH ₄ Emissions from Ferroalloy Production	CH ₄	+	<0.01	1.00	12%	<0.001
CH ₄ Emissions from Silicon Carbide Production and Consumption	CH ₄	+	<0.01	1.00	9%	<0.001
N ₂ O Emissions from Wetlands Remaining Wetlands	N ₂ O	+	<0.01	1.00	74%	<0.001
CH ₄ Emissions from Incineration of Waste	CH ₄	+	<0.01	1.00	NE	<0.001

^a Percent relative uncertainty. If the corresponding uncertainty is asymmetrical, the uncertainty given here is the larger and always positive.

NE Uncertainty not estimated.

+ Does not exceed 0.05 Tg CO₂ Eq.

Table A- 8: 1990-2009 Key Source Category Tier 1 and 2 Analysis—Trend Assessment, without LULUCF

IPCC Source Categories	Direct GHG	1990	2009	Tier 1 Trend Assessment	Tier 2 Trend Assessment	Percent Contribution to Trend (%)	Cumulative Contribution to Trend (%)
		Estimate (Tg CO ₂ Eq.)	Estimate (Tg CO ₂ Eq.)				
CO ₂ Emissions from Mobile Combustion: Road	CO ₂	1,188.9	1,475.6	0.03	0.002	20.1	20
CO ₂ Emissions from Stationary Combustion - Gas	CO ₂	964.5	1,164.6	0.02	0.001	13.1	33
CO ₂ Emissions from Stationary Combustion - Oil	CO ₂	569.1	483.3	0.02	0.001	12.6	46
Emissions from Substitutes for Ozone Depleting Substances	Several	0.3	120.0	0.02	0.001	11.9	58
CO ₂ Emissions from Iron and Steel Production & Metallurgical Coke Production	CO ₂	99.5	41.9	0.01	0.001	6.5	64
CO ₂ Emissions from Mobile Combustion: Aviation	CO ₂	179.3	140.7	0.01	0.001	5.1	69
CH ₄ Emissions from Landfills	CH ₄	147.4	117.5	0.01	0.003	4.0	73
HFC-23 Emissions from HCFC-22 Production	HFCs	36.4	5.4	<0.01	<0.001	3.4	77
N ₂ O Emissions from Mobile Combustion: Road	N ₂ O	40.3	20.3	<0.01	0.001	2.3	79
Fugitive Emissions from Coal Mining	CH ₄	84.1	71.0	<0.01	<0.001	1.9	81
PFC Emissions from Aluminum Production	PFCs	18.5	1.6	<0.01	<0.001	1.8	83
Fugitive Emissions from Natural Gas Systems	CH ₄	189.8	221.2	<0.01	0.001	1.8	85
CO ₂ Emissions from Mobile Combustion: Marine	CO ₂	44.5	30.0	<0.01	<0.001	1.8	86
SF ₆ Emissions from Electrical Transmission and Distribution	SF ₆	28.4	12.8	<0.01	0.001	1.8	88
CH ₄ Emissions from Manure Management	CH ₄	31.7	49.5	<0.01	<0.001	1.5	90
N ₂ O Emissions from Adipic Acid Production	N ₂ O	15.8	1.9	<0.01	0.001	1.5	91
CO ₂ Emissions from Natural Gas Systems	CO ₂	37.6	32.2	<0.01	<0.001	0.8	92
Fugitive Emissions from Petroleum Systems	CH ₄	35.4	30.9	<0.01	0.001	0.7	93
CO ₂ Emissions from Cement Production	CO ₂	33.3	29.0	<0.01	<0.001	0.7	93
CO ₂ Emissions from Ammonia Production and Urea Consumption	CO ₂	16.8	11.8	<0.01	<0.001	0.6	94
CO ₂ Emissions from Mobile Combustion: Other	CO ₂	73.3	73.5	<0.01	<0.001	0.5	94
SF ₆ Emissions from Magnesium Production and Processing	SF ₆	5.4	1.1	<0.01	<0.001	0.5	95
Direct N ₂ O Emissions from Agricultural Soil Management	N ₂ O	153.8	160.2	<0.01	<0.001	0.5	95
N ₂ O Emissions from Nitric Acid Production	N ₂ O	17.7	14.6	<0.01	<0.001	0.4	96
CO ₂ Emissions from Aluminum Production	CO ₂	6.8	3.0	<0.01	<0.001	0.4	96
CO ₂ Emissions from Non-Energy Use of Fuels	CO ₂	118.6	123.4	<0.01	<0.001	0.4	97
CO ₂ Emissions from Incineration of Waste	CO ₂	8.0	12.3	<0.01	<0.001	0.4	97
CH ₄ Emissions from Mobile Combustion: Road	CH ₄	4.2	1.4	<0.01	<0.001	0.3	97
Indirect N ₂ O Emissions from Applied Nitrogen	N ₂ O	44.0	44.4	<0.01	0.001	0.3	98
N ₂ O Emissions from Manure Management	N ₂ O	14.5	17.9	<0.01	<0.001	0.2	98
PFC, HFC, and SF ₆ Emissions from Semiconductor Manufacture	Several	2.9	5.3	<0.01	<0.001	0.2	98
CO ₂ Emissions from Limestone and Dolomite Use	CO ₂	5.1	7.6	<0.01	<0.001	0.2	98
Non-CO ₂ Emissions from Stationary Combustion	CH ₄	7.4	6.2	<0.01	<0.001	0.2	98
CH ₄ Emissions from Enteric Fermentation	CH ₄	132.1	139.8	<0.01	<0.001	0.2	99
N ₂ O Emissions from Composting	N ₂ O	0.4	1.8	<0.01	<0.001	0.1	99
CH ₄ Emissions from Composting	CH ₄	0.3	1.7	<0.01	<0.001	0.1	99
CO ₂ Emissions from Lime Production	CO ₂	11.5	11.2	<0.01	<0.001	0.1	99
N ₂ O Emissions from Wastewater Treatment	N ₂ O	3.7	5.0	<0.01	<0.001	0.1	99
Fugitive Emissions from Abandoned Underground Coal Mines	CH ₄	6.0	5.5	<0.01	<0.001	0.1	99
Non-CO ₂ Emissions from Stationary Combustion	N ₂ O	12.8	12.8	<0.01	<0.001	0.1	99
CO ₂ Emissions from Ferroalloy Production	CO ₂	2.2	1.5	<0.01	<0.001	0.1	99
CO ₂ Emissions from Petrochemical Production	CO ₂	3.3	2.7	<0.01	<0.001	0.1	99
CH ₄ Emissions from Iron and Steel Production & Metallurgical Coke Production	CH ₄	1.0	0.4	<0.01	<0.001	0.1	99
CH ₄ Emissions from Wastewater Treatment	CH ₄	23.5	24.5	<0.01	<0.001	0.1	100
CO ₂ Emissions from Phosphoric Acid Production	CO ₂	1.5	1.0	<0.01	<0.001	0.1	100
N ₂ O Emissions from Mobile Combustion: Aviation	N ₂ O	1.7	1.3	<0.01	<0.001	0.1	100
N ₂ O Emissions from Mobile Combustion: Other	N ₂ O	1.3	1.8	<0.01	<0.001	<0.1	100
CO ₂ Emissions from Stationary Combustion - Coal	CO ₂	1,718.4	1,841.0	<0.01	<0.001	<0.1	100
N ₂ O Emissions from Product Uses	N ₂ O	4.4	4.4	<0.01	<0.001	<0.1	100
CH ₄ Emissions from Rice Cultivation	CH ₄	7.1	7.3	<0.01	<0.001	<0.1	100
CO ₂ Emissions from Titanium Dioxide Production	CO ₂	1.2	1.5	<0.01	<0.001	<0.1	100
CO ₂ Emissions from Silicon Carbide Production and Consumption	CO ₂	0.4	0.1	<0.01	<0.001	<0.1	100

IPCC Source Categories	Direct GHG	1990	2009	Tier 1 Trend Assessment	Tier 2 Trend Assessment	Percent Contribution to Trend (%)	Cumulative Contribution to Trend (%)
		Estimate (Tg CO ₂ Eq.)	Estimate (Tg CO ₂ Eq.)				
CO ₂ Emissions from Zinc Production	CO ₂	0.7	1.0	<0.01	<0.001	<0.1	100
CO ₂ Emissions from Carbon Dioxide Consumption	CO ₂	1.4	1.8	<0.01	<0.001	<0.1	100
N ₂ O Emissions from Mobile Combustion: Marine	N ₂ O	0.6	0.4	<0.01	<0.001	<0.1	100
CO ₂ Emissions from Soda Ash Production and Consumption	CO ₂	4.1	4.3	<0.01	<0.001	<0.1	100
N ₂ O Emissions from Incineration of Waste	N ₂ O	0.5	0.4	<0.01	<0.001	<0.1	100
CO ₂ Emissions from Petroleum Systems	CO ₂	0.6	0.5	<0.01	<0.001	<0.1	100
CH ₄ Emissions from Mobile Combustion: Other	CH ₄	0.3	0.4	<0.01	<0.001	<0.1	100
CH ₄ Emissions from Petrochemical Production	CH ₄	0.9	0.8	<0.01	<0.001	<0.1	100
CH ₄ Emissions from Mobile Combustion: Aviation	CH ₄	0.2	0.1	<0.01	<0.001	<0.1	100
CH ₄ Emissions from Field Burning of Agricultural Residues	CH ₄	0.3	0.2	<0.01	<0.001	<0.1	100
CO ₂ Emissions from Stationary Combustion - Geothermal Energy	CO ₂	0.4	0.4	<0.01	<0.001	<0.1	100
CO ₂ Emissions from Lead Production	CO ₂	0.5	0.5	<0.01	<0.001	<0.1	100
CH ₄ Emissions from Silicon Carbide Production and Consumption	CH ₄	+	+	<0.01	<0.001	<0.1	100
CH ₄ Emissions from Ferroalloy Production	CH ₄	+	+	<0.01	<0.001	<0.1	100
N ₂ O Emissions from Field Burning of Agricultural Residues	N ₂ O	0.1	0.1	<0.01	<0.001	<0.1	100
CH ₄ Emissions from Mobile Combustion: Marine	CH ₄	+	+	<0.01	<0.001	<0.1	100
CH ₄ Emissions from Incineration of Waste	CH ₄	+	+	<0.01	<0.001	<0.1	100

Note: LULUCF sources and sinks are not included in this analysis.

+ Does not exceed 0.05 Tg CO₂ Eq.

Table A- 9: 1990-2009 Key Source Category Tier 1 and 2 Analysis—Trend Assessment, with LULUCF

IPCC Source Categories	Direct GHG	1990	2009	Tier 1 Trend Assessment	Tier 2 Trend Assessment	Percent Contribution to Trend (%)	Cumulative Contribution to Trend (%)
		Estimate (Tg CO ₂ Eq.)	Estimate (Tg CO ₂ Eq.)				
CO ₂ Emissions from Mobile Combustion: Road	CO ₂	1,188.9	1,475.6	0.02	0.002	14.4	14
CO ₂ Emissions from Stationary Combustion - Oil	CO ₂	569.1	483.3	0.02	0.001	10.6	25
CO ₂ Emissions from Changes in Forest Carbon Stocks	CO ₂	681.1	863.1	0.01	0.003	9.7	35
Emissions from Substitutes for Ozone Depleting Substances	Several	0.3	120.0	0.01	0.001	9.4	44
CO ₂ Emissions from Stationary Combustion - Gas	CO ₂	964.5	1,164.6	0.01	0.001	9.1	53
CO ₂ Emissions from Iron and Steel Production & Metallurgical Coke Production	CO ₂	99.5	41.9	0.01	0.001	5.2	58
CO ₂ Emissions from Mobile Combustion: Aviation	CO ₂	179.3	140.7	0.01	0.001	4.3	63
CO ₂ Emissions from Grassland Remaining Grassland	CO ₂	52.2	8.3	0.01	0.002	3.8	67
CH ₄ Emissions from Landfills	CH ₄	147.4	117.5	0.01	0.002	3.4	70
HFC-23 Emissions from HCFC-22 Production	HFCs	36.4	5.4	<0.01	<0.001	2.7	73
CO ₂ Emissions from Urban Trees	CO ₂	57.1	95.9	<0.01	0.001	2.7	75
CO ₂ Emissions from Stationary Combustion - Coal	CO ₂	1,718.4	1,841.0	<0.01	<0.001	2.1	77
N ₂ O Emissions from Mobile Combustion: Road	N ₂ O	40.3	20.3	<0.01	<0.001	1.8	79
Fugitive Emissions from Coal Mining	CH ₄	84.1	71.0	<0.01	<0.001	1.6	81
PFC Emissions from Aluminum Production	PFCs	18.5	1.6	<0.01	<0.001	1.5	82
CO ₂ Emissions from Mobile Combustion: Marine	CO ₂	44.5	30.0	<0.01	<0.001	1.4	84
SF ₆ Emissions from Electrical Transmission and Distribution	SF ₆	28.4	12.8	<0.01	<0.001	1.4	85
N ₂ O Emissions from Adipic Acid Production	N ₂ O	15.8	1.9	<0.01	0.001	1.2	86
CH ₄ Emissions from Manure Management	CH ₄	31.7	49.5	<0.01	<0.001	1.2	87
Fugitive Emissions from Natural Gas Systems	CH ₄	189.8	221.2	<0.01	0.001	1.2	89
CO ₂ Emissions from Cropland Remaining Cropland	CO ₂	29.4	17.4	<0.01	0.003	1.1	90
CO ₂ Emissions from Landfilled Yard Trimmings and Food Scraps	CO ₂	24.2	12.6	<0.01	0.001	1.1	91
CO ₂ Emissions from Natural Gas Systems	CO ₂	37.6	32.2	<0.01	<0.001	0.7	92
Fugitive Emissions from Petroleum Systems	CH ₄	35.4	30.9	<0.01	0.001	0.6	92
CO ₂ Emissions from Cement Production	CO ₂	33.3	29.0	<0.01	<0.001	0.6	93
Direct N ₂ O Emissions from Agricultural Soil Management	N ₂ O	153.8	160.2	<0.01	<0.001	0.6	93
CO ₂ Emissions from Ammonia Production and Urea Consumption	CO ₂	16.8	11.8	<0.01	<0.001	0.5	94

IPCC Source Categories	Direct GHG	1990	2009	Tier 1 Trend Assessment	Tier 2 Trend Assessment	Percent Contribution to Trend (%)	Cumulative Contribution to Trend (%)
		Estimate (Tg CO ₂ Eq.)	Estimate (Tg CO ₂ Eq.)				
CO ₂ Emissions from Mobile Combustion: Other	CO ₂	73.3	73.5	<0.01	<0.001	0.5	94
CO ₂ Emissions from Non-Energy Use of Fuels	CO ₂	118.6	123.4	<0.01	<0.001	0.4	95
SF ₆ Emissions from Magnesium Production and Processing	SF ₆	5.4	1.1	<0.01	<0.001	0.4	95
N ₂ O Emissions from Nitric Acid Production	N ₂ O	17.7	14.6	<0.01	<0.001	0.4	95
CO ₂ Emissions from Aluminum Production	CO ₂	6.8	3.0	<0.01	<0.001	0.3	96
CH ₄ Emissions from Forest Fires	CH ₄	3.2	7.8	<0.01	0.001	0.3	96
CH ₄ Emissions from Enteric Fermentation	CH ₄	132.1	139.8	<0.01	<0.001	0.3	96
CO ₂ Emissions from Incineration of Waste	CO ₂	8.0	12.3	<0.01	<0.001	0.3	97
CO ₂ Emissions from Land Converted to Cropland	CO ₂	2.2	5.9	<0.01	<0.001	0.3	97
N ₂ O Emissions from Forest Fires	N ₂ O	2.6	6.4	<0.01	0.001	0.3	97
Indirect N ₂ O Emissions from Applied Nitrogen	N ₂ O	44.0	44.4	<0.01	0.001	0.3	98
CH ₄ Emissions from Mobile Combustion: Road	CH ₄	4.2	1.4	<0.01	<0.001	0.2	98
PFC, HFC, and SF ₆ Emissions from Semiconductor Manufacture	Several	2.9	5.3	<0.01	<0.001	0.2	98
N ₂ O Emissions from Manure Management	N ₂ O	14.5	17.9	<0.01	<0.001	0.2	98
CO ₂ Emissions from Limestone and Dolomite Use	CO ₂	5.1	7.6	<0.01	<0.001	0.2	98
CO ₂ Emissions from Land Converted to Grassland	CO ₂	19.8	23.6	<0.01	<0.001	0.2	98
Non-CO ₂ Emissions from Stationary Combustion	CH ₄	7.4	6.2	<0.01	<0.001	0.2	99
N ₂ O Emissions from Composting	N ₂ O	0.4	1.8	<0.01	<0.001	0.1	99
CH ₄ Emissions from Composting	CH ₄	0.3	1.7	<0.01	<0.001	0.1	99
CO ₂ Emissions from Lime Production	CO ₂	11.5	11.2	<0.01	<0.001	0.1	99
Non-CO ₂ Emissions from Stationary Combustion	N ₂ O	12.8	12.8	<0.01	<0.001	0.1	99
Fugitive Emissions from Abandoned Underground Coal Mines	CH ₄	6.0	5.5	<0.01	<0.001	0.1	99
N ₂ O Emissions from Wastewater Treatment	N ₂ O	3.7	5.0	<0.01	<0.001	0.1	99
CH ₄ Emissions from Wastewater Treatment	CH ₄	23.5	24.5	<0.01	<0.001	0.1	99
CO ₂ Emissions from Urea Fertilization	CO ₂	2.4	3.6	<0.01	<0.001	0.1	99
CO ₂ Emissions from Ferroalloy Production	CO ₂	2.2	1.5	<0.01	<0.001	0.1	99
CO ₂ Emissions from Petrochemical Production	CO ₂	3.3	2.7	<0.01	<0.001	0.1	99
CO ₂ Emissions from Liming of Agricultural Soils	CO ₂	4.7	4.2	<0.01	<0.001	0.1	100
CH ₄ Emissions from Iron and Steel Production & Metallurgical Coke Production	CH ₄	1.0	0.4	<0.01	<0.001	0.1	100
CO ₂ Emissions from Phosphoric Acid Production	CO ₂	1.5	1.0	<0.01	<0.001	<0.1	100
N ₂ O Emissions from Mobile Combustion: Aviation	N ₂ O	1.7	1.3	<0.01	<0.001	<0.1	100
N ₂ O Emissions from Settlement Soils	N ₂ O	1.0	1.5	<0.01	<0.001	<0.1	100
N ₂ O Emissions from Mobile Combustion: Other	N ₂ O	1.3	1.8	<0.01	<0.001	<0.1	100
CH ₄ Emissions from Rice Cultivation	CH ₄	7.1	7.3	<0.01	<0.001	<0.1	100
N ₂ O Emissions from Product Uses	N ₂ O	4.4	4.4	<0.01	<0.001	<0.1	100
N ₂ O Emissions from Forest Soils	N ₂ O	0.1	0.4	<0.01	<0.001	<0.1	100
CO ₂ Emissions from Silicon Carbide Production and Consumption	CO ₂	0.4	0.1	<0.01	<0.001	<0.1	100
CO ₂ Emissions from Titanium Dioxide Production	CO ₂	1.2	1.5	<0.01	<0.001	<0.1	100
CO ₂ Emissions from Zinc Production	CO ₂	0.7	1.0	<0.01	<0.001	<0.1	100
CO ₂ Emissions from Soda Ash Production and Consumption	CO ₂	4.1	4.3	<0.01	<0.001	<0.1	100
N ₂ O Emissions from Mobile Combustion: Marine	N ₂ O	0.6	0.4	<0.01	<0.001	<0.1	100
CO ₂ Emissions from Carbon Dioxide Consumption	CO ₂	1.4	1.8	<0.01	<0.001	<0.1	100
N ₂ O Emissions from Incineration of Waste	N ₂ O	0.5	0.4	<0.01	<0.001	<0.1	100
CO ₂ Emissions from Petroleum Systems	CO ₂	0.6	0.5	<0.01	<0.001	<0.1	100
CH ₄ Emissions from Petrochemical Production	CH ₄	0.9	0.8	<0.01	<0.001	<0.1	100
CH ₄ Emissions from Mobile Combustion: Other	CH ₄	0.3	0.4	<0.01	<0.001	<0.1	100
CH ₄ Emissions from Mobile Combustion: Aviation	CH ₄	0.2	0.1	<0.01	<0.001	<0.1	100
CH ₄ Emissions from Field Burning of Agricultural Residues	CH ₄	0.3	0.2	<0.01	<0.001	<0.1	100
CO ₂ Emissions from Stationary Combustion - Geothermal Energy	CO ₂	0.4	0.4	<0.01	<0.001	<0.1	100
CO ₂ Emissions from Lead Production	CO ₂	0.5	0.5	<0.01	<0.001	<0.1	100
CO ₂ Emissions from Wetlands Remaining Wetlands	CO ₂	1.0	1.1	<0.01	<0.001	<0.1	100
CH ₄ Emissions from Silicon Carbide Production and Consumption	CH ₄	+	+	<0.01	<0.001	<0.1	100
CH ₄ Emissions from Ferroalloy Production	CH ₄	+	+	<0.01	<0.001	<0.1	100
N ₂ O Emissions from Field Burning of Agricultural Residues	N ₂ O	0.1	0.1	<0.01	<0.001	<0.1	100

IPCC Source Categories	Direct GHG	1990	2009	Tier 1 Trend Assessment	Tier 2 Trend Assessment	Percent Contribution to Trend (%)	Cumulative Contribution to Trend (%)
		Estimate (Tg CO ₂ Eq.)	Estimate (Tg CO ₂ Eq.)				
CH ₄ Emissions from Mobile Combustion: Marine	CH ₄	+	+	<0.01	<0.001	<0.1	100
N ₂ O Emissions from Wetlands Remaining Wetlands	N ₂ O	+	+	<0.01	<0.001	<0.1	100
CH ₄ Emissions from Incineration of Waste	CH ₄	+	+	<0.01	<0.001	<0.1	100

+ Does not exceed 0.05 Tg CO₂ Eq.

References

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ANNEX 2 Methodology and Data for Estimating CO₂ Emissions from Fossil Fuel Combustion

2.1. Methodology for Estimating Emissions of CO₂ from Fossil Fuel Combustion

Carbon dioxide (CO₂) emissions from fossil fuel combustion were estimated using a “bottom-up” methodology characterized by seven steps. These steps are described below.

Step 1: Determine Total Fuel Consumption by Fuel Type and Sector

The bottom-up methodology used by the United States for estimating CO₂ emissions from fossil fuel combustion is conceptually similar to the approach recommended by the Intergovernmental Panel on Climate Change (IPCC) for countries that intend to develop detailed, sectoral-based emission estimates (IPCC/UNEP/OECD/IEA 1997). Total consumption data and adjustments to consumption are presented in Columns 2 through 13 of Table A- 10.

Adjusted consumption data are presented in Columns 2 through 8 of Table A- 11 through Table A- 30 with totals by fuel type in Column 8 and totals by end-use sector in the last rows. Fuel consumption data for the bottom-up approach were obtained directly from the Energy Information Administration (EIA) of the U.S. Department of Energy. These data were first gathered in physical units, and then converted to their energy equivalents (see the Constants, Units, and Conversions Annex). The EIA data were collected through a variety of consumption surveys at the point of delivery or use and qualified with survey data on fuel production, imports, exports, and stock changes. Individual data elements were supplied by a variety of sources within EIA. Most information was taken from published reports, although some data were drawn from unpublished energy studies and databases maintained by EIA.

Energy consumption data were aggregated by sector (i.e., residential, commercial, industrial, transportation, electricity generation, and U.S. territories), primary fuel type (e.g., coal, natural gas, and petroleum), and secondary fuel type (e.g., motor gasoline, distillate fuel, etc.). The 2009 total adjusted energy consumption across all sectors, including territories, and energy types was 71,949.8 trillion British thermal units (TBTu), as indicated in the last entry of Column 8 in Table A- 11. This total excludes fuel used for non-energy purposes and fuel consumed as international bunkers, both of which were deducted in earlier steps.

Electricity consumption information was allocated to each sector based on EIA’s distribution of electricity retail sales to ultimate customers (i.e., residential, commercial, industrial, and other). Because the “other” fuel use includes sales to both the commercial and transportation sectors, EIA’s limited transportation electricity use data were subtracted from “other” electricity use and also reported separately. This total was consequently combined with the commercial electricity data. Further information on these electricity end uses is described in EIA’s *Annual Energy Review* (EIA 2010b).

There are also three basic differences between the consumption data presented in Table A- 11 through Table A- 30 and those recommended in the IPCC emission inventory methodology.

First, consumption data in the U.S. Inventory are presented using higher heating values (HHV)¹ rather than the lower heating values (LHV)² reflected in the IPCC emission inventory methodology. This convention is followed because data obtained from EIA are based on HHV. Of note, however, is that EIA renewable energy statistics are often published using LHV. The difference between the two conventions relates to the treatment of the heat energy that is consumed in the process of evaporating the water contained in the fuel. The simplified convention used by the International Energy Agency for converting from HHV to LHV is to multiply the energy content by 0.95 for petroleum and coal and by 0.9 for natural gas.

¹ Also referred to as Gross Calorific Values (GCV).

² Also referred to as Net Calorific Values (NCV).

Second, while EIA's energy use data for the United States includes only the 50 U.S. states and the District of Columbia, the data reported to the UNFCCC are to include energy consumption within territories. Therefore, consumption estimates for U.S. territories³ were added to domestic consumption of fossil fuels. Energy consumption data from U.S. territories are presented in Column 7 of Table A- 11 through Table A- 30. It is reported separately from domestic sectoral consumption, because it is collected separately by EIA with no sectoral disaggregation.

Third, there were a number of modifications made in this report that may cause consumption information herein to differ from figures given in the cited literature. These are (1) the reallocation of select amounts of coking coal, petroleum coke, natural gas, residual fuel oil, and other oil (>401 F) for processes accounted for in the Industrial Processes chapter, (2) corrections for synthetic natural gas production, (3) subtraction of other fuels used for non-energy purposes, and (4) subtraction of international bunker fuels. These adjustments are described in the following steps.

Step 2: Subtract uses accounted for in the Industrial Processes chapter.

Portions of the fuel consumption data for seven fuel categories—coking coal, distillate fuel, industrial other coal, petroleum coke, natural gas, residual fuel oil, and other oil (>401 F)—were reallocated to the Industrial Processes chapter, as these portions were consumed as raw materials during non-energy related industrial processes. Emissions from these fuels used as raw materials are presented in the Industrial Processes chapter, and are removed from the energy and non-energy consumption estimates within the Energy chapter.

- Coking coal, also called “coal coke,” is used as a raw material (specifically as a reducing agent) in the blast furnace process to produce iron and steel, lead, and zinc and therefore is not used as a fuel for this process.
- Similarly, petroleum coke is used in multiple processes as a raw material, and is thus not used as a fuel in those applications. The processes in which petroleum coke is used include (1) ferroalloy production, (2) aluminum production (for the production of C anodes and cathodes), (3) titanium dioxide production (in the chloride process), (4) ammonia production, and (5) silicon carbide.
- Natural gas consumption is used for the production of ammonia, and blast furnace and coke oven gas used in iron and steel production.
- Residual fuel oil and other oil (>401F) are both used in the production of C black.
- Natural gas, distillate fuel, coal, and metallurgical coke are used to produce pig iron through the reduction of iron ore in the production of iron and steel.

Step 3: Adjust for Conversion of Fossil Fuels and Exports

First, a portion of industrial “other” coal that is accounted for in EIA coal combustion statistics is actually used to make “synthetic natural gas” via coal gasification at the Dakota Gasification Plant, a synthetic natural gas plant. The plant produces synthetic natural gas and byproduct CO₂. The synthetic natural gas enters the natural gas distribution system. Since October 2000, a portion of the CO₂ produced by the coal gasification plant has been exported to Canada by pipeline. The remainder of the CO₂ byproduct from the plant is released to the atmosphere. The energy in this synthetic natural gas enters the natural gas distribution stream, and is accounted for in EIA natural gas combustion statistics. Because this energy of the synthetic natural gas is already accounted for as natural gas combustion, this amount of energy is deducted from the industrial coal consumption statistics to avoid double counting. The exported CO₂ is not emitted to the atmosphere in the United States, and therefore the energy used to produce this amount of CO₂ is subtracted from industrial other coal.

Step 4: Subtract Consumption for Non-Energy Use

U.S. aggregate energy statistics include consumption of fossil fuels for non-energy purposes. Depending on the end-use, non-energy uses of fossil fuels can result in long term storage of some or all of the C contained in the fuel. For example, asphalt made from petroleum can sequester up to 100 percent of the C contained in the petroleum feedstock for extended periods of time. Other non-energy fossil fuel products, such as lubricants or plastics also store C, but can lose or emit

³ 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

some of this C when they are used and/or burned as waste.⁴ As the emission pathways of C used for non-energy purposes are vastly different than fuel combustion, these emissions are estimated separately in the Carbon Emitted in Products from Non-Energy Uses of Fossil Fuels section in this chapter. Therefore, the amount of fuels used for non-energy purposes, shown in Table A-31, was subtracted from total fuel consumption.

Step 5: Subtract Consumption of International Bunker Fuels

Emissions from international transport activities, or international bunker fuel consumption, are not included in national totals, as required by the IPCC (IPCC/UNEP/OECD/IEA 1997). There is currently disagreement internationally as to how these emissions should be allocated, and until this issue is resolved, countries are asked to report them separately. EIA energy statistics, however, include these bunker fuels—jet fuel for aircraft, and distillate fuel oil and residual fuel oil for marine shipping—as part of fuel consumption by the transportation end-use sector. Therefore, the amount of consumption for international bunker fuels was estimated and subtracted from total fuel consumption (see Table A-32). Emissions from international bunker fuels have been estimated separately and not included in national totals.⁵

Step 6: Determine the C Content of All Fuels

The C content of combusted fossil fuels was estimated by multiplying adjusted energy consumption (Columns 2 through 8 of Table A- 11 through Table A- 30) by fuel-specific C content coefficients (see Table A- 33 and Table A- 34) that reflect the amount of C per unit of energy in each fuel. The C content coefficients used in the U.S. inventory were derived by EIA from detailed fuel information and are similar to the C content coefficients contained in the IPCC's default methodology (IPCC/UNEP/OECD/IEA 1997), with modifications reflecting fuel qualities specific to the United States.

Step 7: Estimate CO₂ Emissions

Actual CO₂ emissions in the United States were summarized by major fuel (i.e., coal, petroleum, natural gas, geothermal) and consuming sector (i.e., residential, commercial, industrial, transportation, electricity generation, and U.S. territories). Emission estimates are expressed in teragrams of carbon dioxide equivalents (Tg CO₂ Eq.). To convert from C content to CO₂ emissions, the fraction of C that is oxidized was applied. This fraction was 100 percent based on guidance in IPCC (2006).

To determine total emissions by final end-use sector, emissions from electricity generation were distributed to each end-use sector according to its share of aggregate electricity consumption (see Table A-35). This pro-rated approach to allocating emissions from electricity generation may overestimate or underestimate emissions for particular sectors due to differences in the average C content of fuel mixes burned to generate electricity.

⁴ See the Waste Incineration section of the Energy chapter and the Waste Incineration Annex for a discussion of emissions from the combustion of plastics in the municipal solid waste stream.

⁵ Refer to the International Bunker Fuels section of the Energy chapter for a description of the methodology for distinguishing between bunker and non-bunker fuel consumption.

Table A- 10: 2009 Energy Consumption Data by Fuel Type (TBtu) and Adjusted Energy Consumption Data

	1	2	3	4	5	6	7	8	9	10	11	12	13
Fuel Type	Total Consumption (TBtu) ^a							Adjustments (TBtu) ^b			Total Adjusted Consumption		
	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Bunker Fuel	Unadjusted NEU Consumption				
									Ind.	Trans.		Terr.	
Total Coal	6.8	61.5	899.3	NE	18,296.2	38.2	19,302.0		18.5				19,283.4
Residential Coal	6.8						6.8						6.8
Commercial Coal		61.5					61.5						61.5
Industrial Coking Coal			6.1				6.1		6.1				
Industrial Other Coal			893.2				893.2		12.4				880.8
Transportation Coal				NE			NE						
Electric Power Coal					18,296.2		18,296.2						18,296.2
U.S. Territory Coal (bit)						38.2	38.2						38.2
Natural Gas	4,852.1	3,168.3	7,275.6	684.2	7,038.5	27.4	23,046.2		388.4				22,657.8
Total Petroleum	1,196.5	708.5	7,865.3	25,177.1	389.8	560.3	35,897.5	1,678.1	4,079.4	127.1		56.3	29,956.7
Asphalt & Road Oil			873.1				873.1		873.1				
Aviation Gasoline				26.6			26.6						26.6
Distillate Fuel Oil	591.7	406.3	1,085.5	5,555.0	70.6	74.3	7,783.4	112.3	17.5				7,653.6
Jet Fuel				2,883.3		41.7	2,925.0	961.0					1,964.0
Kerosene	26.2	5.3	4.9			7.6	43.9						43.9
LPG	578.7	165.4	1,878.4	41.2		14.9	2,678.6		1,520.5				1,158.1
Lubricants			134.5	127.1		1.0	262.6		134.5	127.1		1.0	
Motor Gasoline		68.8	376.3	15,779.7		199.8	16,424.7						16,424.7
Residual Fuel		62.4	102.7	764.2	180.7	165.7	1,275.7	604.8					670.9
Other Petroleum													
AvGas Blend			(0.8)				(0.8)						(0.8)
Components													
Crude Oil													
MoGas Blend													
Components													
Misc. Products			151.8			55.2	207.1		151.8			55.2	
Naphtha (<401 deg. F)			471.9				471.9		471.9				
Other Oil (>401 deg. F)			424.8				424.8		424.8				
Pentanes Plus			127.5				127.5		97.7				29.9
Petroleum Coke		0.3	799.0		138.6		937.9		195.4				742.4
Still Gas			1,455.0				1,455.0		133.9				1,321.1
Special Naphtha			46.2				46.2		46.2				
Unfinished Oils			(77.8)				(77.8)						(77.8)
Waxes			12.2				12.2		12.2				
Geothermal					51.9		51.9						51.9
TOTAL (All Fuels)	6,055.5	3,938.3	16,040.1	25,861.3	25,776.4	625.9	78,297.5	1,678.1	4,486.3	127.1		56.3	71,949.8

^a Expressed as gross calorific values (i.e., higher heating values).

^b Adjustments are subtracted from total consumption estimates and include biofuels, conversion of fossil fuels, non-energy use (see Table A-31), and international bunker fuel consumption (see Table A-32). NE (Not Estimated)

Table A- 11: 2009 Energy Consumption Data and CO₂ Emissions from Fossil Fuel Combustion by Fuel Type

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Adjusted Consumption (TBtu) ^a							Emissions ^b (Tg CO ₂ Eq.) from Energy Use							
Fuel Type	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	
Total Coal	6.8	61.5	880.8	NE	18,296.2	38.2	19,283.4	0.6	5.8	83.4	NE	1,747.6	3.5	1,841.0	
Residential Coal	6.8						6.8	0.6						0.6	
Commercial Coal		61.5					61.5		5.8					5.8	
Industrial Other Coal			880.8				880.8			83.4				83.4	
Transportation Coal				NE										NE	
Electric Power Coal					18,296.2		18,296.2					1,747.6		1,747.6	
U.S. Territory Coal (bit)						38.2	38.2						3.5	3.5	
Natural Gas	4,852.1	3,168.3	6,887.2	684.2	7,038.5	27.4	22,657.8	257.2	167.9	365.0	36.3	373.1	1.5	1,200.9	
Total Petroleum	1,196.5	708.5	3,785.9	23,371.9	389.8	504.0	29,956.7	81.4	50.3	282.0	1,683.4	32.9	36.7	2,166.7	
Asphalt & Road Oil															
Aviation Gasoline				26.6			26.6				1.8			1.8	
Distillate Fuel Oil	591.7	406.3	1,068.1	5,442.7	70.6	74.3	7,653.6	43.8	30.0	79.0	402.5	5.2	5.5	566.0	
Jet Fuel				1,922.3		41.7	1,964.0				138.8		3.0	141.8	
Kerosene	26.2	5.3	4.9			7.6	43.9	1.9	0.4	0.4			0.6	3.2	
LPG	578.7	165.4	357.9	41.2		14.9	1,158.1	35.7	10.2	22.1	2.5		0.9	71.5	
Lubricants															
Motor Gasoline		68.8	376.3	15,779.7		199.8	16,424.7		4.9	26.8	1,125.7		14.3	1,171.7	
Residual Fuel		62.4	102.7	159.4	180.7	165.7	670.9		4.7	7.7	12.0	13.6	12.4	50.4	
Other Petroleum															
AvGas Blend Components			(0.8)				(0.8)			(0.1)				(0.1)	
Crude Oil															
MoGas Blend Components															
Misc. Products															
Naphtha (<401 deg. F)															
Other Oil (>401 deg. F)															
Pentanes Plus			29.9				29.9			2.1				2.1	
Petroleum Coke		0.3	603.6		138.6		742.4		0.0	61.6		14.2		75.8	
Still Gas			1,321.1				1,321.1			88.1				88.1	
Special Naphtha															
Unfinished Oils			(77.8)				(77.8)			(5.8)				(5.8)	
Waxes															
Geothermal					51.9		51.9					0.4		0.4	
TOTAL (All Fuels)	6,055.5	3,938.3	11,553.8	24,056.2	25,776.4	569.6	71,949.8	339.2	224.0	730.4	1,719.7	2,154.0	41.7	5,209.0	

^a Expressed as gross calorific values (i.e., higher heating values).

^b Adjustments are subtracted from total consumption estimates and include biofuels, conversion of fossil fuels, non-energy use (see Table A-31), and international bunker fuel consumption (see Table A-32).

NE (Not Estimated)

Table A-12: 2008 Energy Consumption Data and CO₂ Emissions from Fossil Fuel Combustion by Fuel Type

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Adjusted Consumption (TBTU) ^a							Emissions ^b (Tg CO ₂ Eq.) from Energy Use							
Fuel Type	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	
Total Coal	7.7	69.1	1,083.4	NE	20,513.0	35.7	21,708.7	0.7	6.5	102.6	NE	1,959.4	3.3	2,072.5	
Residential Coal	7.7						7.7	0.7						0.7	
Commercial Coal		69.1					69.1		6.5					6.5	
Industrial Other Coal			1,083.4				1,083.4			102.6				102.6	
Transportation Coal				NE										NE	
Electric Power Coal					20,513.0		20,513.0					1,959.4		1,959.4	
U.S. Territory Coal (bit)						35.7	35.7						3.3	3.3	
Natural Gas	4,989.4	3,211.3	7,377.7	694.5	6,828.9	29.3	23,130.9	264.4	170.2	391.0	36.8	361.9	1.6	1,226.0	
Total Petroleum	1,214.7	669.3	4,165.2	24,319.9	467.7	478.6	31,315.4	83.1	47.4	309.3	1,753.1	39.2	35.0	2,267.1	
Asphalt & Road Oil															
Aviation Gasoline				28.3			28.3				2.0			2.0	
Distillate Fuel Oil	640.7	355.9	1,197.9	5,996.5	73.1	94.3	8,358.3	47.4	26.3	88.6	443.5	5.4	7.0	618.2	
Jet Fuel				2,147.3		34.9	2,182.2				155.1		2.5	157.6	
Kerosene	21.3	4.3	4.0			5.8	35.3	1.6	0.3	0.3			0.4	2.6	
LPG	552.7	158.0	382.0	39.4		15.7	1,147.8	34.1	9.7	23.6	2.4		1.0	70.8	
Lubricants															
Motor Gasoline		77.7	424.9	15,843.4		134.0	16,480.1		5.5	30.3	1,130.3		9.6	1,175.7	
Residual Fuel		73.2	135.6	265.0	240.4	193.9	908.1		5.5	10.2	19.9	18.1	14.6	68.2	
Other Petroleum															
AvGas Blend Components			0.1				0.1			0.0				0.0	
Crude Oil															
MoGas Blend Components															
Misc. Products															
Naphtha (<401 deg. F)															
Other Oil (>401 deg. F)															
Pentanes Plus			35.8				35.8			2.5				2.5	
Petroleum Coke		0.3	615.6		154.2		770.1		0.0	62.9		15.7		78.6	
Still Gas			1,423.0				1,423.0			94.9				94.9	
Special Naphtha															
Unfinished Oils			(53.7)				(53.7)			(4.0)				(4.0)	
Waxes															
Geothermal					51.0		51.0					0.4		0.4	
TOTAL (All Fuels)	6,211.7	3,949.7	12,626.2	25,014.4	27,860.5	543.5	76,206.1	348.2	224.2	802.9	1,789.9	2,360.9	39.8	5,565.9	

^a Expressed as gross calorific values (i.e., higher heating values).

^b Adjustments are subtracted from total consumption estimates and include biofuels, conversion of fossil fuels, non-energy use (see Table A-31), and international bunker fuel consumption (see Table A-32).

NE (Not Estimated)

Table A-13: 2007 Energy Consumption Data and CO₂ Emissions from Fossil Fuel Combustion by Fuel Type

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Adjusted Consumption (TBTU) ^a							Emissions ^b (Tg CO ₂ Eq.) from Energy Use							
Fuel Type	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	
Total Coal	7.8	70.0	1,130.3	NE	20,807.7	46.5	22,062.4	0.7	6.7	107.0	NE	1,987.3	4.3	2,106.0	
Residential Coal	7.8						7.8	0.7						0.7	
Commercial Coal		70.0					70.0		6.7					6.7	
Industrial Other Coal			1,130.3				1,130.3			107.0				107.0	
Transportation Coal				NE										NE	
Electric Power Coal					20,807.7		20,807.7					1,987.3		1,987.3	
U.S. Territory Coal (bit)						46.5	46.5						4.3	4.3	
Natural Gas	4,849.6	3,094.1	7,339.6	665.4	7,005.2	26.8	22,980.6	257.0	164.0	389.0	35.3	371.3	1.4	1,218.0	
Total Petroleum	1,224.9	680.7	4,679.9	25,685.8	657.1	551.7	33,480.1	84.6	48.7	346.0	1,858.7	53.9	40.4	2,432.4	
Asphalt & Road Oil															
Aviation Gasoline				31.6			31.6				2.2			2.2	
Distillate Fuel Oil	697.3	368.7	1,185.5	6,439.7	89.3	136.5	8,917.0	51.6	27.3	87.7	476.3	6.6	10.1	659.5	
Jet Fuel				2,336.3		55.5	2,391.8				168.7		4.0	172.7	
Kerosene	43.9	9.2	13.4			5.2	71.8	3.2	0.7	1.0			0.4	5.3	
LPG	483.7	121.4	563.7	21.9		11.6	1,202.3	29.8	7.5	34.8	1.4		0.7	74.2	
Lubricants															
Motor Gasoline		105.6	528.7	16,470.1		157.0	17,261.4		7.6	37.9	1,181.2		11.3	1,238.0	
Residual Fuel		75.4	130.4	386.1	396.6	185.9	1,174.4		5.7	9.8	29.0	29.8	14.0	88.2	
Other Petroleum															
AvGas Blend Components			1.8				1.8			0.1				0.1	
Crude Oil															
MoGas Blend Components															
Misc. Products															
Naphtha (<401 deg. F)															
Other Oil (>401 deg. F)															
Pentanes Plus			42.0				42.0			2.9				2.9	
Petroleum Coke		0.4	666.7		171.2		838.3		0.0	68.1		17.5		85.6	
Still Gas			1,482.6				1,482.6			98.9				98.9	
Special Naphtha															
Unfinished Oils			65.2				65.2			4.8				4.8	
Waxes															
Geothermal					49.9		49.9					0.4		0.4	
TOTAL (All Fuels)	6,082.2	3,844.8	13,149.8	26,351.2	28,520.0	625.0	78,572.9	342.4	219.4	842.0	1,894.0	2,412.8	46.1	5,756.7	

^a Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-31), and international bunker fuel consumption (see Table A-32).

^b Consumption and/or emissions of select fuels are shown as negative due to differences in EIA energy balancing accounting. These are designated with parentheses.
NE (Not Estimated)

Table A-14: 2006 Energy Consumption Data and CO₂ Emissions from Fossil Fuel Combustion by Fuel Type

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Fuel Type	Adjusted Consumption (TBtu) ^a							Emissions ^b (Tg CO ₂ Eq.) from Energy Use							
	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	
Total Coal	6.4	64.8	1,188.3	NE	20,461.9	36.9	21,758.2	0.6	6.2	112.6	NE	1,953.7	3.4	2,076.5	
Residential Coal	6.4						6.4	0.6						0.6	
Commercial Coal		64.8					64.8		6.2					6.2	
Industrial Other Coal			1,188.3				1,188.3			112.6				112.6	
Transportation Coal				NE										NE	
Electric Power Coal					20,461.9		20,461.9					1,953.7		1,953.7	
U.S. Territory Coal (bit)						36.9	36.9						3.4	3.4	
Natural Gas	4,475.9	2,901.7	7,125.0	625.0	6,375.1	26.1	21,528.8	237.3	153.8	377.7	33.1	338.0	1.4	1,141.3	
Total Petroleum	1,204.9	677.7	4,842.3	25,589.8	648.1	620.9	33,583.6	83.6	48.5	357.9	1,845.0	54.4	45.5	2,434.9	
Asphalt & Road Oil															
Aviation Gasoline				33.4			33.4				2.3			2.3	
Distillate Fuel Oil	693.0	390.5	1,199.4	6,358.6	73.7	90.2	8,805.3	51.3	28.9	88.7	470.3	5.4	6.7	651.2	
Jet Fuel				2,347.1		76.1	2,423.2				169.5		5.5	175.0	
Kerosene	66.4	15.2	29.6			4.4	115.5	4.9	1.1	2.2			0.3	8.5	
LPG	445.5	123.2	587.5	27.5		6.6	1,190.2	27.5	7.6	36.3	1.7		0.4	73.5	
Lubricants															
Motor Gasoline		73.4	567.0	16,516.8		188.8	17,345.9		5.2	40.4	1,178.2		13.5	1,237.4	
Residual Fuel		75.3	176.4	306.3	360.5	254.8	1,173.3		5.7	13.2	23.0	27.1	19.1	88.1	
Other Petroleum															
AvGas Blend Components			0.6				0.6			0.0				0.0	
Crude Oil															
MoGas Blend Components															
Misc. Products															
Naphtha (<401 deg. F)															
Other Oil (>401 deg. F)															
Pentanes Plus			32.8				32.8			2.3				2.3	
Petroleum Coke		0.3	682.5		213.9		896.7		0.0	69.7		21.8		91.6	
Still Gas			1,496.1				1,496.1			99.8				99.8	
Special Naphtha															
Unfinished Oils			70.3				70.3			5.2				5.2	
Waxes															
Geothermal					49.7		49.7					0.4		0.4	
TOTAL (All Fuels)	5,687.2	3,644.2	13,155.6	26,214.7	27,534.8	683.9	76,920.4	321.5	208.6	848.2	1,878.1	2,346.4	50.3	5,653.1	

^a Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-31), and international bunker fuel consumption (see Table A-32).

^b Consumption and/or emissions of select fuels are shown as negative due to differences in EIA energy balancing accounting. These are designated with parentheses.
NE (Not Estimated)

Table A-15: 2005 Energy Consumption Data and CO₂ Emissions from Fossil Fuel Combustion by Fuel Type

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Fuel Type	Adjusted Consumption (TBtu) ^a							Emissions ^b (Tg CO ₂ Eq.) from Energy Use							
	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	
Total Coal	8.4	97.0	1,219.1	NE	20,737.2	32.7	22,094.5	0.8	9.3	115.3	NE	1,983.8	3.0	2,112.3	
Residential Coal	8.4						8.4	0.8						0.8	
Commercial Coal		97.0					97.0		9.3					9.3	
Industrial Other Coal			1,219.1				1,219.1			115.3				115.3	
Transportation Coal				NE										NE	
Electric Power Coal					20,737.2		20,737.2					1,983.8		1,983.8	
U.S. Territory Coal (bit)						32.7	32.7						3.0	3.0	
Natural Gas	4,946.4	3,073.2	7,184.9	623.9	6,014.5	24.3	21,867.2	262.2	162.9	380.8	33.1	318.8	1.3	1,159.0	
Total Petroleum	1,369.2	716.0	4,401.3	25,932.6	1,234.5	623.3	34,276.9	94.9	51.3	326.9	1,863.5	99.2	45.7	2,481.5	
Asphalt & Road Oil															
Aviation Gasoline				35.4			35.4				2.4			2.4	
Distillate Fuel Oil	772.6	404.7	1,124.5	6,193.8	114.6	121.3	8,731.6	57.1	29.9	83.2	458.1	8.5	9.0	645.8	
Jet Fuel				2,689.2		66.0	2,755.2				194.2		4.8	199.0	
Kerosene	83.8	21.6	39.1			5.8	150.2	6.1	1.6	2.9			0.4	11.0	
LPG	512.9	131.4	521.0	28.2		0.8	1,194.2	31.7	8.1	32.2	1.7		0.0	73.7	
Lubricants															
Motor Gasoline		42.2	328.4	16,729.6		194.3	17,294.4		3.0	23.3	1,187.8		13.8	1,227.9	
Residual Fuel		115.8	223.2	256.4	876.5	235.2	1,707.2		8.7	16.8	19.3	65.8	17.7	128.2	
Other Petroleum															
AvGas Blend Components			8.3				8.3			0.6				0.6	
Crude Oil															
MoGas Blend Components															
Misc. Products															
Naphtha (<401 deg. F)															
Other Oil (>401 deg. F)															
Pentanes Plus			45.9				45.9			3.2				3.2	
Petroleum Coke		0.3	678.6		243.5		922.3		0.0	69.3		24.9		94.2	
Still Gas			1,429.4				1,429.4			95.4				95.4	
Special Naphtha															
Unfinished Oils			2.8				2.8			0.2				0.2	
Waxes															
Geothermal					50.1		50.1					0.4		0.4	
TOTAL (All Fuels)	6,324.0	3,886.2	12,805.3	26,556.5	28,036.4	680.4	78,288.8	357.9	223.5	823.1	1,896.6	2,402.1	50.0	5,753.2	

^a Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-31), and international bunker fuel consumption (see Table A-32).

^b Consumption and/or emissions of select fuels are shown as negative due to differences in EIA energy balancing accounting. These are designated with parentheses.
NE (Not Estimated)

Table A-16: 2004 Energy Consumption Data and CO₂ Emissions from Fossil Fuel Combustion by Fuel Type

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Fuel Type	Adjusted Consumption (TBtu) ^a							Emissions ^b (Tg CO ₂ Eq.) from Energy Use							
	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	
Total Coal	11.4	102.9	1,262.0	NE	20,305.0	32.0	21,713.3	1.1	9.8	118.3	NE	1,943.1	2.9	2,075.1	
Residential Coal	11.4						11.4	1.1						1.1	
Commercial Coal		102.9					102.9		9.8					9.8	
Industrial Other Coal			1,262.0				1,262.0			118.3				118.3	
Transportation Coal				NE										NE	
Electric Power Coal					20,305.0		20,305.0					1,943.1		1,943.1	
U.S. Territory Coal (bit)						32.0	32.0						2.9	2.9	
Natural Gas	4,980.8	3,201.0	7,802.3	602.0	5,594.9	24.6	22,205.6	264.1	169.7	413.7	31.9	296.7	1.3	1,177.5	
Total Petroleum	1,474.6	766.7	4,282.6	25,529.7	1,212.4	653.6	33,919.5	102.7	54.9	317.7	1,834.9	96.9	47.9	2,455.0	
Asphalt & Road Oil															
Aviation Gasoline				31.2			31.2				2.2			2.2	
Distillate Fuel Oil	878.1	447.0	1,136.6	5,917.7	111.3	134.4	8,625.2	64.9	33.1	84.1	437.7	8.2	9.9	637.9	
Jet Fuel				2,525.0		68.8	2,593.7				182.4		5.0	187.3	
Kerosene	84.8	20.5	28.2			6.0	139.5	6.2	1.5	2.1			0.4	10.2	
LPG	511.7	152.0	564.8	19.1		0.8	1,248.4	31.6	9.4	34.9	1.2		0.0	77.1	
Lubricants															
Motor Gasoline			203.4	16,850.3		198.6	17,276.7		1.7	14.5	1,197.6		14.1	1,227.9	
Residual Fuel		122.5	195.3	186.4	879.0	245.0	1,628.2		9.2	14.7	14.0	66.0	18.4	122.3	
Other Petroleum															
AvGas Blend Components			10.6				10.6			0.7				0.7	
Crude Oil															
MoGas Blend Components															
Misc. Products															
Naphtha (<401 deg. F)															
Other Oil (>401 deg. F)															
Pentanes Plus			52.1				52.1			3.6				3.6	
Petroleum Coke		0.3	683.9		222.1		906.2		0.0	69.8		22.7		92.5	
Still Gas			1,483.3				1,483.3			99.0				99.0	
Special Naphtha															
Unfinished Oils			(75.6)				(75.6)			(5.6)				(5.6)	
Waxes															
Geothermal					50.5		50.5					0.4		0.4	
TOTAL (All Fuels)	6,466.8	4,070.6	13,346.9	26,131.6	27,162.9	710.2	77,889.0	367.9	234.4	849.6	1,866.8	2,337.0	52.2	5,708.0	

^a Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-31), and international bunker fuel consumption (see Table A-32).

^b Consumption and/or emissions of select fuels are shown as negative due to differences in EIA energy balancing accounting. These are designated with parentheses.
NE (Not Estimated)

Table A-17: 2003 Energy Consumption Data and CO₂ Emissions from Fossil Fuel Combustion by Fuel Type

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Adjusted Consumption (TBTu) ^a							Emissions ^b (Tg CO ₂ Eq.) from Energy Use							
Fuel Type	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	
Total Coal	12.2	82.0	1,248.8	NE	20,184.7	33.9	21,561.7	1.2	7.8	117.0	NE	1,931.0	3.1	2,060.1	
Residential Coal	12.2						12.2	1.2						1.2	
Commercial Coal		82.0					82.0		7.8					7.8	
Industrial Other Coal			1,248.8				1,248.8			117.0				117.0	
Transportation Coal				NE										NE	
Electric Power Coal					20,184.7		20,184.7					1,931.0		1,931.0	
U.S. Territory Coal (bit)						33.9	33.9						3.1	3.1	
Natural Gas	5,209.4	3,260.9	7,806.1	627.4	5,246.2	26.9	22,177.0	275.9	172.7	413.4	33.2	277.8	1.4	1,174.3	
Total Petroleum	1,466.1	762.1	4,018.7	24,937.8	1,205.0	621.8	33,011.5	101.8	54.5	299.3	1,790.4	95.0	45.3	2,386.3	
Asphalt & Road Oil															
Aviation Gasoline				30.2			30.2				2.1			2.1	
Distillate Fuel Oil	851.3	453.1	1,054.1	5,710.9	161.0	120.5	8,350.8	63.0	33.5	78.0	422.4	11.9	8.9	617.6	
Jet Fuel				2,480.8		76.1	2,556.9				179.2		5.5	184.7	
Kerosene	70.3	18.6	24.1			10.7	123.7	5.1	1.4	1.8			0.8	9.1	
LPG	544.5	156.9	484.6	16.5		10.5	1,213.0	33.7	9.7	30.0	1.0		0.7	75.0	
Lubricants															
Motor Gasoline			119.2	16,600.2		210.1	16,951.6		1.6	8.5	1,178.3		14.9	1,203.2	
Residual Fuel		111.1	171.7	99.1	869.4	193.9	1,445.2		8.3	12.9	7.4	65.3	14.6	108.5	
Other Petroleum															
AvGas Blend Components			7.5				7.5			0.5				0.5	
Crude Oil															
MoGas Blend Components															
Misc. Products															
Naphtha (<401 deg. F)															
Other Oil (>401 deg. F)															
Pentanes Plus			51.7				51.7			3.6				3.6	
Petroleum Coke		0.3	678.9		174.7		853.9		0.0	69.3		17.8		87.2	
Still Gas			1,477.3				1,477.3			98.6				98.6	
Special Naphtha															
Unfinished Oils			(50.4)				(50.4)			(3.7)				(3.7)	
Waxes															
Geothermal					49.2		49.2					0.4		0.4	
TOTAL (All Fuels)	6,687.8	4,104.9	13,073.5	25,565.3	26,685.2	682.6	76,799.3	378.8	235.0	829.6	1,823.6	2,304.2	49.9	5,621.1	

^a Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-31), and international bunker fuel consumption (see Table A-32).

^b Consumption and/or emissions of select fuels are shown as negative due to differences in EIA energy balancing accounting. These are designated with parentheses.
NE (Not Estimated)

Table A-18: 2002 Energy Consumption Data and CO₂ Emissions from Fossil Fuel Combustion by Fuel Type

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Fuel Type	Adjusted Consumption (TBtu) ^a							Emissions ^b (Tg CO ₂ Eq.) from Energy Use							
	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	
Total Coal	12.2	89.8	1,243.7	NE	19,782.8	10.8	21,139.3	1.2	8.6	116.6	NE	1,889.9	1.0	2,017.2	
Residential Coal	12.2						12.2	1.2						1.2	
Commercial Coal		89.8					89.8		8.6					8.6	
Industrial Other Coal			1,243.7				1,243.7			116.6				116.6	
Transportation Coal				NE										NE	
Electric Power Coal					19,782.8		19,782.8					1,889.9		1,889.9	
U.S. Territory Coal (bit)						10.8	10.8						1.0	1.0	
Natural Gas	5,014.5	3,225.0	8,100.0	701.6	5,766.8	22.8	22,830.7	265.8	170.9	429.3	37.2	305.7	1.2	1,210.1	
Total Petroleum	1,358.9	645.4	3,860.0	24,844.0	961.3	556.8	32,226.5	93.9	46.1	287.5	1,785.1	76.8	40.6	2,329.9	
Asphalt & Road Oil															
Aviation Gasoline				33.7			33.7				2.3			2.3	
Distillate Fuel Oil	761.8	393.4	1,048.4	5,595.9	127.4	92.8	8,019.7	56.3	29.1	77.5	413.9	9.4	6.9	593.1	
Jet Fuel				2,448.5		61.8	2,510.2				176.8		4.5	181.3	
Kerosene	59.9	15.9	13.8			8.2	97.9	4.4	1.2	1.0			0.6	7.2	
LPG	537.1	140.8	539.3	14.3		11.2	1,242.7	33.2	8.7	33.3	0.9		0.7	76.8	
Lubricants															
Motor Gasoline		15.2	104.2	16,523.7		189.4	16,832.5		1.1	7.4	1,174.1		13.5	1,196.0	
Residual Fuel		79.8	146.1	227.9	658.7	193.6	1,306.1		6.0	11.0	17.1	49.5	14.5	98.1	
Other Petroleum															
AvGas Blend Components			7.5				7.5			0.5				0.5	
Crude Oil															
MoGas Blend Components															
Misc. Products															
Naphtha (<401 deg. F)															
Other Oil (>401 deg. F)															
Pentanes Plus			52.4				52.4			3.7				3.7	
Petroleum Coke		0.2	680.7		175.2		856.1		0.0	69.5		17.9		87.4	
Still Gas			1,403.3				1,403.3			93.6				93.6	
Special Naphtha															
Unfinished Oils			(135.7)				(135.7)			(10.1)				(10.1)	
Waxes															
Geothermal					49.4		49.4					0.4		0.4	
TOTAL (All Fuels)	6,385.6	3,960.3	13,203.7	25,545.6	26,560.3	590.5	76,245.9	360.9	225.6	833.4	1,822.3	2,272.7	42.8	5,557.6	

^a Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-31), and international bunker fuel consumption (see Table A-32).

^b Consumption and/or emissions of select fuels are shown as negative due to differences in EIA energy balancing accounting. These are designated with parentheses.
NE (Not Estimated)

Table A-19: 2001 Energy Consumption Data and CO₂ Emissions from Fossil Fuel Combustion by Fuel Type

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Adjusted Consumption (TBTU) ^a							Emissions ^b (Tg CO ₂ Eq.) from Energy Use							
Fuel Type	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	
Total Coal	12.0	96.9	1,358.4	NE	19,613.7	3.8	21,084.8	1.1	9.2	127.8	NE	1,869.8	0.4	2,008.4	
Residential Coal	12.0						12.0	1.1						1.1	
Commercial Coal		96.9					96.9		9.2					9.2	
Industrial Other Coal			1,358.4				1,358.4			127.8				127.8	
Transportation Coal				NE										NE	
Electric Power Coal					19,613.7		19,613.7					1,869.8		1,869.8	
U.S. Territory Coal (bit)						3.8	3.8						0.4	0.4	
Natural Gas	4,889.0	3,097.3	7,933.2	658.0	5,458.1	22.9	22,058.5	259.1	164.2	420.5	34.9	289.3	1.2	1,169.1	
Total Petroleum	1,463.0	718.6	3,932.7	24,428.5	1,276.6	632.2	32,451.6	101.8	51.5	293.4	1,752.8	98.5	46.2	2,344.0	
Asphalt & Road Oil															
Aviation Gasoline				34.9			34.9				2.4			2.4	
Distillate Fuel Oil	842.2	471.4	1,181.8	5,417.0	170.5	109.4	8,192.3	62.3	34.9	87.4	400.6	12.6	8.1	605.9	
Jet Fuel				2,605.2		98.9	2,704.0				188.1		7.1	195.3	
Kerosene	95.1	31.4	23.2			0.9	150.6	7.0	2.3	1.7			0.1	11.0	
LPG	525.7	142.7	461.0	13.7		7.0	1,150.1	32.5	8.8	28.5	0.8		0.4	71.1	
Lubricants															
Motor Gasoline			3.1	16,198.3		187.6	16,413.2		0.2	1.7	1,148.7		13.3	1,164.0	
Residual Fuel		69.9	156.1	159.5	1,002.8	228.4	1,616.7		5.2	11.7	12.0	75.3	17.2	121.4	
Other Petroleum															
AvGas Blend Components			6.1				6.1			0.4				0.4	
Crude Oil															
MoGas Blend Components															
Misc. Products															
Naphtha (<401 deg. F)															
Other Oil (>401 deg. F)															
Pentanes Plus			61.6				61.6			4.3				4.3	
Petroleum Coke		0.2	663.4		103.2		766.8		0.0	67.7		10.5		78.3	
Still Gas			1,430.7				1,430.7			95.5				95.5	
Special Naphtha															
Unfinished Oils			(75.4)				(75.4)			(5.6)				(5.6)	
Waxes															
Geothermal					46.9		46.9					0.4		0.4	
TOTAL (All Fuels)	6,364.0	3,912.7	13,224.3	25,086.6	26,395.2	658.9	75,641.7	362.0	224.9	841.7	1,787.6	2,257.9	47.8	5,521.9	

^a Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-31), and international bunker fuel consumption (see Table A-32).

^b Consumption and/or emissions of select fuels are shown as negative due to differences in EIA energy balancing accounting. These are designated with parentheses.
NE (Not Estimated)

Table A-20: 2000 Energy Consumption Data and CO₂ Emissions from Fossil Fuel Combustion by Fuel Type

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Fuel Type	Adjusted Consumption (TBtu)^a							Emissions^b (Tg CO₂ Eq.) from Energy Use							
	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	
Total Coal	11.4	91.9	1,348.8	NE	20,220.2	10.3	21,682.4	1.1	8.8	127.3	NE	1,927.4	0.9	2,065.5	
Residential Coal	11.4						11.4	1.1						1.1	
Commercial Coal		91.9					91.9		8.8					8.8	
Industrial Other Coal			1,348.8				1,348.8			127.3				127.3	
Transportation Coal				NE										NE	
Electric Power Coal					20,220.2		20,220.2					1,927.4		1,927.4	
U.S. Territory Coal (bit)						10.3	10.3						0.9	0.9	
Natural Gas	5,104.6	3,251.6	8,619.2	672.0	5,293.4	12.7	22,953.5	270.7	172.5	457.2	35.6	280.8	0.7	1,217.4	
Total Petroleum	1,427.5	694.0	3,586.6	24,715.2	1,144.3	471.7	32,039.3	98.8	49.6	266.6	1,773.9	88.4	34.2	2,311.6	
Asphalt & Road Oil															
Aviation Gasoline				36.3			36.3				2.5			2.5	
Distillate Fuel Oil	778.0	422.2	1,003.7	5,442.4	174.8	71.3	7,892.5	57.5	31.2	74.2	402.5	12.9	5.3	583.7	
Jet Fuel				2,766.4		74.1	2,840.5				199.8		5.3	205.1	
Kerosene	94.6	29.7	15.6			2.4	142.2	6.9	2.2	1.1			0.2	10.4	
LPG	554.9	150.4	562.6	11.9		8.0	1,287.8	34.4	9.3	34.9	0.7		0.5	79.8	
Lubricants															
Motor Gasoline				16,014.8		185.1	16,199.8				1,135.0		13.1	1,148.1	
Residual Fuel		91.6	190.3	443.5	870.8	130.9	1,727.1		6.9	14.3	33.3	65.4	9.8	129.7	
Other Petroleum															
AvGas Blend Components			3.8				3.8			0.3				0.3	
Crude Oil															
MoGas Blend Components															
Misc. Products															
Naphtha (<401 deg. F)															
Other Oil (>401 deg. F)															
Pentanes Plus			106.5				106.5			7.5				7.5	
Petroleum Coke		0.2	669.5		98.6		768.3		0.0	68.4		10.1		78.5	
Still Gas			1,435.6				1,435.6			95.8				95.8	
Special Naphtha															
Unfinished Oils			(401.2)				(401.2)			(29.7)				(29.7)	
Waxes															
Geothermal					48.1		48.1					0.4		0.4	
TOTAL (All Fuels)	6,543.5	4,037.4	13,554.5	25,387.2	26,706.0	494.6	76,723.2	370.7	230.8	851.1	1,809.5	2,296.9	35.9	5,594.8	

^a Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-31), and international bunker fuel consumption (see Table A-32).

^b Consumption and/or emissions of select fuels are shown as negative due to differences in EIA energy balancing accounting. These are designated with parentheses.
NE (Not Estimated)

Table A-21: 1999 Energy Consumption Data and CO₂ Emissions from Fossil Fuel Combustion by Fuel Type

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Fuel Type	Adjusted Consumption (TBTu)^a							Emissions^b (Tg CO₂ Eq.) from Energy Use							
	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	
Total Coal	14.0	102.5	1,372.8	NE	19,279.5	10.2	20,779.0	1.3	9.8	129.9	NE	1,836.4	0.9	1,978.3	
Residential Coal	14.0						14.0	1.3						1.3	
Commercial Coal		102.5					102.5		9.8					9.8	
Industrial Other Coal			1,372.8				1,372.8			129.9				129.9	
Transportation Coal				NE										NE	
Electric Power Coal					19,279.5		19,279.5					1,836.4		1,836.4	
U.S. Territory Coal (bit)						10.2	10.2						0.9	0.9	
Natural Gas	4,834.9	3,115.0	8,401.6	675.3	4,902.1		21,929.0	256.3	165.1	445.4	35.8	259.9		1,162.6	
Total Petroleum	1,342.1	613.9	3,465.8	24,071.1	1,211.4	461.0	31,165.3	92.8	43.8	260.0	1,725.9	93.8	33.5	2,249.9	
Asphalt & Road Oil															
Aviation Gasoline				39.2			39.2				2.7			2.7	
Distillate Fuel Oil	705.0	373.4	983.4	5,251.3	140.1	79.4	7,532.6	52.1	27.6	72.7	388.4	10.4	5.9	557.1	
Jet Fuel				2,677.5		59.5	2,737.1				193.4		4.3	197.7	
Kerosene	111.2	26.9	12.8			3.7	154.7	8.1	2.0	0.9			0.3	11.3	
LPG	526.0	140.2	395.9	14.3		8.3	1,084.6	32.5	8.7	24.5	0.9		0.5	67.1	
Lubricants															
Motor Gasoline				15,913.1		164.0	16,077.2				1,127.4		11.6	1,139.0	
Residual Fuel		73.3	154.0	175.7	958.7	146.0	1,507.8		5.5	11.6	13.2	72.0	11.0	113.2	
Other Petroleum															
AvGas Blend Components			6.4				6.4			0.4				0.4	
Crude Oil															
MoGas Blend Components															
Misc. Products															
Naphtha (<401 deg. F)															
Other Oil (>401 deg. F)															
Pentanes Plus			103.5				103.5			7.2				7.2	
Petroleum Coke		0.1	676.5		112.5		789.1		0.0	69.1		11.5		80.6	
Still Gas			1,421.1				1,421.1			94.8				94.8	
Special Naphtha															
Unfinished Oils			(287.9)				(287.9)			(21.3)				(21.3)	
Waxes															
Geothermal					50.6		50.6					0.4		0.4	
TOTAL (All Fuels)	6,191.0	3,831.5	13,240.1	24,746.4	25,443.6	471.2	73,923.8	350.5	218.7	835.3	1,761.7	2,190.5	34.5	5,391.1	

^a Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-31), and international bunker fuel consumption (see Table A-32).

^b Consumption and/or emissions of select fuels are shown as negative due to differences in EIA energy balancing accounting. These are designated with parentheses.
NE (Not Estimated)

Table A-22: 1998 Energy Consumption Data and CO₂ Emissions from Fossil Fuel Combustion by Fuel Type

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Fuel Type	Adjusted Consumption (TBtu) ^a							Emissions ^b (Tg CO ₂ Eq.) from Energy Use							Total
	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	
Total Coal	11.5	93.4	1,470.8	NE	19,215.7	10.5	20,802.0	1.1	8.9	139.1	NE	1,828.2	1.0	1,978.3	
Residential Coal	11.5						11.5	1.1						1.1	
Commercial Coal		93.4					93.4		8.9					8.9	
Industrial Other Coal			1,470.8				1,470.8			139.1				139.1	
Transportation Coal				NE										NE	
Electric Power Coal					19,215.7		19,215.7					1,828.2		1,828.2	
U.S. Territory Coal (bit)						10.5	10.5						1.0	1.0	
Natural Gas	4,646.1	3,083.0	8,826.5	666.1	4,674.9		21,896.6	246.0	163.3	467.4	35.3	247.6		1,159.5	
Total Petroleum	1,207.3	609.1	3,379.3	23,154.5	1,306.2	445.4	30,102.0	84.0	43.7	254.7	1,661.9	101.3	32.4	2,178.0	
Asphalt & Road Oil															
Aviation Gasoline				35.5			35.5				2.5			2.5	
Distillate Fuel Oil	675.1	375.1	1,027.9	4,955.2	135.7	71.9	7,240.8	49.9	27.7	76.0	366.5	10.0	5.3	535.5	
Jet Fuel				2,483.9		59.9	2,543.7				179.4		4.3	183.7	
Kerosene	108.3	31.2	22.1			6.3	167.8	7.9	2.3	1.6			0.5	12.3	
LPG	423.9	117.6	271.6	17.6		5.9	836.7	26.1	7.2	16.7	1.1		0.4	51.6	
Lubricants															
Motor Gasoline				15,583.4		160.3	15,743.8				1,106.6		11.4	1,118.0	
Residual Fuel		85.2	173.3	78.9	1,047.0	141.1	1,525.5		6.4	13.0	5.9	78.6	10.6	114.6	
Other Petroleum															
AvGas Blend Components			4.0				4.0			0.3				0.3	
Crude Oil															
MoGas Blend Components															
Misc. Products															
Naphtha (<401 deg. F)															
Other Oil (>401 deg. F)															
Pentanes Plus			89.7				89.7			6.3				6.3	
Petroleum Coke		0.1	667.5		123.6		791.2		0.0	68.2		12.6		80.8	
Still Gas			1,437.3				1,437.3			95.9				95.9	
Special Naphtha															
Unfinished Oils			(313.9)				(313.9)			(23.3)				(23.3)	
Waxes															
Geothermal					50.4		50.4					0.4		0.4	
TOTAL (All Fuels)	5,865.0	3,785.5	13,676.6	23,820.6	25,247.2	456.0	72,850.9	331.1	215.9	861.2	1,697.2	2,177.4	33.4	5,316.2	

^a Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-31), and international bunker fuel consumption (see Table A-32).

^b Consumption and/or emissions of select fuels are shown as negative due to differences in EIA energy balancing accounting. These are designated with parentheses.
NE (Not Estimated)

Table A-23: 1997 Energy Consumption Data and CO₂ Emissions from Fossil Fuel Combustion by Fuel Type

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Adjusted Consumption (TBTU) ^a							Emissions ^b (Tg CO ₂ Eq.) from Energy Use							
Fuel Type	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	
Total Coal	16.0	129.4	1,457.0	NE	18,904.5	10.4	20,517.4	1.5	12.3	137.6	NE	1,797.0	1.0	1,949.4	
Residential Coal	16.0						16.0	1.5						1.5	
Commercial Coal		129.4					129.4		12.3					12.3	
Industrial Other Coal			1,457.0				1,457.0			137.6				137.6	
Transportation Coal				NE										NE	
Electric Power Coal					18,904.5		18,904.5					1,797.0		1,797.0	
U.S. Territory Coal (bit)						10.4	10.4						1.0	1.0	
Natural Gas	5,092.9	3,285.3	9,052.1	780.3	4,125.5		22,336.2	270.1	174.2	480.0	41.4	218.8		1,184.4	
Total Petroleum	1,333.5	655.1	3,754.9	22,649.5	926.8	445.3	29,765.2	93.0	47.1	279.8	1,625.3	72.2	32.4	2,149.8	
Asphalt & Road Oil															
Aviation Gasoline				39.7			39.7				2.7			2.7	
Distillate Fuel Oil	785.9	398.9	1,053.7	4,802.2	110.6	81.6	7,232.7	58.1	29.5	77.9	355.2	8.2	6.0	534.9	
Jet Fuel				2,509.5		62.1	2,571.6				181.2		4.5	185.7	
Kerosene	92.9	24.6	18.8			4.0	140.3	6.8	1.8	1.4			0.3	10.3	
LPG	454.8	120.2	429.9	14.2		6.5	1,025.7	28.1	7.4	26.5	0.9		0.4	63.3	
Lubricants															
Motor Gasoline				15,147.5		160.0	15,307.5				1,075.0		11.4	1,086.4	
Residual Fuel		111.2	235.6	136.5	714.6	131.1	1,329.0		8.4	17.7	10.3	53.7	9.8	99.8	
Other Petroleum															
AvGas Blend Components			9.1				9.1			0.6				0.6	
Crude Oil			4.6				4.6			0.3				0.3	
MoGas Blend Components															
Misc. Products															
Naphtha (<401 deg. F)															
Other Oil (>401 deg. F)															
Pentanes Plus			30.0				30.0			2.1				2.1	
Petroleum Coke		0.1	631.1		101.6		732.8		0.0	64.4		10.4		74.8	
Still Gas			1,445.1				1,445.1			96.4				96.4	
Special Naphtha															
Unfinished Oils			(102.9)				(102.9)			(7.6)				(7.6)	
Waxes															
Geothermal					50.2		50.2					0.4		0.4	
TOTAL (All Fuels)	6,442.5	4,069.8	14,264.1	23,429.8	24,007.1	455.7	72,669.1	364.6	233.6	897.4	1,666.6	2,088.4	33.4	5,284.0	

^a Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-31), and international bunker fuel consumption (see Table A-32).

^b Consumption and/or emissions of select fuels are shown as negative due to differences in EIA energy balancing accounting. These are designated with parentheses.
NE (Not Estimated)

Table A-24: 1996 Energy Consumption Data and CO₂ Emissions from Fossil Fuel Combustion by Fuel Type

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Adjusted Consumption (TBtu) ^a							Emissions ^b (Tg CO ₂ Eq.) from Energy Use							
Fuel Type	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	
Total Coal	16.6	121.6	1,454.9	NE	18,429.0	10.3	20,032.4	1.6	11.6	137.4	NE	1,752.4	1.0	1,903.9	
Residential Coal	16.6						16.6	1.6						1.6	
Commercial Coal		121.6					121.6		11.6					11.6	
Industrial Other Coal			1,454.9				1,454.9			137.4				137.4	
Transportation Coal				NE										NE	
Electric Power Coal					18,429.0		18,429.0					1,752.4		1,752.4	
U.S. Territory Coal (bit)						10.3	10.3						1.0	1.0	
Natural Gas	5,354.4	3,226.3	9,048.6	736.9	3,862.4		22,228.7	283.9	171.1	479.8	39.1	204.8		1,178.7	
Total Petroleum	1,396.6	718.3	3,760.8	22,406.2	817.4	434.6	29,533.9	97.5	51.8	280.6	1,608.0	63.4	31.6	2,132.8	
Asphalt & Road Oil															
Aviation Gasoline				37.4			37.4				2.6			2.6	
Distillate Fuel Oil	839.0	437.6	1,046.7	4,599.0	109.4	76.5	7,108.1	62.1	32.4	77.4	340.1	8.1	5.7	525.7	
Jet Fuel				2,459.9		78.5	2,538.4				177.7		5.7	183.3	
Kerosene	88.8	21.0	18.3			3.0	131.1	6.5	1.5	1.3			0.2	9.6	
LPG	468.7	122.4	401.7	15.6		7.3	1,015.8	28.9	7.5	24.8	1.0		0.5	62.6	
Lubricants															
Motor Gasoline				14,979.4		151.4	15,130.8				1,063.0		10.7	1,073.8	
Residual Fuel		137.2	281.7	314.9	628.4	118.0	1,480.1		10.3	21.2	23.6	47.2	8.9	111.1	
Other Petroleum															
AvGas Blend Components			7.0				7.0			0.5				0.5	
Crude Oil			13.7				13.7			1.0				1.0	
MoGas Blend Components															
Misc. Products															
Naphtha (<401 deg. F)															
Other Oil (>401 deg. F)															
Pentanes Plus			38.5				38.5			2.7				2.7	
Petroleum Coke		0.1	629.0		79.6		708.7		0.0	64.2		8.1		72.4	
Still Gas			1,437.1				1,437.1			95.9				95.9	
Special Naphtha															
Unfinished Oils			(112.8)				(112.8)			(8.4)				(8.4)	
Waxes															
Geothermal					48.9		48.9					0.4		0.4	
TOTAL (All Fuels)	6,767.5	4,066.2	14,264.4	23,143.1	23,157.7	445.0	71,843.9	383.0	234.5	897.8	1,647.1	2,021.0	32.5	5,215.9	

^a Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-31), and international bunker fuel consumption (see Table A-32).

^b Consumption and/or emissions of select fuels are shown as negative due to differences in EIA energy balancing accounting. These are designated with parentheses.
NE (Not Estimated)

Table A-25: 1995 Energy Consumption Data and CO₂ Emissions from Fossil Fuel Combustion by Fuel Type

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Fuel Type	Adjusted Consumption (TBTu) ^a							Emissions ^b (Tg CO ₂ Eq.) from Energy Use							
	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	
Total Coal	17.5	116.8	1,526.9	NE	17,466.3	10.2	19,137.7	1.7	11.2	144.4	NE	1,660.7	0.9	1,819.0	
Residential Coal	17.5						17.5	1.7						1.7	
Commercial Coal		116.8					116.8		11.2					11.2	
Industrial Other Coal			1,526.9				1,526.9			144.4				144.4	
Transportation Coal				NE										NE	
Electric Power Coal					17,466.3		17,466.3					1,660.7		1,660.7	
U.S. Territory Coal (bit)						10.2	10.2						0.9	0.9	
Natural Gas	4,954.2	3,096.0	8,736.2	724.0	4,302.0		21,812.3	262.7	164.2	463.3	38.4	228.1		1,156.6	
Total Petroleum	1,260.9	694.0	3,417.3	21,916.2	754.6	461.8	28,504.7	88.3	50.1	255.0	1,569.8	58.7	33.6	2,055.6	
Asphalt & Road Oil															
Aviation Gasoline				39.6			39.6				2.7			2.7	
Distillate Fuel Oil	791.8	419.1	966.7	4,383.3	108.1	89.5	6,758.4	58.6	31.0	71.5	324.2	8.0	6.6	499.8	
Jet Fuel				2,409.8		75.7	2,485.5				170.9		5.4	176.3	
Kerosene	74.3	22.1	15.4			3.6	115.4	5.4	1.6	1.1			0.3	8.4	
LPG	394.8	108.7	403.4	17.7		5.6	930.2	24.4	6.7	24.9	1.1		0.3	57.4	
Lubricants															
Motor Gasoline		2.5	27.2	14,678.5		146.7	14,854.9		0.2	1.9	1,041.8		10.4	1,054.3	
Residual Fuel		141.5	284.7	387.3	566.0	140.7	1,520.1		10.6	21.4	29.1	42.5	10.6	114.2	
Other Petroleum															
AvGas Blend Components			5.3				5.3			0.4				0.4	
Crude Oil			14.5				14.5			1.1				1.1	
MoGas Blend Components															
Misc. Products															
Naphtha (<401 deg. F)															
Other Oil (>401 deg. F)															
Pentanes Plus			34.5				34.5			2.4				2.4	
Petroleum Coke		0.1	609.1		80.6		689.8		0.0	62.2		8.2		70.4	
Still Gas			1,377.3				1,377.3			91.9				91.9	
Special Naphtha															
Unfinished Oils			(320.9)				(320.9)			(23.8)				(23.8)	
Waxes															
Geothermal					45.6		45.6					0.3		0.3	
TOTAL (All Fuels)	6,232.5	3,906.8	13,680.4	22,640.1	22,568.5	472.0	69,500.3	352.7	225.5	862.7	1,608.2	1,947.9	34.5	5,031.5	

^a Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-31), and international bunker fuel consumption (see Table A-32).

^b Consumption and/or emissions of select fuels are shown as negative due to differences in EIA energy balancing accounting. These are designated with parentheses.
NE (Not Estimated)

Table A-26: 1994 Energy Consumption Data and CO₂ Emissions from Fossil Fuel Combustion by Fuel Type

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Adjusted Consumption (TBtu) ^a							Emissions ^b (Tg CO ₂ Eq.) from Energy Use							
Fuel Type	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	
Total Coal	20.8	118.1	1,594.9	NE	17,260.9	10.0	19,004.7	2.0	11.3	150.7	NE	1,638.8	0.9	1,803.7	
Residential Coal	20.8						20.8	2.0						2.0	
Commercial Coal		118.1					118.1		11.3					11.3	
Industrial Other Coal			1,594.9				1,594.9			150.7				150.7	
Transportation Coal				NE										NE	
Electric Power Coal					17,260.9		17,260.9					1,638.8		1,638.8	
U.S. Territory Coal (bit)						10.0	10.0						0.9	0.9	
Natural Gas	4,959.8	2,962.0	8,290.4	708.5	3,977.3		20,898.0	262.9	157.0	439.4	37.6	210.8		1,107.6	
Total Petroleum	1,305.3	745.9	3,631.6	21,379.1	1,058.8	506.3	28,627.0	91.8	54.0	270.3	1,531.3	81.3	36.9	2,065.6	
Asphalt & Road Oil															
Aviation Gasoline				38.1			38.1				2.6			2.6	
Distillate Fuel Oil	856.7	447.1	975.8	4,187.0	120.1	118.8	6,705.5	63.4	33.1	72.2	309.7	8.9	8.8	495.9	
Jet Fuel				2,360.6		65.8	2,426.4				167.5		4.7	172.2	
Kerosene	64.9	19.5	16.9			3.0	104.3	4.8	1.4	1.2			0.2	7.6	
LPG	383.7	107.3	423.1	34.0		7.3	955.3	23.7	6.6	26.1	2.1		0.4	59.0	
Lubricants															
Motor Gasoline				14,401.3		147.4	14,548.7				1,022.5		10.5	1,033.0	
Residual Fuel		171.9	368.4	358.1	869.0	164.1	1,931.5		12.9	27.7	26.9	65.3	12.3	145.0	
Other Petroleum															
AvGas Blend Components			6.1				6.1			0.4				0.4	
Crude Oil			18.7				18.7			1.4				1.4	
MoGas Blend Components															
Misc. Products															
Naphtha (<401 deg. F)															
Other Oil (>401 deg. F)															
Pentanes Plus			80.8				80.8			5.7				5.7	
Petroleum Coke		0.1	607.9		69.7		677.7		0.0	62.1		7.1		69.2	
Still Gas			1,413.2				1,413.2			94.3				94.3	
Special Naphtha															
Unfinished Oils			(279.2)				(279.2)			(20.7)				(20.7)	
Waxes															
Geothermal					53.0		53.0					0.4		0.4	
TOTAL (All Fuels)	6,286.0	3,826.0	13,516.8	22,087.7	22,350.0	516.3	68,582.8	356.7	222.3	860.4	1,568.8	1,931.2	37.8	4,977.4	

^a Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-31), and international bunker fuel consumption (see Table A-32).

^b Consumption and/or emissions of select fuels are shown as negative due to differences in EIA energy balancing accounting. These are designated with parentheses.
NE (Not Estimated)

Table A-27: 1993 Energy Consumption Data and CO₂ Emissions from Fossil Fuel Combustion by Fuel Type

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Fuel Type	Adjusted Consumption (TBTu) ^a							Emissions ^b (Tg CO ₂ Eq.) from Energy Use							
	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	
Total Coal	25.7	117.3	1,585.0	NE	17,195.9	9.6	18,933.5	2.5	11.3	149.8	NE	1,632.5	0.9	1,796.9	
Residential Coal	25.7						25.7	2.5						2.5	
Commercial Coal		117.3					117.3		11.3					11.3	
Industrial Other Coal			1,585.0				1,585.0			149.8				149.8	
Transportation Coal				NE										NE	
Electric Power Coal					17,195.9		17,195.9					1,632.5		1,632.5	
U.S. Territory Coal (bit)						9.6	9.6						0.9	0.9	
Natural Gas	5,063.3	2,923.3	8,281.4	644.7	3,537.5		20,450.1	268.4	155.0	439.0	34.2	187.5		1,084.2	
Total Petroleum	1,348.5	743.4	3,508.4	20,859.5	1,123.8	459.9	28,043.3	94.9	53.8	261.9	1,497.8	86.4	33.6	2,028.4	
Asphalt & Road Oil															
Aviation Gasoline				38.4			38.4				2.7			2.7	
Distillate Fuel Oil	883.3	447.2	990.1	3,889.4	86.5	104.9	6,401.3	65.3	33.1	73.2	287.6	6.4	7.8	473.4	
Jet Fuel				2,306.9		62.1	2,369.0				163.8		4.4	168.3	
Kerosene	75.6	14.0	13.1			3.8	106.5	5.5	1.0	1.0			0.3	7.8	
LPG	389.6	109.2	412.2	20.2		4.9	936.2	24.0	6.7	25.4	1.2		0.3	57.8	
Lubricants															
Motor Gasoline				14,237.0		128.3	14,365.3				1,014.8		9.1	1,023.9	
Residual Fuel		172.7	391.2	367.5	958.6	155.9	2,046.0		13.0	29.4	27.6	72.0	11.7	153.6	
Other Petroleum															
AvGas Blend Components			0.1				0.1			0.0				0.0	
Crude Oil			21.2				21.2			1.6				1.6	
MoGas Blend Components															
Misc. Products															
Naphtha (<401 deg. F)															
Other Oil (>401 deg. F)															
Pentanes Plus			56.4				56.4			3.9				3.9	
Petroleum Coke		0.2	618.4		78.6		697.2		0.0	63.1		8.0		71.2	
Still Gas			1,401.8				1,401.8			93.5				93.5	
Special Naphtha															
Unfinished Oils			(396.0)				(396.0)			(29.3)				(29.3)	
Waxes															
Geothermal					57.3		57.3					0.4		0.4	
TOTAL (All Fuels)	6,437.5	3,783.9	13,374.7	21,504.2	21,914.5	469.5	67,484.3	365.8	220.1	850.6	1,531.9	1,906.9	34.5	4,909.8	

^a Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-31), and international bunker fuel consumption (see Table A-32).

^b Consumption and/or emissions of select fuels are shown as negative due to differences in EIA energy balancing accounting. These are designated with parentheses.
NE (Not Estimated)

Table A-28: 1992 Energy Consumption Data and CO₂ Emissions from Fossil Fuel Combustion by Fuel Type

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Fuel Type	Adjusted Consumption (TBtu) ^a							Emissions ^b (Tg CO ₂ Eq.) from Energy Use							
	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	
Total Coal	25.6	116.6	1,554.1	NE	16,465.6	8.8	18,170.6	2.5	11.3	147.4	NE	1,569.6	0.8	1,731.5	
Residential Coal	25.6						25.6	2.5						2.5	
Commercial Coal		116.6					116.6		11.3					11.3	
Industrial Other Coal			1,554.1				1,554.1			147.4				147.4	
Transportation Coal				NE										NE	
Electric Power Coal					16,465.6		16,465.6					1,569.6		1,569.6	
U.S. Territory Coal (bit)						8.8	8.8						0.8	0.8	
Natural Gas	4,804.6	2,871.2	8,129.3	608.1	3,511.5		19,924.7	254.5	152.1	430.7	32.2	186.0		1,055.6	
Total Petroleum	1,365.8	788.9	3,850.2	20,366.5	990.7	444.9	27,807.1	96.5	57.3	284.9	1,465.0	75.5	32.5	2,011.6	
Asphalt & Road Oil															
Aviation Gasoline				41.1			41.1				2.8			2.8	
Distillate Fuel Oil	931.4	481.7	1,028.5	3,665.7	73.5	91.8	6,272.7	68.9	35.6	76.1	271.1	5.4	6.8	463.9	
Jet Fuel				2,267.7		61.3	2,329.0				161.2		4.4	165.6	
Kerosene	65.0	11.1	9.8			3.3	89.2	4.8	0.8	0.7			0.2	6.5	
LPG	369.4	106.9	441.8	19.4		11.9	949.4	22.8	6.6	27.3	1.2		0.7	58.7	
Lubricants															
Motor Gasoline				13,972.5		122.1	14,094.7				998.6		8.7	1,007.4	
Residual Fuel		189.1	328.1	400.1	872.2	154.6	1,944.0		14.2	24.6	30.0	65.5	11.6	146.0	
Other Petroleum															
AvGas Blend Components			0.2				0.2			0.0				0.0	
Crude Oil			27.4				27.4			2.0				2.0	
MoGas Blend Components			75.7				75.7			5.4				5.4	
Misc. Products															
Naphtha (<401 deg. F)															
Other Oil (>401 deg. F)															
Pentanes Plus			261.0				261.0			18.3				18.3	
Petroleum Coke		0.1	596.9		45.0		642.0		0.0	61.0		4.6		65.6	
Still Gas			1,435.7				1,435.7			95.8				95.8	
Special Naphtha															
Unfinished Oils			(354.8)				(354.8)			(26.3)				(26.3)	
Waxes															
Geothermal					55.1		55.1					0.4		0.4	
TOTAL (All Fuels)	6,196.0	3,776.7	13,533.6	20,974.6	21,022.9	453.7	65,957.5	353.5	220.6	863.0	1,497.3	1,831.5	33.3	4,799.1	

^a Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-31), and international bunker fuel consumption (see Table A-32).

^b Consumption and/or emissions of select fuels are shown as negative due to differences in EIA energy balancing accounting. These are designated with parentheses.
NE (Not Estimated)

Table A-29: 1991 Energy Consumption Data and CO₂ Emissions from Fossil Fuel Combustion by Fuel Type

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Fuel Type	Adjusted Consumption (TBtu)^a							Emissions^b (Tg CO₂ Eq.) from Energy Use							
	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	
Total Coal	25.4	115.5	1,602.2	NE	16,249.7	7.7	18,000.5	2.4	11.1	152.1	NE	1,548.2	0.7	1,714.5	
Residential Coal	25.4						25.4	2.4						2.4	
Commercial Coal		115.5					115.5		11.1					11.1	
Industrial Other Coal			1,602.2				1,602.2			152.1				152.1	
Transportation Coal				NE										NE	
Electric Power Coal					16,249.7		16,249.7					1,548.2		1,548.2	
U.S. Territory Coal (bit)						7.7	7.7						0.7	0.7	
Natural Gas	4,667.2	2,795.4	7,828.1	620.3	3,377.4		19,288.4	247.3	148.1	414.7	32.9	178.9		1,021.9	
Total Petroleum	1,381.5	903.6	3,578.0	19,671.2	1,198.3	425.4	27,158.0	97.5	65.6	265.2	1,411.6	90.7	30.9	1,961.4	
Asphalt & Road Oil															
Aviation Gasoline				41.7			41.7				2.9			2.9	
Distillate Fuel Oil	931.0	517.7	1,050.8	3,449.7	83.6	71.4	6,104.1	68.9	38.3	77.7	255.1	6.2	5.3	451.4	
Jet Fuel				2,329.0			2,407.2				165.7		5.6	171.2	
Kerosene	72.3	12.1	11.4			2.8	98.6	5.3	0.9	0.8			0.2	7.2	
LPG	378.1	108.2	342.2	21.1		13.8	863.5	23.3	6.7	21.1	1.3		0.9	53.3	
Lubricants															
Motor Gasoline		53.7	122.0	13,605.2		124.7	13,905.6		3.8	8.7	969.7		8.9	991.1	
Residual Fuel		211.9	270.9	224.4	1,085.3	134.6	1,927.2		15.9	20.3	16.9	81.5	10.1	144.7	
Other Petroleum															
AvGas Blend Components			(0.1)				(0.1)			(0.0)				(0.0)	
Crude Oil			38.9				38.9			2.9				2.9	
MoGas Blend Components			(25.9)				(25.9)			(1.8)				(1.8)	
Misc. Products															
Naphtha (<401 deg. F)															
Other Oil (>401 deg. F)															
Pentanes Plus			249.2				249.2			17.5				17.5	
Petroleum Coke			564.2		29.3		593.5			57.6		3.0		60.6	
Still Gas			1,404.5				1,404.5			93.7				93.7	
Special Naphtha															
Unfinished Oils			(450.2)				(450.2)			(33.3)				(33.3)	
Waxes															
Geothermal					54.5		54.5					0.4		0.4	
TOTAL (All Fuels)	6,074.0	3,814.5	13,008.3	20,291.5	20,879.8	433.2	64,501.4	347.2	224.8	832.0	1,444.4	1,818.2	31.6	4,698.2	

^a Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-31), and international bunker fuel consumption (see Table A-32).

^b Consumption and/or emissions of select fuels are shown as negative due to differences in EIA energy balancing accounting. These are designated with parentheses.
NE (Not Estimated)

Table A- 30: 1990 Energy Consumption Data and CO₂ Emissions from Fossil Fuel Combustion by Fuel Type

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Fuel Type	Adjusted Consumption (TBtu) ^a							Emissions ^b (Tg CO ₂ Eq.) from Energy Use							
	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	
Total Coal	31.1	124.5	1,640.1	NE	16,261.0	7.0	18,063.6	3.0	12.0	155.3	NE	1,547.6	0.6	1,718.4	
Residential Coal	31.1						31.1	3.0						3.0	
Commercial Coal		124.5					124.5		12.0					12.0	
Industrial Other Coal			1,640.1				1,640.1			155.3				155.3	
Transportation Coal				NE										NE	
Electric Power Coal					16,261.0		16,261.0					1,547.6		1,547.6	
U.S. Territory Coal (bit)						7.0	7.0						0.6	0.6	
Natural Gas	4,490.9	2,682.2	7,720.8	679.9	3,308.5		18,882.3	238.0	142.1	409.1	36.0	175.3		1,000.6	
Total Petroleum	1,375.2	891.4	3,810.9	20,213.2	1,289.4	374.8	27,955.0	97.4	64.9	282.1	1,449.9	97.5	27.2	2,019.0	
Asphalt & Road Oil															
Aviation Gasoline				45.0			45.0				3.1			3.1	
Distillate Fuel Oil	959.2	525.4	1,098.5	3,554.8	96.5	74.0	6,308.4	70.9	38.9	81.2	262.9	7.1	5.5	466.5	
Jet Fuel				2,477.2		61.0	2,538.2				176.2		4.3	180.5	
Kerosene	63.9	11.8	12.3			2.6	90.6	4.7	0.9	0.9			0.2	6.6	
LPG	352.1	102.3	380.2	22.9		14.4	871.9	21.8	6.3	23.5	1.4		0.9	53.9	
Lubricants															
Motor Gasoline		22.1	36.8	13,813.0		101.0	13,972.8		1.6	2.6	983.7		7.2	995.1	
Residual Fuel		229.8	364.1	300.3	1,162.6	121.8	2,178.7		17.3	27.3	22.6	87.3	9.2	163.6	
Other Petroleum															
AvGas Blend Components			0.2				0.2			0.0				0.0	
Crude Oil			50.9				50.9			3.8				3.8	
MoGas Blend Components			53.7				53.7			3.8				3.8	
Misc. Products															
Naphtha (<401 deg. F)															
Other Oil (>401 deg. F)															
Pentanes Plus			167.8				167.8			11.7				11.7	
Petroleum Coke			563.5		30.4		593.9			57.5		3.1		60.6	
Still Gas			1,451.9				1,451.9			96.9				96.9	
Special Naphtha															
Unfinished Oils			(369.0)				(369.0)			(27.3)				(27.3)	
Waxes															
Geothermal					52.7		52.7					0.4		0.4	
TOTAL (All Fuels)	5,897.2	3,698.1	13,171.7	20,893.1	20,911.6	381.9	64,953.5	338.3	219.0	846.5	1,485.9	1,820.8	27.9	4,738.4	

^a Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-31), and international bunker fuel consumption (see Table A-32).

^b Consumption and/or emissions of select fuels are shown as negative due to differences in EIA energy balancing accounting. These are designated with parentheses.
NE (Not Estimated)

Table A-31: Unadjusted Non-Energy Fuel Consumption (TBtu)

Sector/Fuel Type	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Industry	4,509.4	5,194.9	5,270.5	5,493.3	5,723.5	5,981.5	5,607.6	5,266.7	5,350.5	5,308.0	5,845.9	5,532.4	5,510.7	5,324.7	4,855.6	4,486.3
Industrial Coking Coal	+	37.2	23.5	0.0	10.4	39.5	53.0	24.3	39.8	51.2	167.1	79.8	62.3	1.7	28.4	6.1
Industrial Other Coal	8.2	11.3	11.4	11.2	10.4	11.1	12.4	11.3	12.0	11.9	11.9	11.9	12.4	12.4	12.4	12.4
Natural Gas to Chemical Plants, Other Uses	301.7	357.2	360.3	386.7	426.6	436.6	438.4	407.7	380.7	384.4	403.8	411.3	416.8	432.1	406.0	388.4
Asphalt & Road Oil	1,170.2	1,178.2	1,175.9	1,223.6	1,262.6	1,324.4	1,275.7	1,256.9	1,240.0	1,219.5	1,303.8	1,323.2	1,261.2	1,197.0	1,012.0	873.1
LPG	1,201.4	1,586.9	1,652.0	1,670.4	1,744.4	1,820.7	1,665.4	1,553.4	1,620.3	1,545.1	1,576.4	1,488.1	1,516.8	1,542.2	1,442.1	1,520.5
Lubricants	186.3	177.8	172.5	182.3	190.8	192.8	189.9	174.0	171.9	159.0	161.0	160.2	156.1	161.2	149.6	134.5
Pentanes Plus	82.6	303.4	316.5	298.9	204.3	261.4	236.7	201.6	171.4	169.1	170.4	150.3	107.3	137.4	117.2	97.7
Naphtha (<401 deg. F)	347.8	373.0	479.3	536.4	584.0	502.1	613.5	493.7	582.6	613.0	749.4	698.7	628.9	562.5	477.2	471.9
Other Oil (>401 deg. F)	753.9	801.0	729.6	861.3	818.7	811.1	722.2	662.4	632.1	699.4	779.5	708.0	790.6	744.1	647.8	424.8
Still Gas	21.3	40.1	0.0	2.1	0.0	16.1	12.6	35.8	57.8	59.0	62.9	67.7	57.2	44.2	47.3	133.9
Petroleum Coke	150.7	112.2	127.8	96.3	191.0	259.3	126.6	194.2	161.4	145.8	249.7	210.5	251.5	239.2	252.1	195.4
Special Naphtha	107.1	70.8	74.5	72.3	107.3	145.4	97.4	78.5	102.4	80.5	51.0	62.5	70.1	78.0	84.9	46.2
Other (Wax/Misc.)																
Distillate Fuel Oil	7.0	8.0	9.2	10.4	11.7	11.7	11.7	11.7	11.7	13.1	14.6	16.0	17.5	17.5	17.5	17.5
Waxes	33.3	40.6	48.7	43.7	42.4	37.4	33.1	36.3	32.2	31.0	30.8	31.4	26.1	21.9	19.1	12.2
Miscellaneous Products	137.8	97.1	89.0	97.8	119.0	111.9	119.2	124.9	134.2	126.0	113.4	112.8	136.0	133.5	142.0	151.8
Transportation	176.0	167.9	163.0	172.1	180.2	182.1	179.4	164.3	162.4	150.1	152.1	151.3	147.4	152.2	141.3	127.1
Lubricants	176.0	167.9	163.0	172.1	180.2	182.1	179.4	164.3	162.4	150.1	152.1	151.3	147.4	152.2	141.3	127.1
U.S. Territories	86.7	90.8	121.7	131.6	135.0	139.3	152.2	80.3	140.2	123.5	110.8	121.9	133.4	108.4	126.7	56.3
Lubricants	0.7	2.0	1.5	2.5	1.3	1.4	3.1	0.0	3.0	4.9	5.1	4.6	6.2	5.9	2.7	1.0
Other Petroleum (Misc. Prod.)	86.0	88.8	120.2	129.1	133.8	138.0	149.1	80.3	137.2	118.6	105.7	117.3	127.2	102.5	124.1	55.2
Total	4,772.1	5,453.6	5,555.1	5,797.0	6,038.7	6,302.9	5,939.1	5,511.3	5,653.0	5,581.6	6,108.7	5,805.7	5,791.5	5,585.4	5,123.6	4,669.7

Note: These values are unadjusted non-energy fuel use provided by EIA. They have not yet been adjusted to remove petroleum feedstock exports and processes accounted for in the Industrial Processes Chapter.

+ Does not exceed 0.05 TBtu.

Table A-32: International Bunker Fuel Consumption (TBtu)

Fuel Type	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Marine Residual Fuel Oil	715.7	523.2	536.4	575.2	594.8	489.7	444.1	426.0	448.9	471.8	553.1	581.0	599.4	607.5	654.6	604.8
Marine Distillate Fuel Oil & Other	158.0	125.7	114.1	125.5	158.8	113.6	85.9	72.4	82.6	103.9	143.6	126.9	119.3	111.3	122.2	112.3
Aviation Jet Fuel	652.3	722.4	814.3	798.7	872.9	784.3	813.9	820.8	891.9	784.6	857.6	785.6	1,032.3	1,021.3	1,045.5	961.0
Total	1,526.0	1,371.4	1,464.8	1,499.4	1,626.5	1,387.6	1,343.9	1,319.3	1,423.3	1,360.3	1,554.2	1,493.5	1,750.9	1,740.2	1,822.3	1,678.1

Table A- 33: Key Assumptions for Estimating CO₂ Emissions

Fuel Type	C Content Coefficient (Tg C/QBtu)
Coal	
Residential Coal	[a]
Commercial Coal	[a]
Industrial Coking Coal	[a]
Industrial Other Coal	[a]
Electric Power Coal	[a]
U.S. Territory Coal (bit)	25.14
Pipeline Natural Gas	[a]
Flare Gas ^a	15.31
Petroleum	
Asphalt & Road Oil	20.55
Aviation Gasoline	18.86
Distillate Fuel Oil No. 1	19.98
Distillate Fuel Oil No. 2 ^b	20.17
Distillate Fuel Oil No. 4	20.47
Jet Fuel	[a]
Kerosene	19.96
LPG (energy use)	[a]
LPG (non-energy use)	[a]
Lubricants	20.20
Motor Gasoline	[a]
Residual Fuel Oil No. 5	19.89
Residual Fuel Oil No. 6 ^b	20.48
Other Petroleum	
AvGas Blend Components	18.87
Crude Oil	[a]
MoGas Blend Components	[a]
Misc. Products	[a]
Misc. Products (Territories)	[a]
Naphtha (<401 deg. F)	18.55
Other Oil (>401 deg. F)	20.17
Pentanes Plus	19.10
Petroleum Coke	27.85
Still Gas	18.20
Special Naphtha	19.74
Unfinished Oils	[a]
Waxes	19.80
Geothermal	2.05

^a Flare gas is not used in the CO₂ from fossil fuel combustion calculations and is presented for informational purposes only.

^b Distillate fuel oil No.2 and residual fuel oil No. 6 are used in the CO₂ from fossil fuel combustion calculations, and other oil types are presented for informational purposes only. An additional discussion on the derivation of these carbon content coefficients is presented in Annex 2.2.

Sources: C coefficients from EIA (2009b) and EPA 2010a.

[a] These coefficients vary annually due to fluctuations in fuel quality (see Table A- 34)

Table A- 34: Annually Variable C Content Coefficients by Year (Tg C/QBtu)

Fuel Type	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Residential Coal	26.20	26.13	26.04	25.90	26.07	25.98	26.01	26.00	25.98	26.04	25.91	26.09	26.29	25.94	25.71*	25.71*
Commercial Coal	26.20	26.13	26.04	25.90	26.07	25.98	26.01	26.00	25.98	26.04	25.91	26.09	26.29	25.94	25.71	25.71
Industrial Coking Coal	25.53	25.57	25.56	25.59	25.62	25.59	25.63	25.63	25.65	25.63	25.63	25.60	25.60	25.61	25.61	25.61
Industrial Other Coal	25.82	25.80	25.75	25.75	25.79	25.80	25.74	25.66	25.57	25.55	25.56	25.80	25.84	25.82	25.82	25.82
Electric Power Coal	25.96	25.93	25.93	25.93	25.95	25.98	26.00	26.00	26.05	26.09	26.10	26.09	26.04	26.05	26.05	26.05
Pipeline Natural Gas	14.45	14.46	14.46	14.46	14.44	14.46	14.47	14.46	14.46	14.44	14.46	14.46	14.46	14.46	14.46	14.46
LPG (energy use)	16.86	16.82	16.82	16.84	16.81	16.86	16.89	16.87	16.85	16.86	16.84	16.84	16.83	16.82	16.83	16.83
LPG (non-energy use)	17.06	17.09	17.10	17.08	17.08	17.07	17.09	17.10	17.09	17.09	17.07	17.06	17.06	17.05	17.06	17.06
Motor Gasoline	19.42	19.36	19.35	19.36	19.37	19.32	19.33	19.34	19.38	19.36	19.38	19.36	19.45	19.56	19.46	19.46
Jet Fuel	19.40	19.34	19.70	19.70	19.70	19.70	19.70	19.70	19.70	19.70	19.70	19.70	19.70	19.70	19.70	19.70
MoGas Blend																
Components	19.42	19.36	19.35	19.36	19.37	19.32	19.33	19.34	19.38	19.36	19.38	19.36	19.45	19.56	19.46	19.46
Misc. Products	20.15	20.21	20.23	20.22	20.22	20.17	20.22	20.27	20.28	20.25	20.31	20.31	20.28	20.28	20.31	20.31
Unfinished Oils	20.15	20.21	20.23	20.22	20.22	20.17	20.22	20.27	20.28	20.25	20.31	20.31	20.28	20.28	20.31	20.31
Crude Oil	20.15	20.21	20.23	20.22	20.22	20.17	20.22	20.27	20.28	20.25	20.31	20.31	20.28	20.28	20.31	20.31

*U.S. EIA discontinued collection of residential sector coal consumption data in 2008, because consumption of coal in the residential sector is extremely limited. Therefore, the number cited here is developed from commercial/institutional consumption.

Source: EPA (2010a)

Table A-35: Electricity Consumption by End-Use Sector (Billion Kilowatt-Hours)

End-Use Sector	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Residential	924	1,043	1,083	1,076	1,130	1,145	1,192	1,202	1,265	1,276	1,292	1,359	1,352	1,392	1,380	1,363
Commercial	838	953	980	1,027	1,078	1,104	1,159	1,191	1,205	1,199	1,230	1,275	1,300	1,336	1,336	1,323
Industrial	1,070	1,163	1,186	1,194	1,212	1,230	1,235	1,159	1,156	1,181	1,186	1,169	1,158	1,187	1,183	1,048
Transportation	5	5	5	5	5	5	5	6	6	7	7	8	7	8	8	8
Total	2,837	3,164	3,254	3,302	3,425	3,484	3,592	3,557	3,632	3,662	3,716	3,811	3,817	3,924	3,906	3,741

Note: Does not include the U.S. territories.

Source: EIA (2010b)

2.2. Methodology for Estimating the Carbon Content of Fossil Fuels

This sub-annex presents the background and methodology for estimating the carbon (C) content of fossil fuels combusted in the United States. The C content of a particular fossil fuel represents the maximum potential emissions to the atmosphere if all C in the fuel is oxidized during combustion. The C content coefficients used in past editions of this report were developed using methods first outlined in the U.S. Energy Information Administration's (EIA) *Emissions of Greenhouse Gases in the United States: 1987-1992* (1994) and were developed primarily by EIA. For this report, EPA has updated many of the C content coefficients based on carbon dioxide emission factors developed for the Mandatory Reporting of Greenhouse Gases Rule, signed in September 2009 (EPA, 2009b, 2010). This sub-annex describes an updated methodology for estimating the C content of natural gas, and presents a time-series analysis of changes in U.S. C content coefficients for coal, petroleum products and natural gas. A summary of C content coefficients used in this report appears in Table A- 36.

Though the methods for estimating C contents for coal, natural gas, and petroleum products differ in their details, they each follow the same basic approach. First, because C coefficients are presented in terms of mass per unit energy (i.e., teragrams C per quadrillion Btu or Tg C/QBtu), those fuels that are typically described in volumetric units (petroleum products and natural gas) are converted to units of mass using an estimated density. Second, C contents are derived from fuel sample data, using descriptive statistics to estimate the C share of the fuel by weight. The heat content of the fuel is then estimated based on the sample data, or where sample data are unavailable or unrepresentative, by default values that reflect the characteristics of the fuel as defined by market requirements. A discussion of each fuel appears below.

The C content of coal is described first because approximately one-third of all U.S. C emissions from fossil fuel combustion are associated with coal consumption. The methods and sources for estimating the C content of natural gas are provided next. Approximately one-fifth of U.S. greenhouse gas emissions from fossil fuel combustion are attributable to natural gas consumption. Finally, this sub-annex examines C contents of petroleum products. U.S. energy consumption statistics account for more than 20 different petroleum products.

Table A- 36: Carbon Content Coefficients Used in this Report (Tg Carbon/QBtu)

Fuel Type	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Coal																
Residential Coal ^a	26.20	26.13	26.04	25.90	26.07	25.98	26.01	26.00	25.98	26.04	25.91	26.09	26.29	25.94	25.71*	25.71*
Commercial Coal ^a	26.20	26.13	26.04	25.90	26.07	25.98	26.01	26.00	25.98	26.04	25.91	26.09	26.29	25.94	25.71	25.71
Industrial Coking Coal ^a	25.53	25.57	25.56	25.59	25.62	25.59	25.63	25.63	25.65	25.63	25.63	25.60	25.60	25.61	25.61	25.61
Industrial Other Coal ^a	25.82	25.80	25.75	25.75	25.79	25.80	25.74	25.66	25.57	25.55	25.56	25.80	25.84	25.82	25.82	25.82
Utility Coal ^{a,b}	25.96	25.93	25.93	25.93	25.95	25.98	26.00	26.00	26.05	26.09	26.10	26.09	26.04	26.05	26.05	26.05
Pipeline Natural Gas^c	14.45	14.46	14.46	14.46	14.44	14.46	14.47	14.46	14.46	14.44	14.46	14.46	14.46	14.46	14.46	14.46
Flare Gas	15.31	15.31	15.31	15.31	15.31	15.31	15.31	15.31	15.31	15.31	15.31	15.31	15.31	15.31	15.31	15.31
Petroleum																
Asphalt and Road Oil	20.55	20.55	20.55	20.55	20.55	20.55	20.55	20.55	20.55	20.55	20.55	20.55	20.55	20.55	20.55	20.55
Aviation Gasoline	18.86	18.86	18.86	18.86	18.86	18.86	18.86	18.86	18.86	18.86	18.86	18.86	18.86	18.86	18.86	18.86
Distillate Fuel Oil No. 1	19.98	19.98	19.98	19.98	19.98	19.98	19.98	19.98	19.98	19.98	19.98	19.98	19.98	19.98	19.98	19.98
Distillate Fuel Oil No. 2	20.17	20.17	20.17	20.17	20.17	20.17	20.17	20.17	20.17	20.17	20.17	20.17	20.17	20.17	20.17	20.17
Distillate Fuel Oil No. 4	20.47	20.47	20.47	20.47	20.47	20.47	20.47	20.47	20.47	20.47	20.47	20.47	20.47	20.47	20.47	20.47
Jet Fuel ^a	19.73	19.70	19.70	19.70	19.70	19.70	19.70	19.70	19.70	19.70	19.70	19.70	19.70	19.70	19.70	19.70
Kerosene	19.96	19.96	19.96	19.96	19.96	19.96	19.96	19.96	19.96	19.96	19.96	19.96	19.96	19.96	19.96	19.96
LPG (energy use) ^c	16.86	16.82	16.82	16.84	16.81	16.86	16.89	16.87	16.85	16.86	16.84	16.84	16.83	16.82	16.83	16.83
LPG (non-energy use) ^c	17.06	17.09	17.10	17.08	17.08	17.07	17.09	17.10	17.09	17.07	17.06	17.06	17.05	17.06	17.06	17.06
Lubricants	20.20	20.20	20.20	20.20	20.20	20.20	20.20	20.20	20.20	20.20	20.20	20.20	20.20	20.20	20.20	20.20
Motor Gasoline ^c	19.42	19.36	19.35	19.36	19.37	19.32	19.33	19.34	19.38	19.36	19.38	19.36	19.45	19.56	19.46	19.46
Residual Fuel No. 5	19.89	19.89	19.89	19.89	19.89	19.89	19.89	19.89	19.89	19.89	19.89	19.89	19.89	19.89	19.89	19.89
Residual Fuel No. 6	20.48	20.48	20.48	20.48	20.48	20.48	20.48	20.48	20.48	20.48	20.48	20.48	20.48	20.48	20.48	20.48
Other Petroleum																
Av Gas Blend Comp.	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87
Mo Gas Blend Comp ^c	19.42	19.36	19.35	19.36	19.37	19.32	19.33	19.34	19.38	19.36	19.38	19.36	19.45	19.56	19.46	19.46
Crude Oil ^c	20.15	20.21	20.23	20.22	20.22	20.17	20.22	20.27	20.28	20.25	20.31	20.31	20.28	20.28	20.31	20.31
Misc. Products ^c	20.15	20.21	20.23	20.22	20.22	20.17	20.22	20.27	20.28	20.25	20.31	20.31	20.28	20.28	20.31	20.31
Misc. Products (Terr.)	20.15	20.21	20.23	20.22	20.22	20.17	20.22	20.27	20.28	20.25	20.31	20.31	20.28	20.28	20.31	20.31
Naphtha (<401 deg. F)	18.55	18.55	18.55	18.55	18.55	18.55	18.55	18.55	18.55	18.55	18.55	18.55	18.55	18.55	18.55	18.55
Other oil (>401 deg. F)	20.17	20.17	20.17	20.17	20.17	20.17	20.17	20.17	20.17	20.17	20.17	20.17	20.17	20.17	20.17	20.17
Pentanes Plus	19.10	19.10	19.10	19.10	19.10	19.10	19.10	19.10	19.10	19.10	19.10	19.10	19.10	19.10	19.10	19.10
Petroleum Coke	27.85	27.85	27.85	27.85	27.85	27.85	27.85	27.85	27.85	27.85	27.85	27.85	27.85	27.85	27.85	27.85
Still Gas	18.20	18.20	18.20	18.20	18.20	18.20	18.20	18.20	18.20	18.20	18.20	18.20	18.20	18.20	18.20	18.20
Special Naphtha	19.74	19.74	19.74	19.74	19.74	19.74	19.74	19.74	19.74	19.74	19.74	19.74	19.74	19.74	19.74	19.74
Unfinished Oils ^c	20.15	20.21	20.23	20.22	20.22	20.17	20.22	20.27	20.28	20.25	20.31	20.31	20.28	20.28	20.31	20.31
Waxes	19.80	19.80	19.80	19.80	19.80	19.80	19.80	19.80	19.80	19.80	19.80	19.80	19.80	19.80	19.80	19.80
Other Wax and Misc.	19.80	19.80	19.80	19.80	19.80	19.80	19.80	19.80	19.80	19.80	19.80	19.80	19.80	19.80	19.80	19.80
Geothermal	2.05	2.05	2.05	2.05	2.05	2.05	2.05	2.05	2.05	2.05	2.05	2.05	2.05	2.05	2.05	2.05

*U.S. EIA discontinued collection of residential sector coal consumption data in 2008, because consumption of coal in the residential sector is extremely limited. Therefore, the number cited here is developed from commercial/institutional consumption.

^aC contents vary annually based on changes in annual mix of production and end-use consumption of coal from each producing state.

^bC content for utility coal used in the electric power calculations. All coefficients based on higher heating value. Higher heating value (gross heating value) is the total amount of heat released when a fuel is burned. Coal, crude oil, and natural gas all include chemical compounds of carbon and hydrogen. When those fuels are burned, the carbon and hydrogen combine with oxygen in the air to produce CO₂ and water. Some of the energy released in burning goes into transforming the water into steam and is usually lost. The amount of heat spent in transforming the water into steam is counted as part of

gross heat content. Lower heating value (net heating value), in contrast, does not include the heat spent in transforming the water into steam. Using a simplified methodology based on International Energy Agency defaults, higher heating value can be converted to lower heating value for coal and petroleum products by multiplying by 0.95 and for natural gas by multiplying by 0.90. Carbon content coefficients are presented in higher heating value because U.S. energy statistics are reported by higher heating value.

^aC contents vary annually based on changes in fuel composition.

Coal

Approximately one-third of all U.S. CO₂ emissions from fossil fuel combustion are associated with coal consumption. Although the IPCC guidelines provide C contents for coal according to rank, it was necessary to develop C content coefficients by consuming sector to match the format in which coal consumption is reported by EIA. Because the C content of coal varies by the state in which it was mined and by coal rank, and because the sources of coal for each consuming sector vary by year, the weighted average C content for coal combusted in each consuming sector also varies over time. A time series of C contents by coal rank and consuming sector appears in Table A- 37.⁶

Methodology

The methodology for developing C contents for coal by consuming sector consists of four steps. An additional step has been taken to calculate C contents by coal rank to facilitate comparison with IPCC default values.

Step 1. Determine carbon contents by rank and by state of origin

C contents by rank and state of origin are estimated on the basis of 7,092 coal samples, 6,588 of which were collected by the U.S. Geological Survey (USGS 1998) and 504 samples that come from the Pennsylvania State University database (PSU 2010). These coal samples are classified according to rank and state of origin. For each rank in each state, the average heat content and C content of the coal samples are calculated based on the proximate (heat) and ultimate (percent carbon) analyses of the samples. Dividing the C content (reported in pounds CO₂) by the heat content (reported in million Btu or MMBtu) yields an average C content coefficient. This coefficient is then converted into units of Tg C/QBtu.

Step 2. Determine weighted average carbon content by state

C contents by rank and origin calculated in Step 1 are then weighted by the annual share of state production that was each rank. State production by rank is obtained from the EIA. This step yields a single carbon content per state that varies annually based on production. However, most coal-producing states produce only one rank of coal. For these states the weighted factor equals the carbon content calculated in Step 1 and is constant across the time series.

Step 3. Allocate sectoral consumption by state of origin

U.S. energy statistics⁷ through 2007 provide data on the origin of coal used in four areas: 1) the electric power industry, 2) industrial coking, 3) all other industrial uses, and 4) the residential and commercial end-use sectors.⁸ Because U.S. energy statistics do not provide the distribution of coal rank consumed by each consuming sector, it is assumed that each sector consumes a representative mixture of coal ranks from a particular state that matches the mixture of all coal produced in that state during the year. Thus, the weighted state-level factor developed in Step 2 is applied.

Step 4. Weight sectoral carbon contents to reflect the rank and state of origin of coal consumed

Sectoral C contents are calculated by multiplying the share of coal purchased from each state by the state's weighted C content estimated in Step 2. The resulting partial C contents are then totaled across all states to generate a national sectoral C content.

$$C_{\text{sector}} = S_{\text{state1}} \times C_{\text{state1}} + S_{\text{state2}} \times C_{\text{state2}} + \dots + S_{\text{state50}} \times C_{\text{state50}}$$

Where,

C_{sector} = The C content by consuming sector;

⁶ For a comparison to earlier estimated carbon contents please see *Chronology and Explanation of Changes in Individual Carbon Content Coefficients of Fossil Fuels* near the end of this annex.

⁷ U.S. Energy Information Administration (EIA). *Coal Distribution – Annual* (2001-2008); and *Coal Industry Annual* (1990-2000).

⁸ Beginning in 2008, the EIA collects and reports data on commercial and institutional coal consumption, rather than residential and commercial consumption. Thus, the residential / commercial coal coefficient reported in Table A- 36 for 2009 represents the mix of coal consumed by commercial and institutional users. Currently, only an extremely small amount of coal is consumed in the U.S. Residential Sector.

S_{state} = The portion of consuming sector coal consumption attributed to production from a given state;
 C_{state} = The estimated weighted C content of all ranks produced in a given state.

Table A- 37: Carbon Content Coefficients for Coal by Consuming Sector and Coal Rank (Tg C/QBtu) (1990-2009)

Consuming Sector	1990		1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Electric Power	25.96		25.93	25.93	25.93	25.95	25.98	26.00	26.00	26.05	26.09	26.10	26.09	26.04	26.05	26.05	26.05
Industrial Coking	25.53		25.57	25.56	25.59	25.62	25.59	25.63	25.63	25.65	25.63	25.63	25.60	25.60	25.61	25.61	25.61
Other Industrial	25.82		25.80	25.75	25.75	25.79	25.80	25.74	25.66	25.57	25.55	25.56	25.80	25.84	25.82	25.82	25.82
Residential/ Commercial	26.20		26.13	26.04	25.90	26.07	25.98	26.01	26.00	25.98	26.04	25.91	26.09	26.29	25.94	25.71	25.71
Coal Rank																	
Anthracite	28.28		28.28	28.28	28.28	28.28	28.28	28.28	28.28	28.28	28.28	28.28	28.28	28.28	28.28	28.28	28.28
Bituminous	25.38		25.42	25.43	25.43	25.43	25.44	25.45	25.46	25.46	25.45	25.45	25.45	25.45	25.45	25.44	25.44
Sub-bituminous	26.50		26.50	26.50	26.50	26.50	26.50	26.49	26.50	26.50	26.50	26.50	26.50	26.50	26.50	26.50	26.50
Lignite	26.58		26.59	26.58	26.59	26.59	26.60	26.61	26.62	26.63	26.62	26.62	26.62	26.62	26.64	26.65	26.65

^a In 2008, the EIA began collecting consumption data for commercial and institutional consumption rather than commercial and residential consumption.

Sources: C content coefficients calculated from USGS (1998) and PSU (2010); data presented in EPA (2010b).

Step 5. Develop national-level carbon contents by rank for comparison to IPCC defaults

Although not used to calculate emissions, national-level C contents by rank are more easily compared to C contents of other countries than are sectoral C contents. This step requires weighting the state-level C contents by rank developed under Step 1 by overall coal production by state and rank. Each state-level C content by rank is multiplied by the share of national production of that rank that each state represents. The resulting partial C contents are then summed across all states to generate an overall C content for each rank.

$$N_{\text{rank}} = P_{\text{rank1}} \times C_{\text{rank1}} + P_{\text{rank2}} \times C_{\text{rank2}} + \dots + P_{\text{rankn}} \times C_{\text{rankn}}$$

Where,

N_{rank} = The national C content by rank;

P_{rank} = The portion of U.S. coal production of a given rank attributed to each state; and

C_{rank} = The estimated C content of a given rank in each state.

Data Sources

The ultimate analysis of coal samples was based on the 7,092 coal samples, 6,588 of which are from USGS (1998) and 504 that come from the Pennsylvania State University Coal Database (PSU 2010). Data contained in the USGS's CoalQual Database are derived primarily from samples taken between 1973 and 1989, and were largely reported in State Geological Surveys. Data in the PSU Coal Database are mainly from samples collected by PSU since 1967 and are housed at the PSU Sample Bank. Only the subset of PSU samples that are whole-seam channel samples are included in the development of carbon factors in order to increase data accuracy.

Data on coal consumption by sector and state of origin, as well as coal production by state and rank, were obtained from EIA. The EIA's *Annual Coal Report* is the source for state coal production by rank from 2001-2008. In prior years, the EIA reported this data in its *Coal Industry Annual*. Data for coal consumption by state of origin and consuming sector for 2001 to 2008 was obtained from the EIA's *Coal Distribution – Annual*. For 1990-2000, end-use data was obtained from the *Coal Industry Annual*.

Uncertainty

C contents vary considerably by state. Bituminous coal production and sub-bituminous coal production represented 47.3 percent and 46.1 percent of total U.S. supply in 2008, respectively. State average C content coefficients for bituminous coal vary from a low of 85.59 kg CO₂ per MMBtu in Texas to a high of 105.21 kg CO₂ per MMBtu in Montana. However, Texas bituminous coal is considered anomalous,⁹ has not been produced since 2004 and production since 1990 peaked at just 446,000 short tons in 1996. The next lowest average emission factor for bituminous coal is found in Western Kentucky (91.36 kg CO₂ per MMBtu). In 2000, Montana produced no bituminous coal and Western Kentucky production accounted for just 4.5 percent of overall bituminous production. In 2008, more than 60 percent of bituminous coal was produced in three states: West Virginia, Kentucky (predominantly from the Eastern production region), and Pennsylvania, and this share has remained fairly constant since 1990. These three states show a variation in C content for bituminous coals of ±0.7 percent, based on more than 2,000 samples (see Table A-38).

Similarly, the C content coefficients for sub-bituminous coal range from 91.29 kg CO₂ per MMBtu in Utah to 98.10 kg CO₂ per MMBtu in Alaska. However, Utah has no recorded production of sub-bituminous coal since 1990. Production of sub-bituminous coal in Alaska has made up less than 0.7 percent of total sub-bituminous production since 1990, with even this small share declining over time. Wyoming has represented between 75 percent and 87 percent of total sub-bituminous coal production in the United States in each year since 1990. Thus, the C content coefficient for Wyoming (97.22 kg CO₂ per MMBtu), based on 455 samples, dominates the national average.

The interquartile range of C content coefficients among samples of sub-bituminous coal in Wyoming was ±1.5 percent from the mean. Similarly, this range among samples of bituminous coal from West Virginia, Kentucky, and Pennsylvania was ±1.2 percent or less for each state. The large number of samples and the low variability within the sample set of the states that represent the predominant source of supply of U.S. coal suggest that the uncertainty in this factor is very low, on the order of ±1.0 percent.

⁹ See, for example: San Filippo, 1999. USGS. (U.S. Geological Survey Open-File Report 99-301), Ch. 4.

For comparison, J. Quick (2010) completed an analysis similar in methodology to that used here, in order to generate national average carbon emission factors as well as county-level factors. This study's rank-based national average factors have a maximum deviation from the factors developed here by EPA of -0.55 percent, which is for lignite (range: -0.55 to +0.1 percent). This corroboration further supports the assertion of minimal uncertainty in the application of the rank-based factors derived for the purposes of this Inventory.

Table A-38: Variability in Carbon Content Coefficients by Rank Across States (Kilograms CO₂ Per MMBtu)

State	Number of Samples	Bituminous	Sub-bituminous	Anthracite	Lignite
Alabama	951	92.84	-	-	99.10
Alaska	91	98.33	98.10	-	98.65
Arizona	15	93.94	97.34	-	-
Arkansas	80	96.36	-	-	94.97
Colorado	318	94.37	96.52	-	101.10
Georgia	35	95.01	-	-	-
Idaho	1	-	94.90	-	-
Illinois	57	92.33	-	-	-
Indiana	146	92.65	-	-	-
Iowa	100	91.87	-	-	-
Kansas	29	90.91	-	-	-
Kentucky	897	92.61	-	-	-
Louisiana	1	-	-	-	96.01
Maryland	47	94.29	-	-	-
Massachusetts	3	-	-	114.82	-
Michigan	3	92.88	-	-	-
Mississippi	8	-	-	-	98.19
Missouri	111	91.71	-	-	-
Montana	309	105.21	97.73	103.60	99.40
Nevada	2	94.41	-	-	99.86
New Mexico	185	94.29	94.89	103.92	-
North Dakota	202	-	93.97	-	99.48
Ohio	674	91.84	-	-	-
Oklahoma	63	92.33	-	-	-
Pennsylvania	861	93.33	-	103.68	-
Tennessee	61	92.82	-	-	-
Texas	64	85.59	94.19	-	94.47
Utah	169	95.75	91.29	-	-
Virginia	470	93.51	-	98.54	-
Washington	18	94.53	97.36	102.53	106.55
West Virginia	612	93.84	-	-	-
Wyoming	503	94.80	97.22	-	-
U.S. Average	7,092	93.13	96.94	104.29	98.63

Notes: - Indicates No Sample Data Available.

Sources: Calculated from USGS (1998), and PSU (2010); data presented in EPA (2010).

Natural Gas

Natural gas is predominantly composed of methane, which is 75 percent C by weight and contains 14.2 Tg C/QBtu (higher heating value), but it may also contain many other compounds that can lower or raise its overall C content. These other compounds may be divided into two classes: 1) natural gas liquids (NGLs), and 2) non-hydrocarbon gases. The most common NGLs are ethane (C₂H₆), propane (C₃H₈), butane (C₄H₁₀), and, to a lesser extent, pentane (C₅H₁₂) and hexane (C₆H₁₄). Because the NGLs have more C atoms than methane (which has only one), their presence increases the overall C content of natural gas. NGLs have a commercial value greater than that of methane, and therefore are usually separated from raw natural gas at gas processing plants and sold as separate products. Ethane is typically used as a petrochemical feedstock, propane and butane have diverse uses, and natural gasoline¹⁰ contributes to the gasoline/naphtha "octane pool," used primarily to make motor gasoline.

¹⁰ A term used in the gas processing industry to refer to a mixture of liquid hydrocarbons (mostly pentanes and heavier hydrocarbons) extracted from natural gas.

Raw natural gas can also contain varying amounts of non-hydrocarbon gases, such as CO₂, nitrogen, helium and other noble gases, and hydrogen sulfide. The share of non-hydrocarbon gases is usually less than 5 percent of the total, but there are individual natural gas reservoirs where the share can be much larger. The treatment of non-hydrocarbon gases in raw gas varies. Hydrogen sulfide is always removed. Inert gases are removed if their presence is substantial enough to reduce the energy content of the gas below pipeline specifications (see Step 1, below). Otherwise, inert gases will usually be left in the natural gas. Because the raw gas that is usually flared (see Step 2, below) contains NGLs and CO₂, it will typically have a higher overall C content than gas that has been processed and moved to end-use customers via transmission and distribution pipelines.

Methodology

The methodology for estimating the C contents of pipeline and flared natural gas can be described in five steps.

Step 1. Define pipeline-quality natural gas

In the United States, pipeline-quality natural gas is required to have an energy content greater than 970 Btu per cubic foot, but less than 1,100 Btu per cubic foot. Hydrogen sulfide content must be negligible. Typical pipeline-quality natural gas is about 95 percent methane, 3 percent NGLs, and 2 percent non-hydrocarbon gases, of which approximately half is CO₂.

However, there remains a range of gas compositions that are consistent with pipeline specifications. The minimum C content coefficient for natural gas would match that for pure methane, which equates to an energy content of 1,005 Btu per standard cubic foot. Gas compositions with higher or lower Btu content tend to have higher C emission factors, because the "low" Btu gas has a higher content of inert gases (including CO₂ offset with more NGLs), while "high" Btu gas tends to have more NGLs.

Step 2. Define flared gas

Every year, a certain amount of natural gas is flared in the United States. There are several reasons that gas is flared:

- There may be no market for some batches of natural gas, the amount may be too small or too variable, or the quality might be too poor to justify treating the gas and transporting it to market (such is the case when gas contains large shares of CO₂). Most natural gas that is flared for these reasons is "rich" associated gas, with relatively high energy content, high NGL content, and a high C content.
- Gas treatment plants may flare substantial volumes of natural gas because of "process upsets," because the gas is "off spec," or possibly as part of an emissions control system. Gas flared at processing plants may be of variable quality.

Data on the energy content of flare gas, as reported by states to EIA, indicate an average energy content of 1,130 Btu per standard cubic foot (EIA 1994). Flare gas may have an even higher energy content than reported by EIA since rich associated gas can have energy contents as high as 1,300 to 1,400 Btu per cubic foot.

Step 3. Determine a relationship between carbon content and heat content

A relationship between C content and heat content may be used to develop a C content coefficient for natural gas consumed in the United States. In 1994, EIA examined the composition (including C contents) of 6,743 samples of pipeline-quality natural gas from utilities and/or pipeline companies in 26 cities located in 19 states. To demonstrate that these samples were representative of actual natural gas "as consumed" in the United States, their heat content was compared to that of the national average. For the most recent year, the average heat content of natural gas consumed in the United States was 1,029 Btu per cubic foot, and has varied by less than 1 percent (1,027 to 1,029 Btu per cubic foot) over the past 5 years. Meanwhile, the average heat content of the 6,743 samples was 1,027 Btu per cubic foot, and the median heat content was 1,031 Btu per cubic foot. Thus, the average heat content of the sample set falls well within the typical range of natural gas consumed in the United States, suggesting that these samples continue to be representative of natural gas "as consumed" in the United States. The average and median composition of these samples appear in Table A-39.

Table A-39: Composition of Natural Gas (Percent)

Compound	Average	Median
Methane	93.07	95.00
Ethane	3.21	2.79
Propane	0.59	0.48
Higher Hydrocarbons	0.32	0.30
Non-hydrocarbons	2.81	1.43
Higher Heating Value (Btu per cubic foot)	1,027	1,031

Source: Gas Technology Institute (1992).

Carbon contents were calculated for a series of sub-samples based on their CO₂ content and heat content. Carbon contents were calculated for the groups of samples with less than 1.0 percent (n=5,181) and less than 1.5 percent CO₂ only (n=6,522) and those with less than 1.0 or 1.5 percent CO₂ and less than 1,050 Btu/cf (n= 4,888 and 6,166, respectively). These stratifications were chosen to exclude samples with CO₂ content and heat contents outside the range of pipeline-quality natural gas. In addition, hexane was removed from the samples since it is usually stripped out of raw natural gas before delivery because it is a valuable natural gas liquid used as a feedstock for gasoline. The average carbon contents for the four separate sub-samples are shown below in Table A-40.

Table A-40: Carbon Content of Pipeline-Quality Natural Gas by CO₂ and Heat Content (Tg C/QBtu)

Sample	Average Carbon Content
Full Sample	14.48
< 1.0% CO ₂	14.43
< 1.5% CO ₂	14.47
< 1.0 % CO ₂ and <1,050 Btu/cf	14.42
< 1.5 % CO ₂ and <1,050 Btu/cf	14.47

Source: EPA (2010).

Step 4. Apply carbon content coefficients developed in Step 3 to pipeline natural gas

A regression analysis was performed on the sub-samples in to further examine the relationship between carbon content and heat content. The regression used carbon content as the dependent variable and heat content as the independent variable. The resulting R-squared values¹¹ for each of the sub-samples ranged from 0.79 for samples with less than 1.5% CO₂ and under 1,050 Btu/cf to 0.91 for samples containing less than 1.0% CO₂ only. However, the sub-sample with less than 1.5% CO₂ and 1,050 Btu/cf was chosen as the representative sample for two reasons. First, it most accurately reflects the range of CO₂ content and heat content of pipeline quality natural gas. Secondly, the R-squared value, although it is the lowest of the sub-groups tested, remains relatively high. This high R-squared indicates a low percentage of variation in C content as related to heat content. The regression for this sub-sample resulted in the following equation:

$$\text{C Content} = (0.011 \times \text{Heat Content}) + 3.5341$$

This equation was used to estimate the annual predicted carbon content of natural gas from 1990 to 2009 based on the EIA's national average pipeline-quality gas heat content for each year. The table of average carbon contents for each year is shown below in Table A-41.

Table A-41: Carbon Content Coefficients for Natural Gas (Tg Carbon/QBtu)

Fuel Type	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Natural Gas	14.45	14.46	14.46	14.46	14.44	14.46	14.47	14.46	14.46	14.44	14.46	14.46	14.46	14.46	14.46	14.46

Source: EPA (2010)

Step 5. Apply carbon content coefficients developed in Step 3 to flare gas

Selecting a C content coefficient for flare gas was much more difficult than for pipeline natural gas, because of the uncertainty of its composition and of the combustion efficiency of the flare. Because EIA estimates the heat content of flare gas at 1,130 Btu per cubic foot, the average C content for samples with more than 1,100 Btu per cubic foot (n=18) was chosen as the relevant sub-sample from which to calculate a flare gas carbon content. It should be noted that the sample dataset did not include any samples with more than 1,130 Btu per cubic foot.

¹¹ R-squared represents the percentage of variation in the dependent variable (in this case carbon content) explained by variation in the independent variables.

Hexane was not removed from flare gas samples since it is assumed that natural gas liquids are present in samples with higher heat contents. Carbon contents were calculated for each sample with a heat content of more than 1,100 Btu per cubic foot. The simple average carbon content for the sample sub-set representing flare gas is shown below in Table A-42.

Table A-42: Carbon Content of Flare Gas (Tg C/QBtu)

Relevant Sub-Sample	Average Carbon Content
>1,100 Btu/cf	15.31

Source: EPA (2010)

Data Sources

Natural gas samples were obtained from the Gas Technology Institute (1992). Average heat content data for natural gas consumed in the United States was taken from EIA (2009a).

Uncertainty

The assignment of C content coefficients for natural gas, and particularly for flare gas, requires more subjective judgment than the methodology used for coal. This subjective judgment may introduce additional uncertainty.

Figure A-1 shows the relationship between the calculated C content for each natural gas sample and its energy content. This figure illustrates the relatively restricted range of variation in both the energy content (which varies by about 6 percent from average) and the C emission coefficient of natural gas (which varies by about 5 percent). Thus, the knowledge that gas has been sold via pipeline to an end-use consumer allows its C emission coefficient to be predicted with an accuracy of ± 5.0 percent.

Figure A-1: Carbon Content for Samples of Pipeline-Quality Natural Gas Included in the Gas Technology Institute Database

Natural gas suppliers may achieve the same overall energy content from a wide variety of methane, higher hydrocarbon, and non-hydrocarbon gas combinations. Thus, the plot reveals large variations in C content for a single Btu value. In fact, the variation in C content for a single Btu value may be nearly as great as the variation for the whole sample. As a result, while energy content has some predictive value, the specific energy content does not substantially improve the accuracy of an estimated C content coefficient beyond the ± 5.0 percent offered with the knowledge that it is of pipeline-quality.

The plot of C content also reveals other interesting anomalies. Samples with the lowest emissions coefficients tend to have energy contents of about 1,000 Btu per cubic foot. They are composed of almost pure methane. Samples with a greater proportion of NGLs (e.g., ethane, propane, and butane) tend to have energy contents greater than 1,000 Btu per cubic foot, along with higher emissions coefficients. Samples with a greater proportion of inert gases tend to have lower energy content, but they usually contain carbon dioxide as one of the inert gases and, consequently, also tend to have higher emission coefficients (see left side of Figure A-1).

For the full sample ($n=6,743$), the average C content of a cubic foot of gas was 14.48 Tg C/QBtu (see Table A-41). Additionally, a regression analysis using the full sample produced a predicted C content of 14.49 Tg C/QBtu based on a heat content of 1,029 Btu/cf (the average heat content in the U.S. for the most recent year). However, these two values include an upward influence on the resulting carbon content that is caused by inclusion in the sample set of the samples that contain large amounts of inert carbon dioxide and those samples with more than 1,050 Btu per cubic foot that contain an unusually large amount of NGLs. Because typical gas consumed in the United States does not contain such a large amount of carbon dioxide or natural gas liquids, a carbon content of 14.47 Tg C/QBtu, based on samples with less than 1.5 percent carbon dioxide and less than 1,050 Btu per cubic foot, better represents the pipeline-quality fuels typically consumed.

Petroleum

There are four critical determinants of the C content coefficient for a petroleum-based fuel:

- The density of the fuel (e.g., the weight in kilograms of one barrel of fuel);
- The fraction by mass of the product that consists of hydrocarbons, and the fraction of non-hydrocarbon impurities;
- The specific types of ‘families’ of hydrocarbons that make up the hydrocarbon portion of the fuel; and
- The heat content of the fuel.

$$C_{\text{fuel}} = (D_{\text{fuel}} \times S_{\text{fuel}}) / E_{\text{fuel}}$$

Where,

C_{fuel} = The C content coefficient of the fuel;
 D_{fuel} = The density of the fuel;
 S_{fuel} = The share of the fuel that is C; and
 E_{fuel} = The heat content of the fuel.

Most of the density, carbon share or heat contents applied to calculate the carbon coefficients for petroleum products that are described in this sub-Annex and applied to this emissions inventory have been updated for this edition of the report. These changes have been made where necessary to increase the accuracy of the underlying data or to align the petroleum properties data used in this report with that developed for use in the Mandatory Reporting of Greenhouse Gases Rule (EPA 2009b).

Petroleum products vary between 5.6 degrees API gravity (dense products such as asphalt and road oil) and 247 degrees (ethane).¹² This is a range in density of 60 to 150 kilograms per barrel, or ± 50 percent. The variation in C content, however, is much smaller (± 5 to 7 percent) for products produced by standard distillation refining: ethane is 80 percent C by weight, while petroleum coke is 90 to 92 percent C. This tightly bound range of C contents can be explained by basic petroleum chemistry (see below). Additional refining can increase carbon contents. Calcined coke, for example, is formed by heat treating petroleum coke to about 1600 degrees Kelvin (calcining), to expel volatile materials and increase the percentage of elemental carbon. This product can contain as much as 97 to 99 percent carbon. Calcined coke is mainly used in the aluminum and steel industry to produce carbon anodes.

Petroleum Chemistry

Crude oil and petroleum products are typically mixtures of several hundred distinct compounds, predominantly hydrocarbons. All hydrocarbons contain hydrogen and C in various proportions. When crude oil is distilled into petroleum products, it is sorted into fractions by the boiling temperature of these hundreds of organic compounds. Boiling temperature is strongly correlated with the number of C atoms in each molecule. Petroleum products consisting of relatively simple molecules and few C atoms have low boiling temperatures, while larger molecules with more C atoms have higher boiling temperatures.

Products that boil off at higher temperatures are usually more dense, which implies greater C content as well. Petroleum products with higher C contents, in general, have lower energy content per unit mass and higher energy content per unit volume than products with lower C contents. Empirical research led to the establishment of a set of quantitative relationships between density, energy content per unit weight and volume, and C and hydrogen content. Figure A-2 compares C content coefficients calculated on the basis of the derived formula with actual C content coefficients for a range of crude oils, fuel oils, petroleum products, and pure hydrocarbons. The actual fuel samples were drawn from the sources described below in the discussions of individual petroleum products.

Figure A-2: Estimated and Actual Relationships Between Petroleum Carbon Content Coefficients and Hydrocarbon Density

¹² API gravity is an arbitrary scale expressing the gravity or density of liquid petroleum products, as established by the American Petroleum Institute (API). The measuring scale is calibrated in terms of degrees API. The higher the API gravity, the lighter the compound. Light crude oils generally exceed 38 degrees API and heavy crude oils are all crude oils with an API gravity of 22 degrees or below. Intermediate crude oils fall in the range of 22 degrees to 38 degrees API gravity. API gravity can be calculated with the following formula: $\text{API Gravity} = (141.5 / \text{Specific Gravity}) - 131.5$. Specific gravity is the density of a material relative to that of water. At standard temperature and pressure, there are 62.36 pounds of water per cubic foot, or 8.337 pounds water per gallon.

The derived empirical relationship between C content per unit heat and density is based on the types of hydrocarbons most frequently encountered. Petroleum fuels can vary from this relationship due to non-hydrocarbon impurities and variations in molecular structure among classes of hydrocarbons. In the absence of more exact information, this empirical relationship offers a good indication of C content.

Non-hydrocarbon Impurities

Most fuels contain a certain share of non-hydrocarbon material. This is also primarily true of crude oils and fuel oils. The most common impurity is sulfur, which typically accounts for between 0.5 and 4 percent of the mass of most crude oils, and can form an even higher percentage of heavy fuel oils. Some crude oils and fuel oils also contain appreciable quantities of oxygen and nitrogen, typically in the form of asphaltenes or various acids. The nitrogen and oxygen content of crude oils can range from near zero to a few percent by weight. Lighter petroleum products have much lower levels of impurities, because the refining process tends to concentrate all of the non-hydrocarbons in the residual oil fraction. Light products usually contain less than 0.5 percent non-hydrocarbons by mass. Thus, the C content of heavy fuel oils can often be several percent lower than that of lighter fuels, due entirely to the presence of non-hydrocarbons.

Variations in Hydrocarbon Classes

Hydrocarbons can be divided into five general categories, each with a distinctive relationship between density and C content and physical properties. Refiners tend to control the mix of hydrocarbon types in particular products in order to give petroleum products distinct properties. The main classes of hydrocarbons are described below.

Paraffins. Paraffins are the most common constituent of crude oil, usually comprising 60 percent by mass. Paraffins are straight-chain hydrocarbons with the general formula C_nH_{2n+2} . Paraffins include ethane (C_2H_6), propane (C_3H_8), butane (C_4H_{10}), and octane (C_8H_{18}). As the chemical formula suggests, the C content of the paraffins increases with their C number: ethane is 79.89 percent C by weight, octane 84.12 percent. As the size of paraffin molecules increases, the C content approaches the limiting value of 85.7 percent asymptotical (see Figure A-3).

Cycloparaffins. Cycloparaffins are similar to paraffins, except that the C molecules form ring structures rather than straight chains, and consequently require two fewer hydrogen molecules than paraffins. Cycloparaffins always have the general formula C_nH_{2n} and are 85.63 percent C by mass, regardless of molecular size.

Olefins. Olefins are a very reactive and unstable form of paraffin: a straight chain with two carbon atoms double bonded together (thus are unsaturated) compared to the carbon atoms in a paraffin (which are saturated with hydrogen).. They are never found in crude oil but are created in moderate quantities by the refining process. Gasoline, for example, may contain between 2 and 20 percent olefins. They also have the general formula C_nH_{2n} , and hence are also always 85.63 percent C by weight. Propylene (C_3H_6), a common intermediate petrochemical product, is an olefin.

Aromatics. Aromatics are very reactive hydrocarbons that are relatively uncommon in crude oil (10 percent or less). Light aromatics increase the octane level in gasoline, and consequently are deliberately created by catalytic reforming of heavy naphtha. Aromatics also take the form of ring structures with some double bonds between C atoms. The most common aromatics are benzene (C_6H_6), toluene (C_7H_8), and xylene (C_8H_{10}). The general formula for aromatics is C_nH_{2n-6} . Benzene is 92.26 percent C by mass, while xylene is 90.51 percent C by mass and toluene is 91.25 percent C by mass. Unlike the other hydrocarbon families, the C content of aromatics declines asymptotically toward 85.7 percent with increasing C number and density (see Figure A-3).

Polynuclear Aromatics. Polynuclear aromatics are large molecules with a multiple ring structure and few hydrogen atoms, such as naphthalene ($C_{10}H_8$ and 93.71 percent C by mass) and anthracene ($C_{14}H_{10}$ and 97.7 percent C). They are relatively rare but do appear in heavier petroleum products.

Figure A-3 illustrates the share of C by weight for each class of hydrocarbon. Hydrocarbon molecules containing 2 to 4 C atoms are all natural gas liquids; hydrocarbons with 5 to 10 C atoms are predominantly found in naphtha and gasoline; and hydrocarbon compounds with 12 to 20 C atoms comprise "middle distillates," which are used to make diesel fuel, kerosene and jet fuel. Larger molecules which can be vacuum distilled may be used as lubricants, waxes, and residual fuel oil or cracked and blended into the gasoline or distillate pools.

Figure A-3: Carbon Content of Pure Hydrocarbons as a Function of Carbon Number

If one knows nothing about the composition of a particular petroleum product, assuming that it is 85.7 percent C by mass is not an unreasonable first approximation. Since denser products have higher C numbers, this guess would be most likely to be correct for crude oils and fuel oils. The C content of lighter products is more affected by the shares of paraffins and aromatics in the blend.

Energy Content of Petroleum Products

The exact energy content (gross heat of combustion) of petroleum products is not generally known. EIA estimates energy consumption in Btu on the basis of a set of industry-standard conversion factors. These conversion factors are generally accurate to within 3 to 5 percent.

Individual Petroleum Products

The United States maintains data on the consumption of more than 20 separate petroleum products and product categories. The C contents, heat contents, and density for each product are provided below in Table A-43. A description of the methods and data sources for estimating the key parameters for each individual petroleum product appears below.

Table A-43: Carbon Content Coefficients and Underlying Data for Petroleum Products

Fuel	2008 Carbon Content (Tg C/QBtu)	Gross Heat of Combustion (MMBtu/Barrel)	Density (API Gravity)	Percent Carbon
Motor Gasoline	19.46	a	a	a
LPG(total)	16.97	b	b	b
LPG (energy use)	16.83	b	b	b
LPG (non-energy use)	17.06	b	b	b
Jet Fuel	19.70	5.670	42.0	86.30
Distillate Fuel No. 1	19.98	5.822	35.3	86.40
Distillate Fuel No. 2	20.17	5.809	35.8	87.30
Distillate Fuel No. 4	20.47	6.135	23.2	86.47
Residual Fuel No. 5	19.89	5.879	33.0	85.67
Residual Fuel No. 6	20.48	6.317	15.5	84.67
Asphalt and Road Oil	20.55	6.636	5.6	83.47
Lubricants	20.20	6.065	25.7	85.80
Naphtha (< 400 deg. F) ^c	18.55	5.248	62.4	84.11
Other Oils (>400 deg. F) ^c	20.17	5.825	35.8	87.30
Aviation Gas	18.86	5.048	69.0	85.00
Kerosene	19.96	5.825	35.3	86.40
Petroleum Coke	27.85	6.024	-	92.28
Special Naphtha	19.74	5.248	52.0	84.75
Petroleum Waxes	19.80	5.537	43.3	85.30
Still Gas	18.20	6.000	-	77.70
Crude Oil	20.31	5.800	31.2	85.49
Unfinished Oils	20.31	5.825	31.2	85.49
Miscellaneous Products	20.31	5.796	31.2	85.49
Pentanes Plus	19.10	4.620	81.3	83.63

^a Calculation of the carbon content coefficient for motor gasoline in 2008 uses separate higher heating values for conventional and reformulated gasoline of 5.253 and 5.150, respectively (EIA 2008a). Densities and carbon shares (percent carbon) are annually variable and separated by both fuel formulation and grade, see Motor Gasoline and Blending Components, below, for details.

^b LPG is a blend of multiple paraffinic hydrocarbons: ethane, propane, isobutane, and normal butane, each with their own heat content, density and C content, see Table A-46.

^c Petrochemical feedstocks have been split into naphthas and other oils for this inventory report. Parameters presented are for naphthas with a boiling temperature less than 400 degrees Fahrenheit. Other oils are petrochemical feedstocks with higher boiling points. They are assumed to have the same characteristics as distillate fuel oil no. 2.

- No sample data available

Sources: EIA (1994), EIA (2009a), EPA (2009b), and EPA (2010).

Motor Gasoline and Motor Gasoline Blending Components

Motor gasoline is a complex mixture of relatively volatile hydrocarbons with or without small quantities of additives, blended to form a fuel suitable for use in spark-ignition engines.¹³ “Motor Gasoline” includes conventional gasoline; all types of oxygenated gasoline, including gasohol; and reformulated gasoline; but excludes aviation gasoline.

Gasoline is the most widely used petroleum product in the United States, and its combustion accounts for nearly 20 percent of all U.S. CO₂ emissions. EIA collects consumption data (i.e., “petroleum products supplied” to end-users) for several types of finished gasoline over the 1990-2008 time period: regular, mid-grade and premium conventional gasoline (all years) and regular, mid-grade and premium reformulated gasoline (November 1994 to 2008). Leaded and oxygenated gasoline are not separately included in the data used for this report.¹⁴

The American Society for Testing and Materials (ASTM) standards permit a broad range of densities for gasoline, ranging from 50 to 70 degrees API gravity, or 111.52 to 112.65 kilograms per barrel (EIA 1994), which implies a range of possible C and energy contents per barrel. Table A- 44 reflects changes in the density of gasoline over time and across grades and formulations of gasoline through 2008.

Table A- 44: Motor Gasoline Density, 1990 – 2009 (Degrees API)

Fuel Grade	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Conventional - Winter Grade																
Low Octane	62.0	59.8	60.6	61.5	61.8	61.6	61.6	61.7	61.6	61.8	62.4	62.6	62.7	63.1	63.0	63.0
High Octane	59.0	58.0	58.5	59.3	60.0	60.3	59.7	59.1	59.0	59.9	60.7	60.9	60.0	60.3	60.9	60.9
Conventional - Summer Grade																
Low Octane	58.2	56.1	56.9	57.1	57.6	57.7	56.8	57.2	56.5	56.8	57.4	57.9	57.8	57.5	58.6	58.6
High Octane	55.5	55.1	55.3	56.4	55.7	57.4	55.8	55.5	55.7	56.0	57.0	57.0	57.4	56.9	58.0	58.0
Reformulated - Winter Grade																
Low Octane	NA	61.9	62.3	62.1	62.7	62.7	62.7	62.6	61.9	62.1	62.7	62.8	62.3	62.1	62.4	62.4
High Octane	NA	59.9	60.8	62.1	61.4	61.0	61.1	61.0	61.8	61.9	61.8	61.8	61.7	62.1	62.5	62.5
Reformulated - Summer Grade																
Low Octane	NA	58.5	58.0	58.8	58.4	58.4	58.4	58.8	58.2	59.1	58.1	58.4	58.7	58.5	59.1	59.1
High Octane	NA	56.7	57.8	58.4	58.5	57.8	58.3	58.2	58.0	58.7	58.9	58.1	59.0	59.3	59.8	59.8

Notes: NA – Not Applicable, fuel type was not analyzed.

Source: National Institute of Petroleum and Energy Research (1990 through 2009).

The density of motor gasoline increased across all grades through 1994, partly as a result of the leaded gasoline phase-out. In order to maintain the “anti-knock” quality and octane ratings of gasoline in the absence of lead, the portion of aromatic hydrocarbons blended into gasoline through the refining process was increased. As discussed above, aromatic hydrocarbons have a lower ratio of hydrogen to C than other hydrocarbons typically found in gasoline, and therefore increase fuel density.

The trend in gasoline density was reversed beginning in 1996 with the development of fuel additives that raised oxygen content. In 1995, a requirement for reformulated gasoline in non-attainment areas implemented under the Clean Air Act Amendments further changed the composition of gasoline consumed in the United States. Through 2005, methyl tertiary butyl ether (MTBE), ethanol, ethyl tertiary butyl ether (ETBE) and tertiary amyl methyl ether (TAME) were added to reformulated and sometimes to conventional gasoline to boost its oxygen content, reduce its toxics impacts and increase its octane. The increased oxygen reduced the emissions of carbon monoxide and unburned hydrocarbons. These oxygen-rich blending components are also much lower in C than standard gasoline. The average gallon of reformulated gasoline consumed in 2005 contained over 10 percent MTBE and 0.6 percent TAME (by volume). The characteristics of reformulated fuel additives appear in Table A-45.

¹³ Motor gasoline, as defined in ASTM Specification D 4814 or Federal Specification VV-G-1690C, is characterized as having a boiling range of 122 degrees to 158 degrees Fahrenheit at the 10-percent recovery point to 365 degrees to 374 degrees Fahrenheit at the 90-percent recovery point.

¹⁴ Oxygenated gasoline volumes are included in the conventional gasoline data provided by EIA from 2007 onwards. Leaded gasoline was included in total gasoline by EIA until October 1993.

Table A-45: Characteristics of Major Reformulated Fuel Additives

Additive	Density (Degrees	
	API	Carbon Share (Percent)
MTBE	58.6	68.13
ETBE	58.5	70.53
TAME	51.2	70.53
DIPE	62.7	70.53
Ethanol (100%)	45.8	52.14

Source: EPA, 2009b.

Since 2005, due to concerns about the potential environmental consequences of the use of MTBE in fuels, there has been a shift away from the addition of MTBE, TAME, ETBE and DIPE and towards the use of ethanol as a fuel oxygenate.¹⁵ Ethanol, also called ethyl alcohol, is an anhydrous alcohol with molecular formula C₂H₅OH. Ethanol has a lower carbon share than other oxygenates, approximately 52 percent compared to about 70 percent for MTBE and TAME. The density of ethanol was calculated by fitting density data at 10 degree intervals to a polynomial of order two and then using the fit to interpolate the value of the density at 15 degrees Celsius. A common fuel mixture of 10 percent denatured ethanol (denatured by 2% hydrocarbons) and 90 percent gasoline, known as E10, is widely used in the U.S. and does not require any modification to vehicle engines or fuel systems. The average gallon of reformulated alcohol blend gasoline in 2008 contained 8.6 percent ethanol (by volume). As of 2010, ten States require the use of ethanol-blended fuel.¹⁶ Ethanol blends up to E85 (85 percent ethanol, 15 percent gasoline) are in use in the United States but can only be used in specially designed vehicles called flexible fuel vehicles (FFVs). Most ethanol fuel in the United States is produced using corn as feedstock,¹⁷ although production pathways utilizing agricultural waste, woody biomass and other resources are in development.

Methodology

Step 1. Disaggregate U.S. gasoline consumption by grade and type

Separate monthly data for U.S. sales to end users of finished gasoline by product grade and season for both standard gasoline and reformulated gasoline were obtained from the EIA.

Step 2. Develop carbon content coefficients for each grade and type

Annual C content coefficients for each gasoline grade, type and season are derived from four parameters for each constituent of the finished gasoline blend: the volumetric share of each constituent,¹⁸ the density of the constituent, share of the constituent¹⁹ that is C; and the energy content of a gallon of the relevant formulation of gasoline. The percent by mass of each constituent of each gasoline type was calculated using percent by volume data from NIPER and the density of each constituent. The ether additives listed in Table A-45 are accounted for in both reformulated fuels and conventional fuels, to the extent that they were present in the fuel. From 2006 onward, reformulated fuel mass percentages are calculated from their constituents, net of the share provided by ethanol. C content coefficients were then derived from the calculated percent by mass values by weighting the carbon share of each constituent by its contribution to the total mass of the finished motor gasoline product.

Step 3. Weight overall gasoline carbon content coefficient for consumption of each grade and type

The C content for each grade, type and season of fuel is multiplied by the share of annual consumption represented by the grade and fuel type during the relevant time period. Individual coefficients are then summed and totaled to yield an overall C content coefficient for each year.

¹⁵ The annual motor gasoline carbon contents that are applied for this inventory do not include the carbon contributed by the ethanol contained in reformulated fuels. Ethanol is a biofuel, and 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.

¹⁶ Ethanol.org. <http://www.ethanol.org/index.php?id=79&parentid=26>. Retrieved 2-19-2010.

¹⁷ "Ethanol Market Penetration". Alternative Fuels and Advanced Vehicles Data Center, US DOE. <http://www.afdc.energy.gov/afdc/ethanol/market.html>. Retrieved 2-19-2010.

¹⁸ Calculations account for the properties of the individual constituents of gasoline, including, as applicable to the fuel grade and type: aromatics (excluding benzene), olefins, benzene, saturates, MTBE, TAME, ETBE, DIPE and ethanol.

¹⁹ Saturates are assumed to be octane and aromatics are assumed to be toluene.

Data Sources

Data for the density of motor gasoline were derived from the National Institute for Petroleum and Energy Research (NIPER) (1990 through 2009). Data on the characteristics of reformulated gasoline, including C share, were also taken from NIPER (1990 through 2009).

Standard heat contents for motor gasoline of 5.253 MMBtu per barrel conventional gasoline and 5.150 MMBtu per barrel reformulated gasoline²⁰ were adopted from EIA (2009a).

Uncertainty

The uncertainty underlying the C content coefficients for motor gasoline has three underlying sources: the uncertainty in the averages published by NIPER, uncertainty in the C shares assumed in the EPA's analysis to be representative of the constituent hydrocarbon classes within gasoline (aromatics, olefins and saturates) and uncertainty in the heat contents applied.

A variable number of samples are used each year to determine the average percent by volume share of each hydrocarbon within each grade, season and formulation of gasoline that are obtained from NIPER. The total number of samples analyzed for each seasonal NIPER report varies from approximately 730 to over 1,800 samples over the period from 1990 through 2008. The number of samples analyzed that underlie the calculation of the average make-up of each seasonal formulation and grade varies from approximately 50 to over 400, with the greatest number of samples each season being of conventional, regular or premium gasoline. Further, not all sample data submitted to NIPER contains data for each of the properties, such that the number of samples underlying each constituent average value for each season, grade and formulation may be variable within the single gasoline type (e.g., of the 1,073 samples for which some data was obtained for gasoline sold in Winter 1995-1996, benzene content was provided for all samples, while olefin, aromatic and saturate content was provided for just 736 of those samples).

The distribution of sample origin collected for the NIPER report and the calculation of national averages are not reflective of sales volumes. The publication of simple, rather than sales-weighted averages to represent national average values increases the uncertainty in their application to the calculation of carbon content factors for the purposes of this inventory. Further, data for each sample is submitted voluntarily, which may also affect their representativeness.

Additionally, because the simple average constituent shares are calculated based upon data that have been renormalized to account for the share of ethers and alcohols, total average volume shares may not equal 100 percent.

The simple average for each hydrocarbon constituent is contained within a range of values that are as wide as +74.5/-63 percent of the mean across the Winter 2007-2008 and +49.6/-51.3 percent across the Summer 2008 samples of conventional, regular grade gasoline. However, these wide ranges exist for benzene, which generally accounts for only 1 percent, by volume, of each gallon. In contrast, saturates, the class of hydrocarbon that contribute the largest share, by volume, ranges only +6.4/-6.5 percent for the same set of Winter samples and +15.7/-8.8 percent for the Summer samples.

Secondly, EPA's calculation of C content factors for each gasoline type includes the following assumptions: for the purposes of assigning a carbon share to each compound in the blend, aromatic content (other than benzene) is assumed to be toluene and saturated hydrocarbons are assumed to be octane. All olefins have the same carbon share because they all have a molecular formula in the form C_nH_{2n} , so the C share applied to the olefin portion of the total gasoline blend does not increase the level of uncertainty in the calculation. These assumptions are based upon the use of octane and octane isomers as the primary saturates and toluene as the primary non-benzene aromatic in U.S. motor gasoline blends. The octane rating of a particular blend is based upon the equivalent iso-octane to heptane ratio, which is achieved through significant octane content relative to the other saturates. Aside from benzene, U.S. gasolines will include toluene as a major aromatic component, so toluene may be assumed a reasonable representative of total non-benzene aromatic content (EPA 2009a).

For each hydrocarbon category, the assumed C content lies within a range of possible values for all such hydrocarbons. Among saturated hydrocarbons, the C share of octane (84.12 percent) is at the high end of the range while ethane is represents the low end of the range (79.89 percent C). Total saturates constitute from 40 to 95 percent by volume of a given gasoline blend. For aromatics, toluene (91.25 percent C) lies in the middle of the possible range. This range is bounded by cumene (89.94 percent C) and naphthalene (93.71 percent C). Total aromatics may make up between 3 and 50 percent by volume of any given gasoline blend. The range of these potential values contributes to the uncertainty surrounding the final calculated carbon factors.

²⁰ The reformulated gasoline heat content is applied to both reformulated blends containing ethers and those containing ethanol.

However, as demonstrated above in Figure A-3, the amount of variation in C content of gasoline is restricted by the compounds in the fuel to ± 4 percent. Further, despite variation in sampling survey response, sample size and annually variable fuel formulation requirements, the observed variation in the annual weighted motor gasoline coefficients estimated for this inventory is ± 0.8 percent over 1990 through 2008.

The third primary contributor to uncertainty is the assumed heat content. The heat contents are industry standards established many years ago. The heat contents are standard conversion factors used by EIA to convert volumetric energy data to energy units. Because the heat contents of fuels change over time, without necessarily and directly altering their volume, the conversion of known volumetric data to energy units may introduce bias. Thus, a more precise approach to estimating emissions factors would be to calculate C content per unit of volume, rather than per unit of energy. Adopting this approach, however, makes it difficult to compare U.S. C content coefficients with those of other nations.

The changes in density of motor gasoline over the last decade suggest that the heat content of the fuels is also changing. However, that change within any season grade has been less than 1 percent over the decade. Of greater concern is the use of a standardized heat content across grades that show a variation in density of ± 1.5 percent from the mean for conventional gasoline and ± 1.0 percent for reformulated fuels.

Jet Fuel

Jet fuel is a refined petroleum product used in jet aircraft engines. There are two classes of jet fuel used in the United States: “naphtha-based” jet fuels and “kerosene-based” jet fuels. In 1989, 13 percent of U.S. consumption was naphtha-based fuel, with the remainder kerosene-based jet fuel. In 1993, the U.S. Department of Defense began a conversion from naphtha-based JP-4 jet fuel to kerosene-based jet fuel, because of the possibility of increased demand for reformulated motor gasoline limiting refinery production of naphtha-based jet fuel. By 1996, naphtha-based jet fuel represented less than one-half of one percent of all jet fuel consumption. The C content coefficient for jet fuel used in this report prior to 1996 represents a consumption-weighted combination of the naphtha-based and kerosene-based coefficients. From 1996 to 2008, only the kerosene-based portion of total consumption is considered significant.

Methodology

Step 1. Estimate the carbon content for naphtha-based jet fuels

Because naphtha-based jet fuels are used on a limited basis in the United States, sample data on its characteristics are limited. The density of naphtha-based jet fuel (49 degrees) was estimated as the central point of the acceptable API gravity range published by ASTM. The heat content of the fuel was assumed to be 5.355 MMBtu per barrel based on EIA industry standards. The C fraction was derived from an estimated hydrogen content of 14.1 percent (Martel and Angello 1977), and an estimated content of sulfur and other non-hydrocarbons of 0.1 percent.

Step 2. Estimate the carbon content for kerosene-based jet fuels

The density of kerosene-based jet fuels was estimated at 42 degrees API and the carbon share at 86.3 percent. The density estimate was based on 38 fuel samples examined by NIPER. Carbon share was estimated on the basis of a hydrogen content of 13.6 percent found in fuel samples taken in 1959 and reported by Martel and Angello, and on an assumed sulfur content of 0.1 percent. The EIA’s standard heat content of 5.670 MMBtu per barrel was adopted for kerosene-based jet fuel.

Step 3. Weight the overall jet fuel carbon content coefficient for consumption of each type of fuel (1990-1995 only)

For years 1990 through 1995, the C content for each jet fuel type (naphtha-based, kerosene-based) is multiplied by the share of overall consumption of that fuel type, as reported by EIA (2009a). Individual coefficients are then summed and totaled to yield an overall C content coefficient. Only the kerosene-based C coefficient is reflected in the overall jet fuel coefficient for 1996 through 2008.

Data Sources

Data on the C content of naphtha-based jet fuel was taken from C.R. Martel and L.C. Angello (1977). Data on the density of naphtha-based jet fuel was taken from ASTM (1985). Standard heat contents for kerosene and naphtha-based jet fuels were adopted from EIA (2009a). Data on the C content of kerosene-based jet fuel is based on C.R. Martel and L.C. Angello (1977) and the density is derived from NIPER (1993).

Uncertainty

Variability in jet fuel is relatively small with the average C share of kerosene-based jet fuel varying by less than ± 1 percent and the density varying by ± 1 percent. This is because the ratio of fuel mass to useful energy must be tightly bounded to maximize safety and range. There is more uncertainty associated with the density and C share of naphtha-based jet fuel because sample data were unavailable and default values were used. This uncertainty has only a small impact on the overall uncertainty of the C content coefficient for jet fuels, however, because naphtha-based jet fuel represents a small and declining share of total jet fuel consumption in the United States and is treated as negligible when calculating carbon content factors for 1996 onwards.

Distillate Fuel

Distillate fuel is a general classification for diesel fuels and fuel oils. Products known as No. 1, No. 2, and No. 4 diesel fuel are used in on-highway diesel engines, such as those in trucks and automobiles, as well as off-highway engines, such as those in railroad locomotives and agricultural machinery. No. 1, No. 2, and No. 4 fuel oils are also used for space heating and electric power generation.

Methodology

For this inventory, separate C coefficients have been estimated for each of the three distillates, although the level of aggregation of U.S. energy statistics requires that a single coefficient is used to represent all three grades in inventory calculations. In past inventories, the emission coefficient was only determined for distillate No. 2. Distillate No. 2 remains the representative grade applied to the distillate class for calculation purposes. Coefficients developed for Nos. 1 and 4 distillate are provided for informational purposes. The C share each distillate is drawn from Perry's Chemical Engineers' Handbook, 8th Ed. (Green & Perry 2008). Each C share was combined with individual heat contents of 5.822, 5.809 and 6.135 MMBtu per barrel, respectively for distillates No. 1, No. 2 and No. 4, and densities of 35.3, 35.8 and 23.2 degrees API to calculate C coefficients for each distillate type.

Data Sources

Densities for distillate Nos. 1 and 2 were derived from Alliance of Automobile Manufacturers, Diesel Survey – Winter 2008 (AAM 2009). Densities are based on four, and 144 samples, respectively. The density of distillate fuel oil No. 4 is taken from Perry's Chemical Engineer's Handbook, 8th Ed. (Green & Perry, 2008), Table 24-6.

Heat contents are adopted from EPA (2009b). And carbon shares for each distillate are from Perry's Chemical Engineers' Handbook (Green & Perry 2008), Table 24-6.

Uncertainty

The primary source of uncertainty for the estimated C content of distillate fuel is the selection of No. 2 distillate as the typical distillate fuel oil or diesel fuel. No.2 fuel oil is generally consumed for home heating. No.1 distillate is generally less dense and if it is consumed in large portions for mobile sources, the application of the C content estimated for No. 2 for this report is likely to be too high when applied to both Nos. 1 and 2 distillates. The opposite is true of the application of a coefficient based upon the properties of No. 2 to the consumption of No. 4 distillate, which is of a significantly higher density and thus, has a higher C coefficient despite its lower C share. The overall effect on uncertainty from applying a single factor will depend on the relative annual consumption of each distillate.

The densities applied to the calculation of each carbon factor are an underlying a source of uncertainty. While the density of No. 1 distillate is based upon just four samples, the factor applied to all distillates in the inventory estimates (that for No. 2 oil) is based on a much larger sample size (144). Given the range of densities for these three distillate fuel classes (0.1342 to 0.1452 MT/bbl at 60°F), the uncertainty associated with the assumed density of distillate fuels is predominately a result of the use of No. 2 to represent all distillate consumption. There is also a small amount of uncertainty in the No. 2 distillate density itself. This is due to the possible variation across seasonal diesel formulations and fuel grades and between stationary and transport applications within the No. 2 distillate classification. The range of the density of the samples of No. 2 diesel (regular grade, 15ppm sulfur) is ± 2.5 percent from the mean, while the range in density across the small sample set of No. 1 diesel is -2.1 to +1.6 percent of the mean. Samples from AAM (2009) of Premium No. 2 diesel (n=5) and higher sulfur (500 ppm S) regular diesel (n=2), which are also consumed in the U.S., each have nominally higher average densities (+1.3 percent and +0.6 percent, respectively) than do the low-sulfur regular diesel samples that underlie the density applied in this inventory.

The use of the 144 AAM samples to define the density of No. 2 distillate (and those four samples used to define that of No. 1 distillate) may introduce additional uncertainty because the samples were collected from just one season of on-road fuel production (Winter 2008). Despite the limited sample frame, the average No. 2 density calculated from the samples is applied to the calculation of a uniform C coefficient applicable for all years of the inventory and for all types of distillate consumption. The ASTM standards for each grade of diesel fuel oil do not include a required range in which the density must lie, and the density (as well as heat content and carbon share) may vary according to the additives in each seasonal blend and the sulfur content of each sub-grade.

However, previous studies also show relatively low variation in density across samples of No. 2 and across all distillates, supporting the application of a single No. 2 density to all U.S. distillate consumption. The average density calculated from samples analyzed by the EIA in 1994 (n=7) differs only very slightly from the value applied for the purposes of this inventory (-0.12 percent for No. 2 distillate). Further, the difference between the mean density applied to this inventory (No. 2 only) and that calculated from EIA samples of all distillates, regardless of grade, is also near zero (-0.06 percent, based on n=14, of distillates Nos. 1, 2 and 4 combined).

A C share of 87.30 percent is applied to No. 2 distillate, while No. 1 and No. 4 have C shares estimated at 86.40 and 86.47 percent, respectively. Again, the application of parameters specific to No. 2 to the consumption of all three distillates contributes to an increased level of uncertainty in the overall coefficient and emissions estimate and its broad application. For comparison, four No. 1 fuel oil samples obtained by EIA (1994) contained an average of 86.19 percent C, while seven samples No. 2 fuel oil from the same EIA analysis showed an average of 86.60 percent C. Additionally, three samples of No. 4 distillate indicate an average C share of 85.81 percent. The range of C share observed across the seven No. 2 samples is 86.1 to 87.5 percent, and across all samples (all three grades, n=14) the range is 85.3 to 87.5 percent C. There also exists an uncertainty of ± 1 percent in the share of C in No. 2 based on the limited sample size.

Residual Fuel

Residual fuel is a general classification for the heavier oils, known as No. 5 and No. 6 fuel oils, that remain after the distillate fuel oils and lighter hydrocarbons are distilled away in refinery operations. Residual fuel conforms to ASTM Specifications D 396 and D 975 and Federal Specification VV-F-815C. No. 5, a residual fuel oil of medium viscosity, is also known as Navy Special and is defined in Military Specification MIL-F-859E, including Amendment 2 (NATO Symbol F-770). It is used in steam-powered vessels in government service and inshore power plants. No. 6 fuel oil includes Bunker C fuel oil and is used for the production of electric power, space heating, vessel bunkering, and various industrial purposes.

In the United States, electric utilities purchase about one-third of the residual oil consumed. A somewhat larger share is used for vessel bunkering, and the balance is used in the commercial and industrial sectors. The residual oil (defined as No. 6 fuel oil) consumed by electric utilities has an energy content of 6.287 MMBtu per barrel (EIA 2008a) and an average sulfur content of 1 percent (EIA 2001). This implies a density of about 17 degrees API.

Methodology

Because U.S. energy consumption statistics are available only as an aggregate of Nos. 5 and 6 residual oil, a single coefficient must be used to represent the full residual fuel category. As in earlier editions of this report, residual fuel oil has been defined as No. 6 fuel oil, due to the majority of residual consumed in the United States being No. 6. However, for this report, a separate coefficient for fuel oil No. 5 has also been developed for informational purposes. Densities of 33.0 and 15.5 degrees API were adopted when developing the C content coefficients for Nos. 5 and 6, respectively (Wauquier, J.-P., ed. 1995; Green & Perry, ed. 2008).

The estimated C share of fuel oil No. 5 is 85.67 percent, based on an average of 12 ultimate analyses of samples of fuel oil (EIA 1994). An average share of C in No. 6 residual oil of 84.67 percent by mass was used, based on Perry's, 8th Ed. (Green & Perry 2008).

Data Sources

Data on the C share and density of residual fuel oil No. 6 were obtained from Green & Perry, ed. (2008).

Data on the C share of fuel oil No. 5 was adopted from EIA (1994), and the density of No. 5 was obtained from Wauquier, J.-P., ed. (1995).

Heat contents for both Nos. 5 and 6 fuel oil are adopted from EPA (2009b).

Uncertainty

Beyond the application of a C factor based upon No. 6 oil to all residual oil consumption, the largest source of uncertainty in estimating the C content of residual fuel centers on the estimates of density. Fuel oils are likely to differ depending on the application of the fuel (i.e., power generation or as a marine vessel fuel). Slight differences between the density of residual fuel used by utilities and that used in mobile applications are likely attributable to non-sulfur impurities, which reduce the energy content of the fuel, but do not greatly affect the density of the product. Impurities of several percent are commonly observed in residual oil. The extent of the presence of impurities has a greater effect on the uncertainty of C share estimation than it does on density. This is because these impurities do provide some Btu content to the fuel, but they are absent of carbon. Fuel oils with significant sulfur, nitrogen and heavy metals contents would have a different total carbon share than a fuel oil that is closer to pure hydrocarbon. This contributes to the uncertainty of the estimation of an average C share and C coefficient for these varied fuels.

The 12 samples of residual oil (EIA 1994) cover a density range from 4.3 percent below to 8.2 percent above the mean density. The observed range of C share in these samples is -2.5 to +1.8 percent of the mean. Overall, the uncertainty associated with the C content of residual fuel is probably ± 1 percent.

Liquefied Petroleum Gases (LPG)

EIA identifies four categories of paraffinic hydrocarbons as LPG: ethane, propane, isobutane, and n-butane. Because each of these compounds is a pure paraffinic hydrocarbon, their C shares are easily derived by taking into account the atomic weight of C (12.01) and the atomic weight of hydrogen (1.01). Thus, for example, the C share of propane, C₃H₈, is 81.71 percent. The densities and heat contents of the compounds are also well known, allowing C content coefficients to be calculated directly. Table A-46 summarizes the physical characteristic of LPG.

Table A-46: Physical Characteristics of Liquefied Petroleum Gases

Compound	Chemical Formula	Density (Barrels Per Metric Ton)	Carbon Content (Percent)	Energy Content (MMBtu/Barrel)	Carbon Content Coefficient (Tg C/QBtu)
Ethane	C ₂ H ₆	11.55	79.89	3.082	17.16
Propane	C ₃ H ₈	12.76	81.71	3.836	16.76
Isobutane	C ₄ H ₁₀	11.42	82.66	3.974	17.77
n-butane	C ₄ H ₁₀	10.98	82.66	4.326	17.75

Source: Densities – CRC Handbook of Chemistry and Physics (2008/09); Carbon Contents – derived from the atomic weights of the elements; Energy Contents – EPA (2009b). All values are for the compound in liquid form. The density and energy content of ethane are for refrigerated ethane (-89 degrees C). Values for n-butane are for pressurized butane (-25 degrees C).

Methodology

Step 1. Assign carbon content coefficients to each pure paraffinic compound

Based on their known physical characteristics, a C content coefficient is assigned to each compound contained in the U.S. energy statistics category, Liquefied Petroleum Gases.

Step 2. Weight individual LPG coefficients for share of fuel use consumption

A C content coefficient for LPG used as fuel is developed based on the consumption mix of the individual compounds reported in U.S. energy statistics.

Step 3. Weight individual LPG coefficients for share of non-fuel use consumption

The mix of LPG consumed for non-fuel use differs significantly from the mix of LPG that is combusted. While the majority of LPG consumed for fuel use is propane, ethane is the largest component of LPG used for non-fuel applications. A C content coefficient for LPG used for non-fuel applications is developed based on the consumption mix of the individual compounds reported in U.S. energy statistics.

Step 4. Weight the carbon content coefficients for fuel use and non-fuel use by their respective shares of consumption

The changing shares of LPG fuel use and non-fuel use consumption appear below in Table A- 47.

Data Sources

Data on C share was derived via calculations based on atomic weights of each element of the four individual compounds. Densities are from the CRC Handbook of Chemistry and Physics, 89th Ed.. The energy content of each LPG is

from the EPA (2009b). LPG consumption was based on data obtained from API (1990 through 2008) and EIA (2009b). Non-fuel use of LPG was obtained from API (1990 through 2008).

Uncertainty

Because LPG consists of pure paraffinic compounds whose density, heat content and C share are physical constants, there is limited uncertainty associated with the C content coefficient for this petroleum product. Any uncertainty is associated with the collection of data tabulating fuel- and non-fuel consumption in U.S. energy statistics. This uncertainty is likely less than ± 3 percent.

Table A- 47: Consumption and Carbon Content Coefficients of Liquefied Petroleum Gases, 1990-2009

	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Energy Consumption (QBtu)																
Fuel Use	0.88	0.94	1.02	1.04	0.84	1.08	1.31	1.16	1.25	1.22	1.26	1.21	1.19	1.20	1.13	1.13
Ethane	0.04	0.03	0.04	0.07	0.00	0.01	0.10	0.06	0.06	0.06	0.06	0.06	0.06	0.07	0.06	0.07
Propane	0.77	0.86	0.94	0.92	0.80	0.97	1.07	1.00	1.10	1.07	1.12	1.08	1.07	1.09	1.02	1.02
Butane	0.06	0.03	0.03	0.03	0.02	0.06	0.07	0.06	0.05	0.06	0.06	0.05	0.05	0.05	0.05	0.03
Isobutane	0.01	0.02	0.02	0.02	0.02	0.05	0.06	0.04	0.04	0.03	0.01	0.01	0.01	0.00	0.00	0.01
Non-Fuel Use	1.35	1.78	1.87	1.88	1.96	2.06	1.90	1.77	1.85	1.75	1.80	1.70	1.74	1.78	1.67	1.80
Ethane	0.71	0.89	0.97	0.93	0.96	1.08	1.04	0.96	1.00	0.92	0.97	0.91	0.98	1.03	0.95	1.12
Propane	0.51	0.67	0.64	0.71	0.77	0.77	0.65	0.59	0.64	0.63	0.66	0.63	0.63	0.64	0.60	0.60
Butane	0.11	0.15	0.15	0.13	0.12	0.12	0.11	0.13	0.12	0.13	0.13	0.12	0.12	0.11	0.12	0.08
Isobutane	0.02	0.08	0.10	0.11	0.12	0.09	0.09	0.09	0.08	0.07	0.03	0.03	0.02	0.01	0.00	0.01
Carbon Content (Tg C/QBtu)																
Fuel Use	16.86	16.82	16.82	16.84	16.81	16.86	16.89	16.87	16.85	16.86	16.84	16.84	16.83	16.82	16.83	16.82
Non-Fuel Use	17.06	17.09	17.10	17.08	17.08	17.07	17.09	17.10	17.09	17.09	17.07	17.06	17.06	17.05	17.06	17.06

Sources: Fuel use of LPG based on data from EIA (2009b) and API (1990 through 2007). Non-fuel use of LPG from API (1990 through 2008). Volumes converted using the energy contents provided in Table A-46. C contents from EPA (2010).

Aviation Gasoline

Aviation gasoline is used in piston-powered airplane engines. It is a complex mixture of relatively volatile hydrocarbons with or without small quantities of additives, blended to form a fuel suitable for use in aviation reciprocating engines. Fuel specifications are provided in ASTM Specification D910 and Military Specification MIL-G-5572. Aviation gas is a relatively minor contributor to greenhouse gas emissions compared to other petroleum products, representing approximately 0.1 percent of all consumption.

The ASTM standards for boiling and freezing points in aviation gasoline effectively limit the aromatics content to a maximum of 25 percent (ASTM D910). Because weight is critical in the operation of an airplane, aviation gas must have as many Btu per pound (implying a lower density) as possible, given other requirements of piston engines such as high anti-knock quality.

Methodology

A C content coefficient for aviation gasoline was calculated on the basis of the EIA standard heat content of 5.048 MMBtu per barrel. This implies a density of approximately 69 degrees API gravity or 5.884 pounds per gallon, based on the relationship between heat content and density of petroleum liquids, as described in *Thermal Properties of Petroleum Products* (DOC 1929). To estimate the share of C in the fuel, it was assumed that aviation gasoline is 87.5 percent iso-octane, 9.0 percent toluene, and 3.5 percent xylene. The maximum allowable sulfur content in aviation gasoline is 0.05 percent, and the maximum allowable lead content is 0.1 percent. These amounts were judged negligible and excluded for the purposes of this analysis. This yielded a C share of 85.00 percent and a C content coefficient of 18.86 Tg C/QBtu.

Data Sources

Data sources include ASTM (1985). A standard heat content for aviation gas was adopted from EIA (2009a).

Uncertainty

The relationship used to calculate density from heat content has an accuracy of five percent at 1 atm. The uncertainty associated with the C content coefficient for aviation gasoline is larger than that for other liquid petroleum products examined because no ultimate analyses of samples are available. Given the requirements for safe operation of

piston-powered aircraft the composition of aviation gas is well bounded and the uncertainty of the C content coefficient is likely to be ± 5 percent.

Still Gas

Still gas, or refinery gas, is composed of light hydrocarbon gases that are released as petroleum is processed in a refinery. The composition of still gas is highly variable, depending primarily on the nature of the refining process and secondarily on the composition of the product being processed. Petroleum refineries produce still gas from many different processes. Still gas can be used as a fuel or feedstock within the refinery, sold as a petrochemical feedstock, or purified and sold as pipeline-quality natural gas. For the purposes of this inventory, the coefficient derived here is only applied to still gas that is consumed as a fuel. In general, still gas tends to include large amounts of free hydrogen and methane, as well as smaller amounts of heavier hydrocarbons. Because different refinery operations result in different gaseous byproducts, it is difficult to determine what represents typical still gas.

Methodology

The properties of still gas used to calculate the carbon content are taken from the literature. The carbon share of still gas was calculated from its net calorific value and carbon content from IPCC (2006). This calculation yields a carbon share of 77.7 percent. The density of still gas was estimated to be 0.1405 metric tons per barrel based on its heat content (from EIA 2008a) and the relationship between heat content and density that is described by the U.S. Department of Commerce, Bureau of Standards (DOC 1929).

Data Sources

The carbon share of still gas is calculated from data provided by IPCC (2006). Density is estimated at 0.1405 metric tons per barrel, approximately 28.3 degrees API, based on the heat content of 6.00 MMBtu/barrel of still gas from EIA (2009a).

Uncertainty

The EIA obtained data on four samples of still gas. Table A-48 below shows the composition of those samples.

Table A-48: Composition, Energy Content, and Carbon Content Coefficient for Four Samples of Still Gas

Sample	Hydrogen (%)	Methane (%)	Ethane (%)	Propane (%)	Btu Per Cubic Foot	Carbon Content (Tg C/QBtu)
One	12.7	28.1	17.1	11.9	1,388	17.51
Two	34.7	20.5	20.5	6.7	1,143	14.33
Three	72.0	12.8	10.3	3.8	672	10.23
Four	17.0	31.0	16.2	2.4	1,100	15.99

Sources: EIA (2008b).

Because the composition of still gas is highly heterogeneous, the C content coefficient for this product is highly uncertain. Gas streams with a large free hydrogen content are likely to be used as refinery or chemical feedstocks. Therefore, the sample cited above with the very high H content of 72 percent (and the lowest calculated C content) is less likely to be representative of the still gas streams to which the calculated coefficient is applied. The C content coefficient used for this report is probably at the high end of the plausible range given that it is higher than the greatest sample-based C content in Table A-48.

Asphalt

Asphalt is used to pave roads. Because most of its C is retained in those roads, it is a small source of carbon dioxide emissions. It is derived from a class of hydrocarbons called "asphaltenes," which are abundant in some crude oils but not in others. Asphaltenes have oxygen and nitrogen atoms bound into their molecular structure, so that they tend to have lower C contents than do other hydrocarbons.

Methodology

Ultimate analyses of twelve samples of asphalts showed an average C content of 83.47 percent. The EIA standard Btu content for asphalt of 6.636 MMBtu per barrel was assumed. The ASTM petroleum measurement tables show a density of 5.6 degrees API or 8.605 pounds per gallon for asphalt. Together, these variables generate C content coefficient of 20.55 Tg C/QBtu.

Data Sources

A standard heat content for asphalt was adopted from EIA (2009a). The density of asphalt was determined by the ASTM (1985). C share is adopted from analyses in EIA (2008b).

Uncertainty

The share of C in asphalt ranges from 79 to 88 percent by weight. Also present in the mixture are hydrogen and sulfur, with shares by weight ranging from seven to 13 percent for hydrogen, and from trace levels to eight percent for sulfur. Because C share and total heat content in asphalts do vary systematically, the overall C content coefficient is likely to be accurate to ± 5 percent.

Lubricants

Lubricants are substances used to reduce friction between bearing surfaces, or incorporated into processing materials used in the manufacture of other products, or used as carriers of other materials. Petroleum lubricants may be produced either from distillates or residues. Lubricants include all grades of lubricating oils, from spindle oil to cylinder oil to those used in greases. Lubricant consumption is dominated by motor oil for automobiles, but there is a large range of product compositions and end uses within this category.

Methodology

The ASTM Petroleum Measurement tables give the density of lubricants at 25.6 degrees API, or 0.1428 metric tons per barrel. Ultimate analysis of a single sample of motor oil yielded a C content of 85.80 percent. A standard heat content of 6.065 MMBtu per barrel was adopted from EIA. These factors produce a C content coefficient of 20.20 Tg C/QBtu.

Data Sources

A standard heat content was adopted from the EIA (2009a). The carbon content of lubricants is adopted from ultimate analysis of one sample of motor oil (EPA 2009a). The density of lubricating oils was determined by ASTM (1985).

Uncertainty

Uncertainty in the estimated C content coefficient for lubricants is driven by the large range of product compositions and end uses in this category combined with an inability to establish the shares of the various products captured under this category in U.S. energy statistics. Because lubricants may be produced from either the distillate or residual fractions during refineries, the possible C content coefficients range from 19.89 Tg C/QBtu to 21.48 Tg C/QBtu or an uncertainty band from -1.5 percent to $+1.4$ percent of the estimated value.

Petrochemical Feedstocks

U.S. energy statistics distinguish between two different kinds of petrochemical feedstocks: those with a boiling temperature below 400 degrees Fahrenheit, generally called “naphtha,” and those with a boiling temperature 401 degrees Fahrenheit and above, referred to as “other oils” for the purposes of this inventory.

Methodology

The C content of these petrochemical feedstocks are estimated independently according to the following steps.

Step 1. Estimate the carbon content coefficient for naphtha

Because reformed naphtha is used to make motor gasoline (hydrogen is released to raise aromatics content and octane rating), “straight-run” naphtha is assumed to be used as a petrochemical feedstock. Ultimate analyses of five samples of naphtha were examined and showed an average C share of 84.11 percent. A density of 62.4 degrees API gravity was taken from the Handbook of Petroleum Refining Processes, 3rd ed. The standard EIA heat content of 5.248 MMBtu per barrel is used to estimate a C content coefficient of 18.55 Tg C/QBtu.

Step 2. Estimate the carbon content coefficient for petrochemical feedstocks with a boiling temperature 400 degrees Fahrenheit and above (“other oils”)

The boiling temperature of this product places it into the “middle distillate” fraction in the refining process, and EIA estimates that these petrochemical feedstocks have the same heat content as distillate fuel No. 2. Thus, the C content

coefficient of 20.17 Tg C/QBtu used for distillate fuel No. 2 is also adopted for this portion of the petrochemical feedstocks category.

Data Sources

Naphthas: Data on the C content was taken from Unzelman (1992). Density is from Meyers (2004). A standard heat content for naphthas was adopted from EIA (2009a). Other oils: See Distillate Fuel, Distillate No.2.

Uncertainty

Petrochemical feedstocks are not so much distinguished on the basis of chemical composition as on the identity of the purchaser, who are presumed to be a chemical company or a petrochemical unit co-located on the refinery grounds. Naphthas are defined, for the purposes of U.S. energy statistics, as those naphtha products destined for use as a petrochemical feedstock. Because naphthas are also commonly used to produce motor gasoline, there exists a considerable degree of uncertainty about the exact composition of petrochemical feedstocks.

Different naphthas are distinguished by their density and by the share of paraffins, isoparaffins, olefins, naphthenes and aromatics contained in the oil. Naphtha from the same crude oil fraction may have vastly different properties depending on the source of the crude. Two different samples of Egyptian crude, for example, produced two straight run naphthas having naphthene and paraffin contents (percent volume) that differ by 18.1 and 17.5 percent, respectively (Matar and Hatch, 2000).

Naphthas are typically used either as a petrochemical feedstock or a gasoline feedstock, with lighter paraffinic naphthas going to petrochemical production. Naphthas that are rich in aromatics and naphthenes tend to be reformed or blended into gasoline. Thus, the product category encompasses a range of possible fuel compositions, creating a range of possible C shares and densities. The uncertainty associated with the calculated C content of naphthas is primarily a function of the uncertainty that underlies the average carbon share calculation, which is based on a limited number of samples. Two additional samples cited by the EIA (1994) have a range of 83.80 to 84.42 percent C.

The uncertainty of the carbon content for other oils is based upon the assumption of distillate oil No. 2 as a product representative of the ill-defined classification of "other oils," and from the calculation of the C content of No. 2 itself (see "Distillate Fuels," above). While No. 2 distillate is used as a proxy for "other oils" for the purposes of this inventory's carbon coefficient, important differences exist between these two petroleum products, contributing some uncertainty to the cross-application. Other oils are defined herein as those "oils with a boiling range equal to or greater than 401°F that are generally intended for use as a petrochemical feedstock and are not defined elsewhere." For comparison, various material safety data sheets (MSDSs) published by producers of distillate No. 2 indicate a boiling range for this product of 320-700 degrees Fahrenheit. The relatively open definition of the classification "other oils" leaves room for potentially significant variation in the heating value, density and carbon share properties of each feedstock oil having a boiling point above 400 degrees Fahrenheit, creating a large band of uncertainty beyond that associated with the C factor for distillate No. 2.

Kerosene

A light petroleum distillate that is used in space heaters, cook stoves, and water heaters and is suitable for use as a light source when burned in wick-fed lamps, kerosene is drawn from the same petroleum fraction as jet fuel. Kerosene is generally comparable to No.1 distillate oil.

Methodology

The average density and C share of kerosene are assumed to be the same as those for distillate No. 1 since the physical characteristics of the products are very similar. Thus, a density of 35.3 degrees API and average C share of 86.40 percent were applied to a standard heat content for distillate No. 1 of 5.825 MMBtu per barrel to yield a C content coefficient of 19.96 Tg C/QBtu.

Data Sources

A standard heat content for distillate No.1 was adopted from EIA (2009a).

Uncertainty

Uncertainty in the estimated C content for kerosene is driven by the selection of distillate No. 1 as a proxy for kerosene. If kerosene is more like kerosene-based jet fuel, the true C content coefficient is likely to be some 1.3 percent lower. If kerosene is more aptly compared to No. 2 distillate oil, then the true C content coefficient is likely to be about

1.1 percent higher. While kerosene is a light petroleum distillate, like distillate No. 1, the two oil classes are do have some variation in their properties. For example, the boiling range of kerosene is 250-550 degrees Fahrenheit, whereas No. 1 oils typically boil over a range from 350-615 degrees Fahrenheit. The properties of individual kerosenes will vary with their use and particular crude origin, as well. Both kerosene and fuel oil No. 1 are primarily composed of hydrocarbons having 9 to 16 carbon atoms per molecule. However, kerosene is a straight-run No. 1 fuel oil, additional cracking processes and additives contribute to the range of possible fuels that make up the broader distillate No. 1 oil category.

Petroleum Coke

Petroleum coke is the solid residue by-product of the extensive processing of crude oil. It is a coal-like solid, usually has a C content greater than 90 percent, and is used as a boiler fuel and industrial raw material.

Methodology

Ultimate analyses of two samples of petroleum coke showed an average C share of 92.28 percent. The ASTM standard density of 9.543 pounds per gallon was adopted and the EIA standard energy content of 6.024 MMBtu per barrel assumed. Together, these factors produced an estimated C content coefficient of 27.85 Tg C/QBtu.

Data Sources

C content was derived from two samples from Martin, S.W. (1960). The density of petroleum coke was taken from the ASTM (1985). A standard heat content for petroleum coke was adopted from EIA (2009a).

Uncertainty

The uncertainty associated with the estimated C content coefficient of petroleum coke can be traced to two factors: the use of only two samples to establish C contents and a standard heat content which may be too low. Together, these uncertainties are likely to bias the C content coefficient upwards by as much as 6 percent.

Special Naphtha

Special naphtha is defined as a light petroleum product to be used for solvent applications, including commercial hexane and four classes of solvent: Stoddard solvent, used in dry cleaning; high flash point solvent, used as an industrial paint because of its slow evaporative characteristics; odorless solvent, most often used for residential paints; and high solvency mineral spirits, used for architectural finishes. These products differ in both density and C percentage, requiring the development of multiple coefficients.

Methodology

The method for estimating the C content coefficient of special naphtha includes three steps.

Step 1. Estimate the carbon content coefficient for hexane

Hexane is a pure paraffin containing 6 C atoms and 14 hydrogen atoms; thus, it is 83.63 percent C. Its density is 83.7 degrees API or 5.477 pounds per gallon and its derived C content coefficient is 21.40 Tg C/QBtu.

Step 2. Estimate the carbon contents of non-hexane special naphthas

The hydrocarbon compounds in special naphthas are assumed to be either paraffinic or aromatic (see discussion above). The portion of aromatics in odorless solvents is estimated at less than 1 percent, Stoddard and high flash point solvents contain 15 percent aromatics and high solvency mineral spirits contain 30 percent aromatics (Boldt and Hall 1977). These assumptions, when combined with the relevant densities, yield the C content factors contained in Table A-49, below.

Table A-49: Characteristics of Non-hexane Special Naphthas

Special Naphtha	Aromatic Content (Percent)	Density (Degrees API)	Carbon Share (Percent Mass)	Carbon Content (Tg C/QBtu)
Odorless Solvent	1	55.0	84.51	19.41
Stoddard Solvent	15	47.9	84.44	20.11
High Flash Point	15	47.6	84.70	20.17
Mineral Spirits	30	43.6	85.83	20.99

Sources: EIA (2008b) and Boldt and Hall (1977).

Step 3. Develop weighted carbon content coefficient based on consumption of each special naphtha

EIA reports only a single consumption figure for special naphtha. The C contents of the five special naphthas are weighted according to the following formula: approximately 10 percent of all special naphtha consumed is hexane; the remaining 90 percent is assumed to be distributed evenly among the four other solvents. The resulting emissions coefficient for special naphthas is 19.74 Tg C/QBtu.

Data Sources

A standard heat content for special naphtha was adopted from EIA (2009a). Density and aromatic contents were adopted from Boldt and Hall (1977).

Uncertainty

The principal uncertainty associated with the estimated C content coefficient for special naphtha is the allocation of overall consumption across individual solvents. The overall uncertainty is bounded on the low end by the C content of odorless solvent and on the upper end by the C content of hexane. This implies an uncertainty band of -1.7 percent to +8.4 percent.

Petroleum Waxes

The ASTM standards define petroleum wax as a product separated from petroleum that is solid or semi-solid at 77 degrees Fahrenheit (25 degrees Celsius). The two classes of petroleum wax are paraffin waxes and microcrystalline waxes. They differ in the number of C atoms and the type of hydrocarbon compounds. Microcrystalline waxes have longer C chains and more variation in their chemical bonds than paraffin waxes.

Methodology

The method for estimating the C content coefficient for petroleum waxes includes three steps.

Step 1. Estimate the carbon content of paraffin waxes

For the purposes of this analysis, paraffin waxes are assumed to be composed of 100 percent paraffinic compounds with a chain of 25 C atoms. The resulting C share for paraffinic wax is 85.23 percent and the density is estimated at 45 degrees API or 6.684 pounds per gallon.

Step 2. Estimate the carbon content of microcrystalline waxes

Microcrystalline waxes are assumed to consist of 50 percent paraffinic and 50 percent cycloparaffinic compounds with a chain of 40 C atoms, yielding a C share of 85.56 percent. The density of microcrystalline waxes is estimated at 36.7 degrees API, based on a sample of 10 microcrystalline waxes found in the *Petroleum Products Handbook*.

Step 3. Develop a carbon content coefficient for petroleum waxes by weighting the density and carbon content of paraffinic and microcrystalline waxes

A weighted average density and C content was calculated for petroleum waxes, assuming that wax consumption is 80 percent paraffin wax and 20 percent microcrystalline wax. The weighted average C content is 85.30 percent, and the weighted average density is 6.75 pounds per gallon. EIA's standard heat content for waxes is 5.537 MMBtu per barrel. These inputs yield a C content coefficient for petroleum waxes of 19.80 Tg C/QBtu.

Data Sources

Density of paraffin wax was taken from ASTM (1985). Density of microcrystalline waxes was derived from 10 samples found in Guthrie (1960). A standard heat content for petroleum waxes was adopted from EIA (2009a).

Uncertainty

Although there is considerable qualitative uncertainty associated with the allocation of petroleum waxes and microcrystalline waxes, the quantitative variation in the C contents for all waxes is limited to ± 1 percent because of the nearly uniform relationship between C and other elements in petroleum waxes broadly defined.

Crude Oil, Unfinished Oils, and Miscellaneous Products

U.S. energy statistics include several categories of petroleum products designed to ensure that reported refinery accounts "balance" and cover any "loopholes" in the taxonomy of petroleum products. These categories include crude oil,

unfinished oils, and miscellaneous products. Crude oil is rarely consumed directly, miscellaneous products account for less than one percent of oil consumption, and unfinished oils are a balancing item that may show negative consumption. For C accounting purposes, it was assumed that all these products have the same C content as crude oil.

Methodology

EIA reports on the average density and sulfur content of U.S. crude oil purchased by refineries. To develop a method of estimating C content based on this information, results of ultimate analyses of 182 crude oil samples were collected. Within the sample set, C content ranged from 82 to 88 percent C, but almost all samples fell between 84 percent and 86 percent C. The density and sulfur content of the crude oil data were regressed on the C content, producing the following equation:

$$\text{Percent C} = 76.99 + (10.19 \times \text{Specific Gravity}) + (-0.76 \times \text{Sulfur Content})$$

Absent the term representing sulfur content, the equation had an R-squared of only 0.35.²¹ When C content was adjusted to exclude sulfur, the R-squared value rose to 0.65. While sulfur is the most important non-hydrocarbon impurity, nitrogen and oxygen can also be significant, but they do not seem to be correlated with either density or sulfur content. Restating these results, density accounts for about 35 percent of the variation in C content, impurities account for about 30 percent of the variation, and the remaining 35 percent is accounted for by other factors, including (presumably) the degree to which aromatics and polynuclear aromatics are present in the crude oil. Applying this equation to the 2008 crude oil quality data (30.21 degrees API and 1.47 percent sulfur) produces an estimated C content of 84.79 percent. Applying the density and C content to the EIA standard energy content for crude oil of 5.800 MMBtu per barrel produced an emissions coefficient of 20.31 Tg C/QBtu.

Data Sources

C content was derived from 182 crude oil samples, including 150 samples from U.S. National Research Council (1927). A standard heat content for crude oil was adopted from EIA (2009a).

Uncertainty

The uncertainty of the estimated C content for crude oil centers on the 35 percent of variation that cannot be explained by density and sulfur content. This variation is likely to alter the C content coefficient by ± 3 percent. Since unfinished oils and miscellaneous products are impossible to define, the uncertainty of applying a crude oil C content is likely to be bounded by the range of petroleum products described in this chapter at ± 10 percent.

Chronology and Explanation of Changes in Individual Carbon Content Coefficients of Fossil Fuels

Coal

Original 1994 Analysis

A set of 5,426 coal samples from the EIA coal analysis file were used to develop carbon content estimates. The results from that sample set appear below in Table A-50. The EIA Coal Analysis File was originally developed by the U.S. Bureau of Mines and contained over 60,000 coal samples obtained through numerous coal seams throughout the United States. Many of the samples were collected starting in the 1940s and 1950s through the 1980s and analyzed in U.S. government laboratories.

Table A-50: Carbon Content Coefficients for Coal by Consuming Sector and Coal Rank, 1990 – 2000 (Tg C/QBtu)

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Consuming Sector											
Electric Power	25.68	25.69	25.69	26.71	25.72	25.74	25.74	25.76	25.76	25.76	25.76
Industrial Coking	25.51	25.51	25.51	25.51	25.52	25.53	25.55	25.56	25.56	25.56	25.56
Other Industrial	25.58	25.59	25.62	25.61	25.63	25.63	25.61	25.63	25.63	25.63	25.63
Residential/Commercial	25.92	26.00	26.13	25.97	25.95	26.00	25.92	26.00	26.00	26.00	26.00
Coal Rank											
Anthracite	28.13	28.13	28.13	28.13	28.13	28.13	28.13	28.13	28.13	28.13	28.13

²¹ R-squared represents the percentage of variation in the dependent variable (in this case carbon content) explained by variation in the independent variables.

Bituminous	25.37	25.37	25.37	25.37	25.37	25.37	25.37	25.37	25.37	25.37	25.37
Subbituminous	26.24	26.24	26.24	26.24	26.24	26.24	26.24	26.24	26.24	26.24	26.24
Lignite	26.62	26.62	26.62	26.62	26.62	26.62	26.62	26.62	26.62	26.62	26.62

Sources: Emission factors by consuming sector from B.D. Hong and E.R. Slatnick, "Carbon Dioxide Emission Factors for Coal," U.S. Energy Information Administration, *Quarterly Coal Report*, January-March 1994. (Washington, DC, 1994) and Emission factors by rank from Science Applications International Corporation, "Analysis of the Relationship Between Heat and Carbon Content of U.S. Fuels: Final Task Report," Prepared for the U.S. Energy Information Administration, Office of Coal, Nuclear, Electric and Alternative Fuels (Washington, DC 1992).

2002 Update

The methodology employed for these estimates was unchanged from previous years; however, the underlying coal data sample set was updated. A new database, CoalQual 2.0 (1998), compiled by the U.S. Geological Survey was adopted for the updated analysis. The updated sample set included 6,588 coal samples collected by the USGS and its state affiliates between 1973 and 1989. The decision to switch to the sample data contained in the USGS CoalQual database from the EIA database was made because the samples contained in the USGS database were collected and analyzed more recently than those obtained by EIA from the Bureau of Mines. The new coefficients developed in the 2002 revision were in use through the 1990-2007 Inventory and are provided in Table A-51, below.

Table A-51: Carbon Content Coefficients for Coal by Consuming Sector and Coal Rank, 1990 – 2000 (Tg C/QBtu)

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Consuming Sector											
Electric Power	25.68	25.69	25.69	25.71	25.72	25.74	25.74	25.76	25.76	25.76	25.76
Industrial Coking	25.51	25.51	25.51	25.51	25.52	25.53	25.55	25.56	25.56	25.56	25.56
Other Industrial	25.58	25.60	25.62	25.61	25.63	25.63	25.61	25.63	25.63	25.63	25.63
Residential/Commercial	25.92	26.00	26.13	25.97	25.95	26.00	25.92	26.00	26.00	26.00	26.00
Coal Rank											
Anthracite	28.26	28.26	28.26	28.26	28.26	28.26	28.26	28.26	28.26	28.26	28.26
Bituminous	25.43	25.45	25.44	25.45	25.46	25.47	25.47	25.48	25.47	25.48	25.49
Sub-bituminous	26.50	26.49	26.49	26.48	26.49	26.49	26.49	26.49	26.49	26.49	26.48
Lignite	26.19	26.21	26.22	26.21	26.24	26.22	26.17	26.20	26.23	26.26	26.30

Sources: Data from USGS, U.S. Coal Quality Database Version 2.0 (1998) and analysis prepared by SAIC, 2007.

2007 Update

The analysis of the USGS Coal Qual data was updated in 2007 to make a technical correction that affected the value for lignite and those sectors which consume lignite Table A-52 contains the annual coefficients that resulted from the 2007 analysis.

Table A-52: Carbon Content Coefficients for Coal by Consuming Sector and Coal Rank, 1990-2007 [Tg C/QBtu]

	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Consuming Sector														
Electric Power	25.68	25.74	25.74	25.76	25.76	25.76	25.76	25.76	25.76	25.76	25.76	25.76	25.76	25.76
Industrial Coking	25.51	25.53	25.55	25.56	25.56	25.56	25.56	25.56	25.56	25.56	25.56	25.56	25.56	25.56
Other Industrial	25.58	25.63	25.61	25.63	25.63	25.63	25.63	25.63	25.63	25.63	25.63	25.63	25.63	25.63
Residential/Commercial	25.92	26.00	25.92	26.00	26.00	26.00	26.00	26.00	26.00	26.00	26.00	26.00	26.00	26.00
Coal Rank														
Anthracite	28.26	28.26	28.26	28.26	28.26	28.26	28.26	28.26	28.26	28.26	28.26	28.26	28.26	28.26
Bituminous	25.43	25.47	25.47	25.48	25.47	25.48	25.49	25.49	25.49	25.49	25.49	25.49	25.49	25.49
Sub-bituminous	26.50	26.49	26.49	26.49	26.49	26.49	26.48	26.48	26.48	26.48	26.48	26.48	26.48	26.48
Lignite	26.19	26.22	26.17	26.20	26.23	26.26	26.30	26.30	26.30	26.30	26.30	26.30	26.30	26.57

Sources: Data from USGS, U.S. Coal Quality Database Version 2.0 (1998) and analysis prepared by (SAIC 2007).

2010 Update

The estimated annual C content coefficients for coal by rank and sector of consumption were updated again in 2010. Sample data from the Energy Institute at Pennsylvania State University (504 samples) were added to the 6,588 USGS samples to create a new database of 7,092 samples. The same analytical method used in the 2002 update was applied using these additional samples to calculate revised state-level carbon contents for each coal rank and then for national average consumption by end-use sector and by rank.

Natural Gas

A revised analytical methodology underlies the natural gas coefficients used in this report. Prior to the current Inventory, descriptive statistics were used to stratify 6,743 samples of pipeline quality natural gas by heat content and then to determine the average C content of natural gas at the national average heat content (EIA 1994). The same coefficient was applied to all pipeline natural gas consumption for all years, because U.S. energy statistics showed a range of national average heat contents of pipeline gas of only 1,025 to 1,031 Btu per cubic foot (1 percent) from 1990 through 1994. A separate factor was developed in the same manner for all flared gas. In the previous Inventory, a weighted national average C content was calculated using the average C contents for each sub-sample of gas that conformed with an individual state's typical cubic foot of natural gas since there is regional variation in energy content. The result was a weighted national average of 14.47 Tg C/QBtu.

The current Inventory is revised to make use of the same set of samples, but utilizes a regression equation, as described above, of sample-based heat content and carbon content data in order to calculate annually-variable national average C content coefficients based on annual national average heat contents for pipeline natural gas and for flare gas. In addition, the revised analysis calculates an average C content from all samples with less than 1.5 percent CO₂ and less than 1,050 Btu/cf (samples most closely approximating the makeup of pipeline quality natural gas). The result was identical to the previous weighted national average of 14.47 Tg C/QBtu. The average C contents from the 1994 calculations are presented in Table A-53 below for comparison.

Table A-53: Carbon Content of Pipeline-Quality Natural Gas by Energy Content (Tg C/QBtu)

Sample	Average Carbon Content
GRI Full Sample	14.51
Greater than 1,000 Btu	14.47
1,025 to 1,035 Btu	14.45
975 to 1,000 Btu	14.73
1,000 to 1,025 Btu	14.43
1,025 to 1,050 Btu	14.47
1,050 to 1,075 Btu	14.58
1,075 to 1,100 Btu	14.65
Greater than 1,100 Btu	14.92
Weighted National Average	14.47

Source: EIA (1994).

Petroleum Products

All of the petroleum product carbon coefficients except that for Aviation Gasoline Blending Components have been updated for the current Inventory. EPA is updating these factors to better align the fuel properties data that underlie the Inventory factors with those published in the Mandatory Reporting of Greenhouse Gases Rule (EPA 2009b), Suppliers of Petroleum Products (MM) and Stationary Combustion (C) subparts. The coefficients that were applied in the previous report are provided in Table A-49 below. Specifically, each of the coefficients used in this report have been calculated from updated density and C share data, largely adopted from analyses undertaken for the Rule (EPA 2009b). In some cases, the heat content applied to the conversion to a carbon-per-unit-energy basis has also been updated. Additionally, the category Misc. Products (Territories), which is based upon the coefficients calculated for crude oil, has been allowed to vary annually with the crude oil coefficient. The petrochemical feedstock category has been eliminated for this report because the constituent products – naphthas and other oils – are estimated independently. Further, although the level of aggregation of U.S. energy statistics currently limits the application of coefficients for residual and distillate fuels to these two generic classifications, individual coefficients for the five major types of fuel oil (Nos. 1, 2, 4, 5 and 6) have been estimated for the current report and are presented in Table A-43 above. Each of the C coefficients applied in the previous Inventory is provided below for comparison (Table A-54).

Table A-54: Carbon Content Coefficients and Underlying Data for Petroleum Products

Fuel	2007 Carbon Content (Tg C/QBtu)	Gross Heat of Combustion (MMBtu/Barrel)	Density (API Gravity)	Percent Carbon
Motor Gasoline	19.33	5.219	59.1	86.60
LPG(total)	16.99	a	a	a
LPG (energy use)	17.18	a	a	a
LPG (non-energy use)	16.76	a	a	a
Jet Fuel	19.33	5.670	42.0	86.30
Distillate Fuel	19.95	5.825	35.5	86.34
Residual Fuel	21.49	6.287	11.0	85.68
Asphalt and Road Oil	20.62	6.636	5.6	83.47
Lubricants	20.24	6.065	25.6	85.80
Petrochemical				
Feedstocks	19.37	5.248 ^b	67.1 ^b	84.11 ^b
Aviation Gas	18.87	5.048	69.0	85.00
Kerosene	19.72	5.670	41.4	86.01
Petroleum Coke	27.85	6.024	-	92.28
Special Naphtha	19.86	5.248	51.2	84.76
Petroleum Waxes	19.81	5.537	43.3	85.29
Still Gas	17.51	6.000	-	-
Crude Oil	20.33	5.800	30.5	85.49
Unfinished Oils	20.33	5.825	30.5	85.49
Miscellaneous Products	20.33	5.796	30.5	85.49
Pentanes Plus	18.24	4.620	81.7	83.70
Natural Gasoline	14.47	4.620	81.7	83.70

^a LPG is a blend of multiple paraffinic hydrocarbons: ethane, propane, isobutane, and normal butane, each with their own heat content, density and C content, see Table A-46.

^b Parameters presented are for naphthas with a boiling temperature less than 400 degrees Fahrenheit. Petrochemical feedstocks with higher boiling points are assumed to have the same characteristics as distillate fuel.

- No sample data available

Sources: EIA (1994), EIA (2008a), and SAIC (2007).

Additional revisions to the inventory's carbon coefficients since 1990 are detailed below.

Jet Fuel

1995 Update

Between 1994 and 1995, the C content coefficient for kerosene-based jet fuel was revised downward from 19.71 Tg C/QBtu to 19.33 Tg C/QBtu. This downward revision was the result of a shift in the sample set used from one collected between 1959 and 1972 and reported on by Martel and Angello in 1977 to one collected by Boeing in 1989 and published by Hadaller and Mumenthly in 1990. The downward revision was a result of a decrease in density, as well as slightly lower C shares than in the earlier samples. However, the assumed heat content is unchanged because it is based on an EIA standard and probably yields a downward bias in the revised C content coefficient.

2008 Inventory Update

The coefficient was revised again for the 2008 inventory, returning to Martel and Angello and NIPER as the source of the carbon share and density data, respectively, for kerosene-based fuels. This change was made in order to align the coefficients used for this report with the values used in the Mandatory Reporting of Greenhouse Gases Rule (EPA 2009b). The return to the use of the Martel and Angello and NIPER coefficients was deemed more appropriate for the Rule as it was considered a more conservative coefficient given the uncertainty and variability in coefficients across the types of jet fuel in use in the U.S. The factor will be revisited in future inventories in light of data received from reporting entities in response to the Rule.

Liquefied Petroleum Gases (LPG)

The C content coefficient of LPG is updated annually to reflect changes in the consumption mix of the underlying compounds: ethane; propane; isobutane; and normal butane. In 1994, EIA included pentanes plus—assumed to have the characteristics of hexane—in the mix of compounds broadly described as LPG. In 1995, EIA removed

pentanes plus from this fuel category. Because pentanes plus is relatively rich in C per unit of energy, its removal from the consumption mix lowered the C content coefficient for LPG from 17.26 Tg C/QBtu to 16.99 Tg C/QBtu. In 1998, EIA began separating LPG consumption into two categories: energy use and non-fuel use and providing individual coefficients for each. Because LPG for fuel use typically contains higher proportions of propane than LPG for non-fuel use, the C content coefficient for fuel use was 1.8 to 2.5 percent higher than the coefficient for non-fuel use in previous Inventories (see Table A-49).

However, for the current update of the LPG coefficients, the assumptions that underlie the selection of density and heat content data for each pure LPG compound have been updated, leading to a significant revision of the assumed properties of ethane. For this report, the physical characteristics of ethane, which constitutes over 90 percent of LPG consumption for non-fuel uses, have been updated to reflect ethane that is in (refrigerated) liquid form. Previously, the share of ethane was included using the density and energy content of gaseous ethane. Table A-55, below, compares the values applied for each of the compounds under the two sets of coefficient calculations. The carbon share of each pure compound was also updated by using more precise values for each compound's molecular weight.

Due in large part to the revised assumptions for ethane, the weighted C content for non-fuel use is now higher than that of the weighted coefficient for fuel use, which is dominated by the consumption of more dense propane. Under the revised assumptions, each annual weighted coefficient for non-fuel LPG consumption is 1.2 to 1.7 percent higher each year than is that for LPGs consumed for fuel (energy) uses.

Table A-55: Physical Characteristics of Liquefied Petroleum Gases

Compound	Chemical Formula	1990-2007	Updated	1990-2007	Updated	1990-2007	Updated
		Density (bbl / MT)	Density (bbl / MT)	Energy Content (MMBtu/bbl)	Energy Content (MMBtu/bbl)	C Content Coefficient (Tg C/QBtu)	C Content Coefficient (Tg C/QBtu)
Ethane	C ₂ H ₆	16.88	11.55	2.916	3.082	16.25	17.16
Propane	C ₃ H ₈	12.44	12.76	3.824	3.836	17.20	16.76
Isobutane	C ₄ H ₁₀	11.20	11.42	4.162	3.974	17.75	17.77
n-butane	C ₄ H ₁₀	10.79	10.98	4.328	4.326	17.72	17.75

Sources: Updated: Densities – CRC Handbook of Chemistry and Physics, 89th Ed. (2008/09); Energy Contents – EPA (2009b). All values are for the compound in liquid form. The density and energy content of ethane are for refrigerated ethane (-89 degrees C). Values for n-butane are for pressurized butane (-25 degrees C). Values in previous editions of this inventory: Gurthrie (1960).

Motor Gasoline

The C content coefficient for motor gasoline varies annually based on the density of and proportion of additives in a representative sample of motor gasoline examined each year. However, in 1997 EIA began incorporating the effects of the introduction of reformulated gasoline into its estimate of C content coefficients for motor gasoline. This change resulted in a downward step function in C content coefficients for gasoline of approximately 0.3 percent beginning in 1995. In 2005-2006 reformulated fuels containing ethers began to be phased out nationally. Ethanol was added to gasoline blends as a replacement oxygenate, leading to another shift in gasoline density (see Table A- 44), in the list and proportion of constituents that form the blend and in the blended C share based on those constituents.

Table A-56: Carbon Content Coefficients for Petroleum Products, 1990-2007 [Tg C/QBtu]

Fuel Type	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Petroleum														
Asphalt and Road Oil	20.62	20.62	20.62	20.62	20.62	20.62	20.62	20.62	20.62	20.62	20.62	20.62	20.62	20.62
Aviation Gasoline	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87
Distillate Fuel Oil	19.95	19.95	19.95	19.95	19.95	19.95	19.95	19.95	19.95	19.95	19.95	19.95	19.95	19.95
Jet Fuel ^a	19.40	19.34	19.33	19.33	19.33	19.33	19.33	19.33	19.33	19.33	19.33	19.33	19.33	19.33
Kerosene	19.72	19.72	19.72	19.72	19.72	19.72	19.72	19.72	19.72	19.72	19.72	19.72	19.72	19.72
LPG (energy use) ^a	17.21	17.20	17.20	17.18	17.23	17.25	17.20	17.21	17.20	17.21	17.20	17.19	17.19	17.18
LPG (non-energy use) ^a	16.83	16.87	16.86	16.88	16.88	16.84	16.81	16.83	16.82	16.84	16.81	16.81	16.78	16.76
Lubricants	20.24	20.24	20.24	20.24	20.24	20.24	20.24	20.24	20.24	20.24	20.24	20.24	20.24	20.24
Motor Gasoline ^a	19.41	19.38	19.36	19.35	19.33	19.33	19.34	19.34	19.35	19.33	19.33	19.33	19.33	19.33
Residual Fuel	21.49	21.49	21.49	21.49	21.49	21.49	21.49	21.49	21.49	21.49	21.49	21.49	21.49	21.49
Other Petroleum														
Av Gas Blend Comp.	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87	18.87
Mo Gas Blend Comp ^a	19.41	19.38	19.36	19.35	19.33	19.33	19.34	19.34	19.35	19.33	19.33	19.33	19.33	19.33
Crude Oil ^a	20.16	20.23	20.25	20.24	20.24	20.19	20.23	20.29	20.30	20.28	20.33	20.33	20.33	20.33
Misc. Products ^a	20.16	20.23	20.25	20.24	20.24	20.19	20.23	20.29	20.30	20.28	20.33	20.33	20.33	20.33
Misc. Products (Terr.)	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00
Naphtha (<401 deg. F)	18.14	18.14	18.14	18.14	18.14	18.14	18.14	18.14	18.14	18.14	18.14	18.14	18.14	18.14
Other oil (>401 deg. F)	19.95	19.95	19.95	19.95	19.95	19.95	19.95	19.95	19.95	19.95	19.95	19.95	19.95	19.95
Pentanes Plus	18.24	18.24	18.24	18.24	18.24	18.24	18.24	18.24	18.24	18.24	18.24	18.24	18.24	18.24
Petrochemical Feed.	19.37	19.37	19.37	19.37	19.37	19.37	19.37	19.37	19.37	19.37	19.37	19.37	19.37	19.37
Petroleum Coke	27.85	27.85	27.85	27.85	27.85	27.85	27.85	27.85	27.85	27.85	27.85	27.85	27.85	27.85
Still Gas	17.51	17.51	17.51	17.51	17.51	17.51	17.51	17.51	17.51	17.51	17.51	17.51	17.51	17.51
Special Naphtha	19.86	19.86	19.86	19.86	19.86	19.86	19.86	19.86	19.86	19.86	19.86	19.86	19.86	19.86
Unfinished Oils ^a	20.16	20.23	20.25	20.24	20.24	20.19	20.23	20.29	20.30	20.28	20.33	20.33	20.33	20.33
Waxes	19.81	19.81	19.81	19.81	19.81	19.81	19.81	19.81	19.81	19.81	19.81	19.81	19.81	19.81
Other Wax and Misc.	19.81	19.81	19.81	19.81	19.81	19.81	19.81	19.81	19.81	19.81	19.81	19.81	19.81	19.81

^aC contents vary annually based on changes in fuel composition.

^bC content for utility coal used in the electric power calculations. All coefficients based on higher heating value. Higher heating value (gross heating value) is the total amount of heat released when a fuel is burned. Coal, crude oil, and natural gas all include chemical compounds of carbon and hydrogen. When those fuels are burned, the carbon and hydrogen combine with oxygen in the air to produce CO₂ and water. Some of the energy released in burning goes into transforming the water into steam and is usually lost. The amount of heat spent in transforming the water into steam is counted as part of gross heat content. Lower heating value (net heating value), in contrast, does not include the heat spent in transforming the water into steam. Using a simplified methodology based on International Energy Agency defaults, higher heating value can be converted to lower heating value for coal and petroleum products by multiplying by 0.95 and for natural gas by multiplying by 0.90. Carbon content coefficients are presented in higher heating value because U.S. energy statistics are reported by higher heating value.

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2.3. Methodology for Estimating Carbon Emitted from Non-Energy Uses of Fossil Fuels

Carbon (C) storage associated with the non-energy use of fossil fuels was calculated by multiplying each fuel's potential emissions (i.e., each fuel's total C content) by a fuel-specific storage factor, as listed in Table A-57. The remaining C—i.e., that which is not stored—is emitted. This sub-annex explains the methods and data sources employed in developing the storage factors for petrochemical feedstocks (industrial other coal, natural gas for non-fertilizer uses, LPG, pentanes plus, naphthas, other oils, still gas, special naphtha), asphalt and road oil, lubricants, waxes, and miscellaneous products. The storage factors²² for the remaining non-energy fuel uses are either based on values recommended for use by IPCC (2006), or when these were not available, assumptions based on the potential fate of C in the respective NEU products.

Table A-57: Fuel Types and Percent of C Stored for Non-Energy Uses

Sector/Fuel Type	Storage Factor (%)
Industry	-
Industrial Coking Coal ^a	10
Industrial Other Coal ^b	58
Natural Gas to Chemical Plants ^b	58
Asphalt & Road Oil	100
LPG ^b	58
Lubricants	9
Pentanes Plus ^b	58
Naphtha (<401 deg. F) ^b	58
Other Oil (>401 deg. F) ^b	58
Still Gas ^b	58
Petroleum Coke ^c	30
Special Naphtha ^b	58
Distillate Fuel Oil	50
Waxes	58
Miscellaneous Products	0
Transportation	-
Lubricants	9
U.S. Territories	-
Lubricants	9
Other Petroleum (Misc. Prod.)	10

- Not applicable

^a Includes processes for which specific coking coal consumption and emission factor data are not available. Consumption of coking coal for production of iron and steel is covered in the Industrial Processes chapter.

^b The storage factor listed is the value for 2009. As described in this annex, the factor varies over time.

^c Assumes petroleum coke consumption is for pigments. Consumption of petroleum coke for production of primary aluminum anodes, electric arc furnace anodes, titanium dioxide, ammonia, urea, and ferroalloys is covered in the Industrial Processes chapter.

The following sections describe the non-energy uses in greater detail, outlining the methods employed and data used in estimating each storage factor. Several of the fuel types tracked by EIA are used in organic chemical synthesis and in other manufacturing processes, and are referred to collectively as “petrochemical feedstocks.” Because the methods and data used to analyze them overlap, they are handled as a group and are discussed first. Discussions of the storage factors for asphalt and road oil, lubricants, waxes, and miscellaneous products follow.

²² Throughout this section, references to “storage factors” represent the proportion of carbon stored.

Petrochemical Feedstocks

Petrochemical feedstocks—industrial other coal, natural gas for non-fertilizer uses, LPG, pentanes plus, naphthas, other oils, still gas, special naphtha—are used in the manufacture of a wide variety of man-made chemicals and products. Plastics, rubber, synthetic fibers, solvents, paints, fertilizers, pharmaceuticals, and food additives are just a few of the derivatives of these fuel types. Chemically speaking, these fuels are diverse, ranging from simple natural gas (i.e., predominantly CH₄) to heavier, more complex naphthas and other oils.²³

After adjustments for (1) use in industrial processes and (2) net exports, these eight fuel categories constituted approximately 189.1 Tg CO₂ Eq., or 62% percent, of the 306.1 Tg CO₂ Eq. of non-energy fuel consumption in 2009. For 2009 the storage factor for the eight fuel categories was 58 percent. In other words, of the net consumption, 58 percent was destined for long-term storage in products—including products subsequently combusted for waste disposal—while the remaining 42 percent was emitted to the atmosphere directly as CO₂ (e.g., through combustion of industrial byproducts) or indirectly as CO₂ precursors (e.g., through evaporative product use). The indirect emissions include a variety of organic gases such as volatile organic compounds (VOCs) and carbon monoxide (CO), which eventually oxidize into CO₂ in the atmosphere. The derivation of the storage factor is described in the following sections.

Methodology and Data Sources

The petrochemical feedstocks storage factor is equal to the ratio of C stored in the final products to total C content for the non-energy fossil fuel feedstocks used in industrial processes, after adjusting for net exports of feedstocks. One aggregate storage factor was calculated to represent all eight fuel feedstock types. The feedstocks were grouped because of the overlap of their derivative products. Due to the many reaction pathways involved in producing petrochemical products (or wastes), it becomes extraordinarily complex to link individual products (or wastes) to their parent fuel feedstocks.

Import and export data for feedstocks were obtained from the Energy Information Administration (EIA) for the major categories of petrochemical feedstocks. EIA's *Petroleum Supply Annual* publication tracks imports and exports of petrochemical feedstocks, including butanes, butylenes, ethane, ethylene, propane, propylene, LPG, and naphthas (i.e., most of the large volume primary chemicals produced by petroleum refineries). These imports and exports are already factored into the U.S. fuel consumption statistics. However, EIA does not track imports and exports of chemical intermediates and products produced by the chemical industry (e.g., xylenes, vinyl chloride), which are derived from the primary chemicals produced by the refineries. These products represent very large flows of C derived from fossil fuels (i.e., fossil C), so estimates of net flows not already considered in EIA's dataset were developed for the entire time series from 1990 to 2009.

The approach to estimate imports and exports involves three steps, listed here and then described in more detail below:

- Step 1. Identify commodities derived from petrochemical feedstocks, and calculate net import/export for each.
- Step 2. Estimate the C content for each commodity.
- Step 3. Sum the net C imports/exports across all commodities.

Step 1 relies heavily on information provided by the National Petrochemical and Refiners Association (NPRA) and U.S. Bureau of the Census (BoC) trade statistics published by the U.S. International Trade Commission (USITC). NPRA provided a spreadsheet of the ten-digit BoC Harmonized Tariff Schedule (HTS) Commodity Codes used to compile import-export data for periodic reports issued to NPRA's membership on trade issues. Additional feedstock commodities were identified by HTS code in the BoC data system and included in the net import/export analysis.

One of the difficulties in analyzing trade data is that a large portion of the outputs from the refining industry are fuels and fuel components, and it was difficult to segregate these from the outputs used for non-energy uses. The NPRA-supplied codes identify fuels and fuel components, thus providing a sound basis for isolating net imports/exports of petrochemical feedstocks. Although MTBE and related ether imports are included in the published NPRA data, these commodities are not included in the total net imports/exports calculated here, because it is assumed that they are fuel additives and do not contribute to domestic petrochemical feedstocks. Net exports of MTBE and related ethers are also not included in the totals, as these commodities are considered to be refinery products that are already accounted for in the

²³ Naphthas are compounds distilled from petroleum containing 4 to 12 carbon atoms per molecule and having a boiling point less than 401° F. "Other oils" are distillates containing 12 to 25 carbon atoms per molecule and having a boiling point greater than 401° F.

EIA data. Imports and exports of commodities for which production and consumption data are provided by EIA (e.g., butane, ethylene, and liquefied petroleum gases) are also not included in the totals, to avoid double-counting.

Another difficulty is that one must be careful to assure that there is not double-counting of imports and exports in the data set. Other parts of the mass balance (described later) provide information on C flows, in some cases based on production data and in other cases based on consumption data. Production data relates only to production within the country; consumption data incorporates information on imports and exports as well as production. Because many commodities are emissive in their use, but not necessarily their production, consumption data is appropriately used in calculations for emissive fates. For purposes of developing an overall mass balance on U.S. non-energy uses of C, for those materials that are non-emissive (e.g., plastics), production data is most applicable. And for purposes of adjusting the mass balance to incorporate C flows associated with imports and exports, it was necessary to carefully review whether or not the mass balance already incorporated cross-boundary flows (through the use of consumption data), and to adjust the import/export balance accordingly.

The BoC trade statistics are publicly available²⁴ and cover a complete time series from 1990 to 2009. These statistics include information on imports and exports of thousands of commodities. After collecting information on annual flows of the more than 100 commodities identified by NPRA, Step 2 involves calculating the C content for each commodity from its chemical formula. In cases where the imports and exports were expressed in units of volume, rather than mass, they were converted to mass based on the commodities' densities.

Step 3 involves summing the net C imports/exports across all commodities. The results of this step are shown in Table A-58. As shown in the table, the United States has been a net exporter of chemical intermediates and products throughout the 1990 to 2009 period.

Table A-58: Net Exports of Petrochemical Feedstocks, 1990 – 2009 (Tg CO₂ Eq)

	1990	1995	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Net Exports	12.0	11.1	8.3	1.8	7.3	14.8	20.2	6.5	4.1	8.4	4.5	9.0

After adjusting for imports and exports, the C budget is adjusted for the quantity of C that is used in the Industrial Processes sector of the Inventory. Fossil fuels used for non-energy purposes in industrial processes—and for which C emissions and storage have been characterized through mass balance calculations and/or emission factors that directly link the non-energy use fossil fuel raw material and the industrial process product—are not included in the non-energy use sector. These industrial processes (and their non-energy use fossil fuel raw materials) include iron and steel (coal coke), primary aluminum (petroleum coke), titanium oxide (petroleum coke), ferroalloys (petroleum coke), and ammonia and urea (petroleum coke and natural gas).

For each year of the Inventory, the total C content of non-energy uses was calculated by starting with the EIA estimate of non-energy use, and reducing it by the adjustment factor for net exports (see Table A-58) to yield net domestic fuel consumption for non-energy. The balance was apportioned to either stored C or emissive C, based on a storage factor.

The overall storage factor for the feedstocks was determined by developing a mass balance on the C in feedstocks, and characterizing products, uses, and environmental releases as resulting in either storage or emissions. The total C in the system was estimated by multiplying net domestic consumption for non-energy by the C content of each of the feedstocks (i.e., industrial other coal, natural gas for non-fertilizer uses, LPG, pentanes plus, naphthas, other oils, still gas, special naphtha). C content values for the fuel feedstocks are discussed in the Estimating Emissions from Fossil Fuel Combustion and Estimating the Carbon Content from Fossil Fuel Combustion Annexes.

Next, C pools and releases in a variety of industrial releases, energy recovery processes, and products were characterized. The C fate categories are plastics, energy recovery, synthetic rubber, synthetic fibers, organic solvents, C black, detergents and personal cleansers, industrial non-methane volatile organic compound (NMVOC) emissions, hazardous waste incineration, industrial toxic chemical (i.e., TRI) releases, pesticides, food additives, antifreeze and deicers (glycols), and silicones.²⁵

²⁴ See the U.S. International Trade Commission (USITC) Trade Dataweb at <<http://dataweb.usitc.gov/>>.

²⁵ For the most part, the releases covered by the U.S. Toxic Release Inventory (TRI) represent air emissions or water discharges associated with production facilities. Similarly, VOC emissions are generally associated with production facilities. These emissions could have been accounted for as part of the Waste chapter, but because they are not necessarily associated with waste management, they were included here. Toxic releases are not a “product” category, but they are referred to as such for ease of discussion.

The C in each product or waste produced was categorized as either stored or emitted. The aggregate storage factor is the C-weighted average of storage across fuel types. As discussed later in the section on uncertainty, the sum of stored C and emitted C (i.e., the outputs of the system) exceeded total C consumption (i.e., the inputs to the system) for some years in the time series.²⁶ To address this mass imbalance, the storage factor was calculated as C storage divided by total C outputs (rather than C storage divided by C inputs).

Note that the system boundaries for the storage factor do not encompass the entire life-cycle of fossil-based C consumed in the United States insofar as emissions of CO₂ from waste combustion are accounted for separately in the Inventory and are discussed in the Incineration of Waste section of the Energy chapter.

The following sections provide details on the calculation steps, assumptions, and data sources employed in estimating and classifying the C in each product and waste shown in Table A-59. Summing the C stored and dividing it by total C outputs yields the overall storage factor, as shown in the following equation for 2009:

$$\text{Overall Storage Factor} = \text{C Stored} / (\text{C Stored} + \text{C Emitted}) = \\ 129.3 \text{ Tg CO}_2 \text{ Eq.} / (129.3 + 93.4) \text{ Tg CO}_2 \text{ Eq.} = 58\%$$

Table A-59: C Stored and Emitted by Products from Feedstocks in 2009 (Tg CO₂ Eq.)

Product/Waste Type	C Stored (Tg CO ₂ Eq.)	C Emitted (Tg CO ₂ Eq.)
Industrial Releases	0.1	4.4
TRI Releases	0.1	1.0
Industrial VOCs		2.3
Non-combustion CO		0.7
Hazardous Waste Incin.		0.4
Energy Recovery		74.8
Products	129.2	14.2
Plastics	111.1	
Synthetic Rubber	10.7	
Antifreeze and deicers		0.9
Abraded tire rubber		0.3
Food additives		0.8
Silicones	0.5	
Synthetic Fiber	6.7	
Pesticides	0.3	0.2
Soaps, shampoos, detergents		6.7
Solvent VOCs		5.3
Total	129.3	93.4

- Not applicable

Note: Totals may not sum due to independent rounding.

The three categories of C accounted for in the table are industrial releases, energy recovery, and products. Each is discussed below.

Industrial Releases

Industrial releases include toxic chemicals reported through the Toxics Release Inventory, industrial emissions of volatile organic compounds (VOCs), CO emissions (other than those related to fuel combustion), and emissions from hazardous waste incineration.

²⁶ Overall, there was fairly close agreement between inputs and outputs: for the entire 1990 through 2009 time series, inputs exceeded outputs by a time-weighted average of 0.2 percent. During the period 1990 through 2000, carbon inputs exceeded carbon outputs (i.e., the sum of carbon stored and carbon emitted) by a time-weighted average of 10 percent. For those years, the assumption was made that the “missing” carbon was lost through fates leading to emissions. This discrepancy shifted during the period from 2001 through 2009, in which carbon outputs exceeded carbon inputs by a time-weighted average of 12 percent.

TRI Releases

Fossil-derived C is found in many toxic substances released by industrial facilities. The Toxics Release Inventory (TRI), maintained by EPA, tracks these releases by chemical and environmental release medium (i.e., land, air, or water) on a biennial basis (EPA 2000b). By examining the C contents and receiving media for the top 35 toxic chemicals released, which account for 90 percent of the total mass of chemicals, the quantity of C stored and emitted in the form of toxic releases can be estimated.

The TRI specifies releases by chemical, so C contents were assigned to each chemical based on molecular formula. The TRI also classifies releases by disposal location as either off-site or on-site. The on-site releases are further subdivided into air emissions, surface water discharges, underground injection, and releases to land; the latter is further broken down to disposal in a RCRA Subtitle C (i.e., hazardous waste) landfill or to “Other On-Site Land Disposal.”²⁷ The C released in each disposal location is provided in Table A-60.

Each on-site classification was assigned a storage factor. A 100 percent storage factor was applied to disposition of C to underground injection and to disposal to RCRA-permitted landfills, while the other disposition categories were assumed to result in an ultimate fate of emission as CO₂ (i.e., a storage factor of zero was applied to these categories.) The release allocation is not reported for off-site releases; therefore, the approach was to develop a C-weighted average storage factor for the on-site C and apply it to the off-site releases.

For the remaining 10 percent of the TRI releases, the weights of all chemicals were added and an average C content value, based upon the top 35 chemicals’ C contents, was applied. The storage and emission allocation for the remaining 10 percent of the TRI releases was carried out in the same fashion as for the 35 major chemicals.

Data on TRI releases for the full 1990 through 2009 time series were not readily available. Since this category is small (less than 1 Tg C emitted and stored), the 1998 value was applied for the entire time series.

Table A-60: 1998 TRI Releases by Disposal Location (Gg CO₂ Eq.)

Disposal Location	Carbon Stored (Gg CO₂ Eq.)	Carbon Emitted (Gg CO₂ Eq.)
Air Emissions	-	924.0
Surface Water Discharges	-	6.7
Underground Injection	89.4	-
RCRA Subtitle C Landfill Disposal	1.4	-
Other On-Site Land Releases	-	15.9
Off-site Releases	6.4	36.0
Total	97.2	982.6

- Not applicable

Note: Totals may not sum due to independent rounding.

Volatile Organic Compound Emissions from Industrial Processes and Solvent Evaporation Emissions

Data on annual non-methane volatile organic compound (NMVOC) emissions were obtained from preliminary data (EPA 2010, EPA 2009b), and disaggregated based on EPA (2003b), which, in its final iteration, will be published on the National Emission Inventory (NEI) Air Pollutant Emission Trends web site. The 1990-2009 Trends data include information on NMVOC emissions by end-use category; some of these fall into the heading of “industrial releases” in Table A-60 above, and others are related to “product use”; for ease of discussion, both are covered here. The end-use categories that represent “Industrial NMVOC Emissions” include some chemical and allied products, certain petroleum related industries, and other industrial processes. NMVOC emissions from solvent utilization (product use) were considered to be a result of non-energy use of petrochemical feedstocks. These categories were used to distinguish non-energy uses from energy uses; other categories where VOCs could be emitted due to combustion of fossil fuels were excluded to avoid double counting.

Because solvent evaporation and industrial NMVOC emission data are provided in tons of total NMVOCs, assumptions were made concerning the average C content of the NMVOCs for each category of emissions. The assumptions for calculating the C fraction of industrial and solvent utilization emissions were made separately and differ significantly. For industrial NMVOC emissions, a C content of 85 percent was assumed. This value was chosen to reflect

²⁷ Only the top 9 chemicals had their land releases separated into RCRA Landfills and Other Land Disposal. For the remaining chemicals, it was assumed that the ratio of disposal in these two categories was equal to the carbon-weighted average of the land disposal fate of the top 9 chemicals (i.e., 8 percent attributed to RCRA Landfills and 92 percent in the “Other” category).

the C content of an average volatile organic compound based on the list of the most abundant NMVOCs provided in the Trends Report. The list contains only pure hydrocarbons, including saturated alkanes (C contents ranging from 80 to 85 percent based upon C number), alkenes (C contents approximately 85 percent), and some aromatics (C contents approximately 90 percent, depending upon substitution).

An EPA solvent evaporation emissions dataset (Tooly 2001) was used to estimate the C content of solvent emissions. The dataset identifies solvent emissions by compound or compound category for six different solvent end-use categories: degreasing, graphic arts, dry cleaning, surface coating, other industrial processes, and non-industrial processes. The percent C of each compound identified in the dataset was calculated based on the molecular formula of the individual compound (e.g., the C content of methylene chloride is 14 percent; the C content of toluene is 91 percent). For solvent emissions that are identified in the EPA dataset only by chemical category (e.g., butanediol derivatives) a single individual compound was selected to represent each category, and the C content of the category was estimated based on the C content of the representative compound. The overall C content of the solvent evaporation emissions for 1998, estimated to be 56 percent, is assumed to be constant across the entire time series.

The results of the industrial and solvent NMVOC emissions analysis are provided in Table A-61 for 1990 through 2009. Solvent evaporation emissions in 2009 were 5.3 Tg CO₂ Eq., and industrial NMVOC emissions in 2009 were 2.3 Tg CO₂ Eq.

Table A-61: Industrial and Solvent NMVOC Emissions

	1990	1995	2000	2005	2006	2007	2008	2009
Industrial NMVOCs^a								
NMVOCs ('000 Short Tons)	1,279	1,358	803	824	806	788	769	829
Carbon Content (%)	85%	85%	85%	85%	85%	85%	85%	85%
Carbon Emitted (Tg CO ₂ Eq.)	3.6	3.8	2.3	2.3	2.3	2.2	2.2	2.3
Solvent Evaporation^b								
Solvents ('000 Short Tons)	5,750	6,183	4,832	4,245	4,239	4,232	4,226	2,847
Carbon Content (%)	56%	56%	56%	56%	56%	56%	56%	56%
Carbon Emitted (Tg CO ₂ Eq.)	10.8	11.6	9.0	7.9	7.9	7.9	7.9	5.3

^a Includes emissions from chemical and allied products, petroleum and related industries, and other industrial processes categories.

^b Includes solvent usage and solvent evaporation emissions from degreasing, graphic arts, dry cleaning, surface coating, other industrial processes, and non-industrial processes.

Non-Combustion Carbon Monoxide Emissions

Carbon monoxide (CO) emissions data were also obtained from the NEI preliminary data (EPA 2010, EPA 2009b), and disaggregated based on EPA (2003b).. There are three categories of CO emissions in the report that are classified as process-related emissions not related to fuel combustion. These include chemical and allied products manufacturing, metals processing, and other industrial processes. Some of these CO emissions are accounted for in the Industrial Processes section of this report, and are therefore not accounted for in this section. These include total C emissions from the primary aluminum, titanium dioxide, iron and steel, and ferroalloys production processes. The total C (CO and CO₂) emissions from oil and gas production, petroleum refining, and asphalt manufacturing are also accounted for elsewhere in this Inventory. Biogenic emissions (e.g., pulp and paper process emissions) are accounted for in the Land Use, Land-Use Change and Forestry chapter and excluded from calculation of CO emissions in this section. Those CO emissions that are not accounted for elsewhere are considered to be byproducts of non-fuel use of feedstocks, and are thus included in the calculation of the petrochemical feedstocks storage factor. Table A-62 lists the CO emissions that remain after taking into account the exclusions listed above.

Table A-62: Non-Combustion Carbon Monoxide Emissions^a

	1990	1995	2000	2005	2006	2007	2008	2009
Thousand short tons CO	489	481	623	461	469	477	484	461
Carbon Emitted (Tg CO ₂ Eq.)	0.7	0.7	0.9	0.7	0.7	0.7	0.7	0.7

^a Includes emissions from chemical and allied products, petroleum and related industries, metals processing, and other industrial processes categories.

Hazardous Waste Incineration

Hazardous wastes are defined by the EPA under the Resource Conservation and Recovery Act (RCRA).²⁸ Industrial wastes, such as rejected products, spent reagents, reaction by-products, and sludges from wastewater or air pollution control, are federally regulated as hazardous wastes if they are found to be ignitable, corrosive, reactive, or toxic according to standardized tests or studies conducted by the EPA.

Hazardous wastes must be treated prior to disposal according to the federal regulations established under the authority of RCRA. Combustion is one of the most common techniques for hazardous waste treatment, particularly for those wastes that are primarily organic in composition or contain primarily organic contaminants. Generally speaking, combustion devices fall into two categories: incinerators that burn waste solely for the purpose of waste management, and boilers and industrial furnaces (BIFs) that burn waste in part to recover energy from the waste. More than half of the hazardous waste combusted in the United States is burned in BIFs; because these processes are included in the energy recovery calculations described below, they are not included as part of hazardous waste incineration.

EPA's Office of Solid Waste requires biennial reporting of hazardous waste management activities, and these reports provide estimates of the amount of hazardous waste burned for incineration or energy recovery. EPA stores this information in its Biennial Reporting System (BRS) database (EPA 2000a, 2007a). Combusted hazardous wastes are identified based on EPA-defined management system types M041 through M049 (incineration). Combusted quantities are grouped into four representative waste form categories based on the form codes reported in the BRS: aqueous liquids, organic liquids and sludges, organic solids, and inorganic solids. To relate hazardous waste quantities to C emissions, "fuel equivalent" factors were derived for hazardous waste by assuming that the hazardous wastes are simple mixtures of a common fuel, water, and noncombustible ash. For liquids and sludges, crude oil is used as the fuel equivalent and coal is used to represent solids.

Fuel equivalent factors were multiplied by the tons of waste incinerated to obtain the tons of fuel equivalent. Multiplying the tons of fuel equivalent by the C content factors (discussed in the Estimating the Carbon Content from Fossil Fuel Combustion Annex) yields tons of C emitted. Implied C content is calculated by dividing the tons of C emitted by the associated tons of waste incinerated.

Waste quantity data for hazardous wastes were obtained from EPA's BRS database for reporting years 1989, 1991, 1993, 1995, 1997, 1999, 2001, 2003, 2005, and 2007 (EPA 2000a, 2007a). Values for 2008 and 2009 were held constant at the 2007 level. Combusted waste quantities were obtained from Form GM (Generation and Management) for wastes burned on site and Form WR (Wastes Received) for waste received from off-site for combustion. For each of the waste types, assumptions were developed on average waste composition (see Table A-63). Regulations require incinerators to achieve at least 99.99 percent destruction of organics; this formed the basis for assuming the fraction of C oxidized. Emissions from hazardous waste incineration in 2007 were 0.4 Tg CO₂ Eq. Table A-64 lists the CO₂ emissions from hazardous waste incineration.

Table A-63: Assumed Composition of Combusted Hazardous Waste by Weight (Percent)

Waste Type	Water (%)	Noncombustibles (%)	Fuel Equivalent (%)
Aqueous Waste	90	5	5
Organic Liquids and Sludges	40	20	40
Organic Solids	20	40	40
Inorganic Solids	20	70	10

Table A-64: CO₂ Emitted from Hazardous Waste Incineration (Tg CO₂ Eq.)

	1990	1995	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
CO ₂ Emissions	1.1	1.7	1.0	0.6	0.6	0.6	0.6	0.6	0.5	0.4	0.4	0.4

Energy Recovery

The amount of feedstocks combusted for energy recovery was estimated from data included in EIA's Manufacturers Energy Consumption Survey (MECS) for 1991, 1994, 1998, 2002, and 2006 (EIA 1994, 1997, 2001, 2005, 2010a). Some fraction of the fossil C exiting refineries and designated for use for feedstock purposes actually ends up being combusted for energy recovery (despite the designation of feedstocks as a "non-energy" use) because the chemical reactions in which fuel feedstocks are used are not 100 percent efficient. These chemical reactions may generate

²⁸ [42 U.S.C. §6924, SDWA §3004]

unreacted raw material feedstocks or generate byproducts that have a high energy content. The chemical industry and many downstream industries are energy-intensive and often have boilers or other energy recovery units on-site, and thus these unreacted feedstocks or byproducts are often combusted for energy recovery. Also, as noted above in the section on hazardous waste incineration, regulations provide a strong incentive—and in some cases require—burning of organic wastes generated from chemical production processes.

Information available from the MECS include data on the consumption for energy recovery of “other” fuels in the petroleum and coal products, chemicals, primary metals, nonmetallic minerals, and other manufacturing sectors. These “other” fuels include refinery still gas; waste gas; waste oils, tars, and related materials; petroleum coke, coke oven and blast furnace gases; scrap tires; and other uncharacterized fuels. Fuel use of petroleum coke is included separately in the fuel use data provided annually by EIA, and energy recovery of coke oven gas and blast furnace gas (i.e., byproducts of the iron and steel production process) is addressed in the Iron and Steel production section in the Industrial Processes chapter. Consumption of refinery still gas in the refinery sector is also included separately in the fuel use data from EIA. The combustion of scrap tires in cement kilns, lime kilns, and electric arc furnaces is accounted for in the Waste Incineration chapter; data from the Rubber Manufacturers Association (RMA 2009a) were used to difference out energy recovery from scrap tires in these industries. Consumption of net steam, assumed to be generated from fossil fuel combustion, is also included separately in the fuel use data from EIA. Therefore, these categories of “other” fuels are addressed elsewhere in the Inventory and not considered as part of the petrochemical feedstocks energy recovery analysis. The remaining categories of fuels, including waste gas; waste oils, tars, and related materials; and other uncharacterized fuels are assumed to be petrochemical feedstocks burned for energy recovery (see Table A-65). The conversion factors listed in the Estimating Emissions from Fossil Fuel Combustion Annex were used to convert the Btu values for each fuel feedstock to Tg CO₂. Petrochemical feedstocks combusted for energy recovery corresponded to 42.5 Tg CO₂ Eq. in 1991, 35.1 Tg CO₂ Eq. in 1994, 58.0 Tg CO₂ Eq. in 1998, 70.6 Tg CO₂ in 2002, and 74.8 in 2006. Values for petrochemical feedstocks burned for energy recovery for years between 1991 and 1994, between 1994 and 1998, between 1998 and 2002, and between 2002 and 2006 have been estimated by linear interpolation. The value for 1990 is assumed to be the same as the value for 1991, and values for years subsequent to 2006 are assumed to be the same as the value for 2006 (Table A-66).

Table A-65: Summary of 2006 MECS Data for Other Fuels Used in Manufacturing/Energy Recovery (Trillion Btu)

Subsector and Industry	NAICS CODE	Waste Gas ^a	Waste Oils/Tars ^b	Refinery Still Gas ^c	Net Steam ^d	Other Fuels ^e
Printing and Related Support	323	0	0	0	0	0
Petroleum and Coal Products	324	0	7	1,482	110	90
Chemicals	325	459	15	0	168	435
Plastics and Rubber Products	326	0	0	0	0	0
Nonmetallic Mineral Products	327	1	20	0	1	14
Primary Metals	331	1	0	0	17	20
Fabricated Metal Products	332	0	0	0	0	0
Machinery	333	0	0	0	1	1
Computer and Electronic Products	334	0	0	0	0	1
Electrical Equip., Appliances, Components	335	0	0	0	0	0
Transportation Equipment	336	5	0	0	0	11
Furniture and Related Products	337	0	0	0	0	0
Miscellaneous	339	0	0	0	0	0
Total (Trillion Btu)		466	42	1482	297	572
Average C Content (Tg/QBtu)		18.14	20.62	17.51	0	19.37
Fraction Oxidized		1	1	1	0	1
Total C (Tg)		8.45	0.87	25.95	0.00	11.08
Total C (Tg) (ex. still gas from refining)		8.45	0.87	-	-	11.08

^a C content: Waste Gas is assumed to be same as naphtha <401 deg. F

^b C content: Waste Oils/Tars is assumed to be same as asphalt/road oil

^c Refinery “still gas” fuel consumption is reported elsewhere in the Inventory and is excluded from the total C content estimate

^d Net steam fuel consumption is reported elsewhere in the Inventory and is excluded from the total C content estimate

^e C content: “Other” is assumed to be the same as petrochemical feedstocks

Table A-66: Carbon Emitted from Fuels Burned for Energy Recovery (Tg CO₂ Eq.)

	1990	1995	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
C Emissions	42.5	40.8	64.3	67.4	70.6	71.6	72.7	73.7	74.8	74.8	74.8	74.8

Products

More C is found in products than in industrial releases or energy recovery. The principal types of products are plastics; synthetic rubber; synthetic fiber; C black; pesticides; soaps, detergents, and cleansers; food additives; antifreeze and deicers (glycols); silicones; and solvents. Solvent evaporation was discussed previously along with industrial releases of NMVOCs; the other product types are discussed below.

Plastics

Data on annual production of plastics through 2005 were taken from the American Plastics Council (APC), as published in *Chemical & Engineering News* and on the APC and Society of Plastics Industry (SPI) websites, and through direct communication with the APC (APC 2000, 2001, 2003 through 2006; SPI 2000; Eldredge-Roebuck 2000). Data for 2006 and subsequent years were taken from the American Chemistry Council (ACC 2007 through 2009 supplemented by Vallianos 2011). Production was organized by resin type (see Table A-67) and by year. Several of the resin categories included production from Canada and/or Mexico, in addition to the U.S. values for part of the time series. The production data for the affected resins and years were corrected using an economic adjustment factor, based on the percent of North American production value in this industry sector accounted for by the United States. A C content was then assigned for each resin. These C contents were based on molecular formulae and are listed in Table A-68 and Table A-69. In cases where the resin type is generic, referring to a group of chemicals and not a single polymer (e.g., phenolic resins, other styrenic resins), a representative compound was chosen. For other resins, a weighted C content of 68 percent was assumed (i.e., it was assumed that these resins had the same content as those for which a representative compound could be assigned).

There were no emissive uses of plastics identified, so 100 percent of the C was considered stored in products. As noted in the chapter, an estimate of emissions related to the combustion of these plastics in the municipal solid waste stream can be found in the Incineration of Waste section of the Energy chapter; those emissions are not incorporated in the mass balance for feedstocks (described in this annex) to avoid double-counting.

Table A-67: 2009 Plastic Resin Production (Tg dry weight) and C Stored (Tg CO₂ Eq.)

Resin Type	2009 Production ^a (Tg dry weight)	Carbon Stored (Tg CO ₂ Eq.)
Epoxy	0.24	0.7
Urea	0.47	0.6
Melamine	0.47	0.5
Phenolic	1.44	4.0
Low-Density Polyethylene (LDPE)	2.74	8.6
Linear Low-Density Polyethylene (LLDPE)	5.39	17.0
High Density Polyethylene (HDPE)	6.97	21.9
Polypropylene (PP)	6.65	20.9
Acrylonitrile-butadiene-styrene (ABS)	0.37	1.2
Other Styrenics ^c	0.48	1.6
Polystyrene (PS)	2.00	6.8
Nylon	0.38	0.9
Polyvinyl chloride (PVC) ^b	5.24	7.4
Thermoplastic Polyester	3.24	7.4
All Other (including Polyester (unsaturated))	4.61	11.6
Total	40.70	111.1

^a Production estimates provided by the American Chemistry Council include Canadian production for Urea, Melamine, Phenolic, LDPE, LLDPE, HDPE, PP, ABS, SAN, Other Styrenics, PS, Nylon, PVC, and Thermoplastic Polyester, and Mexican production for PP, ABS, SAN, Other Styrenics, Nylon, and Thermoplastic Polyester. Values have been adjusted to account just for U.S. production.

^b Includes copolymers

^c Includes Styrene-acrylonitrile (SAN)

Note: Totals may not sum due to independent rounding.

Table A-68: Assigned C Contents of Plastic Resins (% by weight)

Resin Type	C Content	Source of C Content Assumption
Epoxy	76%	Typical epoxy resin made from epichlorhydrin and bisphenol A
Polyester (Unsaturated)	63%	Poly (ethylene terephthalate) (PET)
Urea	34%	50% carbamal, 50% N-(hydroxymethyl) urea *

Melamine	29%	Trimethylol melamine *
Phenolic	77%	Phenol
Low-Density Polyethylene (LDPE)	86%	Polyethylene
Linear Low-Density Polyethylene (LLDPE)	86%	Polyethylene
High Density Polyethylene (HDPE)	86%	Polyethylene
Polypropylene (PP)	86%	Polypropylene
Acrylonitrile-Butadiene-Styrene (ABS)	85%	50% styrene, 25% acrylonitrile, 25% butadiene
Styrene-Acrylonitrile (SAN)	80%	50% styrene, 50% acrylonitrile
Other Styrenics	92%	Polystyrene
Polystyrene (PS)	92%	Polystyrene
Nylon	65%	Average of nylon resins (see Table A-69)
Polyvinyl Chloride (PVC)	38%	Polyvinyl chloride
Thermoplastic Polyester	63%	Polyethylene terephthalate
All Other	69%	Weighted average of other resin production

*Does not include alcoholic hydrogens.

Table A-69: Major Nylon Resins and their C Contents (% by weight)

Resin	C Content
Nylon 6	64%
Nylon 6,6	64%
Nylon 4	52%
Nylon 6,10	68%
Nylon 6,11	69%
Nylon 6,12	70%
Nylon 11	72%

Synthetic Rubber

Data on synthetic rubber in tires were derived from data on the scrap tire market and the composition of scrap tires from the Rubber Manufacturers' Association (RMA). The market information is presented in the report *Scrap Tire Markets in the United States 2007 Edition* (RMA 2009a), while the tire composition information is from the "Scrap Tires, Facts and Figures" section of the organization's website (RMA 2009b). Data on synthetic rubber in other products (durable goods, nondurable goods, and containers and packaging) were obtained from EPA's *Municipal Solid Waste in the United States* reports (1996 through 2003a, 2005, 2007b, and 2008, 2009a, 2011) and detailed unpublished backup data for some years not shown in the *Characterization of Municipal Solid Waste in the United States* reports (Schneider 2007). The abraded rubber from scrap passenger tires was assumed to be 2.5 lbs per scrap tire, while the abraded rubber from scrap commercial tires was assumed to be 10 lbs per scrap tire. Data on abraded rubber weight were obtained by calculating the average weight difference between new and scrap tires (RMA 2009b).

A C content for synthetic rubber (90 percent for tire synthetic rubber and 85 percent for non-tire synthetic rubber) was assigned based on the weighted average of C contents (based on molecular formula) by elastomer type consumed in 1998, 2001, and 2002 (see Table A-70). The 1998 consumption data were obtained from the International Institute of Synthetic Rubber Producers (IISRP) press release "Synthetic Rubber Use Growth to Continue Through 2004, Says IISRP and RMA" (IISRP 2000). The 2001 and 2002 consumption data were obtained from the IISRP press release, "IISRP Forecasts Moderate Growth in North America to 2007" (IISRP 2003).

The rubber in tires that is abraded during use (the difference between new tire and scrap tire rubber weight) was considered to be 100 percent emitted. Other than abraded rubber, there were no emissive uses of scrap tire and non-tire rubber identified, so 100 percent of the non-abraded amount was assumed stored. Emissions related to the combustion of rubber in scrap tires and consumer goods can be found in the Incineration of Waste section of the Energy chapter.

Table A-70: 2002 Rubber Consumption (Gg) and C Content (%)

Elastomer Type	2002 Consumption (Gg)*	C Content
SBR Solid	768	91%
Polybutadiene	583	89%
Ethylene Propylene	301	86%
Polychloroprene	54	59%
NBR Solid	84	77%
Polyisoprene	58	88%
Others	367	88%
Weighted Average	-	90%
Total	2,215	-

* Includes consumption in Canada.

- Not applicable

Note: Totals may not sum due to independent rounding.

Synthetic Fibers

Annual synthetic fiber production data were obtained from the Fiber Economics Bureau, as published in *Chemical & Engineering News* (FEB 2001, 2003, 2005, 2007, 2009, 2010). These data are organized by year and fiber type. For each fiber, a C content was assigned based on molecular formula (see Table A-71). For polyester, the C content for poly (ethylene terephthalate) (PET) was used as a representative compound. For nylon, the average C content of nylon 6 and nylon 6,6 was used, since these are the most widely produced nylon fibers. Cellulosic fibers, such as acetate and rayon, have been omitted from the synthetic fibers' C accounting displayed here because much of their C is of biogenic origin and carbon fluxes from biogenic compounds are accounted for in the Land Use, Land-Use Change and Forestry chapter. These fibers account for only 4 percent of overall fiber production by weight.

There were no emissive uses of fibers identified, so 100 percent of the C was considered stored. Note that emissions related to the combustion of textiles in municipal solid waste are accounted for under the Incineration of Waste section of the Energy chapter.

Table A-71: 2009 Fiber Production (Tg), C Content (%), and C Stored (Tg CO₂ Eq.)

Fiber Type	Production (Tg)	C Content	C Stored (Tg CO₂ Eq.)
Polyester	0.9	63%	2.14
Nylon	0.6	64%	1.46
Olefin	1.0	86%	3.00
Acrylic	+	68%	0.07
Total	2.5	-	6.68

+ Less than 0.05 Tg

- Not applicable

Note: Totals may not sum due to independent rounding

Pesticides

Pesticide consumption data were obtained from the *1994/1995, 1996/1997, 1998/1999, and 2000/2001 Pesticides Industry Sales and Usage Market Estimates* (EPA 1998, 1999, 2002, 2004) reports. The most recent data available were for 2001, so it was assumed that the 2002 through 2009 consumption was equal to that of 2001. Active ingredient compound names and consumption weights were available for the top 25 agriculturally-used pesticides and top 10 pesticides used in the home and garden and the industry/commercial/government categories. The report provides a range of consumption for each active ingredient; the midpoint was used to represent actual consumption. Each of these compounds was assigned a C content value based on molecular formula. If the compound contained aromatic rings substituted with chlorine or other halogens, then the compound was considered persistent and the C in the compound was assumed to be stored. All other pesticides were assumed to release their C to the atmosphere. Over one-third of 2001 total pesticide active ingredient consumption was not specified by chemical type in the *Sales and Usage* report (EPA 2004). This unspecified portion of the active ingredient consumption was treated as a single chemical and assigned a C content and a storage factor based on the weighted average of the known chemicals' values.

Table A-72: Active Ingredient Consumption in Pesticides (Million lbs.) and C Emitted and Stored (Tg CO₂ Eq.) in 2001

Pesticide Use*	Active Ingredient (Million lbs.)	C Emitted (Tg CO₂ Eq.)	C Stored (Tg CO₂ Eq.)
Agricultural Uses	458.5	0.1	0.2
Non-Agricultural Uses	84.5	+	+
Home & Garden	38.5	+	+
Industry/Gov't/Commercial	46.0	+	+
Other	345.0	0.1	0.1
Total	888.0	0.2	0.3

+ Less than 0.05 Tg CO₂ Eq.

*2001 estimates (EPA 2004b).

Note: Totals may not sum due to independent rounding.

Soaps, Shampoos, and Detergents

Cleansers—soaps, shampoos, and detergents—are among the major consumer products that may contain fossil C. All of the C in cleansers was assumed to be fossil-derived, and, as cleansers eventually biodegrade, all of the C was assumed to be emitted. The first step in estimating C flows was to characterize the “ingredients” in a sample of cleansers. For this analysis, cleansers were limited to the following personal household cleaning products: bar soap, shampoo, laundry detergent (liquid and granular), dishwasher detergent, and dishwashing liquid. Data on the annual consumption of household personal cleansers were obtained from the U.S. Census Bureau 1992, 1997, 2002, and 2007 Economic Census (U.S. Bureau of the Census 1994, 1999, 2004, 2009). Consumption values for 1990 and 1991 were assumed to be the same as the 1992 value; consumption was interpolated between 1992 and 1997, 1997 and 2002, and 2002 and 2007; consumption for 2008 and 2009 was assumed to equal the 2007 value. Cleanser consumption values were adjusted by import and export data to develop US consumption estimates.

Chemical formulae were used to determine C contents (as percentages) of the ingredients in the cleansers. Each product’s overall C content was then derived from the composition and contents of its ingredients. From these values the mean C content for cleansers was calculated to be 21.9 percent.

The Census Bureau presents consumption data in terms of quantity (in units of million gallons or million pounds) and/or terms of value (thousands of dollars) for eight specific categories, such as “household liquid laundry detergents, heavy duty” and “household dry alkaline automatic dishwashing detergents.” Additionally, the report provides dollar values for the total consumption of “soaps, detergents, etc.—dry” and “soaps, detergents, etc.—liquid.” The categories for which both quantity and value data are available is a subset of total production. Those categories that presented both quantity and value data were used to derive pounds per dollar and gallons per dollar conversion rates, and they were extrapolated (based on the Census Bureau estimate of total value) to estimate the total quantity of dry and liquid²⁹ cleanser categories, respectively.

Next, the total tonnage of cleansers was calculated (wet and dry combined) for 1997. Multiplying the mean C content (21.9 percent) by this value yielded an estimate of 4.6 Tg CO₂ Eq. in cleansers for 1997. For all subsequent years, it was assumed that the ratio of value of shipments to total carbon content remained constant. For 1998 through 2009, value of shipments was adjusted to 1997 dollars using the producer price index for soap and other detergent manufacturing (Bureau of Labor Statistics 2009). The ratio of value of shipments to carbon content was then applied to arrive at total carbon content of cleansers. For 1992, 2002, and 2007 the estimates are 3.6 Tg CO₂ Eq., 5.1 Tg CO₂ Eq., 7.6 Tg CO₂ Eq., respectively. Estimates for other years are based on these values as described above, and are shown in Table A-73.

Table A-73: C Emitted from Utilization of Soaps, Shampoos, and Detergents (Tg CO₂ Eq.)

	1990	1995	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
C Emissions	3.6	4.2	4.5	4.8	5.1	5.7	6.2	6.7	7.0	7.6	7.1	6.7

Antifreeze and Deicers

Glycol compounds, including ethylene glycol, propylene glycol, diethylene glycol, and triethylene glycol, are used as antifreeze in motor vehicles, deicing fluids for commercial aircraft, and other similar uses. These glycol compounds are assumed to ultimately enter wastewater treatment plants where they are degraded by the wastewater treatment process to CO₂ or to otherwise biodegrade to CO₂. Glycols are water soluble and degrade rapidly in the environment (Howard 1993).

Annual production data for each glycol compound used as antifreeze and deicers were obtained from the Guide to the Business of Chemistry (ACC 2010). Import and export data were used to adjust annual production data to annual consumption data. The percentage of the annual consumption of each glycol compound used for antifreeze and deicing applications was estimated from Chemical Profiles data published on The Innovation Group website and from similar data published in the Chemical Market Reporter, which became ICIS Chemical Business in 2005. Production data for propylene glycol, diethylene glycol, and triethylene glycol are no longer reported in the Guide to the Business of Chemistry, so data from ICIS Chemical Business on total demand was used with import and export data to estimate production of these chemicals.

The glycol compounds consumed in antifreeze and deicing applications is assumed to be 100 percent emitted as CO₂. Emissions of CO₂ from utilization of antifreeze and deicers are summarized in Table A-74.

²⁹ A density of 1.05 g/mL—slightly denser than water—was assumed for liquid cleansers.

Table A-74: C Emitted from Utilization of Antifreeze and Deicers (Tg CO₂ Eq.)

	1990	1995	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
C Emissions	1.2	1.3	1.5	1.2	1.3	1.2	1.4	1.2	1.3	1.2	1.0	0.9

Food Additives

Petrochemical feedstocks are used to manufacture synthetic food additives, including preservatives, flavoring agents, and processing agents. These compounds include glycerin, propylene glycol, benzoic acid, and other compounds. These compounds are incorporated into food products, and are assumed to ultimately enter wastewater treatment plants where they are degraded by the wastewater treatment processes to CO₂ or to otherwise biodegrade to CO₂. Certain food additives, e.g., glycerin, are manufactured both from petrochemical feedstocks and from biogenic feedstocks. Food additives that are derived from biogenic feedstocks are accounted for in the Land Use, Land-Use Change and Forestry chapter.

Annual production data for food additive compounds were obtained from the Guide to the Business of Chemistry (ACC 2010). Import and export data were used to adjust annual production data to annual consumption data. The percentage of the annual consumption of food additive compounds was estimated from Chemical Profiles data published on The Innovation Group website³⁰ and from similar data published in the Chemical Market Reporter, which became ICIS Chemical Business in 2005.³¹ Production data for several food additive compounds are no longer reported in the Guide to the Business of Chemistry, so data from ICIS Chemical Business on total demand was used with import and export data to estimate production of these chemicals. The consumption of synthetic food additives is assumed to be 100 percent emitted as CO₂. Emissions of CO₂ from utilization of synthetic food additives are summarized in Table A-75.

Table A-75: C Emitted from Utilization of Food Additives (Tg CO₂ Eq.)

	1990	1995	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
C Emissions	0.6	0.7	0.7	0.6	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8

Silicones

Silicone compounds (e.g., polymethyl siloxane) are used as sealants and in manufactured products. Silicone compounds are manufactured from petrochemical feedstocks including methyl chloride. It is assumed that petrochemical feedstocks used to manufacture silicones are incorporated into the silicone products and not emitted as CO₂ in the manufacturing process. It is also assumed that the C contained in the silicone products is stored, and not emitted as CO₂.

Annual production data for each silicone manufacturing compound were obtained from the Guide to the Business of Chemistry (ACC 2010). Import and export data were used to adjust annual production data to annual consumption data. The percentage of the annual consumption of each silicone manufacturing compound was estimated from Chemical Profiles data published on The Innovation Group website and from similar data published in the Chemical Market Reporter, which became ICIS Chemical Business in 2005. The consumption of silicone manufacturing compounds is assumed to be 100 percent stored, and not emitted as CO₂. Storage of silicone manufacturing compounds is summarized in Table A-76.

Table A-76: C Stored in Silicone Products (Tg CO₂ Eq.)

	1990	1995	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
C Storage	0.3	0.4	0.4	0.4	0.5	0.5	0.5	0.4	0.5	0.5	0.5	0.5

Uncertainty

A Tier 2 Monte Carlo analysis was performed using @RISK software to determine the level of uncertainty surrounding the estimates of the feedstocks C storage factor and the quantity of C emitted from feedstocks in 2009. The Tier 2 analysis was performed to allow the specification of probability density functions for key variables, within a computational structure that mirrors the calculation of the Inventory estimate. Statistical analyses or expert judgments of uncertainty were not available directly from the information sources for the activity variables; thus, uncertainty estimates were determined using assumptions based on source category knowledge. Uncertainty estimates for production data (the majority of the variables) were assumed to exhibit a normal distribution with a relative error of ±20 percent in the underlying EIA estimates, plus an additional ±15 percent to account for uncertainty in the assignment of imports and

³⁰ <http://www.the-innovation-group.com/ChemProfiles>

³¹ <http://www.icis.com/home/default.aspx>

exports. An additional 10 percent (for a total of ± 45 percent) was applied to the production of other oils (>401 deg. F) to reflect the additional uncertainty in the assignment of part of the production quantity to industrial processes. A relatively narrow uniform distribution ± 1 percent to ± 15 percent, depending on the fuel type) was applied to each C coefficient.

The Monte Carlo analysis produced a storage factor distribution that approximates a normal curve, with a mean of 58 percent, a standard deviation of 1 percent, and the 95 percent confidence interval of 56 percent and 60 percent. This compares to the calculated Inventory estimate of 58 percent. The analysis produced a C emission distribution approximating a normal curve with a mean of 78.8 Tg CO₂ Eq., standard deviation of 8.5 Tg CO₂ Eq., and 95 percent confidence limits of 63.4 and 96.1 Tg CO₂ Eq. This compares with a calculated Inventory estimate of 79.3 Tg CO₂ Eq.

The apparently tight confidence limits for the storage factor and C storage probably understate uncertainty, as a result of the way this initial analysis was structured. As discussed above, 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 17 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 factors are relatively well-characterized, this approach yields a result that is probably biased toward understating uncertainty.

As far as specific sources of uncertainty, there are several cross-cutting factors that pervade the characterization of C flows for feedstocks. The aggregate storage factor for petrochemical feedstocks (industrial other coal, natural gas for non-fertilizer uses, LPG, pentanes plus, naphthas, other oils, still gas, special naphtha) is based on assuming that the ultimate fates of all of these fuel types—in terms of storage and emissions—are similar. In addition, there are uncertainties associated with the simplifying assumptions made for each end use category C estimate. Generally, the estimate for a product is subject to one or more of the following uncertainties:

- The value used for estimating the C content has been assumed or assigned based upon a representative compound.
- The split between C storage and emission has been assumed based on an examination of the environmental fate of the products in each end use category.
- Environmental fates leading to emissions are assumed to operate rapidly, i.e., emissions are assumed to occur within one year of when the fossil C enters the non-energy mass balance. Some of the pathways that lead to emissions as CO₂ may actually take place on a time-scale of several years or decades. By attributing the emissions to the year in which the C enters the mass balance (i.e., the year in which it leaves refineries as a non-energy fuel use and thus starts being tracked by EIA), this approach has the effect of “front-end loading” the emission profile.

Another cross-cutting source of uncertainty is that for several sources the amount of C stored or emitted was calculated based on data for only a single year. This specific year may not be representative of storage for the entire Inventory period. Sources of uncertainty associated with specific elements of the analysis are discussed below.

Import and export data for petrochemical feedstocks were obtained from EIA, the National Petroleum Refiners Association, and the U.S. BoC for the major categories of petrochemical feedstocks (EIA 2001a, NPRA 2001, and U.S. BoC 2006). The complexity of the organic chemical industry, with multiple feedstocks, intermediates, and subtle differences in nomenclature, makes it difficult to ensure that the adjustments to the EIA data for imports and exports is accurate and the approach used here may underestimate or overestimate net exports of C.

Oxidation factors have been applied to non-energy uses of petrochemical feedstocks in the same manner as for energy uses. However, for those fuels where IPCC storage factors are used, this “oxidation factor” may be inherent in the storage factor applied when calculating emissions from non-energy consumption, which would result in a double-counting of the unoxidized C. Oxidation factors are small corrections, on the order of 1 percent, and therefore application of oxidation factors to non-energy uses may result in a slight underestimation of C emissions from non-energy uses.

The major uncertainty in using the TRI data is the possibility of double counting emissions that are already accounted for in the NMVOC data (see above) and in the storage and emission assumptions used. The approach for predicting environmental fate simplifies some complex processes, and the balance between storage and emissions is very sensitive to the assumptions on fate. Extrapolating from known to unknown characteristics also introduces uncertainty. The two extrapolations with the greatest uncertainty are: 1) that the release media and fate of the off-site releases were assumed to be the same as for on-site releases, and 2) that the C content of the least frequent 10 percent of TRI releases was assumed to be the same as for the chemicals comprising 90 percent of the releases. However, the contribution of these chemicals to the overall estimate is small. The off-site releases only account for 3 percent of the total releases, by weight, and, by definition, the less frequent compounds only account for 10 percent of the total releases.

The principal sources of uncertainty in estimating CO₂ emissions from solvent evaporation and industrial NMVOC emissions are in the estimates of (a) total emissions and (b) their C content. Solvent evaporation and industrial NMVOC emissions reported by EPA are based on a number of data sources and emission factors, and may underestimate or overestimate emissions. The C content for solvent evaporation emissions is calculated directly from the specific solvent compounds identified by EPA as being emitted, and is thought to have relatively low uncertainty. The C content for industrial emissions has more uncertainty, however, as it is calculated from the average C content of an average volatile organic compound based on the list of the most abundant measured NMVOCs provided in EPA (2002a).

Uncertainty in the hazardous waste combustion analysis is introduced by the assumptions about the composition of combusted hazardous wastes, including the characterization that hazardous wastes are similar to mixtures of water, noncombustibles, and fuel equivalent materials. Another limitation is the assumption that all of the C that enters hazardous waste combustion is emitted—some small fraction is likely to be sequestered in combustion ash—but given that the destruction and removal efficiency for hazardous organics is required to meet or exceed 99.99 percent, this is a very minor source of uncertainty. C emission estimates from hazardous waste should be considered central value estimates that are likely to be accurate to within ± 50 percent.

The amount of feedstocks combusted for energy recovery was estimated from data included in the Manufacturers Energy Consumption Surveys (MECS) for 1991, 1994, 1998, 2002, and 2006 (EIA 1994, 1997, 2001, 2005, 2010a). MECS is a comprehensive survey that is conducted every four years and intended to represent U.S. industry as a whole, but because EIA does not receive data from all manufacturers (i.e., it is a sample rather than a census), EIA must extrapolate from the sample. Also, the “other” fuels are identified in the MECS data in broad categories, including refinery still gas; waste gas; waste oils, tars, and related materials; petroleum coke, coke oven and blast furnace gases; and other uncharacterized fuels. Moreover, the industries using these “other” fuels are also identified only in broad categories, including the petroleum and coal products, chemicals, primary metals, nonmetallic minerals, and other manufacturing sectors. The “other” fuel consumption data are reported in BTUs (energy units) and there is uncertainty concerning the selection of a specific conversion factor for each broad “other” fuel category to convert energy units to mass units. Taken as a whole, the estimate of energy recovery emissions probably introduces more uncertainty than any other element of the non-energy analysis.

Uncertainty in the C storage estimate for plastics arises primarily from four factors. First, production of some plastic resins is not tracked directly and must be estimated based on other market data. Second, the raw data on production for several resins include Canadian and/or Mexican production and may overestimate the amount of plastic produced from U.S. fuel feedstocks; this analysis includes adjustments to “back out” the Canadian and Mexican values, but these adjustments are approximate. Third, the assumed C content values are estimates for representative compounds, and thus do not account for the many formulations of resins available. This uncertainty is greater for resin categories that are generic (e.g., phenolics, other styrenics, nylon) than for resins with more specific formulations (e.g., polypropylene, polyethylene). Fourth, the assumption that all of the C contained in plastics is stored ignores certain end uses (e.g., adhesives and coatings) where the resin may be released to the atmosphere; however, these end-uses are likely to be small relative to use in plastics.

The quantity of C stored in synthetic rubber only accounts for the C stored in scrap tire synthetic rubber. The value does not take into account the rubber stored in other durable goods, clothing, footwear, and other non-durable goods, or containers and packaging. This adds uncertainty to the total mass balance of C stored. There are also uncertainties as to the assignment of C content values; however, they are much smaller than in the case of plastics. There are probably fewer variations in rubber formulations than in plastics, and the range of potential C content values is much narrower. Lastly, assuming that all of the C contained in rubber is stored ignores the possibility of volatilization or degradation during product lifetimes. However, the proportion of the total C that is released to the atmosphere during use is probably negligible.

A small degree of uncertainty arises from the assignment of C content values in textiles; however, the magnitude of this uncertainty is less than that for plastics or rubber. Although there is considerable variation in final textile products, the stock fiber formulations are standardized and proscribed explicitly by the Federal Trade Commission.

For pesticides, the largest source of uncertainty involves the assumption that an active ingredient’s C is either 0 percent stored or 100 percent stored. This split is a generalization of chemical behavior, based upon active-ingredient molecular structure, and not on compound-specific environmental data. The mechanism by which a compound is bound or released from soils is very complicated and can be affected by many variables, including the type of crop, temperature, application method, and harvesting practice. Another smaller source of uncertainty arises from the C content values applied to the unaccounted for portion of active ingredient. C contents vary widely among pesticides, from 7 to 72 percent, and the remaining pesticides may have a chemical make-up that is very different from the 32 pesticides that have

been examined. Additionally, pesticide consumption data were only available for 1987, 1993, 1995, 1997, 1999, and 2001; the majority of the time series data were interpolated or held constant at the latest (2001) value. Another source of uncertainty is that only the “active” ingredients of pesticides are considered in the calculations; the “inactive” ingredients may also be derived from petrochemical feedstocks.

It is important to note that development of this uncertainty analysis is a multi-year process. The current feedstocks analysis examines NEU fuels that end in storage fates. Thus only C stored in pesticides, plastics, synthetic fibers, synthetic rubbers, silicones, and TRI releases to underground injection and Subtitle C landfills is accounted for in the uncertainty estimate above. In the future this analysis will be expanded to include the uncertainty surrounding emitted fates in addition to the storage fates. Estimates of variable uncertainty will also be refined where possible to include fewer assumptions. With these major changes in future Inventories, the uncertainty estimate is expected to change, and likely increase. An increase in the uncertainty estimate in the coming years will not indicate that the Inventory calculations have become less certain, but rather that the methods for estimating uncertainty have become more comprehensive; thus, potential future changes in the results of this analysis will reflect a change in the uncertainty analysis, not a change in the Inventory quality.

Asphalt and Road Oil

Asphalt is one of the principal non-energy uses of fossil fuels. The term “asphalt” generally refers to a mixture of asphalt cement and a rock material aggregate, a volatile petroleum distillate, or water. For the purposes of this analysis, “asphalt” is used interchangeably with asphalt cement, a residue of crude oil. Though minor amounts of C are emitted during production, asphalt has an overall C storage factor of almost 100 percent, as discussed below.

Paving is the primary application of asphalt cement, comprising 86 percent of production. The three types of asphalt paving produced in the United States are hot mix asphalt (HMA), cut-backs, and emulsified asphalt. HMA, which makes up 90 percent of total asphalt paving (EPA 2001), contains asphalt cement mixed with an aggregate of rock materials. Cut-back asphalt is composed of asphalt cement thinned with a volatile petroleum distillate (e.g., naphtha). Emulsified asphalt contains only asphalt cement and water. Roofing products are the other significant end use of asphalt cement, accounting for approximately 14 percent of U.S. production (Kelly 2000). No data were available on the fate of C in asphalt roofing; it was assumed that it has the same fate as C in asphalt paving applications.

Methodology and Data Sources

A C storage factor was calculated for each type of asphalt paving. The fraction of C emitted by each asphalt type was multiplied by consumption data for asphalt paving (EPA 2001) to estimate a weighted average C storage factor for asphalt as a whole.

The fraction of C emitted by HMA was determined by first calculating the organic emissions (volatile organic compounds [VOCs], carbon monoxide [CO], polycyclic aromatic hydrocarbons [PAHs], hazardous air pollutants [HAPs], and phenol) from HMA paving, using emission factors reported in EPA (2001) and total HMA production.³² The next step was to estimate the C content of the organic emissions. This calculation was based on the C content of CO and phenol, and an assumption of 85 percent C content for PAHs and HAPs. The C content of asphalt paving is a function of (1) the proportion of asphalt cement in asphalt paving, assumed to be 8 percent asphalt cement content based on EPA (2001), and (2) the proportion of C in asphalt cement. For the latter factor, all paving types were characterized as having a mass fraction of 85 percent C in asphalt cement, based on the assumption that asphalt is primarily composed of saturated paraffinic hydrocarbons. By combining these estimates, the result is that over 99.99 percent of the C in asphalt cement was retained (i.e., stored), and less than 0.01 percent was emitted.

Cut-back asphalt is produced in three forms: rapid, medium, and slow cure. The production processes for all three forms emit C primarily from the volatile petroleum distillate used in the process as a diluent to thin the asphalt cement so that it can be applied more readily (EPA 2001).

A mass balance on C losses from asphalt was constructed by first estimating the amount of carbon emitted as VOCs. Values for medium cure asphalt are used to represent all cut-back asphalt. The average weight of distillates used in medium cure cut-back asphalt (35 percent) is multiplied by the loss rate (as emissions of VOCs) of 70 percent from the *Emissions Inventory Guidebook* to arrive at an estimate that 25 percent of the diluent is emitted (Environment Canada 2006). Next, the fraction of C in the asphalt/ diluent mix that is emitted was estimated, assuming 85 percent C content; this yields an overall storage factor of 93.5 percent for cut-back asphalt.

³² The emission factors are expressed as a function of asphalt paving tonnage (i.e., including the rock aggregate as well as the asphalt cement).

One caveat associated with this calculation is that it is possible that the carbon flows for asphalt and diluent (volatile petroleum distillate) are accounted for separately in the EIA statistics on fossil fuel flows, and thus the mass balance calculation may need to re-map the system boundaries to correctly account for carbon flows. EPA plans to re-evaluate this calculation in the future.

It was assumed that there was no loss of C from emulsified asphalt (i.e., the storage factor is 100 percent) based on personal communication with an expert from Akzo Nobel Coatings, Inc. (James 2000).

Data on asphalt and road oil consumption and C content factors were supplied by EIA. Hot mix asphalt production and emissions factors, and the asphalt cement content of HMA were obtained from “Hot Mix Asphalt Plants Emissions Assessment Report” from EPA’s *AP-42* (EPA 2001) publication. The consumption data for cut-back and emulsified asphalts were taken from a Moulthrop, et al. study used as guidance for estimating air pollutant emissions from paving processes (EIIP 2001). “Asphalt Paving Operation” *AP-42* (EPA 2001) provided the emissions source information used in the calculation of the C storage factor for cut-back asphalt. The storage factor for emulsified asphalt was provided by Alan James of Akzo Nobel Coatings, Inc. (James 2000).

Uncertainty

A Tier 2 Monte Carlo analysis was performed using @RISK software to determine the level of uncertainty surrounding the estimates of the asphalt C storage factor and the quantity of C stored in asphalt in 2009. The Tier 2 analysis was performed to allow the specification of probability density functions for key variables, within a computational structure that mirrors the calculation of the Inventory estimate. Statistical analyses or expert judgments of uncertainty were not available directly from the information sources for the activity variables; thus, uncertainty estimates were determined using assumptions based on source category knowledge. Uncertainty estimates for asphalt production were assumed to be ± 20 percent, while the asphalt property variables were assumed to have narrower distributions. A narrow uniform distribution, with maximum 5 percent uncertainty (± 5 percent) around the mean, was applied to the C content coefficient.

The Monte Carlo analysis produced a tight distribution of storage factor values, with the 95 percent confidence interval of 99.1 percent and 99.8 percent, with the mean value of 99.5 percent. This compares to the storage factor value used in the Inventory of 99.6 percent. The analysis produced a C emission distribution with a mean of 0.31 Tg CO₂ Eq., standard deviation of 0.13 and 95 percent confidence limits of 0.12 Tg CO₂ Eq. and 0.63 Tg CO₂ Eq. This compares with an Inventory calculated estimate of 0.29 Tg CO₂ Eq.

The principal source of uncertainty is that the available data are from short-term studies of emissions associated with the production and application of asphalt. As a practical matter, the cement in asphalt deteriorates over time, contributing to the need for periodic re-paving. Whether this deterioration is due to physical erosion of the cement and continued storage of C in a refractory form or physicochemical degradation and eventual release of CO₂ is uncertain. Long-term studies may reveal higher lifetime emissions rates associated with degradation.

Many of the values used in the analysis are also uncertain and are based on estimates and professional judgment. For example, the asphalt cement input for hot mix asphalt was based on expert advice indicating that the range is variable—from about 3 to 5 percent—with actual content based on climate and geographical factors (Connolly 2000). Over this range, the effect on the calculated C storage factor is minimal (on the order of 0.1 percent). Similarly, changes in the assumed C content of asphalt cement would have only a minor effect.

The consumption figures for cut-back and emulsified asphalts are based on information reported for 1994. More recent trends indicate a decrease in cut-back use due to high VOC emission levels and a related increase in emulsified asphalt use as a substitute. This change in trend would indicate an overestimate of emissions from asphalt.

Future improvements to this uncertainty analysis, and to the overall estimation of a storage factor for asphalt, include characterizing the long-term fate of asphalt.

Lubricants

Lubricants are used in industrial and transportation applications. They can be subdivided into oils and greases, which differ in terms of physical characteristics (e.g., viscosity), commercial applications, and environmental fate. According to EIA (2010b), the C content from U.S. production of lubricants in 2009 was approximately 5.3 Tg C. Based on apportioning oils and greases to various environmental fates, and characterizing those fates as resulting in either long-term storage or emissions, the overall C storage factor was estimated to be 9.2 percent; thus, emissions in 2009 were about 4.8 Tg C, or 17.7 Tg CO₂ Eq.

Methodology and Data Sources

For each lubricant category, a storage factor was derived by identifying disposal fates and applying assumptions as to the disposition of the C for each practice. An overall lubricant C storage factor was calculated by taking a production-weighted average of the oil and grease storage factors.

Oils

Regulation of used oil in the United States has changed dramatically over the past 20 years.³³ The effect of these regulations and policies has been to restrict landfilling and dumping, and to encourage collection of used oil. The economics of the petroleum industry have generally not favored re-refining—instead, most of the used oil that has been collected has been combusted.

Table A-77 provides an estimated allocation of the fates of lubricant oils (Rinehart 2000), along with an estimate of the proportion of C stored in each fate. The ultimate fate of the majority of oils (about 84 percent) is combustion, either during initial use or after collection as used oil. Combustion results in 99 percent oxidation to CO₂ (EIIP 1999), with correspondingly little long-term storage of C in the form of ash. Dumping onto the ground or into storm sewers, primarily by “do-it-yourselfers” who change their own oil, is another fate that results in conversion to CO₂ given that the releases are generally small and most of the oil is biodegraded (based on the observation that land farming—application to soil—is one of the most frequently used methods for degrading refinery wastes). In the landfill environment, which tends to be anaerobic within municipal landfills, it is assumed that 90 percent of the oil persists in an undegraded form, based on analogy with the persistence of petroleum in native petroleum-bearing strata, which is also anaerobic. Re-refining adds a recycling loop to the fate of oil. Re-refined oil was assumed to have a storage factor equal to the weighted average for the other fates (i.e., after re-refining, the oil would have the same probability of combustion, landfilling, or dumping as virgin oil), that is, it was assumed that about 97 percent of the C in re-refined oil is ultimately oxidized. Because of the dominance of fates that result in eventual release as CO₂, only about 3 percent of the C in oil lubricants goes into long-term storage.

Table A-77: Commercial and Environmental Fate of Oil Lubricants (Percent)

Fate of Oil	Portion of Total Oil	C Stored
Combusted During Use	20%	0.2%
Not Combusted During Use	80%	2.7%
Combusted as Used Oil *	64%	0.6%
Dumped on the ground or in storm sewers	6%	-
Landfilled	2%	1.8%
Re-refined into lube oil base stock and other products	8%	0.2%
Weighted Average		2.9%

* (e.g., in boilers or space heaters)

- Not applicable

Greases

Table A-78 provides analogous estimates for lubricant greases. Unlike oils, grease is generally not combusted during use, and combustion for energy recovery and re-refining is thought to be negligible. Although little is known about the fate of waste grease, it was assumed that 90 percent of the non-combusted portion is landfilled, and the remainder is dumped onto the ground or storm sewers. Because much of the waste grease will be in containers that render it relatively inaccessible to biodegradation, and because greases contain longer chain paraffins, which are more persistent than oils, it was assumed that 90 percent and 50 percent of the C in landfilled and dumped grease, respectively, would be stored. The overall storage factor is 82 percent for grease.

³³ For example, the U.S. EPA “RCRA (Resource Conservation and Recovery Act) On-line” web site (<<http://www.epa.gov/rcraonline/>>) has over 50 entries on used oil regulation and policy for 1994 through 2000.

Table A-78: Commercial and Environmental Fate of Grease Lubricants (Percent)

Fate of Grease	Portion of Total Grease	C Stored
Combusted During Use	5%	0.1%
Not Combusted During Use	95%	81.7%
Landfilled	86%	77.0%
Dumped on the ground or in storm sewers	10%	4.8%
Weighted Average	-	81.8%

- Not applicable

Having derived separate storage factors for oil and grease, the last step was to estimate the weighted average for lubricants as a whole. No data were found apportioning the mass of lubricants into these two categories, but the U.S. Census Bureau does maintain records of the value of production of lubricating oils and lubricating greases. These were retrieved from the relevant industry series summaries from the 1997 Economic Census (Census Bureau 1999). Assuming that the mass of lubricants can be allocated according to the proportion of value of production (92 percent oil, 8 percent grease), applying these weights to the storage factors for oils and greases (3 percent and 82 percent) yields an overall storage factor of 9.2 percent.

Uncertainty

A Tier 2 Monte Carlo analysis was performed using @RISK software to determine the level of uncertainty surrounding the estimates of the lubricants weighted average C storage factor and the quantity of C emitted from lubricants in 2009. The Tier 2 analysis was performed to allow the specification of probability density functions for key variables, within a computational structure that mirrors the calculation of the Inventory estimate. Statistical analyses or expert judgments of uncertainty were not available directly from the information sources for the activity variables; thus, uncertainty estimates were determined using assumptions based on source category knowledge. Uncertainty estimates for oil and grease variables were assumed to have a moderate variance, in triangular or uniform distribution. Uncertainty estimates for lubricants production were assumed to be rather high (± 20 percent). A narrow uniform distribution, with 6 percent uncertainty (± 6 percent) around the mean, was applied to the lubricant C content coefficient.

The Monte Carlo analysis produced a storage factor distribution with the 95 percent confidence interval of 4 percent and 17 percent around a mean value of 10 percent. This compares to the calculated Inventory estimate of 9 percent. The analysis produced a C emission distribution approximating a normal curve with a mean of 17.5 Tg CO₂ Eq., standard deviation of 1.5 and 95 percent confidence limits of 14.6 Tg CO₂ Eq. and 20.5 Tg CO₂ Eq.. This compares with an Inventory calculated estimate of 17.7 Tg CO₂ Eq..

The principal sources of uncertainty for the disposition of lubricants are the estimates of the commercial use, post-use, and environmental fate of lubricants, which, as noted above, are largely based on assumptions and judgment. There is no comprehensive system to track used oil and greases, which makes it difficult to develop a verifiable estimate of the commercial fates of oil and grease. The environmental fate estimates for percent of C stored are less uncertain, but also introduce uncertainty in the estimate.

The assumption that the mass of oil and grease can be divided according to their value also introduces uncertainty. Given the large difference between the storage factors for oil and grease, changes in their share of total lubricant production have a large effect on the weighted storage factor.

Future improvements to the analysis of uncertainty surrounding the lubricants C storage factor and C stored include further refinement of the uncertainty estimates for the individual activity variables.

Waxes

Waxes are organic substances that are solid at ambient temperature, but whose viscosity decreases as temperature increases. Most commercial waxes are produced from petroleum refining, though “mineral” waxes derived from animals, plants, and lignite [coal] are also used. An analysis of wax end uses in the United States, and the fate of C in these uses, suggests that about 42 percent of C in waxes is emitted, and 58 percent is stored.

Methodology and Data Sources

The National Petroleum Refiners Association (NPRA) considers the exact amount of wax consumed each year by end use to be proprietary (Maguire 2004). In general, about thirty percent of the wax consumed each year is used in packaging materials, though this percentage has declined in recent years. The next highest wax end use, and fastest growing end use, is candles, followed by construction materials and firelogs. Table A-79 categorizes some of the wax end uses, which the NPRA generally classifies into cosmetics, plastics, tires and rubber, hot melt (adhesives), chemically modified wax substances, and other miscellaneous wax uses (NPRA 2002)

Table A-79: Emissive and Non-emissive (Storage) Fates of Waxes: Uses by Fate and Percent of Total Mass

Use	Emissive	Non-emissive
Packaging	6%	24%
Non-packaging	36%	34%
Candles	18%	2%
Construction Materials	4%	14%
Firelogs	7%	+
Cosmetics	1%	2%
Plastics	1%	2%
Tires/Rubber	1%	1%
Hot Melts	1%	1%
Chemically Modified	0%	1%
Other	2%	9%
Total	42%	58%

+ Does not exceed 0.5 percent

A C storage factor for each wax end use was estimated and then summed across all end uses to provide an overall C storage factor for wax. Because no specific data on C contents of wax used in each end use were available, all wax products are assumed to have the same C content. Table A-80 categorizes wax end uses identified by the NPRA, and lists each end use's estimated C storage factor.

Table A-80: Wax End-Uses by Fate, Percent of Total Mass, Percent C Stored, and Percent of Total C Mass Stored

Use	Percent of Total Wax Mass	Percent of C Stored	Percent of Total C Mass Stored
Packaging	30%	79%	24%
Non-Packaging			
Candles	20%	10%	2%
Construction Materials	18%	79%	14%
Firelogs	7%	1%	+
Cosmetics	3%	79%	2%
Plastics	3%	79%	2%
Tires/Rubber	3%	47%	1%
Hot Melts	3%	50%	1%
Chemically Modified	1%	79%	1%
Other	12%	79%	9%
Total	100%	NA	58%

+ Does not exceed 0.5 percent

Source, mass percentages: NPRA 2002. Estimates of percent stored are based on professional judgment, ICF Consulting.

Note: Totals may not sum due to independent rounding.

Emissive wax end-uses include candles, firelogs (synthetic fireplace logs), hotmelts (adhesives), matches, and explosives. At about 20 percent, candles consume the greatest portion of wax among emissive end uses. As candles combust during use, they release emissions to the atmosphere. For the purposes of the Inventory, it is assumed that 90 percent of C contained in candles is emitted as CO₂. In firelogs, petroleum wax is used as a binder and as a fuel, and is combusted during product use, likely resulting in the emission of nearly all C contained in the product. Similarly, C contained in hotmelts is assumed to be emitted as CO₂ as heat is applied to these products during use. It is estimated that 50 percent of the C contained in hot melts is stored. Together, candles, firelogs, and hotmelts constitute approximately 30 percent of annual wax production (NPRA 2002).

All of the wax utilized in the production of packaging, cosmetics, plastics, tires and rubber, and other products is assumed to remain in the product (i.e., it is assumed that there are no emissions of CO₂ from wax during the production of the product). Wax is used in many different packaging materials including wrappers, cartons, papers, paperboard, and

corrugated products (NPRA 2002). Davie (1993) and Davie et al. (1995) suggest that wax coatings in packaging products degrade rapidly in an aerobic environment, producing CO₂; however, because packaging products ultimately enter landfills typically having an anaerobic environment, most of the C from this end use is assumed to be stored in the landfill.

In construction materials, petroleum wax is used as a water repellent on wood-based composite boards, such as particle board (IGI 2002). Wax used for this end-use should follow the life-cycle of the harvested wood used in product, which is classified into one of 21 categories, evaluated by life-cycle, and ultimately assumed to either be disposed of in landfills or be combusted (EPA 2003).

The fate of wax used for packaging, in construction materials, and for most remaining end uses is ultimately to enter the municipal solid waste (MSW) stream, where it is either combusted or sent to landfill for disposal. Most of the C contained in these wax products will be stored. It is assumed that approximately 21 percent of the C contained in these products will be emitted through combustion or at landfill. With the exception of tires and rubber, these end-uses are assigned a C storage factor of 79 percent.

Waxes used in tires and rubber follow the life cycle of the tire and rubber products. Used tires are ultimately recycled, landfilled, or combusted. The life-cycle of tires is addressed elsewhere in this annex as part of the discussion of rubber products derived from petrochemical feedstocks. For the purposes of the estimation of the C storage factor for waxes, wax contained in tires and rubber products is assigned a C storage factor of 47 percent.

Uncertainty

A Tier 2 Monte Carlo analysis was performed using @RISK software to determine the level of uncertainty surrounding the estimates of the wax C storage factor and the quantity of C emitted from wax in 2009. A Tier 2 analysis was performed to allow the specification of probability density functions for key variables, within a computational structure that mirrors the calculation of the Inventory estimate. Statistical analyses or expert judgments of uncertainty were not available directly from the information sources for the activity variables; thus, uncertainty estimates were determined using assumptions based on source category knowledge. Uncertainty estimates for wax variables were assumed to have a moderate variance, in normal, uniform, or triangular distribution; uniform distributions were applied to total consumption of waxes and the C content coefficients.

The Monte Carlo analysis produced a storage factor distribution, whose 95 percent confidence interval values fell within the range of 49 percent and 71 percent, around the mean value of about 60 percent. This compares to the calculated Inventory estimate of 58 percent. The analysis produced an emission distribution, with the 95 percent confidence interval values of 0.3 Tg CO₂ Eq. and 0.7 Tg CO₂ Eq., with a mean value of 0.4 Tg CO₂ Eq. This compares with a calculated Inventory estimate of 0.4 Tg CO₂ Eq., which falls within the range of 95 percent confidence limits established by this quantitative uncertainty analysis. Uncertainty associated with the wax storage factor is considerable due to several assumptions pertaining to wax imports/exports, consumption, and fates.

Miscellaneous Products

Miscellaneous products are defined by the U.S. Energy Information Administration as: "all finished [petroleum] products not classified elsewhere, e.g., petrolatum; lube refining byproducts (e.g., aromatic extracts and tars); absorption oils; ram-jet fuel; petroleum rocket fuel; synthetic natural gas feedstocks; and specialty oils."

Methodology and Data Sources

Data are not available concerning the distribution of each of the above-listed subcategories within the "miscellaneous products" category. However, based on the anticipated disposition of the products in each subcategory, it is assumed that all of the C content of miscellaneous products is emitted rather than stored. Petrolatum and specialty oils (which include greases) are likely to end up in solid waste or wastewater streams rather than in durable products, and would be emitted through waste treatment. Absorption oil is used in natural gas processing and is not a feedstock for manufacture of durable products. Jet fuel and rocket fuel are assumed to be combusted in use, and synthetic natural gas feedstocks are assumed to be converted to synthetic natural gas that is also combusted in use. Lube refining byproducts could potentially be used as feedstocks for manufacture of durable goods, but such byproducts are more likely to be used in emissive uses. Lube refining byproducts and absorption oils are liquids and are precluded from disposal in landfills. Because no sequestering end uses of any of the miscellaneous products subcategories have been identified, a zero percent storage factor is assigned to miscellaneous products. According to EIA (2010b), the C content of miscellaneous petroleum

products in 2009 was approximately 20.3 Tg C/QBtu. One hundred percent of the C content is assumed to be emitted to the atmosphere, where it is oxidized to CO₂.

Uncertainty

A separate uncertainty analysis was not conducted for miscellaneous products, though this category was included in the uncertainty analysis of other non-energy uses discussed in the following section.

Other Non-Energy Uses

The remaining fuel types use storage factors that are not based on U.S.-specific analysis. For industrial coking coal and distillate fuel oil, storage factors were taken from IPCC (2006), which in turn draws from Marland and Rotty (1984). These factors are 0.1 and 0.5, respectively.

IPCC does not provide guidance on storage factors for the remaining fuel types (petroleum coke, miscellaneous products, and other petroleum), and assumptions were made based on the potential fate of C in the respective NEUs. Specifically, the storage factor for petroleum coke is 0.3, based on information from Huurman (2006) indicating that petroleum coke is used in the Netherlands for production of pigments, with 30% being stored long-term. EIA defines “miscellaneous products” as “all finished products not classified elsewhere (e.g., petrolatum, lube refining byproducts (aromatic extracts and tars), absorption oils, ram-jet fuel, petroleum rocket fuels, synthetic natural gas feedstocks, and specialty oils).” All of these uses are emissive, and therefore the storage factor for miscellaneous products is set at zero (EIA 20010b). The “other petroleum” category is reported by U.S. territories and accounts mostly for the same products as miscellaneous products, but probably also includes some asphalt, known to be non-emissive. The exact amount of asphalt or any of the other miscellaneous products is confidential business information, but based on judgment the storage factor for this category was estimated at 0.1.

For all these fuel types, the overall methodology simply involves multiplying C content by a storage factor, yielding an estimate of the mass of C stored. To provide a complete analysis of uncertainty for the entire NEU subcategory, the uncertainty around the estimate of “other” NEUs was characterized, as discussed below.

Uncertainty

A Tier 2 Monte Carlo analysis was performed using @RISK software to determine the level of uncertainty surrounding the weighted average of the remaining fuels’ C storage factors and the total quantity of C emitted from these other fuels in 2009. A Tier 2 analysis was performed to allow the specification of probability density functions for key variables, within a computational structure that mirrors the calculation of the Inventory estimate. Statistical analyses or expert judgments of uncertainty were not available directly from the information sources for some of the activity variables; thus, uncertainty estimates were determined using assumptions based on source category knowledge. A uniform distribution was applied to coking coal consumption, while the remaining consumption inputs were assumed to be normally distributed. The C content coefficients were assumed to have a uniform distribution; the greatest uncertainty range of 10 percent (±10%) around the inventory value, was applied to coking coal and miscellaneous products. C coefficients for distillate fuel oil ranged from 18.5 to 21.1 Tg C/QBtu. The fuel-specific storage factors were assigned wide triangular distributions indicating greater uncertainty.

The Monte Carlo analysis produced a storage factor distribution with 95 percent confidence limits of 16 percent and 66 percent, with a mean of 39 percent. This compares to the Inventory calculation of weighted average (across the various fuels) storage factor of about 17 percent. The analysis produced an emission distribution, with the 95 percent confidence limit of 10.3 Tg CO₂ Eq. and 27.0 Tg CO₂ Eq., and a mean of 18.9 Tg CO₂ Eq.. This compares with the Inventory estimate of 25.7 Tg CO₂ Eq., which falls closer to the upper boundary of the 95 percent confidence limit. The uncertainty analysis results are driven primarily by the very broad uncertainty inputs for the storage factors.

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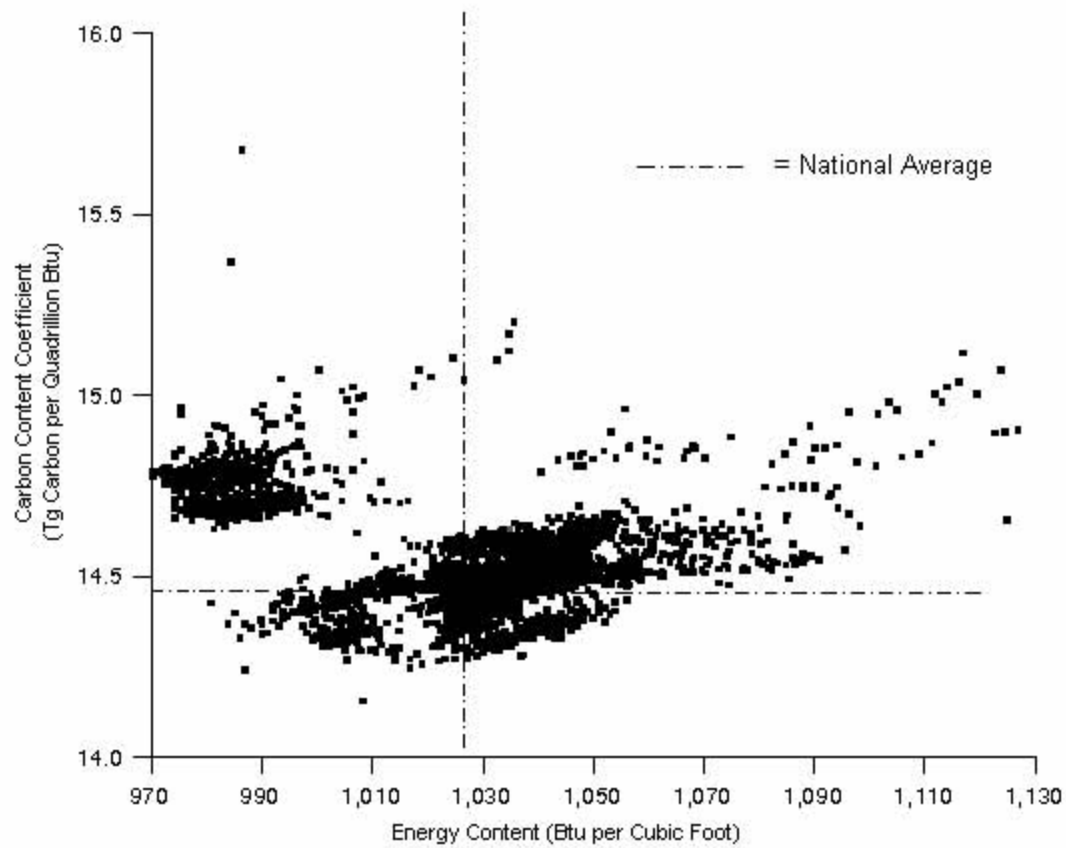
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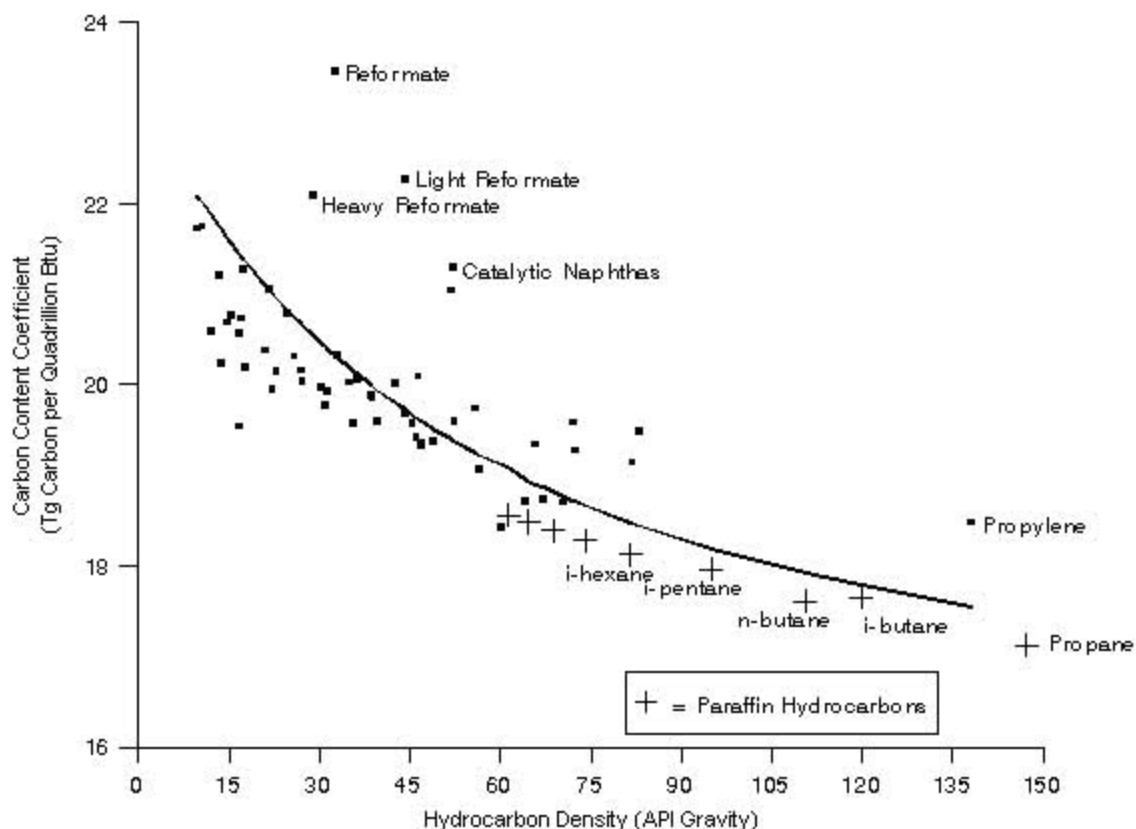
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Figure A-1: Carbon Content for Samples of Pipeline-Quality Natural Gas Included in the Gas Technology Institute Database



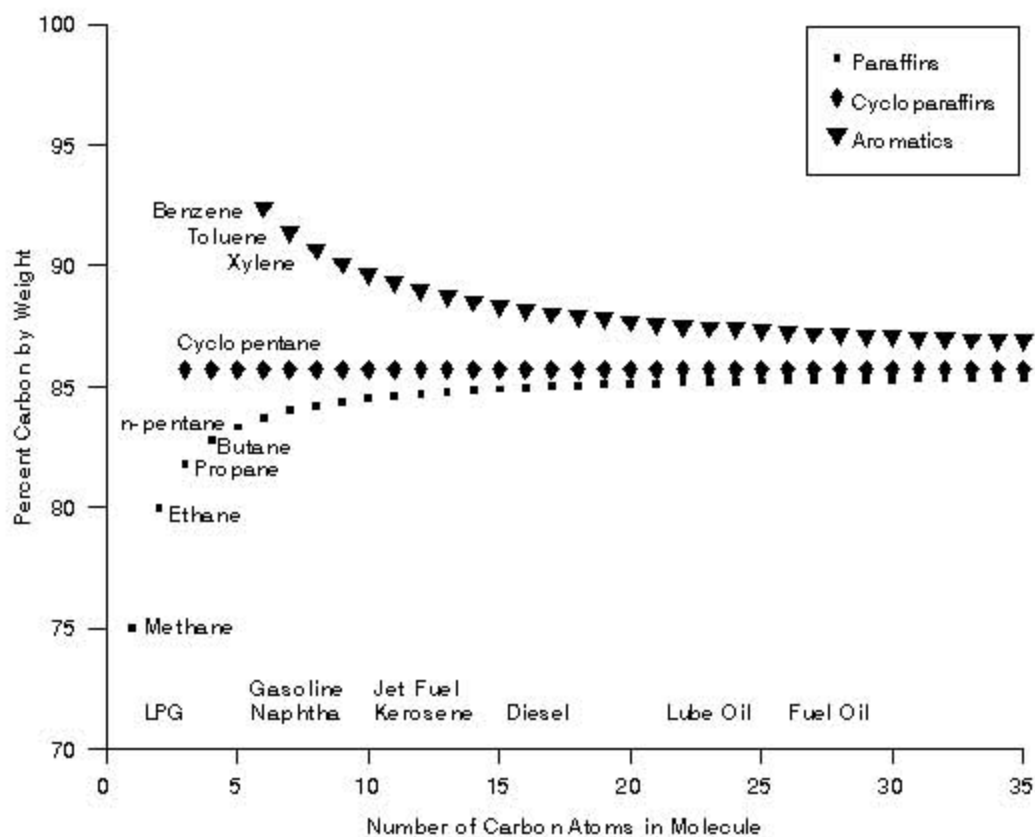
Source: EIA (1994) Energy Information Administration, Emissions of Greenhouse Gases in the United States 1987-1992, U.S. Department of Energy, Washington, DC, November, 1994, DOE/EIA 0573, Appendix A.

Figure A-2: Estimated and Actual Relationships Between Petroleum Carbon Content Coefficients and Hydrocarbon Density



Source: Carbon content factors for paraffins are calculated based on the properties of hydrocarbons in V. Guthrie (ed.), *Petroleum Products Handbook* (New York: McGraw Hill, 1960) p. 33. Carbon content factors from other petroleum products are drawn from sources described below. Relationship between density and emission factors based on the relationship between density and energy content in U.S. Department of Commerce, National Bureau of Standards, *Thermal Properties of Petroleum Products*, Miscellaneous Publication, No. 97 (Washington, D.C., 1929), pp.16-21, and relationship between energy content and fuel composition in S. Ringen, J. Lanum, and F.P. Miknis, "Calculating Heating Values from the Elemental Composition of Fossil Fuels," *Fuel*, Vol. 58 (January 1979), p.69.

Figure A-3: Carbon Content of Pure Hydrocarbons as a Function of Carbon Number



Source: J.M. Hunt, *Petroleum Geochemistry and Geology* (San Francisco, CA, W.H. Freeman and Company, 1979), pp. 31-37.

ANNEX 3 Methodological Descriptions for Additional Source or Sink Categories

3.1. Methodology for Estimating Emissions of CH₄, N₂O, and Indirect Greenhouse Gases from Stationary Combustion

Estimates of CH₄ and N₂O Emissions

Methane (CH₄) and nitrous oxide (N₂O) emissions from stationary combustion were estimated using IPCC emission factors and methods. Estimates were obtained by multiplying emission factors—by sector and fuel type—by fossil fuel and wood consumption data. This “top-down” methodology is characterized by two basic steps, described below. Data are presented in Table A-81 through Table A-85.

Step 1: Determine Energy Consumption by Sector and Fuel Type

Energy consumption from stationary combustion activities was grouped by sector: industrial, commercial, residential, electric power, and U.S. territories. For CH₄ and N₂O, estimates were based upon consumption of coal, gas, oil, and wood. Energy consumption data for the United States were obtained from EIA’s *Monthly Energy Review, January 2010* and Published Supplemental Tables on Petroleum Product detail (EIA 2011). Wood consumption data for the United States was obtained from EIA’s *Annual Energy Review* (EIA 2010). Because the United States does not include territories in its national energy statistics, fuel consumption data for territories were collected separately from the EIA from Jacobs (2010).³⁴ Fuel consumption for the industrial sector was adjusted to subtract out construction and agricultural use, which is reported under mobile sources.³⁵ Construction and agricultural fuel use was obtained from EPA (2010). The energy consumption data by sector were then adjusted from higher to lower heating values by multiplying by 0.9 for natural gas and wood and by 0.95 for coal and petroleum fuel. This is a simplified convention used by the International Energy Agency. Table A-81 provides annual energy consumption data for the years 1990 through 2009.

Step 2: Determine the Amount of CH₄ and N₂O Emitted

Activity data for each sector and fuel type were then multiplied by emission factors to obtain emission estimates. Emission factors for the residential, commercial, industrial, and electric power sectors were taken from the *2006 IPCC Guidelines for National Greenhouse Gas Inventories* (IPCC 2006). These N₂O emission factors by fuel type (consistent across sectors) were also assumed for U.S. territories. The CH₄ emission factors by fuel type for U.S. territories were estimated based on the emission factor for the primary sector in which each fuel was combusted. Table A-82 provides emission factors used for each sector and fuel type.

Estimates of NO_x, CO, and NMVOC Emissions

Emissions estimates for NO_x, CO, and NMVOCs were obtained from preliminary data (EPA 2010b, EPA 2009) and disaggregated based on EPA (2003), which, in its final iteration, will be published on the National Emission Inventory (NEI) Air Pollutant Emission Trends web site.

For indirect greenhouse gases, the major source categories included coal, fuel oil, natural gas, wood, other fuels (i.e., bagasse, liquefied petroleum gases, coke, coke oven gas, and others), and stationary internal combustion, which includes emissions from internal combustion engines not used in transportation. EPA periodically estimates emissions of NO_x, CO, and NMVOCs by sector and fuel type using a “bottom-up” estimating procedure. In other words, the emissions were calculated either for individual sources (e.g., industrial boilers) or for many sources combined, using basic activity data (e.g., fuel consumption or deliveries, etc.) as indicators of emissions. The national activity data used to calculate the individual categories were obtained from various sources. Depending upon the category, these activity data may include

³⁴ U.S. territories data also include combustion from mobile activities because data to allocate territories’ energy use were unavailable. For this reason, CH₄ and N₂O emissions from combustion by U.S. Territories are only included in the stationary combustion totals.

³⁵ 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.

fuel consumption or deliveries of fuel, tons of refuse burned, raw material processed, etc. Activity data were used in conjunction with emission factors that relate the quantity of emissions to the activity. Table A-83 through Table A-85 present indirect greenhouse gas emission estimates for 1990 through 2008.

The basic calculation procedure for most source categories presented in EPA (2003) and EPA (2009) is represented by the following equation:

$$E_{p,s} = A_s \times EF_{p,s} \times (1 - C_{p,s}/100)$$

Where,

E	= Emissions
p	= Pollutant
s	= Source category
A	= Activity level
EF	= Emission factor
C	= Percent control efficiency

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

Table A-81: Fuel Consumption by Stationary Combustion for Calculating CH₄ and N₂O Emissions (Tbtu)

Fuel/End-Use Sector	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Coal	18,064	19,138	20,032	20,517	20,802	20,779	21,682	21,085	21,139	21,562	21,713	22,095	21,758	22,062	21,709	19,283
Residential	31	17	17	16	12	14	11	12	12	12	11	8	6	8	8	7
Commercial	124	117	122	129	93	103	92	97	90	82	103	97	65	70	69	61
Industrial	1,640	1,527	1,455	1,457	1,471	1,373	1,349	1,358	1,244	1,249	1,262	1,219	1,188	1,130	1,083	881
Electric Power	16,261	17,466	18,429	18,905	19,216	19,279	20,220	19,614	19,783	20,185	20,305	20,737	20,462	20,808	20,513	18,296
U.S. Territories	7	10	10	10	11	10	10	4	11	34	32	33	37	47	36	38
Petroleum	6,749	5,425	5,933	5,879	5,697	5,844	6,047	6,657	5,978	6,630	6,881	6,812	6,413	6,217	5,439	4,994
Residential	1,375	1,261	1,397	1,334	1,207	1,342	1,427	1,463	1,359	1,466	1,475	1,369	1,205	1,225	1,215	1,197
Commercial	891	694	718	655	609	614	694	719	645	762	767	716	678	681	669	708
Industrial	2,818	2,254	2,566	2,519	2,129	2,216	2,310	2,567	2,456	2,576	2,774	2,869	3,261	3,103	2,609	2,195
Electric Power	1,289	755	817	927	1,306	1,211	1,144	1,277	961	1,205	1,212	1,235	648	657	468	390
U.S. Territories	375	462	435	445	445	461	472	632	557	622	654	623	621	552	479	504
Natural Gas	18,202	21,088	21,492	21,556	21,230	21,254	22,281	21,400	22,129	21,550	21,604	21,243	20,904	22,315	22,436	21,974
Residential	4,491	4,954	5,354	5,093	4,646	4,835	5,105	4,889	5,014	5,209	4,981	4,946	4,476	4,850	4,989	4,852
Commercial	2,682	3,096	3,226	3,285	3,083	3,115	3,252	3,097	3,225	3,261	3,201	3,073	2,902	3,094	3,211	3,168
Industrial	7,721	8,736	9,049	9,052	8,827	8,402	8,619	7,933	8,100	7,806	7,802	7,185	7,125	7,340	7,378	6,887
Electric Power	3,309	4,302	3,862	4,126	4,675	4,902	5,293	5,458	5,767	5,246	5,595	6,015	6,375	7,005	6,829	7,038
U.S. Territories	0	0	0	0	0	0	13	23	23	27	25	24	26	27	29	27
Wood	2,216	2,370	2,437	2,371	2,184	2,214	2,262	2,006	1,995	2,002	2,121	2,136	2,109	2,098	2,044	1,891
Residential	580	520	540	430	380	390	420	370	380	400	410	430	390	430	450	430
Commercial	66	72	76	73	64	67	71	67	69	71	70	70	65	69	73	72
Industrial	1,442	1,652	1,683	1,731	1,603	1,620	1,636	1,443	1,396	1,363	1,476	1,452	1,472	1,413	1,344	1,217
Electric Power	129	125	138	137	137	138	134	126	150	167	165	185	182	186	177	173
U.S. Territories	NE	NE	NE	NE	NE	NE	NE	NE	NE	NE	NE	NE	NE	NE	NE	NE

NE (Not Estimated)

Note: Totals may not sum due to independent rounding.

Table A-82: CH₄ and N₂O Emission Factors by Fuel Type and Sector (g/GJ)³⁶

Fuel/End-Use Sector	CH ₄	N ₂ O
Coal		
Residential	300	1.5
Commercial	10	1.5
Industrial	10	1.5
Electric Power	1	1.5
U.S. Territories	1	1.5
Petroleum		
Residential	10	0.6
Commercial	10	0.6
Industrial	3	0.6
Electric Power	3	0.6
U.S. Territories	5	0.6
Natural Gas		
Residential	5	0.1
Commercial	5	0.1
Industrial	1	0.1
Electric Power	1	0.1
U.S. Territories	1	0.1
Wood		
Residential	300	4.0
Commercial	300	4.0
Industrial	30	4.0
Electric Power	30	4.0
U.S. Territories	NA	NA

NA (Not Applicable)

³⁶ GJ (Gigajoule) = 10⁹ joules. One joule = 9.486×10⁻⁴ Btu

Table A-83: NOx Emissions from Stationary Combustion (Gg)

Sector/Fuel Type	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Electric Power	6,045	5,792	5,581	5,683	5,637	5,183	4,829	4,453	4,265	3,988	3,711	3,434	3,121	3,007	2,722	1,766
Coal	5,119	5,061	5,079	5,118	4,932	4,437	4,130	3,802	3,634	3,398	3,162	2,926	2,659	2,562	2,319	1,505
Fuel Oil	200	87	107	131	202	179	147	149	142	133	124	114	104	100	91	59
Natural gas	513	510	248	277	329	393	376	325	310	290	270	250	227	219	198	128
Wood	NA	NA	5	6	24	33	36	37	36	33	31	29	26	25	23	15
Other Fuels ^a	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Internal Combustion	213	134	142	150	149	141	140	140	143	134	124	115	105	101	91	59
Industrial	2,559	2,650	2,666	2,614	2,570	2,283	2,278	2,296	1,699	1,638	1,577	1,515	1,520	1,525	1,530	1,478
Coal	530	541	490	487	475	475	484	518	384	370	356	342	343	344	345	334
Fuel Oil	240	224	203	196	190	190	166	153	114	110	105	101	102	102	102	99
Natural gas	877	999	900	880	869	706	710	711	526	507	488	469	471	472	474	458
Wood	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other Fuels ^a	119	111	109	103	104	100	109	116	86	82	79	76	77	77	77	74
Internal Combustion	792	774	965	948	932	813	809	798	591	569	548	527	528	530	532	514
Commercial	671	607	734	539	510	483	507	428	438	456	473	490	486	483	479	501
Coal	36	35	30	32	34	23	21	21	19	19	19	19	19	19	19	19
Fuel Oil	88	94	86	88	73	54	52	52	50	49	49	49	49	49	49	49
Natural gas	181	210	224	229	220	156	161	165	157	156	156	155	155	155	154	154
Wood	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other Fuels ^a	366	269	394	191	183	249	273	189	213	231	249	267	263	261	257	280
Residential	749	813	726	699	651	441	439	446	423	421	420	418	417	417	416	414
Coal ^b	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Fuel Oil ^b	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Natural Gas ^b	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Wood	42	44	27	27	27	25	21	22	21	21	21	20	20	20	20	20
Other Fuels ^a	707	769	699	671	624	416	417	424	402	400	399	397	397	396	396	394
Total	10,023	9,862	9,707	9,534	9,369	8,390	8,053	7,623	6,825	6,503	6,181	5,858	5,545	5,432	5,148	4,159

NA (Not Applicable)

^a “Other Fuels” include LPG, waste oil, coke oven gas, coke, and non-residential wood (EPA 2003, 2009, 2010b).^b Residential coal, fuel oil, and natural gas emissions are included in the “Other Fuels” category (EPA 2003, 2009, 2010b).

Note: Totals may not sum due to independent rounding.

Table A-84: CO Emissions from Stationary Combustion (Gg)

Sector/Fuel Type	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Electric Power	329	337	369	385	410	450	439	439	595	590	586	582	598	616	633	631
Coal	213	227	228	233	220	187	221	220	298	296	293	292	300	308	317	316
Fuel Oil	18	9	11	13	17	36	27	28	38	37	37	37	38	39	40	40
Natural gas	46	49	72	76	88	150	96	92	125	124	123	122	126	129	133	132
Wood	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other Fuels ^a	NA	NA	7	8	30	24	31	32	44	43	43	43	44	45	46	46
Internal Combustion	52	52	52	54	55	52	63	67	91	90	89	89	91	94	97	96
Industrial	797	958	1,078	1,054	1,044	1,100	1,106	1,137	1,149	1,115	1,080	1,045	1,064	1,084	1,103	1,030
Coal	95	88	100	99	96	114	118	125	127	123	119	115	117	119	121	113

Fuel Oil	67	64	49	47	46	54	48	45	46	44	43	42	42	43	44	41
Natural gas	205	313	307	307	305	350	355	366	370	359	347	336	342	349	355	331
Wood	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other Fuels ^a	253	270	316	302	303	286	300	321	325	315	305	296	301	307	312	291
Internal Combustion	177	222	305	299	294	296	285	279	282	274	265	257	261	266	271	253
Commercial	205	211	122	126	122	151	151	154	177	173	169	166	166	167	168	158
Coal	13	14	13	13	14	16	14	13	15	15	15	14	15	15	15	14
Fuel Oil	16	17	17	18	15	17	17	17	20	19	19	19	19	19	19	18
Natural gas	40	49	58	59	57	81	83	84	97	95	93	91	91	92	92	87
Wood	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other Fuels ^a	136	132	34	36	36	36	36	38	44	43	42	41	42	42	42	40
Residential	3,668	3,877	2,364	2,361	2,352	3,323	2,644	2,648	3,044	2,981	2,919	2,856	2,867	2,878	2,889	2,725
Coal ^b	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Fuel Oil ^b	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Natural Gas ^b	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Wood	3,430	3,629	2,133	2,133	2,133	3,094	2,416	2,424	2,787	2,730	2,672	2,615	2,624	2,635	2,645	2,495
Other Fuels ^a	238	248	231	229	220	229	228	224	257	252	246	241	242	243	244	230
Total	5,000	5,383	3,934	3,926	3,928	5,024	4,340	4,377	4,965	4,860	4,753	4,649	4,695	4,744	4,792	4,543

NA (Not Applicable)

^a “Other Fuels” include LPG, waste oil, coke oven gas, coke, and non-residential wood (EPA 2003, 2009, 2010b).

^b Residential coal, fuel oil, and natural gas emissions are included in the “Other Fuels” category (EPA 2003, 2009, 2010b).

Note: Totals may not sum due to independent rounding.

Table A-85: NMVOC Emissions from Stationary Combustion (Gg)

Sector/Fuel Type	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Electric Power	43	40	44	47	51	49	56	55	44	44	44	44	44	45	45	46
Coal	24	26	25	26	26	25	27	26	21	21	21	21	21	22	22	22
Fuel Oil	5	2	3	4	5	4	4	4	4	4	4	3	4	4	4	4
Natural gas	2	2	7	7	9	9	12	12	10	10	10	10	10	10	10	10
Wood	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other Fuels ^a	NA	NA	+	+	1	2	2	2	1	1	1	1	1	1	1	1
Internal Combustion	11	9	9	10	10	10	11	11	8	8	8	8	8	9	9	9
Industrial	165	187	163	160	159	156	157	160	138	132	126	121	120	119	118	110
Coal	7	5	6	6	6	9	9	10	9	9	8	8	8	8	8	7
Fuel Oil	11	11	8	7	7	10	9	9	7	7	7	6	6	6	6	6
Natural gas	52	66	54	54	54	52	53	54	47	45	43	41	41	40	40	37
Wood	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other Fuels ^a	46	45	33	31	31	26	27	29	25	24	23	22	22	22	22	20
Internal Combustion	49	60	63	62	61	60	58	57	49	47	45	43	43	42	42	39
Commercial	18	21	22	22	21	25	28	29	61	53	45	33	36	38	40	23
Coal	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	+
Fuel Oil	3	3	3	3	3	3	4	4	6	5	3	2	3	4	5	1

Natural gas	7	10	13	13	12	11	14	14	23	18	14	9	12	16	19	4
Wood	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other Fuels ^a	8	8	5	5	5	10	9	10	31	29	27	22	19	17	15	18
Residential	686	725	788	788	786	815	837	837	1,341	1,066	792	519	719	918	1,117	244
Coal ^b	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Fuel Oil ^b	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Natural Gas ^b	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Wood	651	688	756	757	756	794	809	809	1,298	1,032	767	502	695	888	1,081	236
Other Fuels ^a	35	37	33	32	30	21	27	27	43	35	26	17	23	30	36	8
Total	912	973	1,018	1,017	1,016	1,045	1,077	1,081	1,585	1,296	1,008	716	918	1,120	1,321	424

NA (Not Applicable)

+ Does not exceed 1 Gg.

^a “Other Fuels” include LPG, waste oil, coke oven gas, coke, and non-residential wood (EPA 2003, 2009, 2010b).

^b Residential coal, fuel oil, and natural gas emissions are included in the “Other Fuels” category (EPA 2003, 2009, 2010b).

Note: Totals may not sum due to independent rounding.

3.2. Methodology for Estimating Emissions of CH₄, N₂O, and Indirect Greenhouse Gases from Mobile Combustion and Methodology for and Supplemental Information on Transportation-Related GHG Emissions

Estimating CO₂ Emissions by Transportation Mode

Transportation-related CO₂ emissions, as presented in the Carbon Dioxide Emissions from Fossil Fuel Combustion section of the Energy chapter, were calculated using the methodology described in Annex 2.1. This section provides additional information on the data sources and approach used for each transportation fuel type. As noted in Annex 2.1, CO₂ emissions estimates for the transportation sector were calculated directly for on-road diesel fuel and motor gasoline based on data sources for individual modes of transportation (considered a “bottom up” approach). For most other fuel and energy types (i.e., jet fuel, aviation gasoline, residual fuel oil, natural gas, LPG, and electricity), CO₂ emissions were calculated based on transportation sector-wide fuel consumption estimates from the Energy Information Administration (EIA 2007b and EIA 2007 through 2009) and apportioned to individual modes (considered a “top down” approach).

Based on interagency discussions between EPA, EIA, and FHWA beginning in 2005, it was agreed that use of “bottom up” data would be more accurate for diesel fuel and motor gasoline, based on the availability of reliable transportation-specific data sources. A “bottom up” diesel calculation was implemented in the 1990-2005 Inventory, and a bottom-up gasoline calculation was introduced in the 1990-2006 Inventory for the calculation of emissions from on-road vehicles. Motor gasoline and diesel consumption data for on-road vehicles come from FHWA’s *Highway Statistics*, Table VM-1 (FHWA 1996 through 2009), and are based on federal and state fuel tax records. These fuel consumption estimates were then combined with estimates of fuel shares by vehicle type from DOE’s *Transportation Energy Data Book* (DOE 1993 through 2009) to develop an estimate of fuel consumption for each vehicle type (i.e., passenger cars, light-duty trucks, buses, medium- and heavy-duty trucks, motorcycles). The on-road gas and diesel fuel consumption estimates by vehicle type were then adjusted for each year so that the sum of gasoline and diesel fuel consumption across all vehicle categories matched the fuel consumption estimates in *Highway Statistics*’ Tables MF-21 and MF-27 (FHWA 1996 through 2010). Table MF-21 provided fuel consumption estimates for the most current Inventory year; Table MF-27 provided fuel consumption estimates for years 1990-2008. This resulted in a final estimate of motor gasoline and diesel fuel use by vehicle type, consistent with the FHWA total for on-road motor gasoline and diesel fuel use.

Estimates of diesel fuel consumption from rail were taken from the Association of American Railroads (AAR 2008 through 2010) for Class I railroads, the American Public Transportation Association (APTA 2007 through 2010 and APTA 2006) and Gaffney (2007) for commuter rail, the Upper Great Plains Transportation Institute (Benson 2002 through 2004) and Whorton (2006 through 2009) for Class II and III railroads, and DOE’s *Transportation Energy Data Book* (DOE 1993 through 2010) for passenger rail. Estimates of diesel from ships and boats were taken from EIA’s *Fuel Oil and Kerosene Sales* (1991 through 2011).

Since EIA’s total fuel consumption estimate for each fuel type is considered to be accurate at the national level, adjustments needed to be made in the estimates for other sectors to equal the EIA total. In the case of motor gasoline, estimates of fuel use by recreational boats come from EPA’s NONROAD Model (EPA 2010b), and these estimates along with those from other sectors (e.g., commercial sector, industrial sector) were adjusted. Similarly, to ensure consistency with EIA’s total diesel estimate for all sectors, the diesel consumption totals for the residential, commercial, and industrial sectors were adjusted downward proportionately.

As noted above, for fuels other than motor gasoline and diesel, EIA’s transportation sector total was apportioned to specific transportation sources. For jet fuel, estimates come from: DOT (1991 through 2010) and FAA (2011, 2006) for commercial aircraft, FAA (2009) for general aviation aircraft, and DESC (2008) for military aircraft. Estimates for biofuels, including ethanol and biodiesel were discussed separately and were not apportioned to specific transportation sources. Consumption estimates for biofuels were calculated based on data from the Energy Information Administration (EIA2010b).

Table A-86 displays estimated fuel consumption by fuel and vehicle type. Table A-87 displays estimated energy consumption by fuel and vehicle type. The values in both of these tables correspond to the figures used to calculate CO₂ emissions from transportation. Except as noted above, they are estimated based on EIA transportation sector energy estimates by fuel type, with activity data used to apportion consumption to the various modes of transport. For motor gasoline, the figures do not include ethanol blended with gasoline; although ethanol is included in FHWA’s totals for reported motor gasoline use. Ethanol is a biofuel and in order to be in line with IPCC methodological guidance and

UNFCCC reporting obligations, net carbon fluxes in biogenic carbon reservoirs in croplands are accounted for in the estimates for Land Use, Land-Use Change and Forestry chapter, not in Energy chapter totals. Ethanol and biodiesel consumption estimates are shown separately in Table A-88.

Table A-86. Fuel Consumption by Fuel and Vehicle Type (million gallons unless otherwise specified)^a

Fuel/Vehicle Type	1990	1995	2000	2005	2006	2007	2008	2009
Motor Gasoline^b	110,440.9	118,216.0	129,101.8	137,294.2	132,944.7	132,543.8	127,524.7	127,012.2
Passenger Cars	69,762.4	67,948.0	72,859.7	76,059.6	71,645.8	70,548.0	67,022.7	66,945.0
Light-Duty Trucks	34,698.4	44,369.3	50,773.8	55,336.4	55,459.3	56,117.9	54,889.7	54,826.0
Motorcycles	194.0	200.3	209.8	183.4	212.2	230.9	241.5	241.2
Buses	38.9	41.7	43.6	41.9	41.7	43.6	42.8	38.9
Medium- and Heavy-Duty Trucks	4,349.8	4,071.6	4,095.5	3,960.1	4,008.3	4,046.5	3,803.7	3,454.2
Recreational Boats ^c	1,397.3	1,585.1	1,119.3	1,597.9	1,577.4	1,556.9	1,524.2	1,506.8
Distillate Fuel Oil (Diesel Fuel)	25,631.2	31,604.6	39,241.4	44,659.2	45,847.6	46,432.3	43,236.5	39,243.4
Passenger Cars	771.2	764.9	356.1	414.0	403.2	399.7	382.4	380.2
Light-Duty Trucks	1,118.5	1,452.0	1,960.6	2,518.4	2,609.9	2,658.5	2,618.5	2,603.2
Buses	781.0	851.1	996.6	1,030.1	1,048.5	1,048.5	1,007.3	910.4
Medium- and Heavy-Duty Trucks	18,574.2	23,240.7	30,179.9	35,160.0	36,078.5	36,665.4	34,706.1	31,368.6
Recreational Boats	190.4	228.1	265.6	305.4	313.4	321.4	87.8	337.5
Ships and Other Boats	735.3	1,204.3	1,376.8	785.3	729.5	799.8	218.4	118.8
Rail	3,460.6	3,863.5	4,105.9	4,446.1	4,664.5	4,538.9	4,216.0	3,524.8
Jet Fuel^d	18,349.7	17,850.3	20,491.9	19,919.9	17,386.1	17,305.8	15,906.2	14,239.3
Commercial Aircraft	14,103.4	14,795.9	17,352.8	16,532.7	14,065.0	14,163.9	12,533.8	11,425.1
General Aviation Aircraft	662.9	559.8	972.0	1,526.7	1,642.6	1,485.6	1,705.7	1,364.3
Military Aircraft	3,583.4	2,494.6	2,167.1	1,860.5	1,678.5	1,656.3	1,666.8	1,449.9
Aviation Gasoline^d	374.2	329.3	301.9	294.2	278.3	262.8	235.3	221.0
General Aviation Aircraft	374.2	329.3	301.9	294.2	278.3	262.8	235.3	221.0
Residual Fuel Oil^{d,e}	2,006.2	2,587.4	2,962.5	1,713.1	2,046.3	2,579.4	1,770.5	1,064.8
Ships and Other Boats	2,006.2	2,587.4	2,962.5	1,713.1	2,046.3	2,579.4	1,770.5	1,064.8
Natural Gas^d (million cubic feet)	0.7	0.7	0.7	0.6	0.6	0.6	0.7	0.7
Passenger Cars	-	+	-	-	-	-	-	-
Light-Duty Trucks	-	+	-	-	-	-	-	-
Buses	-	+	+	+	+	+	+	+
Pipelines	0.7	0.7	0.6	0.6	0.6	0.6	0.7	0.6
LPG^d	265.2	205.5	138.4	308.7	320.0	256.7	459.5	487.5
Buses	-	1.6	1.5	1.0	1.0	-	-	-
Light-Duty Trucks	106.1	98.3	88.0	233.2	229.5	184.7	334.0	354.3
Medium- and Heavy-Duty Trucks	159.1	105.6	48.8	74.6	89.5	72.0	125.5	133.2
Electricity^d	4,751.2	4,974.5	5,381.9	7,506.4	7,357.6	8,172.6	7,699.6	7,688.5
Rail	4,751.2	4,974.5	5,381.9	7,506.4	7,357.6	8,172.6	7,699.6	7,688.5

^a FHWA data on vehicle miles traveled from the VM-1 table were not available for 2009 due to a delay caused by changes in data collection procedures. Based on data from FHWA's Traffic Volume Trends Program, the overall increase in VMT between 2008 and 2009 was estimated to be 0.2%. Total VMT was distributed among vehicle classes based on trends in fuel consumption by fuel type between 2008 and 2009, as described below.

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

^b Figures do not include ethanol blended in motor gasoline. Net carbon fluxes associated with ethanol are accounted for in the Land Use, Land-Use Change and Forestry chapter.

^c Fluctuations in recreational boat gasoline estimates reflect the use of this category to reconcile bottom-up values with EIA total gasoline estimates.

^d Estimated based on EIA transportation sector energy estimates by fuel type, with bottom-up activity data used for apportionment to modes.

^e Fluctuations in reported fuel consumption may reflect data collection problems.

+ Less than 0.05 million gallons or 0.05 million cubic feet

- Unreported or zero

Table A-87: Energy Consumption by Fuel and Vehicle Type (Tbtu)

Fuel/Vehicle Type	1990	1995	2000	2005	2006	2007	2008	2009
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Motor Gasoline^b	13,813.0	14,678.5	16,014.8	16,729.6	16,516.8	16,470.1	15,843.4	15,779.7
Passenger Cars	8,725.3	8,436.9	9,038.1	9,268.0	8,901.1	8,766.4	8,326.8	8,317.1
Light-Duty Trucks	4,339.8	5,509.2	6,298.4	6,742.8	6,890.2	6,973.3	6,819.4	6,811.5
Motorcycles	24.3	24.9	26.0	22.8	26.4	28.7	30.0	30.0
Buses	4.9	5.2	5.4	5.1	5.2	5.4	5.3	4.8
Medium- and Heavy-Duty Trucks	544.0	505.6	508.0	492.2	498.0	502.8	472.6	429.1
Recreational Boats ^c	174.8	196.8	138.8	198.6	196.0	193.5	189.4	187.2
Distillate Fuel Oil								
(Diesel Fuel)	3,554.8	4,383.3	5,442.4	6,193.8	6,358.6	6,439.7	5,996.5	5,442.7
Passenger Cars	107.0	106.1	49.4	57.4	55.9	55.4	53.0	52.7
Light-Duty Trucks	155.1	201.4	271.9	349.3	362.0	368.7	363.2	361.0
Buses	108.3	118.0	138.2	142.9	145.4	145.4	139.7	126.3
Medium- and Heavy-Duty Trucks	2,576.1	3,223.3	4,185.7	4,876.4	5,003.7	5,085.1	4,813.4	4,350.5
Recreational Boats	26.4	31.6	36.8	42.4	43.5	44.6	12.2	46.8
Ships and Other Boats	102.0	167.0	190.9	108.9	101.2	110.9	30.3	16.5
Rail	480.0	535.8	569.4	616.6	646.9	629.5	584.7	488.9
Jet Fuel^c	2,477.2	2,409.8	2,766.4	2,689.2	2,347.1	2,336.3	2,147.3	1,922.3
Commercial Aircraft	1,904.0	1,997.4	2,342.6	2,231.9	1,898.8	1,912.1	1,692.1	1,542.4
General Aviation								
Aircraft	89.5	75.6	131.2	206.1	221.8	200.6	230.3	184.2
Military Aircraft	483.8	336.8	292.6	251.2	226.6	223.6	225.0	195.7
Aviation Gasoline^d	45.0	39.6	36.3	35.4	33.4	31.6	28.3	26.6
General Aviation								
Aircraft	45.0	39.6	36.3	35.4	33.4	31.6	28.3	26.6
Residual Fuel Oil^{d,e}	300.3	387.3	443.5	256.4	306.3	386.1	265.0	159.4
Ships and Other Boats	300.3	387.3	443.5	256.4	306.3	386.1	265.0	159.4
Natural Gas^d	679.9	724.0	672.0	623.9	625.0	665.4	694.5	684.2
Passenger Cars	-	1.9	-	-	-	-	-	-
Light-Duty Trucks	-	0.1	-	-	-	-	-	-
Buses	-	1.0	8.3	15.8	15.5	18.6	20.7	20.8
Pipelines	679.9	721.0	663.7	608.1	609.4	646.8	673.8	663.5
LPG^d	22.9	17.7	11.9	28.2	27.5	21.9	39.4	41.2
Buses	-	0.1	0.1	0.1	0.1	-	-	-
Light-Duty Trucks	9.2	8.5	7.6	21.3	19.7	15.8	28.6	30.0
Medium- and Heavy-Duty Trucks	13.7	9.1	4.2	6.8	7.7	6.2	10.8	11.3
Electricity^d	16.2	17.0	18.4	25.6	25.1	27.9	26.1	26.1
Rail	16.2	17.0	18.4	25.6	25.1	27.9	26.1	26.1
Total	20,909.3	22,657.1	25,405.6	26,582.1	26,239.8	26,379.1	25,040.5	24,082.3

^a FHWA data on vehicle miles traveled from the VM-1 table were not available for 2009 due to a delay caused by changes in data collection procedures. Based on data from FHWA's Traffic Volume Trends Program, the overall increase in VMT between 2008 and 2009 was estimated to be 0.2%. Total VMT was distributed among vehicle classes based on trends in fuel consumption by fuel type between 2008 and 2009, as described below.

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

^b Figures do not include ethanol blended in motor gasoline. Net carbon fluxes associated with ethanol are accounted for in the Land Use, Land-Use Change and Forestry chapter.

^c Fluctuations in recreational boat gasoline estimates reflect the use of this category to reconcile bottom-up values with EIA total gasoline estimates.

^d Estimated based on EIA transportation sector energy estimates, with bottom-up data used for apportionment to modes

^e Fluctuations in reported fuel consumption may reflect data collection problems.

- Unreported or zero

Table A-88. Biofuel Consumption by Fuel Type (million gallons)

Fuel Type	1990	1995	2000	2005	2006	2007	2008	2009
Ethanol	717.5	1,335.8	1,601.7	3,888.0	5,245.0	6,611.6	9,331.5	10,432.2
Biodiesel	NA	NA	NA	137.5	394.6	542.3	484.9	514.0

Estimates of CH₄ and N₂O Emissions

Mobile source emissions of greenhouse gases other than CO₂ are reported by transport mode (e.g., road, rail, aviation, and waterborne), vehicle type, and fuel type. Emissions estimates of CH₄ and N₂O were derived using a methodology similar to that outlined in the *Revised 1996 IPCC Guidelines* (IPCC/UNEP/OECD/IEA 1997).

Activity data were obtained from a number of U.S. government agencies and other publications. Depending on the category, these basic activity data included fuel consumption and vehicle miles traveled (VMT). These estimates were then multiplied by emission factors, expressed as grams per unit of fuel consumed or per vehicle mile.

Methodology for On-Road Gasoline and Diesel Vehicles

Step 1: Determine Vehicle Miles Traveled by Vehicle Type, Fuel Type, and Model Year

VMT by vehicle type (e.g., passenger cars, light-duty trucks, medium- and heavy-duty trucks,³⁷ buses, and motorcycles) were obtained from the Federal Highway Administration's (FHWA) *Highway Statistics* (FHWA 1996 through 2009). As these vehicle categories are not fuel-specific, VMT for each vehicle type was disaggregated by fuel type (gasoline, diesel) so that the appropriate emission factors could be applied. VMT from *Highway Statistics* Table VM-1 (FHWA 1996 through 2009) was allocated to fuel types (gasoline, diesel, other) using historical estimates of fuel shares reported in the Appendix to the *Transportation Energy Data Book* (DOE 1993 through 2010). These fuel shares are drawn from various sources, including the Vehicle Inventory and Use Survey, the National Vehicle Population Profile, and the American Public Transportation Association. The fuel shares were first adjusted proportionately so that the gasoline and diesel shares for each vehicle type summed to 100 percent in order to develop an interim estimate of VMT for each vehicle/fuel type category that summed to the total national VMT estimate. VMT for alternative fuel vehicles (AFVs) was calculated separately, and the methodology is explained in the following section on AFVs. Estimates of VMT from AFVs were then subtracted from the appropriate interim VMT estimates to develop the final VMT estimates by vehicle/fuel type category.³⁸ The resulting national VMT estimates for gasoline and diesel on-road vehicles are presented in Table A- 89 and Table A- 90, respectively.

Total VMT for each on-road category (i.e., gasoline passenger cars, light-duty gasoline trucks, heavy-duty gasoline vehicles, diesel passenger cars, light-duty diesel trucks, medium- and heavy-duty diesel vehicles, and motorcycles) were distributed across 31 model years shown for 2009 in Table A- 93. Distributions for 1990-2007 are presented in the Inventory Docket. This distribution was derived by weighting the appropriate age distribution of the U.S. vehicle fleet according to vehicle registrations by the average annual age-specific vehicle mileage accumulation of U.S. vehicles. Age distribution values were obtained from EPA's MOBILE6 model for all years before 1999 (EPA 2000) and EPA's MOVES model for years 1999 forward (EPA 2010a).³⁹ Age-specific vehicle mileage accumulation was obtained from EPA's MOBILE6 model (EPA 2000).

Step 2: Allocate VMT Data to Control Technology Type

VMT by vehicle type for each model year was distributed across various control technologies as shown in Table A- 97 through Table A- 100. The categories "EPA Tier 0" and "EPA Tier 1" were used instead of the early three-way catalyst and advanced three-way catalyst categories, respectively, as defined in the *Revised 1996 IPCC Guidelines*. EPA Tier 0, EPA Tier 1, EPA Tier 2, and LEV refer to U.S. emission regulations, rather than control technologies; however, each does correspond to particular combinations of control technologies and engine design. EPA Tier 2 and its predecessors EPA Tier 1 and Tier 0 apply to vehicles equipped with three-way catalysts. The introduction of "early three-way catalysts," and "advanced three-way catalysts," as described in the *Revised 1996 IPCC Guidelines*, roughly correspond to the introduction of EPA Tier 0 and EPA Tier 1 regulations (EPA 1998).⁴⁰ EPA Tier 2 regulations affect vehicles produced starting in 2004 and are responsible for a noticeable decrease in N₂O emissions compared EPA Tier 1 emissions technology (EPA 1999b).

³⁷ Medium-duty trucks include vehicles with a gross vehicle weight rating (GVWR) of 8,500 to 14,000 lbs. while heavy-duty trucks include those with a GVWR of over 14,000 lbs.

³⁸ In Inventories through 2002, gasoline-electric hybrid vehicles were considered part of an "alternative fuel and advanced technology" category. However, vehicles are now only separated into gasoline, diesel, or alternative fuel categories, and gas-electric hybrids are now considered within the gasoline vehicle category.

³⁹ Age distributions were held constant for the period 1990-1998, and reflect a 25-year vehicle age span. EPA (2010) provides a variable age distribution and 31-year vehicle age span beginning in year 1999.

⁴⁰ For further description, see "Definitions of Emission Control Technologies and Standards" section of this annex.

Control technology assignments for light and heavy-duty conventional fuel vehicles for model years 1972 (when regulations began to take effect) through 1995 were estimated in EPA (1998). Assignments for 1998 through 2007 were determined using confidential engine family sales data submitted to EPA (EPA 2007b). Vehicle classes and emission standard tiers to which each engine family was certified were taken from annual certification test results and data (EPA 2007a). This information was used to determine the fraction of sales of each class of vehicle that met EPA Tier 0, EPA Tier 1, Tier 2, and LEV standards. Assignments for 1996 and 1997 were estimated based on the fact that EPA Tier 1 standards for light-duty vehicles were fully phased in by 1996. Tier 2 began initial phase-in by 2004.

Step 3: Determine CH₄ and N₂O Emission Factors by Vehicle, Fuel, and Control Technology Type

Emission factors for gasoline and diesel on-road vehicles were developed by ICF (2004). These factors were based on EPA and CARB laboratory test results of different vehicle and control technology types. The EPA and CARB tests were designed following the Federal Test Procedure (FTP), which covers three separate driving segments, since vehicles emit varying amounts of GHGs 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 later analyzed to determine quantities of gases present. The emission characteristics of segment 2 was used to define running emissions, and subtracted from the total FTP emissions to determine start emissions. These were then recombined based upon MOBILE6.2's ratio of start to running emissions for each vehicle class to approximate average driving characteristics.

Step 4: Determine the Amount of CH₄ and N₂O Emitted by Vehicle, Fuel, and Control Technology Type

Emissions of CH₄ and N₂O were then calculated by multiplying total VMT by vehicle, fuel, and control technology type by the emission factors developed in Step 3.

Methodology for Alternative Fuel Vehicles (AFVs)

Step 1: Determine Vehicle Miles Traveled by Vehicle and Fuel Type

VMT for alternative fuel and advanced technology vehicles were calculated from "VMT Projections for Alternative Fueled and Advanced Technology Vehicles through 2025" (Browning 2003). Alternative Fuels include Compressed Natural Gas (CNG), Liquid Natural Gas (LNG), Liquefied Petroleum Gas (LPG), Ethanol, Methanol, and Electric Vehicles (battery powered). Most of the vehicles that use these fuels run on an Internal Combustion Engine (ICE) powered by the alternative fuel, although many of the vehicles can run on either the alternative fuel or gasoline (or diesel), or some combination.⁴¹ The data obtained include vehicle fuel use and total number of vehicles in use from 1992 through 2007. Because AFVs run on different fuel types, their fuel use characteristics are not directly comparable. Accordingly, fuel economy for each vehicle type is expressed in gasoline equivalent terms, i.e., how much gasoline contains the equivalent amount of energy as the alternative fuel. Energy economy ratios (the ratio of the gasoline equivalent fuel economy of a given technology to that of conventional gasoline or diesel vehicles) were taken from full fuel cycle studies done for the California Air Resources Board (Unnasch and Browning, Kassoy 2001). These ratios were used to estimate fuel economy in miles per gasoline gallon equivalent for each alternative fuel and vehicle type. Energy use per fuel type was then divided among the various weight categories and vehicle technologies that use that fuel. Total VMT per vehicle type for each calendar year was then determined by dividing the energy usage by the fuel economy. Note that for AFVs capable of running on both/either traditional and alternative fuels, the VMT given reflects only those miles driven that were powered by the alternative fuel, as explained in Browning (2003). VMT estimates for AFVs by vehicle category (passenger car, light-duty truck, heavy-duty vehicles) are shown in Table A- 91, while more detailed estimates of VMT by control technology are shown in Table A- 92.

⁴¹ Fuel types used in combination depend on the vehicle class. For light-duty vehicles, gasoline is generally blended with ethanol or methanol; some vehicles are also designed to run on gasoline or an alternative fuel – either natural gas or LPG – but not at the same time, while other vehicles are designed to run on E85 (85% ethanol) or gasoline, or any mixture of the two. Heavy-duty vehicles are more likely to run on a combination of diesel fuel and either natural gas, LPG, ethanol, or methanol.

Step 2: Determine CH₄ and N₂O Emission Factors by Vehicle and Alternative Fuel Type

CH₄ and N₂O emission factors for alternative fuel vehicles (AFVs) are calculated according to studies by Argonne National Laboratory (2006) and Lipman & Delucchi (2002), and are reported in ICF (2006a). In these studies, N₂O and CH₄ emissions for AFVs were expressed as a multiplier corresponding to conventional vehicle counterpart emissions. Emission estimates in these studies represent the current AFV fleet and were compared against Tier 1 emissions from light-duty gasoline vehicles to develop new multipliers. Alternative fuel heavy-duty vehicles were compared against gasoline heavy-duty vehicles as most alternative fuel heavy-duty vehicles use catalytic after treatment and perform more like gasoline vehicles than diesel vehicles. These emission factors are shown in Table A- 102.

Step 3: Determine the Amount of CH₄ and N₂O Emitted by Vehicle and Fuel Type

Emissions of CH₄ and N₂O were calculated by multiplying total VMT for each vehicle and fuel type (Step 1) by the appropriate emission factors (Step 2).

Methodology for Non-Road Mobile Sources

CH₄ and N₂O emissions from non-road mobile sources were estimated by applying emission factors to the amount of fuel consumed by mode and vehicle type.

Activity data for non-road vehicles include annual fuel consumption statistics by transportation mode and fuel type, as shown in Table A- 96. Consumption data for ships and other boats (i.e., vessel bunkering) were obtained from DHS (2008) and EIA (1991 through 2011) for distillate fuel, and DHS (2008) and EIA (2007b) for residual fuel; marine transport fuel consumption data for U.S. territories (EIA 2008b, EIA 1991 through 2011) were added to domestic consumption, and this total was reduced by the amount of fuel used for international bunkers.⁴² Gasoline consumption by recreational boats was obtained from EPA's NONROAD model (EPA 2010). Annual diesel consumption for Class I rail was obtained from the Association of American Railroads (AAR) (2008), diesel consumption from commuter rail was obtained from APTA (2007 through 2010) and Gaffney (2007), and consumption by Class II and III rail was provided by Benson (2002 through 2004) and Whorton (2006 through 2009). Diesel consumption by commuter and intercity rail was obtained from DOE (1993 through 2010). Data on the consumption of jet fuel and aviation gasoline in aircraft were obtained from EIA (2007b), as described in Annex 2.1: Methodology for Estimating Emissions of CO₂ from Fossil Fuel Combustion, and were reduced by the amount allocated to international bunker fuels. Pipeline fuel consumption was obtained from EIA (2007 through 2010) (note: pipelines are a transportation source but are stationary, not mobile, sources). Data on fuel consumption by all non-transportation mobile sources⁴³ were obtained from EPA's NONROAD model (EPA 2010) and from FHWA (1996 through 2010) for gasoline consumption for trucks used off-road.

Emissions of CH₄ and N₂O from non-road mobile sources were calculated by multiplying U.S. default emission factors in the *Revised 1996 IPCC Guidelines* (IPCC/UNEP/OECD/IEA 1997) by activity data for each source type (see Table A- 103).

Estimates of NO_x, CO, and NMVOC Emissions

The emission estimates of NO_x, CO, and NMVOCs from mobile combustion (transportation) were obtained from preliminary data (EPA 2010, EPA 2009), which, in final iteration, will be published on the EPA's National Emission Inventory (NEI) Air Pollutant Emission Trends web site. This EPA report provides emission estimates for these gases by fuel type using a procedure whereby emissions were calculated using basic activity data, such as amount of fuel delivered or miles traveled, as indicators of emissions.

Table A- 104 through Table A- 106 provides complete emission estimates for 1990 through 2009.

Table A- 89: Vehicle Miles Traveled for Gasoline On-Road Vehicles (10⁹ Miles)^a

Year	Passenger Cars	Light-Duty Trucks	Heavy-Duty Vehicles	Motorcycles
1990	1391.2	554.3	25.4	9.6
1991	1341.7	627.2	25.0	9.2
1992	1354.8	682.9	24.8	9.6

⁴² See International Bunker Fuels section of the Energy Chapter.

⁴³ "Non-transportation mobile sources" are defined as any vehicle or equipment not used on the traditional road system, but excluding aircraft, rail and watercraft. This category includes snowmobiles, golf carts, riding lawn mowers, agricultural equipment, and trucks used for off-road purposes, among others.

1993	1356.5	720.5	24.5	9.9
1994	1387.5	738.8	25.0	10.2
1995	1420.6	762.5	24.7	9.8
1996	1454.7	788.0	24.0	9.9
1997	1488.5	820.8	23.6	10.1
1998	1536.6	836.8	23.6	10.3
1999	1559.1	867.4	23.8	10.6
2000	1591.5	886.7	23.6	10.5
2001	1619.3	904.9	23.2	9.6
2002	1649.2	925.8	23.1	9.6
2003	1662.6	943.0	23.5	9.6
2004	1690.2	984.2	23.8	10.1
2005	1698.6	997.5	24.1	10.5
2006	1680.8	1037.2	24.2	12.0
2007	1662.7	1065.6	24.7	13.6
2008	1,606.4	1,062.0	24.7	14.5
2009	1,621.1	1,071.7	22.7	14.6

Source: Derived from FHWA (1996 through 2009).

^a FHWA data on vehicle miles traveled from the VM-1 table were not available for 2009 due to a delay caused by changes in data collection procedures. Based on data from FHWA's Traffic Volume Trends Program, the overall increase in VMT between 2008 and 2009 was estimated to be 0.2%. Total VMT was distributed among vehicle classes based on trends in fuel consumption by fuel type between 2008 and 2009

Table A- 90: Vehicle Miles Traveled for Diesel On-Road Vehicles (10⁹ Miles)^a

Year	Passenger Cars	Light-Duty Trucks	Heavy-Duty Vehicles
1990	16.9	19.7	125.5
1991	16.3	21.6	129.3
1992	16.5	23.4	133.5
1993	17.9	24.7	140.3
1994	18.3	25.3	150.5
1995	17.3	26.9	158.7
1996	14.7	27.8	164.3
1997	13.5	29.0	173.4
1998	12.4	30.5	178.4
1999	9.4	32.6	185.3
2000	8.0	35.2	188.0
2001	8.1	37.0	191.1
2002	8.3	38.9	196.4
2003	8.3	39.6	199.1
2004	8.4	41.3	201.6
2005	8.4	41.9	202.8
2006	8.3	43.5	201.4
2007	8.1	44.6	204.7
2008	7.8	44.4	205.5
2009	7.9	44.8	187.8

Source: Derived from FHWA (1996 through 2009).

^a FHWA data on vehicle miles traveled from the VM-1 table were not available for 2009 due to a delay caused by changes in data collection procedures. Based on data from FHWA's Traffic Volume Trends Program, the overall increase in VMT between 2008 and 2009 was estimated to be 0.2%. Total VMT was distributed among vehicle classes based on trends in fuel consumption by fuel type between 2008 and 2009

Table A- 91: Vehicle Miles Traveled for Alternative Fuel On-Road Vehicles (10⁹ Miles)

Year	Passenger Cars	Light-Duty Trucks	Heavy-Duty Vehicles
1990	0.2	0.7	1.1
1991	0.2	0.6	1.0
1992	0.3	0.6	0.9
1993	0.3	0.6	1.3
1994	0.3	0.5	1.2
1995	0.4	0.6	1.2
1996	0.5	0.7	1.2
1997	0.6	0.9	1.3

1998	0.6	1.0	1.4
1999	0.6	1.0	1.3
2000	0.8	1.2	1.5
2001	0.9	1.2	1.8
2002	1.0	1.3	2.0
2003	1.2	1.4	2.1
2004	1.3	1.6	2.2
2005	1.4	1.6	2.1
2006	1.5	1.8	3.7
2007	1.6	2.0	4.6
2008	1.7	2.2	4.3
2009	1.8	2.3	4.8

Source: Derived from Browning (2003).

Table A- 92: Detailed Vehicle Miles Traveled for Alternative Fuel On-Road Vehicles (10⁶ Miles)

Vehicle Type	1990	1995	2000	2005	2006	2007	2008	2009
Passenger Cars	206.3	400.6	788.1	1,362.2	1,481.2	1,606.3	1,662.3	1,813.0
Methanol-Flex Fuel ICE	-	40.9	13.2	-	-	-	-	-
Ethanol-Flex Fuel ICE	+	2.2	120.4	399.1	429.8	504.4	554.2	661.0
CNG ICE	10.6	28.0	68.9	118.8	125.0	129.2	129.7	135.3
CNG Bi-fuel	28.2	75.1	202.9	253.3	275.0	295.3	306.5	330.4
LPG ICE	20.6	40.3	41.9	31.3	24.9	18.5	16.5	11.8
LPG Bi-fuel	146.9	201.7	197.6	175.1	149.1	123.0	112.0	94.4
Biodiesel (BD20)	-	-	8.2	93.8	186.4	246.1	259.3	295.0
NEVs	-	5.2	62.4	135.5	135.7	136.0	136.2	136.5
Electric Vehicle	-	7.2	72.6	155.2	155.2	153.8	147.8	148.7
Light-Duty Trucks	660.7	606.8	1,162.0	1,640.0	1,840.3	1,992.0	2,153.0	2,299.7
Ethanol-Flex Fuel ICE	-	1.3	122.6	415.0	518.7	657.7	788.5	921.7
CNG ICE	10.9	29.6	145.9	163.8	169.3	175.4	181.8	186.3
CNG Bi-fuel	24.2	71.0	280.1	348.2	365.8	389.2	405.2	432.9
LPG ICE	56.9	48.5	58.4	57.3	54.6	38.4	36.1	32.9
LPG Bi-fuel	568.7	449.4	511.9	502.3	491.4	438.5	422.1	383.6
Biodiesel (BD20)	-	-	8.2	76.7	163.8	219.2	240.9	263.0
Electric Vehicle	-	7.1	35.0	76.4	76.4	73.1	77.8	78.4
Medium-Duty Trucks	508.0	458.4	629.6	831.4	866.4	866.9	921.0	924.0
CNG Bi-fuel	2.3	20.1	117.0	300.7	314.2	337.4	370.8	396.8
LPG ICE	24.3	20.0	29.7	36.8	33.8	31.3	30.9	31.0
LPG Bi-fuel	481.4	418.3	475.9	444.8	362.5	289.1	284.3	223.2
Biodiesel (BD20)	-	-	7.0	49.1	156.0	209.1	235.0	272.9
Heavy-Duty Trucks	523.9	627.0	712.3	1,084.9	2,495.7	3,337.8	3,024.7	3,435.3
Neat Methanol ICE	3.0	7.8	-	-	-	-	-	-
Neat Ethanol ICE	-	2.0	0.1	-	-	-	-	-
CNG ICE	12.7	32.2	83.7	218.7	252.8	332.1	495.3	516.8
LPG ICE	36.3	46.3	48.3	69.0	65.5	65.3	64.8	64.8
LPG Bi-fuel	471.9	531.9	529.7	569.4	524.1	512.9	505.2	502.2
LNG	-	6.9	22.2	117.3	126.5	141.8	158.1	174.2
Biodiesel (BD20)	-	-	28.3	110.4	1,526.8	2,285.7	1,801.4	2,177.3
Buses	41.4	80.5	111.9	207.4	349.7	406.1	412.3	422.1
Neat Methanol ICE	1.9	3.7	-	-	-	-	-	-
Neat Ethanol ICE	0.1	2.2	-	-	-	-	-	-
CNG ICE	11.2	37.5	53.4	122.9	123.4	131.7	139.2	148.8
LPG ICE	28.2	30.9	35.6	34.6	35.1	33.5	33.7	33.9
LNG	-	4.3	13.3	27.8	28.1	25.1	21.1	18.8
Biodiesel (BD20)	-	-	4.5	15.6	156.8	209.1	210.9	212.5
Electric	-	2.0	5.1	6.5	6.2	6.3	6.7	7.3
Total VMT	1,940.3	2,173.4	3,403.9	5,125.9	7,033.3	8,209.0	8,173.3	8,894.0

Source: Derived from Browning (2003).

Note: Throughout the rest of this Inventory, medium-duty trucks are grouped with heavy-duty trucks; they are reported separately here because these two categories may run on a slightly different range of fuel types.

+ Less than 0.05 million vehicle miles traveled

- Unreported or zero

Table A- 93: Age Distribution by Vehicle/Fuel Type for On-Road Vehicles,^a 2009

Vehicle Age	LDGV	LDGT	HDGV	LDDV ^b	LDDT	HDDV	MC
0	5.2%	4.0%	5.2%	4.6%	4.1%	5.6%	6.2%
1	5.8%	5.0%	5.7%	5.2%	5.1%	6.2%	12.2%
2	6.4%	7.4%	5.9%	5.8%	6.8%	6.5%	11.0%
3	6.6%	7.5%	6.0%	5.9%	6.5%	7.9%	10.4%
4	6.4%	7.9%	6.0%	5.7%	6.8%	7.6%	9.1%
5	6.2%	7.6%	4.7%	5.5%	10.0%	6.0%	7.7%
6	6.1%	7.1%	3.8%	5.5%	7.2%	4.6%	6.6%
7	6.4%	6.7%	3.3%	5.7%	7.7%	4.2%	5.8%
8	6.4%	6.3%	3.9%	5.7%	8.0%	4.6%	5.0%
9	6.5%	5.8%	4.3%	0.0%	6.6%	5.5%	4.0%
10	6.0%	5.0%	4.3%	0.0%	7.1%	5.8%	3.0%
11	5.3%	4.5%	3.5%	0.0%	1.7%	4.5%	2.5%
12	4.9%	3.8%	2.7%	0.0%	4.3%	3.5%	2.4%
13	4.3%	3.4%	2.7%	0.0%	2.9%	3.3%	2.1%
14	3.7%	2.9%	3.2%	0.0%	2.8%	3.7%	1.6%
15	3.1%	2.6%	3.3%	0.0%	2.4%	3.2%	1.9%
16	2.3%	2.1%	2.5%	0.0%	1.8%	2.4%	1.5%
17	1.8%	1.6%	1.8%	0.0%	1.2%	1.6%	1.3%
18	1.4%	1.3%	1.8%	0.0%	1.0%	1.6%	1.0%
19	1.2%	1.3%	2.3%	0.0%	0.9%	1.8%	0.8%
20	1.0%	1.1%	3.1%	0.0%	0.8%	2.0%	0.6%
21	0.8%	1.1%	2.9%	0.0%	0.6%	1.7%	0.5%
22	0.6%	0.9%	2.5%	0.0%	0.5%	1.3%	0.5%
23	0.5%	0.8%	3.1%	0.0%	0.7%	1.4%	0.4%
24	0.4%	0.7%	2.4%	1.0%	0.6%	1.0%	0.4%
25	0.3%	0.5%	1.5%	1.1%	0.6%	0.6%	0.3%
26	0.2%	0.3%	2.3%	1.2%	0.5%	0.6%	0.2%
27	0.1%	0.2%	1.3%	1.6%	0.5%	0.3%	0.2%
28	0.1%	0.2%	1.2%	1.6%	0.1%	0.3%	0.2%
29	0.1%	0.2%	1.4%	0.8%	0.2%	0.3%	0.2%
30	0.1%	0.2%	1.6%	0.6%	0.1%	0.3%	0.3%
Total	100%	100%	100%	57%	100%	100%	100%

Source: EPA (2010).

^a The following abbreviations correspond to vehicle types: LDGV (light-duty gasoline vehicles), LDGT (light-duty gasoline trucks), HDGV (heavy-duty gasoline vehicles), LDDV (light-duty diesel vehicles), LDDT (light-duty diesel trucks), HDDV (heavy-duty diesel vehicles), and MC (motorcycles).

^b According to EPA's MOVES model, sales of diesel passenger cars in model years 9-23 was very small compared to total passenger car sales, so the calculated fraction of these vehicles in these model years was stored as zero.

Table A- 94: Annual Average Vehicle Mileage Accumulation per Vehicle^a (miles)

Vehicle Age	LDGV	LDGT	HDGV	LDDV	LDDT	HDDV	MC ^b
0	14,910	19,906	20,218	14,910	26,371	28,787	4,786
1	14,174	18,707	18,935	14,174	24,137	26,304	4,475
2	13,475	17,559	17,100	13,475	22,095	24,038	4,164
3	12,810	16,462	16,611	12,810	20,228	21,968	3,853
4	12,178	15,413	15,560	12,178	18,521	20,078	3,543
5	11,577	14,411	14,576	11,577	16,960	18,351	3,232
6	11,006	13,454	13,655	11,006	15,533	16,775	2,921
7	10,463	12,541	12,793	10,463	14,227	15,334	2,611
8	9,947	11,671	11,987	9,947	13,032	14,019	2,300
9	9,456	10,843	11,231	9,456	11,939	12,817	1,989
10	8,989	10,055	10,524	8,989	10,939	11,719	1,678
11	8,546	9,306	9,863	8,546	10,024	10,716	1,368
12	8,124	8,597	9,243	8,124	9,186	9,799	1,368
13	7,723	7,925	8,662	7,723	8,420	8,962	1,368

14	7,342	7,290	8,028	7,342	7,718	8,196	1,368
15	6,980	6,690	7,610	6,980	7,075	7,497	1,368
16	6,636	6,127	7,133	6,636	6,487	6,857	1,368
17	6,308	5,598	6,687	6,308	5,948	6,273	1,368
18	5,997	5,103	6,269	5,997	5,454	5,739	1,368
19	5,701	4,642	5,877	5,701	5,002	5,250	1,368
20	5,420	4,214	5,510	5,420	4,588	4,804	1,368
21	5,152	3,818	5,166	5,152	4,209	4,396	1,368
22	4,898	3,455	4,844	4,898	3,861	4,023	1,368
23	4,656	3,123	4,542	4,656	3,542	3,681	1,368
24	4,427	2,822	4,259	4,427	3,250	3,369	1,368
25	4,427	2,822	4,259	4,427	3,250	3,369	1,368
26	4,427	2,822	4,259	4,427	3,250	3,369	1,368
27	4,427	2,822	4,259	4,427	3,250	3,369	1,368
28	4,427	2,822	4,259	4,427	3,250	3,369	1,368
29	4,427	2,822	4,259	4,427	3,250	3,369	1,368
30	4,427	2,822	4,259	4,427	3,250	3,369	1,368

Source: EPA (2000).

^aThe following abbreviations correspond to vehicle types: LDGV (light-duty gasoline vehicles), LDGT (light-duty gasoline trucks), HDGV (heavy-duty gasoline vehicles), LDDV (light-duty diesel vehicles), LDDT (light-duty diesel trucks), HDDV (heavy-duty diesel vehicles), and MC (motorcycles).

^bBecause of a lack of data, all motorcycles over 12 years old are considered to have the same emissions and travel characteristics, and therefore are presented in aggregate.

Table A- 95: VMT Distribution by Vehicle Age and Vehicle/Fuel Type, ^a 2009

Vehicle Age	LDGV	LDGT	HDGV	LDDV ^b	LDDT	HDDV	MC
0	7.56%	6.52%	9.50%	10.78%	7.43%	10.67%	9.53%
1	8.03%	7.67%	9.80%	11.44%	8.51%	10.80%	17.45%
2	8.49%	10.68%	9.15%	12.11%	10.26%	10.30%	14.68%
3	8.23%	10.14%	8.97%	11.74%	9.01%	11.49%	12.87%
4	7.65%	9.95%	8.40%	10.90%	8.65%	10.06%	10.36%
5	7.00%	8.98%	6.23%	9.98%	11.59%	7.30%	8.02%
6	6.59%	7.87%	4.64%	9.39%	7.68%	5.15%	6.13%
7	6.51%	6.85%	3.83%	9.28%	7.54%	4.27%	4.88%
8	6.24%	6.07%	4.20%	8.90%	7.14%	4.27%	3.65%
9	6.04%	5.20%	4.34%	0.00%	5.43%	4.69%	2.52%
10	5.25%	4.14%	4.08%	0.00%	5.32%	4.46%	1.60%
11	4.45%	3.40%	3.14%	0.00%	1.19%	3.18%	1.12%
12	3.92%	2.65%	2.26%	0.00%	2.69%	2.27%	1.07%
13	3.28%	2.20%	2.15%	0.00%	1.69%	1.95%	0.94%
14	2.63%	1.71%	2.33%	0.00%	1.46%	2.00%	0.71%
15	2.11%	1.42%	2.30%	0.00%	1.15%	1.57%	0.81%
16	1.52%	1.05%	1.60%	0.00%	0.80%	1.08%	0.66%
17	1.10%	0.75%	1.09%	0.00%	0.51%	0.68%	0.55%
18	0.81%	0.54%	1.01%	0.00%	0.36%	0.60%	0.44%
19	0.67%	0.49%	1.21%	0.00%	0.32%	0.64%	0.36%
20	0.52%	0.40%	1.56%	0.00%	0.24%	0.64%	0.26%
21	0.41%	0.33%	1.36%	0.00%	0.16%	0.50%	0.22%
22	0.29%	0.26%	1.08%	0.00%	0.13%	0.36%	0.22%
23	0.23%	0.20%	1.29%	0.00%	0.16%	0.33%	0.18%
24	0.16%	0.15%	0.94%	0.69%	0.13%	0.22%	0.15%
25	0.11%	0.12%	0.56%	0.78%	0.13%	0.14%	0.14%
26	0.07%	0.08%	0.87%	0.86%	0.12%	0.13%	0.10%
27	0.05%	0.05%	0.48%	1.11%	0.11%	0.07%	0.08%
28	0.04%	0.04%	0.48%	1.12%	0.03%	0.06%	0.08%
29	0.03%	0.04%	0.53%	0.54%	0.04%	0.06%	0.09%
30	0.03%	0.05%	0.62%	0.38%	0.02%	0.06%	0.14%
Total	100%	100%	100%	100%	100%	100%	100%

Note: Estimated by weighting data in Table A- 93 by data in Table A- 94.

^aThe following abbreviations correspond to vehicle types: LDGV (light-duty gasoline vehicles), LDGT (light-duty gasoline trucks), HDGV (heavy-duty gasoline vehicles), LDDV (light-duty diesel vehicles), LDDT (light-duty diesel trucks), HDDV (heavy-duty diesel vehicles), and MC (motorcycles).

^bAccording to EPA's MOVES model, sales of diesel passenger cars in model years 9-23 was very small compared to total passenger car sales, so the calculated fraction of these vehicles in these model years was stored as zero.

Table A- 96: Fuel Consumption for Off-Road Sources by Fuel Type (million gallons)

Vehicle Type/Year	1990	1995	2000	2005	2006	2007	2008	2009
Aircraft^a	18,723.9	18,179.6	20,793.7	20,214.1	17,664.4	17,568.6	16,141.6	14,460.2
Aviation Gasoline	374.2	329.3	301.9	294.2	278.3	262.8	235.3	221.0
Jet Fuel	18,349.7	17,850.3	20,491.9	19,919.9	17,386.1	17,305.8	15,906.2	14,239.3
Ships and Other								
Boats	4,507.2	5,789.1	6,430.6	4,882.7	5,144.6	5,747.1	4,113.4	3,548.7
Diesel	1,043.1	1,545.7	1,750.1	1,471.4	1,410.5	1,490.7	675.7	825.7
Gasoline	1,403.4	1,597.3	1,652.9	1,629.9	1,619.6	1,609.6	1,599.8	1,590.7
Residual	2,060.7	2,646.1	3,027.5	1,781.4	2,114.5	2,646.8	1,837.9	1,132.3
Construction/ Mining								
Equipment^b	4,160.3	4,834.7	5,439.1	6,520.5	6,656.4	6,683.7	6,835.0	6,960.0
Diesel	3,674.4	4,386.9	5,094.9	5,823.4	5,968.2	6,112.9	6,257.7	6,402.5
Gasoline	485.9	447.8	344.2	697.1	688.3	570.8	577.3	557.5
Agricultural Equipment^c	3,133.7	3,698.3	3,874.5	4,715.0	4,947.8	4,861.5	4,516.6	4,640.9
Diesel	2,320.9	2,771.6	3,222.3	3,637.2	3,719.1	3,800.9	3,882.8	3,964.6
Gasoline	812.8	926.7	652.3	1,077.8	1,228.7	1,060.6	633.8	676.3
Rail	3,460.6	3,863.5	4,105.9	4,446.1	4,664.5	4,538.9	4,216.0	3,524.8
Diesel	3,460.6	3,863.5	4,105.9	4,446.1	4,664.5	4,538.9	4,216.0	3,524.8
Other^d	5,916.5	6,524.8	6,826.1	8,281.2	8,396.1	8,255.6	8,386.7	8,481.6
Diesel	1,423.3	1,720.0	2,016.0	2,340.3	2,405.4	2,470.6	2,535.8	2,601.0
Gasoline	4,493.2	4,804.7	4,810.2	5,940.9	5,990.7	5,785.0	5,850.9	5,880.7
Total	39,902.2	42,890.0	47,470.0	49,059.5	47,473.8	47,655.5	44,209.2	41,616.4

Sources: AAR (2008 through 2009), APTA (2007 through 2009), BEA (1991 through 2005), Benson (2002 through 2004), DHS (2008), DOC (1991 through 2008), DESC (2008), DOE (1993 through 2009), DOT (1991 through 2009), EIA (2002), EIA (2007b), EIA (2008), EIA (2007 through 2008), EIA (1991 through 2011), EPA (2007b), FAA (200), FAA (2006), Gaffney (2007), and Whorton (2006 through 2009).

^a For aircraft, this is aviation gasoline. For all other categories, this is motor gasoline.

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

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

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

Table A- 97: Control Technology Assignments for Gasoline Passenger Cars (Percent of VMT)

Model Years	Non-catalyst	Oxidation	EPA Tier 0	EPA Tier 1	LEV	EPA Tier 2
1973-1974	100%	-	-	-	-	-
1975	20%	80%	-	-	-	-
1976-1977	15%	85%	-	-	-	-
1978-1979	10%	90%	-	-	-	-
1980	5%	88%	7%	-	-	-
1981	-	15%	85%	-	-	-
1982	-	14%	86%	-	-	-
1983	-	12%	88%	-	-	-
1984-1993	-	-	100%	-	-	-
1994	-	-	60%	40%	-	-
1995	-	-	20%	80%	-	-
1996	-	-	1%	97%	2%	-
1997	-	-	0.5%	96.5%	3%	-
1998	-	-	<1%	87%	13%	-
1999	-	-	<1%	67%	33%	-
2000	-	-	-	44%	56%	-
2001	-	-	-	3%	97%	-
2002	-	-	-	1%	99%	-
2003	-	-	-	<1%	87%	13%
2004	-	-	-	<1%	41%	59%
2005	-	-	-	-	38%	62%
2006	-	-	-	-	18%	82%
2007	-	-	-	-	4%	96%
2008	-	-	-	-	2%	98%
2009	-	-	-	-	-	100%

Sources: EPA (1998), EPA (2007a), and EPA (2007b).

Note: Detailed descriptions of emissions control technologies are provided in the following section of this annex.

- Not applicable.

Table A- 98: Control Technology Assignments for Gasoline Light-Duty Trucks (Percent of VMT)^a

Model Years	Non-catalyst	Oxidation	EPA Tier 0	EPA Tier 1	LEV ^b	EPA Tier 2
1973-1974	100%	-	-	-	-	-
1975	30%	70%	-	-	-	-
1976	20%	80%	-	-	-	-
1977-1978	25%	75%	-	-	-	-
1979-1980	20%	80%	-	-	-	-
1981	-	95%	5%	-	-	-
1982	-	90%	10%	-	-	-
1983	-	80%	20%	-	-	-
1984	-	70%	30%	-	-	-
1985	-	60%	40%	-	-	-
1986	-	50%	50%	-	-	-
1987-1993	-	5%	95%	-	-	-
1994	-	-	60%	40%	-	-
1995	-	-	20%	80%	-	-
1996	-	-	-	100%	-	-
1997	-	-	-	100%	-	-
1998	-	-	-	80%	20%	-
1999	-	-	-	57%	43%	-
2000	-	-	-	65%	35%	-
2001	-	-	-	1%	99%	-
2002	-	-	-	10%	90%	-
2003	-	-	-	<1%	53%	47%
2004	-	-	-	-	72%	28%
2005	-	-	-	-	38%	62%
2006	-	-	-	-	25%	75%
2007	-	-	-	-	14%	86%
2008	-	-	-	-	-	100%
2009	-	-	-	-	-	100%

Sources: EPA (1998), EPA (2007a), and EPA (2007b).

^a Detailed descriptions of emissions control technologies are provided in the following section of this annex.

^b The proportion of LEVs as a whole has decreased since 2001, as carmakers have been able to achieve greater emission reductions with certain types of LEVs, such as ULEVs. Because ULEVs emit about half the emissions of LEVs, a carmaker can reduce the total number of LEVs they need to build to meet a specified emission average for all of their vehicles in a given model year.

- Not applicable.

Table A- 99: Control Technology Assignments for Gasoline Heavy-Duty Vehicles (Percent of VMT)^a

Model Years	Uncontrolled	Non-catalyst	Oxidation	EPA Tier 0	EPA Tier 1	LEV ^b	EPA Tier 2
≤1981	100%	-	-	-	-	-	-
1982-1984	95%	-	5%	-	-	-	-
1985-1986	-	95%	5%	-	-	-	-
1987	-	70%	15%	15%	-	-	-
1988-1989	-	60%	25%	15%	-	-	-
1990-1995	-	45%	30%	25%	-	-	-
1996	-	-	25%	10%	65%	-	-
1997	-	-	10%	5%	85%	-	-
1998	-	-	-	-	96%	4%	-
1999	-	-	-	-	78%	22%	-
2000	-	-	-	-	54%	46%	-
2001	-	-	-	-	64%	36%	-
2002	-	-	-	-	69%	31%	-
2003	-	-	-	-	65%	30%	5%
2004	-	-	-	-	5%	37%	59%
2005	-	-	-	-	-	23%	77%
2006	-	-	-	-	-	22%	78%
2007	-	-	-	-	-	21%	79%
2008	-	-	-	-	-	20%	80%
2009	-	-	-	-	-	19%	81%

Sources: EPA (1998), EPA (2007a), and EPA (2007b).

^a Detailed descriptions of emissions control technologies are provided in the following section of this annex.

^b The proportion of LEVs as a whole has decreased since 2000, as carmakers have been able to achieve greater emission reductions with certain types of LEVs, such as ULEVs. Because ULEVs emit about half the emissions of LEVs, a manufacturer can reduce the total number of LEVs they need to build to meet a specified emission average for all of their vehicles in a given model year.

- Not applicable.

Table A- 100: Control Technology Assignments for Diesel On-Road Vehicles and Motorcycles

Vehicle Type/Control Technology	Model Years
Diesel Passenger Cars and Light-Duty Trucks	
Uncontrolled	1960-1982
Moderate control	1983-1995
Advanced control	1996-2009
Diesel Medium- and Heavy-Duty Trucks and Buses	
Uncontrolled	1960-1990
Moderate control	1991-2003
Advanced control	2004-2006
Aftertreatment	2007-2009
Motorcycles	
Uncontrolled	1960-1995
Non-catalyst controls	1996-2009

Source: EPA (1998) and Browning (2005)

Note: Detailed descriptions of emissions control technologies are provided in the following section of this annex.

Table A- 101: Emission Factors for CH₄ and N₂O for On-Road Vehicles

Vehicle Type/Control Technology	N ₂ O (g/mi)	CH ₄ (g/mi)
Gasoline Passenger Cars		
EPA Tier 2	0.0036	0.0173
Low Emission Vehicles	0.0150	0.0105
EPA Tier 1 ^a	0.0429	0.0271
EPA Tier 0 ^a	0.0647	0.0704
Oxidation Catalyst	0.0504	0.1355
Non-Catalyst Control	0.0197	0.1696
Uncontrolled	0.0197	0.1780
Gasoline Light-Duty Trucks		
EPA Tier 2	0.0066	0.0163
Low Emission Vehicles	0.0157	0.0148
EPA Tier 1 ^a	0.0871	0.0452
EPA Tier 0 ^a	0.1056	0.0776
Oxidation Catalyst	0.0639	0.1516
Non-Catalyst Control	0.0218	0.1908
Uncontrolled	0.0220	0.2024
Gasoline Heavy-Duty Vehicles		
EPA Tier 2	0.0134	0.0333
Low Emission Vehicles	0.0320	0.0303
EPA Tier 1 ^a	0.1750	0.0655
EPA Tier 0 ^a	0.2135	0.2630
Oxidation Catalyst	0.1317	0.2356
Non-Catalyst Control	0.0473	0.4181
Uncontrolled	0.0497	0.4604
Diesel Passenger Cars		
Advanced	0.0010	0.0005
Moderate	0.0010	0.0005
Uncontrolled	0.0012	0.0006
Diesel Light-Duty Trucks		
Advanced	0.0015	0.0010
Moderate	0.0014	0.0009
Uncontrolled	0.0017	0.0011
Diesel Medium- and Heavy-Duty Trucks and Buses		
Aftertreatment	0.0048	0.0051
Advanced	0.0048	0.0051
Moderate	0.0048	0.0051
Uncontrolled	0.0048	0.0051
Motorcycles		
Non-Catalyst Control	0.0069	0.0672
Uncontrolled	0.0087	0.0899

Source: ICF (2006b and 2004).

^aThe categories “EPA Tier 0” and “EPA Tier 1” were substituted for the early three-way catalyst and advanced three-way catalyst categories, respectively, as defined in the *Revised 1996 IPCC Guidelines*. Detailed descriptions of emissions control technologies are provided at the end of this annex.

Table A- 102: Emission Factors for CH₄ and N₂O for Alternative Fuel Vehicles (g/mi)

	N ₂ O	CH ₄
Light Duty Vehicles		
Methanol	0.067	0.018
CNG	0.050	0.737
LPG	0.067	0.037
Ethanol	0.067	0.055
Biodiesel (BD20)	0.001	0.0005
Medium- and Heavy-Duty Trucks		
Methanol	0.175	0.066
CNG	0.175	1.966
LNG	0.175	1.966
LPG	0.175	0.066
Ethanol	0.175	0.197
Biodiesel (BD20)	0.005	0.005
Buses		
Methanol	0.175	0.066
CNG	0.175	1.966
Ethanol	0.175	0.197
Biodiesel (BD20)	0.005	0.005

Source: Developed by ICF (2006a) using ANL (2006) and Lipman and Delucchi (2002).

Table A- 103: Emission Factors for CH₄ and N₂O Emissions from Non-Road Mobile Combustion (g/kg fuel)

Vehicle Type/Fuel Type	N ₂ O	CH ₄
Ships and Boats		
Residual	0.16	0.03
Gasoline	0.08	0.23
Diesel	0.14	0.02
Rail		
Diesel	0.08	0.25
Agricultural Equipment^a		
Gasoline	0.08	0.45
Diesel	0.08	0.45
Construction/Mining Equipment^c		
Gasoline	0.08	0.18
Diesel	0.08	0.18
Other Non-Road		
All “Other” Categories ^c	0.08	0.18
Aircraft		
Jet Fuel	0.10	0.087
Aviation Gasoline	0.04	2.64

Source: IPCC/UNEP/OECD/IEA (1997) and ICF (2009).

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

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

^c “Other” includes snowmobiles and other recreational equipment, logging equipment, lawn and garden equipment, railroad equipment, airport equipment, commercial equipment, and industrial equipment, as well as fuel consumption from trucks that are used off-road for commercial/industrial purposes.

Table A- 104: NO_x Emissions from Mobile Combustion (Gg)

Fuel Type/Vehicle Type	1990	1995	2000	2005	2006	2007	2008	2009
Gasoline On-Road								
Passenger Cars	3,847	2,752	2,084	1,692	1,581	1,469	1,357	1,207
Light-Duty Trucks	1,364	1,325	1,303	1,073	1,002	931	860	765
Medium- and Heavy-Duty Trucks and Buses	515	469	411	326	304	283	261	232
Motorcycles	20	14	13	11	11	10	9	8
Diesel On-Road								
Passenger Cars	39	19	7	5	5	4	4	3
Light-Duty Trucks	20	12	6	5	4	4	4	3

Medium- and Heavy-Duty Trucks and Buses	2,897	3,462	3,791	2,778	2,594	2,411	2,228	1,981
Alternative Fuel On-Road^a	IE	IE	IE	IE	IE	IE	IE	IE
Non-Road	2,160	2,483	2,584	3,122	2,988	2,853	2,718	2,007
Ships and Boats	402	488	506	646	618	590	562	415
Rail	338	433	451	576	551	527	502	371
Aircraft ^b	25	31	40	47	45	43	41	30
Agricultural Equipment ^c	437	478	484	565	540	516	491	363
Construction/Mining Equipment ^d	641	697	697	811	776	741	706	521
Other ^e	318	357	407	478	457	437	416	307
Total	10,862	10,536	10,199	9,012	8,488	7,965	7,441	6,206

^aNO_x emissions from alternative fuel on-road vehicles are included under gasoline and diesel on-road.

^b Aircraft estimates include only emissions related to LTO cycles, and therefore do not include cruise altitude emissions.

^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.

Note: Totals may not sum due to independent rounding.

IE = Included Elsewhere

Table A- 105: CO Emissions from Mobile Combustion (Gg)

Fuel Type/Vehicle Type	1990	1995	2000	2005	2006	2007	2008	2009
Gasoline On-Road	98,328	74,673	60,657	43,374	40,492	37,610	34,727	34,199
Passenger Cars	60,757	42,065	32,867	24,166	22,560	20,954	19,348	19,054
Light-Duty Trucks	29,237	27,048	24,532	17,264	16,117	14,969	13,822	13,612
Medium- and Heavy-Duty Trucks and Buses	8,093	5,404	3,104	1,844	1,721	1,599	1,476	1,454
Motorcycles	240	155	154	100	94	87	80	79
Diesel On-Road	1,696	1,424	1,088	665	621	576	532	524
Passenger Cars	35	18	7	4	4	4	4	4
Light-Duty Trucks	22	16	6	4	4	3	3	3
Medium- and Heavy-Duty Trucks and Buses	1,639	1,391	1,075	656	613	569	525	517
Alternative Fuel On-Road^a	IE	IE	IE	IE	IE	IE	IE	IE
Non-Road	19,337	21,533	21,814	18,652	17,859	17,067	16,274	8,633
Ships and Boats	1,559	1,781	1,825	1,534	1,469	1,404	1,339	710
Rail	85	93	90	75	72	69	66	35
Aircraft ^b	217	224	245	196	187	179	171	91
Agricultural Equipment ^c	581	628	626	520	498	476	454	241
Construction/Mining Equipment ^d	1,090	1,132	1,047	872	835	798	761	404
Other ^e	15,805	17,676	17,981	15,455	14,798	14,141	13,484	7,153
Total	119,360	97,630	83,559	62,692	58,972	55,253	51,533	43,355

^aNO_x emissions from alternative fuel on-road vehicles are included under gasoline and diesel on-road.

^b Aircraft estimates include only emissions related to LTO cycles, and therefore do not include cruise altitude emissions.

^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.

Note: Totals may not sum due to independent rounding.

IE = Included Elsewhere

Table A- 106: NMVOCs Emissions from Mobile Combustion (Gg)

Fuel Type/Vehicle Type	1990	1995	2000	2005	2006	2007	2008	2009
Gasoline On-Road	8,110	5,819	4,615	3,558	3,358	3,158	2,958	2,878
Passenger Cars	5,120	3,394	2,610	1,987	1,875	1,764	1,652	1,607
Light-Duty Trucks	2,374	2,019	1,750	1,382	1,304	1,226	1,149	1,118
Medium- and Heavy-Duty Trucks and Buses	575	382	232	171	162	152	142	138

Motorcycles	42	24	23	18	17	16	15	15
Diesel On-Road	406	304	216	172	163	153	143	139
Passenger Cars	16	8	3	3	2	2	2	2
Light-Duty Trucks	14	9	4	3	3	3	3	2
Medium- and Heavy-Duty Trucks and Buses	377	286	209	167	157	148	139	135
Alternative Fuel On-Road^a	IE	IE	IE	IE	IE	IE	IE	IE
Non-Road	2,415	2,622	2,399	2,600	2,516	2,430	2,346	1,134
Ships and Boats	608	739	744	798	772	746	720	348
Rail	33	36	35	39	37	36	35	17
Aircraft ^b	28	28	24	21	20	20	19	9
Agricultural Equipment ^c	85	86	76	79	77	74	71	35
Construction/Mining Equipment ^d	149	152	130	137	132	128	123	60
Other ^e	1,512	1,580	1,390	1,527	1,477	1,427	1,378	666
Total	10,932	8,745	7,229	6,330	6,037	5,742	5,447	4,151

^aNO_x emissions from alternative fuel on-road vehicles are included under gasoline and diesel on-road.

^b Aircraft estimates include only emissions related to LTO cycles, and therefore do not include cruise altitude emissions.

^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.

Note: Totals may not sum due to independent rounding.

IE = Included Elsewhere

Definitions of Emission Control Technologies and Standards

The N₂O and CH₄ emission factors used depend on the emission standards in place and the corresponding level of control technology for each vehicle type. Table A- 97 through Table A- 100 show the years in which these technologies or standards were in place and the penetration level for each vehicle type. These categories are defined below.

Uncontrolled

Vehicles manufactured prior to the implementation of pollution control technologies are designated as uncontrolled. Gasoline passenger cars and light-duty trucks (pre-1973), gasoline heavy-duty vehicles (pre-1984), diesel vehicles (pre-1983), and motorcycles (pre-1996) are assumed to have no control technologies in place.

Gasoline Emission Controls

Below are the control technologies and emissions standards applicable to gasoline vehicles.

Non-catalyst

These emission controls were common in gasoline passenger cars and light-duty gasoline trucks during model years (1973-1974) but phased out thereafter, in heavy-duty gasoline vehicles beginning in the mid-1980s, and in motorcycles beginning in 1996. This technology reduces hydrocarbon (HC) and carbon monoxide (CO) emissions through adjustments to ignition timing and air-fuel ratio, air injection into the exhaust manifold, and exhaust gas recirculation (EGR) valves, which also helps meet vehicle NO_x standards.

Oxidation Catalyst

This control technology designation represents the introduction of the catalytic converter, and was the most common technology in gasoline passenger cars and light-duty gasoline trucks made from 1975 to 1980 (cars) and 1975 to 1985 (trucks). This technology was also used in some heavy-duty gasoline vehicles between 1982 and 1997. The two-way catalytic converter oxidizes HC and CO, significantly reducing emissions over 80 percent beyond non-catalyst-system capacity. One reason unleaded gasoline was introduced in 1975 was due to the fact that oxidation catalysts cannot function properly with leaded gasoline.

EPA Tier 0

This emission standard from the Clean Air Act was met through the implementation of early "three-way" catalysts, therefore this technology was used in gasoline passenger cars and light-duty gasoline trucks sold beginning in the early 1980s, and remained common until 1994. This more sophisticated emission control system improves the efficiency of the catalyst by converting CO and HC to CO₂ and H₂O, reducing NO_x to nitrogen and oxygen, and using an on-board diagnostic computer and oxygen sensor. In addition, this type of catalyst includes a fuel metering system (carburetor or fuel injection) with electronic "trim" (also known as a "closed-loop system"). New cars with three-way catalysts met the Clean Air Act's amended standards (enacted in 1977) of reducing HC to 0.41 g/mile by 1980, CO to 3.4 g/mile by 1981 and NO_x to 1.0 g/mile by 1981.

EPA Tier 1

This emission standard created through the 1990 amendments to the Clean Air Act limited passenger car NO_x emissions to 0.4 g/mi, and HC emissions to 0.25 g/mi. These bounds respectively amounted to a 60 and 40 percent reduction from the EPA Tier 0 standard set in 1981. For light-duty trucks, this standard set emissions at 0.4 to 1.1 g/mi for NO_x, and 0.25 to 0.39 g/mi for HCs, depending on the weight of the truck. Emission reductions were met through the use of more advanced emission control systems, and applied to light-duty gasoline vehicles beginning in 1994. These advanced emission control systems included advanced three-way catalysts, electronically controlled fuel injection and ignition timing, EGR, and air injection.

EPA Tier 2

This emission standard was specified in the 1990 amendments to the Clean Air Act, limiting passenger car NO_x emissions to 0.07 g/mi on average and aligning emissions standards for passenger cars and light-duty trucks. Manufacturers can meet this average emission level by producing vehicles in 11 emission "Bins", the three highest of which expire in 2006. These new emission levels represent a 77 to 95% reduction in emissions from the EPA Tier 1 standard set in 1994. Emission reductions were met through the use of more advanced emission control systems and lower sulfur fuels and are applied to vehicles beginning in 2004. These advanced emission control systems include improved combustion, advanced three-way catalysts, electronically controlled fuel injection and ignition timing, EGR, and air injection.

Low Emission Vehicles (LEV)

This emission standard requires a much higher emission control level than the Tier 1 standard. Applied to light-duty gasoline passenger cars and trucks beginning in small numbers in the mid-1990s, LEV includes multi-port fuel injection with adaptive learning, an advanced computer diagnostics systems and advanced and close coupled catalysts with secondary air injection. LEVs as defined here include transitional low-emission vehicles (TLEVs), low emission vehicles, ultra-low emission vehicles (ULEVs) and super ultra-low emission vehicles (SULEVs). In this analysis, all categories of LEVs are treated the same due to the fact that there are very limited CH₄ or N₂O emission factor data for LEVs to distinguish among the different types of vehicles. Zero emission vehicles (ZEVs) are incorporated into the alternative fuel and advanced technology vehicle assessments.

Diesel Emission Controls

Below are the two levels of emissions control for diesel vehicles.

Moderate control

Improved injection timing technology and combustion system design for light- and heavy-duty diesel vehicles (generally in place in model years 1983 to 1995) are considered moderate control technologies. These controls were implemented to meet emission standards for diesel trucks and buses adopted by the EPA in 1985 to be met in 1991 and 1994.

Advanced control

EGR and modern electronic control of the fuel injection system are designated as advanced control technologies. These technologies provide diesel vehicles with the level of emission control necessary to comply with standards in place from 1996 through 2006.

Aftertreatment

Use of diesel particulate filters (DPFs), oxidation catalysts and NOx absorbers or selective catalytic reduction (SCR) systems are designated as aftertreatment control. These technologies provide diesel vehicles with a level of emission control necessary to comply with standards in place from 2007 on.

Supplemental Information on GHG Emissions from Transportation and Other Mobile Sources

This section of this Annex includes supplemental information on the contribution of transportation and other mobile sources to U.S. greenhouse gas emissions. In the main body of the Inventory report, emission estimates are generally presented by greenhouse gas, with separate discussions of the methodologies used to estimate CO₂, N₂O, CH₄, and HFC emissions. Although the inventory is not required to provide detail beyond what is contained in the body of this report, the IPCC allows presentation of additional data and detail on emission sources. The purpose of this sub-annex, within the annex that details the calculation methods and data used for non- CO₂ calculations, is to provide all transportation estimates presented throughout the report in one place.

This section of this Annex reports total greenhouse gas emissions from transportation and other (non-transportation) mobile sources in CO₂ equivalents, with information on the contribution by greenhouse gas and by mode, vehicle type, and fuel type. In order to calculate these figures, additional analyses were conducted to develop estimates of CO₂ from non-transportation mobile sources (e.g., agricultural equipment, construction/mining equipment, recreational vehicles), and to provide more detailed breakdowns of emissions by source.

Estimation of CO₂ from Non-Transportation Mobile Sources

The estimates of N₂O and CH₄ from fuel combustion presented in the Energy chapter of the inventory include both transportation sources and other mobile sources. Other mobile sources include construction/mining equipment, agricultural equipment, vehicles used off-road, and other sources that have utility associated with their movement but do not have a primary purpose of transporting people or goods (e.g., snowmobiles, riding lawnmowers, etc.). Estimates of CO₂ from non-transportation mobile sources, based on EIA fuel consumption estimates, are included in the agricultural, industrial, and commercial sectors. In order to provide comparable information on transportation and mobile sources, Table A- 107 provides estimates of CO₂ from these other mobile sources, developed from EPA's NONROAD model and FHWA's *Highway Statistics*. These other mobile source estimates were developed using the same fuel consumption data utilized in developing the N₂O and CH₄ estimates.

Table A- 107: CO₂ Emissions from Non-Transportation Mobile Sources (Tg CO₂ Eq.)

Fuel Type/Vehicle Type	1990	1995	2000	2005	2006	2007	2008	2009
Agricultural Equipment ^a	31.0	36.6	38.8	46.8	49.0	48.4	45.4	46.7
Construction/Mining Equipment ^b	42.0	48.9	55.3	65.9	67.3	67.8	69.3	70.6
Other Sources ^c	54.5	59.8	62.8	76.2	77.6	76.7	77.7	78.6
Total	127.6	145.4	156.9	188.9	193.9	193.0	192.4	195.9

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

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

^c "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.

Estimation of HFC Emissions from Transportation Sources

In addition to CO₂, N₂O and CH₄ emissions, transportation sources also result in emissions of HFCs. HFCs are emitted to the atmosphere during equipment manufacture and operation (as a result of component failure, leaks, and purges), as well as at servicing and disposal events. There are three categories of transportation-related HFC emissions; Mobile AC represents the emissions from air conditioning units in passenger cars and light-duty trucks, Comfort Cooling represents the emissions from air conditioning units in passenger trains and buses, and Refrigerated Transport represents the emissions from units used to cool freight during transportation.

Table A- 108 below presents these HFC emissions. Table A- 109 presents all transportation and mobile source greenhouse gas emissions, including HFC emissions.

Table A- 108: HFC Emissions from Transportation Sources

Vehicle Type	1990	1995	2000	2005	2006	2007	2008	2009
Mobile AC	-	16.7	46.0	59.4	58.3	54.7	50.7	45.9
Passenger Cars	-	10.1	24.3	28.4	27.1	24.6	22.1	19.3
Light-Duty Trucks	-	6.5	21.7	31.0	31.2	30.1	28.6	26.6
Comfort Cooling for								
Trains and Buses	-	+	0.1	0.2	0.3	0.3	0.4	0.4
School and Tour Buses	-	+	0.1	0.2	0.3	0.3	0.3	0.4
Transit Buses	-	+	+	+	+	+	+	+
Rail	-	-	-	+	+	+	+	+
Refrigerated Transport	-	2.3	9.6	13.2	13.6	13.8	13.8	13.9
Medium- and Heavy-Duty Trucks	-	1.7	7.4	11.1	11.4	11.5	11.6	11.6
Rail	-	0.5	2.0	2.1	2.2	2.2	2.2	2.2
Ships and Other Boats	-	+	0.1	+	+	+	+	+
Total	-	19.0	55.7	72.9	72.2	68.8	64.9	60.2

Note: Totals may not sum due to independent rounding.

+ Less than 0.05 Tg CO₂ Eq.

- Unreported or zero

Contribution of Transportation and Mobile Sources to Greenhouse Gas Emissions, by Mode/Vehicle Type/Fuel Type

Table A- 109 presents estimates of greenhouse gas emissions from an expanded analysis including all transportation and additional mobile sources, as well as emissions from electricity generation by the consuming category, in CO₂ equivalents. In total, transportation and non-transportation mobile sources emitted 2,014.7 Tg CO₂ Eq. in 2009, an increase of 20 percent from 1990. Transportation sources account for 1,816.9 Tg CO₂ Eq. while non-transportation mobile sources account for 197.7 Tg CO₂ Eq. These estimates include HFC emissions for mobile AC, comfort cooling for trains and buses, and refrigerated transport. These estimates were generated using the estimates of CO₂ emissions from transportation sources reported in the Carbon Dioxide Emissions from Fossil Fuel Combustion section, and CH₄ emissions and N₂O emissions reported in the Mobile Combustion section of the Energy chapter; information on HFCs from mobile air conditioners, comfort cooling for trains and buses, and refrigerated transportation from Chapter 4; and estimates of CO₂ emitted from non-transportation mobile sources reported in Table A- 107 above.

Although all emissions reported here are based on estimates reported throughout this inventory, some additional calculations were performed in order to provide a detailed breakdown of emissions by mode and vehicle category. In the case of N₂O and CH₄, additional calculations were performed to develop emissions estimates by type of aircraft and type of heavy-duty vehicle (i.e., medium- and heavy-duty trucks or buses) to match the level of detail for CO₂ emissions. N₂O and CH₄ estimates were developed for individual aircraft types by multiplying the emissions estimates for aircraft for each fuel type (jet fuel and aviation gasoline) by the portion of fuel used by each aircraft type (from FAA 2010, 2009, and 2006). Similarly, N₂O and CH₄ estimates were developed for medium- and heavy-duty trucks and buses by multiplying the emission estimates for heavy-duty vehicles for each fuel type (gasoline, diesel) from the Mobile Combustion section in the Energy chapter, by the portion of fuel used by each vehicle type (from DOE 1993 through 2010). Otherwise, the table and figure are drawn directly from emission estimates presented elsewhere in the inventory, and are dependent on the methodologies presented in Annex 2.1 (for CO₂), Chapter 4, and Annex 3.8 (for HFCs), and earlier in this Annex (for CH₄ and N₂O).

Transportation sources include on-road vehicles, aircraft, boats and ships, rail, and pipelines (note: pipelines are a transportation source but are stationary, not mobile sources). In addition, transportation-related greenhouse gas emissions also include HFC released from mobile air conditioners and refrigerated transportation, and the release of CO₂ from lubricants (such as motor oil) used in transportation. Together, transportation sources were responsible for 1,816.9 Tg CO₂ Eq. in 2009.

On-road vehicles were responsible for about 77 percent of all transportation and non-transportation mobile GHG emissions in 2009. Although passenger cars make up the largest component of on-road vehicle greenhouse gas emissions, light-duty and medium- and heavy-duty trucks have been the primary sources of growth in on-road vehicle emissions. Between 1990 and 2009, greenhouse gas emissions from passenger cars decreased 5 percent, while emissions from light-duty trucks increased 64 percent, largely due to the increased use of sport-utility vehicles and other light-duty trucks. Meanwhile, greenhouse gas emissions from medium- and heavy-duty trucks increased 58 percent, reflecting the increased volume of total freight movement and an increasing share transported by trucks.

Greenhouse gas emissions from aircraft decreased 22 percent between 1990 and 2009. Emissions from military aircraft decreased 59 percent and commercial aircraft emissions rose 2 percent between 1990 and 2007 then dropped 19 percent from 2007 to 2009.

Non-transportation mobile sources, such as construction/mining equipment, agricultural equipment, and industrial/commercial equipment, emitted approximately 197.7 Tg CO₂ Eq. in 2009. Together, these sources emitted more greenhouse gases than ships and boats, rail, and pipelines combined. Emissions from non-transportation mobile sources increased rapidly, growing approximately 54 percent between 1990 and 2009. CH₄ and N₂O emissions from these sources are included in the “Mobile Combustion” section and CO₂ emissions are included in the relevant economic sectors.

Contribution of Transportation and Mobile Sources to Greenhouse Gas Emissions, by Gas

Table A- 110 presents estimates of greenhouse gas emissions from transportation and other mobile sources broken down by greenhouse gas. As this table shows, CO₂ accounts for the vast majority of transportation greenhouse gas emissions (approximately 96 percent in 2009). Emissions of CO₂ from transportation and mobile sources increased by 300.2 Tg CO₂ Eq. between 1990 and 2009. In contrast, the combined emissions of CH₄ and N₂O decreased by 22.7 Tg CO₂ Eq. over the same period, due largely to the introduction of control technologies designed to reduce criteria pollutant emissions.⁴⁴ Meanwhile, HFC emissions from mobile air conditioners and refrigerated transport increased from virtually no emissions in 1990 to 60.2 Tg CO₂ Eq. in 2009 as these chemicals were phased in as substitutes for ozone depleting substances. It should be noted, however, that the ozone depleting substances that HFCs replaced are also powerful greenhouse gases, but are not included in national greenhouse gas inventories due to their mandated phase out.

Greenhouse Gas Emissions from Freight and Passenger Transportation

Table A- 111 and Table A- 112 present greenhouse gas estimates from transportation, broken down into the passenger and freight categories. Passenger modes include light-duty vehicles, buses, passenger rail, aircraft (general aviation and commercial aircraft), recreational boats, and mobile air conditioners, and are illustrated in Table A- 111. Freight modes include medium- and heavy-duty trucks, freight rail, refrigerated transport, waterborne freight vessels, pipelines, and commercial aircraft and are illustrated in Table A- 112. Commercial aircraft do carry some freight, in addition to passengers, and for this Inventory, the emissions have been split between passenger and freight transportation. (In previous Inventories, all commercial aircraft emissions were considered passenger transportation.) The amount of commercial aircraft emissions to allocate to the passenger and freight categories was calculated using BTS data on freight shipped by commercial aircraft, and the total number of passengers enplaned. Each passenger was considered to weigh an average of 150 pounds, with a luggage weight of 50 pounds. The total freight weight and total passenger weight carried were used to determine percent shares which were used to split the total commercial aircraft emissions estimates. The remaining transportation and mobile emissions were from sources not considered to be either freight or passenger modes (e.g., construction/mining and agricultural equipment, lubricants).

The estimates in these tables are derived from the estimates presented in Table A- 109. In addition, estimates of fuel consumption from DOE (1993 through 2010) were used to allocate rail emissions between passenger and freight categories.

In 2009, passenger transportation modes emitted 1,322.1 Tg CO₂ Eq., while freight transportation modes emitted 475.3 Tg CO₂ Eq. Since 1990, the rate of growth of greenhouse gas emissions from freight sources has been 7 percent higher than emissions from passenger sources, due largely to the rapid increase in emissions associated with medium- and heavy-duty trucks.

Table A- 109: Total U.S. Greenhouse Gas Emissions from Transportation and Mobile Sources (Tg CO₂ Eq.)

Mode / Vehicle Type / Fuel Type	1990	1995	2000	2005	2006	2007	2008	2009	Percent Change 1990-2009
Transportation									
Total^a	1,548.3	1,698.5	1,935.8	2,022.2	1,999.0	2,008.9	1,895.4	1,816.9	17%
On-Road Vehicles	1,235.2	1,371.3	1,575.1	1,682.9	1,679.7	1,682.1	1,603.8	1,557.4	26%
Passenger Cars	657.4	646.0	695.3	709.5	682.9	672.0	632.5	627.4	-5%
Gasoline	649.4	627.8	667.3	676.9	651.6	643.3	606.5	604.1	-7%
Diesel	7.9	7.9	3.7	4.2	4.1	4.1	3.9	3.9	-51%
AFVs	+	0.1	+	+	+	+	+	+	551%
HFCs from	+	10.1	24.3	28.4	27.1	24.6	22.1	19.3	NA

⁴⁴ The decline in CFC emissions is not captured in the official transportation estimates.

Mobile AC									
Light-Duty Trucks	336.6	436.6	512.1	551.3	564.0	570.3	553.8	551.0	64%
Gasoline	324.5	414.6	469.8	493.0	504.7	511.8	496.5	495.8	53%
Diesel	11.5	14.9	20.1	25.9	26.8	27.3	26.9	26.7	133%
AFVs	0.6	0.5	0.5	1.4	1.3	1.0	1.8	1.9	227%
HFCs from Mobile AC	+	6.5	21.7	31.0	31.2	30.1	28.6	26.6	NA
Medium- and Heavy-Duty Trucks	231.1	277.8	354.6	408.4	418.6	425.2	403.1	365.6	58%
Gasoline	39.5	36.8	37.0	35.8	36.3	36.8	34.4	31.1	-21%
Diesel	190.7	238.6	309.9	361.0	370.4	376.4	356.3	322.0	69%
AFVs	0.9	0.6	0.3	0.5	0.6	0.5	0.8	0.8	-6%
HFCs from Refrigerated Transport	+	1.7	7.4	11.1	11.4	11.5	11.6	11.6	NA
Buses	8.4	9.2	11.2	12.0	12.3	12.5	12.2	11.2	34%
Gasoline	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	-1%
Diesel	8.0	8.7	10.2	10.6	10.8	10.8	10.3	9.3	17%
AFVs	+	0.1	0.5	0.9	0.8	1.0	1.1	1.1	40569%
HFCs from Comfort Cooling	+	+	0.1	0.2	0.3	0.3	0.4	0.4	NA
Motorcycles	1.8	1.8	1.9	1.7	1.9	2.1	2.2	2.2	24%
Gasoline	1.8	1.8	1.9	1.7	1.9	2.1	2.2	2.2	24%
Aircraft	181.2	175.4	204.4	198.7	173.6	172.7	158.7	142.1	-22%
Commercial Aircraft	136.8	143.1	170.9	162.8	138.5	139.5	123.4	112.5	-18%
Jet Fuel	136.8	143.1	170.9	162.8	138.5	139.5	123.4	112.5	-18%
General Aviation Aircraft	9.6	8.2	12.1	17.5	18.5	16.9	18.8	15.3	59%
Jet Fuel	6.4	5.4	9.6	15.0	16.2	14.6	16.8	13.4	109%
Aviation Gasoline	3.2	2.8	2.6	2.5	2.4	2.2	2.0	1.9	-41%
Military Aircraft	34.8	24.1	21.3	18.3	16.5	16.3	16.4	14.3	-59%
Jet Fuel	34.8	24.1	21.3	18.3	16.5	16.3	16.4	14.3	-59%
Ships and Boats^b	45.1	58.6	61.0	45.2	48.4	55.2	37.1	30.5	-32%
Gasoline	12.6	14.1	10.0	14.2	14.1	14.0	13.6	13.5	7%
Distillate Fuel	9.6	14.9	17.1	11.4	10.9	11.7	3.2	4.8	-50%
Residual Fuel	22.9	29.5	33.8	19.6	23.4	29.5	20.2	12.2	-47%
HFCs from Refrigerated Transport	-	+	0.1	+	+	+	+	+	NA
Rail	39.0	43.7	48.1	53.0	55.1	54.3	50.6	43.3	11%
Distillate Fuel	35.8	40.0	42.5	46.0	48.3	47.0	43.6	36.5	2%
Electricity	3.1	3.1	3.5	4.8	4.5	5.0	4.7	4.4	45%
HFCs from Comfort Cooling	+	+	+	+	+	+	+	+	NA
HFCs from Refrigerated Transport	+	0.5	2.0	2.1	2.2	2.2	2.2	2.2	NA
Other Emissions from Rail Electricity Use	0.1	0.1	+	0.1	0.1	0.1	0.1	0.1	-9%
Pipelines^c	36.0	38.2	35.2	32.3	32.3	34.3	35.7	35.2	-2%
Natural Gas	36.0	38.2	35.2	32.3	32.3	34.3	35.7	35.2	-2%
Other Transportation	11.8	11.3	12.1	10.2	9.9	10.2	9.5	8.5	-28%
Lubricants	11.8	11.3	12.1	10.2	9.9	10.2	9.5	8.5	-28%
Non-Transportation Mobile Total	128.8	146.8	158.3	190.7	195.8	194.8	194.2	197.7	54%
Agricultural Equipment^d	31.4	37.0	39.2	47.3	49.6	49.0	45.9	47.2	50%

Gasoline	7.3	8.3	5.8	9.6	11.0	9.6	5.7	6.1	-17%
Diesel	24.1	28.7	33.4	37.7	38.6	39.4	40.3	41.1	71%
Construction/ Mining Equipment^e	42.4	49.4	55.8	66.5	67.9	68.4	69.9	71.2	68%
Gasoline	4.4	4.0	3.1	6.2	6.2	5.1	5.2	5.0	14%
Diesel	38.0	45.4	52.7	60.3	61.8	63.3	64.8	66.3	74%
Other Equipment^f	55.0	60.4	63.4	76.9	78.3	77.4	78.4	79.3	44%
Gasoline	40.3	42.6	42.5	52.7	53.4	51.8	52.2	52.4	30%
Diesel	14.7	17.8	20.9	24.2	24.9	25.6	26.2	26.9	83%
Transportation and Non- Transportation Mobile Total	1,677.1	1,845.3	2,094.1	2,212.9	2,194.8	2,203.6	2,089.7	2,014.7	20%

^a Not including emissions from international bunker fuels.

^b Fluctuations in emission estimates reflect data collection problems.

^c Includes only CO₂ from natural gas used to power pipelines; does not include emissions from electricity use or non-CO₂ gases.

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

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

^f "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.

+ Less than 0.05 Tg CO₂ Eq.

- Unreported or zero

NA = Not Applicable, as there were no HFC emissions allocated to the transport sector in 1990, and thus a growth rate cannot be calculated.

Table A- 110: Transportation and Mobile Source Emissions by Gas (Tg CO₂ Eq.)

Gas	1990	1995	2000	2005	2006	2007	2008	2009	Percent Change 1990- 2009
CO ₂	1,628.4	1,767.9	1,981.9	2,100.4	2,086.5	2,102.2	1,996.5	1,928.6	18%
N ₂ O	43.9	54.0	53.2	36.9	33.6	30.3	26.1	23.9	-46%
CH ₄	4.7	4.3	3.4	2.5	2.2	2.2	2.0	2.0	-58%
HFC	-	19.0	55.7	72.9	72.2	68.8	64.9	60.2	NA
Total	1,677.0	1,845.2	2,094.1	2,212.8	2,194.7	2,203.5	2,089.6	2,014.6	20%

- Unreported or zero

NA = Not Applicable, as there were no HFC emissions allocated to the transport sector in 1990, and thus a growth rate cannot be calculated.

Figure A-4: Domestic Greenhouse Gas Emissions by Mode and Vehicle Type, 1990 to 2009 (Tg CO₂ Eq.)

Table A- 111: Greenhouse Gas Emissions from Passenger Transportation (Tg CO₂ Eq.)

Vehicle Type	1990	1995	2000	2005	2006	2007	2008	2009	Percent Change 1990- 2009
On-Road Vehicles	1,004.1	1,093.5	1,220.5	1,274.5	1,261.1	1,256.9	1,200.8	1,191.7	19%
Passenger Cars	657.4	646.0	695.3	709.5	682.9	672.0	632.5	627.4	-5%
Light-Duty Trucks	336.6	436.6	512.1	551.3	564.0	570.3	553.8	551.0	64%
Buses	8.4	9.2	11.2	12.0	12.3	12.5	12.2	11.2	34%
Motorcycles	1.8	1.8	1.9	1.7	1.9	2.1	2.2	2.2	24%
Aircraft	122.7	126.5	153.4	154.4	135.3	136.0	124.3	111.4	-9%
General Aviation	9.6	8.2	12.1	17.5	18.5	16.9	18.8	15.3	59%
Commercial Aircraft	113.1	118.3	141.3	136.8	116.7	119.2	105.5	96.1	-15%
Recreational Boats	14.5	16.4	12.7	17.4	17.3	17.3	14.5	16.9	17%
Passenger Rail	4.4	4.5	5.2	6.2	6.0	6.5	6.2	6.0	37%

Total	1,145.7	1,241.0	1,391.8	1,452.5	1,419.7	1,416.8	1,345.8	1,326.1	16%
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Note: Data from DOE (1993 through 2010) were used to disaggregate emissions from rail and buses. Emissions from HFCs have been included in these estimates.

Table A- 112: Greenhouse Gas Emissions from Domestic Freight Transportation (Tg CO₂ Eq.)

By Mode	1990	1995	2000	2005	2006	2007	2008	2009	Percent Change 1990-2009
Trucking	231.1	277.8	354.6	408.4	418.6	425.2	403.1	365.6	58%
Freight Rail	34.5	39.1	42.8	46.7	49.0	47.8	44.5	37.2	8%
Ships and Other Boats	30.6	42.2	48.3	27.9	31.1	37.9	22.6	13.5	-56%
Pipelines	36.0	38.2	35.2	32.2	32.3	34.3	35.7	35.2	-2%
Commercial Aircraft	23.7	24.8	29.6	26.0	21.8	20.3	18.0	16.4	-31%
Total	356.0	422.1	510.5	541.1	552.8	565.5	523.7	467.9	31%

Note: Data from DOE (1993 through 2010) were used to disaggregate emissions from rail and buses. Emissions from HFCs have been included in these estimates.

3.3. Methodology for Estimating CH₄ Emissions from Coal Mining

The methodology for estimating CH₄ emissions from coal mining consists of two distinct steps. The first step addresses emissions from underground mines. For these mines, 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 CH₄ emissions for surface mines and post-mining activities. In contrast to the methodology for underground mines, which uses mine-specific data, the surface mine and post-mining activities analysis consists of multiplying basin-specific coal production by basin-specific emission factors.

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

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

Step 1.1: Estimate CH₄ Liberated from Ventilation Systems

All coal mines with detectable CH₄ emissions⁴⁵ use ventilation systems to ensure that CH₄ levels remain within safe concentrations. Many coal mines do not have detectable levels of CH₄, while others emit several million cubic feet per day (MMCFD) from their ventilation systems. On a quarterly basis, the U.S. Mine Safety and Health Administration (MSHA) measures CH₄ emissions levels at underground mines. MSHA maintains a database of measurement data from all underground mines with detectable levels of CH₄ in their ventilation air. Based on the four quarterly measurements, MSHA estimates average daily CH₄ liberated at each of the underground mines with detectable emissions.

For the years 1990 through 1996, 1998 through 2006, 2008 and 2009, MSHA emissions data were obtained for a large but incomplete subset of all mines with detectable emissions. This subset includes mines emitting at least 0.1 MMCFD for some years and at least 0.5 MMCFD for other years, as shown in Table A- 113. Well over 90 percent of all ventilation emissions were concentrated in these subsets. For 1997 and 2007, the complete MSHA databases for all 586 mines (in 1997) and 730 mines (in 2007) with detectable CH₄ emissions were obtained. These mines were assumed to account for 100 percent of CH₄ liberated from underground mines. Using the complete database from 1997, the proportion of total emissions accounted for by mines emitting less than 0.1 MMCFD or 0.5 MMCFD was estimated (see Table A- 113). The proportion was then applied to the years 1990 through 2006 to account for the less than 5 percent of ventilation emissions coming from mines without MSHA data.

For 1990 through 1999, average daily CH₄ emissions were multiplied by the number of days in the year (i.e., coal mine assumed in operation for all four quarters) to determine the annual emissions for each mine. For 2000 through 2009, MSHA provided quarterly emissions. The average daily CH₄ emissions were multiplied by the number of days corresponding to the number of quarters the mine vent was operating. For example, if the mine vent was operational in one out of the four quarters, the average daily CH₄ emissions were multiplied by 92 days. Total ventilation emissions for a particular year were estimated by summing emissions from individual mines.

⁴⁵ MSHA records coal mine methane readings with concentrations of greater than 50 ppm (parts per million) methane. Readings below this threshold are considered non-detectable.

Table A- 113: Mine-Specific Data Used to Estimate Ventilation Emissions

Year	Individual Mine Data Used
1990	All Mines Emitting at Least 0.1 MMCFD (Assumed to Account for 97.8% of Total)*
1991	1990 Emissions Factors Used Instead of Mine-Specific Data
1992	1990 Emissions Factors Used Instead of Mine-Specific Data
1993	All Mines Emitting at Least 0.1 MMCFD (Assumed to Account for 97.8% of Total)*
1994	All Mines Emitting at Least 0.1 MMCFD (Assumed to Account for 97.8% of Total)*
1995	All Mines Emitting at Least 0.5 MMCFD (Assumed to Account for 94.1% of Total)*
1996	All Mines Emitting at Least 0.5 MMCFD (Assumed to Account for 94.1% of Total)*
1997	All Mines with Detectable Emissions (Assumed to Account for 100% of Total)
1998	All Mines Emitting at Least 0.1 MMCFD (Assumed to Account for 97.8% of Total)*
1999	All Mines Emitting at Least 0.1 MMCFD (Assumed to Account for 97.8% of Total)*
2000	All Mines Emitting at Least 0.1 MMCFD (Assumed to Account for 97.8% of Total)*
2001	All Mines Emitting at Least 0.1 MMCFD (Assumed to Account for 97.8% of Total)*
2002	All Mines Emitting at Least 0.1 MMCFD (Assumed to Account for 97.8% of Total)*
2003	All Mines Emitting at Least 0.1 MMCFD (Assumed to Account for 97.8% of Total)*
2004	All Mines Emitting at Least 0.1 MMCFD (Assumed to Account for 97.8% of Total)*
2005	All Mines Emitting at Least 0.1 MMCFD (Assumed to Account for 97.8% of Total)*
2006	All Mines Emitting at Least 0.1 MMCFD (Assumed to Account for 97.8% of Total)*
2007	All Mines with Detectable Emissions (Assumed to Account for 100% of Total)
2008	All Mines Emitting at Least 0.1 MMCFD (Assumed to Account for 98.96% of Total)**
2009	All Mines Emitting at Least 0.1 MMCFD (Assumed to Account for 98.96% of Total)**

* Factor derived from a complete set of individual mine data collected for 1997.

** Factor derived from a complete set of individual mine data collected for 2007.

Step 1.2: Estimate CH₄ Liberated from Degasification Systems

Coal mines use several different types of degasification systems to remove CH₄, including vertical wells and horizontal boreholes to recover CH₄ prior to mining of the coal seam. Gob wells and cross-measure boreholes recover CH₄ from the overburden (i.e., GOB area) after mining of the seam (primarily in longwall mines).

MSHA collects information about the presence and type of degasification systems in some mines, but does not collect quantitative data on the amount of CH₄ liberated. Thus, the methodology estimated degasification emissions on a mine-by-mine basis based on other sources of available data. Many of the coal mines employing degasification systems have provided EPA with information regarding CH₄ liberated from their degasification systems. For these mines, this reported information was used as the estimate. In other cases in which mines sell CH₄ recovered from degasification systems to a pipeline, gas sales were used to estimate CH₄ liberated from degasification systems (see Step 1.3). Finally, for those mines that do not sell CH₄ to a pipeline and have not provided information to EPA, CH₄ liberated from degasification systems was estimated based on the type of system employed. For example, for coal mines employing gob wells and horizontal boreholes, the methodology assumes that degasification emissions account for 40 percent of total CH₄ liberated from the mine.

Step 1.3: Estimate CH₄ Recovered from Degasification Systems and Utilized (Emissions Avoided)

In 2009, fourteen active coal mines had CH₄ recovery and use projects. Thirteen mines sold the recovered CH₄ to a pipeline, one used the CH₄ on site to heat mine ventilation air, and one of the coal mines used CH₄ to generate electricity. One of the mines that sold gas to a pipeline also used CH₄ to fuel a thermal coal dryer. In order to calculate emissions avoided from pipeline sales, information was needed regarding the amount of gas recovered and the number of years in advance of mining that wells were drilled. Several state agencies provided gas sales data, which were used to estimate emissions avoided for these projects. Additionally, coal mine operators provided information on gas sales and/or the number of years in advance of mining. Emissions avoided were attributed to the year in which the coal seam was mined. For example, if a coal mine recovered and sold CH₄ using a vertical well drilled five years in advance of mining, the emissions avoided associated with those gas sales (cumulative production) were attributed to the well at the time it was mined through (e.g., five years of gas production). Where individual well data is not available, estimated percentages of the operator's annual gas sales within the field around the coal mine are attributed to emissions avoidance. For some mines, individual well data were used to assign gas sales to the appropriate emissions avoided year. In most cases, coal mine operators provided this information, which was then used to estimate emissions avoided for a particular year. Additionally, several state agencies provided production data for individual wells.

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

Mine-specific data were not available for estimating CH₄ emissions from surface coal mines or for post-mining activities. For surface mines and post-mining activities, basin-specific coal production was multiplied by a basin-specific emission factor to determine CH₄ emissions.

Step 2.1: Define the Geographic Resolution of the Analysis and Collect Coal Production Data

The first step in estimating CH₄ emissions from surface mining and post-mining activities was to define the geographic resolution of the analysis and to collect coal production data at that level of resolution. The analysis was conducted by coal basin as defined in Table A- 114, which presents coal basin definitions by basin and by state.

The Energy Information Administration's (EIA) Annual Coal Report includes state- and county-specific underground and surface coal production by year. To calculate production by basin, the state level data were grouped into coal basins using the basin definitions listed in Table A- 114. For two states—West Virginia and Kentucky—county-level production data was used for the basin assignments because coal production occurred from geologically distinct coal basins within these states. Table A- 115 presents the coal production data aggregated by basin.

Step 2.2: Estimate Emissions Factors for Each Emissions Type

Emission factors for surface mined coal were developed from the *in situ* CH₄ content of the surface coal in each basin. Based on an analysis presented in EPA (1993), surface mining emission factors were estimated to be from 1 to 3 times the average *in situ* CH₄ content in the basin. For this analysis, the surface mining emission factor was determined to be twice the *in situ* CH₄ content in the basin. Furthermore, the post-mining emission factors used were estimated to be 25 to 40 percent of the average *in situ* CH₄ content in the basin. For this analysis, the post-mining emission factor was determined to be 32.5 percent of the *in situ* CH₄ content in the basin. Table A- 116 presents the average *in situ* content for each basin, along with the resulting emission factor estimates.

Step 2.3: Estimate CH₄ Emitted

The total amount of CH₄ emitted was calculated by multiplying the coal production in each basin by the appropriate emission factors.

Total annual CH₄ emissions are equal to the sum of underground mine emissions plus surface mine emissions plus post-mining emissions. Table A- 117 and Table A- 118 present estimates of CH₄ liberated, used, and emitted for 1990 through 2008. Table A- 119 provides emissions by state.

Table A- 114: Coal Basin Definitions by Basin and by State

Basin	States
Northern Appalachian Basin	Maryland, Ohio, Pennsylvania, West Virginia North
Central Appalachian Basin	Kentucky East, Tennessee, Virginia, West Virginia South
Warrior Basin	Alabama, Mississippi
Illinois Basin	Illinois, Indiana, Kentucky West
South West and Rockies Basin	Arizona, California, Colorado, New Mexico, Utah
North Great Plains Basin	Montana, North Dakota, Wyoming
West Interior Basin	Arkansas, Iowa, Kansas, Louisiana, Missouri, Oklahoma, Texas
Northwest Basin	Alaska, Washington
State	Basin
Alabama	Warrior Basin
Alaska	Northwest Basin
Arizona	South West and Rockies Basin
Arkansas	West Interior Basin
California	South West and Rockies Basin
Colorado	South West and Rockies Basin
Illinois	Illinois Basin
Indiana	Illinois Basin
Iowa	West Interior Basin
Kansas	West Interior Basin
Kentucky East	Central Appalachian Basin
Kentucky West	Illinois Basin
Louisiana	West Interior Basin
Maryland	Northern Appalachian Basin

Mississippi	Warrior Basin
Missouri	West Interior Basin
Montana	North Great Plains Basin
New Mexico	South West and Rockies Basin
North Dakota	North Great Plains Basin
Ohio	Northern Appalachian Basin
Oklahoma	West Interior Basin
Pennsylvania	Northern Appalachian Basin
Tennessee	Central Appalachian Basin
Texas	West Interior Basin
Utah	South West and Rockies Basin
Virginia	Central Appalachian Basin
Washington	Northwest Basin
West Virginia South	Central Appalachian Basin
West Virginia North	Northern Appalachian Basin
Wyoming	North Great Plains Basin

Table A- 115: Annual Coal Production (Thousand Short Tons)

Basin	1990	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Underground Coal Production	423,556	399,102	396,249	409,850	420,657	417,729	391,791	372,766	380,627	357,384	352,785	367,558	368,611	359,020	351,791	357,074	332,061
N. Appalachia	103,865	100,122	98,103	106,729	112,135	116,718	107,575	105,374	107,025	98,643	98,369	106,915	111,151	107,827	106,024	105,228	99,629
Cent. Appalachia	198,412	170,893	166,495	171,845	177,720	171,279	157,058	150,584	152,457	137,224	130,724	128,559	123,083	117,738	110,103	114,998	98,689
Warrior	17,531	14,471	17,605	18,217	18,505	17,316	14,799	15,895	15,172	14,916	15,375	16,114	13,295	10,737	11,462	12,281	11,505
Illinois	69,167	69,050	69,009	67,046	64,728	64,463	63,529	53,720	54,364	54,016	51,780	56,320	59,180	61,726	61,924	64,609	67,186
S. West/Rockies	32,754	41,681	42,994	43,088	44,503	45,983	46,957	45,742	51,193	52,121	56,111	59,039	60,865	59,670	58,815	55,781	50,416
N. Great Plains	1,722	2,738	2,018	2,788	2,854	1,723	1,673	1,210	-	-	32	201	572	840	2,869	3,669	4,248
West Interior	105	147	25	137	212	247	200	241	415,623	464	394	410	465	482	594	508	388
Northwest	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Surface Coal Production	602,753	634,401	636,726	654,007	669,271	699,806	708,639	700,608	745,306	735,912	717,869	743,553	762,191	802,975	793,689	813,321	740,175
N. Appalachia	60,761	44,960	39,372	39,788	40,179	41,043	33,928	34,908	35,334	30,088	27,370	28,174	28,873	28,376	26,121	30,413	26,552
Cent. Appalachia	94,343	106,129	106,250	108,869	113,275	108,345	107,507	110,479	116,983	111,340	99,419	103,968	112,222	118,388	116,226	118,962	97,778
Warrior	11,413	8,795	7,036	6,420	5,963	5,697	4,723	4,252	4,796	6,320	8,437	9,742	11,599	11,889	11,410	11,172	10,731
Illinois	72,000	51,868	40,376	44,754	46,862	45,715	40,474	33,631	40,894	39,380	36,675	34,016	33,702	33,362	33,736	34,266	34,837
S. West/Rockies	43,863	49,119	46,643	43,814	48,374	49,635	50,349	49,587	52,180	50,006	41,237	42,558	42,756	36,798	34,310	34,283	32,167
N. Great Plains	249,356	308,279	331,367	343,404	349,612	385,438	407,683	407,670	438,367	441,346	444,007	466,224	474,056	518,136	523,695	538,387	496,290
West Interior	64,310	58,791	59,116	60,912	59,061	57,951	58,309	54,170	50,613	50,459	53,411	51,706	52,263	52,021	46,867	44,361	39,960
Northwest	6,707	6,460	6,566	6,046	5,945	5,982	5,666	5,911	6,138	6,973	7,313	7,165	6,720	4,005	1,324	1,477	1,860
Total Coal Production	931,068	937,594	937,115	965,131	988,783	1,013,828	998,310	973,765	1,021,446	991,838	971,297	1,008,000	1,025,864	1,054,162	1,039,178	1,170,395	1,072,236
N. Appalachia	164,626	145,082	137,475	146,517	152,314	157,761	141,503	140,282	142,360	128,731	125,739	135,089	140,024	136,203	132,143	135,641	126,181
Cent. Appalachia	292,755	277,022	272,745	280,714	290,995	279,624	264,565	261,063	269,440	248,564	230,143	232,527	235,305	236,126	226,328	233,960	196,467
Warrior	28,944	23,266	24,641	24,637	24,468	23,013	19,522	20,147	19,967	21,236	23,812	25,856	24,894	22,626	22,872	23,453	22,236
Illinois	141,167	120,918	109,385	111,800	111,590	110,178	104,003	87,351	95,258	93,396	88,455	90,336	92,882	95,088	95,660	98,875	102,023
S. West/Rockies	76,617	90,800	89,637	86,902	92,877	95,618	97,306	95,329	103,373	102,127	97,348	101,597	103,621	96,468	93,125	90,064	82,583
N. Great Plains	251,078	311,017	333,385	346,192	352,466	387,161	409,356	408,880	438,367	441,346	444,039	466,425	474,628	518,976	526,564	542,056	500,538
West Interior	64,415	58,938	59,141	61,049	59,273	58,198	58,509	54,411	51,028	50,923	53,805	52,116	52,728	52,503	47,462	44,869	40,348
Northwest	6,707	6,460	6,566	6,046	5,945	5,982	5,666	5,911	6,138	6,973	7,313	7,165	6,720	4,005	1,324	1,477	1,860

Source for 1990-2009 data: EIA (1990 through 2009), Annual Coal Report. U.S. Department of Energy, Washington, DC, Table 1.

Note: Totals may not sum due to independent rounding.

Table A- 116: Coal Surface and Post-Mining CH₄ Emission Factors (ft³ per Short Ton)

Basin	Surface Average <i>in situ</i> Content	Underground Average <i>In situ</i> Content	Surface Mine Factors	Post-Mining Surface Factors	Post Mining Underground
Northern Appalachia	59.5	138.4	119.0	19.3	45.0
Central Appalachia (WV)	24.9	136.8	49.8	8.1	44.5
Central Appalachia (VA)	24.9	399.1	49.8	8.1	129.7
Central Appalachia (E KY)	24.9	61.4	49.8	8.1	20.0
Warrior	30.7	266.7	61.4	10.0	86.7
Illinois	34.3	64.3	68.6	11.1	20.9
Rockies (Piceance Basin)	33.1	196.4	66.2	10.8	63.8
Rockies (Uinta Basin)	16.0	99.4	32.0	5.2	32.3
Rockies (San Juan Basin)	7.3	104.8	14.6	2.4	34.1
Rockies (Green River Basin)	33.1	247.2	66.2	10.8	80.3
Rockies (Raton Basin)	33.1	127.9	66.2	10.8	41.6
N. Great Plains (WY, MT)	20.0	15.8	40.0	6.5	5.1
N. Great Plains (ND)	5.6	15.8	11.2	1.8	5.1
West Interior (Forest City, Cherokee Basins)	34.3	64.3	68.6	11.1	20.9
West Interior (Arkoma Basin)	74.5	331.2	149.0	24.2	107.6
West Interior (Gulf Coast Basin)	11.0	127.9	22.0	3.6	41.6
Northwest (AK)	16.0	160.0	32.0	1.8	52.0
Northwest (WA)	16.0	47.3	32.0	5.2	15.4

Sources: 1986 USBM Circular 9067, *Results of the Direct Method Determination of the Gas Contents of U.S. Coal Basins*, 1983 U.S. DOE Report (DOE/METC/83-76), *Methane Recovery from Coalbeds: A Potential Energy Source*, 1986-88 Gas Research Institute Topical Reports, A Geologic Assessment of Natural Gas from Coal Seams; *Surface Mines Emissions Assessment*, U.S. EPA Draft Report, November 2005.

Table A- 117: Underground Coal Mining CH₄ Emissions (Billion Cubic Feet)

Activity	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Ventilation Output	112	NA	NA	95	96	100	90	96	94	92	87	84	79	76	83	75	79	81	100	114
Adjustment Factor for Mine Data*	97.8%	NA	NA	97.8%	97.8%	91.4%	91.4%	100.0%	97.8%	97.8%	97.8%	97.8%	97.8%	97.8%	97.8%	97.8%	97.8%	100.0%	99.0%	99.0%
Adjusted Ventilation Output	114	NA	NA	97	98	109	99	96	96	94	89	86	80	77	84	77	80	81	101	115
Degasification System Liberated	54	NA	NA	45	46	36	52	43	49	40	45	49	51	50	45	48	54	44	49	51
Total Underground Liberated	168	164	162	142	144	146	150	139	146	134	135	135	131	127	130	124	134	125	150	166
Recovered & Used	(14)	(15)	(17)	(23)	(27)	(30)	(37)	(28)	(35)	(31)	(37)	(41)	(43)	(38)	(40)	(37)	(46)	(37)	(40)	(41)
Total	154	150	145	120	117	116	113	111	110	103	98	95	88	89	90	87	88	88	110	125

* Refer to Table A- 113.

Note: Totals may not sum due to independent rounding.

Table A- 118: Total Coal Mining CH₄ Emissions (Billion Cubic Feet)

Activity	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Underground Mining	154	150	145	120	117	116	113	111	110	103	98	95	88	89	90	87	88	88	110	125
Surface Mining	30	28	28	28	29	28	29	30	31	31	30	33	32	31	32	33	35	34	35	32
Post-Mining (Underground)	19	18	18	16	17	17	18	18	18	17	17	17	16	16	16	16	15	15	15	14
Post-Mining (Surface)	5	5	5	4	5	5	5	5	5	5	5	5	5	5	5	5	6	6	6	5
Total	208	201	195	167	168	166	165	164	165	156	149	149	140	141	144	141	144	143	166	176

Note: Totals may not sum due to independent rounding.

Table A- 119: Total Coal Mining CH₄ Emissions by State (Million Cubic Feet)

State	1990	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Alabama	32,272	29,630	33,735	29,556	26,426	26,440	25,702	23,342	21,896	18,686	19,288	18,246	15,912	14,699	17,159	21,120	23,975
Alaska	63	58	63	55	54	50	58	61	56	43	40	56	54	53	49	55	69
Arizona	192	222	203	177	199	192	200	223	228	217	205	216	205	139	135	136	127
Arkansas	7	8	5	4	3	4	4	2	2	2	1	1	1	4	144	237	119
California	1	-	-	-	-	+	+	+	+	+	+	+	+	+	+	-	-
Colorado	10,325	9,192	7,582	5,972	9,189	9,181	9,390	10,808	11,117	12,082	13,216	12,582	13,608	13,102	13,180	12,998	14,100
Illinois	10,502	10,585	11,563	10,876	8,534	7,847	7,810	8,542	7,270	5,972	4,744	5,798	6,586	6,954	4,493	7,759	7,322
Indiana	2,795	2,495	2,025	2,192	2,742	2,878	2,650	2,231	3,373	3,496	3,821	3,531	3,702	4,029	4,347	5,452	6,155
Iowa	30	4	-	-	-	+	+	+	+	+	+	+	+	+	+	-	-
Kansas	57	23	23	19	29	27	33	16	14	16	12	6	14	34	33	18	15
Kentucky	10,956	11,259	10,269	8,987	10,451	10,005	9,561	9,105	9,363	8,464	8,028	7,926	7,494	9,135	9,278	10,641	12,617
Louisiana	81	89	95	82	91	82	76	94	95	97	103	97	106	105	80	98	94
Maryland	519	237	237	259	267	251	225	331	340	401	391	411	421	435	261	325	273
Mississippi	-	-	-	-	-	0	1	57	43	165	264	256	254	271	253	203	246
Missouri	211	67	44	57	32	30	31	35	29	20	43	46	48	31	19	20	36
Montana	1,749	1,936	1,834	1,756	1,906	1,992	1,911	1,783	1,820	1,738	1,719	1,853	1,870	1,931	2,016	2,076	1,804
New Mexico	451	679	586	408	459	489	497	464	630	1,280	1,864	2,052	3,001	2,970	2,660	3,479	3,904
North Dakota	380	420	392	389	385	389	405	407	397	401	401	390	390	396	385	386	390
Ohio	5,065	4,583	4,189	4,068	4,349	4,350	3,914	3,519	3,619	2,831	2,649	3,183	3,385	3,413	2,672	3,959	4,746
Oklahoma	285	359	323	286	385	395	469	454	620	660	620	849	877	658	774	970	646

Pennsylvania	22,735	24,024	25,611	26,440	30,026	30,888	24,867	24,830	22,252	19,668	20,281	20,020	18,289	18,727	19,519	21,044	23,216
Tennessee	296	101	112	143	148	116	119	99	142	142	124	136	140	117	120	105	84
Texas	1,426	1,339	1,347	1,411	1,364	1,345	1,357	1,240	1,152	1,157	1,215	1,173	1,175	1,165	1,073	998	898
Utah	3,587	2,626	2,570	2,810	3,566	3,859	3,633	2,816	2,080	2,709	3,408	5,253	4,787	5,445	3,678	5,524	5,449
Virginia	46,137	26,742	20,059	19,771	16,851	13,978	13,321	12,065	11,506	11,227	11,906	11,389	8,790	9,830	10,118	9,334	8,172
Washington	186	182	181	170	167	173	153	159	172	217	232	210	196	96	+	-	-
West Virginia	49,039	30,664	30,552	36,384	33,554	35,566	33,599	30,563	33,985	31,405	28,474	29,465	30,612	29,510	29,654	37,406	41,241
Wyoming	8,496	10,912	12,185	12,838	12,994	14,549	15,607	15,725	17,147	17,352	17,497	18,435	18,784	20,752	20,974	21,601	19,903
Total	207,844	168,433	165,785	165,109	164,171	165,075	155,568	149,371	149,348	140,449	140,544	143,581	140,698	144,004	143,076	165,945	175,598

- Zero Cubic Feet

+ Does not exceed 0.5 Million Cubic Feet

Note: The emission estimates provided above are inclusive of emissions from underground mines, surface mines and post-mining activities. The following states have neither underground nor surface mining and thus report no emissions as a result of coal mining: Connecticut, Delaware, Florida, Georgia, Hawaii, Idaho, Maine, Massachusetts, Michigan, Minnesota, Nebraska, Nevada, New Hampshire, New Jersey, New York, North Carolina, Oregon, Rhode Island, South Carolina, South Dakota, Vermont, and Wisconsin.

3.4. Methodology for Estimating CH₄ and CO₂ Emissions from Natural Gas Systems

The following steps were used to estimate CH₄ and non-energy CO₂ emissions from natural gas systems.

Step 1: Calculate Emission Estimates for Base Year 1992 Using EPA Adjusted GRI/EPA Study

The first step in estimating CH₄ and non-energy related (i.e., fugitive, vented and flared) CO₂ emissions from natural gas systems was to develop a detailed base year estimate of emissions. The study by EPA/GRI (1996) divides the industry into four stages to construct a detailed emission inventory for the year 1992. These stages include: field production, processing, transmission and storage (i.e., both underground and liquefied gas storage), and distribution. This study produced emission factors and activity data for over 100 different emission sources within the natural gas system. Emissions for 1992 were estimated by multiplying activity levels by emission factors for each system component and then summing by stage.

Since publication activity data for some of the components in the system have been updated based on publicly available data. For other sources where annual activity data are not available, a set of industry activity factor drivers was developed that can be used to update activity data. Table A-120 through Table A-123 display the 2009 activity levels, CH₄ emission factors, and CH₄ emissions for each stage. These data are shown to illustrate the kind of data used to calculate CH₄ and non-energy CO₂ emissions from all stages. Many emission factors determined by EPA/GRI (1996) were assumed to be representative of emissions from each source type over the period 1990 through 2009.

However, several emission factors have been updated since publication of the EPA/GRI 1996 study. Notably, emission factors for gas well cleanups (EPA 2006a, HPDI 2009), condensate storage tanks (EPA 1999, HPDI 2009, TERC 2009), and centrifugal compressors (EPA 2006b, WGC 2009) have been revised. Emissions for gas well completions and workovers (re-completions) with hydraulic fracturing (i.e. unconventional) (EPA 2004, 2007), which were not included in the EPA/GRI study, have also been added. The EPA/GRI study and Inventory did, however, include an estimate for well completions without hydraulic fracturing under the source category Completion Flaring.. The revised 2009 emission factor for centrifugal compressors will be reevaluated in the next Inventory cycle.

For most sources, the CH₄ emission factors were adjusted for CO₂ content when estimating fugitive and vented non-energy CO₂ emissions. In the case of non-energy CO₂ emissions from flared sources, acid gas removal units and condensate tanks, specific industry data related to those sources was used to derive their respective emission factors.

The activity levels and CH₄ emission factors in Table A-120 are arranged into regions designated by the National Energy Modeling System (NEMS) for Oil and Gas Supply. NEMS for Oil and Gas Supply splits the continental United States into 6 regions: Northeast, Midcontinent, Rocky Mountain, South West, West Coast and Gulf Coast. GRI, however, does not evaluate activity data for each of these regions separately. The GRI national AF estimates were allocated to the NEMS oil and gas supply module regions using the NEMS regional gas well counts to national well count ratios.

Step 2: Collect Aggregate Statistics on Main Driver Variables

As detailed data on each of the over 100 sources were not available for the period 1990 through 2009, activity levels were estimated using aggregate statistics on key drivers, including: number of producing wells (EIA 2010a-b, New Mexico 2010a-b, Texas 2010a-b), number of gas plants (AGA 1991-1997; OGJ 1998-2010), number of shallow and deep offshore platforms (BOEMRE 2010a-d), miles of transmission pipeline (OPS 2010a), miles of distribution pipeline (OPS 2010b), miles of distribution services (OPS 2010b), and energy consumption (EIA 2010c). Table A-124 provides the activity levels of some of the key drivers in the natural gas analysis.

Step 3: Estimate CH₄ Emissions for Each Year and Stage

Emissions from each stage of the natural gas industry were estimated by multiplying the activity factors by the appropriate emission factors, summing all sources for each stage and then accounting for CH₄ reductions reported to the Natural Gas STAR Program and CH₄ reductions resulting from regulations such as National Emission Standards for Hazardous Air Pollutants (NESHAP) regulations.

Industry partners report CH₄ emission reductions by project to the Natural Gas STAR Program. The reductions are estimates using actual measurement data or equipment-specific emission factors. The reductions undergo quality assurance and quality control checks to identify errors, inconsistencies, or irregular data before being incorporated into the Inventory. These quality assurance and quality control checks include matching Natural Gas STAR reported reductions to

specific inventory sources to make sure that a reported reduction for one source is not greater than the emission estimate for that source. Total emissions are estimated by adding the emission estimates from each stage. The base year of the inventory is 1992; therefore any reductions reported for 1992 or earlier are considered to be already included in the base-year emission factors and are not subtracted from the inventory estimate. If the reported reduction occurred between 1990 and 1992, then the reduction is added back into the estimate for the appropriate year(s). The reductions are also adjusted to remove the sunset period which is relevant to Natural Gas STAR accounting but not the Inventory. For example, replacing a gas-assisted pump with an electric pump permanently reduces the vented methane emissions from that source, even after the Natural Gas STAR sunset period. CH₄ emission reductions from the Natural Gas STAR Program beyond the efforts reflected in the 1992 base year are summarized in Table A-125.

The 1990 Clean Air Act (CAA) sets the limits on the amount of hazardous air pollutants (HAPs) that can be emitted in the United States. The NESHAP regulations set the standards to limit emissions of HAPs. The emission sources are required to use the Maximum Achievable Control Technology, giving the operators flexibility to choose the type of control measure(s) to implement. In regards to the oil and natural gas industry, the NESHAP regulation addresses HAPs from the oil and natural gas production sectors and the natural gas transmission and storage sectors of the industry. Though the regulation deals specifically with HAPs reductions, methane emissions are also reduced.

The NESHAP regulation requires that glycol dehydration unit vents and storage tanks that have HAP emissions and exceed a gas throughput and liquids throughput value, respectively, be connected to a closed loop emission control system that reduces emissions by 95 percent. Also, gas processing plants exceeding the threshold natural gas throughput limit are required to routinely implement Leak Detection and Survey (LDAR) programs. The emissions reductions achieved as a result of NESHAP regulations were estimated using data provided in the Federal Register Background Information Document (BID) for this regulation. The BID provides the levels of control measures in place before the enactment of regulation. The emissions reductions were estimated by analyzing the portion of the industry without control measures already in place that would be impacted by the regulation. The reductions are representative of the control measures in both the oil and natural gas industry. CH₄ emission reductions from regulations, such as NESHAP, are summarized in Table A-126.

Additionally, some states, such as Wyoming, may require that natural gas produced during well completions not be vented. In these regions emissions from natural gas well completions and re-completions are either recovered for sales or must be flared. The volume of gas recovered by bringing equipment to the wellsite for the treatment and injection of the produced completion gas into the sales pipeline is reported by Natural Gas STAR. The remaining volume of completion gas from states that do not allow the venting of this gas is flared.

Step 4: Estimate CO₂ Emissions for Each Year and Stage

The same procedure for estimating CH₄ emissions holds true for estimating non-energy related CO₂ emissions, except the emission estimates are not corrected for reductions due to the Natural Gas STAR program or other regulations.

Produced natural gas is composed of primarily CH₄, but as shown in Table A-131, the natural gas contains, in some cases, as much as 8 percent CO₂. The same vented and fugitive emissions of natural gas that led to CH₄ emissions also contain a certain volume of CO₂. Accordingly, the CO₂ emissions for each sector can be estimated using the same methane activity and emissions factors for these vented and fugitive sources. The primary difference is that EPA/GRI emission factors are adjusted for CO₂ content in each sector.

Using the default CH₄ content of produced natural gas from EPA/GRI (1996) of 78.8 percent, the corresponding amount of CO₂ emissions from the production sector can be estimated. Each sector of the natural gas system has varying CO₂ contents, similar to the way the CH₄ content varies among the sectors. Table A-131 shows the CO₂ content for the different well types in the production sector of the natural gas system. In the estimation of CO₂ emissions from the production sector, the production sector CH₄ emission factors were used as a basis to estimate CO₂ emissions; however, they were converted to CO₂ emission factors by multiplication by a conversion factor. This conversion factor is the ratio of CO₂ content in the gas stream (in this case the production concentrations provided in Table A-131) to the corresponding CH₄ content of the same gas stream. The three exceptions to this methodology are CO₂ emissions from flares, acid gas removal units, and condensate tanks. In the case of flare emissions, a direct CO₂ emission factor from EIA (1996) was used. This emission factor was applied to the portion of offshore gas that is not vented and all of the gas reported as vented and flared onshore by EIA. The amount of CO₂ emissions from an acid gas unit in a processing plant is equal to the difference in CO₂ concentrations between produced natural gas and pipeline quality gas applied to the throughput of the plant. This methodology was applied to the natural gas throughput using national average CO₂ concentrations in produced gas (3.45 percent) and transmission quality gas (1 percent). For condensate tanks, a series of E&P Tank (EPA

1999) simulations provide the total CO₂ vented per barrel of condensate throughput from fixed roof tank flash gas for condensate gravities of API 45 degree and higher. The ratios of emissions to throughput were used to estimate the CO₂ emission factor for condensate passing through fixed roof tanks. The detailed source emission estimates for CH₄ and CO₂ from the production sector are presented in Table A-127 and

Table A-132, respectively.

In the processing sector, the CO₂ content of the natural gas remains the same as the CO₂ content in the production sector for the equipment upstream of the acid gas removal unit because produced natural gas is usually only minimally treated after being produced and then transported to natural gas processing plants via gathering pipelines. The CO₂ content in gas for the remaining equipment that is downstream of the acid gas removal is the same as in pipeline quality gas. The EPA/GRI study estimates the average CH₄ content of natural gas in the processing sector to be 87 percent CH₄. Consequently, the processing sector CH₄ emission factors were proportioned to reflect the CO₂ content of either produced natural gas or pipeline quality gas using the same methodology as the production sector. The detailed source emission estimates for CH₄ and CO₂ from the processing sector are presented in Table A-128 and Table A-133, respectively.

For the transmission sector, CO₂ content in natural gas transmission pipelines was estimated for the top twenty transmission pipeline companies in the United States (separate analyses identified the top twenty companies based on gas throughput and total pipeline miles). The weighted average CO₂ content in the transmission pipeline quality gas in both cases—total gas throughput and total miles of pipeline—was estimated to be about 1 percent. To estimate the CO₂ emissions for the transmission sector the CH₄ emission factors were proportioned from the 93.4 percent CH₄ reported in EPA/GRI (1996) to reflect the 1 percent CO₂ content found in transmission quality natural gas. The detailed source emissions estimates for CH₄ and CO₂ for the transmission sector are presented in Table A-129 and Table A-134, respectively.

The natural gas in the distribution sector of the system has the same characteristics as the natural gas in the transmission sector. The CH₄ content (93.4 percent) and CO₂ content (1 percent) are identical due to the absence of any further treatment between sector boundaries. Thus, the CH₄ emissions factors were converted to CO₂ emission factors using the same methodology as discussed for the transmission sector. The detailed source emission estimates for CH₄ and CO₂ for the distribution sector are presented in Table A-130 and Table A-135, respectively.

Because Partners report only CH₄ emission reductions to the Natural Gas STAR Program, there was no need to adjust for the Natural Gas STAR program in the CO₂ emissions estimates for any of the sectors in the natural gas system. The impact of regulations, such as NESHAP, on CO₂ emission reductions are not currently addressed in the CO₂ emission estimates.

Table A-120: 2009 Data and CH₄ Emissions (Mg) for the Natural Gas Production Stage

Activity	2009 EPA Inventory Values		
	Activity Data	Emission Factor	Emissions (Mg)
North East			
Gas Wells			
NE - Associated Gas Wells ^{1,2}	46,914 wells	NA	NA
NE - Non-associated Gas Wells (less Unconventional)	183,834 wells	7.59 scfd/well	9,804.22
NE - Unconventional Gas Wells ³	0 wells	NE scfd/well	0
Field Separation Equipment			
Heaters	368 heaters	15.13 scfd/heater	39.10
Separators	130,522 separators	0.96 scfd/sep	877.52
Dehydrators	1,213 dehydrators	23.15 scfd/dehy	197.33
Meters/Piping	9,230 meters	9.59 scfd/meter	622.25
Gathering Compressors			
Small Reciprocating Compressors	184 compressors	284.95 scfd/comp	368.26
Large Reciprocating Compressors	24 compressors	16,182 scfd/comp	2,730.18
Large Reciprocating Stations	3 stations	8,776.43 scfd/station	185.09
Pipeline Leaks	87,900 miles	56.57 scfd/mile	34,954.19
Drilling and Well Completion			
Completion Flaring	266 completions/yr	780 scf/comp	4.00
Unconventional Gas Well Completions	0 completions/yr	7,694,435 scf/comp	0
Well Drilling	8,170 Wells	2,706 scf/well	425.89
Normal Operations			
Pneumatic Device Vents	89,343 controllers	367 scfd/device	230,608.23
Chemical Injection Pumps	919 active pumps	264 scfd/pump	1,705.46

Activity	2009 EPA Inventory Values		
	Activity Data	Emission Factor	Emissions (Mg)
Kimray Pumps	354,971 MMscf/yr	1,056 scf/MMscf	7,217.80
Dehydrator Vents	398,396 MMscf/yr	293.3 scf/MMscf	2,250.58
Condensate Tank Vents			
Condensate Tanks without Control Devices	0 MMbbl/yr	21.87 scf/bbl	0
Condensate Tanks with Control Devices	0 MMbbl/yr	4.37 scf/bbl	0
Compressor Exhaust Vented			
Gas Engines	0 MMHPhr	0.26 scf/HPhr	0
Well Workovers			
Conventional Gas Wells	7,997 workovers/yr	2,612 scf/w.o.	402.26
Unconventional Gas Wells	0 workovers/yr	7,694,435 scf/w.o.	0
Well Clean Ups (LP Gas Wells)	75,923 LP Gas Wells	1,361,786 scfy/LP well	1,991,319.86
Blowdowns			
Vessel BD	132,103 vessels	83 scfy/vessel	211.21
Pipeline BD	87,900 miles (gathering)	329 scfy/mile	556.73
Compressor BD	184 compressors	4,016 scfy/comp	14.22
Compressor Starts	184 compressors	8,985 scfy/comp	31.81
Upsets			
Pressure Relief Valves	352,630 PRV	36 scfy/PRV	245.75
Mishaps	21,975 miles	712 scf/mile	301.34
Midcontinent			
Gas Wells			
MC - Associated Gas Wells ^{1,2}	72,935 wells	NA	NA
MC - Non-associated Gas Wells	73,913 wells	7.54 scfd/well	3,918.89
MC - Unconventional Gas Wells	13,277 wells	4.71 scfd/well	439.78
Field Separation Equipment			
Heaters	35,399 heaters	15.08 scfd/heater	3,753.52
Separators	37,928 separators	0.95 scfd/sep	254.26
Dehydrators	12,518 dehydrators	96.70 scfd/dehy	8,510.31
Meters/Piping	119,028 meters	9.56 scfd/meter	8,001.30
Gathering Compressors			
Small Reciprocating Compressors	9,852 compressors	284.13 scfd/comp	19,679.53
Large Reciprocating Compressors	16 compressors	16,135 scfd/comp	1,814.87
Large Reciprocating Stations	2 stations	8,751.13 scfd/station	123.04
Pipeline Leaks	68,424 miles	56.40 scfd/mile	27,130.93
Drilling and Well Completion			
Completion Flaring	126 completions/yr	778 scf/comp	1.89
Unconventional Gas Well Completions	575 completions/yr	7,672,247 scf/comp	84,966.30
Well Drilling	3,875 wells	2,699 scf/well	201.41
Normal Operations			
Pneumatic Device Vents	135,232 controllers	366 scfd/device	348,046.02
Chemical Injection Pumps	12,381 active pumps	263 scfd/pump	22,905.82
Kimray Pumps	3,664,068 MMscf/yr	1,053 scf/MMscf	74,288.52
Dehydrator Vents	4,112,309 MMscf/yr	292.5 scf/MMscf	23,163.89
Condensate Tank Vents			
Condensate Tanks without Control Devices	13 MMbbl/yr	302.75 scf/bbl	75,803.69
Condensate Tanks with Control Devices	13 MMbbl/yr	60.55 scf/bbl	15,160.74
Compressor Exhaust Vented			
Gas Engines	16,304 MMHPhr	0.25 scf/HPhr	79,973.26
Well Workovers			
Conventional Gas Wells	3,793 workovers/yr	2,604 scf/w.o.	190.24
Unconventional Gas Wells	1,328 workovers/yr	7,672,247 scf/w.o.	196,190.87
Well Clean Ups (LP Gas Wells)	30,526 LP Gas Wells	711,385 scfy/LP well	418,245.79
Blowdowns			
Vessel BD	85,845 vessels	83 scfy/vessel	136.85
Pipeline BD	68,424 miles (gathering)	328 scfy/mile	432.13
Compressor BD	9,852 compressors	4,005 scfy/comp	759.96
Compressor Starts	9,852 compressors	8,960 scfy/comp	1,700.15
Upsets			
Pressure Relief Valves	167,248 PRV	36 scfy/PRV	116.22
Mishaps	17,106 miles	710 scf/mile	233.90
Rocky Mountain			
Gas Wells			

Activity	2009 EPA Inventory Values		
	Activity Data	Emission Factor	Emissions (Mg)
RM - Associated Gas Wells ^{1,2}	14,948 wells	NA	NA
RM - Non-associated Gas Wells	75,418 wells	35.62 scfd/well	18,882.55
RM - Unconventional Gas Wells	23,417 wells	6.97 scfd/well	1,147.38
Field Separation Equipment			
Heaters	45,069 heaters	57.43 scfd/heater	18,196.66
Separators	49,319 separators	121.42 scfd/sep	42,097.53
Dehydrators	14,190 dehydrators	90.68 scfd/dehy	9,046.43
Meters/Piping	114,129 meters	52.65 scfd/meter	42,238.56
Gathering Compressors			
Small Reciprocating Compressors	10,971 compressors	266.44 scfd/comp	20,549.03
Large Reciprocating Compressors	32 compressors	15,131 scfd/comp	3,403.78
Large Reciprocating Stations	4 stations	8,206.34 scfd/station	230.76
Pipeline Leaks	125,062 miles	52.89 scfd/mile	46,501.51
Drilling and Well Completion			
Completion Flaring ¹	143 completions/yr	729 scf/comp	2.01
Unconventional Gas Well Completions	0 completions/yr	7,194,624 scf/comp	0
Well Drilling	4,393 wells	2,531 scf/well	214.10
Normal Operations			
Pneumatic Device Vents	144,695 controllers	343 scfd/device	349,219.02
Chemical Injection Pumps	17,593 active pumps	247 scfd/pump	30,521.75
Kimray Pumps	4,153,459 MMscf/yr	987 scf/MMscf	78,968.46
Dehydrator Vents	4,661,570 MMscf/yr	274.3 scf/MMscf	24,623.14
Condensate Tank Vents			
Condensate Tanks without Control Devices	12 MMbbl/yr	21.87 scf/bbl	5,054.59
Condensate Tanks with Control Devices	12 MMbbl/yr	4.37 scf/bbl	1,010.92
Compressor Exhaust Vented			
Gas Engines	18,481 MMHPhr	0.24 scf/HPhr	85,011.32
Well Workovers			
Conventional Gas Wells	4,299 workovers/yr	2,442 scf/w.o.	202.20
Unconventional Gas Wells	2,342 workovers/yr	7,194,624 scf/w.o.	324,485.75
Well Clean Ups (LP Gas Wells)	31,148 LP Gas Wells	710,583 scfy/LP well	426,283.58
Blowdowns			
Vessel BD	108,578 vessels	78 scfy/vessel	162.32
Pipeline BD	125,062 miles (gathering)	307 scfy/mile	740.65
Compressor BD	10,971 compressors	3,756 scfy/comp	793.54
Compressor Starts	10,971 compressors	8,402 scfy/comp	1,775.27
Upsets			
Pressure Relief Valves	189,586 PRV	34 scfy/PRV	123.54
Mishaps	31,266 miles	666 scf/mile	400.89
Coal Bed Methane			
Powder River	gal produced 28,577,932,572 water	Gg/gallon water 2.002E-09 drainage	57,494.47
South West			
Gas Wells			
SW - Associated Gas Wells ^{1,2}	56,810 wells	NA	NA
SW - Non-associated Gas Wells	27,802 wells	37.24 scfd/well	7,278.09
SW - Unconventional Gas Wells	13,740 wells	36.52 scfd/well	3,527.07
Field Separation Equipment			
Heaters	11,258 heaters	58.97 scfd/heater	4,667.26
Separators	23,347 separators	124.68 scfd/sep	20,462.48
Dehydrators	5,964 dehydrators	93.12 scfd/dehy	3,904.30
Meters/Piping	50,678 meters	54.06 scfd/meter	19,258.70
Gathering Compressors			
Small Reciprocating Compressors	5,650 compressors	273.59 scfd/comp	10,866.09
Large Reciprocating Compressors	16 compressors	15,536 scfd/comp	1,747.51
Large Reciprocating Stations	2 stations	8,426.34 scfd/station	118.47
Pipeline Leaks	60,894 miles	54.31 scfd/mile	23,249.07
Drilling and Well Completion			
Completion Flaring	60 completions/yr	749 scf/comp	0.87
Unconventional Gas Well Completions	3,594 completions/yr	7,387,499 scf/comp	511,365.92
Well Drilling	1,846 wells	2,598 scf/well	92.40
Normal Operations			
Pneumatic Device Vents	55,168 controllers	353 scfd/device	136,716.45
Chemical Injection Pumps	2,534 active pumps	253 scfd/pump	4,514.24

Activity	2009 EPA Inventory Values		
	Activity Data	Emission Factor	Emissions (Mg)
Kimray Pumps	1,745,768 MMscf/yr	1,014 scf/MMscf	34,081.57
Dehydrator Vents	1,959,335 MMscf/yr	281.6 scf/MMscf	10,626.97
Condensate Tank Vents			
Condensate Tanks without Control Devices	7 MMbbl/yr	302.75 scf/bbl	40,817.37
Condensate Tanks with Control Devices	7 MMbbl/yr	60.55 scf/bbl	8,163.47
Compressor Exhaust Vented			
Gas Engines	7,768 MMHPhr	0.25 scf/HPhr	36,689.57
Well Workovers			
Conventional Gas Wells	1,807 workovers/yr	2,507 scf/w.o.	87.27
Unconventional Gas Wells	1,374 workovers/yr	7,387,499 scf/w.o.	195,497.16
Well Clean Ups (LP Gas Wells)	11,482 LP Gas Wells	864,974 scfy/LP well	191,288.32
Blowdowns			
Vessel BD	40,569 vessels	80 scfy/vessel	62.27
Pipeline BD	60,894 miles (gathering)	316 scfy/mile	370.30
Compressor BD	5,650 compressors	3,856 scfy/comp	419.62
Compressor Starts	5,650 compressors	8,627 scfy/comp	938.74
Upsets			
Pressure Relief Valves	79,686 PRV	35 scfy/PRV	53.32
Mishaps	15,224 miles	684 scf/mile	200.44
West Coast			
Gas Wells			
WC - Associated Gas Wells ^{1,2}	24,548 wells	NA	NA
WC - Non-associated Gas Wells	1,786 wells	42.49 scfd/well	533.50
WC - Unconventional Gas Wells ³	0 wells	NE	0
Field Separation Equipment			
Heaters	1,786 heaters	67.29 scfd/heater	844.89
Separators	1,304 separators	142.27 scfd/sep	1,303.93
Dehydrators	256 dehydrators	106.25 scfd/dehy	191.54
Meters/Piping	3,364 meters	61.68 scfd/meter	1,458.59
Gathering Compressors			
Small Reciprocating Compressors	2,074 compressors	312.19 scfd/comp	4,550.68
Large Reciprocating Compressors	8 compressors	17,728 scfd/comp	997.03
Large Reciprocating Stations	1 stations	9,615.15 scfd/station	67.59
Pipeline Leaks	16,367 miles	61.97 scfd/mile	7,130.46
Drilling and Well Completion			
Completion Flaring	3 completions/yr	855 scf/comp	0.04
Unconventional Gas Well Completions	0 completions/yr	8,429,754 scf/comp	0
Well Drilling	79 wells	2,965 scf/well	4.53
Normal Operations			
Pneumatic Device Vents	1,790 controllers	402 scfd/device	5,060.58
Chemical Injection Pumps	1,213 active pumps	289 scfd/pump	2,465.10
Kimray Pumps	75,055 MMscf/yr	1,157 scf/MMscf	1,671.97
Dehydrator Vents	84,237 MMscf/yr	321.3 scf/MMscf	521.34
Condensate Tank Vents			
Condensate Tanks without Control Devices	0 MMbbl/yr	21.87 scf/bbl	0
Condensate Tanks with Control Devices	0 MMbbl/yr	4.37 scf/bbl	0
Compressor Exhaust Vented			
Gas Engines	334 MMHPhr	0.28 scf/HPhr	1,799.92
Well Workovers			
Conventional Gas Wells	78 workovers/yr	2,861 scf/w.o.	4.30
Unconventional Gas Wells	0 workovers/yr	8,429,754 scf/w.o.	0
Well Clean Ups (LP Gas Wells)	738 LP Gas Wells	1,491,925 scfy/LP well	21,195.07
Blowdowns			
Vessel BD	3,346 vessels	91 scfy/vessel	5.86
Pipeline BD	16,367 miles (gathering)	360 scfy/mile	113.57
Compressor BD	2,074 compressors	4,400 scfy/comp	175.73
Compressor Starts	2,074 compressors	9,844 scfy/comp	393.14
Upsets			
Pressure Relief Valves	3,426 PRV	40 scfy/PRV	2.62
Mishaps	4,092 miles	780 scf/mile	61.48
Gulf Coast			
Gas Wells			

Activity	2009 EPA Inventory Values		
	Activity Data	Emission Factor	Emissions (Mg)
GC - Associated Gas Wells ^{1,2}	27,134 wells	NA	NA
GC - Non-associated Gas Wells	75,046 wells	40.97 scfd/well	21,613.40
GC - Unconventional Gas Wells ³	0 wells	NE scfd/well	0
Field Separation Equipment			
Heaters	16,810 heaters	64.88 scfd/heater	7,667.69
Separators	49,381 separators	137.17 scfd/sep	47,618.06
Dehydrators	10,775 dehydrators	102.45 scfd/dehy	7,760.09
Meters/Piping	87,505 meters	59.48 scfd/meter	36,586.28
Gathering Compressors			
Small Reciprocating Compressors	6,079 compressors	301.01 scfd/comp	12,863.02
Large Reciprocating Compressors	24 compressors	17,094 scfd/comp	2,884.00
Large Reciprocating Stations	3 stations	9,270.90 scfd/station	195.52
Pipeline Leaks	98,419 miles	59.75 scfd/mile	41,342.16
Drilling and Well Completion			
Completion Flaring	109 completions/yr	824 scf/comp	1.73
Unconventional Gas Well Completions	0 completions/yr	8,127,942 scf/comp	0
Well Drilling	3,335 wells	2,859 scf/well	183.66
Normal Operations			
Pneumatic Device Vents	52,157 controllers	388 scfd/device	142,210.39
Chemical Injection Pumps	2,477 active pumps	279 scfd/pump	4,853.92
Kimray Pumps	3,153,749 MMscf/yr	1,115 scf/MMscf	67,739.71
Dehydrator Vents	3,539,561 MMscf/yr	309.8 scf/MMscf	21,121.91
Condensate Tank Vents			
Condensate Tanks without Control Devices	33 MMbbl/yr	21.87 scf/bbl	13,900.13
Condensate Tanks with Control Devices	33 MMbbl/yr	4.37 scf/bbl	2,780.03
Compressor Exhaust Vented			
Gas Engines	14,033 MMHPhr	0.27 scf/HPhr	72,923.33
Well Workovers			
Conventional Gas Wells	3,265 workovers/yr	2,759 scf/w.o.	173.49
Unconventional Gas Wells	0 workovers/yr	8,127,942 scf/w.o.	0
Well Clean Ups (LP Gas Wells)	30,994 LP Gas Wells	2,522,975 scfy/LP well	1,506,084
Blowdowns			
Vessel BD	76,966 vessels	88 scfy/vessel	129.99
Pipeline BD	98,419 miles (gathering)	347 scfy/mile	658.48
Compressor BD	6,079 compressors	4,243 scfy/comp	496.73
Compressor Starts	6,079 compressors	9,492 scfy/comp	1,111.26
Upsets			
Pressure Relief Valves	143,954 PRV	38 scfy/PRV	105.98
Mishaps	24,605 miles	752 scf/mile	356.41
Coal Bed Methane			
Black Warrior	5,026 wells	0.0023 Gg/well	11,693.03
Offshore Platforms			
Shallow water Gas Platforms (GoM and Pacific)	Shallow water 2,072 gas platforms	19,178 scfd/platform	279,356
Deepwater Gas Platforms (GoM and Pacific)	Deepwater gas 40 platforms	79,452 scfd/platform	22,389

¹ Emissions from oil wells that produce associated gas are estimated in the Petroleum Systems model. Here the oil wells count is used as a driver only.

² NA = not applicable; i.e. this data is not applicable for the Natural Gas systems model.

³ NE = not estimate; some emission factors were not estimated because there is no corresponding activity for that region.

Table A-121: 2009 Data and CH₄ Emissions (Mg) for the Natural Gas Processing Stage

Activity	2009 EPA Inventory Values			
	Activity Data		Emission Factor	Emissions(Mg)
Plants	578	plants	7,906 scfd/plant	32,124
Recip. Compressors	4,876	compressors	11,196 scfd/comp	383,767
Centrifugal Compressors (wet seals)	646	compressors	51,370 scfd/comp	233,371
Centrifugal Compressors (dry seals)	140	compressors	25,189 scfd/comp	24,725
Compressor Exhaust				
Gas Engines	35,030	MMHPhr	0.24 scf/HPhr	161,923
Gas Turbines	41,535	MMHPhr	0.01 scf/HPhr	4,560

	2009 EPA Inventory Values				
Activity	Activity Data		Emission Factor		Emissions(Mg)
AGR Vents	293	AGR units	6,083	scfd/AGR	12,527
Kimray Pumps	1,269,018	MMscf/yr	178	scf/MMscf	4,344
Dehydrator Vents	11,432,591	MMscf/yr	122	scf/MMscf	26,764
Pneumatic Devices	578	gas plants	164,721	scfy/plant	1,834
Blowdowns/Venting	578	gas plants	4,060	Mscfy/plant	45,197

Table A-122: 2009 Data and CH₄ Emissions (Mg) for the Natural Gas Transmission Stage

	2009 EPA Inventory Values				
Activity	Activity Data		Emission Factor		Emissions(Mg)
Pipeline Leaks	301,546	miles	1.55	Scfd/ mile	3,294
<i>Compressor Stations (Transmission)</i>					
Station	1,790	Stations	8,778	Scfd/station	110,458
Recip Compressor	7,197	Compressors	15,205	Scfd/ comp	769,264
Centrifugal Compressor (wet seals)	667	Compressors	50,222	Scfd/ comp	235,445
Centrifugal Compressor (dry seals)	55	Compressors	32,208	Scfd/ comp	12,436
<i>Compressor Stations (Storage)</i>					
Station	392	Stations	21,507	Scfd/ comp	59,230
Recip Compressor	1,152	Compressors	21,116	Scfd/ comp	171,007
Centrifugal Compressor (wet seals)	84	Compressors	45,441	Scfd/ comp	26,819
Centrifugal Compressor (dry seals)	29	Compressors	31,989	Scfd/ comp	6,532
Wells (Storage)	18,267	Wells	115	Scfd/ comp	14,704
M&R (Trans. Co. Interconnect)	2,684	Stations	3,984	scfd/station	75,180
M&R (Farm Taps + Direct Sales)	79,592	Stations	31	scfd/station	17,457
Dehydrator vents (Transmission)	1,141,012	MMscf/Year	94	scf/MMscf	2,060
Dehydrator vents (Storage)	2,029,824	MMscf/Year	117	scf/MMscf	4,581
<i>Compressor Exhaust</i>					
Engines (Transmission)	45,546	MMHPhr	0.24	scf/HPhr	210,531
Turbines (Transmission)	10,868	MMHPhr	0.01	scf/HPhr	1,193
Engines (Storage)	4,995	MMHPhr	0.24	scf/HPhr	23,091
Turbines (Storage)	1,755	MMHPhr	0.01	scf/HPhr	193
Generators (Engines)	2,229	MMHPhr	0.24	scf/HPhr	10,302
Generators (Turbines)	26	MMHPhr	0.01	scf/HPhr	3
<i>Pneumatic Devices Trans + Stor</i>					
Pneumatic Devices Trans	70,458	Devices	162,197	Scfy/device	220,104
Pneumatic Devices Storage	15,421	Devices	162,197	Scfy/device	48,174
<i>Routine Maintenance/Upsets</i>					
Pipeline venting	301,546	Miles	32	Mscfy/mile	183,816
<i>Station Venting Trans + Storage</i>					
Station Venting Transmission	1,790	Compressor Stations	4,359	Mscfy/station	150,278
Station Venting Storage	392	Compressor Stations	4,359	Mscfy/station	32,890
LNG Storage					
LNG Stations	70	Stations	21,507	scfd/station	10,623
LNG Reciprocating Compressors	270	Compressors	21,116	scfd/comp	40,147
LNG Centrifugal Compressors	64	Compressors	30,573	scfd/comp	13,766
<i>LNG Compressor Exhaust</i>					
LNG Engines	718	MMHPhr	0.24	scf/HPhr	3,320
LNG Turbines	113	MMHPhr	0.01	scf/HPhr	12
LNG Station Venting	70	Stations	4,359	Mscfy/station	5,899
LNG Import Terminals					
LNG Stations	9	Stations	21,507	scfd/station	1,376
LNG Reciprocating Compressors	44	Compressors	21,116	scfd/comp	6,561
LNG Centrifugal Compressors	8	Compressors	30,573	scfd/comp	1,676
<i>LNG Compressor Exhaust</i>					
LNG Engines	1,904	MMHPhr	0.24	scf/HPhr	8,802
LNG Turbines	461	MMHPhr	0.01	scf/HPhr	51

Activity	2009 EPA Inventory Values			
	Activity Data	Emission Factor	Emissions(Mg)	
LNG Station Venting	9 Stations	4,359 Mscfy/station	764	

Table A-123: 2009 Data and CH₄ Emissions (Mg) for the Natural Gas Distribution Stage

Activity	2009 EPA Inventory Values				
	Activity Data		Emission Factor		Emissions(Mg)
<i>Pipeline Leaks</i>					
Mains—Cast Iron	35,429	miles	239	Mscf/mile-yr	162,880
Mains—Unprotected steel	67,331	miles	110	Mscf/mile-yr	142,893
Mains—Protected steel	484,337	miles	3	Mscf/mile-yr	28,609
Mains—Plastic	621,404	miles	10	Mscf/mile-yr	118,605
Services—Unprotected steel	5,218,497	services	2	Mscf/service	170,941
Services Protected steel	15,389,666	services	0.2	Mscf/service	52,314
Services—Plastic	42,601,520	services	0.01	Mscf/service	7,629
Services—Copper	1,083,539	services	0.3	Mscf/service	5,308
<i>Meter/Regulator (City Gates)</i>					
M&R >300	3,945	stations	180	scfh/station	119,685
M&R 100-300	14,398	stations	96	scfh/station	232,233
M&R <100	7,696	stations	4	scfh/station	5,596
Reg >300	4,314	stations	162	scfh/station	117,825
R-Vault >300	2,533	stations	1	scfh/station	556
Reg 100-300	13,049	stations	41	scfh/station	89,166
R-Vault 100-300	5,863	stations	0.2	scfh/station	178
Reg 40-100	39,159	stations	1	scfh/station	6,871
R-Vault 40-100	34,726	stations	0.1	scfh/station	507
Reg <40	16,604	stations	0.1	scfh/station	373
<i>Customer Meters</i>					
Residential	40,646,493	outdr meters	143	scfy/meter	112,160
Commercial/Industry	4,121,452	meters	48	scfy/meter	3,802
<i>Routine Maintenance</i>					
Pressure Relief Valve Releases	1,208,501	mile main	0.1	Mscf/mile	1,164
Pipeline Blowdown	1,316,917	miles	0.1	Mscfy/mile	2,587
<i>Upsets</i>					
Mishaps (Dig-ins)	1,316,917	miles	2	Mscfy/mile	40,328

Table A-124: Key Activity Data Drivers

Variable	Units	1990	1992	1995	2000	2005	2006	2007	2008	2009
Transmission Pipelines Length	miles	291,990	291,468	296,947	298,957	300,663	300,458	301,180	303,388	301,546
Wells										
NE—Associated Gas Wells*	# wells	68,261	67,489	66,102	58,671	46,471	47,034	46,646	47,088	46,914
NE—Non-associated Gas Wells*	# wells	124,241	129,157	129,789	143,922	158,238	164,322	172,493	174,682	183,834
MC—Associated Gas Wells*	# wells	64,379	70,640	72,483	67,880	65,652	65,903	69,234	72,622	72,935
MC—Non-associated Gas Wells*	# wells	53,940	59,358	65,585	51,217	71,379	73,914	80,650	82,705	87,190
RM—Associated Gas Wells*	# wells	13,749	14,142	13,745	12,328	13,327	13,437	12,021	14,763	14,948
RM—Non-associated Gas Wells*	# wells	24,339	26,323	32,668	64,539	72,438	75,170	70,532	91,395	98,835
SW—Associated Gas Wells*	# wells	69,339	68,130	59,954	54,830	55,502	54,550	55,251	56,787	56,810
SW—Non-associated Gas Wells*	# wells	24,217	22,609	27,392	32,346	34,194	35,417	38,049	40,176	41,542
WC—Associated Gas Wells*	# wells	20,672	19,819	19,109	20,494	21,562	22,189	22,110	24,271	24,548
WC—Non-associated Gas Wells*	# wells	1,292	1,254	1,114	1,338	1,424	1,503	1,506	1,693	1,786
GC—Associated Gas Wells*	# wells	36,279	35,376	34,792	32,497	28,090	27,319	26,234	27,661	27,134
GC—Non-associated Gas Wells*	# wells	41,753	37,307	41,978	48,316	57,600	60,715	68,188	72,047	75,046
Platforms										
Gulf of Mexico and Pacific OCS Off-shore Platforms	# platforms	3,943	3,966	3,981	4,020	3,911	3,914	3,839	3,761	3,583
GoM and Pacific OCS Deep Water Platforms	# platforms	17	19	23	38	59	67	63	65	68
Gas Plants	# gas plants	761	732	675	585	566	571	574	577	578
Distribution Services	# of services	47,883,083	49,142,008	54,644,033	56,761,042	58,556,335	62,255,435	63,524,388	63,559,296	64,293,222
Steel—Unprotected	# of services	7,633,526	7,138,563	6,151,653	5,675,520	5,308,375	5,642,470	5,448,804	5,388,623	5,218,497
Steel—Protected	# of services	19,781,581	19,742,086	21,002,455	17,855,560	15,883,423	15,732,037	15,756,048	15,456,866	15,389,666
Plastic	# of services	18,879,865	20,692,674	26,044,545	31,795,871	36,152,277	39,632,313	41,092,515	41,573,069	42,601,520
Copper	# of services	1,588,111	1,568,685	1,445,380	1,434,091	1,212,260	1,248,615	1,227,021	1,140,738	1,083,539
Distribution Mains	miles	944,157	888,925	1,001,706	1,048,485	1,093,909	1,209,419	1,198,585	1,188,714	1,208,501
Cast Iron	miles	58,292	52,917	50,625	44,750	37,371	36,977	37,669	36,462	35,429
Steel—Unprotected	miles	108,941	99,619	94,058	82,800	69,291	71,738	69,525	69,374	67,331
Steel—Protected	miles	465,538	469,106	503,288	471,510	461,459	481,811	489,815	479,502	484,337
Plastic	miles	311,386	267,283	353,735	449,425	525,788	618,893	601,575	603,377	621,404

* NEMS (National Energy Modeling System) projects the production, imports, conversion, consumption, and prices of energy, subject to assumptions on macroeconomic and financial factors, world energy markets, resource availability and costs, behavioral and technological choice criteria, cost and performance characteristics of energy technologies, and demographics

Table A-125: CH₄ Reductions Derived from the Natural Gas STAR Program (Gg)

Process	1992*	1995	2000	2005	2006	2007	2008	2009
Production	0	75	318	1,425	1,471	1,863	2,239	1,993
Processing	0	5	23	129	140	139	145	83
Transmission and Storage	0	121	258	500	480	454	440	367
Distribution	0	19	27	35	48	35	28	41
Total	0	220	626	2,090	2,138	2,492	2,852	2,484

*Reductions are relative to 1992; therefore, there are zero reductions in 1992.

Note: These reductions will not match the Natural Gas STAR program reductions. These numbers are adjusted for reductions prior to the 1992 base year, and do not include a sunset period. Totals may not sum due to independent rounding.

Table A-126: CH₄ Reductions Derived from Regulations (Gg)

Process	1990	1995	2000	2005	2006	2007	2008	2009
Production	9.8	24.1	303.6	278.4	1,572	783.5	966.5	733.7
Processing	NA	NA	12.9	12.1	12.4	13.0	13.7	14.2
Transmission and Storage	NA	NA	NA	NA	NA	NA	NA	NA
Distribution	NA	NA	NA	NA	NA	NA	NA	NA
Total	9.8	24.1	316.5	290.5	1,584	796.5	980.2	747.9

NA Not applicable

Note: NESHAP regulations went into effect in 1999. Totals may not sum due to independent rounding.

Table A-127: CH₄ Emission Estimates from the Natural Gas Production Stage Excluding Reductions from the Natural Gas STAR Program and Regulations (Gg)

Activity	1990	1992	1995	2000	2005	2006	2007	2008	2009
Normal Fugitives									
Associated Gas Wells									
Non-Associated Gas Wells (less conventional)	30.82	31.68	37.42	48.05	52.88	50.86	52.48	58.63	62.03
Unconventional Gas Wells	0.01	0.02	0.04	0.26	0.53	1.32	1.53	1.67	1.59
Field Separation Equipment									
Heaters	12.57	13.28	16.48	23.56	26.90	28.01	28.36	33.09	35.17
Separators	43.83	44.16	54.79	76.51	86.43	90.24	94.09	106.73	112.61
Dehydrators	14.75	15.76	17.89	20.77	23.95	24.93	26.17	28.07	29.61
Meter/ Piping	43.61	44.95	54.89	73.80	83.74	87.18	90.23	102.50	108.17
Gathering Compressors									
Small Reciprocating Comp.	30.22	32.15	38.27	45.57	53.85	56.10	58.49	65.19	68.88
Large Reciprocating Comp.	7.50	8.56	9.80	11.70	12.60	12.59	12.71	13.58	13.58
Stations	0.51	0.58	0.66	0.79	0.85	0.85	0.86	0.92	0.92
Pipeline Leaks	98.03	102.22	114.49	133.58	148.45	152.97	160.02	172.60	180.31
Vented and Combusted Drilling and Well Completion									
Completion Flaring	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Unconventional Gas Well Completions	16.48	23.53	31.66	422.38	203.69	2,502.62	855.93	1,089.76	596.33
Well Drilling	0.74	0.54	0.53	1.01	1.63	1.85	1.90	1.93	1.12
Coal Bed Methane									
Powder River	0.04	0.47	1.48	28.76	46.38	56.38	54.60	57.58	57.49
Black Warrior	2.72	4.84	6.25	6.82	9.88	10.45	11.09	11.69	11.69
Normal Operations									
Pneumatic Device Vents	569.76	607.88	697.61	810.83	954.88	991.35	1,043.32	1,145.65	1,211.86
Chemical Injection Pumps	26.89	29.38	35.04	43.44	51.88	53.93	54.93	62.93	66.97
Kimray Pumps	131.82	140.65	159.45	185.01	213.32	222.04	233.36	250.28	263.97
Dehydrator Vents	41.10	43.86	49.72	57.69	66.52	69.24	72.76	78.04	82.31
Condensate Tank Vents									

Activity	1990	1992	1995	2000	2005	2006	2007	2008	2009
Condensate Tanks without Control Device	77.69	59.56	58.09	67.47	99.33	109.76	114.96	135.58	135.58
Condensate Tanks with Control Device	15.54	11.91	11.62	13.49	19.87	21.95	22.99	27.12	27.12
Compressor Exhaust Vented									
Gas Engines	119.06	125.48	151.43	180.03	215.10	224.16	235.19	261.65	276.40
Well Workovers									
Conventional Gas Wells	0.56	0.58	0.64	0.73	0.84	0.87	0.94	1.00	1.06
Unconventional Gas Wells	2.92	7.16	16.07	98.40	241.50	492.00	574.10	685.67	716.17
Well Clean Ups (LP Gas Wells)	2,651.65	2,699.26	2,931.40	3,330.18	3,755.97	3,804.83	4,134.53	4,333.13	4,554.42
Blowdowns									
Vessel BD	0.36	0.38	0.42	0.49	0.56	0.58	0.62	0.67	0.71
Pipeline BD	1.56	1.63	1.82	2.13	2.36	2.44	2.55	2.75	2.87
Compressor BD	1.17	1.24	1.48	1.76	2.08	2.17	2.26	2.52	2.66
Compressor Starts	2.61	2.78	3.31	3.94	4.65	4.85	5.05	5.63	5.95
Upsets									
Pressure Relief									
Valves	0.34	0.35	0.39	0.45	0.51	0.53	0.57	0.61	0.65
Mishaps	0.85	0.88	0.99	1.15	1.28	1.32	1.38	1.49	1.55
Offshore									
Offshore water Gas Platforms (GoM & Pacific)	290.64	298.00	307.56	324.06	321.98	321.51	305.25	298.98	279.36
Deepwater Gas Platforms (GoM & Pacific)	5.21	5.94	7.40	12.81	20.43	23.20	21.10	21.78	22.39
Total	4,242	4,360	4,819	6,028	6,725	9,423	8,274	9,059	8,931

Note: Totals may not sum due to independent rounding.

Table A-128: CH₄ Emission Estimates from the Natural Gas Processing Plants Excluding Reductions from the Natural Gas STAR Program and Regulations (Gg)

Activity	1990	1992	1995	2000	2005	2006	2007	2008	2009
Normal Fugitives									
Plants	42.30	40.68	37.52	32.51	31.46	31.74	31.90	32.07	32.12
Reciprocating									
Compressors	324.94	324.74	338.42	349.51	327.87	337.12	351.55	371.25	383.77
Centrifugal Compressors (wet seals)	240.29	240.15	248.60	251.32	229.24	229.92	230.99	232.45	233.37
Centrifugal Compressors (dry seals)	0.00	0.00	0.81	3.50	6.48	9.50	14.21	20.64	24.73
Vented and Combusted									
Normal Operations									
Compressor Exhaust									
Gas Engines	137.10	137.02	142.79	147.47	138.34	142.24	148.33	156.64	161.92
Gas Turbines	3.86	3.86	4.02	4.15	3.90	4.01	4.18	4.41	4.56
AGR Vents	16.49	15.87	14.63	12.68	12.27	12.38	12.44	12.51	12.53
Kimray Pumps	3.68	3.68	3.83	3.96	3.71	3.82	3.98	4.20	4.34
Dehydrator Vents	22.66	22.65	23.60	24.38	22.87	23.51	24.52	25.89	26.76
Pneumatic Devices	2.41	2.32	2.14	1.86	1.80	1.81	1.82	1.83	1.83
Routine Maintenance									
Blowdowns/Venting	59.51	57.24	52.78	45.74	44.26	44.65	44.88	45.12	45.20
Total	853.24	848.20	869.16	877.08	822.18	840.69	868.81	907.01	931.14

Note: Totals may not sum due to independent rounding.

Table A-129: CH₄ Emission Estimates from the Natural Gas Transmission and Storage Excluding Reductions from the Natural Gas STAR Program and Regulations (Gg)

Activity	1990	1992	1995	2000	2005	2006	2007	2008	2009
Fugitives									
Pipelines Leaks	3.19	3.18	3.24	3.27	3.28	3.28	3.29	3.31	3.29
Compressor Stations (Transmission)									
Station	106.96	106.77	108.77	109.51	110.13	110.06	110.32	111.13	110.46
Recip Compressor	744.89	743.55	757.53	762.66	767.01	766.49	768.33	773.96	769.26
Centrifugal Compressor (wet seals)	246.76	246.32	249.68	245.59	236.93	236.75	236.81	237.00	235.44
Centrifugal Compressor (dry seals)	0.00	0.00	0.81	4.53	11.01	11.01	11.36	12.44	12.44
Compressor Stations (Storage)									
Station	54.64	58.36	60.35	62.17	60.06	54.36	58.76	60.62	59.23
Recip Compressor	157.80	168.48	174.27	179.62	173.53	157.05	169.67	175.16	171.01
Centrifugal Compressor (wet seals)	33.22	35.46	36.55	34.41	30.91	27.39	27.65	27.78	26.82
Centrifugal Compressor (dry seals)	0.00	0.00	0.13	2.54	4.10	4.10	5.72	6.53	6.53
Wells (Storage)	13.56	14.49	14.98	15.43	14.91	13.49	14.59	15.05	14.70
M&R (Trans. Co. Interconnect)	72.80	72.67	74.03	74.53	74.96	74.91	75.09	75.64	75.18
M&R (Farm Taps + Direct Sales)	16.90	16.87	17.19	17.31	17.41	17.39	17.44	17.56	17.46
Vented and Combusted									
Normal Operation									
Dehydrator Vents (Transmission)	1.99	1.99	2.03	2.04	2.05	2.05	2.06	2.07	2.06
Dehydrator Vents (Storage)	4.23	4.51	4.67	4.81	4.65	4.20	4.54	4.69	4.58
Compressor Exhaust									
Engines (Transmission)	176.92	186.65	204.91	215.30	203.10	200.09	213.12	214.32	210.53
Turbines (Transmission)	1.00	1.06	1.16	1.22	1.15	1.13	1.21	1.21	1.19
Engines (Storage)	21.30	22.75	23.53	24.24	23.41	21.19	22.91	23.63	23.09
Turbines (Storage)	0.18	0.19	0.20	0.20	0.20	0.18	0.19	0.20	0.19
Generators (Engines)	8.66	9.13	10.03	10.54	9.94	9.79	10.43	10.49	10.30
Generators (Turbines)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Pneumatic Devices									
Trans+Stor									
Pneumatic Devices Trans	213.13	212.75	216.75	218.21	219.46	219.31	219.84	221.45	220.10
Pneumatic Devices Storage	44.44	47.46	49.09	50.56	48.85	44.21	47.79	49.31	48.17
Routine Maintenance/Upsets									
Pipeline Venting	177.99	177.67	181.01	182.24	183.28	183.15	183.59	184.94	183.82
Station venting									
Trans+Storage									
Station Venting Transmission	145.52	145.26	147.99	148.99	149.84	149.74	150.10	151.20	150.28
Station Venting Storage	30.34	32.41	33.51	34.52	33.35	30.18	32.63	33.66	32.89
LNG Storage									
LNG Stations	9.24	9.45	9.77	10.30	10.62	10.62	10.62	10.62	10.62
LNG Reciprocating Compressors	34.50	35.37	36.67	38.84	40.15	40.15	40.15	40.15	40.15
LNG Centrifugal Compressors	11.78	12.09	12.55	13.31	13.77	13.77	13.77	13.77	13.77
LNG Compressor Exhaust									
LNG Engines	3.21	3.23	3.26	3.30	3.32	3.32	3.32	3.32	3.32
LNG Turbines	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
LNG Station Venting	5.13	5.25	5.43	5.72	5.90	5.90	5.90	5.90	5.90

Activity	1990	1992	1995	2000	2005	2006	2007	2008	2009
LNG Import Terminals									
LNG Stations	0.21	0.21	0.21	0.21	0.42	0.42	0.42	1.06	1.38
LNG Reciprocating Compressors	1.01	1.01	1.01	1.01	2.02	2.02	2.02	5.05	6.56
LNG Centrifugal Compressors	0.26	0.26	0.26	0.26	0.52	0.52	0.52	1.29	1.68
LNG Compressor Exhaust									
LNG Engines	1.74	0.96	0.49	4.41	12.18	11.28	14.81	6.91	8.80
LNG Turbines ¹	0.01	0.00	0.00	0.03	0.07	0.07	0.09	0.04	0.05
LNG Station Venting	0.12	0.12	0.12	0.12	0.24	0.24	0.24	0.59	0.76
Total	2,344	2,376	2,442	2,482	2,473	2,430	2,479	2,502	2,482

¹ Emissions are not actually 0, but too small to show at this level of precision.

Note: Totals may not sum due to independent rounding.

Table A-130: CH₄ Emission Estimates from the Natural Gas Distribution Stage Excluding Reductions from the Natural Gas STAR Program (Gg)

Activity	1990	1992	1995	2000	2005	2006	2007	2008	2009
Pipeline Leaks									
Mains—Cast Iron	267.99	243.28	232.74	205.73	171.81	170.00	173.18	167.63	162.88
Mains—Unprotected steel	231.20	211.42	199.62	175.72	147.05	152.25	147.55	147.23	142.89
Mains—Protected steel	27.50	27.71	29.73	27.85	27.26	28.46	28.93	28.32	28.61
Mains—Plastic	59.43	51.02	67.52	85.78	100.36	118.13	114.82	115.16	118.61
Services—Unprotected steel	250.05	233.84	201.51	185.91	173.89	184.83	178.49	176.51	170.94
Services Protected steel	67.24	67.11	71.39	60.70	53.99	53.48	53.56	52.54	52.31
Services—Plastic	3.38	3.71	4.66	5.69	6.47	7.10	7.36	7.44	7.63
Services—Copper	7.78	7.68	7.08	7.02	5.94	6.12	6.01	5.59	5.31
Meter/Regulator (City Gates)									
M&R >300	110.41	117.93	121.96	125.62	121.36	109.84	118.73	122.50	119.68
M&R 100-300	214.25	228.82	236.64	243.76	235.49	213.13	230.38	237.70	232.23
M&R <100	5.16	5.51	5.70	5.87	5.67	5.14	5.55	5.73	5.60
Reg >300	108.70	116.09	120.06	123.67	119.48	108.13	116.88	120.60	117.83
R-Vault >300	0.51	0.55	0.57	0.58	0.56	0.51	0.55	0.57	0.56
Reg 100-300	82.26	87.86	90.86	93.59	90.42	81.83	88.45	91.26	89.17
R-Vault 100-300	0.16	0.18	0.18	0.19	0.18	0.16	0.18	0.18	0.18
Reg 40-100	6.34	6.77	7.00	7.21	6.97	6.31	6.82	7.03	6.87
R-Vault 40-100	0.47	0.50	0.52	0.53	0.51	0.47	0.50	0.52	0.51
Reg <40	0.34	0.37	0.38	0.39	0.38	0.34	0.37	0.38	0.37
Customer Meters									
Residential	103.47	110.51	114.29	117.72	113.73	102.93	111.26	114.80	112.16
Commercial/Industry	3.97	4.25	4.78	4.66	3.95	3.85	3.98	4.03	3.80
Routine Maintenance									
Pressure Relief Valve Releases	0.91	0.86	0.96	1.01	1.05	1.16	1.15	1.14	1.16
Pipeline Blowdown	2.39	2.55	2.64	2.72	2.62	2.37	2.57	2.65	2.59
Upsets									
Mishaps (Dig-ins)	37.20	39.74	41.09	42.33	40.89	37.01	40.01	41.28	40.33
Total	1,591	1,568	1,562	1,524	1,430	1,394	1,437	1,451	1,422

Note: Totals may not sum due to independent rounding.

Table A-131: U.S. Production Sector CO₂ Content in Natural Gas by NEMS Region and Natural Gas Well type

Well Types	U.S. Region						
	North East	Midcontinent	Gulf Coast	South West	Rocky Mountain	West Coast	Lower-48 States
Conventional	0.92%	0.79%	2.17%	3.81%	7.95%	0.16%	3.41%
Un-conventional	7.42%	0.31%	0.23%	NA	0.64%	NA	4.83%
All types	3.04%	0.79%	2.17%	3.81%	7.58%	0.16%	3.45%

Table A-132: CO₂ Emission Estimates from the Natural Gas Production Stage (Gg)

Activity	1990	1992	1995	2000	2005	2006	2007	2008	2009
Normal Fugitives									
Gas Wells									
Non-Associated Gas Wells	3.56	3.57	4.25	6.46	7.00	6.18	5.86	7.33	8.00
Unconventional Gas Wells ²	0.00	0.00	0.00	0.01	0.01	0.03	0.03	0.03	0.03
Field Separation Equipment									
Heaters	1.86	1.91	2.32	3.95	4.44	4.61	4.48	5.54	5.95
Separators	6.04	5.97	7.17	11.29	12.68	13.20	13.16	15.78	16.82
Dehydrators	1.50	1.54	1.73	2.58	2.83	2.94	2.93	3.38	3.60
Meter/ Piping	5.85	5.85	6.95	10.90	12.21	12.69	12.57	15.14	16.15
Gathering Compressors									
Small Reciprocating Comp.	2.95	2.98	3.57	5.46	6.17	6.41	6.38	7.63	8.15
Large Reciprocating Comp.	0.69	0.91	1.02	1.33	1.40	1.40	1.40	1.62	1.62
Large Reciprocating	0.05	0.06	0.07	0.09	0.09	0.09	0.09	0.11	0.11
Stations									
Pipeline Leaks	10.75	10.85	11.99	16.04	17.64	18.21	18.25	20.80	21.94
Vented and Combusted									
Drilling and Well Completion									
Completion Flaring ²	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Unconventional Gas Well Completions	2.19	1.58	5.27	122.20	21.29	748.86	166.74	108.05	85.45
Well Drilling	0.07	0.05	0.05	0.12	0.18	0.21	0.20	0.22	0.13
Coal Bed Methane									
Powder River ¹	NE	NE	NE	NE	NE	NE	NE	NE	NE
Black Warrior ¹	NE	NE	NE	NE	NE	NE	NE	NE	NE
Normal Operations									
Pneumatic Device Vents	58.49	60.24	69.38	101.86	114.87	119.29	118.75	139.81	149.18
Chemical Injection Pumps	2.95	3.11	3.75	6.33	7.18	7.45	7.20	8.94	9.61
Kimray Pumps	13.41	13.71	15.43	22.91	25.15	26.12	26.05	30.04	31.99
Dehydrator Vents	4.18	4.28	4.81	7.14	7.84	8.15	8.12	9.37	9.98
Condensate Tank Vents									
Condensate Tanks without Control Device	10.25	9.43	8.79	9.34	10.25	11.26	11.17	11.90	11.90
Condensate Tanks with Control Device	2.05	1.89	1.76	1.87	2.05	2.25	2.23	2.38	2.38
Compressor Exhaust Vented									
Gas Engines ¹	NE	NE	NE	NE	NE	NE	NE	NE	NE
Well Workovers									
Gas Wells	0.06	0.06	0.06	0.08	0.09	0.10	0.10	0.11	0.12
Unconventional Gas Wells	0.47	0.84	2.35	22.89	43.99	118.88	135.55	146.36	145.24
Well Clean Ups (LP Gas Wells)	251.41	252.88	273.66	339.56	375.89	367.69	377.12	413.61	439.94
Blowdowns									
Vessel BD	0.04	0.04	0.04	0.06	0.06	0.07	0.07	0.08	0.08
Pipeline BD	0.17	0.17	0.19	0.26	0.28	0.29	0.29	0.33	0.35
Compressor BD	0.11	0.12	0.14	0.21	0.24	0.25	0.25	0.29	0.31
Compressor Starts	0.25	0.26	0.31	0.47	0.53	0.55	0.55	0.66	0.70
Upsets									
Pressure Relief Valves	0.03	0.03	0.04	0.05	0.06	0.06	0.06	0.07	0.07
Mishaps	0.09	0.09	0.10	0.14	0.15	0.16	0.16	0.18	0.19
Flaring Emissions - Onshore	9,092.72	10,172.49	17,167.79	5,525.04	7,193.00	7,812.35	8,664.25	10,024.82	9,545.39
Offshore									
Offshore water Gas Platforms (GoM & Pacific)	1.48	1.51	1.56	1.64	1.63	1.63	1.55	1.52	1.42
Deepwater Gas Platforms (GoM & Pacific)	0.03	0.03	0.04	0.07	0.10	0.12	0.11	0.11	0.11
Flaring Emissions - Offshore	230.37	163.13	197.22	204.31	180.66	146.48	160.05	360.00	360.00
Total	9,704	10,720	17,792	6,425	8,050	9,438	9,746	11,336	10,877

¹ Energy use CO₂ emissions not estimated to avoid double counting. NE = not estimated.² Emissions are not actually 0, but too small to show at this level of precision.

Note: Totals may not sum due to independent rounding.

Table A-133: CO₂ Emission Estimates from the Natural Gas Processing Plants (Gg)

Activity	1990	1992	1995	2000	2005	2006	2007	2008	2009
Normal Fugitives									
Plants – Before CO ₂ removal	2.56	2.46	2.27	1.97	1.90	1.92	1.93	1.94	1.94
Plants – After CO ₂ removal	0.57	0.55	0.50	0.44	0.42	0.43	0.43	0.43	0.43
Reciprocating Compressors – Before CO ₂ removal	19.67	19.66	20.49	21.16	19.85	20.41	21.28	22.47	23.23
Reciprocating Compressors – After CO ₂ removal	4.37	4.36	4.55	4.70	4.41	4.53	4.72	4.99	5.16
Centrifugal Compressors (wet seals) – Before CO ₂ removal	14.55	14.54	15.05	15.21	13.88	13.92	13.98	14.07	14.13
Centrifugal Compressors (wet seals) – After CO ₂ removal	3.23	3.23	3.34	3.38	3.08	3.09	3.10	3.12	3.14
Centrifugal Compressors (dry seals) – Before CO ₂ removal	0	0	0.05	0.21	0.39	0.58	0.86	1.25	1.50
Centrifugal Compressors (dry seals) – After CO ₂ removal	0	0	0.01	0.05	0.09	0.13	0.19	0.28	0.33
Vented and Combusted									
Normal Operations									
Compressor Exhaust									
Gas Engines ¹	NE	NE	NE	NE	NE	NE	NE	NE	NE
Gas Turbines ¹	NE	NE	NE	NE	NE	NE	NE	NE	NE
AGR Vents	27,708	26,652	24,577	23,288	21,694	21,161	21,144	21,328	21,130
Kimray Pumps	0.39	0.39	0.41	0.42	0.40	0.41	0.43	0.45	0.46
Dehydrator Vents	2.42	2.42	2.52	2.61	2.45	2.51	2.62	2.77	2.86
Pneumatic Devices	0.29	0.27	0.25	0.22	0.21	0.21	0.22	0.22	0.22
Routine Maintenance									
Blowdowns/Venting	6.36	6.12	5.64	4.89	4.73	4.78	4.80	4.83	4.83
Total	27,763	26,706	24,632	23,343	21,746	21,214	21,199	21,385	21,189

¹ Energy use CO₂ emissions not estimated to avoid double counting. NE = not estimated.

Note: Totals may not sum due to independent rounding.

Table A-134: CO₂ Emission Estimates from the Natural Gas Transmission and Storage (Gg)

Activity	1990	1992	1995	2000	2005	2006	2007	2008	2009
Fugitives									
Pipelines Leaks	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.10	0.10
Compressor Stations (Transmission)									
Station	3.09	3.08	3.14	3.16	3.18	3.17	3.18	3.21	3.19
Recip Compressor	21.49	21.45	21.85	22.00	22.12	22.11	22.16	22.33	22.19
Centrifugal Compressor (wet seals)	7.12	7.11	7.20	7.08	6.83	6.83	6.83	6.84	6.79
Centrifugal Compressor (dry seals)	0	0	0.02	0.13	0.32	0.32	0.33	0.36	0.36
Compressor Stations (Storage)									
Station	1.58	1.68	1.74	1.79	1.73	1.57	1.69	1.75	1.71
Recip Compressor	4.55	4.86	5.03	5.18	5.01	4.53	4.89	5.05	4.93
Centrifugal Compressor (wet seals)	0.96	1.02	1.05	0.99	0.89	0.79	0.80	0.80	0.77
Centrifugal Compressor (dry seals)	0	0	0.00	0.07	0.12	0.12	0.17	0.19	0.19
Wells (Storage)	0.39	0.42	0.43	0.45	0.43	0.39	0.42	0.43	0.42
M&R (Trans. Co. Interconnect)	2.10	2.10	2.14	2.15	2.16	2.16	2.17	2.18	2.17
M&R (Farm Taps + Direct Sales)	0.49	0.49	0.50	0.50	0.50	0.50	0.50	0.51	0.50
Vented and Combusted									
Normal Operation									
Dehydrator Vents (Transmission)	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Dehydrator Vents (Storage)	0.12	0.13	0.13	0.14	0.13	0.12	0.13	0.14	0.13
Compressor Exhaust									
Engines (Transmission) ¹	NE	NE	NE	NE	NE	NE	NE	NE	NE
Turbines (Transmission) ¹	NE	NE	NE	NE	NE	NE	NE	NE	NE

Activity	1990	1992	1995	2000	2005	2006	2007	2008	2009
Engines (Storage) ¹	NE	NE	NE	NE	NE	NE	NE	NE	NE
Turbines (Storage) ¹	NE	NE	NE	NE	NE	NE	NE	NE	NE
Generators (Engines) ¹	NE	NE	NE	NE	NE	NE	NE	NE	NE
Generators (Turbines) ¹	NE	NE	NE	NE	NE	NE	NE	NE	NE
Pneumatic Devices Trans+Stor									
Pneumatic Devices Trans	6.15	6.14	6.25	6.29	6.33	6.33	6.34	6.39	6.35
Pneumatic Devices Storage	1.28	1.37	1.42	1.46	1.41	1.28	1.38	1.42	1.39
Routine Maintenance/Upsets									
Pipeline Venting	5.13	5.13	5.22	5.26	5.29	5.28	5.30	5.33	5.30
Station venting Trans+Storage									
Station Venting Transmission	4.20	4.19	4.27	4.30	4.32	4.32	4.33	4.36	4.33
Station Venting Storage	0.88	0.93	0.97	1.00	0.96	0.87	0.94	0.97	0.95
LNG Storage									
LNG Stations	0.31	0.32	0.33	0.35	0.36	0.36	0.36	0.36	0.36
LNG Reciprocating Compressors	1.16	1.18	1.23	1.30	1.34	1.34	1.34	1.34	1.34
LNG Centrifugal Compressors	0.39	0.41	0.42	0.45	0.46	0.46	0.46	0.46	0.46
LNG Compressor Exhaust									
LNG Engines ¹	NE	NE	NE	NE	NE	NE	NE	NE	NE
LNG Turbines ¹	NE	NE	NE	NE	NE	NE	NE	NE	NE
LNG Station Venting	0.17	0.18	0.18	0.19	0.20	0.20	0.20	0.20	0.20
LNG Import Terminals									
LNG Stations	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.04	0.05
LNG Reciprocating Compressors	0.03	0.03	0.03	0.03	0.07	0.07	0.07	0.17	0.22
LNG Centrifugal Compressors	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.04	0.06
LNG Compressor Exhaust									
LNG Engines ¹	NE	NE	NE	NE	NE	NE	NE	NE	NE
LNG Turbines ¹	NE	NE	NE	NE	NE	NE	NE	NE	NE
LNG Station Venting ²	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.02	0.03
Total	61.75	62.37	63.73	64.44	64.36	63.31	64.18	65.04	64.55

¹ Energy use CO₂ emissions not estimated to avoid double counting. NE = not estimated.

² Emissions are not actually 0, but too small to show at this level of precision.

Note: Totals may not sum due to independent rounding.

Table A-135: CO₂ Emission Estimates from the Natural Gas Distribution Stage (Gg)

Activity	1990	1992	1995	2000	2005	2006	2007	2008	2009
Pipeline Leaks									
Mains—Cast Iron	7.73	7.02	6.71	5.93	4.96	4.90	5.00	4.84	4.70
Mains—Unprotected steel	6.67	6.10	5.76	5.07	4.24	4.39	4.26	4.25	4.12
Mains—Protected steel	0.79	0.80	0.86	0.80	0.79	0.82	0.83	0.82	0.83
Mains—Plastic	1.71	1.47	1.95	2.47	2.89	3.41	3.31	3.32	3.42
Total Pipeline Miles									
Services—Unprotected steel	7.21	6.75	5.81	5.36	5.02	5.33	5.15	5.09	4.93
Services Protected steel	1.94	1.94	2.06	1.75	1.56	1.54	1.54	1.52	1.51
Services—Plastic	0.10	0.11	0.13	0.16	0.19	0.20	0.21	0.21	0.22
Services—Copper	0.22	0.22	0.20	0.20	0.17	0.18	0.17	0.16	0.15
Meter/Regulator (City Gates)									
M&R >300	3.18	3.40	3.52	3.62	3.50	3.17	3.42	3.53	3.45
M&R 100-300	6.18	6.60	6.83	7.03	6.79	6.15	6.65	6.86	6.70
M&R <100	0.15	0.16	0.16	0.17	0.16	0.15	0.16	0.17	0.16
Reg >300	3.14	3.35	3.46	3.57	3.45	3.12	3.37	3.48	3.40
R-Vault >300	0.01	0.02	0.02	0.02	0.02	0.01	0.02	0.02	0.02
Reg 100-300	2.37	2.53	2.62	2.70	2.61	2.36	2.55	2.63	2.57
R-Vault 100-300	0.00	0.01	0.01	0.01	0.01	0.00	0.01	0.01	0.01
Reg 40-100	0.18	0.20	0.20	0.21	0.20	0.18	0.20	0.20	0.20
R-Vault 40-100	0.01	0.01	0.01	0.02	0.01	0.01	0.01	0.01	0.01
Reg <40	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Customer Meters									
Residential	2.98	3.19	3.30	3.40	3.28	2.97	3.21	3.31	3.24
Commercial/Industry	0.11	0.12	0.14	0.13	0.11	0.11	0.11	0.12	0.11
Routine Maintenance									

Activity	1990		1992		1995		2000		2005	2006	2007	2008	2009
Pressure Relief Valve Releases	0.03		0.02		0.03		0.03		0.03	0.03	0.03	0.03	0.03
Pipeline Blowdown	0.07		0.07		0.08		0.08		0.08	0.07	0.07	0.08	0.07
Upsets													
Mishaps (Dig-ins)	1.07		1.15		1.19		1.22		1.18	1.07	1.15	1.19	1.16
Total	45.90		45.24		45.05		43.97		41.25	40.20	41.46	41.85	41.03

[†] Emissions are not actually 0, but too small to show at this level of precision.

Note: Totals may not sum due to independent rounding.

3.5. Methodology for Estimating CH₄ and CO₂ Emissions from Petroleum Systems

The methodology for estimating CH₄ and non-combustion CO₂ emissions from petroleum systems is based on the 1999 EPA draft report, *Estimates of Methane Emissions from the U.S. Oil Industry* (EPA 1999) and the study, *Methane Emissions from the U.S. Petroleum Industry* (EPA/GRI 1996). Sixty-four activities that emit CH₄ and thirty activities that emit non-combustion CO₂ from petroleum systems were examined from these reports. Most of the activities analyzed involve crude oil production field operations, which accounted for about 98 percent of total oil industry CH₄ emissions. Crude transportation and refining accounted for the remaining CH₄ emissions of less than one half and about one and a half percent, respectively. Non-combustion CO₂ emissions were analyzed for production operations and asphalt blowing in refining operations. Non-combustion CO₂ emissions from transportation operations are not included because they are negligible. The following steps were taken to estimate CH₄ and CO₂ emissions from petroleum systems.

Step 1: Determine Emission Factors for all Activities

The CH₄ emission factors for the majority of the activities for 1995 are taken from the 1999 EPA draft report, which contained the most recent and comprehensive determination of CH₄ emission factors for the 64 CH₄-emitting activities in the oil industry at that time. Emission factors for pneumatic devices in the production sector were recalculated in 2002 using emissions data in the EPA/GRI 1996c study. The gas engine emission factor is taken from the EPA/GRI 1996b study. The oil tank venting emission factor is taken from the API E&P Tank Calc weighted average for API gravity less than 45 API degrees with the distribution of gravities taken from a sample of production data from the HPDI database. Offshore emissions from shallow water and deep water oil platforms are taken from analysis of the Gulf-wide Offshore Activity Data System (GOADS) report (EPA 2005, BOEMRE 2004). The emission factors determined for 1995 were assumed to be representative of emissions from each source type over the period 1990 through 2009. Therefore, the same emission factors are used for each year throughout this period.

The CO₂ emission factors were derived from the corresponding source CH₄ emission factors. The amount of CO₂ in the crude oil stream changes as it passes through various equipment in petroleum production operations. As a result, four distinct stages/streams with varying CO₂ contents exist. The four streams that are used to estimate the emissions factors are the associated gas stream separated from crude oil, hydrocarbons flashed out from crude oil (such as in storage tanks), whole crude oil itself when it leaks downstream, and gas emissions from offshore oil platforms. The standard approach used to estimate CO₂ emission factors was to use the existing CH₄ emissions factors and multiply them by a conversion factor, which is the ratio of CO₂ content to methane content for the particular stream. Ratios of CO₂ to CH₄ volume in emissions are presented in Table A- 5. The two exceptions are the emissions factor for storage tanks, which is estimated using API E&P Tank Calc simulation runs of tank emissions for crude oil of different gravities less than 45 API degrees; and the emissions factor for uncontrolled asphalt blowing, which is estimated using the data and methods provided by API (2009).

Step 2: Determine Activity Levels for Each Year

Activity levels change from year to year. Some factors change in proportion to crude oil rates: production, transportation, refinery runs. Some change in proportion to the number of facilities: oil wells, petroleum refineries. Some factors change proportional to both the rate and number of facilities.

For most sources, activity levels found in the EPA/GRI 1996 for the 1995 base year are extrapolated to other years using publicly-available data sources. For the remaining sources, the activity levels are obtained directly from publicly available data and are not extrapolated from the 1995 base year.

For both sets of data, a determination was made on a case-by-case basis as to which measure of petroleum industry activity best reflects the change in annual activity. Publicly-reported data from the Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE), Energy Information Administration (EIA), American Petroleum Institute (API), the Oil & Gas Journal (O&GJ), the Interstate Oil and Gas Compact Commission (IOGCC), and the U.S. Army Corps of Engineers (USACE) were used to extrapolate the activity levels from the base year to each year between 1990 and 2009. Data used include total domestic crude oil production, number of domestic crude oil wells, total imports and exports of crude oil, total petroleum refinery crude runs, and number of oil-producing offshore platforms. The activity data for the total crude transported in the transportation sector is not available. In this case, all the crude oil that was transported was assumed to go to refineries. Therefore, the activity data for the refining sector was used also for the transportation sector. In the few cases where no data was located, oil industry data based on expert judgment was used. In the case of non-combustion CO₂ emission sources, the activity factors remain the same as for CH₄ emission sources.

Step 3: Estimate Methane and Carbon Dioxide Emissions for Each Activity for Each Year

Annual CH₄ emissions from each of the 64 petroleum system activities and CO₂ emissions from the 30 petroleum system activities were estimated by multiplying the activity data for each year by the corresponding emission factor. These annual emissions for each activity were then summed to estimate the total annual CH₄ and CO₂ emissions, respectively. Table A- 140 provides the CO₂ content in natural gas for equipment in different crude streams to estimate CO₂ emission factors using CH₄^{emission} factors.

Table A-136, Table A-137, Table A-138, and Table A-141 provide 2009 activity factors, emission factors, and emission estimates and Table A-139 and Table A-142 provide a summary of emission estimates for the years 1990, 1995, 2000, and 2005 through 2009. Table A- 140 provides the CO₂ content in natural gas for equipment in different crude streams to estimate CO₂ emission factors using CH₄ emission factors.

Table A-136: 2009 CH₄ Emissions from Petroleum Production Field Operations

Activity/Equipment	2009 EPA Inventory Values			
	Emission Factor	Activity Factor	Emissions (Bcf/yr)	Emissions (Gg/yr)
Vented Emissions			67.625	1,300
Oil Tanks	7.39 scf of CH ₄ /bbl crude	1,490 MMbbl/yr (non stripper wells)	11.016	211.8
Pneumatic Devices, High Bleed	330 scfd CH ₄ /device	139,797 No. of high-bleed devices	16.859	324.2
Pneumatic Devices, Low Bleed	52 scfd CH ₄ /device	259,624 No. of low-bleed devices	4.928	94.76
Chemical Injection Pumps	248 scfd CH ₄ /pump	28,166 No. of pumps	2.550	49.04
Vessel Blowdowns	78 scfy CH ₄ /vessel	182,451 No. of vessels	0.014	0.274
Compressor Blowdowns	3,775 scf/yr of CH ₄ /compressor	2,473 No. of compressors	0.009	0.179
Compressor Starts	8,443 scf/yr. of CH ₄ /compressor	2,473 No. of compressors	0.021	0.401
Stripper wells	2,345 scf/yr of CH ₄ /stripper well	317,230 No. of stripper wells	0.744	14.31
Well Completion Venting	733 scf/completion	11,804 Oil well completions	0.009	0.166
Well Workovers	96 scf CH ₄ /workover	39,450 Oil well workovers	0.004	0.073
Pipeline Pigging	2.40 scfd of CH ₄ /pig station	0 No. of crude pig stations	-	-
Offshore Platforms, Shallow water	54,795 scfd CH ₄ /platform	1,441 No. of shallow water oil platforms	28.823	554.3
Oil, fugitive, vented and combusted				
Offshore Platforms, Deepwater oil, fugitive, vented and combusted	260,274 scfd CH ₄ /platform	28 No. of deep water oil platforms	2.649	50.93
Fugitive Emissions			2.539	49
Oil Wellheads (heavy crude)	0.13 scfd/well	14,718 No. of hvy. crude wells	0.001	0.013
Oil Wellheads (light crude)	16.6 scfd/well	194,052 No. of lt. crude wells	1.178	22.65
Separators (heavy crude)	0.15 scfd CH ₄ /separator	10,740 No. of hvy. crude seps.	0.001	0.012
Separators (light crude)	14 scfd CH ₄ /separator	97,745 No. of lt. crude seps.	0.494	9.504
Heater/Treaters (light crude)	19 scfd CH ₄ /heater	73,966 No. of heater treaters	0.518	9.965
Headers (heavy crude) ¹	0.08 scfd CH ₄ /header	13,721 No. of hvy. crude hdrs.	0.000	0.007
Headers (light crude)	11 scfd CH ₄ /header	42,536 No. of lt. crude hdrs.	0.169	3.241
Floating Roof Tanks	338,306 scf CH ₄ /floating roof tank/yr.	24 No. of floating roof tanks	0.008	0.159
Compressors	100 scfd CH ₄ /compressor	2,473 No. of compressors	0.090	1.736
Large Compressors	16,360 scfd CH ₄ /compressor	0 No. of large comprs.	-	-
Sales Areas	41 scf CH ₄ /loading	1,630,377 Loadings/year	0.066	1.271
Pipelines	NE scfd of CH ₄ /mile of pipeline	11,249 Miles of gathering line	NE	NE
Well Drilling	NE scfd of CH ₄ /oil well drilled	13,255 No. of oil wells drilled	NE	NE
Battery Pumps	0.24 scfd of CH ₄ /pump	157,800 No. of battery pumps	0.014	0.266
Combustion Emissions			4.7926	92.22
Gas Engines	0.24 scf CH ₄ /HP-hr	15,577 MMHP-hr	3.739	71.89
Heaters	0.52 scf CH ₄ /bbl	1956.8 MMbbl/yr	1.020	19.61
Well Drilling	2,453 scf CH ₄ /well drilled	13,255 Oil wells drilled	0.033	0.625

Activity/Equipment	2009 EPA Inventory Values			
	Emission Factor	Activity Factor	Emissions (Bcf/yr)	Emissions (Gg/yr)
Flares	20 scf CH ₄ /Mcf flared	242,355 Mcf flared/yr	0.005	0.932
Process Upset Emissions			0.116	2.233
Pressure Relief Valves	35 scf/yr/PR valve	163,449 No. of PR valves	0.006	0.109
Well Blowouts Onshore	2.5 MMscf/blowout	44.2 No. of blowouts/yr	0.110	2.124
Total			75.08	1,444

- Zero Emissions

¹ Emissions are not actually 0, but too small to show at this level of precision.

NE: Not estimated for lack of data

Table A-137: 2009 CH₄ Emissions from Petroleum Transportation

Activity/Equipment	Emission Factor	Units	Activity Factor	Units	Emissions (Bcf/yr)	Emissions (Gg/yr)
Vented Emissions					0.209	4.024
Tanks	0.021 scf CH ₄ /yr/bbl of crude delivered to refineries		5,233 MMbbl crude feed/yr		0.108	2.073
Truck Loading	0.520 scf CH ₄ /yr/bbl of crude transported by truck		67.8 MMbbl trans. by truck		0.035	0.678
Marine Loading	2.544 scf CH ₄ /1000 gal. crude marine loadings		19,609,664 1,000 gal./yr loaded		0.050	0.959
Rail Loading	0.520 scf CH ₄ /yr/bbl of crude transported by rail		4.2 MMbbl Crude by rail/yr		0.002	0.042
Pump Station Maintenance ¹	36.80 scf CH ₄ /station/yr		496 No. of pump stations		0.000	0.000
Pipeline Pigging	39 scfd of CH ₄ /pig station		992 No. of pig stations		0.014	0.271
Fugitive Emissions					0.050	0.958
Pump Stations	25 scf CH ₄ /mile/yr.		49,585 No. of miles of crude p/l		0.001	0.024
Pipelines	NE scf CH ₄ /bbl crude transported by pipeline		6,431 MMbbl crude piped		NE	NE
Floating Roof Tanks	58,965 scf CH ₄ /floating roof tank/yr.		824 No. of floating roof tanks		0.049	0.934
Combustion Emissions					NE	NE
Pump Engine Drivers	0.24 scf CH ₄ /hp-hr		NE No. of hp-hrs		NE	NE
Heaters	0.521 scf CH ₄ /bbl burned		NE No. of bbl Burned		NE	NE
Total					0.259	4.982

¹ Emissions are not actually 0, but too small to show at this level of precision.

NE: Not estimated for lack of data

Table A-138: 2009 CH₄ Emissions from Petroleum Refining

Activity/Equipment	2009 EPA Inventory Values			
	Emission Factor	Activity Factor	Emissions (Bcf/yr)	Emissions (Gg/yr)
Vented Emissions			1.065	20.48
Tanks	20.6 scf CH ₄ /Mbbl	1,839 Mbbl/calendar day heavy crude feed	0.014	0.266
System Blowdowns	137 scf CH ₄ /Mbbl	14,336 Mbbl/calendar day refinery feed	0.716	13.77
Asphalt Blowing	2,555 scf CH ₄ /Mbbl	359 Mbbl/calendar day production	0.335	6.445
Fugitive Emissions			0.088	1.702
Fuel Gas System	439 Mscf CH ₄ /refinery/yr	150 Refineries	0.066	1.266
Floating Roof Tanks ¹	587 scf CH ₄ /floating roof tank/yr.	767 No. of floating roof tanks	0.000	0.009
Wastewater Treating	1.88 scf CH ₄ /Mbbl	14,336 Mbbl/calendar day refinery feed	0.010	0.189
Cooling Towers	2.36 scf CH ₄ /Mbbl	14,336 Mbbl/calendar day refinery feed	0.012	0.237
Combustion Emissions			0.090	1.723
Atmospheric Distillation	3.61 scf CH ₄ /Mbbl	14,659 Mbbl/calendar day refinery feed	0.019	0.371
Vacuum Distillation	3.61 scf CH ₄ /Mbbl	6,503 Mbbl/calendar day feed	0.009	0.165

Activity/Equipment	2009 EPA Inventory Values			
	Emission Factor	Activity Factor	Emissions (Bcf/yr)	Emissions (Gg/yr)
Thermal Operations	6.01 scf CH ₄ /Mbbl	2,034 Mbbl/calendar day feed	0.004	0.086
Catalytic Cracking	5.17 scf CH ₄ /Mbbl	4,694 Mbbl/calendar day feed	0.009	0.170
Catalytic Reforming	7.22 scf CH ₄ /Mbbl	2,970 Mbbl/calendar day feed	0.008	0.150
Catalytic Hydrocracking	7.22 scf CH ₄ /Mbbl	1,393 Mbbl/calendar day feed	0.004	0.071
Hydrotreating	2.17 scf CH ₄ /Mbbl	2,067 Mbbl/calendar day feed	0.002	0.031
Hydrotreating	6.50 scf CH ₄ /Mbbl	9,480 Mbbl/calendar day feed	0.022	0.432
Alkylation/Polymerization	12.6 scf CH ₄ /Mbbl	1,027 Mbbl/calendar day feed	0.005	0.091
Aromatics/Isomeration	1.80 scf CH ₄ /Mbbl	956 Mbbl/calendar day feed	0.001	0.012
Lube Oil Processing	0.00 scf CH ₄ /Mbbl	165 Mbbl/calendar day feed	0.000	0.000
Engines	0.006 scf CH ₄ /hp-hr	1,128 MMhp-hr/yr	0.006	0.124
Flares	0.189 scf CH ₄ /Mbbl	14,336 Mbbl/calendar day refinery feed	0.001	0.019
Total			1.243	23.90

[†] Emissions are not actually 0, but too small to show at this level of precision.

Table A-139: Summary of CH₄ Emissions from Petroleum Systems (Gg)

Activity	1990	1995	2000	2005	2006	2007	2008	2009
Production Field Operations	1,653	1,557	1,468	1,366	1,365	1,396	1,409	1,444
Pneumatic device venting	489	463	428	397	396	398	416	419
Tank venting	250	226	214	187	188	192	189	212
Combustion & process upsets	88	82	76	71	71	72	75	94
Misc. venting & fugitives	799	762	727	691	693	714	707	696
Wellhead fugitives	26	25	22	19	17	20	23	23
Crude Oil Transportation	7	6	5	5	5	5	5	5
Refining	25	26	28	28	28	27	25	24
Total	1,685	1,589	1,501	1,398	1,398	1,427	1,439	1,473

Note: Totals may not sum due to independent rounding.

Table A-140: Ratios of CO₂ to CH₄ Volume in Emissions from Petroleum Production Field Operations

	Whole Crude, Post-Separator	Associated Gas	Tank Flash Gas	Offshore
Ratio %CO₂ / %CH₄	0.052	0.020	0.017	0.004

Table A-141: 2009 CO₂ Emissions from Petroleum Production Field Operations and Petroleum Refining

Activity/Equipment	2009 EPA Inventory Values			
	Emission Factor	Activity Factor	Emissions (Bcf/yr)	Emissions (Gg/yr)
Vented Emissions			5.972	316.5
Oil Tanks	3.53 scf of CO ₂ /bbl crude	1,490 MMbbl/yr (non stripper wells)	5.256	278.6
Pneumatic Devices, High Bleed	6.704 scfd CO ₂ /device	139,797 No. of high-bleed devices	0.342	18.13
Pneumatic Devices, Low Bleed	1.055 scfd CO ₂ /device	259,624 No. of low-bleed devices	0.100	5.299
Chemical Injection Pumps	5.033 scfd CO ₂ /pump	28,166 No. of pumps	0.052	2.742
Vessel Blowdowns [†]	1.583 scfy CO ₂ /vessel	182,451 No. of vessels	0.000	0.015
Compressor Blowdowns [†]	77 scf/yr of CO ₂ /compressor	2,473 No. of compressors	0.000	0.010
Compressor Starts [†]	171 scf/yr. of CO ₂ /compressor	2,473 No. of compressors	0.000	0.022
Stripper wells	48 scf/yr of CO ₂ /stripper well	317,230 No. of stripper wells vented	0.015	0.800
Well Completion Venting [†]	14.87 scf/completion	11,804 Oil well completions	0.000	0.009
Well Workovers [†]	1.95 scf CO ₂ /workover	39,450 Oil well workovers	0.000	0.004
Pipeline Pigging	NE scfd of CO ₂ /pig station	NE No. of crude pig stations	NE	NE
Offshore Platforms, Shallow water	358 scfd CO ₂ /platform	1,441 No. of shallow water oil platforms	0.188	9.984
Oil, fugitive, vented and combusted				
Offshore Platforms, Deepwater oil,	1,701 scfd CO ₂ /platform	28 No. of deep water oil	0.017	0.917

Activity/Equipment	2009 EPA Inventory Values			
	Emission Factor	Activity Factor	Emissions (Bcf/yr)	Emissions (Gg/yr)
fugitive, vented and combusted		platforms		
Fugitive Emissions			0.052	2.776
Oil Wellheads (heavy crude) ¹	0.003 scfd/well	14,718 No. of hvy. crude wells	0.000	0.001
Oil Wellheads (light crude)	0.337 scfd/well	194,052 No. of lt. crude wells	0.024	1.267
Separators (heavy crude) ¹	0.003 scfd CO ₂ /separator	10,740 No. of hvy. crude seps.	0.000	0.001
Separators (light crude)	0.281 scfd CO ₂ /separator	97,745 No. of lt. crude seps.	0.010	0.531
Heater/Treaters (light crude)	0.319 scfd CO ₂ /heater	73,966 No. of heater treaters	0.009	0.456
Headers (heavy crude) ¹	0.002 scfd CO ₂ /header	13,721 No. of hvy. crude hdrs.	0.000	0.000
Headers (light crude)	0.220 scfd CO ₂ /header	42,536 No. of lt. crude hdrs.	0.003	0.181
Floating Roof Tanks ¹	17,490 scf CO ₂ /floating roof tank/yr.	24 No. of floating roof tanks	0.000	0.023
Compressors	2.029 scfd CO ₂ /compressor	2,473 No. of compressors	0.002	0.097
Large Compressors	332 scfd CO ₂ /compressor	0 No. of large comprs.	0.000	0.000
Sales Areas	2.096 scf CO ₂ /loading	1,630,377 Loadings/year	0.003	0.181
Pipelines	NE scfd of CO ₂ /mile of pipeline	11,249 Miles of gathering line	NE	NE
Well Drilling	NE scfd of CO ₂ /oil well drilled	13,255 No. of oil wells drilled	NE	NE
Battery Pumps	0.012 scfd of CO ₂ /pump	157,800 No. of battery pumps	0.001	0.038
Process Upset Emissions			0.003	0.134
Pressure Relief Valves ¹	1.794 scf/yr/PR valve	163,499 No. of PR valves	0.000	0.016
Well Blowouts Onshore	0.051 MMscf/blowout	44 No. of blowouts/yr	0.002	0.119
Refining Emissions			2.720	144.2
Asphalt Blowing ²	20,736 scf CO ₂ /Mbbl	359 Mbbl/calendar day production	2.720	144.2
Total			8.747	463.6

¹ Emissions are not actually 0, but too small to show at this level of precision.

² Asphalt Blowing emissions are the only significant vented emissions from the refining sector; other sources are too small to show at this level of precision.

NE: Not estimated for lack of data

Energy use CO₂ emissions not estimated to avoid double counting with fossil fuel combustion

Table A-142: Summary of CO₂ Emissions from Petroleum Systems (Gg)

Activity	1990	1995	2000	2005	2006	2007	2008	2009
Production Field Operations	376	341	323	285	285	292	288	319
Pneumatic device venting	27	26	24	22	22	22	23	23
Tank venting	328	296	281	246	246	252	247	278
Misc. venting & fugitives	18	18	17	16	16	16	16	16
Wellhead fugitives	1	1	1	1	1	1	1	1
Refining								
Asphalt Blowing	180	187	211	205	203	182	165	144
Total	555	528	534	490	488	474	453	463

3.6. Methodology for Estimating CO₂, N₂O and CH₄ Emissions from the Incineration of Waste

Emissions of CO₂ from the incineration of waste include CO₂ generated by the incineration of plastics, synthetic rubber and synthetic fibers in municipal solid waste (MSW), and incineration of tires (which are composed in part of synthetic rubber and C black) in a variety of other combustion facilities (e.g., cement kilns). Incineration of waste also results in emissions of N₂O and CH₄. The methodology for calculating emissions from each of these waste incineration sources is described in this Annex.

CO₂ from Plastics Incineration

In the *Municipal Solid Waste Generation, Recycling, and Disposal in the United States: Facts and Figures* reports (EPA 1999 through 2003, 2005 through 2011), the flows of plastics in the U.S. waste stream are reported for seven resin categories. For 2009, the quantity generated, recovered, and discarded for each resin is shown in Table A-143. The data set for 1990 through 2009 is incomplete, and several assumptions were employed to bridge the data gaps. The EPA reports do not provide estimates for individual materials landfilled and incinerated, although they do provide such an estimate for the waste stream as a whole. To estimate the quantity of plastics landfilled and incinerated, total discards were apportioned based on the proportions of landfilling and incineration for the entire U.S. waste stream for each year in the time series according to *Biocycle's State of Garbage in America* (van Haaren et al. 2010). For those years when distribution by resin category was not reported (1990 through 1994), total values were apportioned according to 1995 (the closest year) distribution ratios. Generation and recovery figures for 2002 and 2004 were linearly interpolated between surrounding years' data.

Table A-143: 2008 Plastics in the Municipal Solid Waste Stream by Resin (Gg)

Waste Pathway	PET	HDPE	PVC	LDPE/ LLDPE	PP	PS	Other	Total
Generation	3,202	4,727	1,016	5,715	5,017	2,241	5,144	27,261
Recovery	662	535	0	290	45	18	372	1,923
Discard	2,540	4,191	1,016	5,425	4,971	2,223	4,772	25,338
Landfill	2,316	3,822	926	4,947	4,533	2,027	4,351	23,104
Combustion	224	369	90	478	438	196	421	2,234
Recovery*	21%	11%	0%	5%	1%	1%	7%	7%
Discard*	79%	89%	100%	95%	99%	99%	93%	93%
Landfill*	72%	81%	91%	87%	90%	90%	85%	85%
Combustion*	7%	8%	9%	8%	9%	9%	8%	8%

*As a percent of waste generation.

Note: Totals may not sum due to independent rounding. Abbreviations: PET (polyethylene terephthalate), HDPE (high density polyethylene), PVC (polyvinyl chloride), LDPE/LLDPE (linear low density polyethylene), PP (polypropylene), PS (polystyrene).

Fossil fuel-based CO₂ emissions were calculated as the product of plastic combusted, C content, and fraction oxidized (see Table A-144). The C content of each of the six types of plastics is listed, with the value for "other plastics" assumed equal to the weighted average of the six categories. The fraction oxidized was assumed to be 98 percent.

Table A-144: 2008 Plastics Incinerated (Gg), Carbon Content (%), Fraction Oxidized (%) and Carbon Incinerated (Gg)

Factor	PET	HDPE	PVC	LDPE/ LLDPE	PP	PS	Other ^a	Total
Quantity Combusted	224	369	90	478	438	196	421	2,234
Carbon Content of Resin	63%	86%	38%	86%	86%	92%	66%	-
Fraction Oxidized	98%	98%	98%	98%	98%	98%	98%	-
Carbon in Resin Combusted	137	310	34	402	368	177	271	1,700
Emissions (Tg CO₂ Eq.)	0.5	1.1	0.1	1.5	1.3	0.6	1.0	6.2

^a Weighted average of other plastics produced.

Note: Totals may not sum due to independent rounding.

CO₂ from Incineration of Synthetic Rubber and Carbon Black in Tires

Emissions from tire incineration require two pieces of information: the amount of tires incinerated and the C content of the tires. *Scrap Tire Markets in the United States: 9th Biennial Report* (RMA 2009a) reports that 2,484.4

thousand of the 4,105.8 thousand tons of scrap tires generated in 2007 (approximately 61 percent of generation) were used for fuel purposes. Using RMA's estimates of average tire composition and weight, the mass of synthetic rubber and C black in scrap tires was determined:

- Synthetic rubber in tires was estimated to be 90 percent C by weight, based on the weighted average C contents of the major elastomers used in new tire consumption.⁴⁶ Table A- 145 shows consumption and C content of elastomers used for tires and other products in 2002, the most recent year for which data are available.
- C black is 100 percent C (Aslett Rubber Inc. n.d.).

Multiplying (a) the mass of scrap tires incinerated by (b) the total C content of the synthetic rubber and C black portions of scrap tires and (c) by a 98 percent oxidation factor yielded CO₂ emissions, as shown in Table A- 146. The disposal rate of rubber in tires (0.5 Tg C/yr) is smaller than the consumption rate for tires based on summing the elastomers listed in Table A- 145 (1.3 Tg/yr); this is due to the fact that much of the rubber is lost through tire wear during the product's lifetime and may also reflect the lag time between consumption and disposal of tires. Tire production and fuel use for 1990 through 2007 were taken from RMA 2006 and RMA 2009a; when data were not reported, they were linearly interpolated between bracketing years' data or, for the ends of time series, set equal to the closest year with reported data.

RMA 2009a changed the reporting of scrap tire data from millions of tires to thousands of short tons of scrap tire. As a result, the average weight and percent of the market of light duty and commercial scrap tires was used to convert the previous years from millions of tires to thousands of short tons (STMC 1990 through 1997; RMA 2002 through 2006, 2009b).

Table A- 145: Elastomers Consumed in 2002 (Gg)

Elastomer	Consumed	Carbon Content	Carbon Equivalent
Styrene butadiene rubber solid	768	91%	700
For Tires	660	91%	602
For Other Products*	108	91%	98
Polybutadiene	583	89%	518
For Tires	408	89%	363
For Other Products	175	89%	155
Ethylene Propylene	301	86%	258
For Tires	6	86%	5
For Other Products	295	86%	253
Polychloroprene	54	59%	32
For Tires	0	59%	0
For Other Products	54	59%	32
Nitrile butadiene rubber solid	84	77%	65
For Tires	1	77%	1
For Other Products	83	77%	64
Polyisoprene	58	88%	51
For Tires	48	88%	42
For Other Products	10	88%	9
Others	367	88%	323
For Tires	184	88%	161
For Other Products	184	88%	161
Total	2,215	-	1,950
For Tires	1,307	-	1,174

*Used to calculate C content of non-tire rubber products in municipal solid waste.

- Not applicable

Note: Totals may not sum due to independent rounding.

⁴⁶ The carbon content of tires (1,158 Gg C) divided by the mass of rubber in tires (1,285 Gg) equals 90 percent.

Table A- 146: Scrap Tire Constituents and CO₂ Emissions from Scrap Tire Incineration in 2007

Material	Weight of Material (Tg)	Fraction Oxidized	Carbon Content	Emissions (Tg CO ₂ Eq.)
Synthetic Rubber	0.5	98%	90%	1.8
Carbon Black	0.6	98%	100%	2.3
Total	1.1	-	-	4.1

- Not applicable

CO₂ from Incineration of Synthetic Rubber in Municipal Solid Waste

Similar to the methodology for scrap tires, CO₂ emissions from synthetic rubber in MSW were estimated by multiplying the amount of rubber incinerated by an average rubber C content. The amount of rubber discarded in the MSW stream was estimated from generation and recycling data⁴⁷ provided in the *Municipal Solid Waste Generation, Recycling, and Disposal in the United States: Facts and Figures* reports (EPA 1999 through 2003, 2005 through 2011) and unpublished backup data (Schneider 2007). The reports divide rubber found in MSW into three product categories: other durables (not including tires), non-durables (which includes clothing and footwear and other non-durables), and containers and packaging. EPA (2011) did not report rubber found in the product category “containers and packaging;” however, containers and packaging from miscellaneous material types were reported for 2009. As a result, EPA assumes that rubber containers and packaging are reported under the “miscellaneous” category; and therefore, the quantity reported for 2009 was set equal to the quantity reported for 2008. Since there was negligible recovery for these product types, all the waste generated is considered to be discarded. Similar to the plastics method, discards were apportioned into landfilling and incineration based on their relative proportions, for each year, for the entire U.S. waste stream. The report aggregates rubber and leather in the MSW stream; an assumed synthetic rubber content of 70% was assigned to each product type, as shown in Table A-147.⁴⁸ A C content of 85 percent was assigned to synthetic rubber for all product types (based on the weighted average C content of rubber consumed for non-tire uses), and a 98 percent fraction oxidized was assumed.

Table A-147: Rubber and Leather in Municipal Solid Waste in 2009

Product Type	Incinerated (Gg)	Synthetic Rubber (%)	Carbon Content (%)	Fraction Oxidized (%)	Emissions (Tg CO ₂ Eq.)
Durables (not Tires)	271	70%	85%	98%	0.8
Non-Durables	85	-	-	-	0.3
Clothing and Footwear	63	70%	85%	98%	0.2
Other Non-Durables	22	70%	85%	98%	0.1
Containers and Packaging	2	70%	85%	98%	+
Total	358	-	-	-	1.1

+ Less than 0.05 Tg CO₂ Eq.

- Not applicable.

CO₂ from Incineration of Synthetic Fibers

CO₂ emissions from synthetic fibers were estimated as the product of the amount of synthetic fiber discarded annually and the average C content of synthetic fiber. Fiber in the MSW stream was estimated from data provided in the *Municipal Solid Waste Generation, Recycling, and Disposal in the United States: Facts and Figures* reports (EPA 1999 through 2003, 2005 through 2011) for textiles. Production data for the synthetic fibers was based on data from the American Chemical Society (FEB 2009). The amount of synthetic fiber in MSW was estimated by subtracting (a) the amount recovered from (b) the waste generated (see Table A-148). As with the other materials in the MSW stream, discards were apportioned based on the annually variable proportions of landfilling and incineration for the entire U.S. waste stream as found in van Haaren et al. (2010). It was assumed that approximately 55 percent of the fiber was synthetic in origin, based on information received from the Fiber Economics Bureau (DeZan 2000). An average C content of 70 percent was assigned to synthetic fiber using the production-weighted average of the C contents of the four major fiber

⁴⁷ Discards = Generation minus recycling.

⁴⁸ As a sustainably harvested biogenic material, the incineration of leather is assumed to have no net CO₂ emissions.

types (polyester, nylon, olefin, and acrylic) produced in 1999 (see Table A-149). The equation relating CO₂ emissions to the amount of textiles combusted is shown below.

$$\text{CO}_2 \text{ Emissions from the Incineration of Synthetic Fibers} = \text{Annual Textile Incineration (Gg)} \times (\text{Percent of Total Fiber that is Synthetic}) \times (\text{Average C Content of Synthetic Fiber}) \times (44\text{g CO}_2/12 \text{ g C})$$

Table A-148: Synthetic Textiles in MSW (Gg)

Year	Generation	Recovery	Discards	Incineration
1990	2,884	328	2,557	332
1995	3,674	447	3,227	442
1996	3,832	472	3,361	467
1997	4,090	526	3,564	458
1998	4,269	556	3,713	407
1999	4,498	611	3,887	406
2000	4,686	655	4,031	415
2001	4,870	715	4,155	432
2002	5,123	750	4,373	459
2003	5,297	774	4,522	472
2004	5,451	884	4,567	473
2005	5,649	918	4,731	473
2006	5,893	933	4,959	479
2007	5,927	953	4,974	460
2008	6,170	948	5,222	460
2009	6,319	943	5376	474

Table A-149: Synthetic Fiber Production in 1999

Fiber	Production (Tg)	Carbon Content
Polyester	1.8	63%
Nylon	1.2	64%
Olefin	1.4	86%
Acrylic	0.1	68%
Total	4.5	70%

N₂O and CH₄ from Incineration of Waste

Estimates of N₂O emissions from the incineration of waste in the United States are based on the methodology outlined in the EPA's Compilation of Air Pollutant Emission Factors (EPA 1995) and presented in the *Municipal Solid Waste Generation, Recycling, and Disposal in the United States: Facts and Figures* reports (EPA 1999 through 2003, 2005 through 2011) and unpublished backup data (Schneider 2007). According to this methodology, emissions of N₂O from waste incineration are the product of the mass of waste incinerated, an emission factor of N₂O emitted per unit mass of waste incinerated, and an N₂O emissions control removal efficiency. The mass of waste incinerated was derived from the information published in *BioCycle* (van Haaren et al. 2010). For waste incineration in the United States, an emission factor of 50 g N₂O/metric ton MSW based on the 2006 IPCC Guidelines and an estimated emissions control removal efficiency of zero percent were used (IPCC 2006). It was assumed that all MSW incinerators in the United States use continuously-fed stoker technology (Bahor 2009, ERC 2009).

Estimates of CH₄ emissions from the incineration of waste in the United States are based on the methodology outlined in IPCC's *2006 Guidelines for National Greenhouse Gas Inventories* (IPCC 2006). According to this methodology, emissions of CH₄ from waste incineration are the product of the mass of waste incinerated and an emission factor of CH₄ emitted per unit mass of waste incinerated. Similar to the N₂O emissions methodology, the mass of waste incinerated was derived from the information published in *BioCycle* (van Haaren et al. 2010). For waste incineration in the United States, an emission factor of 0.20 kg CH₄/Gg MSW was used based on the 2006 IPCC Guidelines and assuming that all MSW incinerators in the United States use continuously-fed stoker technology (Bahor 2009, ERC 2009). No information was available on the mass of waste incinerated from *BioCycle* in 2009, so the value was assumed to remain constant at the 2008 level.

Despite the differences in methodology and data sources, the two series of references (EPA's and BioCycle's) provide estimates of total solid waste incinerated that are relatively consistent (see Table A-150).

Table A-150: U.S. Municipal Solid Waste Incinerated, as Reported by EPA and BioCycle (Metric Tons)

Year	EPA	BioCycle
1990	28,939,680	30,632,057
1995	32,241,888	29,639,040
1996	32,740,848	29,707,171
1997	33,294,240	27,798,368
1998	31,216,752	25,489,893
1999	30,881,088	24,296,249
2000	30,599,856	25,974,978
2001	30,481,920	25,942,036 ^a
2002	30,255,120	25,802,917
2003	30,028,320	25,930,542 ^b
2004	28,585,872	26,037,823
2005	28,685,664	25,973,520 ^c
2006	28,985,040	25,853,401
2007	29,003,184	24,788,539 ^d
2008	28,622,160	23,674,017
2009	26,317,872	NA

NA (Not Available)

^a Interpolated between 2000 and 2002 values.

^b Interpolated between 2002 and 2004 values.

^c Interpolated between 2004 and 2006 values.

^d Interpolated between 2006 and 2008 values

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3.7. Methodology for Estimating Emissions from International Bunker Fuels used by the U.S. Military

Bunker fuel emissions estimates for the Department of Defense (DoD) are developed using data generated by the Defense Energy Support Center (DESC) for aviation and naval fuels. The DESC of the Defense Logistics Agency (DLA) prepared a special report based on data in the Fuels Automated System (FAS), a database that recently replaced the Defense Fuels Automated Management System (DFAMS). Data for intermediate fuel oil, however, currently remains in the original DFAMS database. DFAMS/FAS contains data for 1995 through 2009, but the data set was not complete for years prior to 1995. Fuel quantities for 1990 to 1994 were estimated based on a back-calculation of the 1995 DFAMS values using DLA aviation and marine fuel procurement data. The back-calculation was refined in 1999 to better account for the jet fuel conversion from JP4 to JP8 that occurred within DoD between 1992 and 1995.

Step 1: Omit Extra-Territorial Fuel Deliveries

Beginning with the complete FAS data set for each year, the first step in the development of DoD-related emissions from international bunker fuels was to identify data that would be representative of international bunker fuel consumption as that term is defined by decisions of the UNFCCC (i.e., fuel sold to a vessel, aircraft, or installation within the United States or its territories and used in international maritime or aviation transport). Therefore, fuel data were categorized by the location of fuel delivery in order to identify and omit all international fuel transactions/deliveries (i.e., sales abroad).

Step 2: Allocate JP-8 between Aviation and Land-based Vehicles

As a result of DoD⁴⁹ and NATO⁵⁰ policies on implementing the Single Fuel For the Battlefield concept, DoD activities have been increasingly replacing diesel fuel with JP8 (a type of jet fuel) in compression ignition and turbine engines in land-based equipment. Based on this concept and examination of all data describing jet fuel used in land-based vehicles, it was determined that a portion of JP8 consumption should be attributed to ground vehicle use. Based on available Service data and expert judgment, it was determined that a small fraction of the total JP8 use should be reallocated from the aviation subtotal to a new land-based jet fuel category for 1997 and subsequent years. The amount of JP8 reallocated was determined to be between 1.78 and 2.7 times the amount of diesel fuel used, depending on the Service. As a result of this reallocation, the JP8 use reported for aviation will be reduced and the total fuel use for land-based equipment will increase. DoD's total fuel use will not change.

Table A-151 displays DoD's consumption of fuels that remain at the completion of Step 1, summarized by fuel type. Table A-151 reflects the adjustments for jet fuel used in land-based equipment, as described above.

Step 3: Omit Land-Based Fuels

Navy and Air Force land-based fuels (i.e., fuel not used by ships or aircraft) were also omitted for the purpose of calculating international bunker fuels. The remaining fuels, listed below, were considered potential DoD international bunker fuels.

- Marine: naval distillate fuel (F76), marine gas oil (MGO), and intermediate fuel oil (IFO).
- Aviation: jet fuels (JP8, JP5, JP4, JAA, JA1, and JAB).

Step 4: Omit Fuel Transactions Received by Military Services that are not Considered to be International Bunker Fuels

Next, the records were sorted by Military Service. The following assumptions were used regarding bunker fuel use by Service, leaving only the Navy and Air Force as users of military international bunker fuels.

⁴⁹ DoD Directive 4140.43, Fuel Standardization, 1998; DoD Directive 4140.25, DoD Management Policy for Energy Commodities and Related Services, 1999.

⁵⁰ NATO Standard Agreement NATO STANAG 4362, Fuels for Future Ground Equipments Using Compression Ignition or Turbine Engines, 1987.

- Only fuel delivered to a ship, aircraft, or installation in the United States was considered a potential international bunker fuel. Fuel consumed in international aviation or marine transport was included in the bunker fuel estimate of the country where the ship or aircraft was fueled. Fuel consumed entirely within a country's borders was not considered a bunker fuel.
- Based on discussions with the Army staff, only an extremely small percentage of Army aviation emissions, and none of its watercraft emissions, qualified as bunker fuel emissions. The magnitude of these emissions was judged to be insignificant when compared to Air Force and Navy emissions. Based on this, Army bunker fuel emissions were assumed to be zero.
- Marine Corps aircraft operating while embarked consumed fuel reported as delivered to the Navy. Bunker fuel emissions from embarked Marine Corps aircraft were reported in the Navy bunker fuel estimates. Bunker fuel emissions from other Marine Corps operations and training were assumed to be zero.
- Bunker fuel emissions from other DoD and non-DoD activities (i.e., other federal agencies) that purchased fuel from DESC were assumed to be zero.

Step 5: Determine Bunker Fuel Percentages

Next it was necessary to determine what percent of the marine and aviation fuels were used as international bunker fuels. Military aviation bunkers include international operations (i.e., sorties that originate in the United States and end in a foreign country), 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 (e.g., anti-submarine warfare flights). For the Air Force, a bunker fuel weighted average was calculated based on flying hours by major command. International flights were weighted by an adjustment factor to reflect the fact that they typically last longer than domestic flights. In addition, a fuel use correction factor was used to account for the fact that transport aircraft burn more fuel per hour of flight than most tactical aircraft. The Air Force bunker fuel percentage was determined to be 13.2 percent. This percentage was multiplied by total annual Air Force aviation fuel delivered for U.S. activities, producing an estimate for international bunker fuel consumed by the Air Force. The Naval Aviation bunker fuel percentage of total fuel was calculated using flying hour data from Chief of Naval Operations Flying Hour Projection System Budget for fiscal year 1998, and estimates of bunker fuel percent of flights provided by the fleet. The Naval Aviation bunker fuel percentage, determined to be 40.4 percent, was multiplied by total annual Navy aviation fuel delivered for U.S. activities, yielding total Navy aviation bunker fuel consumed.

For marine bunkers, fuels consumed while ships were underway were assumed to be bunker fuels. In 2000, the Navy reported that 79 percent of vessel operations were underway, while the remaining 21 percent of operations occurred in port (i.e., pierside). Therefore, the Navy maritime bunker fuel percentage was determined to be 79 percent. The percentage of time underway may vary from year-to-year. For example, for years prior to 2000, the bunker fuel percentage was 87 percent. Table A-152 and Table A-153 display DoD bunker fuel use totals for the Navy and Air Force.

Step 6: Calculate Emissions from International Bunker Fuels

Bunker fuel totals were multiplied by appropriate emission factors to determine GHG emissions. CO₂ emissions from Aviation Bunkers and distillate Marine Bunkers are the total of military aviation and marine bunker fuels, respectively.

The rows labeled "U.S. Military" and "U.S. Military Naval Fuels" in the tables in the International Bunker Fuels section of the Energy Chapter were based on the totals provided in Table A-152 and Table A-153, below. CO₂ emissions from aviation bunkers and distillate marine bunkers presented in Table A-156, and are based on emissions from fuels tallied in Table A-152 and Table A-153.

Table A-151: Transportation Fuels from Domestic Fuel Deliveries^a (Million Gallons)

Vehicle Type/Fuel	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Aviation	4,598.4	3,099.9	2,941.9	2,685.6	2,741.4	2,635.2	2,664.4	2,900.6	2,609.8	2,615.0	2,703.1	2,338.1	2,092.0	2,081.0	2,067.8	1,831.1
Total Jet Fuels	4,598.4	3,099.9	2,941.9	2,685.6	2,741.4	2,635.2	2,664.4	2,900.6	2,609.6	2,614.9	2,703.1	2,338.0	2,091.9	2,080.9	2,067.7	1,830.9
JP8	285.7	2,182.8	2,253.1	2,072.0	2,122.5	2,066.5	2,122.7	2,326.2	2,091.4	2,094.3	2,126.2	1,838.8	1,709.3	1,618.5	1,616.2	1,374.9
JP5	1,025.4	691.2	615.8	552.8	515.6	505.5	472.1	503.2	442.2	409.1	433.7	421.6	325.5	376.1	362.2	361.4
Other Jet Fuels	3,287.3	225.9	72.9	60.9	103.3	63.3	69.6	71.2	76.1	111.4	143.2	77.6	57.0	86.3	89.2	94.6
Aviation Gasoline	+	+	+	+	+	+	+	+	0.1	0.1	+	0.1	0.1	0.2	0.1	0.2
Marine	686.8	438.9	493.3	639.8	674.2	598.9	454.4	418.4	455.8	609.1	704.5	604.9	531.6	572.8	563.4	500.5
Middle Distillate (MGO)	+	+	38.5	47.5	51.1	49.2	48.3	33.0	41.2	88.1	71.2	54.0	45.8	45.7	55.2	56.8
Naval Distillate (F76)	686.8	438.9	449.0	583.4	608.4	542.9	398.0	369.1	395.1	460.9	583.5	525.9	453.6	516.0	483.4	412.5
Intermediate Fuel Oil (IFO) ^b	+	+	5.9	9.0	14.7	6.7	8.1	16.3	19.5	60.2	49.9	25.0	32.2	11.1	24.9	31.2
Other^c	717.1	310.9	276.9	263.3	256.8	256.0	248.2	109.8	211.1	221.2	170.9	205.6	107.3	169.0	173.6	174.6
Diesel	93.0	119.9	126.1	132.6	139.5	146.8	126.6	26.6	57.7	60.8	46.4	56.8	30.6	47.3	49.1	49.0
Gasoline	624.1	191.1	150.8	119.0	93.9	74.1	74.8	24.7	27.5	26.5	19.4	24.3	11.7	19.2	19.7	19.7
Jet Fuel ^d	+	+	+	11.7	23.4	35.0	46.7	58.4	125.9	133.9	105.1	124.4	65.0	102.6	104.8	105.9
Total (Including Bunkers)	6,002.4	3,849.8	3,712.1	3,588.8	3,672.4	3,490.1	3,367.0	3,428.8	3,276.7	3,445.3	3,578.5	3,148.6	2,730.9	2,822.8	2,804.9	2,506.2

Note: Totals may not sum due to independent rounding.

^a Includes fuel consumption in the United States and U.S. Territories.

^b Intermediate fuel oil (IFO 180 and IFO 380) is a blend of distillate and residual fuels. IFO is used by the Military Sealift Command.

^c Prior to 2001, gasoline and diesel fuel totals were estimated using data provided by the military Services for 1990 and 1996. The 1991 through 1995 data points were interpolated from the Service inventory data. The 1997 through 1999 gasoline and diesel fuel data were initially extrapolated from the 1996 inventory data. Growth factors used for other diesel and gasoline were 5.2 and -21.1 percent, respectively. However, prior diesel fuel estimates from 1997 through 2000 were reduced according to the estimated consumption of jet fuel that is assumed to have replaced the diesel fuel consumption in land-based vehicles. Data sets for other diesel and gasoline consumed by the military in 2000 were estimated based on ground fuels consumption trends. This method produced a result that was more consistent with expected consumption for 2000. In 2001, other gasoline and diesel fuel totals were generated by DESC.

^d The fraction of jet fuel consumed in land-based vehicles was estimated using Service data, DESC data, and expert judgment.

+ Does not exceed 0.05 million gallons.

Table A-152: Total U.S. Military Aviation Bunker Fuel (Million Gallons)

Fuel Type/Service	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
JP8	56.7	300.4	308.8	292.0	306.4	301.4	307.6	341.2	309.5	305.1	309.8	285.6	262.5	249.1	229.4	212.5
Navy	56.7	38.3	39.8	46.9	53.8	55.5	53.4	73.8	86.6	76.3	79.2	70.9	64.7	62.7	59.2	56.4
Air Force	+	262.2	269.0	245.1	252.6	245.9	254.2	267.4	222.9	228.7	230.6	214.7	197.8	186.5	170.3	156.1
JP5	370.5	249.8	219.4	194.2	184.4	175.4	160.3	169.7	158.3	146.1	157.9	160.6	125.0	144.5	139.2	136.9
Navy	365.3	246.3	216.1	191.2	181.4	170.6	155.6	163.7	153.0	141.3	153.8	156.9	122.8	141.8	136.5	133.4
Air Force	5.3	3.5	3.3	3.0	3.0	4.8	4.7	6.1	5.3	4.9	4.1	3.7	2.3	2.7	2.6	3.5
JP4	420.8	21.5	1.1	0.1	+	+	+	+	+	+	+	+	+	+	+	+
Navy	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	0.0
Air Force	420.8	21.5	1.1	0.1	+	+	+	+	+	+	+	+	+	+	+	0.0
JAA	13.7	9.2	10.3	9.4	10.8	10.8	12.5	12.6	13.7	21.7	30.0	15.5	11.7	15.6	16.8	18.1
Navy	8.5	5.7	6.6	5.9	6.6	6.3	7.9	8.0	9.8	15.5	21.5	11.6	9.1	11.7	12.5	12.3
Air Force	5.3	3.5	3.7	3.5	4.2	4.5	4.5	4.6	3.8	6.2	8.6	3.9	2.6	3.9	4.3	5.8
JA1	+	+	+	+	+	+	+	0.1	0.6	0.2	0.5	0.5	0.4	1.1	1.0	0.5
Navy	+	+	+	+	+	+	+	+	+	+	+	+	+	0.1	0.1	+
Air Force	+	+	+	+	+	+	+	0.1	0.6	0.2	0.5	0.5	0.4	1.0	0.8	0.6
JAB	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+
Navy	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+
Air Force	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+
Navy Subtotal	430.5	290.2	262.5	244.0	241.8	232.4	216.9	245.5	249.4	233.1	254.4	239.4	196.6	216.3	208.3	202.1
Air Force Subtotal	431.3	290.7	277.0	251.7	259.9	255.2	263.5	278.1	232.7	239.9	243.7	222.9	203.1	194.0	178.1	166.1
Total	861.8	580.9	539.5	495.6	501.7	487.5	480.4	523.6	482.1	473.0	498.1	462.3	399.7	410.3	386.3	368.1

+ Does not exceed 0.05 million gallons.

Note: Totals may not sum due to independent rounding.

Table A-153: Total U.S. DoD Maritime Bunker Fuel (Million Gallons)

Marine Distillates	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Navy—MGO	+	+	30.3	35.6	31.9	39.7	23.8	22.5	27.1	63.7	56.2	38.0	33.0	31.6	40.9	39.9
Navy—F76	522.4	333.8	331.9	441.7	474.2	466.0	298.6	282.6	305.6	347.8	434.4	413.1	355.9	404.1	376.9	320.0
Navy—IFO	+	+	4.6	7.1	11.6	5.3	6.4	12.9	15.4	47.5	39.4	19.7	25.4	8.8	19.0	24.1
Total	522.4	333.8	366.8	484.3	517.7	511.0	328.8	318.0	348.2	459.0	530.0	470.7	414.3	444.4	436.7	384.0

+ Does not exceed 0.005 million gallons.

Note: Totals may not sum due to independent rounding.

Table A-154: Aviation and Marine Carbon Contents (Tg Carbon/QBtu) and Fraction Oxidized

Mode (Fuel)	Carbon Content Coefficient	Fraction Oxidized
Aviation (Jet Fuel)	Variable	1.00
Marine (Distillate)	20.17	1.00
Marine (Residual)	20.48	1.00

Source: EPA (2010) and IPCC (2006)

Table A-155: Annual Variable Carbon Content Coefficient for Jet Fuel (Tg Carbon/QBtu)

Fuel	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Jet Fuel	19.40	19.34	19.70	19.70	19.70	19.70	19.70	19.70	19.70	19.70	19.70	19.70	19.70	19.70	19.70	19.70

Source: EPA (2010)

Table A-156: Total U.S. DoD CO₂ Emissions from Bunker Fuels (Tg CO₂ Eq.)

Mode	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Aviation	8.1	5.5	5.2	4.8	4.9	4.7	4.7	5.1	4.7	4.6	4.8	4.5	3.9	4.0	3.8	3.6
Marine	5.4	3.4	3.8	5.0	5.3	5.2	3.4	3.3	3.6	4.7	5.4	4.8	4.2	4.6	4.5	3.9
Total	13.4	9.0	9.0	9.8	10.2	10.0	8.0	8.3	8.3	9.3	10.3	9.3	8.1	8.5	8.2	7.5

Note: Totals may not sum due to independent rounding.

3.8. Methodology for Estimating HFC and PFC Emissions from Substitution of Ozone Depleting Substances

Emissions of HFCs and PFCs from the substitution of ozone depleting substances (ODS) are developed using a country-specific modeling approach. The Vintaging Model was developed as a tool for estimating the annual chemical emissions from industrial sectors that have historically used ODS in their products. Under the terms of the Montreal Protocol and the United States' Clean Air Act Amendments of 1990, the domestic U.S. consumption of ODS—chlorofluorocarbons (CFCs), halons, carbon tetrachloride, methyl chloroform, and hydrochlorofluorocarbons (HCFCs)—has been drastically reduced, forcing these industrial sectors to transition to more ozone friendly chemicals. As these industries have moved toward ODS alternatives such as hydrofluorocarbons (HFCs) and perfluorocarbons (PFCs), the Vintaging Model has evolved into a tool for estimating the rise in consumption and emissions of these alternatives, and the decline of ODS consumption and emissions.

The Vintaging Model estimates emissions from five ODS substitute end-use sectors: air-conditioning and refrigeration, foams, aerosols, solvents, and fire-extinguishing. Within these sectors, there are 59 independently modeled end-uses. The model requires information on the market growth for each of the end-uses, as well as a history of the market transition from ODS to alternatives, as well as the characteristics of each end-use such as market size or charge sizes and loss rates. As ODS are phased out, a percentage of the market share originally filled by the ODS is allocated to each of its substitutes.

The model, named for its method of tracking the emissions of annual “vintages” of new equipment that enter into service, is a “bottom-up” model. It models the consumption of chemicals based on estimates of the quantity of equipment or products sold, serviced, and retired each year, and the amount of the chemical required to manufacture and/or maintain the equipment. The Vintaging Model makes use of this market information to build an inventory of the in-use stocks of the equipment and ODS and ODS substitute in each of the end-uses. The simulation is considered to be a “business-as-usual” baseline case, and does not incorporate measures to reduce or eliminate the emissions of these gases other than those regulated by U.S. law or otherwise common in the industry. Emissions are estimated by applying annual leak rates, service emission rates, and disposal emission rates to each population of equipment. By aggregating the emission and consumption output from the different end-uses, the model produces estimates of total annual use and emissions of each chemical.

The Vintaging Model synthesizes data from a variety of sources, including data from the ODS Tracking System maintained by the Stratospheric Protection Division and information from submissions to EPA under the Significant New Alternatives Policy (SNAP) program. Published sources include documents prepared by the United Nations Environment Programme (UNEP) Technical Options Committees, reports from the Alternative Fluorocarbons Environmental Acceptability Study (AFEAS), and conference proceedings from the International Conferences on Ozone Protection Technologies and Earth Technologies Forums. EPA also coordinates extensively with numerous trade associations and individual companies. For example, the Alliance for Responsible Atmospheric Policy; the Air-Conditioning, Heating and Refrigeration Institute; the Association of Home Appliance Manufacturers; the American Automobile Manufacturers Association; and many of their member companies have provided valuable information over the years. In some instances the unpublished information that the EPA uses in the model is classified as Confidential Business Information (CBI). The annual emissions inventories of chemicals are aggregated in such a way that CBI cannot be inferred. Full public disclosure of the inputs to the Vintaging Model would jeopardize the security of the CBI that has been entrusted to the EPA.

The following sections discuss the emission equations used in the Vintaging Model for each broad end-use category. These equations are applied separately for each chemical used within each of the different end-uses. In the majority of these end-uses, more than one ODS substitute chemical is used.

In general, the modeled emissions are a function of the amount of chemical consumed in each end-use market. Estimates of the consumption of ODS alternatives can be inferred by determining the transition path of each regulated ODS used in the early 1990s. Using data gleaned from a variety of sources, assessments are made regarding which alternatives have been used, and what fraction of the ODS market in each end-use has been captured by a given alternative. By combining this with estimates of the total end-use market growth, a consumption value can be estimated for each chemical used within each end-use.

Methodology

The Vintaging Model estimates the use and emissions of ODS alternatives by taking the following steps:

1. *Gather historical data.* The Vintaging Model is populated with information on each end-use, taken from published sources and industry experts.

2. *Simulate the implementation of new, non-ODS technologies.* The Vintaging Model uses detailed characterizations of the existing uses of the ODS, as well as data on how the substitutes are replacing the ODS, to simulate the implementation of new technologies that enter the market in compliance with ODS phase-out policies. As part of this simulation, the ODS substitutes are introduced in each of the end-uses over time as seen historically and as needed to comply with the ODS phase-out.

3. *Estimate emissions of the ODS substitutes.* The chemical use is estimated from the amount of substitutes that are required each year for the manufacture, installation, use, or servicing of products. The emissions are estimated from the emission profile for each vintage of equipment or product in each end-use. By aggregating the emissions from each vintage, a time profile of emissions from each end-use is developed.

Each set of end-uses is discussed in more detail in the following sections.

Refrigeration and Air-Conditioning

For refrigeration and air conditioning products, emission calculations are split into two categories: emissions during equipment lifetime, which arise from annual leakage and service losses, and disposal emissions, which occur at the time of discard. Two separate steps are required to calculate the lifetime emissions from leakage and service, and the emissions resulting from disposal of the equipment. For any given year, these lifetime emissions (for existing equipment) and disposal emissions (from discarded equipment) are summed to calculate the total emissions from refrigeration and air-conditioning. As new technologies replace older ones, it is generally assumed that there are improvements in their leak, service, and disposal emission rates.

Step 1: Calculate lifetime emissions

Emissions from any piece of equipment include both the amount of chemical leaked during equipment operation and the amount emitted during service. Emissions from leakage and servicing can be expressed as follows:

$$Es_j = (l_a + l_s) \times \sum Qc_{j-i+1} \quad \text{for } i = 1 \rightarrow k$$

Where:

Es = Emissions from Equipment Serviced. Emissions in year j from normal leakage and servicing (including recharging) of equipment.

l_a = Annual Leak Rate. Average annual leak rate during normal equipment operation (expressed as a percentage of total chemical charge).

l_s = Service Leak Rate. Average leakage during equipment servicing (expressed as a percentage of total chemical charge).

Qc = Quantity of Chemical in New Equipment. Total amount of a specific chemical used to charge new equipment in a given year by weight.

i = Counter, runs from 1 to lifetime (k).

j = Year of emission.

k = Lifetime. The average lifetime of the equipment.

Step 2: Calculate disposal emissions

The disposal emission equations assume that a certain percentage of the chemical charge will be emitted to the atmosphere when that vintage is discarded. Disposal emissions are thus a function of the quantity of chemical contained in the retiring equipment fleet and the proportion of chemical released at disposal:

$$Ed_j = Qc_{j-k+1} \times [1 - (rm \times rc)]$$

Where:

Ed = Emissions from Equipment Disposed. Emissions in year j from the disposal of equipment.

- Q_c = Quantity of Chemical in New Equipment. Total amount of a specific chemical used to charge new equipment in year $j-k+1$, by weight.
- rm = Chemical Remaining. Amount of chemical remaining in equipment at the time of disposal (expressed as a percentage of total chemical charge).
- rc = Chemical Recovery Rate. Amount of chemical that is recovered just prior to disposal (expressed as a percentage of chemical remaining at disposal (rm)).
- j = Year of emission.
- k = Lifetime. The average lifetime of the equipment.

Step 3: Calculate total emissions

Finally, lifetime and disposal emissions are summed to provide an estimate of total emissions.

$$E_j = Es_j + Ed_j$$

Where:

- E = Total Emissions. Emissions from refrigeration and air conditioning equipment in year j .
- Es = Emissions from Equipment Serviced. Emissions in year j from leakage and servicing (including recharging) of equipment.
- Ed = Emissions from Equipment Disposed. Emissions in year j from the disposal of equipment.
- j = Year of emission.

Assumptions

The assumptions used by the Vintaging Model to trace the transition of each type of equipment away from ODS are presented in Table A- 157, below. As new technologies replace older ones, it is generally assumed that there are improvements in their leak, service, and disposal emission rates. Additionally, the market for each equipment type is assumed to grow independently, according to annual growth rates.

Table A- 157: Refrigeration and Air-Conditioning Market Transition Assumptions

Initial Market Segment	Primary Substitute				Secondary Substitute				Tertiary Substitute				Growth Rate
	Name of Substitute	Start Date	Date of Full Penetration in New Equipment	Maximum Market Penetration	Name of Substitute	Start Date	Date of Full Penetration in New Equipment	Maximum Market Penetration	Name of Substitute	Start Date	Date of Full Penetration in New Equipment	Maximum Market Penetration	
Centrifugal Chillers													
CFC-11	HCFC-123	1993	1993	45%	Unknown								0.5%
	HCFC-22	1991	1993	16%	HFC-134a	2000	2010	100%	None				
	HFC-134a	1992	1993	39%	None								
CFC-12	HFC-134a	1992	1994	53%	None								0.5%
	HCFC-22	1991	1994	16%	HFC-134a	2000	2010	100%	None				
	HCFC-123	1993	1994	31%	Unknown								
R-500	HFC-134a	1992	1994	53%	None								0.5%
	HCFC-22	1991	1994	16%	HFC-134a	2000	2010	100%	None				
	HCFC-123	1993	1994	31%	Unknown								
CFC-114	HFC-236fa	1993	1994	100%	HFC-236fa	1996	1996	100%	HFC-134a	1998	2009	100%	0.2%
Cold Storage													
CFC-12	HCFC-22	1990	1993	65%	R-404A	1996	2010	75%	None				2.5%
					R-507	1996	2010	25%	None				
	R-404A	1994	1996	26%	None								
HCFC-22	R-507	1994	1996	9%	None								2.5%
	HCFC-22	1992	1993	100%	R-404A	1996	2009	8%	None				
					R-507	1996	2009	3%	None				
R-502					R-404A	2009	2010	68%	None				2.5%
					R-507	2009	2010	23%	None				
	HCFC-22	1990	1993	40%	R-404A	1996	2010	38%	None				
					R-507	1996	2010	12%	None				
					Non-ODP/GWP	1996	2010	50%	None				
	R-404A	1993	1996	45%	None								
	R-507	1994	1996	15%	None								
Commercial Unitary Air Conditioners (Large)													
HCFC-22	HCFC-22	1992	1993	100%	R-410A	2001	2005	5%	None				0.8%
					R-407C	2006	2009	1%	None				
					R-410A	2006	2009	9%	None				
					R-407C	2009	2010	5%	None				
					R-410A	2009	2010	81%	None				
Commercial Unitary Air Conditioners (Small)													
HCFC-22	HCFC-22	1992	1993	100%	R-410A	1996	2000	3%	None				0.8%
					R-410A	2001	2005	18%	None				
					R-410A	2006	2009	8%	None				
					R-410A	2009	2010	71%	None				
Dehumidifiers													
HCFC-22	HFC-134a	1997	1997	89%	None								0.2%

Initial Market Segment	Primary Substitute				Secondary Substitute				Tertiary Substitute				Growth Rate
	Name of Substitute	Start Date	Date of Full Penetration in New Equipment	Maximum Market Penetration	Name of Substitute	Start Date	Date of Full Penetration in New Equipment	Maximum Market Penetration	Name of Substitute	Start Date	Date of Full Penetration in New Equipment	Maximum Market Penetration	
	R-410A	2007	2010	11%	None								
Ice Makers													
CFC-12	HFC-134a	1993	1995	100%	None								2.5%
Industrial Process Refrigeration													
CFC-11	HCFC-123	1992	1994	70%	Unknown								2.5%
	HFC-134a	1992	1994	15%	None								
CFC-12	HCFC-22	1991	1994	15%	HFC-134a	1995	2010	100%	None				2.5%
	HCFC-22	1991	1994	10%	HFC-134a	1995	2010	15%	None				
					R-404A	1995	2010	50%	None				
					R-410A	1999	2010	20%	None				
					R-507	1995	2010	15%	None				
	HCFC-123	1992	1994	35%	Unknown								
	HFC-134a	1992	1994	50%	None								
	R-401A	1995	1996	5%	HFC-134a	1997	2000	100%	None				
HCFC-22	HCFC-22	1992	1993	100%	HFC-134a	1995	2009	2%	None				2.5%
					R-404A	1995	2009	5%	None				
					R-410A	1999	2009	2%	None				
					R-507	1995	2009	2%	None				
					HFC-134a	2009	2010	14%	None				
					R-404A	2009	2010	45%	None				
					R-410A	2009	2010	18%	None				
					R-507	2009	2010	14%	None				
Mobile Air Conditioners (Passenger Cars)													
CFC-12	HFC-134a	1992	1994	100%	None								1.9%
Mobile Air Conditioners (Light Duty Trucks)													
CFC-12	HFC-134a	1993	1994	100%	None								-0.4%
Mobile Air Conditioners (School and Tour Buses)													
CFC-12	HCFC-22	1994	1995	0.5%	HFC-134a	2006	2007	100%	None				2.6%
	HFC-134a	1994	1997	99.5%	None								
Mobile Air Conditioners (Transit Buses)													
HCFC-22	HFC-134a	1995	2009	100%	None								2.6%
Mobile Air Conditioners (Trains)													
HCFC-22	HFC-134a	2002	2009	50%	None								2.6%
	R-407C	2002	2009	50%	None								
Packaged Terminal Air Conditioners and Heat Pumps													
HCFC-22					R-410A	2006	2009	10%	None				0.8%
					R-410A	2009	2010	90%	None				
Positive Displacement Chillers													
HCFC-22	HCFC-22	1996	1996	100%	HFC-134a	2000	2009	9%	R-407C	2010	2020	60%	0.5%
					R-407C	2000	2009	1%	R-410A	2010	2020	40%	
									None				

Initial Market Segment	Primary Substitute				Secondary Substitute				Tertiary Substitute				Growth Rate
	Name of Substitute	Start Date	Date of Full Penetration in New Equipment	Maximum Market Penetration	Name of Substitute	Start Date	Date of Full Penetration in New Equipment	Maximum Market Penetration	Name of Substitute	Start Date	Date of Full Penetration in New Equipment	Maximum Market Penetration	
CFC-12	HCFC-22	1993	1993	100%	HFC-134a	2009	2010	81%	R-407C	2010	2020	60%	0.2%
					R-407C	2009	2010	9%	R-410A	2010	2020	40%	
					HFC-134a	2000	2009	9%	None				
					R-407C	2000	2009	1%	R-407C	2010	2020	60%	
					HFC-134a	2009	2010	81%	R-410A	2010	2020	40%	
					R-407C	2009	2010	9%	None	2010	2020	40%	
Refrigerated Appliances													
CFC-12	HFC-134a	1994	1995	100%	HFC-134a	2005	2005	100%	None				0.5%
Residential Unitary Air Conditioners													
HCFC-22	HCFC-22	2006	2006	70%	R-410A	2007	2010	29%	None	2011	2015	100%	0.8%
					R-407C	2010	2010	14%	R-410A				
					R-410A	2010	2010	57%	None				
	R-410A	2006	2006	100%	None								
	R-410A	2000	2005	5%	R-410A	2006	2006	100%	None				
R-410A	2000	2006	5%	None									
R-410A	2006	2006	20%	None									
Retail Food (Large)													
CFC-12	R-502	1988	1990	100%	HCFC-22	1991	1993	100%	R-404A	1995	2000	17.5%	1.7%
R-502	HCFC-22	1990	1993	100%					R-507	1995	2000	7.5%	1.7%
									R-404A	2000	2005	31.5%	
									R-507	2000	2005	13.5%	
									R-404A	2005	2010	18%	
									R-507	2005	2010	12%	
					R-404A	1995	2000	17.5%	None				
					R-507	1995	2000	7.5%	None				
					R-404A	2000	2005	31.5%	None				
					R-507	2000	2005	13.5%	None				
					R-404A	2005	2010	18%	None				
					R-507	2005	2010	12%	None				
Retail Food (Medium)													
HCFC-22	R-404A	1995	2000	17.5%	None								1.7%
	R-507	1995	2000	7.5%	None								
	R-404A	2000	2005	31.5%	None								
	R-507	2000	2005	13.5%	None								
	R-404A	2005	2010	18%	None								
	R-507	2005	2010	12%	None								
Retail Food (Small)													
CFC-12	HCFC-22	1990	1993	90%	HFC-134a	1993	1995	90%	CO ₂	2010	2010	5%	1.7%

Initial Market Segment	Primary Substitute				Secondary Substitute				Tertiary Substitute				Growth Rate		
	Name of Substitute	Start Date	Date of Full Penetration in New Equipment	Maximum Market Penetration	Name of Substitute	Start Date	Date of Full Penetration in New Equipment	Maximum Market Penetration	Name of Substitute	Start Date	Date of Full Penetration in New Equipment	Maximum Market Penetration			
	R-404A R-507	1993 1993	1996 1996	7.5% 2.5%	R-404A R-507 None None	2000 2000	2009 2009	7.5% 2.5%	None None						
Transport Refrigeration															
CFC-12	HFC-134a	1993	1995	98%	None	1995	1999	100%	None				2.5%		
R-502	HCFC-22	1993	1995	2%	HFC-134a										
	HFC-134a	1993	1995	55%	None										
	R-404A	1993	1995	45%	None										
Water-Source and Ground-Source Heat Pumps															
HCFC-22	R-407C	2000	2006	5%					None				0.8%		
	R-410A	2000	2006	5%					None						
	HFC-134a	2000	2009	2%					None						
	R-407C	2006	2009	2.5%					None						
	R-410A	2006	2009	4.5%					None						
	HFC-134a	2009	2010	18%					None						
	R-407C	2009	2010	22.5%					None						
	R-410A	2009	2010	40.5%					None						
Window Units															
HCFC-22	R-407C	2003	2009	3%	None								5.0%		
	R-407C	2009	2010	35%	None										
	R-410A	2003	2009	7%	None										
	R-410A	2009	2010	55%	None										

Table A- 158 presents the average equipment lifetimes and annual HFC emission rates (for servicing and leaks) for each end-use assumed by the Vintaging Model.

Table A- 158. Refrigeration and Air-conditioning Lifetime Assumptions

End-Use	Lifetime (Years)	HFC Emission Rates (%)
Centrifugal Chillers	20 – 27	2.0 – 10.9
Cold Storage	20 – 25	15.0
Commercial Unitary A/C	15	7.9 – 8.6
Dehumidifiers	11	0.5
Ice Makers	20	3.0
Industrial Process Refrigeration	25	3.6 – 12.3
Mobile Air Conditioners	5 – 12	2.3 – 18.0
Positive Displacement Chillers	20	0.5 – 1.5
PTAC/PTHP	12	3.9
Retail Food	15 – 20	7.8 – 29.9
Refrigerated Appliances	14	0.6
Residential Unitary A/C	15	7.2 – 8.3
Transport Refrigeration	12	20.6 – 27.9
Water & Ground Source Heat Pumps	20	3.9
Window Units	12	0.6

Aerosols

ODSs, HFCs and many other chemicals are used as propellant aerosols. Pressurized within a container, a nozzle releases the chemical, which allows the product within the can to also be released. Two types of aerosol products are modeled: metered dose inhalers (MDI) and consumer aerosols. In the United States, the use of CFCs in consumer aerosols was banned in 1978, and many products transitioned to hydrocarbons or “not-in-kind” technologies, such as solid deodorants and finger-pump hair sprays. However, MDIs can continue to use CFCs as propellants because their use has been deemed essential. Essential use exemptions granted to the United States under the Montreal Protocol for CFC use in MDIs are limited to the treatment of asthma and chronic obstructive pulmonary disease.

All HFCs and PFCs used in aerosols are assumed to be emitted in the year of manufacture. Since there is currently no aerosol recycling, it is assumed that all of the annual production of aerosol propellants is released to the atmosphere. The following equation describes the emissions from the aerosols sector.

$$E_j = Qc_j$$

Where:

E = Emissions. Total emissions of a specific chemical in year j from use in aerosol products, by weight.

Qc = Quantity of Chemical. Total quantity of a specific chemical contained in aerosol products sold in year j , by weight.

j = Year of emission.

Transition Assumptions

Transition assumptions and growth rates for those items that use ODSs or HFCs as propellants, including vital medical devices and specialty consumer products, are presented in Table A- 159.

Table A- 159. Aerosol Product Transition Assumptions

Initial Market Segment	Primary Substitute				Secondary Substitute				Growth Rate
	Name of Substitute	Start Date	Date of Full Penetration in New Equipment	Maximum Market Penetration	Name of Substitute	Start Date	Date of Full Penetration in New Equipment	Maximum Market Penetration	
MDIs									
CFC Mix*	HFC-134a	1997	1997	6%	None				0.8%
	Non-ODP/GWP	1998	2007	7%	None				
	CFC Mix*	2000	2000	87%	HFC-134a	2002	2002	34%	
					HFC-134a	2003	2009	47%	
					HFC-227ea	2006	2009	5%	
					HFC-134a	2010	2011	6%	
					HFC-227ea	2010	2011	1%	
					HFC-134a	2011	2012	3%	
					HFC-227ea	2011	2012	0.3%	
					HFC-134a	2014	2014	3%	
					HFC-227ea	2014	2014	0.3%	
Consumer Aerosols (Non-MDIs)									
NA**	HFC-152a	1990	1991	50%	None				2.0%
	HFC-134a	1995	1995	50%	HFC-152a	1997	1998	44%	
					HFC-152a	2001	2005	36%	

*CFC Mix consists of CFC-11, CFC-12 and CFC-114 and represents the weighted average of several CFCs consumed for essential use in MDIs from 1993 to 2008.

**Consumer Aerosols transitioned away from ODS prior to 1985, the year in which the Vintaging Model begins. The portion of the market that is now using HFC propellants is modeled.

Solvents

ODSs, HFCs, PFCs and other chemicals are used as solvents to clean items. For example, electronics may need to be cleaned after production to remove any manufacturing process oils or residues left. Solvents are applied by moving the item to be cleaned within a bath or stream of the solvent. Generally, most solvents are assumed to remain in the liquid phase and are not emitted as gas. Thus, emissions are considered “incomplete,” and are a fixed percentage of the amount of solvent consumed in a year. The remainder of the consumed solvent is assumed to be reused or disposed without being released to the atmosphere. The following equation calculates emissions from solvent applications.

$$E_j = l \times Qc_j$$

Where:

E = Emissions. Total emissions of a specific chemical in year j from use in solvent applications, by weight.

l = Percent Leakage. The percentage of the total chemical that is leaked to the atmosphere, assumed to be 90 percent.

Qc = Quantity of Chemical. Total quantity of a specific chemical sold for use in solvent applications in the year j , by weight.

j = Year of emission.

Transition Assumptions

The transition assumptions and growth rates used within the Vintaging Model for electronics cleaning, metals cleaning, precision cleaning, and adhesives, coatings and inks, are presented in Table A- 160.

Table A- 160. Solvent Market Transition Assumptions

Initial Market Segment	Primary Substitute				Secondary Substitute				Growth Rate
	Name of Substitute	Start Date	Date of Full Penetration in New Equipment	Maximum Market Penetration	Name of Substitute	Start Date	Date of Full Penetration in New Equipment	Maximum Market Penetration	
Adhesives									
CH ₃ CCl ₃	Non-ODP/GWP	1994	1995	100%	None				2.0%
Electronics									
CFC-113	Semi-Aqueous	1994	1995	52%	None				2.0%
	HCFC-225ca/cb	1994	1995	0.2%	Unknown				
	HFC-4310mee	1995	1996	0.7%	None				
	HFE-7100	1994	1995	0.7%	None				
	nPB	1992	1996	5%	None				
	Methyl Siloxanes	1992	1996	0.8%	None				
CH ₃ CCl ₃	No-Clean	1992	1996	40%	None				2.0%
	Non-ODP/GWP	1996	1997	99.8%	None				
	PFC/PFPE	1996	1997	0.2%	Non-ODP/GWP	2000	2003	90%	
					Non-ODP/GWP	2005	2009	10%	
Metals									
CH ₃ CCl ₃	Non-ODP/GWP	1992	1996	100%	None				2.0%
CFC-113	Non-ODP/GWP	1992	1996	100%	None				2.0%
CCl ₄	Non-ODP/GWP	1992	1996	100%	None				2.0%
Precision									
CH ₃ CCl ₃	Non-ODP/GWP	1995	1996	99.3%	None				2.0%
	HFC-4310mee	1995	1996	0.6%	None				
	PFC/PFPE	1995	1996	0.1%	Non-ODP/GWP	2000	2003	90%	
CFC-113	Non-ODP/GWP	1995	1996	96%	Non-ODP/GWP	2005	2009	10%	2.0%
	HCFC-225ca/cb	1995	1996	1%	None				
	HFE-7100	1995	1996	3%	Unknown				
					None				

Non-ODP/GWP includes chemicals with 0 ODP and low GWP, such as hydrocarbons and ammonia, as well as not-in-kind alternatives such as “no clean” technologies.

Fire Extinguishing

ODSs, HFCs, PFCs and other chemicals are used as fire-extinguishing agents, in both hand-held “streaming” applications as well as in built-up “flooding” equipment similar to water sprinkler systems. Although these systems are generally built to be leak-tight, some leaks do occur and of course emissions occur when the agent is released. Total emissions from fire extinguishing are assumed, in aggregate, to equal a percentage of the total quantity of chemical in operation at a given time. For modeling purposes, it is assumed that fire extinguishing equipment leaks at a constant rate for an average equipment lifetime, as shown in the equation below. In streaming systems, non-halon emissions are assumed to be 3.5 percent of all chemical in use in each year, while in flooding systems 2.5 percent of the installed base of chemical is assumed to leak annually. Halon systems are assumed to leak at higher rates. The equation is applied for a single year, accounting for all fire protection equipment in operation in that year. Each fire protection agent is modeled separately. In the Vintaging Model, streaming applications have a 12-year lifetime and flooding applications have a 20-year lifetime.

$$E_j = r \times \sum Q_{C,j-i+1} \quad \text{for } i=1 \rightarrow k$$

Where:

E = Emissions. Total emissions of a specific chemical in year j for streaming fire extinguishing equipment, by weight.

r = Percent Released. The percentage of the total chemical in operation that is released to the atmosphere.

Q_C = Quantity of Chemical. Total amount of a specific chemical used in new fire extinguishing equipment in a given year, $j-i+1$, by weight.

i = Counter, runs from 1 to lifetime (k).

j = Year of emission.

k = Lifetime. The average lifetime of the equipment.

Transition Assumptions

Transition assumptions and growth rates for these two fire extinguishing types are presented in Table A- 161.

Table A- 161. Fire Extinguishing Market Transition Assumptions

Initial Market Segment	Primary Substitute				Secondary Substitute				Growth Rate
	Name of Substitute	Start Date	Date of Full Penetration in New Equipment	Maximum Market Penetration	Name of Substitute	Start Date	Date of Full Penetration in New Equipment	Maximum Market Penetration	
Flooding Agents									
Halon-1301	Halon-1301*	1994	1994	4%	Unknown				2.2%
	HFC-23	1994	1999	0.2%	None				
	HFC-227ea	1994	1999	18%	FK-5-1-12	2003	2010	10%	
					HFC-125	2001	2008	10%	
	Non-ODP/GWP	1994	1994	46%	FK-5-1-12	2003	2010	7%	
	Non-ODP/GWP	1995	2034	10%	None				
	Non-ODP/GWP	1998	2027	10%	None				
	C ₄ F ₁₀	1994	1999	1%	FK-5-1-12	2003	2003	100%	
	HFC-125	1997	2006	11%	None				
Streaming Agents									
Halon-1211	Halon-1211*	1992	1992	5%	Unknown				3.0%
	HFC-236fa	1997	1999	3%	None				
	Halotron	1994	1997	4%	Non-ODP/GWP	2015	2015	25%	
					HFC-236fa	2015	2015	75%	
	Non-ODP/GWP	1993	1994	58%	None				
	Non-ODP/GWP	1995	2024	20%	None				
	Non-ODP/GWP	1999	2018	10%	None				

*Despite the 1994 consumption ban, a small percentage of new halon systems are assumed to continue to be built and filled with stockpiled or recovered supplies.

Foam Blowing

ODSs, HFCs, and other chemicals are used to produce foams, including such items as the foam insulation panels around refrigerators, insulation sprayed on buildings, etc. The chemical is used to create pockets of gas within a substrate, increasing the insulating properties of the item. Foams are given emission profiles depending on the foam type (open cell or closed cell). Open cell foams are assumed to be 100 percent emissive in the year of manufacture. Closed cell foams are assumed to emit a portion of their total HFC content upon manufacture, a portion at a constant rate over the lifetime of the foam, a portion at disposal, and a portion after disposal; these portions vary by end-use.

Step 1: Calculate manufacturing emissions (open-cell and closed-cell foams)

Manufacturing emissions occur in the year of foam manufacture, and are calculated as presented in the following equation.

$$Em_j = lm \times Qc_j$$

Where:

Em_j = Emissions from manufacturing. Total emissions of a specific chemical in year j due to manufacturing losses, by weight.

lm = Loss Rate. Percent of original blowing agent emitted during foam manufacture. For open-cell foams, lm is 100%.

Qc = Quantity of Chemical. Total amount of a specific chemical used to manufacture closed-cell foams in a given year.

j = Year of emission.

Step 2: Calculate lifetime emissions (closed-cell foams)

Lifetime emissions occur annually from closed-cell foams throughout the lifetime of the foam, as calculated as presented in the following equation.

$$Eu_j = lu \times \sum Qc_{j-i+1} \text{ for } i=1 \rightarrow k$$

Where:

Eu_j = Emissions from Lifetime Losses. Total emissions of a specific chemical in year j due to lifetime losses during use, by weight.

lu = Leak Rate. Percent of original blowing agent emitted each year during lifetime use.

Qc = Quantity of Chemical. Total amount of a specific chemical used to manufacture closed-cell foams in a given year.

i = Counter, runs from 1 to lifetime (k).

j = Year of emission.

k = Lifetime. The average lifetime of foam product.

Step 3: Calculate disposal emissions (closed-cell foams)

Disposal emissions occur in the year the foam is disposed, and are calculated as presented in the following equation.

$$Ed_j = ld \times Qc_{j-k}$$

Where:

Ed_j = Emissions from disposal. Total emissions of a specific chemical in year j at disposal, by weight.

ld = Loss Rate. Percent of original blowing agent emitted at disposal.

Qc = Quantity of Chemical. Total amount of a specific chemical used to manufacture closed-cell foams in a given year.

j = Year of emission.

k = Lifetime. The average lifetime of foam product.

Step 4: Calculate post-disposal emissions (closed-cell foams)

Post-Disposal emissions occur in the years after the foam is disposed; for example, emissions might occur while the disposed foam is in a landfill. Currently, the only foam type assumed to have post-disposal emissions is polyurethane foam used as domestic refrigerator and freezer insulation, which is expected to continue to emit for 26 years post-disposal, calculated as presented in the following equation.

$$Ep_j = lp \times \sum Qc_{j-m} \text{ for } m=k \rightarrow k+32$$

Where:

Ep_j = Emissions from post disposal. Total post-disposal emissions of a specific chemical in year j, by weight.

lp = Leak Rate. Percent of original blowing agent emitted post disposal.

Qc = Quantity of Chemical. Total amount of a specific chemical used to manufacture closed-cell foams in a given year.

k = Lifetime. The average lifetime of foam product.

m = Counter. Runs from lifetime (k) to (k+26).

j = Year of emission.

Step 5: Calculate total emissions (open-cell and closed-cell foams)

To calculate total emissions from foams in any given year, emissions from all foam stages must be summed, as presented in the following equation.

$$E_j = Em_j + Eu_j + Ed_j + Ep_j$$

Where:

E_j = Total Emissions. Total emissions of a specific chemical in year j , by weight.

Em = Emissions from manufacturing. Total emissions of a specific chemical in year j due to manufacturing losses, by weight.

Eu_j = Emissions from Lifetime Losses. Total emissions of a specific chemical in year j due to lifetime losses during use, by weight.

Ed_j = Emissions from disposal. Total emissions of a specific chemical in year j at disposal, by weight.

Ep_j = Emissions from post disposal. Total post-disposal emissions of a specific chemical in year j , by weight.

Assumptions

The Vintaging Model contains 13 foam types, whose transition assumptions away from ODS and growth rates are presented in Table A- 162. The emission profiles of these 13 foam types are shown in Table A- 163.

Table A- 162. Foam Blowing Market Transition Assumptions

Initial Market Segment	Primary Substitute				Secondary Substitute				Tertiary Substitute				Growth Rate
	Name of Substitute	Start Date	Date of Full Penetration in New Equipment	Maximum Market Penetration	Name of Substitute	Start Date	Date of Full Penetration in New Equipment	Maximum Market Penetration	Name of Substitute	Start Date	Date of Full Penetration in New Equipment	Maximum Market Penetration	
Commercial Refrigeration Foam													
CFC-11	HCFC-141b	1989	1996	40%	HFC-245fa	2002	2003	80%	None				6.0%
	HCFC-142b	1989	1996	8%	Non-ODP/GWP	2002	2003	20%	None				
					Non-ODP/GWP	2009	2010	80%	None				
					HFC-245fa	2009	2010	20%	None				
					Non-ODP/GWP	2009	2010	80%	None				
	HCFC-22	1989	1996	52%	HFC-245fa	2009	2010	20%	None				
Flexible PU Foam: Integral Skin Foam													
CFC-11	HCFC-141b	1989	1990	100%	HFC-134a	1993	1996	25%	None				2.0%
					HFC-134a	1994	1996	25%	None				
					CO ₂	1993	1996	25%	None				
					CO ₂	1994	1996	25%	None				
Flexible PU Foam: Slabstock Foam, Moulded Foam													
CFC-11	Non-ODP/GWP	1992	1992	100%	None								2.0%
Phenolic Foam													
CFC-11	HCFC-141b	1989	1990	100%	Non-ODP/GWP	1992	1992	100%	None				2.0%
Polyolefin Foam													
CFC-114	HFC-152a	1989	1993	10%	Non-ODP/GWP	2005	2010	100%	None				2.0%
	HCFC-142b	1989	1993	90%	Non-ODP/GWP	1994	1996	100%	None				
PU and PIR Rigid: Boardstock													
CFC-11	HCFC-141b	1993	1996	100%	Non-ODP/GWP	2000	2003	95%	None				6.0%
					HC/HFC-245fa Blend	2000	2003	5%	None				
PU Rigid: Domestic Refrigerator and Freezer Insulation													
CFC-11	HCFC-141b	1993	1995	100%	HFC-134a	1996	2001	7%	Non-ODP/GWP	2002	2003	100%	0.8%
					HFC-245fa	2001	2003	50%	Non-ODP/GWP	2015	2029	100%	
					HFC-245fa	2006	2009	10%	Non-ODP/GWP	2015	2029	100%	
					Non-ODP/GWP	2002	2005	10%	None				
					Non-ODP/GWP	2006	2009	3%	None				
					Non-ODP/GWP	2009	2014	20%	None				
PU Rigid: One Component Foam													
CFC-12	HCFC-142b/22 Blend	1989	1996	70%	Non-ODP/GWP	2009	2010	80%	None				4.0%
					HFC-134a	2009	2010	10%	None				
					HFC-152a	2009	2010	10%	None				

Initial Market Segment	Primary Substitute				Secondary Substitute				Tertiary Substitute				Growth Rate
	Name of Substitute	Start Date	Date of Full Penetration in New Equipment	Maximum Market Penetration	Name of Substitute	Start Date	Date of Full Penetration in New Equipment	Maximum Market Penetration	Name of Substitute	Start Date	Date of Full Penetration in New Equipment	Maximum Market Penetration	
	HCFC-22	1989	1996	30%	Non-ODP/GWP	2009	2010	80%	None				
					HFC-134a	2009	2010	10%	None				
					HFC-152a	2009	2010	10%	None				
PU Rigid: Other: Slabstock Foam													
CFC-11	HCFC-141b	1989	1996	100%	CO ₂	1999	2003	45%	None				2.0%
					Non-ODP/GWP	2001	2003	45%	None				
					HCFC-22	2003	2003	10%	Non-ODP/GWP	2009	2010	100%	
PU Rigid: Sandwich Panels: Continuous and Discontinuous													
CFC-11	HCFC-141b	1989	1996	82%	HCFC-22/Water Blend	2001	2003	20%	HFC Blend	2009	2010	50%	6.0%
					HFC-245fa/CO ₂ Blend	2002	2004	20%	Non-ODP/GWP	2009	2010	50%	
					Non-ODP/GWP	2001	2004	40%	None				
					HFC-134a	2002	2004	20%	None				
	HCFC-22	1989	1996	18%	HFC-245fa/CO ₂ Blend	2009	2010	40%	None				
					Non-ODP/GWP	2009	2010	20%	None				
					CO ₂	2009	2010	20%	None				
					HFC-134a	2009	2010	20%	None				
PU Rigid: Spray Foam													
CFC-11	HCFC-141b	1989	1996	100%	HFC-245fa	2002	2003	30%	None				6.0%
					HFC-245fa/CO ₂ Blend	2002	2003	60%	None				
					Non-ODP/GWP	2001	2003	10%	None				
XPS: Boardstock Foam													
CFC-12	HCFC-142b/22 Blend	1989	1994	10%	HFC-134a	2009	2010	70%	None				2.5%
					HFC-152a	2009	2010	10%	None				
					CO ₂	2009	2010	10%	None				
					Non-ODP/GWP	2009	2010	10%	None				
	HCFC-142b	1989	1994	90%	HFC-134a	2009	2010	70%	None				
					HFC-152a	2009	2010	10%	None				
					CO ₂	2009	2010	10%	None				
					Non-ODP/GWP	2009	2010	10%	None				
XPS: Sheet Foam													
CFC-12	CO ₂	1989	1994	1%	None								2.0%
	Non-ODP/GWP	1989	1994	99%	CO ₂	1995	1999	9%	None				
					HFC-152a	1995	1999	10%	None				

Table A- 163. Emission profile for the foam end-uses

Foam End-Use	Loss at Manufacturing (%)	Annual Leakage Rate (%)	Leakage Lifetime (years)	Loss at Disposal (%)	Total* (%)
Flexible PU Foam: Slabstock Foam, Moulded Foam	100	0	1	0	100
Commercial Refrigeration	6	0.25	15	90.25	100
Rigid PU: Spray Foam	15	1.5	56	1	100
Rigid PU: Slabstock and Other	37.5	0.75	15	51.25	100
Phenolic Foam	23	0.875	32	49	100
Polyolefin Foam	95	2.5	2	0	100
Rigid PU: One Component Foam	100	0	1	0	100
XPS: Sheet Foam*	40	2	25	0	90
XPS: Boardstock Foam	25	0.75	50	37.5	100
Flexible PU Foam: Integral Skin Foam	95	2.5	2	0	100
Rigid PU: Domestic Refrigerator and Freezer Insulation*	4	0.25	14	40.0	47.5
PU and PIR Rigid: Boardstock	6	1	50	44	100
PU Sandwich Panels: Continuous and Discontinuous	5.5	0.5	50	69.5	100

PIR (Polyisocyanurate)

PU (Polyurethane)

XPS (Extruded Polystyrene)

*In general, total emissions from foam end-uses are assumed to be 100 percent, although work is underway to investigate that assumption. In the XPS Sheet/Insulation Board end-use, the source of emission rates and lifetimes did not yield 100 percent emission; it is unclear at this time whether that was intentional. In the Rigid PU Appliance Foam end-use, the source of emission rates and lifetimes did not yield 100 percent emission; the remainder is anticipated to be emitted at a rate of 2.0%/year post-disposal for the next 26 years.

Sterilization

Sterilants kill microorganisms on medical equipment and devices. The principal ODS used in this sector was a blend of 12% ethylene oxide (EtO) and 88% CFC-12, known as "12/88." In that blend, ethylene oxide sterilizes the equipment and CFC-12 is a diluent solvent to form a non-flammable blend. The sterilization sector is modeled as a single end-use. For sterilization applications, all chemicals that are used in the equipment in any given year are assumed to be emitted in that year, as shown in the following equation.

$$E_j = Qc_j$$

Where:

E = Emissions. Total emissions of a specific chemical in year j from use in sterilization equipment, by weight.

Qc = Quantity of Chemical. Total quantity of a specific chemical used in sterilization equipment in year j , by weight.

j = Year of emission.

Assumptions

The Vintaging Model contains 1 sterilization end-use, whose transition assumptions away from ODS and growth rates are presented in Table A- 164.

Table A- 164. Sterilization Market Transition Assumptions

Initial Market Segment	Primary Substitute				Growth Rate
	Name of Substitute	Start Date	Date of Full Penetration in New Equipment	Maximum Market Penetration	
12/88	EtO	1994	1995	95%	2.0%
	Non-ODP/GWP	1994	1995	1%	
	HCFC/EtO Blends	1993	1994	4%	

Model Output

By repeating these calculations for each year, the Vintaging Model creates annual profiles of use and emissions for ODS and ODS substitutes. The results can be shown for each year in two ways: 1) on a chemical-by-chemical basis, summed across the end-uses, or 2) on an end-use or sector basis. Values for use and emissions are calculated both in metric tons and in teragrams of CO₂ equivalents (Tg CO₂ Eq.). The conversion of metric tons of chemical to Tg CO₂ Eq. is accomplished through a linear scaling of tonnage by the global warming potential (GWP) of each chemical.

Throughout its development, the Vintaging Model has undergone annual modifications. As new or more accurate information becomes available, the model is adjusted in such a way that both past and future emission estimates are often altered.

Bank of ODS and ODS Substitutes

The bank of an ODS or an ODS substitute is “the cumulative difference between the chemical that has been consumed in an application or sub-application and that which has already been released” (IPCC 2006). For any given year, the bank is equal to the previous year’s bank, less the chemical in equipment disposed of during the year, plus chemical in new equipment entering the market during that year, less the amount emitted but not replaced, plus the amount added to replace chemical emitted prior to the given year, as shown in the following equation:

$$Bc_j = Bc_{j-1} - Qd_j + Qp_j + E_e - Q_r$$

Where:

- Bc_j = Bank of Chemical. Total bank of a specific chemical in year j , by weight.
- Qd_j = Quantity of Chemical in Equipment Disposed. Total quantity of a specific chemical in equipment disposed of in year j , by weight.
- Qp_j = Quantity of Chemical Penetrating the Market. Total quantity of a specific chemical that is entering the market in year j , by weight.
- E_e = Emissions of Chemical Not Replaced. Total quantity of a specific chemical that is emitted during year j but is not replaced in that year. The Vintaging Model assumes all chemical emitted from refrigeration, air conditioning and fire extinguishing equipment is replaced in the year it is emitted, hence this term is zero for all sectors except foam blowing.
- Q_r = Chemical Replacing Previous Year’s Emissions. Total quantity of a specific chemical that is used to replace emissions that occurred prior to year j . The Vintaging Model assumes all chemical emitted from refrigeration, air conditioning and fire extinguishing equipment is replaced in the year it is emitted, hence this term is zero for all sectors.
- j = Year of emission.

Table A- 165 provides the bank for ODS and ODS substitutes by chemical grouping in metric tons (MT) for 1990-2009.

Table A- 165. Banks of ODS and ODS Substitutes, 1990-2009 (MT)

	CFC	HCFC	HFC
1990	653,338	235,625	868
1995	757,485	454,719	50,761
2000	628,584	878,343	181,693
2001	602,580	947,180	210,207
2002	578,017	999,467	241,960
2003	554,078	1,033,925	280,053
2004	531,714	1,067,106	318,505
2005	513,896	1,103,085	354,544
2006	500,430	1,135,099	390,237
2007	489,582	1,160,421	425,719
2008	482,541	1,174,094	457,860
2009	479,890	1,165,278	498,695

References

IPCC (2006) *2006 IPCC Guidelines for National Greenhouse Gas Inventories*. The National Greenhouse Gas Inventories Programme, The Intergovernmental Panel on Climate Change, H.S. Eggleston, L. Buendia, K. Miwa, T Ngara, and K. Tanabe (eds.). Hayama, Kanagawa, Japan.

3.9. Methodology for Estimating CH₄ Emissions from Enteric Fermentation

Methane emissions from enteric fermentation were estimated for five livestock categories: cattle, horses, sheep, swine, and goats. Emissions from cattle represent the majority of U.S. emissions from enteric fermentation; consequently, the more detailed IPCC Tier 2 methodology was used to estimate emissions from all cattle (except for bulls). The IPCC Tier 1 methodology was used to estimate emissions from bulls and the other types of livestock.

Estimate Methane Emissions from Cattle

This section describes the process used to estimate methane emissions from cattle enteric fermentation using the Cattle Enteric Fermentation Model (CEFM).⁵¹ The CEFM, based on recommendations provided in IPCC/UNEP/OECD/IEA (1997), IPCC (2000) and IPCC (2006), uses information on population, energy requirements, digestible energy, and methane conversion rates to estimate methane emissions.⁵² The emission methodology consists of the following three steps: (1) characterize the cattle population to account for animal population categories with different emission profiles; (2) characterize cattle diets to generate information needed to estimate emission factors; and (3) estimate emissions using these data and the IPCC Tier 2 equations.

Step 1: Characterize U.S. Cattle Population

The national cattle population estimates in the inventory submission are based on data obtained from the U.S. Department of Agriculture's (USDA) National Agricultural Statistics Service Quick Stats database (USDA 2010). A summary of the annual average populations upon which all livestock-related emissions are based is provided in Table A-166. Cattle populations used in the Enteric Fermentation sector were estimated using the cattle transition matrix in the CEFM, which uses January 1 USDA population estimates and weight data to simulate the population of U.S. cattle from birth to slaughter, and results in an estimate of the number of animals in a particular cattle grouping while taking into account the monthly rate of weight gain, the average weight of the animals, and the death and calving rates. The use of supplemental USDA data and the cattle transition matrix in the CEFM results in the cattle population estimates for this sector differing slightly from the January 1 or July 1 USDA point estimates and the cattle population data obtained from the Food and Agriculture Organization of the United Nations (FAO).

Table A-166: Cattle Population Estimates from the CEFM Transition Matrix for 1990-2009

Livestock Type	1990	1995	2000	2005	2006	2007	2008	2009
Calves 0-6 months	22,561	23,499	22,569	21,678	21,621	21,483	21,155	20,940
Dairy								
Dairy Cows	10,015	9,482	9,183	9,004	9,104	9,145	9,257	9,333
Dairy Replacements 7-11 months	1,214	1,216	1,196	1,257	1,277	1,299	1,304	1,325
Dairy Replacements 12-23 months	2,915	2,892	2,812	2,905	3,017	3,043	3,097	3,101
Beef								
Bulls	2,160	2,385	2,293	2,214	2,258	2,214	2,207	2,184
Beef Cows	32,455	35,190	33,575	32,674	32,703	32,644	32,435	31,712
Beef Replacements 7-11 months	1,269	1,493	1,313	1,363	1,380	1,349	1,312	1,287
Beef Replacements 12-23 months	2,967	3,637	3,097	3,171	3,294	3,276	3,169	3,098
Steer Stockers	10,321	11,716	8,724	8,185	8,248	8,302	8,233	8,501
Heifer Stockers	5,946	6,699	5,371	5,015	5,041	4,966	4,868	5,051
Feedlot Cattle	9,549	11,064	13,006	12,652	13,526	13,404	13,070	12,964

Note: Mature animal populations are not assumed to have significant monthly fluctuations, and therefore the populations utilized are the January estimates downloaded from USDA (2010).

The population transition matrix in the CEFM simulates the U.S. cattle population over time and provides an estimate of the population age and weight structure by cattle type on a monthly basis. Since cattle often do not remain in a single population type for an entire year (e.g., calves become stockers, stockers become feedlot animals), and emission

⁵¹ Emissions from bulls are estimated in the CEFM using a Tier 1 approach based on published population statistics and national average emission factors because the variation in diets and within year population is assumed to be minimal. The IPCC recommends the use of a methane conversion factor of zero for calves, because they consume mainly milk, therefore this results in no methane emissions from calves through 6 months.

⁵² Additional information on the Cattle Enteric Fermentation Model can be found in ICF (2006).

profiles vary both between and within each cattle type, these monthly age groups are tracked in the enteric fermentation model to obtain more accurate emission estimates than would be available from annual point estimates of population (such as available from USDA statistics) and weight for each cattle type.

The transition matrix tracks both dairy and beef populations, and divides the populations into males and females, and subdivides the population further into specific cattle groupings for replacement, stocker, feedlot, and mature animals. The matrix is based primarily on two types of data: population statistics and weight statistics (including target weights, slaughter weights, and weight gain). Using the weight data, the transition matrix simulates the growth of animals over time by month. The matrix also relies on supplementary data, such as feedlot placement statistics, slaughter statistics, death rates, and calving rates.

The basic method for tracking population of animals per category is based on the number of births (or graduates) into the monthly age group minus those animals that die or are slaughtered and those that graduate to the next category (such as stockers to feedlot placements).

Each stage in the cattle lifecycle was modeled to simulate the cattle population from birth to slaughter. This level of detail accounts for the variability in CH₄ emissions associated with each life stage. Given that a stage can last less than one year (e.g., beef calves are weaned at 7 months), each is modeled on a per-month basis. The type of cattle also impacts CH₄ emissions (e.g., beef versus dairy). Consequently, there is an independent transition matrix for each of three separate lifecycle phases, 1) calves, 2) replacements and stockers, and 3) feedlot animals. In addition, the number of mature cows is tracked for both dairy and beef stock. Each lifecycle is discussed separately below, and the categories tracked are listed in Table A-167.

Table A-167: Cattle Population Categories Used for Estimating CH₄ Emissions

Dairy Cattle	Beef Cattle
Calves	Calves
Heifer Replacements	Heifer Replacements
Cows	Heifer and Steer Stockers
	Animals in Feedlots (Heifers & Steers)
	Cows
	Bulls*

* Bulls (beef and dairy) are accounted for in a single category.

The key variables tracked for each of these cattle population categories (except bulls) are as follows:

Calves. The number of animals born on a monthly basis was used to initiate monthly cohorts and to determine population age structure. The number of calves born each month was obtained by multiplying annual births by the percentage of births by month. Annual birth information for each year was taken from USDA (2010). For dairy cows, the number of births is assumed to be distributed equally throughout the year (approximately 8.3 percent per month), beef births are distributed according to Table A-168, based on estimates from the National Animal Health Monitoring System (NAHMS) (USDA/APHIS/VS 1998, 1994, 1993). To determine whether calves were born to dairy or beef cows, the dairy cow calving rate (USDA/APHIS/VS 2002, USDA/APHIS/VS 1996) was multiplied by the total dairy cow population to determine the number of births attributable to dairy cows, with the remainder assumed to be attributable to beef cows. Total annual calf births are obtained from USDA, and distributed into monthly cohorts by cattle type (beef or dairy). Calf growth is modeled by month, based on estimated monthly weight gain for each cohort (approximately 61 pounds per month). Total calf population is modified through time to account for veal calf slaughter at 4 months and a calf death loss of 0.35 percent annually (distributed across age cohorts up to six months of age). An example of a transition matrix for calves is shown in Table A-169. Note that calves age one through six months available in January have been tracked through the model based on births and death loss from the previous year.

Table A-168: Estimated Beef Cow Births by Month

Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
7%	15%	28%	22%	9%	3%	2%	2%	3%	4%	3%	3%

Table A-169: Example of Monthly Average Populations from Calf Transition Matrix

Age (month)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
6	1,207	1,199	1,494	1,751	1,684	1,666	2,665	5,005	8,720	7,062	3,279	1,631
5	1,199	1,494	1,751	1,684	1,666	2,665	5,005	8,720	7,062	3,279	1,631	1,212
4	1,494	1,751	1,684	1,666	2,665	5,005	8,720	7,062	3,279	1,631	1,212	1,202
3	1,751	1,684	1,666	2,665	5,005	8,720	7,062	3,279	1,631	1,212	1,202	1,495
2	1,684	1,666	2,665	5,005	8,720	7,062	3,279	1,631	1,212	1,202	1,495	1,748
1	1,666	2,665	5,005	8,720	7,062	3,279	1,631	1,212	1,202	1,495	1,748	1,680
0	2,665	5,005	8,720	7,062	3,279	1,631	1,212	1,202	1,495	1,748	1,680	1,661

Replacements and Stockers. At seven months of age, calves ‘graduate’ and are separated into the applicable cattle types. First the number of replacements required for beef and dairy cattle are calculated based on estimated death losses and population changes between beginning and end of year population estimates. All steer, and remaining heifers (after subtracting required replacements), are considered ‘stockers,’ that is backgrounding animals that are eligible for placement into feedlots as they reach the appropriate weight class. During the stocker phase animals are subtracted out of the transition matrix for placement into feedlots based on feedlot placement statistics from USDA (2010).

The data and calculations that occur for the stocker category include matrices that estimate the population of backgrounding heifers and steer, as well as a matrix for total combined stockers. The matrices start with the beginning of year populations in January and model the progression of each cohort. The age structure of the January population is based on estimated births by month from the previous two years, although in order to balance the population properly, an adjustment is added that slightly reduces population percentages in the older populations. The populations are modified through addition of graduating calves (month 7, bottom row of Table A-170) and subtraction through death loss and animals placed in feedlots. Eventually, an entire cohort population of stockers may be zero, indicating that the complete cohort has been transitioned into feedlots. An example of the transition matrix for stockers is shown in Table A-170.

Table A-170: Example of Monthly Average Populations from Stocker Transition Matrix

Age (month)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
23	202	214	126	47	20	12	10	11	9	7	5	51
22	353	174	59	23	15	12	13	13	9	7	103	311
21	286	81	29	17	15	15	15	12	9	153	421	559
20	133	40	22	17	18	18	14	12	197	526	765	457
19	66	30	22	21	21	17	14	273	620	965	629	212
18	49	30	27	25	20	17	321	779	1,141	795	291	305
17	49	37	31	24	20	379	882	1,442	942	368	546	49
16	60	43	30	24	453	1,004	1,636	1,193	435	779	49	49
15	71	41	30	531	1,160	1,867	1,355	551	985	49	49	61
14	68	41	669	1,324	2,162	1,547	625	1,337	49	49	61	71
13	67	918	1,607	2,471	1,796	716	1,669	49	49	61	71	68
12	1,076	1,774	2,813	2,017	857	2,242	282	49	61	71	68	67
11	2,027	3,105	2,297	962	2,765	365	179	82	91	76	72	1,094
10	3,532	2,542	1,082	3,229	507	253	209	261	213	128	1,151	2,683
9	2,860	1,204	3,588	607	451	425	504	464	429	1,353	2,916	6,195
8	1,328	4,083	770	617	664	915	782	831	1,682	3,596	6,832	5,605
7	4,450	878	871	1,060	1,295	1,232	1,230	2,114	4,188	7,484	6,012	2,665

In order to ensure a balanced population of both stockers and placements, additional data tables are utilized in the stocker matrix calculations. The tables summarize the placement data by weight class and month, and is based on the total number of animals within the population that are available to be placed in feedlots and the actual feedlot placement statistics provided by USDA (2010). In cases where there are discrepancies between the USDA estimated placements by weight class and the calculated animals available by weight, the model pulls available stockers from one higher weight category if available. If there are still not enough animals to fulfill requirements the model pulls animals from the next lower category. Note that in the current time series, this method was able to ensure that total placement data matched USDA estimates, and no shortfalls have occurred.

In addition, average weights were tracked for each monthly age group using starting weight and monthly weight gain estimates. Weight gain (i.e., pounds per month) was estimated based on weight gain needed to reach a set target weight, divided by the number of months remaining before target weight was achieved. Birth weight was assumed to be 88 pounds for both beef and dairy animals. Weaning weights were estimated at 515 lbs. Other reported target weights

were available for 12, 15, 24, and 36 month-old animals, depending on the animal type. Beef cow mature weight was taken from measurements provided by a major British Bos taurus breed (Enns 2008). Beef replacement weight was calculated as 70 percent of mature weight at 15 months and 85 percent of mature weight at 24 months. As dairy weights are not a trait that is typically tracked, mature weight for dairy cows was estimated at 1,500 for all years, based on a personal communication with Kris Johnson (2010) and an estimate from Holstein Association USA (2010). Dairy replacement at 15 months was assumed to be 875 lbs and replacement at 24 months is 1,300 lbs. Live slaughter weights were derived from dressed slaughter weight data for each year (USDA 2010). The annual typical animal mass for each livestock type are presented in Table A- 171

Weight gain for stocker animals was based on monthly gain estimates from Johnson (1999) for 1989, and from average daily estimates from Lippke et al. 2000, Pinchack et al., 2004, Platter et al., 2003, and Skogerboe et al., 2000 for 2000 through 2007. Interim years were calculated linearly, as shown in Table A-172, and weight gain was held constant starting in 2008. Live slaughter weight was estimated as dressed weight divided by 0.63. This ratio represents the dressed weight (i.e. weight of the carcass after removal of the internal organs), to the live weight (i.e. weight taken immediately before slaughter). Table A-172 provides weights and weight gains that vary by year in the CEFM.

Table A- 171: Typical Animal Mass that Varies by Year (lbs)

Year/Cattle Type	Dairy Cows	Dairy Replacements	Beef Cows	Beef Replacements	Steer Stockers	Heifer Stockers	Steer Feedlot	Heifer Feedlot
1990	1,500	900	1,221	820	692	652	923	846
1991	1,500	898	1,225	822	695	656	975	867
1992	1,500	897	1,263	841	714	673	984	878
1993	1,500	899	1,280	852	721	683	930	864
1994	1,500	898	1,280	854	721	689	944	876
1995	1,500	898	1,282	858	735	701	947	880
1996	1,500	898	1,285	859	739	707	940	878
1997	1,500	900	1,286	861	737	708	939	877
1998	1,500	897	1,296	866	736	710	957	892
1999	1,500	899	1,292	862	731	709	960	895
2000	1,500	897	1,272	849	720	702	961	899
2001	1,500	898	1,272	850	726	707	963	901
2002	1,500	897	1,276	852	726	708	982	915
2003	1,500	900	1,308	872	719	702	973	905
2004	1,500	897	1,323	878	719	702	967	905
2005	1,500	895	1,327	880	718	706	975	917
2006	1,500	898	1,341	890	725	713	984	925
2007	1,500	897	1,348	895	721	707	992	928
2008	1,500	898	1,348	895	721	705	1,000	939
2009	1,500	897	1,348	895	731	715	1,007	948

Table A-172: Weight Gains that Vary by Year (lbs)

Year/Cattle Type	Steer Stockers to 12 months(lbs/day)	Steer Stockers to 24 months (lbs/day)	Heifer Stockers to 12 months(lbs/day)	Heifer Stockers to 24 months(lbs/day)
1990	1.53	1.23	1.23	1.08
1991	1.56	1.29	1.29	1.15
1992	1.59	1.35	1.35	1.23
1993	1.62	1.41	1.41	1.30
1994	1.65	1.47	1.47	1.38
1995	1.68	1.53	1.53	1.45
1996	1.71	1.59	1.59	1.53
1997	1.74	1.65	1.65	1.60
1998	1.77	1.71	1.71	1.68
1999	1.80	1.77	1.77	1.75
2000	1.83	1.83	1.83	1.83
2001	1.83	1.83	1.83	1.83
2002	1.83	1.83	1.83	1.83
2003	1.83	1.83	1.83	1.83
2004	1.83	1.83	1.83	1.83
2005	1.83	1.83	1.83	1.83
2006	1.83	1.83	1.83	1.83
2007	1.83	1.83	1.83	1.83
2008	1.83	1.83	1.83	1.83
2009	1.83	1.83	1.83	1.83

Sources: Enns (2008), Johnson (1999), Lippke et al. (2000), NRC (1999), Pinchack et al. (2004), Platter et al. (2003), Skogerboe et al. (2000)

Feedlot Animals. Feedlot placement statistics from USDA provide data on the placement of animals from the stocker population into feedlots on a monthly basis by weight class. The model uses these data to shift a sufficient number of animals from the stocker cohorts into the feedlot populations to match the reported placement data. After animals are placed in feedlots they progress through two steps. First, animals spend 25 days on a step-up diet to become acclimated to the new feed type, during this time weight gain is estimated to be 2.8 to 3 pounds per day (Johnson 1999). Animals are then switched to a finishing diet for a period of time before they are slaughtered. Weight gain during finishing diets is estimated to be 3 to 3.3 pounds per day (Johnson 1999). The length of time an animal spends in a feedlot depends on the start weight (i.e., placement weight), the rate of weight gain during the start-up and finishing phase of diet, and the target weight (as determined by weights at slaughter). Additionally, animals remaining in feedlots at the end of the year are tracked for inclusion in the following year's emission and population counts. For 1990 to 1995, only the total placement data were available, therefore placements for each weight category (displayed in Table A-173) for those years are based on the average of monthly placements from the 1996 to 1998 reported figures. Placement data is available by weight class for all years from 1996 onward. Table A-173 provides a summary of the reported feedlot placement statistics for 2009.

Table A-173: Feedlot Placements in the United States for 2009 (Number of animals placed in Thousand Head)

Weight Placed	When:	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
< 600 lbs		380	320	305	355	395	315	455	435	490	615	510	430
600 – 700 lbs		505	385	340	315	305	290	365	395	450	645	565	420
700 – 800 lbs		553	538	593	405	433	371	458	514	593	579	394	401
> 800 lbs		420	435	570	525	505	415	585	775	855	635	375	295
Total		1,858	1,678	1,808	1,600	1,638	1,391	1,863	2,119	2,388	2,474	1,844	1,546

Source: USDA (2010).

Note: Totals may not sum due to independent rounding.

Mature Animals. Energy requirements and hence, composition of diets, level of intake, and emissions for particular animals, are greatly influenced by whether the animal is pregnant or lactating. Information is therefore needed on the percentage of all mature animals that are pregnant each month, as well as milk production, to estimate CH₄ emissions. A weighted average percent of pregnant cows each month was estimated using information on births by month and average pregnancy term. For beef cattle, a weighted average total milk production per animal per month was estimated using information on typical lactation cycles and amounts (NRC 1999), and data on births by month. This process results in a range of weighted monthly lactation estimates expressed as lbs/animal/month. The monthly estimates from January to December are 3.3, 5.1, 8.7, 12.0, 13.6, 13.3, 11.7, 9.3, 6.9, 4.4, 3.0, and 2.8 lbs milk/animal/day. Annual estimates for dairy cattle were taken from USDA milk production statistics. Dairy lactation estimates for 1990 through 2009 are shown in

Table A-174. Beef and dairy cow and bull populations are assumed to remain relatively static throughout the year, as large fluctuations in population size are assumed to not occur. These estimates are taken from the USDA beginning and end of year population datasets.

Table A-174: Dairy Lactation by State (lbs/ year/cow)*

State/Year	1990	1995	2000	2005	2006	2007	2008	2009
Alabama	12,214	14,176	13,920	14,000	14,500	15,154	15,333	14,909
Alaska	13,300	17,000	14,500	12,273	12,250	14,667	12,000	10,000
Arizona	17,500	19,735	21,820	22,679	22,855	23,260	23,382	23,028
Arkansas	11,841	12,150	12,436	13,545	12,900	12,941	12,400	12,615
California	18,456	19,573	21,130	21,404	21,815	22,440	22,344	22,000
Colorado	17,182	18,687	21,618	22,577	23,155	22,932	22,930	23,089
Connecticut	15,606	16,438	17,778	19,200	19,316	19,211	19,158	18,684
Delaware	13,667	14,500	14,747	16,622	16,286	16,618	16,923	17,000
Florida	14,033	14,698	15,688	16,591	16,447	16,832	17,167	18,061
Georgia	12,973	15,550	16,284	17,259	18,234	18,169	17,829	18,600
Hawaii	13,604	13,654	14,358	12,889	13,256	12,241	10,882	14,200
Idaho	16,475	18,147	20,816	22,332	22,346	22,513	22,432	22,091
Illinois	14,707	15,887	17,450	18,827	19,252	18,612	18,569	18,873
Indiana	14,590	15,375	16,568	20,295	19,861	20,307	19,683	20,137
Iowa	15,118	16,124	18,298	20,641	20,127	20,085	19,995	20,367
Kansas	12,576	14,390	16,923	20,505	20,938	19,882	20,641	21,085
Kentucky	10,947	12,469	12,841	12,896	13,296	13,889	13,444	14,190
Louisiana	11,605	11,908	12,034	12,400	12,375	12,034	12,269	11,870
Maine	14,619	16,025	17,128	18,030	17,938	17,788	18,273	18,061
Maryland	13,461	14,725	16,083	16,099	17,281	18,121	18,375	18,255
Massachusetts	14,871	16,000	17,091	17,059	17,375	17,000	16,933	17,571
Michigan	15,394	17,071	19,017	21,635	22,234	22,761	22,180	22,445
Minnesota	14,127	15,894	17,777	18,091	18,598	18,817	18,927	19,230
Mississippi	12,081	12,909	15,028	15,280	14,957	15,429	14,550	13,889
Missouri	13,632	14,158	14,662	16,026	16,000	14,982	14,682	14,654
Montana	13,542	15,000	17,789	19,579	18,632	18,500	18,412	19,933
Nebraska	13,866	14,797	16,513	17,950	18,328	18,220	18,672	19,721
Nevada	16,400	18,128	19,000	21,680	20,148	20,481	20,704	21,821
New Hampshire	15,100	16,300	17,333	18,875	19,533	19,333	19,933	19,533
New Jersey	13,538	13,913	15,250	16,000	16,182	16,800	16,900	17,889
New Mexico	18,815	18,969	20,944	21,192	21,853	21,958	23,269	24,320
New York	14,658	16,501	17,378	18,639	18,879	19,303	19,859	20,071
North Carolina	15,220	16,314	16,746	18,741	18,510	19,188	18,979	19,644
North Dakota	12,624	13,094	14,292	14,182	14,688	15,310	16,077	16,739
Ohio	13,767	15,917	17,027	17,567	17,737	18,109	18,321	18,744
Oklahoma	12,327	13,611	14,440	16,480	16,630	16,580	16,578	16,983
Oregon	16,273	17,289	18,222	18,876	19,000	19,417	19,772	19,719
Pennsylvania	14,726	16,492	18,081	18,722	19,390	19,422	19,262	19,360
Rhode Island	14,250	14,773	15,667	17,000	17,273	16,455	18,091	17,818
South Carolina	12,771	14,481	16,087	16,000	16,294	17,889	17,889	18,765
South Dakota	12,257	13,398	15,516	17,741	18,580	19,306	19,956	20,128
Tennessee	11,825	13,740	14,789	15,743	15,657	15,857	16,068	16,232
Texas	14,350	15,244	16,503	19,646	19,501	18,982	20,134	20,898
Utah	15,838	16,739	17,573	18,875	20,314	20,376	20,894	20,988
Vermont	14,528	16,210	17,199	18,469	18,383	18,079	18,400	18,289
Virginia	14,213	15,116	15,833	16,990	17,363	17,530	17,612	18,083
Washington	18,532	20,091	22,644	23,270	23,055	23,239	23,344	23,171
West Virginia	11,250	12,667	15,588	14,923	15,385	15,000	15,083	14,727
Wisconsin	13,973	15,397	17,306	18,500	18,824	19,310	19,546	20,079
Wyoming	12,337	13,197	13,571	14,878	17,612	18,831	19,386	18,811

Source: USDA (2010).

* Beef lactation data were developed using the methodology described in Step 1.

Step 2: Characterize U.S. Cattle Population Diets

To support development of digestible energy (DE, the percent of gross energy intake digested by the animal) and CH₄ conversion rate (Y_m, the fraction of gross energy converted to CH₄) values for each of the cattle population categories, data were collected on diets considered representative of different regions. For both grazing animals and animals being fed mixed rations, representative regional diets were estimated using information collected from state livestock specialists and from USDA (1996). The data for each of the diets (e.g., proportions of different feed constituents, such as hay or grains) were used to determine feed chemical composition for use in estimating digestible energy and Y_m for each animal type.

DE and Y_m vary by diet and animal type. The IPCC recommends Y_m values of 3.0±1.0 percent for feedlot cattle and 6.5±1.0 percent for all other cattle (IPCC 2006). Given the availability of detailed diet information for different regions and animal types in the United States, digestible energy and Y_m values unique to the United States⁵³ were developed. Digestible energy and Y_m values were estimated for each cattle population category, for each year in the time series based on physiological modeling, published values, and/or expert opinion.

For dairy cows, ruminant digestion models were used to estimate Y_m. The three major categories of input required by the models are animal description (e.g., cattle type, mature weight), animal performance (e.g., initial and final weight, age at start of period), and feed characteristics (e.g., chemical composition, habitat, grain or forage). Data used to simulate ruminant digestion is provided for a particular animal that is then used to represent a group of animals with similar characteristics. The Y_m values were estimated for 1990 using the Donovan and Baldwin model (1999) that represents physiological processes in the ruminant animals and diet characteristics from USDA (1996). The Donovan and Baldwin model accounts for differing diets (i.e., grain-based or forage-based), so that Y_m values for the variable feeding characteristics within the U.S. cattle population can be estimated. Subsequently, a literature review of dairy diets was conducted and nearly 250 diets were analyzed from 1990 through 2008 across 23 states. Kebreab et al (2008). conducted an evaluation of models and found that the COWPOLL model was the best model for estimating Y_m for dairy. Therefore, the COWPOLL model was used to estimate Y_m values for each of the diets. Due to the variability associated with cattle diets, a function based on the national trend observed from the analysis of the dairy diets was used to calculate 1991 and beyond values based on the regional 1990 Y_m values from Donovan and Baldwin.. The resulting scaling factor is shown below:

$$Y_m = Y_m(1990) \exp\left(\frac{1.22}{(Year - 1980)}\right) / \exp\left(\frac{1.22}{(1990 - 1980)}\right)$$

DE values for dairy cows were estimated from the literature search based on the on annual trends observed in the recent data collection effort. The regional variability observed in the literature search was not statistically significant, and therefore DE was not varied by region.

Considerably less data was available for dairy heifers, so assumptions were based on the relationship of the collected data literature on dairy heifers to the data on dairy cow diets. From this relationship, DE was estimated as the mature cow DE minus three percent, and Y_m was estimated as that of the mature dairy cow plus 0.1 percent.

To calculate the DE values for grazing beef cattle, diet composition assumptions were used to estimate weighted DE values for a combination of forage and supplemental diets. Where DE values were not available for specific feed types, total digestible nutrients (TDN) as a percent of dry matter (DM) intake was used as a proxy for DE, as listed in NRC (2000). Forage diets make up the majority of beef cattle diets, and two separate regional DE values were used to account for the generally lower forage quality in the western United States. For all non-western beef cattle, the forage DE was an average of the seasonal values for Grass Pasture diets listed in Appendix Table 1 of the NRC (2000). This resulted in a DE of 64.7 percent for the forage portion of the diet for all beef cattle in regions other than the west. For beef cattle in the west, the forage DE was calculated as the seasonal average for meadow and range diets listed in Appendix Table 1 of the NRC (2000). This resulted in a DE for the forage portion of the western region diet of 58.5 percent. In addition, it was assumed that each region fed a supplemental diet, as shown in Table A- 175. By weighting the calculated DE values from the forage and supplemental diets, the DE values for the composite diet were calculated.⁵⁴ The percent of each diet that is assumed to be supplemental and the forage DE values used for each region, and the resulting weighted DE values are

⁵³ In some cases, the Y_m values used for this analysis extend beyond the range provided by the IPCC. However, EPA believes that these values are representative for the U.S. due to research conducted to characterize the diets of U.S. cattle and assess the Y_m values associated with different animal performance and feed characteristics in the United States.

⁵⁴ For example, in California the forage DE of 64.7 was used for 95 percent of the grazing cattle diet and a supplemented diet DE of 69.3 percent was used for five percent of the diet, for a total weighted DE of 64.9 percent, as shown in Table A-176.

shown in Table A-176. These values are used for steer and heifer stockers and beef replacements. Finally, for beef cows, the DE value was adjusted downward by two percent to reflect the lower digestibility diets of the mature beef cow based on Johnson (2002). Y_m values for all grazing beef cattle were set at 6.5 percent based on Johnson (2002).

For feedlot animals, DE and Y_m values for 1990 were taken from Johnson (1999). . In the CEFM, values for 1991 through 1999 were linearly extrapolated based on values for 1990 and 2000. DE and Y_m values for 2000 onwards were estimated using the MOLLY model as described in Kebreab et al (2008). In addition, feedlot animals are assumed to spend the first 25 days in the feedlot on a “step-up” diet to become accustomed to the higher quality feedlot diets. The step-up DE and Y_m are calculated as the average of all state forage and feedlot diet DE and Y_m values.

Table A-177 shows the regional DE and Y_m for U.S. cattle in each region for 2009.

Table A- 175: DE Values and Representative Regional Diets (Percent of Diet for each Region) for the Supplemental Diet of Grazing Beef Cattle

Feed	Source of TDN (NRC 2000)	Unweighted TDN or DE	Northern Great Plains					
			California ^a	West	Southcentral	Northeast	Midwest	Southeast
Alfalfa Hay	Table 11-1, feed #4	59.6%	65%	30%	30%	29%	12%	30%
Barley	Table 11-1, feed #12	86.3%	10%	15%				
Bermuda	Table 11-1, feed #17	48.5%						35%
Bermuda Hay	Table 11-1, feed #17	48.5%			40%			
Corn	Table 11-1, feed #38	88.1%	10%	10%	25%	11%	13%	13%
Corn Silage	Table 11-1, feed #39	71.2%			25%	20%	20%	
Cotton Seed Meal	Table 11-1, feed #42	74.4%			7%			
Grass Hay	Table 1a, feed #129, 147, 148	53.7%		40%			30%	
Orchard	Table 11-1, feed #61	53.5%						40%
Soybean Meal		83.1%		5%	5%			5%
Supplement	Table 11-1, feed #70	81.3%						20%
Sorghum	Table 11-1, feed #67	76.4%					7%	
Soybean Hulls	Table 11-1, feed #69	55.5%				50%		
Timothy Hay	Table 11-1, feed #77	89.2%	5%			5%		
Whole Cotton		83.0%			15%	13%		
Seed	Table 11-1, feed #41	87.2%	10%					
Wheat Middlings	Table 1a, feed #433							
Wheat	Table 11-1, feed #83							
Weighted Total			69%	65%	74%	62%	65%	65%

Source of representative regional diets: Donovan (1999).

^aNote that emissions are currently calculated on a state-by-state basis, but diets are applied by the regions shown in the table above. The Western region includes AK, WA, OR, ID, NV, UT, AZ, HI, and NM; the Northeastern region includes PA, NY, MD, DE, NJ, CT, RI, MA, VT, NH, ME, and WV; the Southcentral region includes AR, LA, OK, and TX; the Midwestern region includes MO, IL, IN, OH, MN, WI, MI, and IA; the Northern Great Plains include MT, WY, ND, SD, NE, KS, and CO; and the Southeastern region includes VA, NC, KY, TN, MS, AL, GA, SC, and FL.

Table A-176: Percent of Each Diet that is Supplemental and the Resulting DE Values for Each Region

Region ^a	Percent Supplement	Percent Forage	Forage DE Used	Calculated Weighted Average DE
West	10	90	59	59
Northeast	15	85	65	65
Southcentral	10	90	65	64
Midwest	15	85	65	65
Northern Great Plains	15	85	65	66
Southeast	5	95	65	64
California	5	95	65	65

Sources: Percent of total diet that is supplemental diet, Donovan (1999); Forage DE, NRC (2000).

^aNote that emissions are currently calculated on a state-by-state basis, but diets are applied by the regions shown in the table above. The Western region includes AK, WA, OR, ID, NV, UT, AZ, HI, and NM; the Northeastern region includes PA, NY, MD, DE, NJ, CT, RI, MA, VT, NH, ME, and WV; the Southcentral region includes AR, LA, OK, and TX; the Midwestern region includes MO, IL, IN, OH, MN, WI, MI, and IA; the Northern Great Plains include MT, WY, ND, SD, NE, KS, and CO; and the Southeastern region includes VA, NC, KY, TN, MS, AL, GA, SC, and FL.

Table A-177: Regional Digestible Energy (DE) and CH₄ Conversion Rates (Y_m) for Cattle in 2009

Animal Type	Data	California ^c	West	Northern Great Plains	Southcentral	Northeast	Midwest	Southeast
Beef Repl. Heif.	DE ^a	65	59	66	64	65	65	64
	Y _m ^b	6.5%	6.5%	6.5%	6.5%	6.5%	6.5%	6.5%
Dairy Repl. Heif.	DE	64	64	64	64	64	64	64
	Y _m	6.0%	6.0%	5.7%	6.5%	6.4%	5.7%	7.0%
Steer Stockers	DE	65	59	66	64	65	65	64
	Y _m	6.5%	6.5%	6.5%	6.5%	6.5%	6.5%	6.5%
Heifer Stockers	DE	65	59	66	64	65	65	64
	Y _m	6.5%	6.5%	6.5%	6.5%	6.5%	6.5%	6.5%
Steer Feedlot	DE	83	83	83	83	83	83	83
	Y _m	3.9%	3.9%	3.9%	3.9%	3.9%	3.9%	3.9%
Heifer Feedlot	DE	83	83	83	83	83	83	83
	Y _m	3.9%	3.9%	3.9%	3.9%	3.9%	3.9%	3.9%
Beef Cows	DE	63	57	64	62	63	63	62
	Y _m	6.5%	6.5%	6.5%	6.5%	6.5%	6.5%	6.5%
Dairy Cows	DE	67	67	67	67	67	67	67
	Y _m	5.9%	5.9%	5.6%	6.4%	6.3%	5.6%	6.9%
Steer Step-Up	DE	72	72	72	72	72	72	72
	Y _m	5.2%	5.2%	5.2%	5.2%	5.2%	5.2%	5.2%
Heifer Step-Up	DE	72	72	72	72	72	72	72
	Y _m	5.2%	5.2%	5.2%	5.2%	5.2%	5.2%	5.2%

^a Digestible Energy in units of percent of GE (MJ/Day).

^b Methane Conversion Rate is the fraction of GE in feed converted to methane.

^c Note that emissions are currently calculated on a state-by-state basis, but diets are applied by the regions shown in the table above. The Western region includes AK, WA, OR, ID, NV, UT, AZ, HI, and NM; the Northeastern region includes PA, NY, MD, DE, NJ, CT, RI, MA, VT, NH, ME, and WV; the Southcentral region includes AR, LA, OK, and TX; the Midwestern region includes MO, IL, IN, OH, MN, WI, MI, and IA; the Northern Great Plains include MT, WY, ND, SD, NE, KS, and CO; and the Southeastern region includes VA, NC, KY, TN, MS, AL, GA, SC, and FL.

Step 3: Estimate CH₄ Emissions from Cattle

Emissions by state were estimated in three steps: a) determine gross energy (GE) intake using the IPCC (2006) equations, b) determine an emission factor using the GE values and other factors, and c) sum the daily emissions for each animal type. Finally, the state emissions were aggregated to obtain the national emissions estimate. The necessary data values for each state and animal type include:

- Body Weight (kg)
- Weight Gain (kg/day)
- Net Energy for Activity (C_a, MJ/day)⁵⁵
- Standard Reference Weight (kg)⁵⁶
- Milk Production (kg/day)
- Milk Fat (percent of fat in milk = 4)
- Pregnancy (percent of population that is pregnant)
- DE (percent of gross energy intake digestible)
- Y_m (the fraction of gross energy converted to CH₄)
- Population

Step 3a: Determine Gross Energy, GE

As shown in the following equation, gross energy (GE) is derived based on the net energy estimates and the feed characteristics. Only variables relevant to each animal category are used (e.g., estimates for feedlot animals do not require the NE_l factor). All net energy equations are provided in IPCC (2006).

⁵⁵ Zero for feedlot conditions, 0.17 for high quality confined pasture conditions, and 0.36 for extensive open range or hilly terrain grazing conditions. C_a factor for dairy cows is weighted to account for the fraction of the population in the region that grazes during the year.

⁵⁶ Standard Reference Weight is the mature weight of a female animal of the animal type being estimated, used in the model to account for breed potential.

$$GE = \left[\frac{\left(\frac{NE_m + NE_a + NE_l + NE_{work} + NE_p}{REM} \right) + \left(\frac{NE_g}{REG} \right)}{\frac{DE\%}{100}} \right]$$

Where,

GE	= Gross energy (MJ/day)
NE _m	= Net energy required by the animal for maintenance (MJ/day)
NE _a	= Net energy for animal activity (MJ/day)
NE _l	= Net energy for lactation (MJ/day)
NE _{work}	= Net energy for work (MJ/day)
NE _p	= Net energy required for pregnancy (MJ/day)
REM	= Ratio of net energy available in a diet for maintenance to digestible energy consumed
NE _g	= Net energy needed for growth (MJ/day)
REG	= Ratio of net energy available for growth in a diet to digestible energy consumed
DE	= Digestible energy expressed as a percent of gross energy (percent)

Step 3b: Determine Emission Factor

The emission factor (DayEmit) was determined using the gross energy value and the methane conversion factor (Y_m) for each category. This relationship is shown in the following equation:

$$DayEmit = \frac{GE \times Y_m}{55.65}$$

Where,

DayEmit	= Emission factor (kg CH ₄ /head/day)
GE	= Gross energy intake (MJ/head/day)
Y _m	= CH ₄ conversion rate, which is the fraction of gross energy in feed converted to CH ₄ (%)
55.65	= A factor for the energy content of methane (MJ/kg CH ₄)

The daily emission factors were estimated for each animal type and state, calculated national emission factors are shown by animal type in Table A-178.

Table A-178: Calculated National Emission Factors for Cattle by Animal Type (kg CH₄/head/year)

Cattle Type	1990	1995	2000	2005	2006	2007	2008	2009
Dairy								
Cows	124	125	132	133	134	139	139	140
Replacements 7-11 months	48	46	46	45	45	46	46	46
Replacements 12-23 months	73	69	70	67	67	70	69	70
Beef								
Bulls	53	53	53	53	53	53	53	53
Cows	89	92	91	94	94	94	94	94
Replacements 7-11 months	54	57	57	59	60	60	60	60
Replacements 12-23 months	63	66	66	68	69	69	69	69
Steer Stockers	55	56	58	58	58	58	57	57
Heifer Stockers	51	56	60	59	59	59	59	59
Feedlot Cattle	39	38	39	39	39	42	42	43

Note: To convert to a daily emission factor, the yearly emission factor can be divided by 365 (the number of days in a year).

Step 3c: Estimate Total Emissions

Emissions were summed for each month and for each state population category using the daily emission factor for a representative animal and the number of animals in the category. The following equation was used:

$$\text{Emissions}_{\text{state}} = \text{DayEmit}_{\text{state}} \times \text{Days/Month} \times \text{SubPop}_{\text{state}}$$

Where,

- DayEmit_{State} = The emission factor for the subcategory and state (kg CH₄/head/day)
- Days/Month = The number of days in the month
- SubPop_{State} = The number of animals in the subcategory and state during the month

This process was repeated for each month, and the totals for each state subcategory were summed to achieve an emission estimate for a state for the entire year and state estimates were summed to obtain the national total. The estimates for each of the 10 subcategories of cattle are listed in Table A-179. The emissions for each subcategory were then summed to estimate total emissions from beef cattle and dairy cattle for the entire year.

Table A-179: CH₄ Emissions from Cattle (Gg)

Cattle Type	1990	1995	2000	2005	2006	2007	2008	2009
Dairy	1,513	1,440	1,460	1,449	1,479	1,544	1,564	1,581
Cows	1,242	1,183	1,209	1,197	1,219	1,271	1,289	1,304
Replacements 7-11 months	58	56	55	56	57	60	60	61
Replacements 12-23 months	212	201	196	196	203	213	214	216
Beef	4,502	5,128	4,790	4,731	4,803	4,837	4,796	4,742
Bulls	114	126	122	117	120	117	117	116
Cows	2,887	3,223	3,059	3,056	3,079	3,083	3,065	2,995
Replacements 7-11 months	69	85	74	80	82	81	79	77
Replacements 12-23 months	188	241	204	217	228	228	220	215
Steer Stockers	563	661	508	472	475	478	473	489
Heifer Stockers	305	374	322	298	298	294	288	298
Feedlot Cattle	375	416	502	489	521	556	554	553
Total	6,015	6,567	6,251	6,180	6,282	6,381	6,374	6,323

Notes: Totals may not sum due to independent rounding. Because calves younger than 7 months consume mainly milk the IPCC recommends the use of methane conversion factor of zero, resulting in no methane emissions from this subcategory of cattle.

Emission Estimates from Other Livestock

All livestock population data, except for horses, were taken from the U.S. Department of Agriculture (USDA) National Agricultural Statistics Service (NASS) agricultural statistics database (USDA 2009). Table A-183 of the Manure Management Annex shows the population data for all livestock species that were used for estimating all livestock-related emissions. For each animal category, the USDA publishes monthly, annual, and multi-year livestock population and production estimates. All data were downloaded from the USDA-NASS agricultural database (USDA 2010). The Food and Agriculture Organization (FAO) publishes horse population data. These data were accessed from the FAOSTAT database (FAO 2010). Methane emissions from sheep, goats, swine, and horses were estimated by multiplying published national population estimates by the IPCC emission factor for each year. Table A-180 shows the emission factors used for these other livestock.

Enteric fermentation emissions from all livestock types are shown in Table A-181 and Table A-182.

Table A-180: Emission Factors for Other Livestock (kg CH₄/head/year)

Livestock Type	Emission Factor
Sheep	8
Goats	5
Horses	18
Swine	1.5

Source: IPCC (2006)

Table A-181: CH₄ Emissions from Enteric Fermentation (Tg CO₂ Eq.)

Livestock Type	1990	1995	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Beef Cattle	94.5	107.7	100.6	99.9	100.0	100.0	98.3	99.3	100.9	101.6	100.7	99.6
Dairy Cattle	31.8	30.2	30.7	30.5	30.6	28.4	29.9	30.4	31.1	32.4	32.9	33.2
Horses	1.9	1.9	2.0	2.1	2.3	2.6	3.0	3.5	3.6	3.6	3.6	3.6
Sheep	1.9	1.5	1.2	1.2	1.1	1.1	1.0	1.0	1.0	1.0	1.0	1.0
Swine	1.7	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	2.1	2.1	2.1
Goats	0.3	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Total	132.1	143.5	136.5	135.7	136.1	134.4	134.4	136.5	138.8	141.0	140.6	139.8

Note: Totals may not sum due to independent rounding.

Table A-182: CH₄ Emissions from Enteric Fermentation (Gg)

Livestock Type	1990	1995	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Beef Cattle	4,502	5,128	4,790	4,757	4,761	4,762	4,680	4,731	4,803	4,837	4,796	4,742
Dairy Cattle	1,513	1,440	1,460	1,453	1,457	1,354	1,422	1,449	1,479	1,544	1,564	1,581
Horses	91	92	94	99	108	126	144	166	171	171	171	171
Sheep	91	72	56	55	53	51	49	49	50	49	48	46
Swine	81	88	88	88	90	90	91	92	93	98	101	99
Goats	13	12	12	12	13	13	14	15	15	16	16	16
Total	6,290	6,832	6,502	6,464	6,481	6,396	6,400	6,500	6,611	6,715	6,696	6,655

Note: Totals may not sum due to independent rounding.

3.10. Methodology for Estimating CH₄ and N₂O Emissions from Manure Management

The following steps were used to estimate methane (CH₄) and nitrous oxide (N₂O) emissions from the management of livestock manure. Nitrous oxide emissions associated with pasture, range, or paddock systems and daily spread systems are included in the emission estimates for Agricultural Soil Management (see the Agricultural Soils Management Annex).

Step 1: Livestock Population Characterization Data

Annual animal population data for 1990 through 2009 for all livestock types, except horses and goats were obtained from the USDA National Agricultural Statistics Service (NASS). The population data used in the emissions calculations for cattle, swine, and sheep were downloaded from the USDA NASS Population Estimates Database (USDA 2009a). Poultry population data were obtained from USDA NASS reports (USDA 1995a, 1995b, 1998a, 1999, 2004a, 2004b, 2010a, and 2010b). Horse population data were obtained from the Food and Agriculture Organization (FAO) FAOSTAT database (FAO 2010). Goat population data for 1992, 1997, 2002, and 2007 were obtained from the Census of Agriculture (USDA 2009a). Additional data sources used and adjustments to these data sets are described below.

Cattle: For all cattle groups (cows, heifers, steers, bulls, and calves), the USDA data provide cattle inventories from January (for each state) and July (as a U.S. total only) of each year. Cattle inventories change over the course of the year, sometimes significantly, as new calves are born and as cattle are moved into feedlots and subsequently slaughtered; therefore, to develop the best estimate for the annual animal population, the populations and the individual characteristics, such as weight and weight gain, pregnancy, and lactation of each animal type were tracked in the Cattle Enteric Fermentation Model (CEFM). For animals that have relatively static populations throughout the year, such as mature cows and bulls, the January 1 values were used. For animals that have fluctuating populations throughout the year, such as calves and growing heifers and steer, the populations are modeled based on a transition matrix that uses annual population data from USDA along with USDA data on animal births, placement into feedlots, and slaughter statistics.

Swine: The USDA provides quarterly data for each swine subcategory: breeding, market under 50 pounds (under 23 kg), market 50 to 119 pounds (23 to 54 kg), market 120 to 179 pounds (54 to 81 kg), and market 180 pounds and over (greater than 82 kg). The average of the quarterly data was used in the emissions calculations. For states where only December inventory is reported, the December data were used directly.

Sheep: Population data for lamb and sheep on feed are not available after 1993 (USDA 1994). The number of lamb and sheep on feed for 1994 through 2009 were calculated using the average of the percent of lamb and sheep on feed from 1990 through 1993. In addition, all of the sheep and lamb “on feed” are not necessarily on “feedlots;” they may be on pasture/crop residue supplemented by feed. Data for those animals on feed that are in feedlots versus pasture/crop residue were provided only for lamb in 1993. To calculate the populations of sheep and lamb in feedlots for all years, it was assumed that the percentage of sheep and lamb on feed that are in feedlots versus pasture/crop residue is the same as that for lambs in 1993 (Anderson 2000).

Goats: Annual goat population data by state were available for 1992, 1997, 2002, and 2007 (USDA 2009a). The data for 1992 were used for 1990 through 1992 and the data for 2007 were used for 2007 through 2009. Data for 1993 through 1996, 1998 through 2001, and 2003 through 2006 were extrapolated based on the 1992, 1997, and 2002 Census data.

Poultry: The USDA provides population data for hens (one year old or older), pullets (hens younger than one year old), broilers, other chickens, and turkeys (USDA 1995a, 1995b, 1998a, 1999, 2004a, 2004b, 2010a, and 2010b). The annual population data for broilers and turkeys were adjusted for the turnover (i.e., slaughter) rate (Lange 2000). All poultry population data were adjusted to account for states that report non-disclosed populations to USDA NASS. The combined populations of the states reporting non-disclosed populations are reported as “other” states. State populations for the non-disclosed states were estimated by equally distributing the population attributed to “other” states to each of the non-disclosed states.

Horses: The FAO publishes annual total U.S. horse population, which were accessed from the FAOSTAT database (FAO 2010). State horse population data were estimated using state population distributions from the 1992, 1997, and 2002 Census of Agriculture and the FAO national population data. A summary of the livestock population characterization data used to calculate CH₄ and N₂O emissions is presented in Table A- 183.

Step 2: Waste Characteristics Data

Methane and N₂O emissions calculations are based on the following animal characteristics for each relevant livestock population:

- Volatile solids (VS) excretion rate;
- Maximum methane producing capacity (B₀) for U.S. animal waste;
- Nitrogen excretion rate (Nex); and
- Typical animal mass (TAM).

Table A- 184 presents a summary of the waste characteristics used in the emissions estimates. Published sources were reviewed for U.S.-specific livestock waste characterization data that would be consistent with the animal population data discussed in Step 1. The USDA's Agricultural Waste Management Field Handbook (AWMFH; USDA 1996a, 2008) is one of the primary sources of waste characteristics. Data from the 1996 and 2008 USDA AWMFH were used to estimate VS and Nex for most animal groups across the time series of the inventory, as shown in Table A-3. In some cases, data from the American Society of Agricultural Engineers, Standard D384.1 (ASAE 1998) were used to supplement the USDA data. The VS and Nex data for breeding swine are from a combination of the types of animals that make up this animal group, namely gestating and farrowing swine and boars. It is assumed that a group of breeding swine is typically broken out as 80 percent gestating sows, 15 percent farrowing swine, and 5 percent boars (Safley 2000). Due to the change in USDA reporting of hens and pullets, new nitrogen and VS excretion rates were calculated for the combined population of hens and pullets; a weighted average rate was calculated based on hen and pullet population data from 1990 to 2004.

The method for calculating VS excretion and Nex from beef and dairy cows, heifers, and steers is based on the relationship between animal performance characteristics such as diet, lactation, and weight gain and energy utilization. The method used is outlined by the IPCC Tier II methodology, and is modeled in the enteric fermentation portion of the inventory in order to take advantage of the detailed diet and animal performance data assembled as part of the Tier II analysis for cattle.

Volatile solids content of manure is the fraction of the diet consumed by cattle that is not digested and thus excreted as fecal material; fecal material combined with urinary excretions constitutes manure. The enteric fermentation model requires the estimation of gross energy intake and its fractional digestibility to estimate enteric CH₄ emissions (see the Enteric Fermentation Annex for details on the enteric energy model). These two inputs are used to calculate the indigestible energy per animal unit as gross energy minus digestible energy plus the amount of gross energy for urinary energy excretion per animal unit (2 or 4 percent). This value is then converted to VS production per animal unit using the typical conversion of dietary gross energy to dry organic matter of 18.45 MJ/kg, after subtracting out the ash content of manure. The current equation recommended by the 2006 IPCC Guidelines is:

$$\text{VS production (kg)} = [(GE - DE) + (UE \times GE)] \times \frac{1 - ASH}{18.45}$$

Where,

GE	= Gross energy intake (MJ)
DE	= Digestible energy (MJ)
(UE × GE)	= Urinary energy expressed as fraction of GE, assumed to be 0.04 except for feedlots which are reduced 0.02 as a result of the high grain content of their diet.
ASH	= Ash content of manure calculated as a fraction of the dry matter feed intake (assumed to be 0.08).
18.45	= Conversion factor for dietary GE per kg of dry matter (MJ per kg). This value is relatively constant across a wide range of forage and grain-based feeds commonly consumed by livestock.

Nitrogen uptake in cattle is carried out through dietary protein intake. However, when feed intake of protein exceeds the nutrient requirements of the animal, the excess nitrogen is excreted, primarily through the urine. To calculate the nitrogen excreted by each animal type, the cattle enteric fermentation model (CEFM) utilizes the energy balance calculations recommended by the IPCC (2006) for gross energy and the energy required for growth along with inputs of weight gain, milk production, and the percent of crude protein in the diets. The total nitrogen excreted is measured in the CEFM as nitrogen consumed minus nitrogen retained by the animal for growth and in milk. The basic equation for calculating Nex is shown below, followed by the equations for each of the constituent parts.

$$N_{\text{excreted}} = N_{\text{consumed}} - (N_{\text{growth}} + N_{\text{milk}})$$

Where,

N_{excreted}	= Daily N excreted per animal, kg per animal per day.
N_{consumed}	= Daily N intake per animal, kg per animal per day
N_{growth}	= Nitrogen retained by the animal for growth, kg per animal per day
N_{milk}	= Nitrogen retained in milk, kg per animal per day

The equation for nitrogen consumed is based on the 2006 IPCC Guidelines, and is estimated as:

$$N_{\text{consumed}} = \left[\frac{GE}{18.45} * \left(\frac{CP\%}{6.25} \right) \right]$$

Where:

N_{consumed}	= Daily N intake per animal, kg per animal per day
GE	= Gross energy intake, as calculated in the CEFM, MJ per animal per day
18.45	= Conversion factor for dietary GE per kg of dry matter, MJ per kg.
CP%	= Percent crude protein in diet, input into the CEFM
6.25	= Conversion from kg of dietary protein to kg of dietary N, kg feed per kg N

The portion of consumed nitrogen that is retained as product equals the nitrogen required for weight gain plus that in milk. The nitrogen retained in body weight gain by stockers, replacements, or feedlot animals is calculated using the net energy for growth (NEg), weight gain (WG), and other conversion factors and constants. The equation matches current 2006 IPCC Guidelines recommendations, and is as follows:

$$N_{\text{growth}} = \frac{\left\{ WG * \left[268 - \frac{(7.03 * NEg)}{WG} \right] \right\}}{6.25}$$

Where,

N_{growth}	= Nitrogen retained by the animal for growth, kg per animal per day
WG	= Daily weight gain of the animal, kg per day
268	= Constant from 2006 IPCC Guidelines
7.03	= Constant from 2006 IPCC Guidelines
NEg	= Net energy required for growth, MJ per animal per day
1,000	= Conversion from grams to kilograms
6.25	= Conversion from kg of dietary protein to kg of dietary N, kg feed per kg N

The N content of milk produced also currently matches the 2006 IPCC Guidelines. Milk nitrogen retained as product is calculated using the following equation:

$$N_{\text{milk}} = \frac{milk * \left(\frac{pr\%}{100} \right)}{6.38}$$

Where,

N_{milk}	= Nitrogen retained in milk, kg per animal per day
milk	= Milk production, kg per day
pr%	= Percent protein in milk, estimated from the fat content as $1.9 + 0.4 * \% \text{Fat}$
100	= Conversion from percent to value (e.g., 4% to 0.04)
6.38	= Conversion from kg Protein to kg N

The VS and N equations above were used to calculate VS and Nex rates for each state, cattle type, and year. Table A- 186 presents the state-specific VS and Nex production rates used for cattle in 2009.

Step 3: Waste Management System Usage Data

Table A- 187 summarizes 2009 manure distribution data among waste management systems (WMS) at beef feedlots, dairies, dairy heifer facilities, and swine, layer, broiler, and turkey operations. Manure from the remaining animal types (beef cattle not on feed, sheep, horses, and goats) is managed on pasture, range, or paddocks, on drylot, or with solids storage systems. Additional information on the development of the manure distribution estimates for each animal type is presented below. Definitions of each WMS type are presented in Table A- 188.

Beef Cattle and Dairy Heifers: The beef feedlot and dairy heifer WMS data were developed using information from EPA's Office of Water's engineering cost analyses conducted to support the development of effluent limitations guidelines for Concentrated Animal Feeding Operations (EPA 2002b). Based on EPA site visits and state contacts supporting this work and additional contacts with the national USDA office to estimate the percent of beef steers and heifers in feedlots (Milton 2000), feedlot manure is almost exclusively managed in drylots. Therefore, for these animal groups, the percent of manure deposited in drylots is assumed to be 100 percent. In addition, there is a small amount of manure contained in runoff, which may or may not be collected in runoff ponds. The runoff from feedlots was calculated by region in *Calculations: Percent Distribution of Manure for Waste Management Systems* (ERG 2000b) and was used to estimate the percentage of manure managed in runoff ponds in addition to drylots; this percentage ranges from 0.4 to 1.3 percent. The percentage of manure generating emissions from beef feedlots is therefore greater than 100 percent. The remaining population categories of beef cattle outside of feedlots are managed through pasture, range, or paddock systems, which are utilized for the majority of the population of beef cattle in the country.

Dairy Cows: The WMS data for dairy cows were developed using data from the Census of Agriculture, EPA's Office of Water, USDA, and expert sources. Farm-size distribution data are reported in the 1992, 1997, and 2002 Census of Agriculture (USDA 2009a). It was assumed that the data provided for 1992 were the same as that for 1990 and 1991, and data provided for 2002 were the same as that for 2003 through 2009. Data for 1993 through 1996 and 1998 through 2001 were extrapolated using the 1992, 1997, and 2002 data. The percent of waste by system was estimated using the USDA data broken out by geographic region and farm size.

Based on EPA site visits and state contacts, manure from dairy cows at medium (200 through 700 head) and large (greater than 700 head) operations are managed using either flush systems or scrape/slurry systems. In addition, they may have a solids separator in place prior to their storage component. Estimates of the percent of farms that use each type of system (by geographic region) were developed by EPA's Office of Water, and were used to estimate the percent of waste managed in lagoons (flush systems), liquid/slurry systems (scrape systems), and solid storage (separated solids) (EPA 2002b). Manure management system data for small (fewer than 200 head) dairies were obtained from USDA (2000a). These operations are more likely to use liquid/slurry and solid storage management systems than anaerobic lagoon systems. The reported manure management systems were deep pit, liquid/slurry (includes slurry tank, slurry earth-basin, and aerated lagoon), anaerobic lagoon, and solid storage (includes manure pack, outside storage, and inside storage).

Data regarding the use of daily spread and pasture, range, or paddock systems for dairy cattle were obtained from personal communications with personnel from several organizations. These organizations include state NRCS offices, state extension services, state universities, USDA NASS, and other experts (Deal 2000, Johnson 2000, Miller 2000, Stettler 2000, Sweeten 2000, and Wright 2000). Contacts at Cornell University provided survey data on dairy manure management practices in New York (Poe et al. 1999). Census of Agriculture population data for 1992, 1997, and 2002 (USDA 2009a) were used in conjunction with the state data obtained from personal communications to determine regional percentages of total dairy cattle and dairy waste that are managed using these systems. These percentages were applied to the total annual dairy cow and heifer state population data for 1990 through 2009, which were obtained from the USDA NASS (USDA 2009b).

Of the dairies using systems other than daily spread and pasture, range, or paddock systems, some dairies reported using more than one type of manure management system. Due to limitations in how USDA reports the manure management data, the total percent of systems for a region and farm size is greater than 100 percent. However, manure is typically partitioned to use only one manure management system, rather than transferred between several different systems. Emissions estimates are only calculated for the final manure management system used for each portion of manure. To avoid double counting emissions, the reported percentages of systems in use were adjusted to equal a total of 100 percent using the same distribution of systems. For example, if USDA reported that 65 percent of dairies use deep pits to manage manure and 55 percent of dairies use anaerobic lagoons to manage manure, it was assumed that 54 percent (i.e., 65 percent divided by 120 percent) of the manure is managed with deep pits and 46 percent (i.e., 55 percent divided by 120 percent) of the manure is managed with anaerobic lagoons (ERG 2000a).

Swine: The distribution of manure managed in each WMS was estimated using data from a USDA report and EPA's Office of Water site visits (USDA 1998, ERG 2000a). For operations with less than 200 head, manure management system data were obtained from USDA (USDA 1998). It was assumed that those operations use pasture, range, or paddock systems. For swine operations with greater than 200 head, the percent of waste managed in each system was estimated using the EPA and USDA data broken out by geographic region and farm size. Farm-size distribution data reported in the 1992, 1997, and 2002 Census of Agriculture (USDA 2009a) were used to determine the percentage of all swine utilizing the various manure management systems. It was assumed that the swine farm size data provided for 1992 were the same as that for 1990 and 1991, and data provided for 2002 were the same as that for 2003 through 2009. Data for 1993 through 1996 and 1998 through 2001 were extrapolated using the 1992, 1997, and 2002 data. The reported manure management systems were deep pit, liquid/slurry (includes above- and below-ground slurry), anaerobic lagoon, and solid storage (includes solids separated from liquids).

Some swine operations reported using more than one management system; therefore, the total percent of systems reported by USDA for a region and farm size was greater than 100 percent. Typically, this means that a portion of the manure at a swine operation is handled in one system (e.g., liquid system), and a separate portion of the manure is handled in another system (e.g., dry system). However, it is unlikely that the same manure is moved from one system to another, which could result in increased emissions, so reported systems data were normalized to 100 percent for incorporation into the WMS distribution, using the same method as described above for dairy operations.

Sheep: Waste management system data for sheep were obtained from USDA NASS sheep report for years 1990 through 1993 (USDA 1994). Data for 2001 are obtained from USDA APHIS sheep report (USDA 2003). The data for years 1994-2000 are calculated assuming a linear progression from 1993 to 2001. Due to lack of additional data, data for years 2002 and beyond are assumed to be the same as 2001. It was assumed that all sheep manure not deposited in feedlots was deposited on pasture, range, or paddock lands (Anderson 2000).

Goats and Horses: Waste management system data for 1990 to 2009 were obtained from Appendix H of *Global Methane Emissions from Livestock and Poultry Manure* (EPA 1992). It was assumed that all manure not deposited in pasture, range, or paddock lands was managed in dry systems.

Poultry—Hens (one year old or older), Pullets (hens less than one year old), and Other Chickens: Waste management system data for 1992 were obtained from *Global Methane Emissions from Livestock and Poultry Manure* (EPA 1992). These data were also used to represent 1990 and 1991. The percentage of layer operations using a shallow pit flush house with anaerobic lagoon or high-rise house without bedding was obtained for 1999 from a United Egg Producers voluntary survey (UEP 1999). These data were augmented for key poultry states (AL, AR, CA, FL, GA, IA, IN, MN, MO, NC, NE, OH, PA, TX, and WA) with USDA data (USDA 2000b). It was assumed that the change in system usage between 1990 and 1999 is proportionally distributed among those years of the inventory. It was assumed that system usage in 2000 through 2009 was equal to that estimated for 1999. Data collected for EPA's Office of Water, including information collected during site visits (EPA 2002b), were used to estimate the distribution of waste by management system and animal type.

Poultry—Broilers and Turkeys: The percentage of turkeys and broilers on pasture was obtained from *Global Methane Emissions from Livestock and Poultry Manure* (EPA 1992). It was assumed that one percent of poultry waste is deposited in pastures, ranges, and paddocks (EPA 1992). The remainder of waste is assumed to be deposited in operations with bedding management.

Step 4: Emission Factor Calculations

Methane conversion factors (MCFs) and N₂O emission factors (EFs) used in the emission calculations were determined using the methodologies presented below.

Methane Conversion Factors (MCFs)

Climate-based IPCC default MCFs (IPCC 2006) were used for all dry systems; these factors are presented in Table A- 189. A U.S.-specific methodology was used to develop MCFs for all lagoon and liquid systems.

For animal waste managed in dry systems, the appropriate IPCC default MCF was applied based on annual average temperature data. Each state and year in the inventory was assigned a climate classification of cool, temperate or warm.

For anaerobic lagoons and other liquid systems a climate-based approach based on the van't Hoff-Arrhenius equation was developed to estimate MCFs that reflects the seasonal changes in temperatures, and also accounts for long-term retention time. This approach is consistent with the recently revised guidelines from IPCC (IPCC 2006). The van't Hoff-Arrhenius equation, with a base temperature of 30°C, is shown in the following equation (Safley and Westerman 1990):

$$f = \exp \left[\frac{E(T_2 - T_1)}{RT_1T_2} \right]$$

Where,

- T_1 = 303.15K
- T_2 = Ambient temperature (K) for climate zone (in this case, a weighted value for each state)
- E = Activation energy constant (15,175 cal/mol)
- R = Ideal gas constant (1.987 cal/K mol)

The factor f represents the proportion of VS that are biologically available for conversion to CH₄ based on the temperature of the system. For those animal populations using liquid manure management systems or manure runoff ponds (i.e., dairy cow, dairy heifer, layers, beef in feedlots, and swine) monthly average state temperatures were based on the counties where the specific animal population resides (i.e., the temperatures were weighted based on the percent of animals located in each county). The average county and state temperature data were obtained from the National Climate Data Center (NOAA 2009). County population data were calculated from state-level population data from NASS and county-state distribution data from the 1992, 1997, and 2002 Census data (USDA 2009a). County population distribution data for 1990 and 1991 were assumed to be the same as 1992; county population distribution data for 1993 through 1996 were extrapolated based on 1992 and 1997 data; county population data for 1998 through 2001 were extrapolated based on 1997 and 2002 data; and county population data for 2003 to 2009 were assumed to be the same as 2002.

Annual MCFs for liquid systems are calculated as follows for each animal type, state, and year of the inventory:

- The weighted-average temperature for a state is calculated using the population estimates and average monthly temperature in each county.
- Monthly temperatures are used to calculate a monthly van't Hoff-Arrhenius “f” factor, using the equation presented above. A minimum temperature of 5°C is used for uncovered anaerobic lagoons and 7.5°C is used for liquid/slurry and deep pit systems.
- Monthly production of VS added to the system is estimated based on the number of animals present.
- For lagoon systems, the calculation of methane includes a management and design practices (MDP) factor. This factor, equal to 0.8, was developed based on model comparisons to empirical CH₄ measurement data from anaerobic lagoon systems in the United States (ERG 2001). The MDP factor represents a variety of factors that may affect methane production in lagoon systems.
- The amount of VS available for conversion to CH₄ is assumed to be equal to the amount of VS produced during the month (from Step 3). For anaerobic lagoons, the amount of VS available also includes VS that may remain in the system from previous months.
- The amount of VS consumed during the month is equal to the amount available for conversion multiplied by the “f” factor.

- For anaerobic lagoons, the amount of VS carried over from one month to the next is equal to the amount available for conversion minus the amount consumed. Lagoons are also modeled to have a solids clean-out once per year, occurring after the month of September.
- The estimated amount of CH₄ generated during the month is equal to the monthly VS consumed multiplied by the maximum CH₄ potential of the waste (B_o).

The annual MCF is then calculated as:

$$MCF_{\text{annual}} = \frac{CH_4 \text{ generated}_{\text{annual}}}{VS \text{ produced}_{\text{annual}} \times B_o}$$

Where,

MCF _{annual}	= Methane conversion factor
VS produced _{annual}	= Volatile solids excreted annually
B _o	= Maximum CH ₄ producing potential of the waste

In order to account for the carry-over of VS from one year to the next, it is assumed that a portion of the VS from the previous year are available in the lagoon system in the next year. For example, the VS from October, November, and December of 2005 are available in the lagoon system starting January of 2006 in the MCF calculation for lagoons in 2006. Following this procedure, the resulting MCF for lagoons accounts for temperature variation throughout the year, residual VS in a system (carry-over), and management and design practices that may reduce the VS available for conversion to CH₄. It is assumed that liquid-slurry systems have a retention time less than 30 days, so the liquid-slurry MCF calculation doesn't reflect the VS carry-over.

The liquid system MCFs are presented in Table A-8 by state, WMS, and animal group for 2009.

Nitrous Oxide Emission Factors

Direct N₂O emission factors for manure management systems (kg N₂O-N/kg excreted N) were set equal to the most recent default IPCC factors (IPCC 2006), presented in Table A- 191.

Indirect N₂O emission factors account for two fractions of nitrogen losses: volatilization of ammonia (NH₃) and NO_x (Frac_{gas}) and runoff/leaching (Frac_{runoff/leach}). IPCC default indirect N₂O emission factors were used to estimate indirect N₂O emissions. These factors are 0.010 kg N₂O-N/kg N for volatilization and 0.0075 kg N₂O/kg N for runoff/leaching.

EPA developed country-specific estimates of nitrogen losses for Frac_{gas} and Frac_{runoff/leach} for the U.S. The vast majority of volatilization losses are NH₃. Although there are also some small losses of NO_x, no quantified estimates were available for use and those losses are believed to be small (about 1 percent) in comparison to the NH₃ losses. Therefore, Frac_{gas} values were based on WMS-specific volatilization values estimated from U.S. EPA's *National Emission Inventory - Ammonia Emissions from Animal Agriculture Operations* (EPA 2005). To estimate Frac_{runoff/leach}, EPA used data from EPA's Office of Water that estimate the amount of runoff from beef, dairy, and heifer operations in five geographic regions of the country (EPA 2002b). These estimates were used to develop U.S. runoff factors by animal type, WMS, and region. Nitrogen losses from leaching are believed to be small in comparison to the runoff losses; therefore, Frac_{runoff/leach} was set equal to the runoff loss factor. Nitrogen losses from volatilization and runoff/leaching are presented in Table A-192.

Step 5: CH₄ and N₂O Emission Calculations

To calculate methane emissions for animals other than cattle, EPA first estimated the amount of volatile solids excreted in manure that is managed in each WMS:

$$VS \text{ excreted}_{\text{State, Animal, WMS}} = \text{Population}_{\text{State, Animal}} \times \frac{TAM}{1000} \times VS \times WMS \times 365.25$$

Where,

VS excreted _{State, Animal, WMS}	=	Amount of VS excreted in manure managed in each WMS for each animal type (kg/yr)
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Population _{State, Animal}	=	Annual average state animal population by animal type (head)
TAM	=	Typical animal mass (kg)
VS	=	Volatile solids production rate (kg VS/1000 kg animal mass/day)
WMS	=	Distribution of manure by WMS for each animal type in a state (percent)
365.25	=	Days per year

Using the CEFM VS data for cattle, the amount of VS excreted was calculated using the following equation:

$$\text{VS excreted}_{\text{State, Animal, WMS}} = \text{Population}_{\text{State, Animal}} \times \text{VS} \times \text{WMS}$$

Where,

VS excreted _{State, Animal, WMS}	=	Amount of VS excreted in manure managed in each WMS for each animal type (kg/yr)
Population _{State, Animal}	=	Annual average state animal population by animal type (head)
VS	=	Volatile solids production rate (kg VS/animal/year)
WMS	=	Distribution of manure by WMS for each animal type in a state (percent)

For all animals, the estimated amount of VS was used to calculate methane emissions using the following equation:

$$\text{CH}_4 = \sum_{\text{State, Animal, WMS}} (\text{VS excreted}_{\text{State, Animal, WMS}} \times B_o \times \text{MCF} \times 0.662)$$

Where,

CH ₄	=	CH ₄ emissions (kg CH ₄ /yr)
VS excreted _{WMS, State}	=	Amount of VS excreted in manure managed in each WMS (kg/yr)
B _o	=	Maximum CH ₄ producing capacity (m ³ CH ₄ /kg VS)
MCF _{animal, state, WMS}	=	MCF for the animal group, state and WMS (percent)
0.662	=	Density of methane at 25° C (kg CH ₄ /m ³ CH ₄)

EPA developed a calculation to estimate the amount of CH₄ emitted from anaerobic digestion (AD) systems utilizing CH₄ capture and combustion technology. First, EPA assumed that AD systems produce 90 percent of the maximum CH₄ producing capacity. This value is applied for all climate regions and AD system types. However, EPA realizes that the actual amount of CH₄ produced by each AD system is very variable and will change based on operational and climate conditions and an assumption of 90 percent is likely overestimating CH₄ production from some systems and underestimating CH₄ production in other systems. The CH₄ production of AD systems is calculated using the equation below:

$$\text{CH}_4 \text{ Production AD}_{\text{AD System}} = \text{Population AD}_{\text{AD System}} \times \frac{\text{TAM}}{1000} \times \text{VS} \times B_o \times 0.662 \times 365.25 \times 0.90$$

Where,

CH ₄ Production AD _{AD system}	=	CH ₄ production from a particular AD system, (kg/yr)
Population AD _{state}	=	Number of animals on a particular AD system
VS	=	Volatile solids production rate (kg VS/1000 kg animal mass-day)
TAM	=	Typical Animal Mass (kg/head)
B _o	=	Maximum CH ₄ producing capacity (CH ₄ m ³ /kg VS)
0.662	=	Density of methane at 25° C (kg CH ₄ /m ³ CH ₄)
365.25	=	Days/year
0.90	=	CH ₄ production factor for AD systems

Next, EPA considered the collection efficiency (CE) and destruction efficiency (DE) of the AD system. The CE of covered lagoon systems was assumed to be 75 percent, and the CE of complete mix and plug flow AD systems was assumed to be 99 percent (EPA 2008). The CH₄ DE from flaring or burning in an engine was assumed to be 98 percent;

therefore, the amount of CH₄ that would not be flared or combusted was assumed to be 2 percent (EPA 2008). The amount of CH₄ produced by systems with anaerobic digestion was calculated with the following equation:

$$\text{CH}_4 \text{ Emissions AD} = \sum_{\text{State, Animal, AD Systems}} \left(\left[\text{CH}_4 \text{ Production AD}_{\text{AD system}} \times \text{CE}_{\text{AD system}} \times (1 - \text{DE}) \right] + \left[\text{CH}_4 \text{ Production AD}_{\text{AD system}} \times (1 - \text{CE}_{\text{AD system}}) \right] \right)$$

Where:

CH ₄ Emissions AD	=	CH ₄ emissions from AD systems, (kg/yr)
CH ₄ Production AD _{AD system}	=	CH ₄ production from a particular AD system, (kg/yr)
CE _{AD system}	=	Collection efficiency of the AD system, varies by AD system type
DE	=	Destruction efficiency of the AD system, 0.98 for all systems

In addition to methane emissions, EPA also estimated total N₂O emissions from manure management systems. Total N₂O emissions were calculated by summing direct and indirect N₂O emissions. The first step in estimating direct and indirect N₂O emissions was calculating the amount of nitrogen excreted in manure and managed in each WMS for animals other than cattle using the following equation:

$$\text{N excreted}_{\text{State, Animal, WMS}} = \text{Population}_{\text{State, Animal}} \times \text{WMS} \times \frac{\text{TAM}}{1000} \times \text{Nex} \times 365.25$$

Where,

N excreted _{State, Animal, WMS}	=	Amount of N excreted in manure managed in each WMS for each animal type (kg/yr)
Population _{state}	=	Annual average state animal population by animal type (head)
WMS	=	Distribution of manure by waste management system for each animal type in a state (percent)
TAM	=	Typical animal mass (kg)
Nex	=	Total Kjeldahl nitrogen excretion rate (kg N/1000 kg animal mass/day)
365.25	=	Days per year

Using the CEFM Nex data for cattle, the amount of N excreted was calculated using the following equation:

$$\text{N excreted}_{\text{State, Animal, WMS}} = \text{Population}_{\text{State, Animal}} \times \text{WMS} \times \text{Nex}$$

Where,

N excreted _{State, Animal, WMS}	=	Amount of N excreted in manure managed in each WMS for each animal type (kg/yr)
Population _{state}	=	Annual average state animal population by animal type (head)
WMS	=	Distribution of manure by waste management system for each animal type in a state (percent)
Nex	=	Total Kjeldahl nitrogen excretion rate (kg N/animal/year)

For all animals, direct N₂O emissions were calculated as follows:

$$\text{Direct N}_2\text{O} = \sum_{\text{State, Animal, WMS}} \left(\text{N excreted}_{\text{State, Animal, WMS}} \times \text{EF}_{\text{WMS}} \times \frac{44}{28} \right)$$

Where,

Direct N ₂ O	=	Direct N ₂ O emissions (kg N ₂ O/yr)
N excreted _{State, Animal, WMS}	=	Amount of N excreted in manure managed in each WMS for each animal type (kg/yr)
EF _{WMS}	=	Direct N ₂ O emission factor from IPCC guidelines (kg N ₂ O-N /kg N)
44/28	=	Conversion factor of N ₂ O-N to N ₂ O

Indirect N₂O emissions were calculated for all animals with the following equation:

$$\text{Indirect N}_2\text{O} = \sum_{\text{State, Animal, WMS}} \left(\left[\text{N excreted}_{\text{State, Animal, WMS}} \times \frac{\text{Frac}_{\text{gas, WMS}}}{100} \times \text{EF}_{\text{volatilization}} \times \frac{44}{28} \right] + \left[\text{N excreted}_{\text{State, Animal, WMS}} \times \frac{\text{Frac}_{\text{runoff/leach, WMS}}}{100} \times \text{EF}_{\text{runoff/leach}} \times \frac{44}{28} \right] \right)$$

Where,

Indirect N ₂ O	=	Indirect N ₂ O emissions (kg N ₂ O/yr)
N excreted _{State, Animal, WMS}	=	Amount of N excreted in manure managed in each WMS for each animal type (kg/yr)
Frac _{gas, WMS}	=	Nitrogen lost through volatilization in each WMS
Frac _{runoff/leach, WMS}	=	Nitrogen lost through runoff and leaching in each WMS; data were not available for leaching so the value reflects only runoff
EF _{volatilization}	=	Emission factor for volatilization (0.010 kg N ₂ O-N/kg N)
EF _{runoff/leach}	=	Emission factor for runoff/leaching (0.0075 kg N ₂ O-N/kg N)
44/28	=	Conversion factor of N ₂ O-N to N ₂ O

Emission estimates of CH₄ and N₂O by animal type are presented for all years of the inventory in Table A- 193 and Table A- 194, respectively. Emission estimates for 2009 are presented by animal type and state in Table A- 195 and Table A- 196, respectively.

Table A- 183: Livestock Population (1,000 Head)

Animal Type	1990	1995	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Dairy Cattle	14,144	13,590	13,191	13,217	13,165	13,215	13,021	13,165	13,398	13,487	13,658	13,759
Dairy Cows	10,015	9,482	9,183	9,172	9,106	9,142	8,988	9,004	9,104	9,145	9,257	9,333
Dairy Heifer	4,129	4,108	4,008	4,045	4,060	4,073	4,033	4,162	4,294	4,343	4,401	4,426
Swine ¹	53,941	58,899	58,864	58,913	60,028	59,827	60,735	61,073	61,887	65,417	67,408	66,142
Market <50 lb.	18,359	19,656	19,574	19,659	19,863	19,929	20,222	20,228	20,514	21,812	19,964	19,559
Market 50-119 lb.	11,734	12,836	12,926	12,900	13,284	13,138	13,400	13,519	13,727	14,557	17,219	17,077
Market 120-179 lb.	9,440	10,545	10,748	10,708	11,013	11,050	11,227	11,336	11,443	12,185	12,931	12,517
Market >180 lb.	7,510	8,937	9,385	9,465	9,738	9,701	9,922	9,997	10,113	10,673	11,193	11,084
Breeding	6,899	6,926	6,231	6,181	6,129	6,011	5,963	5,993	6,090	6,190	6,102	5,905
Beef Cattle ²	87,228	95,683	89,948	89,118	89,102	88,232	86,441	86,954	88,070	87,639	86,450	85,736
Feedlot Steers	6,357	7,233	8,304	7,932	8,116	8,416	8,018	8,116	8,724	8,674	8,481	8,450
Feedlot Heifers	3,192	3,831	4,702	4,569	4,557	4,676	4,521	4,536	4,801	4,730	4,589	4,514
NOF Bulls	2,160	2,385	2,293	2,274	2,244	2,248	2,201	2,214	2,258	2,214	2,207	2,184
NOF Calves	22,561	23,499	22,569	22,389	22,325	21,997	21,781	21,678	21,621	21,483	21,155	20,940
NOF Heifers	10,182	11,829	9,781	9,832	9,843	9,564	9,321	9,550	9,716	9,592	9,350	9,436
NOF Steers	10,321	11,716	8,724	8,724	8,883	8,347	8,067	8,185	8,248	8,302	8,233	8,501
NOF Cows	32,455	35,190	33,575	33,398	33,134	32,983	32,531	32,674	32,703	32,644	32,435	31,712
Sheep	11,358	8,989	7,036	6,908	6,623	6,321	6,105	6,135	6,230	6,120	5,950	5,747
Sheep On Feed	1,180	1,771	2,963	3,256	3,143	3,049	2,943	2,982	3,043	3,000	2,911	2,805
Sheep NOF	10,178	7,218	4,073	3,652	3,480	3,272	3,162	3,153	3,187	3,120	3,039	2,942
Goats	2,516	2,357	2,419	2,475	2,530	2,652	2,774	2,897	3,019	3,141	3,141	3,141
Poultry ³	1,537,074	1,826,977	2,033,123	2,060,398	2,097,691	2,085,268	2,130,877	2,150,410	2,154,236	2,166,936	2,175,990	2,086,699
Hens >1 yr.	273,467	299,071	333,593	340,317	340,209	340,979	343,922	348,203	349,888	346,613	339,859	339,526
Pullets	73,167	81,369	95,159	95,656	95,289	100,346	101,429	96,809	96,596	103,816	99,458	101,588
Chickens	6,545	7,637	8,088	8,126	8,353	8,439	8,248	8,289	7,938	8,164	7,589	8,496
Broilers	1,066,209	1,331,940	1,506,127	1,525,413	1,562,015	1,544,155	1,589,209	1,613,091	1,612,327	1,619,400	1,638,055	1,554,636
Turkeys	117,685	106,960	90,155	90,887	91,826	91,349	88,069	84,018	87,487	88,943	91,029	82,453
Horses	5,069	5,130	5,240	5,500	6,000	7,000	8,000	9,200	9,500	9,500	9,500	9,500

Note: Totals may not sum due to independent rounding.

¹ Prior to 2008, the Market <50 lbs category was <60 lbs and the Market 50-119 lbs category was Market 60-119 lbs; USDA updated the categories to be more consistent with international animal categories.

² NOF = Not on Feed

³ Pullets includes laying pullets, pullets younger than 3 months, and pullets older than 3 months.

Table A- 184: Waste Characteristics Data

Animal Group	TAM (kg)	TAM Source	Total Kjeldahl Nitrogen, N_{ex} (kg/day per 1,000 kg mass)	N_{ex} Source	Maximum Methane Generation Potential, B₀ (m³ CH₄/kg VS added)	B₀ Source	Volatile Solids, VS (kg/day per 1,000 kg mass)	VS Source
Dairy Cows	680	Enteric		Moffroid and Pape, 2010	0.24	Morris 1976		Moffroid and Pape, 2010
		Fermentation	Table A- 185				Table A- 185	
Dairy Heifers	406-408	Enteric		Moffroid and Pape, 2010	0.17	Bryant et. al. 1976		Moffroid and Pape, 2010
		Fermentation	Table A- 185				Table A- 185	
Feedlot Steers	419-457	Enteric		Moffroid and Pape, 2010	0.33	Hashimoto 1981		Moffroid and Pape, 2010
		Fermentation	Table A- 185				Table A- 185	
Feedlot Heifers	384-430	Enteric		Moffroid and Pape, 2010	0.33	Hashimoto 1981		Moffroid and Pape, 2010
		Fermentation	Table A- 185				Table A- 185	
NOF Bulls	750	Shuyler 2000	Table A- 186	USDA 1996a	0.17	Hashimoto 1981	Table A- 186	USDA 1996a
NOF Calves	118	USDA 1996a	Table A- 186	USDA 1996a, 2008	0.17	Hashimoto 1981	Table A- 186	USDA 1996a, 2008
NOF Heifers	296-406	Enteric		Moffroid and Pape, 2010	0.17	Hashimoto 1981		Moffroid and Pape, 2010
		Fermentation	Table A- 185				Table A- 185	
NOF Steers	314-335	Enteric		Moffroid and Pape, 2010	0.17	Hashimoto 1981		Moffroid and Pape, 2010
		Fermentation	Table A- 185				Table A- 185	
NOF Cows	554-611	Enteric		Moffroid and Pape, 2010	0.17	Hashimoto 1981		Moffroid and Pape, 2010
		Fermentation	Table A- 185				Table A- 185	
Market Swine <50 lbs.	13	ERG 2010a	Table A- 186	USDA 1996a, 2008	0.48	Hashimoto 1984	Table A- 186	USDA 1996a, 2008
Market Swine <60 lbs.	16	Safley 2000	Table A- 186	USDA 1996a, 2008	0.48	Hashimoto 1984	Table A- 186	USDA 1996a, 2008
Market Swine 50-119 lbs.	39	ERG 2010a	Table A- 186	USDA 1996a, 2008	0.48	Hashimoto 1984	Table A- 186	USDA 1996a, 2008
Market Swine 60-119 lbs.	41	Safley 2000	Table A- 186	USDA 1996a, 2008	0.48	Hashimoto 1984	Table A- 186	USDA 1996a, 2008
Market Swine 120-179 lbs.	68	Safley 2000	Table A- 186	USDA 1996a, 2008	0.48	Hashimoto 1984	Table A- 186	USDA 1996a, 2008
Market Swine >180 lbs.	91	Safley 2000	Table A- 186	USDA 1996a, 2008	0.48	Hashimoto 1984	Table A- 186	USDA 1996a, 2008
Breeding Swine	198	Safley 2000	Table A- 186	USDA 1996a, 2008	0.48	Hashimoto 1984	Table A- 186	USDA 1996a, 2008
Feedlot Sheep	25	EPA 1992	Table A- 186	ASAE 1998, USDA 2008	0.36	EPA 1992	Table A- 186	ASAE 1998, USDA 2008
NOF Sheep	80	EPA 1992	Table A- 186	ASAE 1998, USDA 2008	0.19	EPA 1992	Table A- 186	ASAE 1998, USDA 2008
Goats	64	ASAE 1999	Table A- 186	ASAE 1998	0.17	EPA 1992	Table A- 186	ASAE 1998
Horses	450	ASAE 1999	Table A- 186	ASAE 1998, USDA 2008	0.33	EPA 1992	Table A- 186	ASAE 1998, USDA 2008
Hens >= 1 yr	1.8	ASAE 1999	Table A- 186	USDA 1996a, 2008	0.39	Hill 1982	Table A- 186	USDA 1996a, 2008
Pullets	1.8	ASAE 1999	Table A- 186	USDA 1996a, 2008	0.39	Hill 1982	Table A- 186	USDA 1996a, 2008
Other Chickens	1.8	ASAE 1999	Table A- 186	USDA 1996a, 2008	0.39	Hill 1982	Table A- 186	USDA 1996a, 2008

Broilers	0.9	ASAE 1999	Table A- 186	USDA 1996a, 2008	0.36	Hill 1984	Table A- 186	USDA 1996a, 2008
Turkeys	6.8	ASAE 1999	Table A- 186	USDA 1996a, 2008	0.36	Hill 1984	Table A- 186	USDA 1996a, 2008

Table A- 185: Estimated Volatile Solids and Nitrogen Excreted Production Rate by year for Animals Other Than Cattle (kg/day/1000 kg animal mass)

Animal Type	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
VS																				
Market Swine																				
<50 lb.	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8
Market Swine 50-119 lb.	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4
Market Swine 120-179 lb.	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4
Market Swine >180 lb.	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4
Breeding Swine	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.611	2.623	2.634	2.645	2.656	2.668	2.679	2.69	2.701	2.713	2.724	2.735	2.735
NOF Bulls	6.04	6.04	6.04	6.04	6.04	6.04	6.04	6.04	6.04	6.04	6.04	6.04	6.04	6.04	6.04	6.04	6.04	6.04	6.04	6.04
NOF Calves	6.41	6.41	6.41	6.41	6.41	6.41	6.41	6.5175	6.625	6.733	6.84	6.948	7.055	7.163	7.27	7.378	7.485	7.593	7.7	7.7
Sheep	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.11	9.02	8.93	8.84	8.75	8.66	8.57	8.48	8.39	8.3	8.3
Goats	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5
Hens >1 yr.	10.091	10.091	10.091	10.091	10.091	10.091	10.091	10.097	10.103	10.109	10.115	10.121	10.1265	10.132	10.138	10.144	10.150	10.156	10.162	10.162
Pullets	10.091	10.091	10.091	10.091	10.091	10.091	10.091	10.097	10.103	10.109	10.115	10.121	10.1265	10.132	10.138	10.144	10.150	10.156	10.162	10.162
Chickens	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.817	10.833	10.85	10.867	10.883	10.9	10.917	10.933	10.95	10.967	10.983	11	11
Broilers	15	15	15	15	15	15	15	15.167	15.333	15.5	15.667	15.833	16	16.167	16.333	16.5	16.667	16.833	17	17
Turkeys	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.596	9.492	9.388	9.283	9.179	9.075	8.971	8.867	8.7625	8.658	8.554	8.45	8.45
Horses	10	10	10	10	10	10	10	10	10	9.61	9.22	8.83	8.44	8.05	7.66	7.27	6.88	6.49	6.1	6.1
Nex																				
Market Swine																				
<50 lb.	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.627	0.653	0.68	0.707	0.733	0.76	0.787	0.813	0.84	0.867	0.893	0.92	0.92
Market Swine 50-119 lb.	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.43	0.44	0.45	0.46	0.47	0.48	0.49	0.5	0.51	0.52	0.53	0.54	0.54
Market Swine 120-179 lb.	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.43	0.44	0.45	0.46	0.47	0.48	0.49	0.5	0.51	0.52	0.53	0.54	0.54
Market Swine >180 lb.	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.43	0.44	0.45	0.46	0.47	0.48	0.49	0.5	0.51	0.52	0.53	0.54	0.54
Breeding Swine	0.235	0.235	0.235	0.235	0.235	0.235	0.235	0.232	0.230	0.227	0.224	0.221	0.219	0.216	0.213	0.211	0.208	0.205	0.203	0.203
NOF Bulls	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31
NOF Calves	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.313	0.325	0.338	0.35	0.363	0.375	0.388	0.4	0.413	0.425	0.438	0.45	0.45
Sheep	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.423	0.426	0.429	0.432	0.435	0.438	0.441	0.444	0.447	0.45	0.45
Goats	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45
Hens >1 yr.	0.695	0.695	0.695	0.695	0.695	0.695	0.695	0.703	0.711	0.719	0.727	0.735	0.743	0.750	0.758	0.766	0.774	0.782	0.79	0.79
Pullets	0.695	0.695	0.695	0.695	0.695	0.695	0.695	0.703	0.711	0.719	0.727	0.735	0.743	0.750	0.758	0.766	0.774	0.782	0.79	0.79
Chickens	0.83	0.83	0.83	0.83	0.83	0.83	0.83	0.853	0.875	0.898	0.92	0.943	0.965	0.988	1.01	1.033	1.055	1.078	1.1	1.1
Broilers	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.088	1.077	1.065	1.053	1.042	1.03	1.018	1.007	0.995	0.983	0.972	0.96	0.96
Turkeys	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.730	0.721	0.711	0.702	0.692	0.683	0.673	0.663	0.654	0.644	0.635	0.625	0.625
Horses	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.295	0.289	0.284	0.278	0.273	0.267	0.262	0.256	0.251	0.245	0.245

**Table A- 186: Estimated Volatile Solids and Nitrogen Excreted Production Rate by State for Cattle for 2009
(kg/animal/year)**

State	Volatile Solids							Nitrogen Excreted						
	Dairy Cow	Dairy Heifers	Beef NOF Cow	Beef NOF Heifers	Beef NOF Steer	Beef OF Heifers	Beef OF Steer	Dairy Cow	Dairy Heifers	Beef NOF Cow	Beef NOF Heifers	Beef NOF Steer	Beef OF Heifers	Beef OF Steer
Alabama	2,267.41	1,251.47	1,680.43	1,103.73	979.63	673.81	656.14	135.78	68.85	70.16	48.18	40.04	53.69	55.01
Alaska	1,846.07	1,251.47	2,158.74	1,475.35	1,287.98	758.17	723.58	115.86	68.85	84.14	60.31	49.59	61.06	61.25
Arizona	2,819.52	1,251.47	2,158.74	1,440.02	1,287.98	674.59	656.77	157.68	68.85	84.14	58.35	49.59	53.76	55.07
Arkansas	2,046.05	1,251.47	1,675.36	1,093.22	976.43	731.19	702.01	124.61	68.85	72.93	49.63	41.72	58.70	59.26
California	2,723.70	1,251.47	1,638.85	1,042.04	953.48	688.37	667.78	152.93	68.85	71.23	46.75	40.63	54.96	56.09
Colorado	2,824.09	1,251.47	1,546.94	951.51	896.01	685.35	665.37	157.87	68.85	71.65	44.97	40.74	54.70	55.87
Connecticut	2,494.94	1,251.47	1,652.50	1,093.00	962.06	674.37	656.59	143.73	68.85	68.93	47.85	39.24	53.74	55.06
Delaware	2,369.10	1,251.47	1,652.50	1,062.76	962.06	740.93	709.80	138.33	68.85	68.93	45.95	39.24	59.55	59.98
Florida	2,502.90	1,251.47	1,680.43	1,117.18	979.63	723.70	696.02	145.89	68.85	70.16	49.02	40.04	58.05	58.70
Georgia	2,543.18	1,251.47	1,680.43	1,103.56	979.63	706.46	682.24	147.62	68.85	70.16	48.17	40.04	56.54	57.43
Hawaii	2,159.89	1,251.47	2,158.74	1,450.79	1,287.98	706.46	682.24	129.34	68.85	84.14	58.95	49.59	56.54	57.43
Idaho	2,749.48	1,251.47	2,158.74	1,392.62	1,287.98	679.06	660.34	154.67	68.85	84.14	55.73	49.59	54.15	55.40
Illinois	2,509.01	1,251.47	1,653.05	1,037.84	962.40	664.58	648.76	144.34	68.85	70.73	45.55	40.34	52.88	54.33
Indiana	2,603.48	1,251.47	1,653.05	1,050.80	962.40	661.25	646.10	148.40	68.85	70.73	46.38	40.34	52.59	54.09
Iowa	2,620.71	1,251.47	1,653.05	1,022.85	962.40	675.86	657.78	149.14	68.85	70.73	44.59	40.34	53.87	55.17
Kansas	2,674.30	1,251.47	1,546.94	945.66	896.01	684.40	664.60	151.44	68.85	71.65	44.57	40.74	54.61	55.80
Kentucky	2,213.71	1,251.47	1,680.43	1,092.37	979.63	731.19	702.01	133.47	68.85	70.16	47.47	40.04	58.70	59.26
Louisiana	1,990.33	1,251.47	1,675.36	1,112.51	976.43	714.03	688.29	122.21	68.85	72.93	50.88	41.72	57.20	57.99
Maine	2,448.34	1,251.47	1,652.50	1,080.42	962.06	692.36	670.97	141.73	68.85	68.93	47.06	39.24	55.31	56.39
Maryland	2,462.83	1,251.47	1,652.50	1,066.48	962.06	641.27	630.13	142.36	68.85	68.93	46.18	39.24	50.85	52.61
Massachusetts	2,411.79	1,251.47	1,652.50	1,080.42	962.06	706.46	682.24	140.16	68.85	68.93	47.06	39.24	56.54	57.43
Michigan	2,775.94	1,251.47	1,653.05	1,045.14	962.40	674.88	656.99	155.80	68.85	70.73	46.02	40.34	53.78	55.09
Minnesota	2,535.74	1,251.47	1,653.05	1,047.02	962.40	690.51	669.49	145.49	68.85	70.73	46.14	40.34	55.15	56.25
Mississippi	2,191.18	1,251.47	1,680.43	1,103.12	979.63	680.89	661.80	132.50	68.85	70.16	48.14	40.04	54.31	55.54
Missouri	2,193.82	1,251.47	1,653.05	1,067.85	962.40	681.24	662.08	130.80	68.85	70.73	47.47	40.34	54.34	55.56
Montana	2,588.27	1,251.47	1,546.94	1,003.22	896.01	657.92	643.44	147.74	68.85	71.65	48.53	40.74	52.30	53.84
Nebraska	2,572.43	1,251.47	1,546.94	950.97	896.01	680.84	661.76	147.06	68.85	71.65	44.93	40.74	54.30	55.53
Nevada	2,729.35	1,251.47	2,158.74	1,428.01	1,287.98	691.23	670.06	153.80	68.85	84.14	57.69	49.59	55.21	56.30
New Hampshire	2,558.38	1,251.47	1,652.50	1,073.63	962.06	706.46	682.24	146.46	68.85	68.93	46.63	39.24	56.54	57.43
New Jersey	2,435.51	1,251.47	1,652.50	1,068.91	962.06	745.24	713.24	141.18	68.85	68.93	46.34	39.24	59.93	60.30
New Mexico	2,916.03	1,251.47	2,158.74	1,417.32	1,287.98	667.61	651.18	161.82	68.85	84.14	57.10	49.59	53.15	54.56
New York	2,598.56	1,251.47	1,652.50	1,050.97	962.06	675.38	657.39	148.18	68.85	68.93	45.21	39.24	53.83	55.13
North Carolina	2,621.22	1,251.47	1,680.43	1,103.07	979.63	731.19	702.01	150.97	68.85	70.16	48.14	40.04	58.70	59.26
North Dakota	2,349.60	1,251.47	1,546.94	985.19	896.01	671.24	654.09	137.49	68.85	71.65	47.29	40.74	53.46	54.83
Ohio	2,499.38	1,251.47	1,653.05	1,061.17	962.40	668.17	651.63	143.92	68.85	70.73	47.04	40.34	53.20	54.60
Oklahoma	2,372.40	1,251.47	1,675.36	1,066.91	976.43	672.96	655.46	138.62	68.85	72.93	47.94	41.72	53.61	54.95
Oregon	2,572.28	1,251.47	2,158.74	1,414.00	1,287.98	671.24	654.09	147.06	68.85	84.14	56.91	49.59	53.46	54.83
Pennsylvania	2,545.40	1,251.47	1,652.50	1,050.97	962.06	671.24	654.09	145.90	68.85	68.93	45.21	39.24	53.46	54.83
Rhode Island	2,430.23	1,251.47	1,652.50	1,095.96	962.06	675.44	657.44	140.95	68.85	68.93	48.03	39.24	53.83	55.14
South Carolina	2,555.49	1,251.47	1,680.43	1,107.64	979.63	688.56	667.94	148.15	68.85	70.16	48.42	40.04	54.98	56.11
South Dakota	2,602.79	1,251.47	1,546.94	970.02	896.01	674.32	656.55	148.37	68.85	71.65	46.25	40.74	53.73	55.05
Tennessee	2,366.26	1,251.47	1,680.43	1,100.05	979.63	671.24	654.09	140.02	68.85	70.16	47.95	40.04	53.46	54.83
Texas	2,664.94	1,251.47	1,675.36	1,058.67	976.43	678.95	660.25	151.19	68.85	72.93	47.41	41.72	54.14	55.40
Utah	2,667.08	1,251.47	2,158.74	1,424.78	1,287.98	719.20	692.43	151.13	68.85	84.14	57.51	49.59	57.66	58.37
Vermont	2,465.40	1,251.47	1,652.50	1,055.51	962.06	727.14	698.78	142.47	68.85	68.93	45.49	39.24	58.35	58.96
Virginia	2,504.58	1,251.47	1,680.43	1,097.87	979.63	675.38	657.39	145.96	68.85	70.16	47.81	40.04	53.83	55.13
Washington	2,830.17	1,251.47	2,158.74	1,401.02	1,287.98	674.99	657.08	158.13	68.85	84.14	56.19	49.59	53.79	55.10
West Virginia	2,199.28	1,251.47	1,652.50	1,071.08	962.06	617.96	611.49	131.04	68.85	68.93	46.47	39.24	48.81	50.89
Wisconsin	2,599.14	1,251.47	1,653.05	1,067.78	962.40	676.24	658.08	148.21	68.85	70.73	47.46	40.34	53.90	55.19
Wyoming	2,504.44	1,251.47	1,546.94	989.11	896.01	671.24	654.09	144.14	68.85	71.65	47.56	40.74	53.46	54.83

Source: Moffroid and Pape, 2010.

Table A- 187: 2009 Manure Distribution Among Waste Management Systems by Operation (Percent)

	Beef Feedlots		Dairies ¹						Dairy Heifer Facilities				Swine Operations ¹					Layer Operations		Broiler and Turkey Operations	
State	Dry Lot ²	Liquid/ Slurry ²	Pasture	Daily Spread	Solid Storage	Liquid/ Slurry	Anaerobic Lagoon	Deep Pit	Daily Spread ²	Dry Lot ²	Liquid/ Slurry ²	Pasture ²	Pasture	Solid Storage	Liquid/ Slurry	Anaerobic Lagoon	Deep Pit	Anaerobic Lagoon	Poultry without Litter	Pasture	Poultry with Litter
Alabama	100	1.3	45	17	11	10	17	0	17	38	0	45	5	4	8	51	32	41.9	58.1	1	99
Alaska	100	1.3	4	6	28	24	30	8	6	90	1	4	53	2	13	10	22	25	75	1	99
Arizona	100	0.4	0	10	9	20	61	0	10	90	0	0	14	3	5	50	27	60	40	1	99
Arkansas	100	1.3	57	15	11	7	10	1	15	28	0	57	4	4	12	46	35	0	100	1	99
California	100	1.3	1	11	9	21	58	0	11	88	1	1	13	3	8	47	29	12	88	1	99
Colorado	100	0.4	1	1	12	24	62	1	1	98	0	1	2	5	26	17	50	60	40	1	99
Connecticut	100	1	6	43	17	20	12	2	43	51	0	6	57	2	12	9	20	5	95	1	99
Delaware	100	1	6	44	19	19	10	2	44	50	0	6	12	4	24	18	42	5	95	1	99
Florida	100	1.3	17	22	8	15	39	0	22	61	1	17	71	1	8	6	14	41.9	58.1	1	99
Georgia	100	1.3	40	18	10	11	21	0	18	42	0	40	8	4	10	47	32	41.9	58.1	1	99
Hawaii	100	1.3	1	0	11	21	67	0	0	99	1	1	23	3	18	21	34	25	75	1	99
Idaho	100	0.4	0	1	12	23	63	1	1	99	0	0	46	3	15	10	26	60	40	1	99
Illinois	100	0.6	5	8	43	26	13	5	8	87	0	5	2	5	28	15	50	2	98	1	99
Indiana	100	0.6	8	13	35	24	16	3	13	79	0	8	3	5	28	15	50	0	100	1	99
Iowa	100	0.6	6	10	41	25	14	4	10	83	0	6	1	4	12	48	35	0	100	1	99
Kansas	100	0.6	3	5	28	33	29	3	5	92	0	3	2	5	28	13	51	2	98	1	99
Kentucky	100	1	61	14	14	6	2	2	14	24	0	61	5	4	12	45	34	5	95	1	99
Louisiana	100	1.3	60	14	10	6	9	1	14	26	0	60	54	2	13	10	22	60	40	1	99
Maine	100	1	7	45	20	17	9	2	45	48	0	7	73	1	7	6	13	5	95	1	99
Maryland	100	1	7	44	23	15	8	3	44	49	0	7	21	4	21	16	38	5	95	1	99
Massachusetts	100	1	7	45	24	15	6	3	45	47	0	7	31	3	19	14	32	5	95	1	99
Michigan	100	0.6	3	6	32	33	22	4	6	91	0	3	5	5	25	17	48	2	98	1	99
Minnesota	100	0.6	6	10	44	24	12	5	10	84	0	6	2	5	26	18	49	0	100	1	99
Mississippi	100	1.3	57	15	10	7	10	0	15	28	0	57	2	4	6	57	31	60	40	1	99
Missouri	100	0.6	8	14	48	18	6	5	14	77	0	8	3	5	28	14	51	0	100	1	99
Montana	100	0.4	3	4	25	26	36	6	4	93	0	3	6	5	25	17	47	60	40	1	99
Nebraska	100	0.6	4	6	35	30	21	4	6	90	0	4	3	5	28	15	50	2	98	1	99
Nevada	100	0.4	0	0	11	24	64	0	0	99	0	0	35	2	4	39	20	0	100	1	99
New Hampshire	100	1	7	44	21	16	9	3	44	49	0	7	57	2	12	9	20	5	95	1	99
New Jersey	100	1	8	45	24	14	6	3	45	47	0	8	31	3	19	14	33	5	95	1	99
New Mexico	100	0.4	0	10	9	19	61	0	10	90	0	0	92	0	2	2	4	60	40	1	99
New York	100	1	7	45	20	16	10	2	45	48	0	7	20	4	21	15	40	5	95	1	99
North Carolina	100	1	54	15	12	11	6	1	15	31	0	54	0	4	6	58	31	41.9	58.1	1	99
North Dakota	100	0.6	6	11	45	22	12	4	11	83	0	6	9	5	24	17	45	2	98	1	99
Ohio	100	0.6	8	14	41	23	11	4	14	78	0	8	7	4	27	15	47	0	100	1	99
Oklahoma	100	0.4	0	6	25	23	40	6	6	94	0	0	1	4	6	58	31	60	40	1	99
Oregon	100	1.3	20	0	13	21	44	2	0	80	1	20	58	2	12	9	20	25	75	1	99
Pennsylvania	100	1	9	47	25	12	5	2	47	44	0	9	5	5	25	18	47	0	100	1	99

	Beef Feedlots		Dairies ¹						Dairy Heifer Facilities				Swine Operations ¹					Layer Operations		Broiler and Turkey Operations	
State	Dry Lot ²	Liquid/Slurry ²	Pasture	Daily Spread	Solid Storage	Liquid/Slurry	Anaerobic Lagoon	Deep Pit	Daily Spread ²	Dry Lot ²	Liquid/Slurry ²	Pasture ²	Pasture	Solid Storage	Liquid/Slurry	Anaerobic Lagoon	Deep Pit	Anaerobic Lagoon	Poultry without Litter	Pasture	Poultry with Litter
Rhode Island	100	1	9	47	26	12	4	3	47	44	0	9	56	2	12	9	21	5	95	1	99
South Carolina	100	1.3	54	15	8	9	13	0	15	31	0	54	6	4	9	50	32	60	40	1	99
South Dakota	100	0.6	5	8	38	28	18	4	8	87	0	5	3	5	26	18	48	2	98	1	99
Tennessee	100	1	59	15	12	9	4	2	15	26	0	59	10	4	12	41	33	5	95	1	99
Texas	100	0.4	0	8	13	24	53	2	8	92	0	0	7	3	6	54	29	12	88	1	99
Utah	100	0.4	1	1	17	26	51	3	1	98	0	1	1	6	26	17	51	60	40	1	99
Vermont	100	1	7	44	19	17	10	2	44	49	0	7	86	1	4	3	7	5	95	1	99
Virginia	100	1	57	15	12	9	4	2	15	28	0	57	3	4	7	55	31	5	95	1	99
Washington	100	1.3	17	0	11	22	49	1	0	83	1	17	37	3	17	12	31	12	88	1	99
West Virginia	100	1	7	45	23	16	7	3	45	48	0	7	58	2	11	8	21	5	95	1	99
Wisconsin	100	0.6	7	12	42	24	12	4	12	82	0	7	13	4	24	17	42	2	98	1	99
Wyoming	100	0.4	7	12	22	23	30	6	12	81	0	7	3	5	26	17	49	60	40	1	99

¹ In the methane inventory for manure management, the percent of dairy cows and swine with anaerobic digestion systems is estimated using data from EPA's AgSTAR Program.

² Because manure from beef feedlots and dairy heifers may be managed for long periods of time in multiple systems (i.e., both drylot and runoff collection pond), the percent of manure that generates emissions is greater than 100 percent.

Table A- 188: Manure Management System Descriptions

Manure Management System	Description ¹
Pasture	The manure from pasture and range grazing animals is allowed to lie as is, and is not managed. N ₂ O emissions from deposited manure are covered under the N ₂ O from Agricultural Soils category.
Daily Spread	Manure is routinely removed from a confinement facility and is applied to cropland or pasture within 24 hours of excretion. N ₂ O emissions during storage and treatment are assumed to be zero. N ₂ O emissions from land application are covered under the Agricultural Soils category.
Solid Storage	The storage of manure, typically for a period of several months, in unconfined piles or stacks. Manure is able to be stacked due to the presence of a sufficient amount of bedding material or loss of moisture by evaporation.
Dry Lot	A paved or unpaved open confinement area without any significant vegetative cover where accumulating manure may be removed periodically. Dry lots are most typically found in dry climates but also are used in humid climates.
Liquid/ Slurry	Manure is stored as excreted or with some minimal addition of water to facilitate handling and is stored in either tanks or earthen ponds, usually for periods less than one year.
Anaerobic Lagoon	Uncovered anaerobic lagoons are designed and operated to combine waste stabilization and storage. Lagoon supernatant is usually used to remove manure from the associated confinement facilities to the lagoon. Anaerobic lagoons are designed with varying lengths of storage (up to a year or greater), depending on the climate region, the volatile solids loading rate, and other operational factors. Anaerobic lagoons accumulate sludge over time, diminishing treatment capacity. Lagoons must be cleaned out once every 5 to 15 years, and the sludge is typically applied to agricultural lands. The water from the lagoon may be recycled as flush water or used to irrigate and fertilize fields. Lagoons are sometimes used in combination with a solids separator, typically for dairy waste. Solids separators help control the buildup of nondegradable material such as straw or other bedding materials.
Anaerobic Digester	Animal excreta with or without straw are collected and anaerobically digested in a large containment vessel or covered lagoon. Digesters are designed and operated for waste stabilization by the microbial reduction of complex organic compounds to CO ₂ and CH ₄ , which is captured and flared or used as a fuel.
Deep Pit	Collection and storage of manure usually with little or no added water typically below a slatted floor in an enclosed animal confinement facility. Typical storage periods range from 5 to 12 months, after which manure is removed from the pit and transferred to a treatment system or applied to land.
Poultry with Litter	Enclosed poultry houses use bedding derived from wood shavings, rice hulls, chopped straw, peanut hulls, or other products, depending on availability. The bedding absorbs moisture and dilutes the manure produced by the birds. Litter is typically cleaned out completely once a year. These manure systems are typically used for all poultry breeder flocks and for the production of meat type chickens (broilers) and other fowl.
Poultry without Litter	In high-rise cages or scrape-out/belt systems, manure is excreted onto the floor below with no bedding to absorb moisture. The ventilation system dries the manure as it is stored. When designed and operated properly, this high-rise system is a form of passive windrow composting.

¹ Manure management system descriptions are from the *2006 IPCC Guidelines for National Greenhouse Gas Inventories* (Volume 4: Agriculture, Forestry and Other Land Use, Chapter 10: Emissions from Livestock and Manure Management, Tables 10.18 and 10.21) and the *Development Document for the Final Revisions to the National Pollutant Discharge Elimination System Regulation and the Effluent Guidelines for Concentrated Animal Feeding Operations* (EPA-821-R-03-001, December 2002).

Table A- 189: Methane Conversion Factors (percent) for Dry Systems

Waste Management System	Cool Climate MCF	Temperate Climate MCF	Warm Climate MCF
Aerobic Treatment	0	0	0
Cattle Deep Litter (<1 month)	0.03	0.03	0.3
Cattle Deep Litter (>1 month)	0.21	0.44	0.76
Composting - In Vessel	0.005	0.005	0.005
Composting - Static Pile	0.005	0.005	0.005
Composting-Extensive/ Passive	0.005	0.01	0.015
Composting-Intensive	0.005	0.01	0.015
Daily Spread	0.001	0.005	0.01
Dry Lot	0.01	0.015	0.05
Fuel	0.1	0.1	0.1

Waste Management System	Cool Climate MCF	Temperate Climate MCF	Warm Climate MCF
Pasture	0.01	0.015	0.02
Poultry with bedding	0.015	0.015	0.015
Poultry without bedding	0.015	0.015	0.015
Solid Storage	0.02	0.04	0.05

Table A- 190: Methane Conversion Factors by State for Liquid Systems for 2009 (percent)

State	Dairy		Swine		Beef	Poultry
	Anaerobic Lagoon	Liquid/Slurry and Deep Pit	Anaerobic Lagoon	Liquid/Slurry and Deep Pit	Liquid/Slurry	Anaerobic Lagoon
Alabama	0.76	0.39	0.76	0.38	0.40	0.76
Alaska	0.46	0.14	0.46	0.14	0.14	0.46
Arizona	0.80	0.62	0.75	0.37	0.48	0.76
Arkansas	0.74	0.34	0.75	0.36	0.34	0.74
California	0.75	0.35	0.74	0.32	0.42	0.75
Colorado	0.63	0.21	0.67	0.24	0.22	0.63
Connecticut	0.68	0.24	0.68	0.24	0.25	0.69
Delaware	0.74	0.31	0.74	0.31	0.31	0.74
Florida	0.78	0.52	0.78	0.50	0.51	0.78
Georgia	0.76	0.39	0.76	0.38	0.38	0.75
Hawaii	0.77	0.58	0.77	0.58	0.58	0.77
Idaho	0.67	0.23	0.65	0.22	0.22	0.65
Illinois	0.71	0.28	0.71	0.28	0.27	0.71
Indiana	0.70	0.27	0.71	0.27	0.27	0.71
Iowa	0.68	0.24	0.69	0.25	0.25	0.69
Kansas	0.73	0.30	0.73	0.30	0.30	0.73
Kentucky	0.74	0.31	0.74	0.31	0.31	0.74
Louisiana	0.77	0.46	0.77	0.46	0.47	0.77
Maine	0.63	0.20	0.63	0.20	0.20	0.63
Maryland	0.72	0.29	0.73	0.30	0.30	0.73
Massachusetts	0.67	0.23	0.68	0.24	0.24	0.67
Michigan	0.67	0.23	0.68	0.24	0.23	0.68
Minnesota	0.66	0.23	0.67	0.23	0.23	0.66
Mississippi	0.76	0.41	0.76	0.39	0.41	0.76
Missouri	0.73	0.30	0.72	0.30	0.30	0.73
Montana	0.59	0.19	0.61	0.20	0.20	0.61
Nebraska	0.70	0.26	0.70	0.26	0.25	0.70
Nevada	0.71	0.26	0.71	0.27	0.26	0.71
New Hampshire	0.63	0.20	0.65	0.22	0.20	0.64
New Jersey	0.72	0.28	0.72	0.29	0.28	0.72
New Mexico	0.72	0.30	0.71	0.28	0.28	0.68
New York	0.65	0.22	0.66	0.22	0.22	0.67
North Carolina	0.73	0.31	0.75	0.37	0.32	0.73
North Dakota	0.65	0.21	0.65	0.21	0.21	0.64
Ohio	0.70	0.26	0.71	0.27	0.26	0.71
Oklahoma	0.75	0.37	0.74	0.35	0.34	0.75
Oregon	0.62	0.20	0.63	0.21	0.22	0.64
Pennsylvania	0.69	0.25	0.70	0.26	0.26	0.71
Rhode Island	0.69	0.26	0.69	0.26	0.26	0.69
South Carolina	0.76	0.38	0.76	0.39	0.39	0.76
South Dakota	0.68	0.24	0.68	0.24	0.24	0.68
Tennessee	0.74	0.31	0.75	0.34	0.32	0.74
Texas	0.76	0.44	0.76	0.43	0.37	0.77
Utah	0.67	0.23	0.66	0.22	0.23	0.66
Vermont	0.63	0.21	0.63	0.21	0.21	0.63
Virginia	0.71	0.28	0.73	0.31	0.28	0.72
Washington	0.62	0.20	0.64	0.21	0.22	0.63
West Virginia	0.69	0.26	0.70	0.26	0.26	0.69
Wisconsin	0.66	0.22	0.67	0.23	0.23	0.67
Wyoming	0.59	0.18	0.64	0.21	0.21	0.62

Table A- 191: Direct Nitrous Oxide Emission Factors for 2009 (kg N₂O-N/kg KjdI N)

Waste Management System	Direct N ₂ O Emission Factor
Aerobic Treatment (forced aeration)	0.005
Aerobic Treatment (natural aeration)	0.01
Anaerobic Digester	0
Anaerobic Lagoon	0
Cattle Deep Bed (active mix)	0.07
Cattle Deep Bed (no mix)	0.01
Composting_in vessel	0.006
Composting_intensive	0.1
Composting_passive	0.01
Composting_static	0.006
Daily Spread	0
Deep Pit	0.002
Dry Lot	0.02
Fuel	0
Liquid/Slurry	0.005
Pasture	0
Poultry with bedding	0.001
Poultry without bedding	0.001
Solid Storage	0.005

Table A- 192: Indirect Nitrous Oxide Loss Factors (percent)

Animal Type	Waste Management System	Volatilization Nitrogen Loss	Runoff/Leaching Nitrogen Loss [†]				
			Central	Pacific	Mid- Atlantic	Midwest	South
Beef Cattle	Dry Lot	23	1.1	3.9	3.6	1.9	4.3
Beef Cattle	Liquid/Slurry	26	0	0	0	0	0
Beef Cattle	Pasture	0	0	0	0	0	0
Dairy Cattle	Anaerobic Lagoon	43	0.2	0.8	0.7	0.4	0.9
Dairy Cattle	Daily Spread	10	0	0	0	0	0
Dairy Cattle	Deep Pit	24	0	0	0	0	0
Dairy Cattle	Dry Lot	15	0.6	2	1.8	0.9	2.2
Dairy Cattle	Liquid/Slurry	26	0.2	0.8	0.7	0.4	0.9
Dairy Cattle	Pasture	0	0	0	0	0	0
Dairy Cattle	Solid Storage	27	0.2	0	0	0	0
Goats	Dry Lot	23	1.1	3.9	3.6	1.9	4.3
Goats	Pasture	0	0	0	0	0	0
Horses	Dry Lot	23	0	0	0	0	0
Horses	Pasture	0	0	0	0	0	0
Poultry	Anaerobic Lagoon	54	0.2	0.8	0.7	0.4	0.9
Poultry	Liquid/Slurry	26	0.2	0.8	0.7	0.4	0.9
Poultry	Pasture	0	0	0	0	0	0
Poultry	Poultry with bedding	26	0	0	0	0	0
Poultry	Poultry without bedding	34	0	0	0	0	0
Poultry	Solid Storage	8	0	0	0	0	0
Sheep	Dry Lot	23	1.1	3.9	3.6	1.9	4.3
Sheep	Pasture	0	0	0	0	0	0
Swine	Anaerobic Lagoon	58	0.2	0.8	0.7	0.4	0.9
Swine	Deep Pit	34	0	0	0	0	0
Swine	Liquid/Slurry	26	0.2	0.8	0.7	0.4	0.9
Swine	Pasture	0	0	0	0	0	0
Swine	Solid Storage	45	0	0	0	0	0

[†] Data for nitrogen losses due to leaching were not available, so the values represent only nitrogen losses due to runoff.

Table A- 193: Methane Emissions from Livestock Manure Management (Gg)^a

Animal Type	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Dairy Cattle	599	615	598	623	663	693	702	734	781	854	900	960	997	856	969	1018	1034	1151	1147	1168
Dairy Cows	592	608	591	616	656	686	695	727	774	846	893	952	990	850	962	1011	1027	1143	1139	1159
Dairy Heifer	7	7	7	7	7	7	7	7	7	7	7	7	7	6	7	7	7	8	8	8
Swine	624	676	639	680	741	764	730	783	892	849	834	854	879	857	851	905	889	965	918	903
Market Swine	484	524	500	534	585	608	582	626	720	692	680	696	720	703	701	745	730	798	763	753
Market <50 lbs.	102	110	104	109	119	121	116	125	141	133	131	134	137	135	134	141	139	152	107	105
Market 50-119 lbs.	101	111	105	110	120	124	117	127	144	138	136	138	144	140	140	148	146	159	170	169
Market 120-179 lbs.	136	147	140	151	164	170	163	175	201	193	189	192	199	196	194	208	203	223	223	218
Market >180 lbs.	145	156	152	165	182	194	185	198	235	229	225	232	240	233	233	248	243	264	262	260
Breeding Swine	140	152	139	146	156	155	148	157	172	157	155	158	158	154	150	160	159	166	155	150
Beef Cattle	128	128	131	131	137	140	139	136	139	139	133	135	133	133	130	132	139	136	131	130
Feedlot Steers	14	14	14	13	14	14	14	13	13	14	15	15	15	16	15	15	16	16	16	16
Feedlot Heifers	7	7	7	7	8	8	8	8	8	8	9	9	9	9	9	9	9	9	9	9
NOF Bulls	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
NOF Calves	8	8	8	8	9	9	8	8	9	9	9	9	9	9	9	9	10	10	9	9
NOF Heifers	12	12	13	14	14	15	15	14	14	14	13	13	13	13	12	13	13	13	12	12
NOF Steers	12	12	13	14	13	14	14	13	13	12	11	11	11	10	10	10	10	10	10	10
NOF Cows	69	69	70	71	74	76	76	74	76	76	71	73	71	71	71	71	74	73	70	69
Sheep	7	7	7	6	6	5	5	5	5	4	4	4	4	4	3	3	3	3	3	3
Goats	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Poultry	131	132	127	131	131	128	126	128	130	126	127	131	130	130	129	129	131	134	129	127
Hens >1 yr.	73	72	70	73	72	69	68	67	70	66	67	70	67	68	66	66	66	67	64	64
Total Pullets	25	26	23	23	23	22	21	23	23	21	22	22	22	22	23	22	23	25	23	23
Chickens	4	4	4	4	4	4	3	3	4	4	3	3	4	4	3	3	3	3	3	4
Broilers	19	20	20	21	22	23	24	25	26	27	28	28	29	29	30	31	32	32	33	31
Turkeys	10	10	10	10	9	9	9	9	8	7	7	7	7	7	7	7	7	7	7	6
Horses	22	22	21	21	21	21	21	21	22	21	20	20	21	24	26	28	28	27	24	24

^a Accounts for CH₄ reductions due to capture and destruction of CH₄ at facilities using anaerobic digesters.**Table A- 194: Total (Direct and Indirect) Nitrous Oxide Emissions from Livestock Manure Management (Gg)**

Animal Type	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Dairy Cattle	17.1	17.01	17.03	17.27	17.4	17.7	17.7	17.9	18.0	17.6	17.9	18.2	18.5	16.5	17.8	18.2	18.7	18.8	18.5	18.7
Dairy Cows	10.0	10.07	9.97	10.05	10.1	10.3	10.3	10.4	10.5	10.2	10.5	10.5	10.6	9.6	10.2	10.4	10.7	10.7	10.5	10.7
Dairy Heifer	7.0	6.93	7.06	7.22	7.3	7.4	7.4	7.4	7.5	7.4	7.5	7.7	7.8	7.0	7.5	7.8	8.1	8.1	8.0	8.0
Swine	4.0	4.18	4.33	4.37	4.6	4.5	4.4	4.7	5.1	5.0	5.0	5.1	5.3	5.4	5.6	5.7	5.9	6.3	6.4	6.3
Market Swine	3.0	3.11	3.26	3.29	3.5	3.5	3.3	3.6	4.0	4.1	4.1	4.2	4.4	4.5	4.7	4.8	5.0	5.4	5.6	5.5
Market <50 lbs.	0.6	0.59	0.61	0.60	0.6	0.6	0.6	0.7	0.7	0.7	0.8	0.8	0.8	0.9	0.9	0.9	1.0	1.1	0.8	0.8
Market 50-119 lbs.	0.6	0.67	0.70	0.70	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.9	0.9	0.9	1.0	1.0	1.1	1.3	1.2
Market 120-179 lbs.	0.9	0.90	0.94	0.95	1.0	1.0	1.0	1.0	1.1	1.1	1.1	1.2	1.2	1.3	1.3	1.4	1.4	1.5	1.6	1.6
Market >180 lbs.	0.9	0.95	1.02	1.04	1.1	1.1	1.1	1.2	1.3	1.3	1.3	1.4	1.5	1.5	1.5	1.6	1.6	1.8	1.9	1.9
Breeding Swine	1.0	1.07	1.08	1.07	1.1	1.1	1.0	1.1	1.1	1.0	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.8	0.8
Beef Cattle	19.8	20.33	20.15	19.10	21.0	21.8	21.5	21.5	21.7	24.1	25.0	24.1	24.8	25.1	23.7	24.1	25.8	25.6	25.2	25.2
Feedlot Steers	13.4	13.67	13.56	12.83	13.9	14.4	14.0	13.9	14.1	15.5	16.1	15.4	16.1	16.3	15.3	15.5	16.8	16.7	16.5	16.5

Feedlot Heifers	6.4	6.65	6.60	6.27	7.0	7.4	7.4	7.6	7.6	8.5	8.9	8.7	8.8	8.8	8.4	8.5	9.0	8.9	8.7	8.6
Sheep	0.4	0.41	0.44	0.44	0.6	0.7	0.8	0.9	0.9	1.0	1.1	1.2	1.2	1.2	1.1	1.2	1.2	1.2	1.2	1.1
Goats	0.1	0.07	0.07	0.07	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Poultry	4.7	4.79	4.88	4.96	5.1	5.1	5.3	5.3	5.3	5.3	5.3	5.3	5.4	5.3	5.4	5.4	5.4	5.4	5.4	5.1
Hens >1 yr.	1.0	1.02	1.02	1.03	1.0	1.0	1.0	1.1	1.1	1.1	1.1	1.2	1.2	1.2	1.2	1.3	1.3	1.3	1.3	1.3
Total Pullets	0.3	0.29	0.29	0.29	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Chickens	0.0	0.03	0.03	0.03	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Broilers	2.2	2.26	2.36	2.46	2.6	2.7	2.8	2.8	2.9	2.9	2.9	2.9	3.0	2.9	2.9	3.0	2.9	2.9	2.9	2.7
Turkeys	1.2	1.19	1.18	1.14	1.1	1.1	1.1	1.1	1.0	0.9	0.9	0.9	0.9	0.9	0.8	0.8	0.8	0.8	0.8	0.7
Horses	0.7	0.70	0.71	0.71	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.8	0.9	1.0	1.1	1.1	1.1	1.1	1.1

Table A- 195: Methane Emissions by State from Livestock Manure Management for 2009 (Gg)^a

State	Beef on Feedlots	Beef Not on Feed	Dairy Cow	Dairy Heifer	Swine—Market	Swine—	Layer	Broiler	Turkey	Sheep	Goats	Horses
						Breeding						
Alabama	0.0091	2.5130	0.7878	0.0133	1.8870	0.5402	8.8601	3.6406	0.0528	0.0090	0.0302	0.6750
Alaska	0.0001	0.0214	0.0336	0.0003	0.0036	0.0019	0.1801	0.0000	0.0526	0.0060	0.0001	0.0096
Arizona	0.8202	1.3914	52.2827	0.1192	2.2931	0.6103	0.6572	0.0000	0.0528	0.1057	0.0158	0.5327
Arkansas	0.0042	2.3427	0.4741	0.0095	1.5543	2.1073	0.5189	3.8171	0.7252	0.0090	0.0190	0.6119
California	1.3793	3.5354	401.7280	2.0424	1.5433	0.2113	4.2273	0.2654	0.3751	0.4652	0.0490	1.4005
Colorado	1.5272	2.2547	25.9551	0.0901	4.7356	2.7422	3.1055	+	0.0526	0.1927	0.0122	0.6150
Connecticut	0.0002	0.0214	0.9206	0.0186	0.0086	0.0054	0.2664	0.2645	0.0526	0.0038	0.0011	0.0595
Delaware	0.0002	0.0127	0.3593	0.0041	0.0533	0.0427	0.0727	0.8381	0.0526	0.0060	0.0009	0.0205
Florida	0.0049	3.3731	17.9106	0.0998	0.0643	0.0530	6.8326	0.1526	0.0528	0.0090	0.0216	0.9338
Georgia	0.0078	2.0242	6.0643	0.0614	2.6177	1.0343	15.2216	4.8018	0.0528	0.0090	0.0315	0.5944
Hawaii	0.0014	0.3871	0.3521	0.0029	0.1295	0.0854	0.1325	+	0.0528	0.0090	0.0034	0.0507
Idaho	0.3405	1.7547	113.6925	0.4155	0.1240	0.0714	0.5614	+	0.0526	0.0987	0.0044	0.3824
Illinois	0.2797	1.1587	7.1004	0.0951	36.9889	9.7843	0.2512	+	0.0526	0.0273	0.0084	0.4106
Indiana	0.1859	0.6572	9.9651	0.1057	31.3953	5.4684	0.8165	0.2645	0.3739	0.0235	0.0118	0.4193
Iowa	2.0285	3.3553	15.5070	0.2062	264.5844	28.7171	1.7071	0.2645	0.0526	0.0940	0.0140	0.3719
Kansas	3.8479	5.2668	17.1442	0.1058	18.8129	3.5728	0.0416	+	0.0526	0.0376	0.0124	0.4644
Kentucky	0.0190	2.8498	1.5234	0.0881	5.0055	1.0488	0.5920	1.1114	0.0526	0.0188	0.0245	0.9063
Louisiana	0.0043	1.8598	0.8950	0.0194	0.0565	0.0306	2.1219	0.2654	0.0528	0.0090	0.0081	0.4687
Maine	0.0003	0.0387	1.3237	0.0296	0.0078	0.0058	0.3816	+	0.0526	0.0038	0.0015	0.0628
Maryland	0.0202	0.1159	2.5013	0.0453	0.2579	0.0736	0.2180	1.0567	0.0526	0.0060	0.0042	0.1588
Massachusetts	0.0002	0.0237	0.4876	0.0117	0.0643	0.0141	0.0106	+	0.0526	0.0038	0.0021	0.1062
Michigan	0.2544	0.4613	34.7198	0.2332	8.3149	1.9980	0.6120	0.2645	0.0526	0.0367	0.0070	0.5225
Minnesota	0.4411	1.5054	28.1062	0.4485	58.7581	10.6826	0.3644	0.1622	0.0526	0.0658	0.0092	0.4657
Mississippi	0.0088	1.8861	0.8255	0.0190	5.8277	1.2846	8.2188	2.8818	0.0528	0.0090	0.0115	0.5058
Missouri	0.0965	5.1365	4.7540	0.0650	25.0029	7.4122	0.2482	0.2645	0.4611	0.0390	0.0241	0.7706
Montana	0.0645	3.4419	1.6729	0.0149	1.1172	0.3543	0.3486	+	0.0526	0.1198	0.0031	0.5437
Nebraska	3.9357	5.7938	5.8908	0.0319	25.5224	7.3081	0.5819	0.2645	0.0526	0.0334	0.0086	0.3390
Nevada	0.0092	0.7279	6.3173	0.0153	0.0285	0.0121	0.0214	+	0.0526	0.0315	0.0030	0.0950
New Hampshire	0.0001	0.0181	0.6294	0.0123	0.0107	0.0034	0.0659	+	0.0526	0.0038	0.0010	0.0511
New Jersey	0.0003	0.0283	0.3514	0.0087	0.0531	0.0160	0.0715	+	0.0526	0.0060	0.0027	0.1549
New Mexico	0.2468	1.6482	77.4893	0.2155	0.0015	0.0010	0.5926	+	0.0526	0.0564	0.0089	0.2770
New York	0.0481	0.3778	27.1686	0.5322	0.4586	0.1625	0.4220	0.2645	0.0526	0.0291	0.0100	0.4391
North Carolina	0.0038	1.0137	1.7797	0.0354	151.1504	35.4253	11.0133	2.7590	0.8878	0.0197	0.0369	0.6074
North Dakota	0.1065	2.1409	1.3253	0.0313	0.8294	0.6165	0.0390	+	0.0526	0.0413	0.0011	0.2312
Ohio	0.3035	0.9541	16.8066	0.1837	16.4061	3.1993	0.9148	0.2042	0.1296	0.0611	0.0174	0.6158
Oklahoma	0.5381	6.0089	9.8078	0.0684	32.2081	14.2156	3.5948	0.8181	0.0526	0.0376	0.0313	0.8553
Oregon	0.1395	1.7579	13.5532	0.0933	0.0571	0.0239	0.8226	0.2645	0.0526	0.1034	0.0095	0.4620
Pennsylvania	0.1272	0.6633	15.4864	0.4585	10.2107	1.8110	0.7260	0.5557	0.2243	0.0470	0.0148	0.6010
Rhode Island	+	0.0042	0.0310	0.0009	0.0049	0.0039	0.0696	+	0.0526	0.0038	0.0002	0.0180
South Carolina	0.0025	0.7246	1.0262	0.0186	4.2497	0.4742	5.0711	0.8637	0.2976	0.0090	0.0163	0.3354
South Dakota	0.6037	4.0757	7.4168	0.0632	10.1931	2.8293	0.1373	+	0.1122	0.1433	0.0027	0.3628
Tennessee	0.0071	2.4632	1.5864	0.0796	2.6957	0.4871	0.2492	0.6867	0.0526	0.0160	0.0327	0.7329
Texas	6.2856	22.3466	93.4873	0.5075	14.7215	2.4491	4.3726	2.4289	0.0528	0.6132	0.4273	3.4006
Utah	0.0392	1.1290	14.7238	0.0679	4.0454	1.0264	2.7412	+	0.0798	0.1363	0.0043	0.3088
Vermont	0.0005	0.0547	5.2580	0.1005	0.0032	0.0018	0.0188	+	0.0526	0.0038	0.0016	0.0686
Virginia	0.0505	1.6854	2.7183	0.0776	5.7130	0.8152	0.4380	0.8717	0.4237	0.0352	0.0158	0.4668
Washington	0.2798	1.0249	37.9185	0.1870	0.0989	0.0570	1.1358	0.2645	0.0526	0.0249	0.0082	0.4636
West Virginia	0.0142	0.5231	0.3899	0.0051	0.0223	0.0137	0.0971	0.2994	0.0823	0.0155	0.0070	0.1949
Wisconsin	0.3705	1.1936	70.4229	1.0204	2.4065	0.8365	0.2969	0.1658	0.0526	0.0399	0.0140	0.6197
Wyoming	0.1025	1.6831	0.6483	0.0075	0.2398	0.2827	0.0085	+	0.0526	0.1973	0.0021	0.4158

+ Emission estimate is less than 0.00005 Gg.

^a Accounts for CH₄ reductions due to capture and destruction of CH₄ at facilities using anaerobic digesters.

Table A- 196: Total (Direct and Indirect) Nitrous Oxide Emissions by State from Livestock Manure Management for 2009 (Gg)

State	Beef Feedlot- Heifer	Beef Feedlot- Steers	Dairy Cow	Dairy Heifer	Swine— Market	Swine— Breeding	Layer	Broiler	Turkey	Sheep	Goats	Horses
Alabama	0.0021	0.0040	0.0060	0.0045	0.0099	0.0021	0.0639	0.3221	0.0061	0.0049	0.0024	0.0232
Alaska	+	+	0.0006	0.0004	0.0001	+	0.0031	+	0.0061	0.0016	+	0.0005
Arizona	0.2208	0.4235	0.2285	0.1056	0.0116	0.0024	0.0034	+	0.0061	0.0165	0.0012	0.0183
Arkansas	0.0014	0.0026	0.0050	0.0033	0.0088	0.0087	0.0736	0.3377	0.0840	0.0042	0.0015	0.0210
California	0.3129	0.5977	2.1407	1.6247	0.0085	0.0008	0.0873	0.0235	0.0435	0.0822	0.0039	0.0481
Colorado	0.6402	1.2240	0.1751	0.1381	0.0493	0.0212	0.0192	+	0.0061	0.0452	0.0014	0.0317
Connecticut	0.0001	0.0001	0.0149	0.0133	0.0001	+	0.0116	0.0235	0.0061	0.0030	0.0001	0.0031
Delaware	0.0001	0.0002	0.0049	0.0027	0.0004	0.0003	0.0030	0.0744	0.0061	0.0049	0.0001	0.0011
Florida	0.0011	0.0020	0.0924	0.0506	0.0004	0.0002	0.0469	0.0135	0.0061	0.0049	0.0017	0.0321
Georgia	0.0018	0.0035	0.0434	0.0228	0.0141	0.0041	0.1106	0.4248	0.0061	0.0049	0.0025	0.0204
Hawaii	0.0003	0.0006	0.0018	0.0023	0.0007	0.0003	0.0014	+	0.0061	0.0016	0.0003	0.0017
Idaho	0.1429	0.2737	0.7334	0.6375	0.0013	0.0005	0.0034	+	0.0061	0.0232	0.0005	0.0197
Illinois	0.1096	0.2108	0.1408	0.1205	0.3498	0.0678	0.0181	+	0.0061	0.0190	0.0010	0.0212
Indiana	0.0727	0.1399	0.2096	0.1218	0.3033	0.0388	0.1134	0.0235	0.0435	0.0164	0.0014	0.0216
Iowa	0.8062	1.5456	0.2924	0.2542	1.7628	0.1407	0.2370	0.0235	0.0061	0.0656	0.0017	0.0192
Kansas	1.4902	2.8499	0.1782	0.1401	0.1705	0.0239	0.0030	+	0.0061	0.0262	0.0015	0.0239
Kentucky	0.0068	0.0129	0.0316	0.0288	0.0299	0.0046	0.0246	0.0987	0.0061	0.0152	0.0029	0.0467
Louisiana	0.0010	0.0018	0.0081	0.0043	0.0003	0.0001	0.0111	0.0235	0.0061	0.0042	0.0006	0.0161
Maine	0.0001	0.0002	0.0244	0.0204	0.0001	+	0.0176	+	0.0061	0.0030	0.0002	0.0032
Maryland	0.0071	0.0137	0.0427	0.0300	0.0022	0.0005	0.0091	0.0938	0.0061	0.0049	0.0005	0.0082
Massachusetts	0.0001	0.0001	0.0107	0.0078	0.0006	0.0001	0.0005	+	0.0061	0.0030	0.0002	0.0055
Michigan	0.1022	0.1959	0.5270	0.3146	0.0858	0.0152	0.0453	0.0235	0.0061	0.0256	0.0008	0.0269
Minnesota	0.1778	0.3394	0.6319	0.5617	0.6070	0.0812	0.0506	0.0144	0.0061	0.0459	0.0011	0.0240
Mississippi	0.0020	0.0039	0.0071	0.0047	0.0291	0.0047	0.0430	0.2550	0.0061	0.0049	0.0009	0.0174
Missouri	0.0375	0.0718	0.1234	0.0724	0.2284	0.0499	0.0346	0.0235	0.0536	0.0272	0.0029	0.0397
Montana	0.0270	0.0520	0.0213	0.0218	0.0134	0.0031	0.0022	+	0.0061	0.0281	0.0004	0.0280
Nebraska	1.5630	2.9921	0.0829	0.0423	0.2541	0.0536	0.0425	0.0235	0.0061	0.0233	0.0010	0.0175
Nevada	0.0038	0.0073	0.0368	0.0233	0.0002	0.0001	0.0030	+	0.0061	0.0074	0.0004	0.0049
New Hampshire	+	0.0001	0.0117	0.0087	0.0001	+	0.0030	+	0.0061	0.0030	0.0001	0.0026
New Jersey	0.0001	0.0002	0.0070	0.0055	0.0005	0.0001	0.0030	+	0.0061	0.0049	0.0003	0.0080
New Mexico	0.1006	0.1934	0.4144	0.2955	+	+	0.0034	+	0.0061	0.0132	0.0011	0.0143
New York	0.0181	0.0347	0.4805	0.3629	0.0049	0.0013	0.0186	0.0235	0.0061	0.0236	0.0012	0.0226
North Carolina	0.0014	0.0026	0.0228	0.0144	0.7694	0.1326	0.0811	0.2441	0.1029	0.0107	0.0029	0.0209
North Dakota	0.0431	0.0827	0.0314	0.0387	0.0092	0.0050	0.0030	+	0.0061	0.0289	0.0001	0.0119
Ohio	0.1194	0.2294	0.3446	0.2115	0.1571	0.0225	0.1270	0.0181	0.0151	0.0493	0.0021	0.0317
Oklahoma	0.2153	0.4131	0.0760	0.0657	0.1696	0.0546	0.0190	0.0726	0.0061	0.0262	0.0037	0.0441
Oregon	0.0497	0.0954	0.1223	0.1036	0.0006	0.0002	0.0106	0.0235	0.0061	0.0274	0.0011	0.0238
Pennsylvania	0.0465	0.0892	0.3984	0.2817	0.0966	0.0127	0.1009	0.0493	0.0261	0.0381	0.0018	0.0310
Rhode Island	+	+	0.0008	0.0005	+	+	0.0030	+	0.0061	0.0030	+	0.0009
South Carolina	0.0006	0.0011	0.0076	0.0051	0.0220	0.0018	0.0265	0.0764	0.0345	0.0049	0.0013	0.0115
South Dakota	0.2413	0.4627	0.1309	0.0819	0.1030	0.0210	0.0101	+	0.0130	0.1001	0.0003	0.0187
Tennessee	0.0025	0.0048	0.0238	0.0279	0.0157	0.0021	0.0105	0.0610	0.0061	0.0130	0.0039	0.0378
Texas	1.7394	3.3315	0.5319	0.4742	0.0833	0.0102	0.0892	0.2149	0.0061	0.0959	0.0337	0.1168
Utah	0.0165	0.0313	0.1145	0.1031	0.0599	0.0109	0.0163	+	0.0093	0.0320	0.0005	0.0159
Vermont	0.0002	0.0003	0.1044	0.0703	+	+	0.0009	+	0.0061	0.0030	0.0002	0.0035
Virginia	0.0181	0.0347	0.0430	0.0295	0.0317	0.0033	0.0186	0.0774	0.0493	0.0286	0.0019	0.0241
Washington	0.1000	0.1917	0.2872	0.2164	0.0011	0.0005	0.0274	0.0235	0.0061	0.0066	0.0010	0.0239
West Virginia	0.0051	0.0099	0.0077	0.0034	0.0002	0.0001	0.0043	0.0266	0.0096	0.0126	0.0008	0.0100
Wisconsin	0.1489	0.2855	1.6751	1.2450	0.0246	0.0063	0.0221	0.0147	0.0061	0.0279	0.0017	0.0319
Wyoming	0.0429	0.0824	0.0079	0.0094	0.0045	0.0039	0.0001	+	0.0061	0.0463	0.0002	0.0214

+ Emission estimate is less than 0.00005 Gg.

3.11. Methodology for Estimating N₂O Emissions from Agricultural Soil Management

Nitrous oxide emissions from agricultural soils result from the interaction of the natural processes of denitrification and nitrification with management practices that add or release mineral nitrogen (N) in the soil profile. Emissions can occur directly in the soil where the N is made available or can be transported to another location following volatilization, leaching, or runoff, and then converted into N₂O.

A combination of Tier 1 and Tier 3 approaches was used to estimate direct and indirect N₂O emissions from agricultural soils. The process-based biogeochemical model DAYCENT (a Tier 3 approach) was used to estimate N₂O emissions resulting from croplands on mineral soils that were used to produce major crops, while the IPCC (2006) Tier 1 methodology was applied to estimate N₂O emissions for non-major crop types on mineral soils. The Tier 1 method was also used to estimate direct N₂O emissions due to drainage and cultivation of organic cropland soils. Direct N₂O emissions from grasslands were estimated by using a combination of DAYCENT and IPCC (2006) Tier 1 methods. A combination of DAYCENT and Tier 1 methods was also used to estimate indirect emissions from all managed lands (i.e., croplands, grasslands, forest lands, and settlements). Specifically, the amount of N volatilized from soils, as well as leaching or transport of nitrate (NO₃⁻) off-site in surface runoff waters was computed by DAYCENT for the direct emission analyses, while IPCC default factors were used to estimate N transport for the analyses using the Tier 1 methodology. The indirect N₂O emissions resulting from off-site transport of N were then computed using the IPCC (2006) Tier 1 default emission factor. Overall, the Tier 3 approach is used to estimate approximately 85 percent of direct soil emissions and 70 percent of total soil N₂O emissions associated with agricultural soil management in the United States.

DAYCENT (Del Grosso et al. 2001, Parton et al. 1998) simulates biogeochemical N fluxes between the atmosphere, vegetation, and soil, allowing for a more complete estimation of N₂O emissions than IPCC Tier 1 methods by accounting for the influence of environmental conditions including soil characteristics and weather patterns, specific crop and forage qualities that influence the N cycle, and management practices at a daily time step. For example, plant growth is controlled by nutrient availability, water, and temperature stress; moreover, growth removes mineral N from the soil before it can potentially be converted into N₂O. Nutrient supply is a function of external nutrient additions as well as litter and soil organic matter (SOM) decomposition rates, and increasing decomposition can lead to greater N₂O emissions by enhancing mineral N availability in soils. In this model-based assessment framework, daily maximum/minimum temperature and precipitation, timing and description of management events (e.g., fertilization, tillage, harvest), and soil texture data are model inputs to DAYCENT, which form the basis to simulate key processes and generate robust estimates of N₂O emissions from soils. Key processes simulated within sub-models of DAYCENT include plant production, organic matter formation and decomposition, soil water and soil temperature regimes by layer, and nitrification and denitrification processes (Figure A- 7). Comparison of model results and plot level data show that DAYCENT reliably simulates crop yields, soil organic matter levels, and trace gas fluxes for a number of native and managed systems (Del Grosso et al. 2001, 2005). Comparisons with measured data showed that DAYCENT estimated emissions more accurately and precisely than the IPCC Tier 1 methodology (Figure A- 8). The linear regression of simulated vs. measured emissions for DAYCENT had higher r^2 and a fitted line closer to a perfect 1:1 relationship between measured and modeled N₂O emissions (Del Grosso et al. 2005, 2008). This is not surprising, since DAYCENT includes site-specific factors (climate, soil properties, and previous management) that influence N₂O emissions. Furthermore, DAYCENT also simulated NO₃⁻ leaching (root mean square error = 20 percent) more accurately than IPCC Tier 1 methodology (root mean square error = 69 percent) (Del Grosso et al. 2005). Thus, the Tier 3 approach has reduced uncertainties in the agricultural soil management section relative to earlier Inventory years where the IPCC Tier 1 method was used. The latest operational version of DAYCENT has several improvements, including (1) elimination of the influence of labile (i.e., easily decomposable by microbes) C availability on surface litter denitrification rates, (2) incorporation of precipitation events on surface litter denitrification, and (3) having the wettest soil layer within the rooting zone control plant transpiration.

[Begin Text Box]

Box 1. DAYCENT Model Simulation of Nitrification and Denitrification

The DAYCENT model simulates the two biogeochemical processes, nitrification and denitrification, that result in N₂O emissions from soils (Del Grosso et al. 2000, Parton et al. 2001). Nitrification is calculated for the top 15 cm of soil, while denitrification is calculated for the entire soil profile. The equations and key parameters controlling N₂O emissions from nitrification and denitrification are described below.

Nitrification is controlled by soil ammonium (NH_4^+) concentration, water filled pore space (WFPS), temperature (t), and pH according to the following equation:

$$\text{Nit} = \text{NH}_4 \times K_{\max} \times F(t) \times F(\text{WFPS}) \times F(\text{pH})$$

where,

Nit	=	the soil nitrification rate ($\text{g N/m}^2/\text{day}$)
NH_4	=	the model-derived soil ammonium concentration (g N/m^2)
K_{\max}	=	the maximum fraction of NH_4^+ nitrified ($K_{\max} = 0.10/\text{day}$)
$F(t)$	=	the effect of soil temperature on nitrification (Figure A- 5a)
$F(\text{WFPS})$	=	the effect of soil water content and soil texture on nitrification (Figure A- 5b)
$F(\text{pH})$	=	the effect of soil pH on nitrification (Figure A- 5c)

The current parameterization used in the model assumes that 1.2 percent of nitrified N is converted to N_2O .

N_2O emissions from denitrification are a function of soil NO_3^- concentration, WFPS, heterotrophic (i.e., microbial) respiration, and texture. Denitrification is calculated for each soil layer in the profile, and N_2O emissions from each layer are summed to obtain total soil emissions. The model assumes that denitrification rates are controlled by the availability of soil NO_3^- (electron acceptor), labile C compounds (electron donor) and oxygen (competing electron acceptor). Heterotrophic soil respiration is used as a proxy for labile C availability, while oxygen availability is a function of soil physical properties that influence gas diffusivity, soil WFPS, and oxygen demand. The model selects the minimum of the NO_3^- and CO_2 functions to establish a maximum potential denitrification rate for particular levels of electron acceptor and C substrate and accounts for limitations of oxygen availability to estimate daily denitrification rates according to the following equation:

$$\text{Den} = \min[F(\text{CO}_2), F(\text{NO}_3)] \times F(\text{WFPS})$$

where,

Den	=	the soil denitrification rate ($\mu\text{g N/g soil/day}$)
$F(\text{CO}_2)$	=	a function relating N gas flux to soil respiration (Figure A- 6a)
$F(\text{NO}_3)$	=	a function relating N gas flux to nitrate levels (Figure A- 5b)
$F(\text{WFPS})$	=	a dimensionless multiplier (Figure A- 6c).

The x inflection point of $F(\text{WFPS})$ is a function of respiration and soil gas diffusivity at field capacity (D_{FC}):

$$\text{x inflection} = 0.90 - M(\text{CO}_2)$$

where,

M	=	a multiplier that is a function of D_{FC} .
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Respiration has a much stronger effect on the water curve in clay soils with low D_{FC} than in loam or sandy soils with high D_{FC} (Figure A- 6c). The model assumes that microsites in fine-textured soils can become anaerobic at relatively low water contents when oxygen demand is high.

After calculating total N gas flux, the ratio of $\text{N}_2/\text{N}_2\text{O}$ is estimated so that total N gas emissions can be partitioned between N_2O and N_2 :

$$R_{\text{N}_2/\text{N}_2\text{O}} = F_r(\text{NO}_3/\text{CO}_2) \times F_r(\text{WFPS}).$$

where,

$R_{\text{N}_2/\text{N}_2\text{O}}$	=	the ratio of $\text{N}_2/\text{N}_2\text{O}$
$F_r(\text{NO}_3/\text{CO}_2)$	=	a function estimating the impact of the availability of electron donor relative to substrate
$F_r(\text{WFPS})$	=	a multiplier to account for the effect of soil water on $\text{N}_2:\text{N}_2\text{O}$.

For $F_r(\text{NO}_3/\text{CO}_2)$, as the ratio of electron donor to substrate increases, a higher portion of N gas is assumed to be in the form of N_2O . For $F_r(\text{WFPS})$, as WFPS increases, a higher portion of N gas is assumed to be in the form of N_2 .

[End Box]

Figure A- 5: Effect of Soil Temperature, Water-Filled Pore Space, and pH on Nitrification Rates

Figure A- 6: Effect of Soil Nitrite Concentration, Heterotrophic Respiration Rates, and Water-Filled Pore Space on Denitrification Rates

There are five steps in estimating direct N_2O emissions from cropland and grassland soils, and indirect N_2O emissions from volatilization, leaching, and runoff from all managed lands (i.e., croplands, grasslands, forest lands, and settlements). First, the activity data are derived from a combination of land-use, livestock, crop, and grassland management surveys, as well as expert knowledge. In the second, third, and fourth steps, direct and indirect N_2O emissions are estimated using DAYCENT and/or the Tier 1 method. In the fifth step, total emissions are computed by summing all components. The remainder of this annex describes the methods underlying each step.

Step 1: Derive Activity Data

The activity data requirements vary for major crops, non-major crops, grasslands, organic cropland soils, settlements and forest lands. Activity data were derived for direct and indirect N_2O emission calculations as described below.

Step 1a: Activity Data for Direct Emissions from Crop Production on Mineral Soils

Nitrous oxide emissions from mineral cropland soils include emissions from both major and non-major cropping systems and were estimated using a Tier 3 and Tier 1 approach, respectively.

Major Crop Types: Tier 3 DAYCENT Simulations

The activity data requirements for estimating N_2O emissions from major crop types (corn, soybeans, wheat, alfalfa hay, other hay, sorghum, and cotton) include the following: (1) crop-specific mineral N fertilizer rates and timing, (2) crop-specific manure amendment N rates and timing, (3) other N inputs, (4) crop-specific land management information, (5) native vegetation, (6) daily weather data for every county, (7) sub-county-level soil texture data, and (8) county-level crop areas. The United States was divided into 63 agricultural regions based on common cropping practices as defined by McCarl et al. (1993), and data were assembled and provided as inputs to the DAYCENT biogeochemical ecosystem model.

Synthetic N Fertilizer Application: Data on N fertilizer rates were obtained primarily from the U.S. Department of Agriculture–Economic Research Service 1995 Cropping Practices Survey (ERS 1997). In this survey, data on inorganic N fertilization rates were collected for major crops (corn, cotton, soybeans, and wheat) in the high production states during 1995. It is assumed that the fertilization rates have not changed much during the Inventory reporting period, which is confirmed by the sales data showing relatively minor change in the amount of fertilizer sold for on-farm use across the time series of this Inventory (Ruddy et al. 2006). The trend and therefore the rates and uncertainties reflected in the 1995 survey data are considered representative for 1990 through 2008 (trends will be re-evaluated when new fertilization data are released by U.S. Department of Agriculture). Note that all wheat data were combined into one category and assumed to represent small grains in aggregate. Estimates for sorghum fertilizer rates were derived from corn fertilizer rates using a ratio of national average corn fertilizer rates to national average sorghum fertilizer rates, which were derived from additional publications (NASS 1992, 1999, 2004; ERS 1988; Grant and Krenz 1985; USDA 1954, 1957, 1966). Alfalfa hay is assumed to not be fertilized, but grass hay is fertilized according to rates from published farm enterprise budgets (NRIAI 2003).

The ERS survey parameter “TOT N” (total amount of N applied per acre), with a small number of records deleted as outliers, was used in determining the fraction of crop acres receiving fertilizer and the average fertilizer rates for each region. Mean fertilizer rates and standard deviations for irrigated and rainfed crops were produced for each state with a minimum of 15 data points for irrigated and rainfed, respectively. If a state was not surveyed for a particular crop or if fewer than 15 data points existed for one of the categories, then data were aggregated to U.S. Department of Agriculture Farm Production Regions in order to estimate a mean and standard deviation for fertilization rates (Farm Production Regions are groups of states in the United States with similar agricultural commodities). If Farm Production Region data were not available, crop data were aggregated to the entire United States (all major states surveyed) to estimate a mean and standard deviation for a particular crop in a state lacking sufficient data. Standard deviations for fertilizer rates were used

to construct probability distribution functions (PDFs) with log-normal densities in order to address uncertainties in application rates (see Step 2a for discussion of uncertainty methods). Total fertilizer application data are found in Table A- 197.

Simulations were conducted for the period prior to 1990 in order to initialize the DAYCENT model (see Step 2a), and estimates for crop-specific regional fertilizer rates prior to 1990 were based largely on extrapolation/interpolation of fertilizer rates from the years with available data. For crops in some agricultural regions, little or no data were available, and, therefore, a geographic regional mean was used to simulate N fertilization rates (e.g., no data were available from Alabama during the 1970s and 1980s for corn fertilization rates; therefore, mean values from the southeastern United States were used to simulate fertilization to corn fields in this state).

Managed Livestock Manure⁵⁷ N Amendment Rates and Timing: County-level manure addition estimates have been derived from manure N addition rates developed by the Natural Resources Conservation Service (NRCS) (Edmonds et al. 2003). Working with the farm-level crop and animal data from the 1997 Census of Agriculture, NRCS has coupled estimates of manure N produced with estimates of manure N recoverability by animal waste management system to produce county-level estimates of manure N applied to cropland and pasture. Edmonds et al. (2003) defined a hierarchy that included 24 crops, cropland used as pasture, and permanent pasture. They estimated the area amended with manure and application rates in 1997 for both manure-producing farms and manure-receiving farms within a county and for two scenarios—before implementation of Comprehensive Nutrient Management Plans (baseline) and after implementation (Edmonds et al. 2003). The goal of nutrient management plans is to apply manure nutrients at a rate meeting plant demand, thus limiting leaching losses of nutrients to groundwater and waterways. For DAYCENT simulations, the baseline scenario estimates have been used as the basis for manure amendment applications under the assumption that Comprehensive Nutrient Management Plans have not been fully implemented. This is a conservative assumption because it allows for higher leaching rates due to some over-application of manure to soils. The rates for manure-producing farms and manure-receiving farms have been area-weighted and combined to produce a single county-level estimate for the amount of land amended with manure and the manure N application rate for each crop in each county. Several of the crops in Edmonds et al. (2003) have been area-weighted and combined into broader crop categories. For example, all small grain crops have been combined into one category. In order to address uncertainty in these data, uniform probability distributions were constructed based on the proportion of land receiving manure versus the amount not receiving manure for each crop type and pasture. For example, if 20 percent of land producing corn in a county was amended with manure, randomly drawing a value equal to or greater than 0 and less than 20 would lead to a simulation with a manure amendment, while drawing a value greater than or equal to 20 and less than 100 would lead to no amendment in the simulation (see Step 2a for further discussion of uncertainty methods).

Edmonds et al. (2003) only provides manure application rate data for 1997, but the amount of managed manure available for soil application changes annually, so the area amended with manure was adjusted relative to 1997 to account for all the manure available for application in other years. Specifically, the manure N available for application in other years was divided by the manure N available in 1997. If the ratio was greater than 1, there was more manure N available in that county relative to the amount in 1997, and so it was assumed a larger area was amended with manure. In contrast, ratios less than one implied less area was amended with manure because there was a lower amount available in the year compared to 1997. The amendment area in each county for 1997 was multiplied by the ratio to reflect the impact of manure N availability on the area amended. The amount of managed manure N available for application to soils was calculated by determining the populations of animals that were on feedlots or otherwise housed in order to collect and manage the manure, as described in the Manure Management section (Section 6.2) and annex (Annex 3.10).

To estimate C inputs associated with manure N application rates derived from Edmonds et al. (2003), carbon-nitrogen (C:N) ratios for livestock-specific manure types were adapted from the Agricultural Waste Management Field Handbook (USDA 1996), On-Farm Composting Handbook (NRAES 1992), and recoverability factors provided by Edmonds et al (2003). The C:N ratios were applied to county-level estimates of manure N excreted by animal type and management system to produce a weighted county average C:N ratio for manure amendments. The average C:N ratio was used to determine the associated C input for crop amendments derived from Edmonds et al. (2003).

To account for the common practice of reducing inorganic N fertilizer inputs when manure is added to a cropland soil, crop-specific reduction factors were derived from mineral fertilization data for land amended with manure versus land

⁵⁷ For purposes of the Inventory, total livestock manure is divided into two general categories: (1) managed manure, and (2) unmanaged manure. Managed manure includes manure that is stored in manure management systems such as pits and lagoons, as well as manure applied to soils through daily spread manure operations. Unmanaged manure encompasses all manure deposited on soils by animals on PRP.

not amended with manure in the ERS 1995 Cropping Practices Survey (ERS 1997). Mineral N fertilization rates were reduced for crops receiving manure N based on a fraction of the amount of manure N applied, depending on the crop and whether it was irrigated or rainfed. The reduction factors were randomly selected from PDFs with normal densities in order to address uncertainties in the dependence between manure amendments and mineral fertilizer application.

Manure N that was not applied to major crops and grassland was assumed to be applied to non-major crop types. The fate of manure N is summarized in Table A- 198.

Residue N Inputs: Residue N input is estimated as part of the DAYCENT simulation and is not an input to the model. Unlike the Tier 1 approach, N inputs from crop residues are not considered activity data in the DAYCENT simulations because N availability from this source is simulated by the model based on N uptake during crop growth according to environmental and management conditions, such as temperature, precipitation, and edaphic (i.e., soil) characteristics, in combination with the harvest practices. That is, while the model accounts for the contribution of N from crop residues to the soil profile and subsequent N₂O emissions, this source of mineral soil N is not activity data in the sense that it is not a model input. Similarly, N from mineralization of soil organic matter and asymbiotic N fixation are also simulated by the model. The simulated total N inputs of above- and below-ground residue N and fixed N that was not harvested and not burned (the DAYCENT simulations assumed that 3 percent of non-harvested above ground residues for grain crops were burned) are provided in Table A- 199.

Other N Inputs: Other N inputs are estimated within the DAYCENT simulation, and thus input data are not required, including mineralization from decomposition of soil organic matter and asymbiotic fixation of N from the atmosphere. The influence of additional inputs of N are estimated in the simulations so that there is full accounting of all emissions from managed lands, as recommended by IPCC (2006). The simulated total N inputs from other sources are provided in Table A- 199.

Crop Rotation and Land Management Information: Data were obtained on specific timing and type of cultivation, timing of planting/harvest, and crop rotation schedules for the 63 agricultural regions (Hurd 1930, 1929, Latta 1938, Iowa State College Staff Members 1946, Bogue 1963, Hurt 1994, USDA 2000a, 2000b, CTIC 1998, Piper et al. 1924, Hardies and Hume 1927, Holmes 1902, 1929, Spillman 1902, 1905, 1907, 1908, Chilcott 1910, Smith 1911, Kezer ca 1917, Hargreaves 1993, ERS 2002, Warren 1911, Langston et al. 1922, Russell et al. 1922, Elliott and Tapp 1928, Elliott 1933, Ellsworth 1929, Garey 1929, Holmes 1929, Hodges et al. 1930, Bonnen and Elliott 1931, Brenner et al. 2002, 2001, Smith et al. 2002). As with N fertilizer and manure additions, data were not complete, so regional averages were used to fill spatial gaps in the datasets and interpolation/extrapolation was used to fill temporal gaps. The amount of agricultural residue burning was based on state inventory data (ILENR 1993, Oregon Department of Energy 1995, Noller 1996, Wisconsin Department of Natural Resources 1993, and Cibrowski 1996).

Native Vegetation by County: Pre-agricultural land cover for each county was designated according to the potential native vegetation used in the Vegetation-Ecosystem Modeling and Analysis Project (VEMAP 1995), which was based on the Kuchler (1964) Potential Vegetation Map for the conterminous United States.

Daily Weather Data by County: Daily maximum/minimum temperature and precipitation data were obtained from the DAYMET model, which generates daily surface precipitation, temperature, and other meteorological data at 1 km² resolution driven by weather station observations and an elevation model (Thornton et al. 2000 and 1997, Thornton and Running 1999, DAYMET no date). It is necessary to use computer-generated weather data because weather station data do not exist in each county, and moreover weather station data are for a point in space, while the DAYMET uses this information with interpolation algorithms to derive weather patterns for areas between these stations. DAYMET weather data are available for the United States at 1 km² resolution for 1980 through 2003. For each county, DAYMET weather data were selected from the 1 km² cell that occurred in agricultural lands according to the National Land Cover Dataset (Vogelman et al. 2001). The grid cells formed the basis for county-scale PDFs based on the frequency of cells with same weather patterns. Separate PDFs were developed for cropland, pasture/hay land, and rangeland. A weather record was then randomly selected from the PDFs in each iteration of the Monte Carlo analysis to represent variation in precipitation and temperature at the county scale. Weather data were randomly selected from the previous 23 years to represent 2004 through 2009, accounting for uncertainty in the weather during the years that have no data. The time series will be updated when new weather data are available.

Soil Properties by County: Soil texture data required by DAYCENT were obtained from STATSGO (Soil Survey Staff 2005). Observed data for soil hydraulic properties needed for model inputs were not available, so they were calculated from STATSGO (Soil Survey Staff 2005) texture class and Saxton et al.'s (1986) hydraulic properties calculator. Similar to the weather data, soil types within the STATSGO map that occurred in agricultural lands according to the National Land Cover Dataset (Vogelman et al. 2001) were used to form a county-scale PDF. Specifically, the PDFs were an area-weighted proportion for the extent of overlap between STATSGO map units and agricultural land. Separate PDFs were developed for cropland, pasture/hay land, and rangeland. Individual soil types were randomly selected from

the PDFs during each iteration of the Monte Carlo analysis to represent variation in soil texture and depth at the county scale.

Crop Areas by County: County-level total crop area data were downloaded from the NASS web site for the years 1990 through 2009 (USDA 2010a, 2010b), and these data formed the basis to scale emissions from individual crop types to an entire county.

Non-Major Crop Types: Tier 1 Method

The activity data required for calculating emissions from non-major crop types include: (1) the amount of mineral N in synthetic fertilizers that are applied annually, (2) managed manure N, (3) the amount of N in other commercial organic fertilizers and (4) the amount of N in the above- and below-ground residue retained on and in soils of all non-major crops.

Application of Synthetic Commercial Fertilizers: A process-of-elimination approach was used to estimate synthetic N fertilizer additions to non-major crop types. The total amount of fertilizer used on farms has been estimated by the USGS from 1990-2001 on a county scale from fertilizer sales data (Ruddy et al. 2006). For 2002-2009, county-level fertilizer used on farms was adjusted based on annual fluctuations in total U.S. fertilizer sales (AAPFCO 1995 through 2009). In addition, fertilizer application data are available for major crops and grasslands (discussed in Step 1 sections for Major Crops and Grasslands). Thus, the amount of N applied to non-major crops was assumed to be the remainder of the fertilizer used on farms after subtracting the amount applied to major crops and grasslands. The differences were aggregated to the state level and PDFs were derived based on uncertainties in the amount of N applied to major crops and grasslands. Total fertilizer application is found in Table A- 200.

*Manure and Other Commercial Organic Fertilizers:*⁵⁸ Manure N applied to non-major crops was estimated using the activity data described for major crops (Table A- 198). Estimates of total national annual N additions from other commercial organic fertilizers were derived from organic fertilizer statistics (TVA 1991 through 1994; AAPFCO 1995 through 2009). AAPFCO fertilizer data were not yet available for 2009, so 2008 values were used as a placeholder until data become available. Commercial organic fertilizers include dried blood, tankage, compost, and other; dried manure and sewage sludge that are used as commercial fertilizer were subtracted from totals to avoid double counting. The dried manure N is counted with the non-commercial manure applications, and sewage sludge is assumed to be applied only to grasslands. The organic fertilizer data, which are recorded in mass units of fertilizer, had to be converted to mass units of N by multiplying the consumption values by the average organic fertilizer N contents provided in the annual fertilizer publications. These N contents are weighted average values, and vary from year to year (ranging from 2.3 percent to 3.9 percent over the period 1990 through 2008). The fertilizer consumption data are recorded in “fertilizer year” totals, (i.e., July to June), but were converted to calendar year totals. This was done by assuming that approximately 35 percent of fertilizer usage occurred from July to December and 65 percent from January to June (TVA 1992b). July to December values were not available for calendar year 2008 so a “least squares line” statistical extrapolation using the previous 14 years of data was used to arrive at an approximate value. PDFs were derived for the organic fertilizer applications assuming a default ± 50 percent uncertainty. Annual consumption of other organic fertilizers is presented in Table A- 201.

Retention of Crop Residue: Annual crop yield (metric tons per hectare) and area harvested (hectare) statistics for non-major N-fixing crops, including bean and pulse crops, were taken from U.S. Department of Agriculture crop production reports (USDA 1994, 1998, 2003, 2005, 2006, 2008, 2009, 2010a,b). Crop yield per hectare and area planted were multiplied to determine total crop yield for each crop, which was then converted to tons of dry matter product using the residue dry matter fractions shown in

Table A- 202. Dry matter yield was then converted to tons of above- and below-ground biomass N. Above-ground biomass was calculated by using linear equations to estimate above-ground biomass given dry matter crop yields, and below-ground biomass was calculated by multiplying above-ground biomass by the below-to-above-ground biomass ratio. N inputs were estimated by multiplying above- and below-ground biomass by respective N concentrations. All ratios and equations used to calculate residue N inputs (shown in Table A- 203) are from IPCC (2006) and Williams (2006). PDFs were derived assuming a ± 50 percent uncertainty in the yield estimates (NASS does not provide uncertainty), along with uncertainties provided by the IPCC (2006) for dry matter fractions, above-ground residue, ratio of

⁵⁸ Other commercial organic fertilizers include, dried blood, dried manure, tankage, compost, sewage, and other minor organic fertilizer types, but manure and sewage sludge have been excluded in order to avoid double-counting and ensure consistency across the Inventory as these inputs are calculated using alternative data sources and methods.

below-ground to above-ground biomass, and residue N fractions. The resulting annual biomass N inputs are presented in Table A- 203.

Step 1b: Activity Data for Direct Emissions from Drainage and Cultivation of Organic Cropland Soils

Tier 1 Method

Estimates and associated uncertainty for the area of drained and cultivated organic cropland soils in 1992 and 1997 were obtained from the U.S. Department of Agriculture 1997 *National Resources Inventory* (USDA 2000a, as extracted by Eve 2001, and revised by Ogle 2002).⁵⁹ These areas were grouped by broad climatic region⁶⁰ using temperature and precipitation estimates from Daly et al. (1994, 1998) and then further aggregated to derive total land in temperate and sub-tropical regions. Areas for 1992 were assumed to represent 1990 through 1992 and areas for 1997 were assumed to represent 1993 through 2009 (Table A- 204).

Step 1c: Activity Data for Direct Emissions from Grassland Management

N₂O emissions from non-federal grasslands were estimated using DAYCENT. DAYCENT simulations addressed the influence of legume seeding, managed manure N amendments, unmanaged manure N excreted by livestock and deposited directly onto pasture, range, and paddock (PRP) soils, and synthetic fertilizer applications. N₂O emissions from PRP manure N deposition on federal grasslands and sewage sludge amendments to agricultural soils were addressed using the Tier 1 method.

Tier 3 DAYCENT Simulations

Activity data for DAYCENT simulations of grasslands (i.e., climate, soils, and N inputs) were based on the same sources as those used for major crop types described in Step 1a. In addition to the data sources used for major crops, county-level area data on non-federal pasture and rangeland (i.e., mostly privately-owned) were needed for U.S. grasslands. This information was based on U.S. Land Representation Analysis for Land Use, Land Use Change and Forestry sector (See Section 7.1), and included data compiled from the U.S. Department of Agriculture *National Resources Inventory* (USDA 2000a, Nusser and Goebel 1997, <http://www.ncgc.nrcs.usda.gov/products/nri/index.htm>), the USDA Forest Service (USFS) Forest Inventory and Analysis Database (FIA, <http://fia.fs.fed.us/tools-data/data>) and the U.S. Geological Survey (USGS) National Land Cover Dataset (NLCD, Vogelmann et al. 2001, <http://www.mrlc.gov>). Grassland on non-federal lands is classified using the NRI and grassland on federal lands is classified using the NLCD. Grassland area data from the NRI and NLCD were adjusted to achieve consistency with FIA estimates of Forest Land. Another key source of N for grasslands is PRP manure N deposition. Activity data for PRP manure N excretion from dairy cattle, beef cattle, swine, sheep, goats, poultry, and horses were derived from multiple sources as described in the Manure Management section (Section 6.2) and Annex 3.10. The amount of PRP manure N deposited on non-federal grasslands (non-federal grasslands are mostly under private ownership) was based on the relative proportion of federal and non-federal grasslands in each county based on the U.S. Land Representation Analysis (See Section 7.1). For example, if 75 percent of the grasslands in a county were non-federal then 75 percent of PRP manure N was assumed to be deposited on non-federal grasslands.

Nitrogen fixation by legumes, and N residue inputs from senesced grass litter were included as sources of N to the soil, and were estimated in the DAYCENT simulations as a function of vegetation type, weather, and soil properties. Similar to the methodology for major crops, “other N inputs” were simulated within the DAYCENT model framework in order to estimate all greenhouse gas emissions from managed lands (IPCC 2006), including mineralization from decomposition of soil organic matter and litter, as well as asymbiotic N fixation from the atmosphere. Decomposition rates are a function of litter quality and quantity, soil texture, water content and temperature, and other factors. Total annual amounts of PRP manure N, mineral N fertilizer application, manure N amendments, forage legume N and “other N inputs” can be found in Table A- 205.

⁵⁹ These areas do not include Alaska, but Alaska’s cropland area accounts for less than 0.1 percent of total U.S. cropland area, so this omission is not significant.

⁶⁰ The climatic regions were: (1) cold temperate, dry, (2) cold temperate, moist, (3) sub-tropical, dry, (4) sub-tropical, moist, (5) warm temperate, dry, and (6) warm temperate, moist.

Tier 1 Method: Additional Direct Soil N₂O Emissions

The Tier 1 method was used to estimate emissions from PRP manure that were not simulated with DAYCENT, in addition to emissions due to sewage sludge amendments to agricultural soils.

PRP Manure: PRP manure N data were derived using methods described in the Manure Management section (Section 6.2) and Annex 3.10. The amount of PRP manure N deposited on federal grasslands was based on the relative proportion of federal to non-federal grassland area in each county. As discussed in the Tier 3 DAYCENT Simulations section, the area data were based on the U.S. Department of Agriculture's *National Resources Inventory* (USDA 2000a) and the National Land Cover Dataset (Vogelman et al. 2001), respectively, and were reconciled with the Forest Inventory and Analysis dataset in order to produce the U.S. Land Representation (See Section 7.1). Soil N₂O emissions from the proportion of PRP manure N deposited on federal grasslands were estimated with the Tier 1 method.

Sewage Sludge Amendments: Sewage sludge is generated from the treatment of raw sewage in public or private wastewater treatment works and is typically used as a soil amendment or is sent to waste disposal facilities such as landfills. In this Inventory, all sewage sludge that is amended to agricultural soils is assumed to be applied to grasslands. Estimates of the amounts of sewage sludge N applied to agricultural lands were derived from national data on sewage sludge generation, disposition, and N content. Total sewage sludge generation data for 1988, 1996, and 1998, in dry mass units, were obtained from EPA (1999) and estimates for 2004 were obtained from an independent national biosolids survey (NEBRA 2007). These values were linearly interpolated to estimate values for the intervening years. Sewage sludge generation data are not available after 2004 (Bastian 2007), so the 1990 through 2004 data were linearly extrapolated for the most recent years. The total sludge generation estimates were then converted to units of N by applying an average N content of 3.9 percent (McFarland 2001), and disaggregated into use and disposal practices using historical data in EPA (1993) and NEBRA (2007). The use and disposal practices were agricultural land application, other land application, surface disposal, incineration, landfilling, ocean dumping (ended in 1992), and other disposal. The resulting estimates of sewage sludge N applied to agricultural land were used here; the estimates of sewage sludge N applied to other land and surface-disposed were used in estimating N₂O fluxes from soils in *Settlements Remaining* (see section 7.5 of the Land Use, Land-Use Change, and Forestry chapter). Sewage sludge disposal data are provided in Table A- 206.

Step 1d: Activity Data for Indirect N₂O Emissions from Managed Soils of all Land-Use Types and Managed Manure Systems

Volatilization of N that was applied or deposited as synthetic fertilizer, livestock manure, sewage sludge, and other organic amendments leads to emissions of NH₃ and NO_x to the atmosphere. In turn, this N is returned to soils through atmospheric deposition, thereby increasing mineral N availability and enhancing N₂O production. Additional N is lost from soils through leaching as water percolates through a soil profile and through runoff with overland water flow. N losses from leaching and runoff enter groundwater and waterways, from which a portion is emitted as N₂O. However, N leaching was assumed to be an insignificant source of indirect N₂O in cropland and grassland systems where the amount of precipitation plus irrigation did not exceed 80 percent of the potential evapotranspiration. These areas are typically semi-arid to arid, and nitrate leaching to groundwater is a relatively uncommon event; moreover IPCC (2006) recommends limiting the amount of nitrate leaching assumed to be a source of indirect N₂O emissions based on precipitation, irrigation and potential evapotranspiration.

The activity data for synthetic fertilizer, livestock manure, other organic amendments, residue N inputs, sewage sludge N, and other N inputs are the same as those used in the calculation of direct emissions from agricultural mineral soils, and may be found in Table A- 197 through Table A- 201, Table A- 203, and Table A- 206. The activity data for computing direct and indirect N₂O emissions from settlements and forest lands are described in the Land Use, Land-Use Change, and Forestry chapter.

Using the DAYCENT model, volatilization and leaching/surface run-off of N from soils was computed internally for major crop types and non-federal grasslands. DAYCENT simulates the processes leading to these losses of N based on environmental conditions (i.e., weather patterns and soil characteristics), management impacts (e.g., plowing, irrigation, harvest), and soil N availability. Note that the DAYCENT method accounts for losses of N from all anthropogenic activity, not just the inputs of N from mineral fertilization and organic amendments, which are addressed in the Tier 1 methodology. Similarly, the N available for producing indirect emissions resulting from grassland management as well as deposited PRP manure was also estimated by DAYCENT. Estimated leaching losses of N from DAYCENT were not used in the indirect N₂O calculation if the amount of precipitation plus irrigation did not exceed 80 percent of the potential evapotranspiration. Volatilized losses of N were summed for each day in the annual cycle to provide an estimate of the

amount of N subject to indirect N₂O emissions. In addition, the daily losses of N through leaching and runoff in overland flow were summed for the annual cycle. Uncertainty in the estimates was derived from uncertainties in the activity data for the N inputs (i.e., fertilizer and organic amendments; see Step 1a for further information)

The Tier 1 method was used to estimate N losses from mineral soils due to volatilization and leaching/runoff for non-major crop types, forestland, settlements, sewage sludge applications, and PRP manure on federal grasslands not accounted for by DAYCENT simulations. To estimate volatilized losses, synthetic fertilizers, manure, sewage sludge, and other organic N inputs were multiplied by the fraction subject to gaseous losses using the respective default values of 0.1 kg N/kg N added as mineral fertilizers and 0.2 kg N/kg N added as manure (IPCC 2006). Uncertainty in the volatilized N ranged from 0.03–0.3 kg NH₃-N+NO_x-N/kg N for synthetic fertilizer and 0.05–0.5 kg NH₃-N+NO_x-N/kg N for organic amendments (IPCC 2006). Leaching/runoff losses of N were estimated by summing the N additions from synthetic and other organic fertilizers, manure, sewage sludge, and above- and below-ground crop residues, and then multiplying by the default fraction subject to leaching/runoff losses of 0.3 kg N/kg N applied, with an uncertainty from 0.1–0.8 kg NO₃-N/kg N (IPCC 2006). However, N leaching was assumed to be an insignificant source of indirect N₂O emissions if the amount of precipitation plus irrigation did not exceed 80 percent of the potential evapotranspiration. PDFs were derived for each of the N inputs in the same manner as direct N₂O emissions, discussed in Steps 1a and 1c.

Volatilized N was summed for losses from major crop types, minor crop types, grasslands, settlements, and forest lands. Similarly, the annual amounts of N lost from soil profiles through leaching and surface runoff were summed to obtain the total losses for this pathway.

Step 2: Estimate Direct N₂O Emissions from Cropland Soils

In this step, N₂O emissions were calculated for major crop types and non-major crop types on mineral soils, in addition to emissions associated with drainage and cultivation of organic soils.

Step 2a: Direct N₂O Emissions from Cropland Mineral Soils

Two methods were used to estimate direct N₂O emissions from N additions and crop production on mineral soils. The DAYCENT ecosystem model was used to estimate emissions from major crop types, while the Tier 1 methodology was used to estimate emissions from crops considered non-major types, which are grown on a considerably smaller portion of land than the major types.

Major Crops: Tier 3 DAYCENT Simulations

Simulations were performed over three major time periods for each county in the United States using the DAYCENT model. The first time period was used for simulation of native vegetation up to date of cultivation in the county (1 A.D. to plow out). Plow out was assumed to occur between 1600 and 1850, depending on the state in which the county lies. Simulation of at least 1600 years of native vegetation was needed to initialize soil organic matter (SOM) pools in the model. The second time period of the simulation started at plowout and represents historical agricultural practices up to the modern period (plow out to 1970). Simulation of the historical cropping period was needed to establish modern day SOM levels, which is important because N₂O emissions are sensitive to the amount of SOM. Lastly, simulations were performed for the modern agricultural period (1971 through 2009).

Corn, soybeans, wheat, alfalfa hay, other hay, sorghum, and cotton are defined as major crops and were simulated in every county where they were grown. These crops represent approximately 90 percent of total principal cropland in the United States as defined by the U.S. Department of Agriculture (USDA 2003). Overall, the DAYCENT simulations included approximately 86 percent of total cropland area. For rotations that include a cycle that repeats every two or more years (e.g., corn/soybeans, wheat/corn/fallow), different simulations were performed where each phase of the rotation was simulated every year. For example, 3 rotations were simulated in regions where wheat/corn/fallow cropping is a dominant rotation—one with wheat grown the first year, a second with corn the first year and a third with fallow the first year. This ensured that each crop was represented during each year in one of the three simulations. In cases where the same crop was grown in the same year in two or more distinct rotations for a region, N₂O emissions were averaged across the different rotations to obtain a value for that crop. Emissions from cultivated fallow land were also included. Fallow area was assumed to be equal to winter wheat area in regions where winter wheat/fallow rotations are the dominant land management for winter wheat.

The simulations reported here assumed conventional tillage cultivation, gradual improvement of cultivars, and gradual increases in fertilizer application until 1989. Note that there is a planned improvement to incorporate use of conservation tillage in the United States into this Inventory. The productivity of cultivars (cultivated varieties) has

steadily improved over the last century and therefore it is unrealistic to assume that modern varieties of crops, such as corn, are identical to the popular varieties grown in 1900 in terms of yield potential, N demand, etc. Realistic simulations of historical land management and vegetation type are important because they influence present day soil C and N levels, which influence present-day N cycling and associated N₂O emissions.

Uncertainty estimation was an integral part of this analysis; uncertainty in the input data for the county-scale simulations and structural uncertainty associated with the DAYCENT model predictions were both addressed (Del Grosso et al. 2010). In the first step, a Monte Carlo Analysis was used to propagate input data uncertainty through the modeling process. Thus, input data were randomly selected from PDFs for weather records, soil type, mineral N fertilization rate, and organic amendments. See Step 1a for additional discussion about the PDFs. After selecting a set of inputs for a county, DAYCENT was used to simulate each crop and then the process was repeated until 100 iterations were completed. Due to the computationally intensive requirements for DAYCENT, it was not possible to simulate every county with the Monte Carlo Analysis. Two counties were selected from each of the 63 agricultural regions, and additional counties were added based on the variance in N₂O emissions across regions from the past year's Inventory, using a Neyman allocation (Cochran 1977). A Neyman allocation is based on the variance in N₂O emissions across the 63 regions; regions with larger variances were allocated a larger number of counties for the Monte Carlo Analysis. A total of 300 counties were included in the Monte Carlo Analysis, which is approximately 10 percent of all counties with agricultural land. In addition, all counties were simulated once based on the dominant conditions from the PDFs (i.e., most common soil type, weather condition, manure amendment, and mineral fertilizer rate).

In the second step of the uncertainty analysis, a structural uncertainty estimator was developed to account for uncertainty inherent in model formulation and parameterization using an empirically-based procedure described by Ogle et al. (2007). The procedure is based on developing a statistical relationship between modeled results and field measurements. Specifically, DAYCENT was used to simulate 11 agricultural experiments with 108 treatments, and the results were analyzed using a linear-mixed effect model in which measurements were statistically modeled as a function of simulated emissions. Simulated DAYCENT emissions were a highly significant predictor of the measurements, with a p-value of <0.01. Several other variables were tested in the statistical model to evaluate if DAYCENT exhibited bias under certain conditions related to climate, soil types, and management practices. The type of crop or grassland was significant at an alpha level of 0.05, demonstrating that DAYCENT tended to over-estimate emissions for small grains systems and grassland, but was accurate in predicting the N₂O emissions for other crops. Random effects were included in the model to capture the dependence in time series and data collected from the same site, which were needed to estimate appropriate standard deviations for parameter coefficients.

The structural uncertainty estimator accounted for bias and prediction error in the DAYCENT model results, as well as random error associated with fine-scale emission predictions in counties over a time series from 1990 to 2009. To apply the uncertainty estimator, DAYCENT N₂O emission estimates were used as an input to the linear mixed effect model after randomly selecting statistical parameter coefficients from their joint probability distribution, in addition to random draws from PDFs representing the uncertainty due to site, site by year random effects and the residual error from the linear-mixed effect model (Del Grosso et al. 2010).

In DAYCENT, once N enters the plant/soil system, the model cannot distinguish among the original sources of the N to determine which management activity led to specific N₂O emissions. This means, for example, that N₂O emissions from applied synthetic fertilizer cannot be separated from emissions due to other N inputs, such as crop residues. It is desirable, however, to report emissions associated with specific N inputs. Thus, for each crop in a county, the N inputs in a simulation were determined for anthropogenic practices discussed in IPCC (2006), including synthetic mineral N fertilization, organic amendments, and crop residue N added to soils (including N-fixing crops). The percentage of N input for anthropogenic practices was divided by the total N input, and this proportion was used to determine the amount of N₂O emissions assigned to each of the practices.⁶¹ For example, if 70 percent of the mineral N made available in the soil was due to mineral fertilization, then 70 percent of the N₂O emissions were assigned to this practice. The remainder of soil N₂O emissions is reported under "other N inputs," which includes mineralization due to decomposition of soil organic matter and litter, as well as asymbiotic fixation of mineral N in soils from the atmosphere. Asymbiotic N fixation by soil bacteria is a minor source of N, typically not exceeding 10 percent of total N inputs to agroecosystems. Mineralization of soil organic matter is a more significant source of N, but is still typically less than half of the amount of N made available in the soil compared to fertilization, manure amendments, and symbiotic fixation. Accounting for the

⁶¹ This method is a simplification of reality to allow partitioning of N₂O emissions, as it assumes that all N inputs have an identical chance of being converted to N₂O. This is unlikely to be the case, but DAYCENT does not track N₂O emissions by source of mineral N so this approximation is the only approach that can be used for partitioning N₂O emissions by source of N input. Moreover, this approach is similar to the IPCC Tier 1 method (IPCC 2006), which uses the same direct emissions factor for most N sources (e.g., PRP).

influence of “other N inputs” was necessary in order to meet the recommendation of reporting all emissions from managed lands (IPCC 2006). While this method allows for attribution of N₂O emissions to the individual N inputs to the soils, it is important to realize that sources such as synthetic fertilization may have a larger impact on N₂O emissions than would be suggested by the associated level of N input for this source (Delgado et al. 2009). Further research will be needed to improve upon this attribution method, however.

The final N₂O emission estimate was determined by summing the estimates from the single simulation conducted in each county for the dominant condition to the 63 regions. Estimates were then adjusted to account for the difference between the emissions estimated in the Monte Carlo analysis and the dominant condition simulation on a region-by-region basis (i.e., if the Monte Carlo mean was slightly higher than the dominant condition among the counties included in the Monte Carlo analysis, the total emission estimate for the region would be raised by the difference) (Del Grosso et al. 2010). In turn, regional values were summed to produce the national total. The uncertainty was based on the variance in simulated N₂O emissions for the iterations in the Monte Carlo Analysis and the variance associated with difference between the means from the Monte Carlo Analysis and the simulated N₂O emissions for the dominant condition, expressed as a 95 percent confidence interval (Del Grosso et al. 2010).

Non-Major Crops: Tier 1 Method

To estimate direct N₂O emissions from N additions to non-major crops, the amount of N in applied synthetic fertilizer, manure and other commercial organic fertilizers (i.e., dried blood, tankage, compost, and other) was added to N inputs from crop residues, and the resulting annual totals were multiplied by the IPCC default emission factor of 0.01 kg N₂O-N/kg N (IPCC 2006). The uncertainty was determined based on simple error propagation methods (IPCC 2006). The uncertainty in the default emission factor ranged from 0.3–3.0 kg N₂O-N/kg N (IPCC 2006). Uncertainty in activity data is ± 20 percent for fertilizer additions (Mosier 2004).⁶² Uncertainties in the emission factor and fertilizer additions were combined with uncertainty in the equations used to calculate residue N additions from above- and below-ground biomass dry matter and N concentration to derive overall uncertainty.

Step 2b: Direct N₂O Emissions Due to Drainage and Cultivation of Organic Cropland Soils

To estimate annual N₂O emissions from drainage and cultivation of organic soils, the area of cultivated organic soils in temperate regions was multiplied by the IPCC (2006) default emission factor for temperate soils and the corresponding area in sub-tropical regions was multiplied by the average (12 kg N₂O-N/ha cultivated) of IPCC (2006) default emission factors for temperate (8 kg N₂O-N/ha cultivated) and tropical (16 kg N₂O-N/ha cultivated) organic soils. The uncertainty was determined based on simple error propagation methods (IPCC 2006), including uncertainty in the default emission factor ranging from 2–24 kg N₂O-N/ha (IPCC 2006).

Step 2c: Estimate Total Direct N₂O Emissions from Cropland Soils

In this step, total direct N₂O emissions from cropland soils are calculated by summing direct emissions on mineral soils with emissions resulting from the drainage and cultivation of organic soils (i.e., histosols) (Table A- 207). Uncertainties were combined using the simple error propagation method (IPCC 2006).

Step 3: Estimate Direct N₂O Emissions from Grasslands

DAYCENT was used to estimate direct N₂O emissions from soils in non-federal grasslands (pastures and rangeland), and the Tier 1 method was used for federal grasslands. Managed pastures were simulated with DAYCENT by assuming that the vegetation mix includes forage legumes and grasses, and that grazing intensity was moderate to heavy. Rangelands were simulated without forage legumes and grazing intensity was assumed to be light to moderate. The methodology used to conduct the DAYCENT simulations of grasslands was similar to that for major crop types described above in Step 2a, including the analysis addressing uncertainty in the model inputs and model structure. Carbon and nitrogen additions to grasslands from grazing animals were obtained from county level animal excretion data and area data for federal and non-federal grasslands, as described in Step 1c.

⁶² Note that due to lack of data, uncertainties in managed manure N production, PRP manure N production, other commercial organic fertilizer amendments, indirect losses of N in the DAYCENT simulations, and sewage sludge amendments to soils are currently treated as certain; these sources of uncertainty will be included in future Inventories.

The Tier 1 method was used to estimate emissions from N excreted by livestock on federal lands (i.e., PRP manure N). The Tier 1 method was also used to estimate emissions from sewage sludge application to grasslands. These two sources of N inputs to soils were multiplied by the IPCC (2006) default emission factors (0.01 kg N₂O-N/kg N from sludge and horse, sheep, and goat manure, and 0.02 kg N₂O-N/kg N from cattle, swine, and poultry manure) to estimate N₂O emissions. This emission estimate was summed with the DAYCENT simulated emissions to provide the national total for direct N₂O losses from grasslands (Table A- 208). The uncertainty was determined based on the Tier 1 error propagation methods provided by the IPCC (2006) with uncertainty in the default emission factor ranging from 0.007 to 0.06 kg N₂O-N/kg N (IPCC 2006).

Step 4: Estimate Indirect N₂O Emissions for All Land-Use Types

In this step, N₂O emissions were calculated for the two indirect emission pathways (N₂O emissions due to volatilization, and N₂O emissions due to leaching and runoff of N), which were then summed to yield total indirect N₂O emissions from croplands, grasslands, forest lands, and settlements.

Step 4a: Indirect Emissions Due to Volatilization

Indirect emissions from volatilization of N inputs from synthetic and commercial organic fertilizers, and PRP manure, were calculated according to the amount of mineral N that was transported in gaseous forms from the soil profile and later emitted as soil N₂O following atmospheric deposition. See Step 1d for additional information about the methods used to compute N losses due to volatilization. The estimated N volatilized for all land-use and livestock activities was multiplied by the IPCC default emission factor of 0.01 kg N₂O-N/kg N (IPCC 2006) to compute total N₂O emissions from volatilization. The resulting estimates are provided in Table A- 209. The uncertainty was determined using simple error propagation methods (IPCC 2006), by combining uncertainties in the amount of N volatilized, with uncertainty in the default emission factor ranging from 0.002–0.05 kg N₂O-N/kg N (IPCC 2006).

Step 4b: Indirect Emissions Due to Leaching and Runoff

The amount of mineral N (i.e., synthetic fertilizers, commercial organic fertilizers, PRP manure, crop residue, N mineralization, asymbiotic fixation) that was transported from the soil profile in aqueous form was used to calculate indirect emissions from (1) leaching of mineral N from soils and (2) losses in runoff of water associated with overland flow. See Step 1d for additional information about the methods used to compute N losses from soils due to leaching and runoff in overland water flows.

The total amount of N transported from soil profiles through leaching and surface runoff was multiplied by the IPCC default emission factor of 0.0075 kg N₂O-N/kg N (IPCC 2006) to estimate emissions for this source. The resulting emission estimates are provided in Table A- 210. The uncertainty was determined based on simple error propagation methods (IPCC 2006), including uncertainty in the default emission factor ranging from 0.0005 to 0.025 kg N₂O-N/kg N (IPCC 2006).

Step 5: Estimate Total N₂O Emissions for U.S. Soils

Total emissions were estimated by adding total direct emissions (from major crop types and non-major crop types on mineral cropland soils, drainage and cultivation of organic soils, and grassland management) to indirect emissions for all land use and management activities. U.S. national estimates for this source category are provided in Table A- 210. Uncertainties in the final estimate were combined using simple error propagation methods (IPCC 2006), and expressed as a 95 percent confidence interval.

Direct and indirect emissions of soil N₂O vary regionally in both croplands and grasslands as a function of N inputs, weather, and soil type. A little more than half of the total N₂O emissions from major crops occur in Iowa, Illinois, Nebraska, Minnesota, Texas, Kansas and Indiana where N inputs associated with corn rotations are high or where large land areas are cropped (Table A- 211). On a per area unit basis, direct N₂O emissions are also high in many of the Mississippi River Basin states where there are also high N input to corn and soybean crops (Figure A- 9). Emissions are also high in some western and New England states. Only a small portion of the land in these regions is used for crop production, but management and conditions lead to higher emissions on a per unit area basis than other regions. For example, emissions are high in California, Arizona, and other western states due to intensive irrigation management systems. For some New England states, emissions are high on a per unit area because subsurface soil layers remain frozen

when surface soil layers thaw in spring. This creates saturated conditions near the surface that facilitate denitrification and N₂O emissions. Indirect emissions tend to be high on an area basis in the central and eastern United States because relatively high rainfall facilitates N losses from leaching and runoff and in some western states where irrigation can contribute to leaching and runoff (Figure A- 10).

Direct and indirect emissions from grasslands are typically lower than those from croplands (Table A- 211, Figure A- 11, and Figure A- 12) because N inputs tend to be lower, particularly from synthetic fertilizer. Texas was by far the highest emitter for this category, followed by Nebraska, Montana, Oklahoma, New Mexico Colorado and South Dakota. On a per area unit basis, emissions are lower in the western United States because grasslands in the East and Central regions are more intensively managed (legume seeding, fertilization) while western rangelands receive few, if any, N inputs. Also, rainfall is limited in most of the western United States, and grasslands are not typically irrigated so minimal leaching and runoff of N occurs in these grasslands.

Figure A- 7: DAYCENT Model Flow Diagram

Figure A- 8: Comparisons of Results from DAYCENT Model and IPCC Tier 1 Method with Measurements of Soil N₂O Emissions

Figure A- 9: Major Crops, Average Annual Direct N₂O Emissions, Estimated Using the DAYCENT Model, 1990-2009 (Metric Tons CO₂ Eq./ha/year)

Figure A- 10: Major Crops, Average Annual N Losses Leading to Indirect N₂O Emissions, Estimated Using the DAYCENT Model, 1990-2009 (kg N/ha/year)

Figure A- 11: Grasslands, Average Annual Direct N₂O Emissions, Estimated Using the DAYCENT Model, 1990-2009 (Metric Tons CO₂ Eq./ha/year)

Figure A- 12: Grasslands, Average Annual N Losses Leading to Indirect N₂O Emissions, Estimated Using the DAYCENT Model, 1990-2009 (kg N/ha/year)

Table A- 197: Synthetic Fertilizer N Added to Major Crops (Gg N)

	1990		1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Fertilizer N	7,468		7,307	7,915	7,705	7,641	7,412	7,575	7,450	7,547	7,370	7,355	7,000	6,855	7,428	6,663	6194

Table A- 198: Fate of Livestock Manure Nitrogen (Gg N)

Activity	1990		1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Managed Manure N Applied to Major Crops and Grasslands ^{a,b}	993		968	1,038	1,063	1,116	1,103	1,099	1,086	1,164	1,079	1,077	1,036	847	1,195	1,110	948
Managed Manure N Applied to Non-Major Crops ^b	1,473		1,618	1,568	1,563	1,519	1,561	1,587	1,583	1,585	1,549	1,598	1,687	1,878	1,655	1,649	1,722
Managed Manure N Applied to Grasslands	446		515	514	503	542	478	463	466	470	470	472	475	479	475	474	462
Pasture, Range, & Paddock Manure N	4,083		4,458	4,412	4,296	4,237	4,158	4,056	4,043	4,049	4,072	4,077	4,157	4,209	4,201	4,170	4,123
Total	6,994		7,559	7,532	7,426	7,414	7,300	7,204	7,177	7,268	7,171	7,223	7,355	7,413	7,527	7,403	7,255

^a Accounts for N volatilized and leached/runoff during treatment, storage and transport before soil application.

^b Includes managed manure and daily spread manure amendments

^c Totals may not sum exactly due to rounding.

Table A- 199: Crop Residue N and Other N Inputs to Major Crops as Simulated by DAYCENT (Gg N)

Activity	1990		1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Residue N ^a	2,982		3,305	3,322	3,329	3,099	3,659	3,450	3,151	3,253	3,407	3,231	3,041	3,186	3,164	3,210	2,996
Mineralization & Asymbiotic Fixation	12,406		12,010	12,590	12,811	14,166	12,926	13,548	13,520	13,238	13,216	13,361	12,740	12,800	13,084	12,943	12,345

^a Residue N inputs include unharvested fixed N from legumes as well as crop residue N.

Table A- 200: Synthetic Fertilizer N Added to Non-Major Crops (Gg N)

	1990		1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Fertilizer N	1,076		1,884	1,326	1,638	1,669	1,841	1,546	1,571	1,540	1,838	1,905	2,155	2,039	1,692	2,229	2,653

Table A- 201: Other Organic Commercial Fertilizer Consumption on Agricultural Lands (Gg N)

	1990		1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Other Commercial Organic Fertilizer N ^a	4		10	13	14	12	11	9	7	8	8	9	10	12	15	13	13

^a Includes dried blood, tankage, compost, other. Excludes dried manure and sewage sludge used as commercial fertilizer to avoid double counting.

Table A- 202: Key Assumptions for Production of Non-Major Crops and Retention of Crop Residues

Crop	Dry Matter Fraction of Harvested Product	Above-ground Residue		Ratio of Below-ground Residue to Above-ground Biomass	Residue N Fraction	
		Slope	Intercept		Above-ground	Below-ground
Peanuts for Nuts	0.94	1.07	1.54	0.20	0.016	0.014
Dry Edible Beans	0.90	0.36	0.68	0.19	0.010	0.010
Dry Edible Peas	0.91	1.13	0.85	0.19	0.008	0.008
Austrian Winter Peas	0.91	1.13	0.85	0.19	0.008	0.008
Lentils	0.91	1.13	0.85	0.19	0.008	0.008
Wrinkled Seed Peas	0.91	1.13	0.85	0.19	0.008	0.008
Barley	0.89	0.98	0.59	0.22	0.007	0.014
Oats	0.89	0.91	0.89	0.25	0.007	0.008
Rye	0.88	1.09	0.88	0.22	0.005	0.011
Millet	0.90	1.43	0.14	0.22	0.007	0.009
Rice	0.89	0.95	2.46	0.16	0.007	0.009

Table A- 203: Nitrogen in Crop Residues Retained on Soils Producing Non-Major Crops (Gg N)

Crop	1990		1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Peanuts for Nuts	64		63	65	64	68	66	61	71	61	69	71	77	63	65	79	65
Dry Edible Beans	16		16	15	16	16	16	15	13	16	14	13	15	14	15	15	14
Dry Edible Peas	9		11	9	11	11	10	10	10	10	11	14	15	8	8	14	17
Austrian Winter Peas	8		8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Lentils	9		9	9	9	9	9	10	10	9	9	10	11	10	10	9	11
Wrinkled Seed Peas	9		9	8	8	8	8	8	8	8	8	9	8	8	8	8	9
Barley	112		96	105	96	94	74	86	68	63	76	76	59	51	59	66	63
Oats	55		29	28	30	30	27	28	24	23	27	23	23	20	20	20	20
Rye	9		9	9	8	9	9	9	8	8	9	8	8	8	8	8	8
Millet	7		7	7	7	7	7	3	7	2	5	6	5	4	6	6	4
Rice	80		87	86	91	91	99	94	103	101	97	109	106	95	96	99	105
Total	378		343	349	348	352	336	331	330	311	333	347	336	290	304	332	324

Table A- 204: Drained and Cultivated Organic Soil Area (Thousand Hectares)

Year	Temperate Area	Sub-Tropical Area
1990	444	194
1995	450	196
1996	450	196
1997	450	196
1998	450	196
1999	450	196
2000	450	196
2001	450	196
2002	450	196
2003	450	196
2004	450	196
2005	450	196
2006	450	196
2007	450	196
2008	450	196
2009	450	196

Table A- 205: Synthetic Fertilizer N, PRP Manure N, Organic Manure N Amendment, Forage Legume N, and Other N Inputs Simulated with the DAYCENT Model (Gg N)

N Source	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Fertilizer N	9,678	9,662	10,245	9,973	9,891	9,628	9,747	9,620	9,723	9,553	9,536	9,213	9,088	9,656	8,871	8,385
PRP Manure N	3,718	4,065	4,021	3,906	3,856	3,787	3,697	3,688	3,701	3,728	3,731	3,806	3,856	3,850	3,819	3,781
Managed Manure	1,438	1,483	1,552	1,566	1,658	1,581	1,561	1,552	1,634	1,549	1,549	1,511	1,326	1,670	1,584	1,410
Residue N ^a	11,164	11,560	11,054	11,069	10,667	12,264	11,056	11,078	10,631	11,234	10,855	10,731	10,840	10,875	10,890	10,577
Mineralization & Asymbiotic Fixation	23,864	23,237	23,649	24,172	25,721	23,703	24,190	24,412	23,731	23,942	24,175	23,635	23,549	23,830	23,731	23,285

^aResidue N inputs include unharvested fixed N from legumes as well as crop residue N.

Table A- 206: Sewage Sludge Nitrogen by Disposal Practice (Gg N)

Disposal Practice	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Applied to Agricultural Soils	52	69	72	75	78	81	30	86	89	91	94	98	101	104	106	109
Other Land Application	25	28	29	29	29	30	30	30	30	30	30	31	31	32	32	32
Surface Disposal	20	16	15	14	13	12	10	9	8	6	5	5	4	4	3	3
Total	98	113	116	118	121	122	124	125	127	128	130	134	136	139	141	144

Note: Totals may not sum due to independent rounding.

Table A- 207: Direct N₂O Emissions from Cropland Soils (Tg CO₂ Eq.)

Activity	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Mineral Soils	100.1	107.1	115.5	112.9	116.5	111.1	112.7	120.1	112.5	109.7	116.2	115.2	112.7	114.9	115.0	109.1
Major Crops	85.8	88.3	99.6	95.6	99.2	92.9	95.7	103.1	95.7	91.5	97.4	94.8	92.1	97.1	94.4	86.1
Synthetic Fertilizer	27.1	27.4	31.7	29.6	29.4	27.4	28.4	30.4	28.8	27.0	28.7	28.1	26.7	29.1	26.5	23.9
Managed Manure	3.6	3.6	4.2	4.1	4.1	4.0	4.0	4.4	4.3	3.9	4.1	4.1	3.3	4.6	4.4	3.6
Residue N ^a	10.6	12.4	13.5	12.8	11.6	13.7	12.7	12.7	12.4	12.4	12.6	12.1	12.4	12.4	12.6	11.5
Mineralization and Asymbiotic Fixation	44.6	44.8	50.2	49.0	54.0	47.7	50.6	55.5	50.2	48.3	52.1	50.5	49.7	50.9	50.9	47.1
Non-Major Crops	14.3	18.8	15.9	17.4	17.3	18.3	16.9	17.0	16.8	18.2	18.8	20.4	20.6	17.9	20.6	23.0
Synthetic Fertilizer	5.2	9.2	6.5	8.0	8.1	9.0	7.5	7.7	7.5	9.0	9.3	10.5	9.9	8.2	10.9	12.9
Managed Manure and Other																
Organic Commercial Fertilizer	7.2	7.9	7.7	7.7	7.5	7.7	7.8	7.7	7.8	7.6	7.8	8.3	9.2	8.1	8.1	8.5
Residue N	1.8	1.7	1.7	1.7	1.7	1.6	1.6	1.6	1.5	1.6	1.7	1.6	1.4	1.5	1.6	1.6
Organic Soils	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9
Total*	102.9	110.0	118.4	115.8	119.4	114.0	115.6	123.0	115.4	112.6	119.1	118.1	115.6	117.8	117.9	112.0

+ Less than 0.05 Tg CO₂ Eq.^a Residue N inputs include unharvested fixed N from legumes as well as crop residue N.**Table A- 208: Direct N₂O Emissions from Grasslands (Tg CO₂ Eq.)**

	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
DAYCENT	47.1	45.2	49.4	46.2	47.3	42.9	43.3	47.3	47.5	42.6	44.5	45.6	44.3	43.4	44.9	44.4
Synthetic Fertilizer	3.9	4.1	4.5	4.1	4.2	3.7	3.9	4.1	4.3	3.8	4.0	4.1	4.0	3.9	4.0	3.9
PRP Manure	4.6	4.7	5.2	4.7	4.6	4.4	4.5	4.7	4.7	4.4	4.6	4.9	4.8	4.7	4.9	4.7
Managed Manure	1.5	1.8	2.0	1.8	1.8	1.5	1.6	1.7	1.8	1.5	1.6	1.6	1.6	1.6	1.6	1.6
Residue N ^a	15.6	14.6	15.5	14.6	14.5	14.9	13.8	15.5	15.3	13.9	14.2	14.6	14.2	13.9	14.4	14.1
Mineralization and Asymbiotic Fixation	21.5	20.0	22.3	21.2	22.2	18.4	19.5	21.2	21.3	19.0	20.1	20.4	19.7	19.3	20.0	20.1
Tier 1	3.7	4.1	4.1	4.0	4.0	3.9	3.8	3.7	3.7	3.7	3.7	3.8	3.8	3.8	3.8	3.8
PRP Manure	3.5	3.7	3.7	3.7	3.6	3.5	3.4	3.3	3.3	3.2	3.3	3.3	3.3	3.3	3.3	3.2
Sewage Sludge	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.5
Total	50.9	49.2	53.5	50.3	51.3	46.8	47.1	51.0	51.2	46.3	48.2	49.4	48.1	47.3	48.7	48.2

+ Less than 0.05 Tg CO₂ Eq.^a Residue N inputs include unharvested fixed N from legumes as well as crop residue N.

Table A- 209: Indirect N₂O Emissions (Tg CO₂ Eq.)

Activity	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Volatilization and Atm. Deposition	16.9	18.2	17.6	17.9	17.8	17.8	17.6	17.6	17.5	17.6	17.8	18.2	19.3	17.7	17.8	18.3
Croplands	11.6	12.8	12.4	12.6	12.4	12.6	12.7	12.5	12.5	12.5	12.8	13.1	14.2	12.8	12.9	13.4
Settlements	0.1	0.2	0.2	0.2	0.2	0.2	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Forest Land	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+
Grasslands	5.1	5.2	5.0	5.1	5.2	5.0	4.7	4.9	4.7	4.8	4.8	4.8	4.8	4.7	4.7	4.7
Surface Leaching & Run-off	27.1	30.3	29.8	25.8	29.1	24.5	26.5	28.8	24.8	25.9	26.7	25.7	25.9	26.6	26.3	26.1
Croplands	25.8	29.1	28.1	24.4	27.5	23.0	25.0	27.2	23.2	24.0	24.9	23.7	24.4	24.9	24.5	24.1
Settlements	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Forest Land	+	+	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Grasslands	1.0	0.8	1.4	0.9	1.3	1.0	1.2	1.1	1.2	1.4	1.3	1.5	1.1	1.2	1.2	1.5
Total	44.0	48.5	47.4	43.7	46.9	42.3	44.1	46.3	42.3	43.5	44.5	43.9	45.2	44.3	44.1	44.4

+ Less than 0.05 Tg CO₂ Eq.**Table A- 210: Total N₂O Emissions from Agricultural Soil Management (Tg CO₂ Eq.)**

Activity	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Total Direct	153.8	159.2	171.9	166.1	170.7	160.9	162.6	174.0	166.6	158.9	167.3	167.5	163.7	165.1	166.6	160.2
Direct Emissions from Mineral Cropland Soils	100.1	107.1	115.5	112.9	116.5	111.1	112.7	120.1	112.5	109.7	116.2	115.2	112.7	114.9	115.0	109.1
Synthetic Fertilizer	32.3	36.6	38.2	37.6	37.5	36.4	36.0	38.1	36.3	35.9	37.9	38.6	36.7	37.4	37.3	36.9
Organic Amendment ^a	10.8	11.6	11.9	11.8	11.6	11.7	11.8	12.2	12.1	11.5	12.0	12.3	12.5	12.8	12.5	12.1
Residue N ^b	12.4	14.0	15.2	14.5	13.4	15.3	14.3	14.3	13.9	14.0	14.3	13.7	13.8	13.9	14.3	13.1
Mineralization and Asymbiotic Fixation	44.6	44.8	50.2	49.0	54.0	47.7	50.6	55.5	50.2	48.3	52.1	50.5	49.7	50.9	50.9	47.1
Direct Emissions from Drained Organic Cropland Soils	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9
Direct Emissions from Grasslands*	50.9	49.2	53.5	50.3	51.3	46.8	47.1	51.0	51.2	46.3	48.2	49.4	48.1	47.3	48.7	48.2
Synthetic Mineral Fertilizer	3.9	4.1	4.5	4.1	4.2	3.7	3.9	4.1	4.3	3.8	4.0	4.1	4.0	3.9	4.0	3.9
PRP Manure*	8.1	8.4	8.9	8.4	8.2	7.9	7.9	8.1	8.0	7.6	7.8	8.2	8.1	8.0	8.2	7.9
Managed Manure	1.5	1.8	2.0	1.8	1.8	1.5	1.6	1.7	1.8	1.5	1.6	1.6	1.6	1.6	1.6	1.6
Sewage Sludge	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.5
Residue ^b	15.6	14.6	15.5	14.6	14.5	14.9	13.8	15.5	15.3	13.9	14.2	14.6	14.2	13.9	14.4	14.1
Mineralization and Asymbiotic Fixation	21.5	20.0	22.3	21.2	22.2	18.4	19.5	21.2	21.3	19.0	20.1	20.4	19.7	19.3	20.0	20.1
Total Indirect	44.0	48.5	47.4	43.7	46.9	42.3	44.1	46.3	42.3	43.5	44.5	43.9	45.2	44.3	44.1	44.4
Volatilization	16.9	18.2	17.6	17.9	17.8	17.8	17.6	17.6	17.5	17.6	17.8	18.2	19.3	17.7	17.8	18.3
Leaching/Runoff	27.1	30.3	29.8	25.8	29.1	24.5	26.5	28.8	24.8	25.9	26.7	25.7	25.9	26.6	26.3	26.1
Total Emissions	197.8	207.6	219.3	209.7	217.6	203.2	206.8	220.4	208.8	202.4	211.8	211.3	208.9	209.4	210.7	204.6

+ Less than 0.05 Tg CO₂ Eq.^a Organic amendment inputs include managed manure amendments, daily spread manure and other commercial organic fertilizer (i.e., dried blood, tankage, compost, and other).^b Residue N inputs include unharvested fixed N from legumes as well as crop residue N.

Table A- 211: Total 2009 N₂O Emissions (Direct and Indirect) from Agricultural Soil Management by State (Tg CO₂ Eq.)

State	Croplands ¹	Grasslands ²	Settlements ³	Forest Lands ⁴	Total	Lower Bound	Upper Bound
AL	0.67	0.71	0.03	n.e.	1.42	0.87	2.51
AR	3.07	0.76	0.02	n.e.	3.85	2.47	7.37
AZ	0.91	0.93	0.02	n.e.	1.86	0.95	4.58
CA	6.96	1.80	0.19	n.e.	8.95	5.73	17.46
CO	1.23	2.46	0.02	n.e.	3.71	2.36	6.14
CT	0.57	0.03	0.02	n.e.	0.62	0.36	1.58
DE	0.77	0.01	0.01	n.e.	0.78	0.45	2.38
FL	2.02	1.03	0.22	n.e.	3.27	2.28	5.58
GA	1.22	0.36	0.01	n.e.	1.59	1.02	3.23
HI ⁵	0.00	n.e.	n.e.	n.e.	1.59	1.02	3.23
IA	15.79	0.85	0.07	n.e.	16.71	11.99	33.98
ID	2.19	1.57	0.02	n.e.	3.78	2.34	7.60
IL	11.86	0.37	0.12	n.e.	12.34	8.81	19.28
IN	7.55	0.30	0.07	n.e.	7.92	5.05	12.74
KS	5.66	2.21	0.07	n.e.	7.94	5.58	12.16
KY	2.00	1.14	0.03	n.e.	3.17	1.91	5.69
LA	1.58	0.54	0.04	n.e.	2.16	1.65	3.44
MA	0.13	0.02	0.04	n.e.	0.19	0.13	0.77
MD	1.03	0.09	0.05	n.e.	1.18	0.30	3.27
ME	0.22	0.02	0.01	n.e.	0.25	0.17	1.36
MI	4.48	0.37	0.08	n.e.	4.92	3.50	8.35
MN	9.71	0.80	0.03	n.e.	10.54	7.38	16.41
MO	6.07	1.82	0.07	n.e.	7.96	5.34	12.65
MS	2.44	0.42	0.03	n.e.	2.90	1.81	6.33
MT	2.01	3.09	0.01	n.e.	5.11	3.21	8.22
NC	2.38	0.65	0.05	n.e.	3.08	2.14	6.28
ND	5.46	1.17	0.03	n.e.	6.66	4.46	10.67
NE	6.38	2.98	0.07	n.e.	9.43	6.72	14.63
NH	0.06	0.01	0.01	n.e.	0.08	0.06	0.41
NJ	1.61	0.02	0.07	n.e.	1.71	0.34	5.10
NM	0.54	2.91	0.01	n.e.	3.46	1.66	6.09
NV	0.31	0.61	0.01	n.e.	0.93	0.04	9.01
NY	3.19	0.33	0.07	n.e.	3.60	2.35	7.02
OH	7.37	0.49	0.11	n.e.	7.97	5.67	12.54
OK	1.21	3.02	0.03	n.e.	4.27	1.97	7.83
OR	1.12	1.43	0.01	n.e.	2.56	1.60	5.42
PA	3.05	0.12	0.06	n.e.	3.24	1.77	7.60
RI	0.02	0.00	0.01	n.e.	0.03	0.02	0.58
SC	0.66	0.15	0.03	n.e.	0.85	0.16	2.10
SD	3.25	2.53	0.02	n.e.	5.79	3.97	9.35
TN	1.60	0.77	0.05	n.e.	2.42	1.46	6.22
TX	5.32	8.93	0.09	n.e.	14.34	8.26	22.86
UT	0.64	0.92	0.01	n.e.	1.57	1.06	3.24
VA	4.26	0.84	0.06	n.e.	5.16	3.34	12.17
VT	0.46	0.06	0.00	n.e.	0.52	0.37	1.11
WA	2.28	1.00	0.03	n.e.	3.31	1.24	7.93
WI	6.64	0.77	0.04	n.e.	7.45	5.23	12.13
WV	0.44	0.21	0.01	n.e.	0.66	0.36	1.62
WY	0.51	1.95	0.01	n.e.	2.47	1.69	4.02

¹ Emissions from non-manure organic N inputs for minor crops were not estimated (n.e.) at the state level.

² Emissions from sewage sludge applied to grasslands and were not estimated (n.e.) at the state level.

³ Emissions from sewage sludge applied to settlements were not estimated (n.e.) at the state level.

⁴ Forestland emissions were not estimated (n.e.) at the state level.

⁵ N₂O emissions are not reported for Hawaii except from cropland organic soils.

3.12. Methodology for Estimating Net Carbon Stock Changes in Forest Lands Remaining Forest Lands

This sub-annex expands on the methodology used to calculate net changes in carbon (C) stocks in forest ecosystems and in harvested wood products. Some of the details of C conversion factors and procedures for calculating net CO₂ flux for forests are provided below; full details of selected topics may be found in the cited references.

Carbon Stocks and Net Changes in Forest Ecosystem Carbon Stocks

At least two forest inventories exist for most forest land in the United States. C stocks are estimated based on data from each inventory, at the level of permanent inventory plots. C per hectare (for a sample location) is multiplied by the total number of hectares that the plot represents, and then totals are summed for an area of interest, such as the state of Maine. Net annual C stock changes are calculated by taking the difference between the inventories and dividing by the number of years between the inventories for a selected state or sub-state area.

Forest inventory data

The estimates of forest C stocks are based on data derived from forest inventory surveys. Forest inventory data were obtained from the USDA Forest Service, Forest Inventory and Analysis (FIA) program (Frayer and Furnival 1999). FIA data include remote sensing information and collection of measurements in the field at sample locations called plots. Tree measurements include diameter and species. On a subset of plots, additional measurements or samples are taken of down dead wood, litter, and soil C; however, these are not yet available nationwide for C estimation. The field protocols are thoroughly documented and available for download from the USDA Forest Service (2010c). The inventory was designed for timber volume estimation rather than C stock estimation, so most C pools are not measured directly or are sampled only on a subset of plots. Bechtold and Patterson (2005) provide the estimation procedures for standard forest inventory results. The data are freely available for download at USDA Forest Service (2010b) as the Forest Inventory and Analysis Database (FIADB) Version 4.0; these data are the primary sources of forest inventory used to estimate forest C stocks.

Forest surveys have begun in the U.S. territories and in Hawaii. Meanwhile this inventory assumes that these areas account for a net C change of zero. Survey data are available for the temperate oceanic ecoregion of Alaska (southeast and south central). Inventory data are publicly available for 6.1 million hectares of forest land, and these inventoried lands, comprising 12% of the total forest land in Alaska, contribute to the forest carbon stocks presented here.

Agroforestry systems are also not currently accounted for in the U.S. Inventory, since they are not explicitly inventoried by either of the two primary national natural resource inventory programs: the FIA program of the USDA Forest Service and the National Resources Inventory (NRI) of the USDA Natural Resources Conservation Service (Perry et al. 2005). The majority of these tree-based practices do not meet the size and definitions for forests within each of these resource inventories. The size characteristics that exclude them from inventories also allow these systems to provide their many services without taking the land out of agricultural production, making them an appealing C sequestration option. Agroforestry in the United States has been defined as “intensive land-use management that optimizes the benefits (physical, biological, ecological, economic, social) from bio-physical interactions created when trees and/or shrubs are deliberately combined with crops and/or livestock” (Gold et al. 2000). In the United States, there are six categories of agroforestry practices: riparian forest buffers, windbreaks, alley cropping, silvopasture, forest farming and special applications.⁶³ These practices are used to address many issues facing agricultural lands, such as economic diversification, habitat fragmentation, and water quality. While providing these services and regardless of intent, these tree-based plantings will also reduce atmospheric CO₂. This occurs directly through CO₂ sequestration into woody biomass, and indirectly through enhancement of agricultural production, trapping wind-blown and surface runoff sediments, and/or reducing CO₂ emissions through fuel-use savings (Quam et al. 1992). The effects of these individual practices can potentially be quite large when taken into account within a whole-farm or within an aggregating larger entity (i.e., state-level) (Quam et al. 1992, Schoeneberger 2006). One estimate of the sequestration potential through agroforestry practices in the United States is 90.3 Mt C/year by 2025 (Nair and Nair 2003).

⁶³ More information on agroforestry practices can be found online at <<http://www.unl.edu/nac>>.

Summing state-level C stocks to calculate United States net C flux in forest ecosystems

The overall approach for determining forest C stocks and stock change is based on methodology and algorithms coded into the computer tool described in Smith et al. (2010). It focuses on estimating forest C stocks based on data from two or more forest surveys conducted several years apart for each state or sub-state. There are generally two or more surveys available for download for each state. C stocks are calculated separately for each state based on available inventories conducted since 1990 and for the inventory closest to, but prior to, 1990 if such data are available and consistent with these methods. This approach ensures that the period 1990 (the base year) to present can be adequately represented. Surveys conducted prior to and in the early to mid 1990s focused on land capable of supporting timber production (timberland).⁶⁴ As a result, information on less productive forest land or lands reserved from harvest was limited. Inventory field crews periodically measured all the plots in a state at a frequency of every 5 to 14 years. Generally, forests in states with fast-growing (and therefore rapidly changing) forests tended to be surveyed more often than states with slower-growing (and therefore slowly changing) forests. Older surveys for some states, particularly in the West, also have National Forest System (NFS) lands or reserved lands that were surveyed at different times than productive, privately-owned forest land in the state. Periodic data for each state thus became available at irregular intervals and determining the year of data collection associated with the survey can sometimes be difficult.

Table A-212: Source of Unique Forest Inventory and Average Year of Field Survey Used to Estimate Statewide Carbon Stocks

State/Substate ^a	Source of Inventory Data, Report/Inventory Year ^b	Average Year Assigned to Inventory ^c
Alabama	FIADB 4.0, 1982	1982
	FIADB 4.0, 1990	1990
	FIADB 4.0, 2000	1999
	FIADB 4.0, 2005	2003
Alaska, non-reserved Southcentral	FIADB 4.0, 2009	2007
Alaska, non-reserved Southeast	FIADB 4.0, 2009	2007
Alaska, reserved Southcentral	FIADB 4.0, 2009	2006
Alaska, reserved Southeast	FIADB 4.0, 2009	2006
Arizona, NFS non-woodlands	1987 RPA	1985
	FIADB 4.0, 1999	1996
	FIADB 4.0, 2009	2005
Arizona, NFS woodlands	1987 RPA	1984
	FIADB 4.0, 1999	1996
	FIADB 4.0, 2009	2005
Arizona, non-NFS non-woodlands	FIADB 4.0, 1985	1986
	FIADB 4.0, 1999	1996
	FIADB 4.0, 2009	2006
Arizona, non-NFS woodlands	FIADB 4.0, 1999	1990
	FIADB 4.0, 2009	2006
Arkansas	FIADB 4.0, 1988	1988
	FIADB 4.0, 1995	1996

⁶⁴ Forest land is defined as land at least 120 feet wide and 1 acre in size with at least 10 percent cover (or equivalent stocking by live trees of any size, including land that formerly had such tree cover and that will be naturally or artificially regenerated). Forest land includes transition zones, such as areas between forest and nonforest lands that have at least 10 percent cover (or equivalent stocking) with live trees and forest areas adjacent to urban and built-up lands. Roadside, streamside, and shelterbelt strips of trees must have a crown width of at least 120 feet and continuous length of at least 363 feet to qualify as forest land. Unimproved roads and trails, streams, and clearings in forest areas are classified as forest if they are less than 120 feet wide or an acre in size. Tree-covered areas in agricultural production settings, such as fruit orchards, or tree-covered areas in urban settings, such as city parks, are not considered forest land. (Smith et al. 2009) Timberland is the most productive type of forest land, which is on unreserved land and is producing or capable of producing crops of industrial wood. Productivity is at a minimum rate of 20 cubic feet of industrial wood per acre per year (Woudenberg and Farrenkopf 1995). There are about 203 million hectares of timberland in the conterminous United States, which represents 81 percent of all forest lands over the same area (Smith et al. 2009).

	FIADB 4.0, 2005	2003
	FIADB 4.0, 2009	2007
California, NFS	IDB, 1990s	1997
	FIADB 4.0, 2009	2006
California, non-NFS	IDB, 1990s	1993
	FIADB 4.0, 2009	2006
Colorado, NFS non-woodlands	1997 RPA	1981
	FIADB 4.0, 2009	2006
Colorado, NFS woodlands	1997 RPA	1975
	FIADB 4.0, 1984	1997
	FIADB 4.0, 2009	2006
Colorado, non-NFS non-woodlands	Westwide, 1983	1980
	FIADB 4.0, 2009	2006
Colorado, non-NFS woodlands	Westwide, 1983	1983
	FIADB 4.0, 2009	2006
Connecticut	FIADB 4.0, 1985	1985
	FIADB 4.0, 1998	1998
	FIADB 4.0, 2007	2006
Delaware	FIADB 4.0, 1986	1986
	FIADB 4.0, 1999	1999
	FIADB 4.0, 2008	2007
Florida	FIADB 4.0, 1987	1987
	FIADB 4.0, 1995	1995
	FIADB 4.0, 2007	2005
Georgia	FIADB 4.0, 1989	1989
	FIADB 4.0, 1997	1997
	FIADB 4.0, 2004	2001
	FIADB 4.0, 2008	2006
Idaho, Caribou-Targhee NF	Westwide, 1991	1992
	FIADB 4.0, 2009	2007
Idaho, Kootenai NF	1987 RPA	1988
	FIADB 4.0, 1991	1995
	FIADB 4.0, 2009	2007
Idaho, non-NFS non-woodlands	FIADB 4.0, 1991	1990
	FIADB 4.0, 2009	2007
Idaho, non-NFS woodlands	FIADB 4.0, 1991	1982
	FIADB 4.0, 2009	2007
Idaho, other NFS	Westwide, 1991	1988
	FIADB 4.0, 1991	2000
	FIADB 4.0, 2009	2007
Idaho, Payette NF	1987 RPA	1982
	FIADB 4.0, 2009	2007
Idaho, Salmon-Challis NF	1987 RPA	1978
	FIADB 4.0, 2009	2007
Idaho, Sawtooth NF	Westwide, 1991	1983
	FIADB 4.0, 1991	1996
	FIADB 4.0, 2009	2007
Illinois	FIADB 4.0, 1985	1985
	FIADB 4.0, 1998	1998
	FIADB 4.0, 2005	2004

	FIADB 4.0, 2008	2006
Indiana	FIADB 4.0, 1986	1986
	FIADB 4.0, 1998	1998
	FIADB 4.0, 2003	2001
	FIADB 4.0, 2008	2007
Iowa	FIADB 4.0, 1990	1990
	FIADB 4.0, 2003	2002
	FIADB 4.0, 2008	2006
Kansas	FIADB 4.0, 1981	1981
	FIADB 4.0, 1994	1994
	FIADB 4.0, 2005	2003
	FIADB 4.0, 2008	2007
Kentucky	FIADB 4.0, 1988	1987
	FIADB 4.0, 2004	2002
	FIADB 4.0, 2007	2005
Louisiana	FIADB 4.0, 1984	1984
	FIADB 4.0, 1991	1991
	FIADB 4.0, 2005	2004
Maine	Eastwide, 1982	1983
	FIADB 4.0, 1995	1995
	FIADB 4.0, 2003	2002
	FIADB 4.0, 2008	2007
Maryland	FIADB 4.0, 1986	1986
	FIADB 4.0, 1999	2000
	FIADB 4.0, 2008	2007
Massachusetts	FIADB 4.0, 1985	1985
	FIADB 4.0, 1998	1998
	FIADB 4.0, 2007	2006
Michigan	FIADB 4.0, 1980	1980
	FIADB 4.0, 1993	1993
	FIADB 4.0, 2004	2003
	FIADB 4.0, 2008	2006
Minnesota	FIADB 4.0, 1990	1989
	FIADB 4.0, 2003	2001
	FIADB 4.0, 2008	2006
Mississippi	FIADB 4.0, 1987	1987
	FIADB 4.0, 1994	1994
	FIADB 4.0, 2006	2007
Missouri	FIADB 4.0, 1989	1988
	FIADB 4.0, 2003	2002
	FIADB 4.0, 2008	2006
Montana, NFS	1987 RPA	1988
	FIADB 4.0, 1989	1996
	FIADB 4.0, 2009	2007
Montana, non-NFS non-reserved	FIADB 4.0, 1989	1989
	FIADB 4.0, 2009	2006
Montana, non-NFS reserved	1997 RPA	1990
	FIADB 4.0, 2009	2007
Nebraska	FIADB 4.0, 1983	1983
	FIADB 4.0, 1994	1995

	FIADB 4.0, 2005	2004
	FIADB 4.0, 2008	2006
Nevada, NFS non-woodlands	1987 RPA	1974
	FIADB 4.0, 1989	1997
	FIADB 4.0, 2005	2005
Nevada, NFS woodlands	1987 RPA	1978
	FIADB 4.0, 1989	1997
	FIADB 4.0, 2005	2005
Nevada, non-NFS non-woodlands	1997 RPA	1985
	FIADB 4.0, 2005	2005
Nevada, non-NFS woodlands	FIADB 4.0, 1989	1980
	FIADB 4.0, 2005	2005
New Hampshire	FIADB 4.0, 1983	1983
	FIADB 4.0, 1997	1997
	FIADB 4.0, 2007	2005
New Jersey	FIADB 4.0, 1987	1987
	FIADB 4.0, 1999	1999
	FIADB 4.0, 2008	2007
New Mexico, NFS non-woodlands	1987 RPA	1986
	FIADB 4.0, 1999	1997
New Mexico, NFS woodlands	1987 RPA	1986
	FIADB 4.0, 1999	1997
New Mexico, non-NFS non-woodlands	FIADB 4.0, 1987	1987
	FIADB 4.0, 1999	1999
New Mexico, non-NFS woodlands	FIADB 4.0, 1999	1989
New York, non-reserved	Eastwide, 1980	1981
	FIADB 4.0, 1993	1993
	FIADB 4.0, 2007	2005
New York, reserved	1987 RPA	1988
	FIADB 4.0, 2007	2005
North Carolina	FIADB 4.0, 1984	1984
	FIADB 4.0, 1990	1990
	FIADB 4.0, 2002	2001
	FIADB 4.0, 2007	2006
North Dakota	FIADB 4.0, 1980	1979
	FIADB 4.0, 1995	1995
	FIADB 4.0, 2005	2003
	FIADB 4.0, 2008	2007
Ohio	FIADB 4.0, 1991	1991
	FIADB 4.0, 2006	2005
Oklahoma, Central & West	FIADB 4.0, 1989	1989
Oklahoma, East	FIADB 4.0, 1986	1986
	FIADB 4.0, 1993	1993
	FIADB 4.0, 2008	2008
Oregon, NFS East	IDB, 1990s	1995
	FIADB 4.0, 2009	2006
Oregon, NFS West	IDB, 1990s	1996
	FIADB 4.0, 2009	2006
Oregon, non-NFS East	Westwide, 1992	1991
	IDB, 1990s	1999

	FIADB 4.0, 2009	2005
Oregon, non-NFS West	Westwide, 1992	1989
	IDB, 1990s	1997
	FIADB 4.0, 2009	2006
Pennsylvania	FIADB 4.0, 1989	1990
	FIADB 4.0, 2004	2003
	FIADB 4.0, 2008	2007
Rhode Island	FIADB 4.0, 1985	1985
	FIADB 4.0, 1998	1999
	FIADB 4.0, 2007	2006
South Carolina	FIADB 4.0, 1986	1986
	FIADB 4.0, 1993	1993
	FIADB 4.0, 2001	2001
	FIADB 4.0, 2006	2005
South Dakota, NFS	1997 RPA	1986
	FIADB 4.0, 1995	1999
	FIADB 4.0, 2005	2004
	FIADB 4.0, 2008	2006
South Dakota, non-NFS	1987 RPA	1986
	FIADB 4.0, 1995	1995
	FIADB 4.0, 2005	2004
	FIADB 4.0, 2008	2007
Tennessee	FIADB 4.0, 1989	1989
	FIADB 4.0, 1999	1998
	FIADB 4.0, 2004	2003
	FIADB 4.0, 2007	2006
Texas, Central & West	FIADB 4.0, 2007	2006
Texas, East	FIADB 4.0, 1986	1986
	FIADB 4.0, 1992	1992
	FIADB 4.0, 2003	2003
	FIADB 4.0, 2008	2006
Utah, non-woodlands	FIADB 4.0, 1993	1993
	FIADB 4.0, 2009	2005
Utah, woodlands	FIADB 4.0, 1993	1994
	FIADB 4.0, 2009	2005
Vermont	FIADB 4.0, 1983	1983
	FIADB 4.0, 1997	1997
	FIADB 4.0, 2007	2006
Virginia	FIADB 4.0, 1985	1985
	FIADB 4.0, 1992	1991
	FIADB 4.0, 2001	2000
	FIADB 4.0, 2007	2005
Washington, NFS East	IDB, 1990s	1996
	FIADB 4.0, 2009	2006
Washington, NFS West	IDB, 1990s	1996
	FIADB 4.0, 2009	2006
Washington, non-NFS East	IDB, 1990s	1992
	FIADB 4.0, 2009	2006
Washington, non-NFS West	IDB, 1990s	1990
	FIADB 4.0, 2009	2006

West Virginia	FIADB 4.0, 1989	1988
	FIADB 4.0, 2000	2001
	FIADB 4.0, 2008	2007
Wisconsin	FIADB 4.0, 1983	1982
	FIADB 4.0, 1996	1995
	FIADB 4.0, 2004	2002
	FIADB 4.0, 2008	2006
Wyoming, NFS	1997 RPA	1982
	FIADB 4.0, 2000	2000
Wyoming, non-NFS non-reserved non-woodlands	FIADB 4.0, 1984	1984
	FIADB 4.0, 2000	2002
Wyoming, non-NFS non-reserved woodlands	FIADB 4.0, 1984	1984
	FIADB 4.0, 2000	2002
Wyoming, non-NFS reserved	1997 RPA	1985
	FIADB 4.0, 2000	2000

^a Substate areas (Smith et al. 2010) include National Forests (NFS), all forest ownerships except National Forest (non-NFS), woodlands (forest land dominated by woodland species, such as pinyon and juniper, where stocking cannot be determined (USDA Forest Service 2010c)), non-woodlands (used for clarity to emphasize that woodlands are classified separately), reserved (forest land withdrawn from timber utilization through statute, administrative regulation, or designation, Smith et al. (2009)), and non-reserved (forest land that is not reserved, used for clarity). Some National Forests are listed individually by name, e.g., Payette NF. Oregon and Washington were divided into eastern and western forests (east or west of the crest of the Cascade Mountains). Oklahoma and Texas are divided into East versus Central & West according to forest inventory survey units (USDA Forest Service 2010d). Alaska is represented by a portion of forest land, in the southcentral and southeast part of the state.

^b FIADB 4.0 is the current, publicly available, format of FIA inventory data, and these files were downloaded from the Internet September 12, 2010 (USDA Forest Service 2010b). IDB (Integrated Database) data are a compilation of periodic inventory data from the 1990s for California, Oregon, and Washington (Waddell and Hiserote 2005). Eastwide (Hansen et al. 1992) and Westwide (Woudenberg and Farrenkopf 1995) inventory data are formats that predate the FIADB data. RPA data are periodic national summaries. The year is the nominal, or reporting, year associated with each dataset.

^c Average year is based on average measurement year of forest land survey plots and rounded to the nearest integer year.

A new national plot design and annualized sampling (USDA Forest Service 2010a) was introduced by FIA with most new surveys beginning after 1998. These surveys include sampling of all forest land including reserved and lower productivity lands. Most states have annualized inventory data available as of September 2010. Annualized sampling means that a portion of plots throughout the state is sampled each year, with the goal of measuring all plots once every 5 to 10 years, depending on the region of the United States. The full unique set of data with all measured plots, such that each plot has been measured one time, is called a cycle. Sampling is designed such that partial inventory cycles provide usable, unbiased samples of forest inventory, but with higher sampling errors than the full cycle. After all plots have been measured once, the sequence continues with remeasurement of the first year's plots, starting the next new cycle. Most Eastern states have completed the first full cycle of the annualized inventories and are providing annual updates to the state's forest inventory with each year's remeasurements, such that one plot's measurements are included in subsequent year's annual updates. Thus, annually updated estimates of forest C stocks are accurate, but estimates of stock change cannot utilize the annually updated inventory measurements directly, as there is redundancy in the data used to generate the annual updates of C stock. For example, a typical annual inventory update for an eastern state will include new data from remeasurement on 20 percent of plots; data from the remaining 80 percent of plots is identical to that included in the previous year's annual update. The interpretation and use of the sequence of annual inventory updates can affect trends in annualized stock and stock change. In general, the C stock and stock change calculations use annual inventory summaries (updates) with unique sets of plot-level data (that is, without redundant sets); the most-recent annual update is the exception because it is included in stock change calculations if at least half of the plots in a state include new measurements. Table A-212 lists the specific surveys used in this report, and this list can be compared with the full set of summaries available for download (USDA Forest Service 2010b).

For each pool in each state in each year, C stocks are estimated by linear interpolation between survey years. Similarly, fluxes, or net stock changes, are estimated for each pool in each state by dividing the difference between two successive stocks by the number of intervening years between surveys. Thus, the number of separate stock change estimates for each state or sub-state is one less than the number of available inventories. Annual estimates of stock and net change since the most recent survey are based on linear extrapolation. C stock and flux estimates for each pool are summed over all forest land in all states as identified in Table A-212 to form estimates for the United States. Summed net annual stock change and stock are presented in Table A-213 and Table A-214, respectively. Table A-214 also provides an

estimate of forest area based on the interpolation and extrapolation procedure described above. Estimated net stock change of non-soil forest ecosystem carbon for 2009 for each of the states is shown in Table A-215, which also includes estimated forest area and total non-soil forest carbon stock. The state-level forest areas and carbon stocks are from the most recent inventory available (USDA Forest Service 2010a), and the estimate for net stock change is the mean of the 2000 through 2009 estimates from the carbon calculator (Smith et al. 2010).

Table A-213: Net Annual Changes in Carbon Stocks (Tg C yr⁻¹) in Forest and Harvested Wood Pools, 1990–2009

Carbon Pool	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Forest	(149.8)	(151.4)	(149.8)	(139.5)	(147.1)	(148.4)	(130.3)	(128.6)	(102.8)	(76.9)	(72.4)	(113.0)	(162.3)	(210.3)	(219.6)	(219.9)	(220.6)	(220.6)	(220.6)	(220.6)
Live, aboveground	(98.2)	(99.9)	(100.5)	(97.4)	(101.5)	(102.8)	(92.7)	(95.8)	(84.7)	(78.3)	(78.3)	(89.3)	(103.0)	(118.9)	(122.1)	(122.1)	(122.1)	(122.1)	(122.1)	(122.1)
Live, belowground	(19.3)	(19.7)	(19.8)	(19.3)	(20.1)	(20.5)	(18.4)	(19.0)	(16.9)	(15.7)	(15.7)	(17.9)	(20.5)	(23.5)	(24.1)	(24.1)	(24.1)	(24.1)	(24.1)	(24.1)
Dead Wood	(8.6)	(8.6)	(8.3)	(7.6)	(7.7)	(7.7)	(7.1)	(6.2)	(4.8)	(4.0)	(3.5)	(4.0)	(5.2)	(7.6)	(8.1)	(8.4)	(9.1)	(9.1)	(9.1)	(9.1)
Litter	(8.8)	(8.8)	(9.0)	(8.1)	(7.6)	(6.0)	(5.1)	(5.1)	(0.5)	4.9	7.5	1.8	(5.3)	(9.9)	(11.4)	(11.4)	(11.4)	(11.4)	(11.4)	(11.4)
Soil Organic Carbon	(14.9)	(14.4)	(12.1)	(7.2)	(10.2)	(11.4)	(7.1)	(2.5)	4.1	16.2	17.6	(3.7)	(28.3)	(50.3)	(53.8)	(53.8)	(53.8)	(53.8)	(53.8)	(53.8)
Harvested Wood	(35.9)	(33.8)	(33.8)	(32.9)	(33.4)	(32.3)	(30.6)	(32.0)	(31.1)	(32.5)	(30.8)	(25.5)	(26.8)	(25.9)	(28.7)	(28.7)	(29.6)	(28.1)	(22.4)	(14.8)
Products in Use	(17.7)	(14.9)	(16.3)	(15.0)	(15.9)	(15.1)	(14.1)	(14.7)	(13.4)	(14.1)	(12.8)	(8.7)	(9.6)	(9.7)	(12.4)	(12.4)	(12.3)	(10.7)	(5.2)	1.9
SWDS	(18.3)	(18.8)	(17.4)	(17.9)	(17.5)	(17.2)	(16.5)	(17.3)	(17.7)	(18.4)	(18.0)	(16.8)	(17.2)	(16.2)	(16.3)	(16.3)	(17.3)	(17.4)	(17.2)	(16.7)
Total Net Flux	(185.7)	(185.1)	(183.6)	(172.4)	(180.5)	(180.7)	(160.9)	(160.7)	(133.9)	(109.4)	(103.2)	(138.5)	(189.1)	(236.1)	(248.3)	(248.6)	(250.2)	(248.7)	(243.0)	(235.4)

Table A-214: Carbon Stocks (Tg C) in Forest and Harvested Wood Pools, 1990–2010

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Forest Area (1000 ha)	269,137	269,764	270,395	270,992	271,535	272,071	272,602	273,081	273,553	273,950	274,183	274,386	274,717	275,234	275,976	276,769	277,561	278,354	279,147	279,939	280,732
Carbon Pool																					
Forest	42,783	42,933	43,085	43,234	43,374	43,521	43,669	43,800	43,928	44,031	44,108	44,180	44,293	44,456	44,666	44,886	45,105	45,326	45,547	45,767	45,988
Live, aboveground	15,072	15,171	15,271	15,371	15,468	15,570	15,673	15,765	15,861	15,946	16,024	16,102	16,192	16,295	16,414	16,536	16,658	16,780	16,902	17,024	17,147
Live, belowground	2,995	3,014	3,034	3,053	3,073	3,093	3,113	3,132	3,151	3,168	3,183	3,199	3,217	3,237	3,261	3,285	3,309	3,333	3,357	3,381	3,405
Dead Wood	2,960	2,969	2,978	2,986	2,994	3,001	3,009	3,016	3,022	3,027	3,031	3,035	3,039	3,044	3,052	3,060	3,068	3,077	3,086	3,096	3,105
Litter	4,791	4,799	4,808	4,817	4,825	4,833	4,839	4,844	4,849	4,850	4,845	4,837	4,835	4,841	4,851	4,862	4,873	4,885	4,896	4,908	4,919
Soil Organic Carbon	16,965	16,980	16,995	17,007	17,014	17,024	17,035	17,043	17,045	17,041	17,025	17,007	17,011	17,039	17,089	17,143	17,197	17,251	17,304	17,358	17,412
Harvested Wood	1,859	1,895	1,929	1,963	1,996	2,029	2,061	2,092	2,124	2,155	2,187	2,218	2,244	2,271	2,296	2,325	2,354	2,383	2,412	2,434	2,449
Products in Use	1,231	1,249	1,264	1,280	1,295	1,311	1,326	1,340	1,355	1,368	1,382	1,395	1,404	1,413	1,423	1,436	1,448	1,460	1,471	1,476	1,474
SWDS	628	646	665	683	701	718	735	752	769	787	805	823	840	857	873	890	906	923	941	958	974
Total Carbon Stock	44,643	44,828	45,014	45,197	45,370	45,550	45,731	45,892	46,052	46,186	46,296	46,399	46,537	46,726	46,962	47,211	47,459	47,710	47,958	48,201	48,437

Table A-215: State-level forest area, carbon stock, and net annual stock change. Estimates are forest ecosystem carbon and do not include harvested wood

State	Mean year of field data collection	Forest area (1000 ha)	Nonsoil C stock (Mt C)	Mean net annual nonsoil stock change 2000–2009 (Mt C/yr)
Alabama	2006	9,219	682	(1.2)
Alaska	2007	6,132	1,217	0.0
Arizona	2006	7,572	436	2.0
Arkansas	2007	7,560	644	(3.6)
California	2006	13,333	2,165	(5.2)
Colorado	2006	9,294	915	(5.2)
Connecticut	2007	698	89	0.7
Delaware	2007	143	18	(0.1)
Florida	2005	6,838	471	(5.0)
Georgia	2006	10,046	802	(7.7)
Idaho	2007	8,656	1,053	2.1
Illinois	2006	1,942	215	(5.3)
Indiana	2007	1,920	225	(3.7)
Iowa	2006	1,227	113	(2.8)
Kansas	2007	902	74	(1.5)
Kentucky	2005	5,006	502	(5.3)
Louisiana	2004	5,722	447	0.1
Maine	2007	7,146	741	(1.9)
Maryland	2007	1,009	131	(1.2)
Massachusetts	2007	1,222	166	(0.4)
Michigan	2006	8,021	826	(6.5)
Minnesota	2006	6,876	536	(4.1)
Mississippi	2007	7,941	610	(6.2)
Missouri	2006	6,231	605	(10.5)
Montana	2007	10,356	1,132	(4.2)
Nebraska	2006	538	44	(0.6)
Nevada	2005	4,520	247	(0.8)
New Hampshire	2006	1,944	254	(0.5)
New Jersey	2007	810	86	(0.0)
New Mexico	1994	6,753	484	(3.8)
New York	2006	7,669	943	(6.3)
North Carolina	2006	7,521	727	(6.8)
North Dakota	2007	289	20	0.2
Ohio	2007	3,255	353	(3.0)
Oklahoma	2003	3,235	237	(0.8)
Oregon	2006	12,163	2,007	(8.2)
Pennsylvania	2007	6,739	804	(7.0)
Rhode Island	2007	141	17	(0.0)
South Carolina	2006	5,239	440	(5.7)
South Dakota	2007	753	51	(0.9)
Tennessee	2006	5,659	576	(3.8)
Texas	2006	24,363	977	(2.4)
Utah	2005	7,396	510	(3.4)
Vermont	2007	1,857	250	(0.3)
Virginia	2006	6,400	683	(3.4)
Washington	2006	9,060	1,711	(10.0)
West Virginia	2007	4,846	592	(4.6)
Wisconsin	2006	6,757	620	(6.0)
Wyoming	2001	4,633	468	(1.1)

Table A-216 shows average C density values for forest ecosystem C pools according to region and forest types based on forest lands in this Inventory. These values were calculated by applying plot-level C estimation procedures as described below to the most recent inventory per state as available 12 September 2010 (USDA 2010b). C density values

reflect the most recent survey for each state as available in the FIADB, not potential maximum C storage. C densities are affected by the distribution of stand sizes within a forest type, which can range from regenerating to mature stands. A large proportion of young stands in a particular forest type are likely to reduce the regional average for C density.

Table A-216: Average carbon density (Mg C/ha) by carbon pool and forest area (1000 ha) according to region and forest type, based on the most recent inventory survey available for each state from FIA, corresponding to an average year of 2006

Region (States) Forest Types	Above- ground Biomass	Below- ground Biomass	Dead Wood	Litter	Soil Organic Carbon	Forest Area (1,000 ha)
Carbon Density (Mg C/ha)						(1,000 ha)
Northeast						
(CT,DE,MA,MD,ME,NH,NJ,NY,OH,PA,RI,VT,WV)						
White/Red/Jack Pine	91.6	19.0	11.9	13.7	78.1	1,584
Spruce/Fir	52.7	11.2	13.3	30.7	98.0	2,970
Oak/Pine	77.0	15.2	9.8	27.4	66.9	1,234
Oak/Hickory	82.5	15.6	11.1	8.1	53.1	13,007
Elm/Ash/Cottonwood	59.3	11.3	9.9	6.9	111.7	1,450
Maple/Beech/Birch	77.9	15.0	13.3	27.1	69.6	13,673
Aspen/Birch	48.1	9.5	9.3	8.6	87.4	1,704
Minor Types and Nonstocked	48.2	9.5	10.3	10.9	73.7	1,855
All	74.5	14.4	11.9	17.8	69.0	37,478
Northern Lake States						
(MI,MN,WI)						
White/Red/Jack Pine	54.1	11.3	9.0	12.3	120.8	1,821
Spruce/Fir	40.5	8.6	8.6	33.1	261.8	3,213
Oak/Hickory	70.4	13.3	10.8	7.9	97.1	3,815
Elm/Ash/Cottonwood	52.4	10.0	9.2	7.5	179.9	2,118
Maple/Beech/Birch	74.1	14.2	11.5	27.3	134.3	4,301
Aspen/Birch	40.9	7.9	9.5	8.3	146.1	5,272
Minor Types and Nonstocked	34.5	6.8	8.8	18.0	122.6	1,113
All	54.5	10.7	9.9	16.4	152.3	21,654
Northern Prairie States						
(IA,IL,IN,KS,MO,ND,NE,SD)						
Ponderosa Pine	40.3	8.5	7.1	14.3	48.5	576
Oak/Pine	52.0	10.1	7.5	25.5	40.1	551
Oak/Hickory	69.8	13.2	9.7	7.7	49.4	9,570
Elm/Ash/Cottonwood	74.7	14.0	11.8	6.8	83.2	1,874
Minor Types and Nonstocked	41.6	8.1	8.3	17.9	60.3	1,231
All	66.0	12.5	9.7	9.5	54.5	13,803
Ponderosa Pine	40.3	8.5	7.1	14.3	48.5	576
South Central						
(AL,AR,KY,LA,MS,OK,TN,TX)						
Loblolly/Shortleaf Pine	40.6	8.3	5.5	10.9	55.5	1,198
Loblolly/Shortleaf Pine	45.8	9.4	7.0	9.6	41.9	13,256
Pinyon/Juniper	16.4	3.2	1.9	12.2	37.7	3,894
Oak/Pine	48.1	9.4	6.6	9.3	41.7	5,115
Oak/Hickory	58.5	11.0	6.8	6.4	38.6	24,619
Oak/Gum/Cypress	76.2	14.5	9.2	6.5	52.8	5,131
Elm/Ash/Cottonwood	51.9	9.8	7.1	5.9	49.9	3,441
Woodland Hardwoods	10.3	1.7	0.9	5.0	65.0	8,977
Minor Types and Nonstocked	32.3	6.2	5.8	7.1	54.3	4,271
All	45.9	8.8	5.9	7.4	45.5	68,704
Loblolly/Shortleaf Pine	45.8	9.4	7.0	9.6	41.9	13,256
Southeast						
(FL,GA,NC,SC,VA)						
Longleaf/Slash Pine	34.7	7.1	6.2	9.7	110.0	4,139
Loblolly/Shortleaf Pine	48.6	10.0	8.5	9.6	72.9	9,137
Oak/Pine	52.6	10.3	6.7	9.3	61.4	4,054
Oak/Hickory	73.1	13.8	8.9	6.4	45.3	12,014
Oak/Gum/Cypress	74.2	14.3	9.7	6.5	158.0	4,551
Elm/Ash/Cottonwood	57.9	10.9	9.7	5.6	95.7	760
Minor Types and Nonstocked	45.7	8.7	9.0	5.8	107.0	1,389
All	59.0	11.5	8.4	7.9	79.2	36,044
Coastal Alaska						
(approximately 12 percent of						

forest land in Alaska)						
Spruce/Fir	24.2	5.0	5.6	33.8	62.1	367
Fir/Spruce/Mountain Hemlock						
Hemlock	96.0	20.3	26.8	43.2	62.1	2,233
Hemlock/Sitka Spruce	142.2	30.0	37.5	50.5	116.3	2,754
Aspen/Birch	42.0	8.0	9.1	10.6	42.5	310
Minor Types and Nonstocked	40.0	7.8	10.7	19.5	75.7	469
All	105.5	22.2	28.2	42.5	86.5	6,132
Spruce/Fir	24.2	5.0	5.6	33.8	62.1	367
Pacific Northwest, Westside						
(Western OR and WA)						
Douglas-fir	146.2	30.7	39.0	32.0	94.8	5,956
Fir/Spruce/Mountain Hemlock	150.1	31.7	41.6	38.3	62.1	1,187
Hemlock/Sitka Spruce	174.7	36.8	50.0	37.8	116.3	1,566
Alder/Maple	84.8	16.6	24.2	7.6	115.2	1,189
Minor Types and Nonstocked	68.9	13.7	18.0	13.5	85.9	1,216
All	135.6	28.3	37.0	28.8	95.5	11,114
Pacific Northwest, Eastside						
(Eastern OR and WA)						
Douglas-fir	77.5	16.2	19.5	36.3	94.8	2,089
Ponderosa Pine	48.8	10.2	11.2	22.5	50.7	2,742
Fir/Spruce/Mountain Hemlock	95.3	20.1	27.8	37.9	62.1	1,781
Lodgepole Pine	41.2	8.7	12.0	21.1	52.0	1,041
Western Larch	63.5	13.3	19.2	35.7	45.1	204
Other Western Softwoods	15.7	3.0	4.5	36.2	78.8	1,252
Minor Types and Nonstocked	36.0	7.1	16.1	25.1	81.5	999
All	57.1	11.9	15.8	30.1	68.4	10,109
Pacific Southwest						
(CA)						
Pinyon/Juniper	24.1	4.7	2.3	21.1	26.3	742
Douglas-fir	162.8	33.8	37.3	35.7	40.1	442
Ponderosa Pine	63.7	13.2	15.0	22.4	41.3	899
Fir/Spruce/Mountain Hemlock	158.0	33.4	45.0	38.3	51.9	824
Redwood	219.6	45.9	48.1	60.5	53.8	299
Other Western Softwoods	33.7	6.6	7.6	37.5	49.8	806
California Mixed Conifer	127.8	26.8	32.8	37.9	49.8	3,159
Western Oak	67.0	12.8	7.9	29.7	27.6	3,791
Tanoak/Laurel	132.0	26.0	20.1	28.0	27.6	830
Minor Types and Nonstocked	57.8	11.7	17.7	25.2	37.0	1,540
All	92.0	18.7	20.0	31.9	38.6	13,333
Rocky Mountain, North						
(ID,MT)						
Douglas-fir	72.8	15.4	14.5	37.0	38.8	5,587
Ponderosa Pine	40.0	8.3	8.2	22.9	34.3	1,865
Fir/Spruce/Mountain Hemlock	67.6	14.3	22.1	37.4	44.1	4,471
Lodgepole Pine	50.3	10.7	10.9	23.1	37.2	2,761
Western Larch	60.1	12.7	15.4	36.3	34.2	492
Other Western Softwoods	44.8	9.4	6.9	39.3	31.4	649
Aspen/Birch	31.8	6.0	12.5	26.8	56.6	533
Minor Types and Nonstocked	28.4	5.7	17.0	22.5	42.9	2,655
Rocky Mountain, South						
(AZ,CO,NM,NV,UT,WY)						
Pinyon/Juniper	22.9	4.7	1.0	21.1	19.7	18,738
Douglas-fir	74.7	15.9	16.9	38.1	30.9	1,797
Ponderosa Pine	47.3	10.0	8.2	23.6	24.1	3,570
Fir/Spruce/Mountain Hemlock	79.6	16.9	22.9	38.8	31.5	4,262
Lodgepole Pine	52.0	11.1	13.0	24.0	27.0	2,024
Aspen/Birch	56.9	11.0	13.2	28.5	58.8	2,555
Woodland Hardwoods	19.0	3.6	4.6	28.2	25.9	4,135
Minor Types and Nonstocked	18.7	3.6	7.9	22.6	25.4	3,088
All	36.3	7.5	6.9	25.4	25.8	40,168
United States (forest land included in Inventory)						
	60.0	11.9	11.1	17.6	62.0	277,552

Note: The forest area values in this table do not equal the forest area values reported in Table A-214, because the forest area values in this table are estimated using the most recent dataset per state, with an average year of 2006. The time series of forest area values reported in Table A-214,

in contrast, is constructed following the CCT methods used to construct the carbon stock series. The forest area values reported in Table A-214 and Table A-216 would only be identical if all states were measured simultaneously or they all had identical rates of change.

The Inventory is derived primarily from the current FIADB 4.0 data (USDA Forest Service 2010b), but it also draws on older FIA survey data where necessary. The Resources Planning Act Assessment (RPA) database, which includes periodic summaries of state inventories, is one example. Information about the RPA data is available on the Internet (USDA Forest Service 2010a, see Program Features), and compilations of analytical estimates based on these databases are found in Waddell et al. (1989) and Smith et al. (2001). The basic difference between the RPA database and the FIADB is that the FIADB includes some informative additional details such as individual-tree data. Having only plot-level information (such as volume per hectare) limits the conversion to biomass. This does not constitute a substantial difference for the overall state-wide estimates, but it does affect plot-level precision (Smith et al. 2004). In the past, FIA made their data available in tree-level Eastwide (Hansen et al. 1992) or Westwide (Woudenberg and Farrenkopf 1995) formats, which included inventories for Eastern and Western states, respectively. The current Inventory estimates rely in part on older tree-level data that are not available on the current FIADB site. The Integrated Database (IDB) is a compilation of periodic forest inventory data from the 1990s for California, Oregon, and Washington (Waddell and Hiserote 2005). These data were identified by Heath et al. (submitted) as the most appropriate non-FIADB sources for these states.

An historical focus of the FIA program was to provide information on timber resources of the United States. For this reason, prior to 1998, some forest land, which were less productive or reserved (i.e., land where harvesting was prohibited by law), were less intensively surveyed. This generally meant that on these less productive lands, forest type and area were identified but data were not collected on individual tree measurements. The practical effect that this evolution in inventories has had on estimating forest C stocks from 1990 through the present is that some older surveys of lands do not have the stand-level values for merchantable volume of wood or stand age. Any data gaps identified in the surveys taken before 1998 were filled by assigning average C densities calculated from the more complete, later inventories from the respective states. The overall effect of this necessary approach to generate estimates for C stock is that no net change in C density occurs on those lands with gaps in past surveys.

Estimating C stocks from forest inventory data

For each inventory summary in each state, data are converted to C units or augmented by other ecological data. This collection of conversion factors and models used for inventory-based forest carbon estimates (Smith et al. 2010, Heath et al. in press) was initially developed as an offshoot of the forest carbon simulation model FORCARB (Heath et al. 2010) and is incorporated into a number of applications (Birdsey and Heath 1995, Birdsey and Heath 2001, Heath et al. 2003, Smith et al. 2004, Smith et al. 2007, Hoover and Rebaun 2008). The conversion factors and model coefficients are usually categorized by region, and forest type. Classifications for both region and forest type are subject to change depending on the particular coefficient set. Thus, region and type are specifically defined for each set of estimates. Factors are applied to the survey data at the scale of FIA inventory plots. The results are estimates of C density (Mg per hectare) for the various forest pools. C density for live trees, standing dead trees, understory vegetation, down dead wood, litter, and soil organic matter are estimated. All non-soil pools except litter can be separated into aboveground and belowground components. The live tree and understory C pools are pooled as biomass in this inventory. Similarly, standing dead trees and down dead wood are pooled as dead wood in this inventory. C stocks and fluxes for *Forest Land Remaining Forest Land* are reported in pools following IPCC (2003).

Live tree C pools

The tree C pools include aboveground and belowground (coarse root) C mass of live trees. Separate estimates are made for full-tree and aboveground-only biomass to estimate the belowground component. Most tree C estimates are based on Jenkins et al. (2003) and are functions of species groups and diameter. For example, the equation for estimating aboveground biomass for a live tree of a species in the aspen/alder/cottonwood/willow group is:

$$\text{Biomass (kg dry weight)} = e^{(-2.2094 + 2.3867 \times \ln(\text{diameter}))}$$

Diameter is cm at diameter breast height (d.b.h.), which is measured at 1.37 m above the forest floor. C is calculated by multiplying biomass by 0.5 because biomass is 50 percent of dry weight (IPCC/UNEP/OECD/IEA 1997). A full set of coefficients can be found in Jenkins et al. (2003; Table 4). Belowground root biomass is estimated as a ratio of roots to total aboveground biomass. The equation for ratio of root biomass of a live tree in the aspen/alder/cottonwood/willow group is:

$$\text{Ratio} = e^{(-1.6911 + 0.8160/\text{diameter})}$$

Belowground biomass is calculated by multiplying the ratio by total aboveground biomass. A full set of coefficients can be found in Jenkins et al. (2003; Table 6). The C per tree is summed for each plot, and multiplied by the appropriate expansion factors to obtain a C stock estimate for the plot.

Some inventory data do not provide measurements of individual trees; tree C in these plots is estimated from plot-level growing stock volume of live trees and equations given in Table A-217 and Table A-218. These equations are updates of those in Smith et al. (2003), modified to reduce error and correspond to common forest types defined by inventories. Separate estimates are made for whole-tree and aboveground-only biomass based on forest type group and region. The belowground portion is determined as the difference between the two estimates. C density is estimated based on the growing stock volume of the plot, where growing stock includes live trees of commercial species meeting specified standards. Only trees 12.7 cm (5 inches) d.b.h. and larger are included in growing stock volume. The full sets of coefficients are in Table A-217 and Table A-218. For example, the total C in tree biomass per hectare of aspen-birch in the North averages 8.1 Mg C/ha if growing-stock volume is zero. If growing-stock volume is greater than zero, the estimate is in two parts. Average C density of non-growing-stock trees (sapling and cull trees) is 14.3 Mg C/ha, and the equation for C in growing-stock trees is:

$$\text{Growing-stock trees (Mg C/ha)} = e^{(-0.337 + \ln(\text{volume}) \times 0.933)}$$

Units for volume are m³/ha.

Table A-217: Coefficients for estimating carbon density of live trees (above- and below-ground, MgC/ha) by region and type for plot-level data such as RPA data^a

Region ^b	Forest type group ^c	Carbon density, if Growing Stock Volume (GSV) = 0	C density for non- Growing Stock (GS), if GSV > 0	Coefficient A	Coefficient B
North	Aspen/Birch	8.138	14.335	-0.337	0.933
	Elm/Ash/Cottonwood	16.187	18.707	-0.206	0.920
	Maple/Beech/Birch	6.938	17.054	-0.170	0.925
	Oak/Hickory	13.083	15.914	-0.079	0.932
	Hardwood minor types	10.376	14.127	0.002	0.890
	Oak/Pine	4.079	15.473	-0.146	0.908
	Ponderosa Pine & Exotic	2.595	6.895	-0.074	0.886
	Softwood	6.277	9.766	-0.415	0.943
	Loblolly/Shortleaf Pine	6.424	16.903	-0.487	0.947
	Spruce/Fir	3.908	12.117	-0.349	0.924
	White/Red/Jack Pine	6.277	17.234	-0.380	0.970
	Softwood minor types	1.054	1.238	-0.174	0.866
	Non-stocked	8.425	4.444	0.056	0.828
	Alder/Maple	8.425	10.483	0.041	0.864
Pacific Coast	Other Western Hardwoods	8.425	10.203	-0.167	0.917
	Tanoak/Laurel	8.425	7.400	0.344	0.850
	Hardwood minor types	8.425	4.802	0.333	0.770
	California Mixed Conifer	10.102	4.727	0.137	0.843
	Douglas-fir	2.752	4.961	0.180	0.834
	Fir/Spruce/Mt. Hemlock	10.102	6.462	0.171	0.834
	Hemlock/Sitka Spruce	10.102	8.034	0.085	0.830
	Lodgepole Pine	10.102	5.733	-0.129	0.857
	Pinyon/Juniper	22.552	5.065	-0.070	0.842
	Ponderosa Pine	10.102	2.262	0.145	0.813
	Western Larch	10.102	5.254	-0.264	0.853
	Softwood minor types	10.102	6.771	0.466	0.783
	RPA Western Hardwoods	8.425	7.460	0.302	0.831
	Non-stocked	0.880	0.300	0.049	0.806
Rocky Mountain	Aspen/Birch	4.594	9.516	0.324	0.792
	Harwood minor types	4.866	11.844	0.266	0.814
	Douglas-fir	1.987	5.363	0.331	0.825
	Fir/Spruce/Mt. Hemlock	1.987	6.693	0.065	0.825
	Lodgepole Pine	1.080	8.051	0.003	0.804
	Other Western Softwoods	1.987	12.217	0.361	0.796
	Ponderosa Pine	1.987	5.574	0.382	0.771
	Softwood minor types	1.987	5.496	-0.152	0.836
	RPA Western Hardwood	13.714	11.678	0.246	0.807
	Pinyon/Juniper	22.927	23.301	0.254	0.794

	West. Oak/Other West. Hardwoods	14.441	18.544	0.215	0.796
	Non-stocked	1.111	0.568	0.257	0.732
South	Elm/Ash/Cottonwood	12.841	21.633	-0.144	0.896
	Oak/Gum/Cypress	7.176	23.919	-0.216	0.907
	Oak/Hickory	14.594	20.007	-0.031	0.886
	Hardwood minor types	47.316	40.194	-0.442	0.960
	Oak/Pine	4.106	17.933	-0.086	0.858
	Loblolly/Shortleaf Pine	3.892	12.466	0.206	0.773
	Longleaf/Slash Pine	4.441	8.694	0.110	0.772
	Softwood minor types	7.161	20.189	-0.085	0.868
	Non-stocked	0.467	0.943	0.019	0.734

^a Prediction of C in growing-stock trees is based on $\exp(A + B \cdot \ln(\text{growing stock volume}))$.

^b Regions are North (CT, DE, IA, IL, IN, KS, MA, MD, ME, MI, MN, MO, ND, NE, NH, NJ, NY, OH, PA, RI, SD, VT, WI, WV); Pacific Coast (CA, OR, WA); Rocky Mountain (AZ, CO, ID, MT, NM, NV, UT, WY); and South (AL, AR, FL, GA, KY, LA, MS, NC, OK, SC, TN, TX, VA).

^c Forest type groups are identified in FIADB and RPA data (Smith et al. (2001, USDA Forest Service 2010d).

Table A-218: Coefficients for estimating carbon density of live trees (aboveground only, MgC/ha) by region and type for plot-level data such as RPA data^a

Region ^b	Forest type group ^c	Carbon density, if Growing Stock Volume (GSV)=0	C density for non-GS, if GSV > 0	Coefficient A	Coefficient B
North	Aspen/Birch	6.697	11.880	-0.521	0.934
	Elm/Ash/Cottonwood	13.585	15.653	-0.387	0.922
	Maple/Beech/Birch	5.762	14.219	-0.352	0.926
	Oak/Hickory	10.960	13.306	-0.260	0.933
	Hardwood minor types	8.647	11.796	-0.166	0.888
	Oak/Pine	3.368	12.881	-0.335	0.909
	Ponderosa Pine & Exotic Softwood	2.116	5.671	-0.269	0.886
	Loblolly/Shortleaf Pine	5.098	8.070	-0.620	0.946
	Spruce/Fir	5.206	13.833	-0.684	0.948
	White/Red/Jack Pine	3.174	10.010	-0.548	0.926
	Softwood minor types	5.098	14.246	-0.570	0.971
	Non-stocked	0.880	1.032	-0.357	0.866
Pacific Coast	Alder/Maple	7.006	3.676	-0.138	0.830
	Other Western Hardwoods	7.006	8.709	-0.154	0.867
	Tanoak/Laurel	7.006	8.469	-0.355	0.918
	Western Oak	7.006	6.163	0.167	0.850
	Hardwood minor types	7.006	3.974	0.136	0.773
	California Mixed Conifer	8.309	3.883	-0.061	0.844
	Douglas-fir	2.235	4.072	-0.017	0.835
	Fir/Spruce/Mt. Hemlock	8.309	5.285	-0.027	0.835
	Hemlock/Sitka Spruce	8.309	6.586	-0.113	0.831
	Lodgepole Pine	8.309	4.674	-0.327	0.858
	Pinyon/Juniper	18.583	4.170	-0.263	0.842
	Ponderosa Pine	8.309	1.849	-0.053	0.814
	Western Larch	8.309	4.282	-0.461	0.853
	Softwood minor types	8.309	5.563	0.267	0.784
	RPA Western Hardwoods	7.006	6.202	0.119	0.831
	Non-stocked	0.724	0.247	-0.146	0.808
Rocky Mountain	Aspen/Birch	3.798	7.914	0.139	0.793
	Hardwood minor types	4.027	9.936	0.084	0.815
	Douglas-fir	1.616	4.388	0.134	0.826
	Fir/Spruce/Mt. Hemlock	1.616	5.466	-0.133	0.826
	Lodgepole Pine	0.871	6.571	-0.195	0.805
	Other Western Softwoods	1.616	10.031	0.165	0.797
	Ponderosa Pine	1.616	4.569	0.185	0.772
	Softwood minor types	1.616	4.473	-0.350	0.837
	RPA Western Hardwood	11.341	9.704	0.054	0.809
	Pinyon/Juniper	18.867	19.173	0.059	0.794
South	West. Oak/Other West. Hardwoods	11.942	15.353	0.021	0.796
	Non-stocked	0.916	0.466	0.061	0.733
	Elm/Ash/Cottonwood	10.749	18.129	-0.323	0.897
	Oak/Gum/Cypress	5.987	20.004	-0.400	0.909
	Oak/Hickory	12.223	16.731	-0.215	0.888

Hardwood minor types	39.737	33.739	-0.631	0.964
Oak/Pine	3.394	14.923	-0.277	0.859
Loblolly/Shortleaf Pine	3.172	10.288	0.012	0.773
Longleaf/Slash Pine	3.634	7.176	-0.088	0.773
Softwood minor types	5.893	16.751	-0.280	0.869
Non-stocked	0.388	0.788	-0.171	0.735

^a Prediction of aboveground C in growing-stock trees is based on $\exp(A + B \cdot \ln(\text{growing stock volume}))$.

^b Regions are North (CT, DE, IA, IL, IN, KS, MA, MD, ME, MI, MN, MO, ND, NE, NH, NJ, NY, OH, PA, RI, SD, VT, WI, WV); Pacific Coast (CA, OR, WA); Rocky Mountain (AZ, CO, ID, MT, NM, NV, UT, WY); and South (AL, AR, FL, GA, KY, LA, MS, NC, OK, SC, TN, TX, VA).

^c Forest type groups are identified in FIADB and RPA data (Smith et al. 2001, USDA Forest Service 2010d).

Understory vegetation

Understory vegetation is a minor component of biomass. Understory vegetation is defined as all biomass of undergrowth plants in a forest, including woody shrubs and trees less than one-inch d.b.h. In this inventory, it is assumed that 10 percent of understory C mass is belowground. This general root-to-shoot ratio (0.11) is near the lower range of temperate forest values provided in IPCC (2006) and was selected based on two general assumptions: ratios are likely to be lower for light-limited understory vegetation as compared with larger trees, and a greater proportion of all root mass will be less than 2 mm diameter.

Estimates of C density are based on information in Birdsey (1996), which was applied to FIA permanent plots. These were fit to the equation:

$$\text{Ratio} = e^{(A - B \times \ln(\text{live tree C density}))}$$

In this equation, “ratio” is the ratio of understory C density (Mg C/ha) to live tree C density (above- and below-ground) in Mg C/ha. An additional coefficient is provided as a maximum ratio; that is, any estimate predicted from the equation that is greater than the maximum ratio is set equal to the maximum ratio. A full set of coefficients is in Table A-219. Regions and forest types are the same classifications described in Smith et al. (2003). As an example, the basic calculation for understory C in aspen-birch forests in the Northeast is:

$$\text{Understory (Mg C/ha)} = (\text{live tree C density}) \times e^{(0.855 - 1.03 \times \ln(\text{tree C density}))}$$

This calculation is followed by three possible modifications. First, the maximum value for the ratio is set to 2.02 (see value in column “maximum ratio”); this also applies to stands with zero tree C, which is undefined in the above equation. Second, the minimum ratio is set to 0.005 (Birdsey 1996). Third, nonstocked and pinyon/juniper stands are set to coefficient A, which is a carbon density (Mg C/ha) for these types only.

Table A-219: Coefficients for estimating the ratio of carbon density of understory vegetation (above- and belowground, MgC/ha)^a by region and forest type. The ratio is multiplied by tree carbon density on each plot to produce understory vegetation

Region ^b	Forest Type ^b	A	B	Maximum ratio ^c
NE	Aspen-Birch	0.855	1.032	2.023
	MBB/Other Hardwood	0.892	1.079	2.076
	Oak-Hickory	0.842	1.053	2.057
	Oak-Pine	1.960	1.235	4.203
	Other Pine	2.149	1.268	4.191
	Spruce-Fir	0.825	1.121	2.140
	White-Red-Jack Pine	1.000	1.116	2.098
	Nonstocked	2.020	2.020	2.060
NLS	Aspen-Birch	0.777	1.018	2.023
	Lowland Hardwood	0.650	0.997	2.037
	Maple-Beech-Birch	0.863	1.120	2.129
	Oak-Hickory	0.965	1.091	2.072
	Pine	0.740	1.014	2.046
	Spruce-Fir	1.656	1.318	2.136
	Nonstocked	1.928	1.928	2.117
NPS	Conifer	1.189	1.190	2.114
	Lowland Hardwood	1.370	1.177	2.055
	Maple-Beech-Birch	1.126	1.201	2.130
	Oak-Hickory	1.139	1.138	2.072
	Oak-Pine	2.014	1.215	4.185

	Nonstocked	2.052	2.052	2.072
PSW	Douglas-fir	2.084	1.201	4.626
	Fir-Spruce	1.983	1.268	4.806
	Hardwoods	1.571	1.038	4.745
	Other Conifer	4.032	1.785	4.768
	Pinyon-Juniper	4.430	4.430	4.820
	Redwood	2.513	1.312	4.698
	Nonstocked	4.431	4.431	4.626
PWE	Douglas-fir	1.544	1.064	4.626
	Fir-Spruce	1.583	1.156	4.806
	Hardwoods	1.900	1.133	4.745
	Lodgepole Pine	1.790	1.257	4.823
	Pinyon-Juniper	2.708	2.708	4.820
	Ponderosa Pine	1.768	1.213	4.768
	Nonstocked	4.315	4.315	4.626
PWW	Douglas-fir	1.727	1.108	4.609
	Fir-Spruce	1.770	1.164	4.807
	Other Conifer	2.874	1.534	4.768
	Other Hardwoods	2.157	1.220	4.745
	Red Alder	2.094	1.230	4.745
	Western Hemlock	2.081	1.218	4.693
	Nonstocked	4.401	4.401	4.589
RMN	Douglas-fir	2.342	1.360	4.731
	Fir-Spruce	2.129	1.315	4.749
	Hardwoods	1.860	1.110	4.745
	Lodgepole Pine	2.571	1.500	4.773
	Other Conifer	2.614	1.518	4.821
	Pinyon-Juniper	2.708	2.708	4.820
	Ponderosa Pine	2.099	1.344	4.776
	Nonstocked	4.430	4.430	4.773
RMS	Douglas-fir	5.145	2.232	4.829
	Fir-Spruce	2.861	1.568	4.822
	Hardwoods	1.858	1.110	4.745
	Lodgepole Pine	3.305	1.737	4.797
	Other Conifer	2.134	1.382	4.821
	Pinyon-Juniper	2.757	2.757	4.820
	Ponderosa Pine	3.214	1.732	4.820
	Nonstocked	4.243	4.243	4.797
SC	Bottomland Hardwood	0.917	1.109	1.842
	Misc. Conifer	1.601	1.129	4.191
	Natural Pine	2.166	1.260	4.161
	Oak-Pine	1.903	1.190	4.173
	Planted Pine	1.489	1.037	4.124
	Upland Hardwood	2.089	1.235	4.170
	Nonstocked	4.044	4.044	4.170
SE	Bottomland Hardwood	0.834	1.089	1.842
	Misc. Conifer	1.601	1.129	4.191
	Natural Pine	1.752	1.155	4.178
	Oak-Pine	1.642	1.117	4.195
	Planted Pine	1.470	1.036	4.141
	Upland Hardwood	1.903	1.191	4.182
	Nonstocked	4.033	4.033	4.182

^aPrediction of ratio of understory C to live tree C is based on the equation: $\text{Ratio} = \exp(A - B \cdot \ln(\text{tree_carbon_tph}))$, where "ratio" is the ratio of understory C density to live tree (above-and below- ground) C density, and "tree_carbon_density" is live tree (above-and below- ground) C density in Mg C/ha.

^bRegions and types as defined in Smith et al. (2003)

^cMaximum ratio: any estimate predicted from the equation that is greater than the maximum ratio is set equal to the maximum ratio.

Dead Wood

The standing dead tree C pools include aboveground and belowground (coarse root) mass. Estimates for standing dead tree C are not based on newly available FIA standing dead tree data because updated methodology is not yet available for integrating dead wood carbon estimates based on both older (which do not have consistent measurements of dead wood) and newer surveys. Instead, the estimates are based on a ratio of growing stock volume of live trees, stratified by region and forest type groups, applied at the FIA plot-level. The standing dead tree equations estimate mass; they are

converted to C mass by multiplying by 0.5. An example calculation for standing dead tree C in aspen-birch forests in the Northeast is:

$$\text{Dry weight of dead trees (Mg/ha)} = 1.0 \times (\text{growing stock volume})^{0.499}$$

It is multiplied by 0.5 to obtain Mg C/ha. All coefficients are provided in Table A-220. Note that nonstocked stands are assigned a constant C density (the value of Coefficient A).

Down dead wood is defined as pieces of dead wood greater than 7.5 cm diameter, at transect intersection, that are not attached to live or standing dead trees. Down dead wood includes stumps and roots of harvested trees. Ratio estimates of down dead wood to live tree biomass were developed using FORCARB2 simulations and applied at the plot level (Smith et al. 2004). Estimates for down dead wood correspond to the region and forest type classifications described in Smith et al. (2003). A full set of ratios is provided in Table A-221. An additional component of down dead wood is a regional average estimate of logging residue based on Smith et al. (2006) applied at the plot level. These are based on a regional average C density at age zero and first order decay; initial densities and decay coefficients are provided in Table A-222. These amounts are added to explicitly account for down dead wood following harvest. In practice, this modification resulted in minor changes to the estimates. Example calculations of the two components for down dead wood in 25-year-old aspen-birch forests in the Northeast are:

$$\text{C density (Mg C/ha)} = (\text{live tree C density, above- and below-ground}) \times (0.078) = 7.8\% \text{ of live tree C}$$

Conversion to C units is not necessary because the live tree value is already in terms of C.

$$\text{C density additional for logging residue (Mg C/ha)} = 13.9 \times e^{(-25/12.1)} = 1.8 \text{ (Mg C/ha)}$$

Table A-220: Coefficients for estimating standing dead tree carbon (MgC/ha) by region and forest type group^a

Region ^b	Forest type group ^c	Coefficient A	Coefficient B
MTN	Douglas-fir	3.935	0.312
	Fir/Spruce/Mt. Hemlock	4.550	0.358
	Hemlock/Sitka Spruce	1.000	0.569
	Lodgepole Pine	1.177	0.501
	Ponderosa Pine	1.000	0.455
	Nonstocked	12.855	--
MTS	Douglas-fir	2.200	0.460
	Fir/Spruce/Mt. Hemlock	6.923	0.293
	Lodgepole Pine	1.177	0.501
	Ponderosa Pine	1.944	0.292
	Nonstocked	4.232	--
NC	Aspen/Birch	1.962	0.400
	Elm/Ash/Cottonwood	3.755	0.253
	Maple/Beech/Birch	3.442	0.219
	Planted Pine	1.000	0.298
	Oak/Hickory	2.949	0.236
	Oak/Pine	1.364	0.394
	Spruce/Fir	1.320	0.472
	White/Red/Jack Pine	2.844	0.266
	Nonstocked	2.634	--
NE	Aspen/Birch	1.000	0.499
	Elm/Ash/Cottonwood	4.992	0.134
	Maple/Beech/Birch	3.041	0.306
	Oak/Hickory	3.332	0.191
	Oak/Pine	1.725	0.311
	Spruce/Fir	5.893	0.190
	White/Red/Jack Pine	2.841	0.254
	Nonstocked	2.876	--
PC	California Mixed Conifer	1.000	0.608
	Douglas-fir	1.237	0.559
	Douglas-fir Planted	10.145	0.112
	Fir/Spruce/Mt. Hemlock	4.235	0.415
	Hemlock/Sitka Spruce	1.546	0.562
	Redwood	5.385	0.287
	Nonstocked	7.377	--
SC	Elm/Ash/Cottonwood	2.393	0.284
	Loblolly/Shortleaf Pine	1.203	0.271

	Loblolly/Shortleaf Planted	1.000	0.138
	Oak/Gum/Cypress	4.234	0.121
	Oak/Hickory	2.396	0.186
	Oak/Pine	1.133	0.337
	Nonstocked	0.286	--
SE	Elm/Ash/Cottonwood	1.358	0.476
	Loblolly/Shortleaf Pine	1.000	0.324
	Loblolly/Shortleaf Planted	1.000	0.265
	Oak/Gum/Cypress	1.770	0.329
	Oak/Hickory	2.256	0.257
	Oak/Pine	1.000	0.351
	Nonstocked	0.349	--
South	Longleaf/Slash Pine	1.000	0.184
	Longleaf/Slash Planted	1.000	0.106
West	Alder/Maple	2.190	0.466
	Aspen/Birch	3.062	0.376
	Pinyon/Juniper	3.163	0.100
	Tanoak/Laurel	1.000	0.593
	Western Hardwood/Woodlands	5.595	0.181
	Western Larch	2.049	0.449
	Western Oak	1.996	0.348

^aStanding dead tree C is based on the equation: mass (Mg/ha) = A* (live-tree growing stock volume)^bB. Note that nonstocked stands are assigned a constant C density (the value listed under coefficient A). Note that the standing dead tree equations are for biomass. To convert to C mass, multiply by 0.5.

^bRegions are PC (CA,OR-West,WA-West), MTN (OR-East,WA-East,ID,MT), MTS (AZ,CO,NM,NV,UT,WY), West (regions PC, MTN, and MTS), NC (IA, IL, IN, KS, MI, MN, MO, ND, NE, SD, WI), NE (CT, DE, MA, MD, ME, NH, NJ, NY, OH, PA, RI, VT, WV), SC (AL, AR, KY, LA, MS, OK, TN, TX), SE (FL, GA, NC, SC, VA), and South (regions SC and SE).

^cForest types are described in FIADB documentation (USDA Forest Service, 2010d). Minor forest types within a region that are not explicitly defined/listed in the table of coefficients are assigned to a similar hardwood or softwood forest type.

Table A-221: Ratio for estimating down dead wood by region and forest type. The ratio is multiplied by the live tree carbon density on a plot to produce down dead wood carbon density (MgC/ha)

Region ^a	Forest type ^a	Ratio	Region (cont'd)	Forest type (cont'd)	Ratio (cont'd)
NE	Aspen-Birch	0.078	PWW	Douglas-fir	0.100
	MBB/Other Hardwood	0.071		Fir-Spruce	0.090
	Oak-Hickory	0.068		Other Conifer	0.073
	Oak-Pine	0.061		Other Hardwoods	0.062
	Other Pine	0.065		Red Alder	0.095
	Spruce-Fir	0.092		Western Hemlock	0.099
	White-Red-Jack Pine	0.055		Nonstocked	0.020
	Nonstocked	0.019			
NLS	Aspen-Birch	0.081	RMN	Douglas-fir	0.062
	Lowland Hardwood	0.061		Fir-Spruce	0.100
	Maple-Beech-Birch	0.076		Hardwoods	0.112
	Oak-Hickory	0.077		Lodgepole Pine	0.058
	Pine	0.072		Other Conifer	0.060
	Spruce-Fir	0.087		Pinyon-Juniper	0.030
	Nonstocked	0.027		Ponderosa Pine	0.087
				Nonstocked	0.018
NPS	Conifer	0.073	RMS	Douglas-fir	0.077
	Lowland Hardwood	0.069		Fir-Spruce	0.079
	Maple-Beech-Birch	0.063		Hardwoods	0.064
	Oak-Hickory	0.068		Lodgepole Pine	0.098
	Oak-Pine	0.069		Other Conifer	0.060
	Nonstocked	0.026		Pinyon-Juniper	0.030
PSW	Douglas-fir	0.091	SC	Ponderosa Pine	0.082
	Fir-Spruce	0.109		Nonstocked	0.020
	Hardwoods	0.042		Bottomland Hardwood	0.063
	Other Conifer	0.100		Misc. Conifer	0.068
	Pinyon-Juniper	0.031		Natural Pine	0.068
	Redwood	0.108		Oak-Pine	0.072
	Nonstocked	0.022		Planted Pine	0.077
PWE	Douglas-fir	0.103	SE	Upland Hardwood	0.067
	Fir-Spruce	0.106		Nonstocked	0.013
	Hardwoods	0.027		Bottomland Hardwood	0.064

Lodgepole Pine	0.093	Misc. Conifer	0.081
Pinyon-Juniper	0.032	Natural Pine	0.081
Ponderosa Pine	0.103	Oak-Pine	0.063
Nonstocked	0.024	Planted Pine	0.075
		Upland Hardwood	0.059
		Nonstocked	0.012

^a Regions and types as defined in Smith et al. (2003).

Table A-222: Coefficients for estimating logging residue component of down dead wood.

Region ^a	Forest Type Group ^b (softwood/hardwood)	Initial Carbon	Decay Coefficient
		Density (Mg/ha)	
Alaska	hardwood	6.9	12.1
Alaska	softwood	8.6	32.3
NE	hardwood	13.9	12.1
NE	softwood	12.1	17.9
NLS	hardwood	9.1	12.1
NLS	softwood	7.2	17.9
NPS	hardwood	9.6	12.1
NPS	softwood	6.4	17.9
PSW	hardwood	9.8	12.1
PSW	softwood	17.5	32.3
PWE	hardwood	3.3	12.1
PWE	softwood	9.5	32.3
PWW	hardwood	18.1	12.1
PWW	softwood	23.6	32.3
RMN	hardwood	7.2	43.5
RMN	softwood	9.0	18.1
RMS	hardwood	5.1	43.5
RMS	softwood	3.7	18.1
SC	hardwood	4.2	8.9
SC	softwood	5.5	17.9
SE	hardwood	6.4	8.9
SE	softwood	7.3	17.9

^a Regions are defined in Smith et al. (2003) with the addition of coastal Alaska.

^b Forest types are according to majority hardwood or softwood species.

Litter carbon

C of the litter layer is currently sampled on a subset of the FIA plots. However, these data are not yet available electronically for general application to all inventories in Table A-1. Litter C is the pool of organic C (including material known as duff, humus, and fine woody debris) above the mineral soil and includes woody fragments with diameters of up to 7.5 cm. Estimates therefore continue to be based on equations of Smith and Heath (2002) and applied at the plot level. The equations describe processes for decay or loss of forest floor following harvest and the net accumulation of new forest floor material following stand growth. For example, total forest floor C at a given number of years after a clearcut harvest for aspen-birch forests in the North is:

$$\text{Total forest floor C (Mg C/ha)} = (18.4 \times \text{years}) / (53.7 + \text{years}) + 10.2 \times e^{(-\text{years}/9.2)}$$

See Table 4 of Smith and Heath (2002) for the complete set of coefficients. Note that these are direct estimates of C density; the 0.5 conversion does not apply to litter.

Soil organic carbon

Soil organic carbon (SOC) is currently sampled to a 20 cm depth on subsets of FIA plots, however, these data are not available for the entire United States. Thus, estimates of SOC are based on the national STATSGO spatial database (USDA 1991), and the general approach described by Amichev and Galbraith (2004). In their procedure, SOC was calculated for the conterminous United States using the STATSGO database, and data gaps were filled by representative values from similar soils. Links to region and forest type groups were developed with the assistance of the USDA Forest Service FIA Geospatial Service Center by overlaying FIA forest inventory plots on the soil C map. The average SOC densities are provided in Table A-216.

Carbon in Harvested Wood Products

Estimates of the harvested wood product (HWP) contribution to forest C sinks and emissions (hereafter called “HWP Contribution”) are based on methods described in Skog (2008) using the WOODCARB II model. These methods are based on IPCC (2006) guidance for estimating HWP carbon. The 2006 IPCC Guidelines provide methods that allow Parties to report HWP Contribution using one of several different accounting approaches: production, stock change, and atmospheric flow, as well as a default method. The various approaches are described below. The approaches differ in how HWP Contribution is allocated based on production or consumption as well as what processes (atmospheric fluxes or stock changes) are emphasized.

- **Production approach:** Accounts for the net changes in carbon stocks in forests and in the wood products pool, but attributes both to the producing country.
- **Stock change approach:** Accounts for changes in the product pool within the boundaries of the consuming country.
- **Atmospheric flow approach:** Accounts for net emissions or removals of carbon to and from the atmosphere within national boundaries. C removal due to forest growth is accounted for in the producing country while C emissions to the atmosphere from oxidation of wood products are accounted for in the consuming country.
- **Default approach:** Assumes no change in C stocks in HWP. IPCC (2006) requests that such an assumption be justified if this is how a Party is choosing to report.

The United States uses the production accounting approach (as in previous years) to report HWP Contribution (Table A-223). Though reported U.S. HWP estimates are based on the production approach, estimates resulting from use of the two alternative approaches—the stock change and atmospheric flow approaches—are also presented for comparison (see Table A-224). Annual estimates of change are calculated by tracking the additions to and removals from the pool of products held in end uses (i.e., products in use such as housing or publications) and the pool of products held in solid waste disposal sites (SWDS).

Estimates of five HWP variables that can be used to calculate HWP contribution for the stock change and atmospheric flow approaches for imports and exports are provided in Table A-223. The HWP variables estimated are:

- (1A) annual change of C in wood and paper products in use in the United States,
- (1B) annual change of C in wood and paper products in SWDS in the United States,
- (2A) annual change of C in wood and paper products in use in the United States and other countries where the wood came from trees harvested in the United States,
- (2B) annual change of C in wood and paper products in SWDS in the United States and other countries where the wood came from trees harvested in the United States,
- (3) C in imports of wood, pulp, and paper to the United States,
- (4) C in exports of wood, pulp and paper from the United States, and
- (5) C in annual harvest of wood from forests in the United States.

Table A-223: Harvested wood products from wood harvested in United States—Annual additions of carbon to stocks and total stocks

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Net carbon additions per year (Tg C per year)																					
Total Harvested wood carbon	(35.9)	(33.8)	(33.8)	(32.9)	(33.4)	(32.3)	(30.6)	(32.0)	(31.1)	(32.5)	(30.8)	(25.5)	(26.8)	(25.9)	(28.7)	(28.7)	(29.6)	(28.1)	(22.4)	(14.8)	
Products in use	(17.7)	(14.9)	(16.3)	(15.0)	(15.9)	(15.1)	(14.1)	(14.7)	(13.4)	(14.1)	(12.8)	(8.7)	(9.6)	(9.7)	(12.4)	(12.4)	(12.3)	(10.7)	(5.2)	1.9	
Solid wood products	(14.4)	(11.9)	(12.6)	(12.2)	(12.1)	(11.2)	(11.5)	(11.8)	(11.4)	(12.1)	(11.9)	(10.1)	(10.7)	(10.1)	(11.6)	(11.9)	(10.6)	(8.7)	(4.4)	0.6	
Paper products	(3.3)	(3.1)	(3.7)	(2.8)	(3.8)	(3.8)	(2.6)	(3.0)	(2.0)	(2.0)	(1.0)	1.4	1.1	0.4	(0.8)	(0.5)	(1.7)	(2.0)	(0.8)	1.3	
Products in SWDS	(18.3)	(18.8)	(17.4)	(17.9)	(17.5)	(17.2)	(16.5)	(17.3)	(17.7)	(18.4)	(18.0)	(16.8)	(17.2)	(16.2)	(16.3)	(16.3)	(17.3)	(17.4)	(17.2)	(16.7)	
Solid wood products	(9.9)	(11.1)	(9.5)	(9.7)	(9.8)	(10.7)	(10.6)	(10.3)	(10.2)	(10.6)	(10.7)	(10.7)	(11.1)	(11.1)	(11.3)	(11.5)	(11.6)	(11.7)	(11.5)	(11.2)	
Paper products	(8.3)	(7.7)	(7.9)	(8.3)	(7.7)	(6.5)	(6.0)	(6.9)	(7.5)	(7.8)	(7.3)	(6.0)	(6.1)	(5.1)	(5.0)	(4.8)	(5.7)	(5.7)	(5.7)	(5.4)	
Total Carbon stocks (Tg C)																					
Total Harvested wood carbon	1,859	1,895	1,929	1,963	1,996	2,029	2,061	2,092	2,124	2,155	2,187	2,218	2,244	2,271	2,296	2,325	2,354	2,383	2,412	2,434	2,449
Products in use	1,231	1,249	1,264	1,280	1,295	1,311	1,326	1,340	1,355	1,368	1,382	1,395	1,404	1,413	1,423	1,436	1,448	1,460	1,471	1,476	1,474
Products in SWDS	628	646	665	683	701	718	735	752	769	787	805	823	840	857	873	890	906	923	941	958	974

Note: Parentheses indicate net C sequestration (i.e., a net removal of C from the atmosphere).

Table A-224: Comparison of Net Annual Change in Harvested Wood Products Carbon Stocks Using Alternative Accounting Approaches

HWP Contribution to LULUCF Emissions/ removals (Tg CO ₂ Eq.)			
Inventory Year	Stock Change Approach	Atmospheric Flow Approach	Production Approach
1990	(129.6)	(138.4)	(131.8)
1991	(116.3)	(131.4)	(123.8)
1992	(120.0)	(131.6)	(123.8)
1993	(126.8)	(127.8)	(120.7)
1994	(130.0)	(129.9)	(122.5)
1995	(126.0)	(128.0)	(118.4)
1996	(122.3)	(122.5)	(112.2)
1997	(131.4)	(127.4)	(117.3)
1998	(139.8)	(122.7)	(114.1)
1999	(149.4)	(127.3)	(119.1)
2000	(143.2)	(120.3)	(112.9)
2001	(128.3)	(100.3)	(93.4)
2002	(135.6)	(103.1)	(98.2)
2003	(134.6)	(99.2)	(94.8)
2004	(163.0)	(109.1)	(105.3)
2005	(161.4)	(109.0)	(105.4)
2006	(138.6)	(114.2)	(108.6)
2007	(115.4)	(112.1)	(103.0)

2008	(78.4)	(94.3)	(82.1)
2009	(41.9)	(68.3)	(54.3)

Note: Parentheses indicate net C sequestration (i.e., a net removal of C from the atmosphere).

Table A-225: Harvested Wood Products Sectoral Background Data for LULUCF—United States (production approach)

Inventory year	1A Annual Change in stock of HWP in use from consumption	1B Annual Change in stock of HWP in SWDS from consumption	2A Annual Change in stock of HWP in use produced from domestic harvest	2B Annual Change in stock of HWP in SWDS produced from domestic harvest	3 Annual Imports of wood, and paper products + wood fuel, pulp, recovered paper, roundwood/ chips	4 Annual Exports of wood, and paper products + wood fuel, pulp, recovered paper, roundwood/ chips	5 Annual Domestic Harvest	6 Annual release of carbon to the atmosphere from HWP consumption (from fuelwood & products in use and products in SWDS)	7 Annual release of carbon to the atmosphere from HWP (including firewood) where wood came from domestic harvest (from products in use and products in SWDS)	8 HWP Contribution to AFOLU CO ₂ emissions/removals
	$\Delta C_{HWP\ IU\ DC}$	$\Delta C_{HWP\ SWDS\ DC}$	$\Delta C_{HWP\ IU\ DH}$	$\Delta C_{HWP\ SWDS\ DH}$	P_{IM}	P_{EX}	H	$\uparrow C_{HWP\ DC}$	$\uparrow C_{HWP\ DH}$	
									Gg C /yr	Gg CO ₂ /yr
1990	17,044	18,308	17,659	18,278	12,680	15,078	142,297	104,547	106,359	(131,772)
1991	13,129	18,602	14,940	18,812	11,552	15,667	144,435	108,588	110,682	(123,758)
1992	15,718	17,006	16,334	17,427	12,856	16,032	139,389	103,489	105,627	(123,791)
1993	16,957	17,627	14,971	17,949	14,512	14,788	134,554	99,694	101,633	(120,708)
1994	18,221	17,221	15,930	17,479	15,685	15,665	134,750	99,328	101,342	(122,498)
1995	17,307	17,051	15,065	17,229	16,712	17,266	137,027	102,115	104,733	(118,411)
1996	17,018	16,348	14,092	16,513	16,691	16,733	134,477	101,069	103,872	(112,219)
1997	18,756	17,090	14,740	17,263	17,983	16,877	135,439	100,699	103,436	(117,344)
1998	20,311	17,818	13,376	17,735	19,722	15,057	135,021	101,558	103,911	(114,071)
1999	22,035	18,714	14,123	18,353	21,266	15,245	134,939	100,211	102,464	(119,078)
2000	20,491	18,560	12,828	17,962	22,426	16,185	134,458	101,648	103,667	(112,898)
2001	17,295	17,691	8,711	16,774	22,975	15,336	128,621	101,274	103,136	(93,447)
2002	18,629	18,357	9,570	17,207	24,604	15,744	127,567	99,441	100,791	(98,179)
2003	19,180	17,532	9,676	16,186	25,962	16,303	124,949	97,896	99,086	(94,828)
2004	26,384	18,077	12,429	16,298	31,650	16,948	130,460	100,700	101,733	(105,332)
2005	25,777	18,249	12,394	16,347	31,714	17,423	131,711	101,976	102,971	(105,382)
2006	19,010	18,780	12,308	17,302	25,485	18,836	127,064	95,922	97,454	(108,567)
2007	12,999	18,497	10,673	17,409	21,603	20,670	120,922	90,360	92,840	(102,967)
2008	3,589	17,786	5,203	17,188	16,822	21,156	108,339	82,630	85,948	(82,101)
2009	(5,401)	16,825	(1,857)	16,652	13,281	20,485	95,130	76,501	80,334	(54,250)

Note: $\uparrow C_{HWP\ DC} = H + P_{IM} - P_{EX} - \Delta C_{HWP\ IU\ DC} - \Delta C_{HWP\ SWDS\ DC}$ AND $\uparrow C_{HWP\ DH} = H - \Delta C_{HWP\ IU\ DH} - \Delta C_{HWP\ SWDS\ DH}$. Parentheses indicate net C sequestration (i.e., a net removal of C from the atmosphere).

Annual estimates of variables 1A, 1B, 2A and 2B were calculated by tracking the additions to and removals from the pool of products held in end uses (e.g., products in uses such as housing or publications) and the pool of products held in SWDS. In the case of variables 2A and 2B, the pools include products exported and held in other countries and the pools in the United States exclude products made from wood harvested in other countries. Solidwood products added to pools include lumber and panels. End-use categories for solidwood include single and multifamily housing, alteration and repair of housing, and other end uses. There is one product category and one end-use category for paper. Additions to and removals from pools are tracked beginning in 1900, with the exception that additions of softwood lumber to housing begins in 1800. Solidwood and paper product production and trade data are from USDA Forest Service and other sources (Hair and Ulrich 1963; Hair 1958; USDC Bureau of Census 1976; Ulrich, 1985, 1989; Steer 1948; AF&PA 2006a, 2006b; Howard 2003).

The rate of removals from products in use and the rate of decay of products in SWDS are specified by first order (exponential) decay curves with given half-lives (time at which half of amount placed in use will have been discarded from use). Half-lives for products in use, determined after calibration of the model to meet two criteria, are shown in Table A-226. The first criterion is that the WOODCARB II model estimate of C in houses standing in 2001 needed to match an independent estimate of C in housing based on U.S. Census and USDA Forest Service survey data. The second criterion is that the WOODCARB II model estimate of wood and paper being discarded to SWDS needed to match EPA estimates of discards over the period 1990 to 2000. This calibration strongly influences the estimate of variable 1A, and to a lesser extent variable 2A. The calibration also determines the amounts going to SWDS. In addition, WOODCARB II landfill decay rates have been validated by making sure that estimates of methane emissions from landfills based on EPA data are reasonable in comparison to methane estimates based on WOODCARB II landfill decay rates.

Decay parameters for products in SWDS are shown in Table A-227. Estimates of 1B and 2B also reflect the change over time in the fraction of products discarded to SWDS (versus burning or recycling) and the fraction of SWDS that are sanitary landfills versus dumps.

Variables 2A and 2B are used to estimate HWP contribution under the production accounting approach. A key assumption for estimating these variables is that products exported from the United States and held in pools in other countries have the same half lives for products in use, the same percentage of discarded products going to SWDS, and the same decay rates in SWDS. Summaries of net fluxes and stocks for harvested wood in products and SWDS are in Table A-213 and Table A-214. The decline in net additions to HWP carbon stocks continued though 2009 from the recent high point in 2006. This is due to sharp declines in U.S. production of solidwood and paper products in 2009 primarily due to the decline in housing construction. The low level of gross additions to solidwood and paper products in use in 2009 was exceeded by discards from uses. The result is a net reduction in the amount of HWP carbon that is held in products in use during 2009. For 2009 additions to landfills still exceeded emissions from landfills and the net additions to landfills have remained relatively stable. Overall, there were net carbon additions to HWP in use and in landfills combined.

Table A-226: Half-life of solidwood and paper products in end uses

Parameter	Value	Units
Half life of wood in single family housing 1920 and before	78.0	Years
Half life of wood in single family housing 1920–1939	78.0	Years
Half life of wood in single family housing 1940–1959	80.0	Years
Half life of wood in single family housing 1960–1979	81.9	Years
Half life of wood in single family housing 1980 +	83.9	Years
Ratio of multifamily half live to single family half life	0.61	
Ratio of repair and alterations half life to single family half life	0.30	
Half life for other solidwood product in end uses	38.0	Years
Half life of paper in end uses	2.54	Years

Source: Skog, K.E. (2008) "Sequestration of carbon in harvested wood products for the United States." *Forest Products Journal* 58:56-72.

Table A-227: Parameters determining decay of wood and paper in SWDS

Parameter	Value	Units
Percentage of wood and paper in dumps that is subject to decay	100%	
Percentage of wood in landfills that is subject to decay	23%	
Percentage of paper in landfills that is subject to decay	56%	
Half life of wood in landfills / dumps (portion subject to decay)	29	Years
Half life of paper in landfills/ dumps (portion subject to decay)	14.5	Years

Source: Skog, K.E. (2008) "Sequestration of carbon in harvested wood products for the United States." *Forest Products Journal* 58:56-72

Uncertainty Analysis

The uncertainty analyses for total net flux of forest C (see uncertainty table in LULUCF chapter) are consistent with the IPCC-recommended Tier 2 methodology (IPCC 2006). Separate analyses are produced for forest ecosystem and HWP flux. The uncertainty estimates are from Monte Carlo simulations of the respective models and input data. Methods generally follow those described in Heath and Smith (2000), Smith and Heath (2000), and Skog et al. (2004). Uncertainties surrounding input data or model processes are quantified as probability distribution functions (PDFs), so that a series of sample values can be randomly selected from the distributions. Model simulations are repeated a large number of times to numerically simulate the effect of the random PDF selections on estimated total C flux. The separate results from the ecosystem and HWP simulations are pooled for total uncertainty (see uncertainty table in LULUCF chapter).

Uncertainty surrounding current net C flux in forest ecosystems is based on the value for 2007 as obtained from the Monte Carlo simulation. C stocks are based on forest condition level (plot-level) calculations, and, therefore, uncertainty analysis starts probabilistic sampling at the plot level. Uncertainty surrounding C density (Mg/ha) is defined for each of six C pools for each inventory plot. Live trees are generally assigned normal PDFs, which are defined according to variability information in Jenkins et al. (2003) and the species and number of trees measured on each FIA plot. Plot-level live tree C estimates from RPA data are based on volume; these PDFs also include an additional level of uncertainty based on their respective regression equations. Similarly, the normally-distributed PDFs for standing dead trees are based on both volume regression and the individual-tree uncertainties related to the Jenkins et al. (2003) based estimates. Definitions of these normal distributions, which centered on expected values, depend on region, type, and specific plot information. Where data gaps—tree or volume—are identified for older inventory data, corresponding averages from later data are applied for live and standing dead tree C densities. Uniform PDFs with a range of ± 90 percent of the average are used for these plots.

Distributions for the remaining C pools are triangular or uniform, which partly reflects the lower level of information available about these estimates. Down dead wood, understory, and litter are assigned triangular distributions with the mean at the expected value for each plot and the minimum and mode at 10 percent of the expected value. The use of these PDFs skewed to the right reflects the assumption that a small proportion of plots will have relatively high C densities. Joint sampling of PDFs is specified for two pairs of samples: understory PDF sampling is slightly negatively correlated with live tree PDF sampling, and down dead wood sampling is slightly positively correlated with live tree sampling. This also reflects the structure of the estimates, which are dependent on live tree C. Soil organic C is defined as a uniform PDF at ± 50 percent of the mean. Sub-state or state total carbon stocks associated with each survey are the cumulative sum of random samples from the plot-level PDFs, which are then appropriately expanded to population estimates. These expected values for each carbon pool include uncertainty associated with sampling, which is also incorporated in the Monte Carlo simulation. Sampling errors are determined according to methods described for the FIADB (Bechtold and Patterson 2005), are normally distributed, and are assigned a slight positive correlation between successive surveys for Monte Carlo sampling. More recent annual inventories are assigned higher sampling correlation between successive surveys based on the proportion of plot data jointly included in each. Errors for older inventory data are not available, and these surveys are assigned values consistent with those obtained from the FIADB.

Uncertainty about net C flux in HWP is based on Skog et al. (2004) and Skog (2008). Latin hypercube sampling is the basis for the HWP Monte Carlo simulation. Estimates of the HWP variables and HWP Contribution under the production approach are subject to many sources of uncertainty. An estimate of uncertainty is provided that evaluated the effect of uncertainty in 13 sources, including production and trade data and parameters used to make the estimate. Uncertain data and parameters include data on production and trade and factors to convert them to C, the Census-based estimate of C in housing in 2001, the EPA estimate of wood and paper discarded to SWDS for 1990 to 2000, the limits on decay of wood and paper in SWDS, the decay rate (half-life) of wood and paper in SWDS, the proportion of products produced in the United States made with wood harvested in the United States, and the rate of storage of wood and paper C in other countries that came from United States harvest, compared to storage in the United States.

A total of ten thousand samples are drawn from the PDF input to separately determine uncertainties about forest ecosystem and HWP flux before they are combined for a quantitative estimate of total forest carbon uncertainty (see uncertainty table in LULUCF chapter). Again this year, true Monte Carlo sampling is used for the forest ecosystem estimates (in contrast to Latin hypercube sampling, which was used in some previous estimates), and a part of the QA/QC process includes verifying that the PDFs are adequately sampled.

Emissions from fires

CO₂

As stated in other sections, the forest inventory approach implicitly accounts for emissions due to disturbances. Net C stock change is estimated by subtracting consecutive C stock estimates. A disturbance removes C from the forest. The inventory data, on which net C stock estimates are based, already reflects the C loss because only C remaining in the forest is estimated. Estimating the CO₂ emissions from a disturbance such as fire and adding those emissions to the net CO₂ change in forests would result in double-counting the loss from fire because the inventory data already reflect the loss. There is interest, however, in the size of the CO₂ emissions from disturbances such as fire. The IPCC (2003) methodology and IPCC (2006) default combustion factor for wildfire were employed to estimate emissions from forest fires.

The same methodology was used to estimate emissions from both wildfires and prescribed fires occurring in the lower 48 states. Wildfire area statistics are available, but they include non-forest land, such as shrublands and grasslands. It was thus necessary to develop a rudimentary estimate of the percent of area burned in forest by multiplying the reported area burned by a ratio of total forest land area to the total area considered to be under protection from fire. Data on total area of forest land were obtained from FIA (USDA Forest Service 2010b). Data on “total area considered to be under protection from fire” were available at the state level and obtained for the year 1990 from 1984-1990 Wildfire Statistics prepared by the U.S. Forest Service (USDA Forest Service 1992). Data for years 1998, 2002, 2004, and 2006 were obtained from the National Association of State Foresters (NASF 2008, 2007a, 2007b, 2007c). For states where data were available for all four years, the 1990 value was assumed for years 1990 to 1994, values for 1998 were assumed for years 1995 to 1998, values for 2002 were assumed for years 1999 to 2002, values for 2004 were assumed for years 2003 and 2004, and values for 2006 were assumed for years 2005 to 2009. For states where data were available for all years except 2002, 2004 data were assumed for years 1999 to 2004. For states where data were available for all years except 2004, 2006 data were assumed for 2003 through 2008. For years where data were available for all years except 2006, 2004 data were assumed for years 2003 to 2008. Since no 1998 value was available for Alaska, the 1990 value was assumed for years 1990 to 1997, the 2002 value was assumed for years 1998 to 2002, and the 2004 value was assumed for years 2003 and 2005 to 2009. Data for 1990, 1998, and 2006 were available for New Mexico, so the 1990 value was assumed for years 1990-1995, while the 1998 value was assumed for year 1996 through 2001, and 2006 data were assumed for all remaining years. Data for 1990, 1998, and 2002 were available for Illinois, so the 1990 value was assumed for years 1990-1995, while the 1998 value was assumed for years 1995 through 2001, and the 2002 value was assumed for all remaining years. Total forestland area for the lower 48 states was divided by total area considered to be under protection from wildfire for the lower 48 states across the 1990 to 2009 time series to create ratios that were then applied to reported area burned to estimate the area of forestland burned for the lower 48 states. The ratio was applied to area burned from wildland fires and prescribed fires occurring in the lower 48 states. Reported area burned data for prescribed fires was available from 1998 to 2009 from the National Interagency Fire Center (NIFC 2010). Data for the year 1998 was assumed for years 1990 to 1997.

Forest area burned data for Alaska are from the Alaska Department of Natural Resources (Alaska Department of Natural Resources 2008) or the Alaska Interagency Coordination Center (Alaska Interagency Coordination Center 2010). Data are acres of land which experienced fire activity on forest service land. Based on personal communication with USFS, forest areas under the protection of USFS serve as a proxy for coastal areas, which is where the majority of forest fires in Alaska occur (Heath 2008). According to expert judgment, the coastal area of Alaska included in this Inventory is mostly temperate rainforest and, therefore, there is little call for prescribed burns (Smith 2008a). It was, thus, assumed that reported area burned for prescribed fires covers only prescribed fires in the lower 48 states.

The average C density in the lower 48 states for aboveground biomass C, dead wood C, and litter layer is 91 Mg/ha, according to data from FIA. A default value of 0.45 from IPCC (2006) was assumed for the amount of biomass burned by wildfire (combustion factor value). Thus, approximately 41.0 Mg C/ha is estimated to be emitted by wildfire. For Alaska, an average C density of 179 Mg/ha was used based on data from FIA; this translates into 80.6 Mg C/ha emitted. Based on data from the U.S. Forest Service, a value of 30 Mg/ha was used as the average C density for prescribed fires, where the average C density is adjusted to reflect the fuel load included in dead wood and litter only and the thought that prescribed fires only occur in the lower 48 states (Smith 2008a). Thus, prescribed fires are estimated to emit 13.5 Mg C/ha. Estimates for Mg C/ha were multiplied by estimates of forest area burned by year; the resulting estimates are displayed in Table A-228. C estimates were multiplied by 92.8 percent to account for the proportion of carbon emitted as CO₂ and by 3.67 to yield CO₂ units. Total CO₂ emissions for wildfires and prescribed fires in the lower 48 states and wildfires in Alaska in 2009 were estimated to be 127.0 Tg/yr.

Table A-228: Areas (hectares) from wildfire statistics and corresponding estimates of carbon and CO₂ (Tg/yr) emissions for wildfires and prescribed fires in the lower 48 states and wildfires in Alaska¹

Year	Lower 48 States								Alaska			
	Wildfires				Prescribed Fires				Wildfires			
	Reported area burned ² (ha)	Forest area burned ³ (ha)	Carbon emitted (Tg/yr)	CO ₂ emitted (Tg/yr)	Reported area burned ² (ha)	Forest area burned ³ (ha)	Carbon emitted (Tg/yr)	CO ₂ emitted (Tg/yr)	Forest area burned ⁴ (acres)	Forest area burned (ha)	Carbon emitted (Tg/yr)	CO ₂ emitted (Tg/yr)
1990	579,589	302,372	12	42	355,432	185,429	3	9	8	3	0.0003	0.0009
1991	486,807	254,618	10	35	355,432	185,904	3	9	557	225	0.0182	0.0618
1992	785,892	412,111	17	57	355,432	186,384	3	9	47	19	0.0015	0.0052
1993	438,865	230,704	9	32	355,432	186,845	3	9	110	45	0.0036	0.0122
1994	1,540,987	811,927	33	113	355,432	187,273	3	9	23	9	0.0007	0.0025
1995	727,051	418,819	17	58	355,432	204,747	3	9	7	3	0.0002	0.0008
1996	2,212,309	1,313,377	54	183	355,432	211,008	3	10	103	42	0.0034	0.0115
1997	335,914	199,827	8	28	355,432	211,437	3	10	33	13	0.0011	0.0036
1998	489,246	291,647	12	41	355,432	211,878	3	10	2	1	0.0001	0.0002
1999	1,869,918	1,123,023	46	156	806,780	484,530	7	22	7	3	0.0002	0.0007
2000	2,685,981	1,615,551	66	225	77,789	46,788	1	2	1	1	0.0000	0.0001
2001	1,356,830	817,280	33	114	667,428	402,022	5	18	2,078	841	0.0677	0.2305
2002	2,023,976	1,217,243	50	170	1,086,503	653,436	9	30	28	11	0.0009	0.0031
2003	1,358,986	718,172	29	100	1,147,695	606,513	8	28	17	7	0.0006	0.0019
2004	637,258	342,999	14	48	996,453	536,332	7	25	23	9	0.0008	0.0026
2005	1,629,067	940,471	39	131	934,965	539,761	7	25	353	143	0.0115	0.0392
2006	3,888,011	2,250,696	92	314	1,100,966	637,328	9	29	8	3	0.0003	0.0009
2007	3,512,122	2,038,630	83	284	1,274,383	739,723	10	34	2	1	0.0001	0.0002
2008	2,099,842	1,212,446	50	169	783,068	452,142	6	21	1	0	0.0000	0.0001
2009	1,201,996	711,766	29	99	1,024,306	606,547	8	28	22	9	0.0007	0.0024

¹ Note that these emissions have already been accounted for in the estimates of net annual changes in carbon stocks, which accounts for the amount sequestered minus any emissions, including the assumption that combusted wood may continue to decay through time.

² National Interagency Fire Center (2010).

³ Ratios calculated using forest land area estimates from FIA (USDA Forest Service 2010b) and wildland area under protection estimates from USDA Forest Service (1992) and the National Association of State Foresters (2007).

⁴ 1990–2007 Alaskan forest fires data are from the Alaska Department of Natural Resources (2008). 2008 data are from Alaska Interagency Coordination Center (2009).

Non-CO₂

Emissions of non-CO₂ gases from forest fires were estimated using the default IPCC (2003) methodology, IPCC (2006) emission ratios, and default IPCC (2006) combustion factor for wildfires. Emissions estimates for CH₄ and N₂O are calculated by multiplying the total estimated CO₂ emitted from forest burned by gas-specific emissions ratios and conversion factors. The equations used are:

$$\text{CH}_4 \text{ Emissions} = (\text{CO}_2 \text{ released}) \times 92.8\% \times (44/12) \times (\text{CH}_4 \text{ to CO}_2 \text{ emission ratio})$$

$$\text{N}_2\text{O Emissions} = (\text{CO}_2 \text{ released}) \times 92.8\% \times (44/12) \times (\text{N}_2\text{O to CO}_2 \text{ emission ratio})$$

The resulting estimates are presented in Table A-229.

Table A-229: Estimated carbon released and estimates of non-CO₂ emissions (Tg/yr) for U.S. forests¹

Year	C emitted (Tg/yr)	CH ₄ emitted (Tg/yr)	N ₂ O (Tg/yr)
1990	14.886	0.152	0.008
1991	12.954	0.132	0.007
1992	19.394	0.198	0.011
1993	11.973	0.122	0.007
1994	35.777	0.365	0.020
1995	19.915	0.203	0.011
1996	56.635	0.577	0.032
1997	11.038	0.113	0.006
1998	14.803	0.151	0.008
1999	52.529	0.535	0.030
2000	66.789	0.681	0.038
2001	38.963	0.397	0.022
2002	58.668	0.598	0.033
2003	37.598	0.383	0.021

2004	21.287	0.217	0.012
2005	45.811	0.467	0.026
2006	100.770	1.027	0.057
2007	93.468	0.953	0.053
2008	55.754	0.568	0.031
2009	37.336	0.381	0.021

[†] Calculated based on C emission estimates in Table A-228 and default factors in IPCC (2003, 2006)

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3.13. Methodology for Estimating Net Changes in Carbon Stocks in Mineral and Organic Soils on Cropland and Grassland

This sub-annex describes the methodologies used to calculate annual carbon (C) stock changes from mineral and organic soils under agricultural management, including *Cropland Remaining Cropland*, *Land Converted to Cropland*, *Grassland Remaining Grassland*, and *Land Converted to Grassland*. Three types of methodologies were applied: (1) a Tier 3 approach, employing the Century simulation model, (2) Tier 2 methods with country-specific stock change and emission factors; and (3) Tier 2 methods for estimating additional changes in mineral soil C stocks due to sewage sludge additions to soils and enrollment changes in the Conservation Reserve Program (CRP) after 2003.

The Inventory uses a Tier 3 approach to estimate soil C stock changes for the majority of agricultural lands. This approach has several advantages over the IPCC Tier 1 or 2 approaches:

- It utilizes actual weather data at county scales, rather than a broad climate region classification, enabling quantification of inter-annual variability in C fluxes at finer spatial scales;
- The model uses a more detailed characterization of spatially-mapped soil properties that influence soil C dynamics, as opposed to the broad soil taxonomic classifications of the IPCC methodology;
- The simulation approach provides a more detailed representation of management influences and their interactions than are represented by a discrete factor-based approach in the Tier 1 and 2 methods; and
- Soil C changes are estimated on a more continuous basis (monthly) as a function of the interaction of climate, soil, and land management, compared with the linear change between the start and end of the inventory that is used with the Tier 1 and 2 methods.

The Century model was chosen as an appropriate tool for a Tier 3 approach based on several criteria:

- The model was developed in the United States and has been extensively tested and verified for U.S. conditions. In addition, the model has been widely used by researchers and agencies in many other parts of the world for simulating soil C dynamics at local, regional and national scales (e.g., Brazil, Canada, India, Jordan, Kenya, Mexico).
- The model is capable of simulating cropland, grassland, forest, and savanna ecosystems, and land-use transitions between these different land uses. It is, thus, well suited to model land-use change effects.
- The model was designed to simulate all major types of management practices that influence soil C dynamics, with the exception of cultivated organic soils and a few crops that have not been parameterized for Century simulations (e.g., rice, perennial/horticultural crops, and tobacco). For these latter cases, an IPCC Tier 2 method has been used.
- Much of the data needed for the model was obtainable from existing national databases. The exceptions are CRP enrollment after 2003 and sewage sludge amendments to soils, which are not known at a sufficient resolution to use the Tier 3 model. Soil C stock changes associated with these practices are addressed with a Tier 2 method.

Century Model Description

The Century model simulates C (and also N, P, and S) dynamics, soil temperature, and water dynamics for cropland, grassland, forest, and savanna (mixed forest-grassland) systems. For this analysis, only C and N dynamics have been included for several reasons: to simplify the analysis and reduce data requirements, and because P and S interactions are less important as determinants of land-use- and management-induced changes in soil C stocks for U.S. agricultural systems.

The model has four main components: (1) soil organic matter and nutrient dynamics; (2) plant growth processes; (3) water and temperature dynamics; and (4) management practices. The model was designed to work with readily available input data: monthly weather data (e.g., temperature and precipitation); soil physical properties (e.g., soil texture, drainage condition, rooting depth); and information about land use/land cover (e.g., vegetation attributes) and management activities (see below). The model operates on a monthly time step (with weekly time steps used for soil water dynamics).

Dynamics of organic C and N (Figure A-13) are simulated for the surface and subsurface litter pools and the top 20 cm of the soil profile; mineral N dynamics are simulated through the whole soil profile. Organic C and N stocks are represented by two plant litter pools (labelled metabolic and structural) and three soil organic matter (SOM) pools (labelled active, slow, and passive). The metabolic litter pool represents the easily decomposable constituents of plant residues, while the structural litter pool is composed of more recalcitrant, ligno-cellulose plant materials. The three SOM pools represent a gradient in decomposability, from active SOM (representing microbial biomass and associated

metabolites) having a rapid turnover (months to years), to passive SOM (representing highly processed, humified, condensed decomposition products), which is highly recalcitrant, with mean residence times on the order of several hundred years. The slow pool represents decomposition products of intermediate stability, having a mean residence time on the order of decades and is the fraction that tends to change the most in terms of C content in response to changes in land use and management. Soil texture influences turnover rates of the slow and passive pools. The clay and silt-sized mineral fraction of the soil provides physical protection from microbial attack, leading to slower decomposition and greater SOM stabilization in finely textured soils. Soil temperature and moisture, tillage disturbance, aeration, and other factors influence the decomposition and loss of C from the soil organic matter pools.

Figure A-13: Flow diagram of Carbon submodel (A) and Nitrogen submodel (B)

The plant-growth submodel simulates C assimilation through photosynthesis, N uptake, dry matter production, partitioning of C within the crop or forage, senescence, and mortality. The primary function of the growth submodel is to estimate the amount, type, and timing of organic matter inputs to soil and to represent the influence of the plant on soil water, temperature, and N balance. Yield and removal of harvested biomass are also simulated. Separate submodels are designed to simulate herbaceous plants (i.e., agricultural crops and grasses) and woody vegetation (i.e., trees and scrub). Only the herbaceous plant submodel is currently used in the Inventory. Maximum monthly net primary production (NPP) rate (a parameter of crop and forage species/variety, specified in the model input files) is modified by air temperature and available water to estimate a potential monthly NPP, which is then further subject to nutrient limitations in order to estimate actual NPP and biomass allocation.

The soil-water balance submodel calculates water balance components and changes in soil water availability, which influences both plant growth and decomposition/nutrient cycling processes. The moisture content of soils are simulated through a multi-layer profile based on precipitation, snow accumulation and melting, interception, soil and canopy evaporation, transpiration, soil water movement, runoff, and drainage.

The final main component of the model is the management submodel, which includes options for specifying crop type, crop sequence (e.g., rotation), tillage, fertilization, organic matter addition (e.g., manure amendments), harvest (with variable residue removal), drainage, irrigation, burning, and grazing intensity. An input “schedule” file is used to simulate the timing of management activities and temporal trends; schedules can be organized into discrete time blocks to define a repeated sequence of events (e.g., a crop rotation or a frequency of disturbance such as a burning cycle for perennial grassland). Management options can be specified for any month of a year within a scheduling block, where management codes point to operation-specific parameter files (referred to as *.100 files), which contain the information used to simulate management effects within the model process algorithms. User-specified management activities can be defined by adding to or editing the contents of the *.100 files. Additional details of the model formulation are given in Parton et al. (1987, 1988, 1994) and Metherell et al. (1993), and archived copies of the model source code are available.

The model has been tested for application in U.S. agricultural lands and has been shown to capture the general trends in C storage across approximately 870 field plots from 47 experimental sites (Figure A-14). Some biases and imprecision were found in predictions of soil organic C, which is reflected in the uncertainty associated with Century model results as described in Step 2b of this sub-annex. Additional discussion is provided in Ogle et al. (2007, 2010)

Figure A-14: Comparison of Measured Soil Organic C from Experimental Sites to Modeled Soil Organic C Using the Century Model

IPCC Tier 2 Method Description

The IPCC Tier 2 method has been developed to estimate C stock changes and CO₂ fluxes between soils and the atmosphere based on land-use and management activity (IPCC 2003, 2006; Ogle et al. 2003). For mineral soils (i.e., all soil orders from the USDA taxonomic classification except Histosols), the Tier 2 method uses reference C values to establish baseline C stocks that are modified based on agricultural activities using land-use change, tillage, and input factors. The standard IPCC approach was modified to use agricultural SOC stocks as the reference condition, rather than uncultivated soils under native vegetation. This modification was needed because soil measurements under agricultural

management are much more common and easily identified in the National Soil Survey Characterization Database (NRCS 1997). Measurements of soils under native vegetation are uncommon in the major agricultural regions of the United States because most of the area has been converted into cropland. In addition, country-specific factors were derived for land-use change, tillage, and input factors.

Organic soils used for agricultural production are treated in a separate calculation. These soils are made up of deep (greater than 30 cm) layers of organic material that can decompose at a steady rate over several decades following drainage for crop production or grazing (IPCC 2006). The IPCC approach uses an emission factor to estimate annual losses of CO₂ from cultivated organic soils, rather than an explicit stock change approach.

Methodological Steps for Derivation of Soil Organic C Stock Change Estimates

The inventory of soil C stock changes in U.S. agricultural land combines Tier 2 and 3 approaches. A simulation-based Tier 3 approach was used to estimate soil C changes for most agricultural land (approximately 90 percent of total cropland and grassland) comprising the dominant cropping and grazing systems in the United States, for which the model has been well-tested. Estimates for the remaining area, comprising less-common crop systems (e.g., horticultural, vegetable, tobacco, rice), land converted between non-agricultural and agricultural uses, and all agricultural land occurring on drained organic soils, were developed using the Tier 2 approach. Tier 2 methods were also used to estimate additional changes in mineral soil C stocks due to sewage sludge additions to soils, and enrollment changes in the Conservation Reserve Program after 2003. Most of the activity data sources were common to the Tier 2 and Tier 3 approaches, and, hence, they are described in an integrated manner below. Additional activity data required for the methods are described in adjoining sections, followed by the computation steps.

Step 1: Derive Activity Data

Activity data were compiled for the Tier 3 Century biogeochemical model and Tier 2 IPCC methods, including climate data, soil characteristics, and land-use/management activity data. The first step was to obtain land-use/management activity data, and determine the land base for areas under agricultural management. The areas modeled with Century and those estimated with the Tier 2 IPCC method were also subdivided. Finally, additional data, specific to each method, were collected on other key management activities (e.g., tillage management, fertilizer and manure addition rates) and environmental conditions (e.g., climate and soil characteristics).

Step 1a: Determine the Land Base and Classify Management Systems

Land Base—The *National Resources Inventory* (NRI) provided the basis for identifying the U.S. agricultural land base on non-federal lands, and classifying parcels into *Cropland Remaining Cropland*, *Land Converted to Cropland*, *Grassland Remaining Grassland*, and *Land Converted to Grassland* (USDA-NRCS 2000). Note that the Inventory does not include estimates of C stock changes for grasslands and a minor amount of croplands on federal lands, even though these areas are part of the managed land base for the United States. C stock changes on federal croplands and grasslands will be further evaluated and included in future inventories. The NRI has a stratified multi-stage sampling design, where primary sample units are stratified on the basis of county and township boundaries defined by the U.S. Public Land Survey (Nusser and Goebel 1997). Within a primary sample unit, typically a 160-acre (64.75 ha) square quarter-section, three sample points are selected according to a restricted randomization procedure. Each point in the survey is assigned an area weight (expansion factor) based on other known areas and land-use information (Nusser and Goebel 1997). In principle, the expansion factors represent the amount of area with the land use and land use change history that is the same as the point location. It is important to note that the NRI is a sampling of land use, and therefore there is some uncertainty associated with scaling the point data to a region or the country using the expansion factors. In general, those uncertainties decline at larger scales, such as states compared to smaller county units, because of a larger sample size. An extensive amount of soils, land-use, and land management data have been collected through the survey, which occurs every five years (Nusser et al. 1998).⁶⁵ Primary sources for data include aerial photography and remote sensing imagery as well as field visits and county office records. The annual NRI data product provides crop data for most years between 1979 and 2003, with the exception of 1983, 1988, and 1993. These years were gap-filled using an automated set of rules so that cropping sequences were filled with the most likely crop type given the historical cropping pattern at each NRI point location. Grassland data were reported on 5-year increments prior to 1998, but it was assumed that the land use was also grassland between the years of data collection (see Easter et al. 2008 for more information).

⁶⁵ In the current Inventory, NRI data only provide land-use and management statistics through 2003, but additional data will be incorporated in the future to extend the time series of land use and management data.

NRI points were included in the land base for the agricultural soil C inventory if they were identified as cropland or grassland⁶⁶ between 1990 and 2003 (Table A-230). The most recent national-level data available for NRI were for 2003; and so the designation for 2003 was extended to 2009 in order to provide C stock changes over the entire time series. An additional modification was made to the time series from 2004 to 2009 for *Grassland Remaining Grassland* and *Land Converted to Grassland* associated with the modification of NRI data with the Forest Inventory and Analysis Dataset. Overall, more than 260,000 NRI points were included in the inventory calculations, and the total agricultural land base varied from 370 to 367 million hectares from 1990 through 2009. Each NRI point represents a specific land parcel based upon the weighted expansion factors.

For each year, land parcels were subdivided into *Cropland Remaining Cropland*, *Land Converted to Cropland*, *Grassland Remaining Grassland*, and *Land Converted to Grassland*. Land parcels under cropping management in a specific year were classified as *Cropland Remaining Cropland* if they had been cropland for at least 20 years. Similarly land parcels under grassland management in a specific year of the inventory were classified as *Grassland Remaining Grassland* if they had been designated as grassland for at least 20 years.⁶⁷ Otherwise, land parcels were classified as *Land Converted to Cropland* or *Land Converted to Grassland* based on the most recent use in the inventory time period. Lands are retained in the land-use change categories (i.e., *Land Converted to Cropland* and *Land Converted to Grassland*) for 20 years as recommended by the IPCC guidelines (IPCC 2006).

Table A-230: Total Land Areas for the Agricultural Soil C Inventory, Subdivided by Land Use Categories (Million Hectares)

Category	Land Areas (10 ⁶ ha)									
	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
Mineral Soils										
Cropland Remaining Cropland	166.38	166.14	165.89	163.32	162.27	161.95	161.61	161.26	158.40	158.67
Land Converted to Cropland	14.01	14.24	14.41	14.23	15.71	15.88	16.24	16.37	17.79	17.43
Grassland Remaining Grassland	176.03	175.67	175.38	172.75	171.52	171.43	171.20	171.12	169.79	169.70
Land Converted to Grassland	10.10	10.23	10.44	9.94	10.51	10.77	10.91	11.27	13.73	13.90
Non-Agricultural Uses ^a	2.46	2.46	2.46	8.08	8.08	8.08	8.08	8.08	8.08	8.08
Organic Soils										
Cropland Remaining Cropland	0.70	0.70	0.70	0.72	0.72	0.72	0.72	0.72	0.72	0.72
Land Converted to Cropland	0.07	0.07	0.07	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Grassland Remaining Grassland	0.50	0.50	0.50	0.48	0.48	0.48	0.48	0.48	0.48	0.48
Land Converted to Grassland	0.04	0.04	0.04	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Non-Agricultural Uses ^a	0.04	0.04	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Total	370.32	370.10	369.93	369.66	369.43	369.45	369.40	369.44	369.13	369.12

Category	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Mineral Soils										
Cropland Remaining Cropland	158.83	158.87	159.56	160.72	160.72	160.72	160.72	160.72	160.72	160.72
Land Converted to Cropland	17.09	16.83	16.09	14.87	14.87	14.87	14.87	14.87	14.87	14.87
Grassland Remaining Grassland	169.65	169.50	169.97	170.26	170.04	169.78	169.52	169.25	168.99	168.73
Land Converted to Grassland	14.24	14.64	14.28	13.98	13.91	13.83	13.74	13.66	13.58	13.50
Non-Agricultural Uses ^a	8.08	8.08	8.08	8.08	8.08	8.08	8.08	8.08	8.08	8.08
Organic Soils										
Cropland Remaining Cropland	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72
Land Converted to Cropland	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Grassland Remaining Grassland	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48
Land Converted to Grassland	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Non-Agricultural Uses ^a	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Total	369.24	369.27	369.32	369.25	368.95	368.62	368.27	367.93	367.58	367.23

^a The non-agricultural uses were converted to or from cropland or grassland between 1990 and 2003.

Subdivide Land Base for Tier 2 and 3 Inventory Approaches—The Tier 3 method based on application of the Century model was used to model NRI points on most mineral soils. Parcels of land that were not simulated with Century were allocated to the Tier 2 approach, including (1) land parcels occurring on organic soils; (2) land parcels that included non-agricultural uses such as forest and federal lands in one or more years of the inventory;⁶⁸ (3) land parcels on mineral

⁶⁶ Includes non-federal lands only, because federal lands are not classified into land uses as part of the NRI survey (i.e., they are only designated as federal lands).

⁶⁷ NRI points were classified according to land-use history records starting in 1982 when the NRI survey began, and consequently the classifications were based on less than 20 years from 1990 to 2001.

soils that were very gravelly, cobbly, or shaley (i.e., classified as soils that have greater than 35 percent of soil volume comprised of gravel, cobbles, or shale); or (4) land parcels that were used to produce vegetables, perennial/horticultural crops, tobacco or rice, which was either grown continuously or in rotation with other crops. Century has not been fully tested for non-major crops, horticultural or perennial crops, rice and agricultural use of organic soils. In addition, Century has not been adequately tested for soils with a high gravel, cobble, or shale content, or fully tested for the transitions between agricultural and non-agricultural uses.

Table A-231: Total Land Area Estimated with Tier 2^a and 3 Inventory Approaches (Million Hectares)

Year	Land Areas (10 ⁶ ha)		
	Tier 2*	Tier 3	Total
1990	47.27	323.05	370.32
1991	47.27	322.83	370.10
1992	47.27	322.66	369.93
1993	47.25	322.41	369.66
1994	47.25	322.17	369.43
1995	47.25	322.19	369.45
1996	47.25	322.14	369.40
1997	47.25	322.19	369.44
1998	47.25	321.88	369.13
1999	47.25	321.87	369.12
2000	47.25	321.98	369.24
2001	47.25	322.01	369.27
2002	47.25	322.07	369.32
2003	47.25	321.99	369.25
2004	47.25	321.70	368.95
2005	47.25	321.36	368.62
2006	47.25	321.02	368.27
2007	47.25	320.67	367.93
2008	47.25	320.32	367.58
2009	47.25	319.98	367.23

^a Land use data for 1998-2003 are based on the Revised 1997 NRI data product for the Tier 2 method. Consequently, area data estimates in this table are not used for the Tier 2 portion of the Inventory.

Management System Classification—NRI points on mineral soils were classified into specific crop rotations, continuous pasture/rangeland, and other non-agricultural uses for the Tier 2 inventory analysis based on the survey data (Table A-232). NRI points were assigned to IPCC input categories (low, medium, high, and high with organic amendments) according to the classification provided in IPCC (2006). In addition, NRI differentiates between improved and unimproved grassland, where improvements include irrigation and interseeding of legumes. In order to estimate uncertainties, PDFs for the NRI land-use data were constructed as multivariate normal based on the total area estimates for each land-use/management category and associated covariance matrix. Through this approach, dependencies in land use were taken into account resulting from the likelihood that current use is correlated with past use.

For the Tier 3 inventory estimates, the actual cropping and grassland histories were simulated with the Century model so it was not necessary to classify NRI points into management systems. Uncertainty in the areas associated with each management system was determined from the estimated sampling variance from the NRI survey (Nusser and Goebel 1997). See Step 2b for additional discussion.

Table A-232: Total Land Areas by Land-Use and Management System for the Tier 2 Approach (Million Hectares)

Land-Use/Management System	Land Areas (10 ⁶ ha)	
	1990-92 (Tier 2)	1993-2009 (Tier 2)
Cropland Systems	31.53	29.25
Irrigated Crops	7.27	6.91
Continuous Row Crops	4.12	3.63
Continuous Small Grains	1.25	1.04
Continuous Row Crops and Small Grains	2.30	1.95
Row Crops in Rotation with Hay and/or Pasture	0.30	0.23
Small Grains in Rotation with Hay and/or Pasture	0.06	0.06
Row Crops and Small Grains in Rotation with Hay and/or Pasture	0.03	0.04

⁶⁸ Federal land is treated as forest or nominal grassland for purposes of these calculations, although the specific use is not identified in the NRI survey (USDA-NRCS 2000). Future inventories will include C estimation for the disaggregated land use and land use change categories on federal lands.

Vegetable Crops	2.90	3.16
Low Residue Annual Crops (e.g., Tobacco or Cotton)	0.87	1.03
Small Grains with Fallow	2.01	1.31
Row Crops and Small Grains with Fallow	1.72	1.80
Row Crops with Fallow	0.52	0.34
Miscellaneous Crop Rotations	0.54	0.43
Continuous Rice	0.34	0.31
Rice in Rotation with other crops	1.78	1.91
Continuous Perennial or Horticultural Crops	2.57	2.50
Continuous Hay	0.59	0.50
Continuous Hay with Legumes or Irrigation	1.31	1.12
CRP	1.03	0.96
Aquaculture	0.01	0.01
Grassland Systems	12.02	8.68
Rangeland	5.98	5.16
Continuous Pasture	3.76	2.49
Continuous Pasture with Legumes or Irrigation (i.e., improved)	2.25	1.03
CRP	0.02	0.00
Non-Agricultural Systems	2.46	8.08
Forest	1.53	3.95
Federal	0.01	0.05
Water	0.11	0.25
Settlements	0.04	2.46
Miscellaneous	0.77	1.36
Total	46.01	46.01

Organic soils are also categorized into land-use systems based on drainage (IPCC 2006). Undrained soils are treated as having no loss of organic C. Drained soils are subdivided into those used for cultivated cropland, which are assumed to have high drainage and greater losses of C, and those used for managed pasture, which are assumed to have less drainage and smaller losses of C. Overall, the area of organic soils drained for cropland and grassland has remained relatively stable since 1992 (see Table A-233).

Table A-233: Total Land Areas for Drained Organic Soils By Land Management Category and Climate Region (Million Hectares)

IPCC Land-Use Category for Organic Soils	Land Areas (10 ⁶ ha)					
	Cold Temperate		Warm Temperate		Tropical	
	1992	1997	1992	1997	1992	1997
Undrained	0.07	0.06	0.0020	0.0017	0.12	0.09
Managed Pasture (Low Drainage)	0.42	0.42	0.0136	0.0119	0.07	0.08
Cultivated Cropland (High Drainage)	0.33	0.34	0.0971	0.0974	0.19	0.20
Other Land Uses ^a	0.02	0.01	0.0002	0.0017	0.00	0.02
Total	0.84	0.84	0.11	0.11	0.39	0.39

^aUrban, water, and miscellaneous non-cropland, which are part of the agricultural land base because these areas were converted from or into agricultural land uses during the 1990s.

Step 1b: Obtain Additional Management Activity Data for the Tier 3 Century Model

Tillage Practices—Tillage practices were estimated for each cropping system based on data compiled by the Conservation Technology Information Center (CTIC 1998). CTIC compiles data on cropland area under five tillage classes by major crop species and year for each county. Because the surveys involve county-level aggregate area, they do not fully characterize tillage practices as they are applied within a management sequence (e.g., crop rotation). This is particularly true for area estimates of cropland under no-till, which include a relatively high proportion of “intermittent” no-till, where no-till in one year may be followed by tillage in a subsequent year. For example, a common practice in maize-soybean rotations is to use tillage in the maize crop while no-till is used for soybean, such that no-till practices are not continuous in time. Estimates of the area under continuous no-till were provided by experts at CTIC to account for intermittent tillage activity and its impact on soil C (Towery 2001).

Tillage practices were grouped into 3 categories: full, reduced, and no-tillage. Full tillage was defined as multiple tillage operations every year, including significant soil inversion (e.g., plowing, deep disking) and low surface residue coverage. This definition corresponds to the intensive tillage and “reduced” tillage systems as defined by CTIC (1998). No-till was defined as not disturbing the soil except through the use of fertilizer and seed drills and where no-till is applied to all crops in the rotation. Reduced tillage made up the remainder of the cultivated area, including mulch tillage and ridge

tillage as defined by CTIC and intermittent no-till. The specific tillage implements and applications used for different crops, rotations, and regions to represent the three tillage classes were derived from the 1995 Cropping Practices Survey by the Economic Research Service (ERS 1997).

Tillage data were further processed to construct probability distribution functions (PDFs) using CTIC tillage data. Transitions between tillage systems were based on observed county-level changes in the frequency distribution of the area under full, reduced, and no-till from the 1980s through 2004. Generally, the fraction of full tillage decreased during this time span, with concomitant increases in reduced till and no-till management. Transitions that were modeled and applied to NRI points occurring within a county were full tillage to reduced and no-till, and reduced tillage to no-till. The remaining amount of cropland was assumed to have no change in tillage (e.g., full tillage remained in full tillage). Transition matrices were constructed from CTIC data to represent tillage changes for three time periods, 1980-1989, 1990-1999, 2000-2009. Areas in each of the three tillage classes—full till (FT), reduced till (RT), no-till (NT)—in 1989 (the first year the CTIC data were available) were used for the first time period, data from 1997 were used for the second time period, and data from 2004 were used for the last time period. Percentage areas of cropland in each county were calculated for each possible transition (e.g., FT→FT, FT→RT, FT→NT, RT→RT, RT→NT) to obtain a probability for each tillage transition at an NRI point. Since continuous NT constituted < 1 percent of total cropland prior to 1990, there were no transitions for NT→FT or NT→NT. Uniform probability distributions were established for each tillage scenario in the county. For example, a particular crop rotation had 80 percent chance of remaining in full tillage over the two decades, a 15 percent chance of a transition from full to reduced tillage and a 5 percent chance of a transition from full to no-till. The uniform distribution was subdivided into three segments with random draws in the Monte Carlo simulation (discussed in Step 2b) leading to full tillage over the entire time period if the value was greater than or equal to 0 and less than 80, a transition from full to reduced till if the random draw was equal to or greater than 80 and less than 95, or a transition from full to no-till if the draw was greater than or equal to 95. See step 2b for additional discussion of the uncertainty analysis.

Mineral Fertilizer Application—Data on nitrogen fertilizer rates were obtained primarily from USDA's Economic Research Service's 1995 Cropping Practices Survey (ERS 1997). In this survey, data on inorganic nitrogen fertilization rates were collected for major crops (corn, cotton, soybeans, potatoes, winter wheat, durum wheat, and other spring wheat) in the key crop producing states. Note that all wheat data were combined into one category and assumed to represent small grains in general. Estimates for sorghum fertilizer rates were derived from corn rates using a ratio of national average corn fertilizer rates to national average sorghum fertilizer rates derived from additional publications (NASS 2004, 1999, 1992; ERS 1988; Grant and Krenz 1985; USDA 1954, 1957, 1966).

The ERS survey parameter "TOT N" (total amount of N applied per acre), with a small number of records deleted as outliers, was used in determining the fraction of crop acres receiving fertilizer and the average fertilizer rates for a region. Mean fertilizer rates and standard deviations for irrigated and rainfed crops were produced for each state at the finest resolution available. State-level data were produced for surveyed states if a minimum of 15 data points existed for each of the two categories (irrigated and rainfed). If a state was not surveyed for a particular crop or if fewer than 15 data points existed for one of the categories, then data at the Farm Production Region level were substituted. If Farm Production Region data were not available, then U.S.-level estimates (all major states surveyed) were used in the simulation for that particular crop in the state lacking sufficient data. Note that standard deviations for fertilizer rates on log scale were used to construct PDFs on a log-normal scale, in order to address uncertainties in application rates (see Step 2b for discussion of uncertainty methods).

Manure Application—County-level manure N addition estimates were obtained from the Natural Resources Conservation Service (Edmonds et al. 2003). Working with the farm-level crop and animal data from the 1997 Census of Agriculture, NRCS has coupled estimates of manure nitrogen produced with estimates of manure nitrogen recoverability by animal waste management system to produce county-level estimates of manure nitrogen applied to cropland and pasture. Edmonds et al. (2003) defined a hierarchy of land use systems to which manure is applied, that included 24 crops, cropland used as pasture, and permanent pasture. They estimated the area amended with manure and manure nitrogen application rates in 1997 for both manure-producing farms and manure-receiving farms within a county, for two scenarios—before implementation of Comprehensive Nutrient Management Plans (baseline) and after implementation. The application rates for the baseline scenario were used in the inventory under the assumption that Comprehensive Nutrient Management Plans have not been fully implemented.

In order to derive estimates of manure application rates over time, the availability of managed manure N for application to soils (which are available annually) was used to adjust the amount of area amended with manure on a county scale (Note: Edmonds et al. (2003) only provide information on application rates for 1997). Specifically, the estimated available managed manure N in another year was divided by the managed manure N available in 1997. The amendment area in a county for 1997 was then multiplied by the ratio to reflect the probability of manure amendments based on the variation in available manure N across time. If more managed manure N was available in a given year for a county

relative to the amount available in 1997 (ratio > 1), it was assumed that there was a higher probability of a manure amendment. In contrast, if less managed manure N was available (ratio < 1), the probability of an amendment declined in comparison to 1997. A detailed description of the derivation of the managed manure N availability data is provided in the Manure Management section (Section 6.2) and Annex (Annex 3.10). Managed manure N availability in the 1980s was based on USDA estimates (Kellogg et al. 2000) after adjusting for relative differences in manure N production between the USDA dataset and estimates derived from the method described in Annex 3.10. Unmanaged manure classified as pasture/range/paddock manure was assumed to have negligible impacts on soil C stocks because of the tradeoff between reduced litterfall C versus C ingested by livestock and deposited on soils in manure.

For Century simulations, the amended areas were averaged for three time periods (1980-1989, 1990-1999, and 2000-2009) similar to the tillage transitions. Rates for manure-producing farms and manure-receiving farms have been area-weighted and combined to produce a manure nitrogen application rate for each crop in a county. Several of the crops in Edmonds et al. (2003) have been area-weighted and combined into broader crop categories. For example, all small grain crops have been combined into one category. In order to address uncertainty, uniform probability distributions were constructed based on the proportion of land receiving manure versus the amount not receiving manure for each crop type and pasture. For example, if the 20 percent of land producing corn in a county was amended with manure, randomly drawing a value equal to or greater than 0 and less than 20 would lead to simulation with a manure amendment, while drawing a value greater than or equal to 20 and less than 100 would lead to no amendment in the simulation (see Step 2b for further discussion of uncertainty methods).

To estimate the C inputs associated with the manure N application rates (from Edmonds et al. 2003), C:N ratios for various manure types (based on animal species and manure management system) were estimated from data in the *Agricultural Waste Management Field Handbook* (USDA 1996) and the *On-Farm Composting Handbook* (NRAES 1992). Weighted county-average C:N ratios for total manure applied were then calculated based on the C:N ratio and the manure N production rate for each manure type reported in the county. Manure C addition rates were then calculated by multiplying the county-average manure C:N ratio by the manure N application rates.

To account for the common practice of reducing inorganic nitrogen fertilizer inputs when manure is added to a cropland soil, a set of crop-specific reduction factors were derived from mineral fertilization data for land amended with manure versus land not amended with manure in the ERS 1995 Cropping Practices Survey (ERS 1997). In the simulations, mineral N fertilization rates were reduced for crops receiving manure nitrogen based on a fraction of the amount of manure nitrogen applied, depending on the crop and whether it was irrigated or a rainfed system. The reduction factors were selected from PDFs with normal densities in order to address uncertainties in this dependence between manure amendments and mineral fertilizer application.

Irrigation—NRI differentiates between irrigated and non-irrigated land but does not provide more detailed information on the type and intensity of irrigation. Hence, irrigation was modeled by assuming that applied water was sufficient to meet full crop demand (i.e., irrigation plus precipitation equaled potential evapotranspiration during the growing season).

Step 1c—Obtain Additional Management Activity Data for Tier 2 IPCC Method

Tillage Practices—PDFs were constructed for the CTIC tillage data, as bivariate normal on a log-ratio scale to reflect negative dependence among tillage classes. This structure ensured that simulated tillage percentages were non-negative and summed to 100 percent. CTIC data do not differentiate between continuous and intermittent use of no-tillage, which is important for estimating SOC storage. Thus, regionally based estimates for continuous no-tillage (defined as 5 or more years of continuous use) were modified based on consultation with CTIC experts, as discussed in Step 1a (downward adjustment of total no-tillage acres reported, Towery 2001).

Manure Amendments—Manure management is also a key practice in agricultural lands, with organic amendments leading to significant increases in SOC storage. USDA provides information on the amount of land amended with manure for 1997 based on manure production data and field-scale surveys detailing application rates that had been collected in the *Census of Agriculture* (Edmonds et al. 2003). Similar to the Century model discussion in Step 1b, the amount of land receiving manure was based on the estimates provided by Edmonds et al. (2003), as a proportion of crop and grassland amended with manure within individual climate regions. The resulting proportions were used to re-classify a portion of crop and grassland into a new management category. Specifically, a portion of medium input cropping systems was re-classified as high input, and a portion of the high input systems was re-classified as high input with amendment. In grassland systems, the estimated proportions for land amended with manure were used to re-classify a portion of nominally-managed grassland as improved, and a portion of improved grassland as improved with high input. These classification approaches are consistent with the IPCC inventory methodology (IPCC 2003, 2006). Uncertainties in

the amount of land amended with manure were based on the sample variance at the climate region scale, assuming normal density PDFs (i.e., variance of the climate region estimates, which were derived from county-scale proportions).

Wetland Reserve—Wetlands enrolled in the Conservation Reserve Program have been restored in the Northern Prairie Pothole Region through the Partners for Wildlife Program funded by the U.S. Fish and Wildlife Service. The area of restored wetlands was estimated from contract agreements (Euliss and Gleason 2002). While the contracts provide reasonable estimates of the amount of land restored in the region, they do not provide the information necessary to estimate uncertainty. Consequently, a ± 50 percent range was used to construct the PDFs for the uncertainty analysis.

Step 1d—Obtain Management Activity Data to Compute Additional Changes in Soil Organic C Stocks in Mineral Soils Due to Sewage Sludge Applications and CRP Enrollment after 2003

Two additional influences on soil organic C stocks in mineral soils were estimated using a Tier 2 method, including: sewage sludge additions to agricultural soils and changes in enrollment for the Conservation Reserve Program after 2003.

Total sewage sludge generation data for 1988, 1996, and 1998, in dry mass units, were obtained from an EPA report (EPA 1999) and estimates for 2004 were obtained from an independent national biosolids survey (NEBRA 2007). These values were linearly interpolated to estimate values for the intervening years. Sewage sludge generation data are not available for 2005 onwards (Bastian 2007), so the 1990 through 2004 data were linearly extrapolated for the most recent years. The total sludge generation estimates were then converted to units of N by applying an average N content of 3.9 percent (McFarland 2001), and disaggregated into use and disposal practices using historical data in EPA (1993) and NEBRA (2007). The use and disposal practices were agricultural land application, other land application, surface disposal, incineration, landfilling, ocean dumping (ended in 1992), and other disposal. Sewage sludge N was assumed to be applied at the assimilative capacity provided in Kellogg et al. (2000), which is the amount of nutrients taken up by a crop and removed at harvest, representing the recommended application rate for manure amendments. This capacity varies from year to year, because it is based on specific crop yields during the respective year (Kellogg et al. 2000). Total sewage sludge N available for application was divided by the assimilative capacity to estimate the total land area over which sewage sludge had been applied. The resulting estimates were used for the estimation of soil C stock change.

The change in enrollment for the Conservation Reserve Program after 2003 was based on the amount of land under active contracts from 2004 through 2009 relative to 2003 (USDA-FSA 2010).

Step 1e: Obtain Climate and Soils Data

Tier 3 Century Model—Monthly weather data (temperature and precipitation) from the PRISM database (Parameter-elevation Regressions on Independent Slopes Model) (Daly et al. 1994) were used as an input to the Century model simulations for the period 1895 through 2003. PRISM is based on observed weather data from the National Weather Service network database and statistical models for interpolation and orographic corrections. The primary database consists of approximately 4×4 km grid cells. These data were averaged (weighted by area) for each county in the United States, so that counties are the finest spatial scale represented in the Century simulations.

Soil texture and natural drainage capacity (i.e., hydric vs. non-hydric soil characterization) were the main soil variables used as input to the Century model. Other soil characteristics needed in the simulation, such as field capacity and wilting-point water contents, were estimated from soil texture data using pedo-transfer functions available in the model. Soil input data are derived from the NRI database, which contain descriptions for the soil type at each NRI point (used to specify land-use and management time series—see below). The data are based on field measurements collected as part of soil survey and mapping. Soils are classified according to “soil-series,” which is the most detailed taxonomic level used for soil mapping in the United States. Surface soil texture and hydric condition were obtained from the soil attribute table in the NRI database. Texture is one of the main controls on soil C turnover and stabilization in the Century model, which uses particle size fractions of sand (50–2,000 μm), silt (2–50 μm), and clay ($< 2 \mu\text{m}$) as inputs. NRI points were assigned to one of twelve texture classes for the simulations. Hydric condition specifies whether soils are poorly-drained, and hence prone to water-logging, or moderately to well-drained (non-hydric), in their native (pre-cultivation) condition.⁶⁹ Poorly drained soils can be subject to anaerobic (lack of oxygen) conditions if water inputs (precipitation and irrigation) exceed water losses from drainage and evapotranspiration. Depending on moisture conditions, hydric soils can range from being fully aerobic to completely anaerobic, varying over the year. Decomposition rates are modified according to a linear

⁶⁹ Artificial drainage (e.g., ditch- or tile-drainage) is simulated as a management variable.

function that varies from 0.3 under completely anaerobic conditions to 1.0 under fully aerobic conditions (default parameters in Century).⁷⁰

IPCC Tier 2 Method—The IPCC inventory methodology for agricultural soils divides climate into eight distinct zones based upon average annual temperature, average annual precipitation, and the length of the dry season (IPCC 2006) (Table A-234). Six of these climate zones occur in the conterminous United States and Hawaii (Eve et al. 2001).

Table A-234: Characteristics of the IPCC Climate Zones that Occur in the United States

Climate Zone	Annual Average Temperature (°C)	Average Annual Precipitation (mm)	Length of Dry Season (months)
Cold Temperate, Dry	< 10	< Potential Evapotranspiration	NA
Cold Temperate, Moist	< 10	≥ Potential Evapotranspiration	NA
Warm Temperate, Dry	10 – 20	< 600	NA
Warm Temperate, Moist	10 – 20	≥ Potential Evapotranspiration	NA
Sub-Tropical, Dry*	> 20	< 1,000	Usually long
Sub-Tropical, Moist (w/short dry season) ^a	> 20	1,000 – 2,000	< 5

^a The climate characteristics listed in the table for these zones are those that correspond to the tropical dry and tropical moist zones of the IPCC. They have been renamed “sub-tropical” here.

Mean climate (1961-1990) variables from the PRISM data set (Daly et al. 1994) were used to classify climate zones. Mean annual precipitation and annual temperature data were averaged (weighted by area) for each of the 4×4 km grid cells occurring within a MLRA region. These averages were used to assign a climate zone to each MLRA according to the IPCC climate classification (Figure A-15). MLRAs represent geographic units with relatively similar soils, climate, water resources, and land uses; and there are approximately 180 MLRAs in the United States (NRCS 1981).

Figure A-15: Major Land Resource Areas by IPCC Climate Zone

Soils were classified into one of seven classes based upon texture, morphology, and ability to store organic matter (IPCC 2006). Six of the categories are mineral types and one is organic (i.e., Histosol). Reference C stocks, representing estimates from conventionally managed cropland, were computed for each of the mineral soil types across the various climate zones, based on pedon (i.e., soil) data from the National Soil Survey Characterization Database (NRCS 1997) (Table A-235). These stocks are used in conjunction with management factors to compute the change in SOC stocks that result from management and land-use activity. PDFs, which represent the variability in the stock estimates, were constructed as normal densities based on the mean and variance from the pedon data. Pedon locations were clumped in various parts of the country, which reduces the statistical independence of individual pedon estimates. To account for this lack of independence, samples from each climate by soil zone were tested for spatial autocorrelation using the Moran’s I test, and variance terms were inflated by 10 percent for all zones with significant p-values.

Table A-235: U.S. Soil Groupings Based on the IPCC Categories and Dominant Taxonomic Soil, and Reference Carbon Stocks (Metric Tons C/ha)

IPCC Inventory Soil Categories	USDA Taxonomic Soil Orders	Reference Carbon Stock in Climate Regions					
		Cold Temperate, Dry	Cold Temperate, Moist	Warm Temperate, Dry	Warm Temperate, Moist	Sub-Tropical, Dry	Sub-Tropical, Moist
High Clay Activity Mineral Soils	Vertisols, Mollisols, Inceptisols, Aridisols, and high base status Alfisols	42 (n = 133)	65 (n = 526)	37 (n = 203)	51 (n = 424)	42 (n = 26)	57 (n = 12)
Low Clay Activity Mineral Soils	Ultisols, Oxisols, acidic Alfisols, and many Entisols	45 (n = 37)	52 (n = 113)	25 (n = 86)	40 (n = 300)	39 (n = 13)	47 (n = 7)
Sandy Soils	Any soils with greater than 70 percent sand and less than 8 percent clay (often Entisols)	24 (n = 5)	40 (n = 43)	16 (n = 19)	30 (n = 102)	33 (n = 186)	50 (n = 18)
Volcanic Soils	Andisols	124 (n = 12)	114 (n = 2)	124 (n = 12)	124 (n = 12)	124 (n = 12)	128 (n = 9)
Spodic Soils	Spodosols	86 (n=20)	74 (n = 13)	86 (n=20)	107 (n = 7)	86 (n=20)	86 (n=20)
Aquic Soils	Soils with Aquic suborder	86 (n = 4)	89 (n = 161)	48 (n = 26)	51 (n = 300)	63 (n = 503)	48 (n = 12)

⁷⁰ Hydric soils are primarily subject to anaerobic conditions outside the plant growing season (i.e., in the absence of active plant water uptake). Soils that are water-logged during much of the year are typically classified as organic soils (e.g., peat), which are not simulated with the Century model.

Organic Soils ^a	Histosols	NA	NA	NA	NA	NA	NA
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^a C stocks are not needed for organic soils.

Notes: C stocks are for the top 30 cm of the soil profile, and were estimated from pedon data available in the National Soil Survey Characterization database (NRCS 1997); sample size provided in parentheses (i.e., 'n' values refer to sample size).

Step 2: Estimate Organic C Stock Changes for Agricultural Lands on Mineral Soils Simulated with the Tier 3 Century Model

This methodology description is divided into two sub-steps. First, the model was used to establish the initial conditions and C stocks for 1979, which was the last year before the NRI survey was initiated. In the second sub-step, Century was used to estimate changes in soil organic C stocks based on the land-use and management histories recorded in the NRI (USDA-NRCS 2000), including the reporting period starting in 1990.

Step 2a: Simulate Initial Conditions (Pre-NRI Conditions)

Century model initialization involves two steps, with the goal of estimating the most accurate stock for the pre-NRI history, and the distribution of organic C among the pools represented in the model (e.g., Structural, Metabolic, Active, Slow, Passive). Each pool has a different turnover rate (representing the heterogeneous nature of soil organic matter), and the amount of C in each pool at any point in time influences the forward trajectory of the total soil organic C storage. There is currently no national set of soil C measurements that can be used for establishing initial conditions in the model. Sensitivity analysis of the Century model showed that the rate of change of soil organic matter is relatively insensitive to the *amount* of total soil organic C but is highly sensitive to the relative *distribution* of C among different pools (Parton et al. 1987). By simulating the historical land use prior to the inventory period, initial pool distributions are estimated in an unbiased way.

The first step involves running the model to a steady-state condition (e.g., equilibrium) under native vegetation, with long-term mean climate based on 30-yr averages of the PRISM data (1960-1990), and the soil physical attributes for the NRI points. Native vegetation is represented at the MLRA level for pre-settlement time periods in the United States. The model was run for 7,000 years to represent a pre-settlement era and achieve a steady-state condition.

The second step is to run the model for the period of time from settlement to the beginning of the NRI survey, representing the influence of historic land-use change and management, particularly the conversion of native vegetation to agricultural uses. This encompasses a varying time period from land conversion (depending on historical settlement patterns) to 1979. The information on historical cropping practices used for Century simulations was gathered from a variety of sources, ranging from the historical accounts of farming practices reported in the literature (e.g., Miner 1998) to national level databases (e.g., NASS 2004). A detailed description of the data sources and assumptions used in constructing the base history scenarios of agricultural practices can be found in Williams and Paustian (2005).

Step 2b—Estimate Soil Organic C Stock Changes and Uncertainties

After estimating model initialization, the model is used to simulate the NRI land use and management histories from 1979 through 2003.⁷¹ The simulation system incorporates a dedicated MySQL database server and a 24-node parallel processing computer cluster. Input/output operations are managed by a set of run executive programs written in PERL. The assessment framework for this analysis is illustrated in Figure A-16.

Figure A-16: Uncertainty in Data Inputs

Evaluating uncertainty was an integral part of the analysis, and included three components: (1) uncertainty in the main activity data inputs affecting soil C balance (input uncertainty); (2) uncertainty in the model formulation and parameterization (structural uncertainty); and (3) uncertainty in the land-use and management system areas (scaling uncertainty) (Ogle et al. 2010). For component 1, input uncertainty was evaluated for fertilization management, manure applications, and tillage, which are the primary management activity data that were supplemental to the NRI observations and have significant influence on soil C dynamics. As described in Step 1b, PDFs were derived from surveys at the county scale in most cases. To represent uncertainty in these inputs, a Monte-Carlo Analysis was used with 100 iterations for each NRI cluster-point in which random draws were made from PDFs for fertilizer, manure application, and tillage.

⁷¹ The estimated soil C stock change in 2003 is currently assumed to represent the changes between 2004 and 2009. New estimates will be available in the future to extend the time series of land use and management data.

As described above, an adjustment factor was also selected from PDFs with normal densities to represent the dependence between manure amendments and N fertilizer application rates. The total number of Century simulations was over 12 million for the Monte Carlo Analysis with 100 iterations.

The second component dealt with uncertainty inherent in model formulation and parameterization. An empirically-based procedure was employed to develop a structural uncertainty estimator from the relationship between modeled results and field measurements from agricultural experiments (Ogle et al. 2007). The Century model was initialized for 45 long-term field experiments with over 800 treatments in which soil C was measured under a variety of management conditions (e.g., variation in crop rotation, tillage, fertilization rates, manure amendments). These studies were obtained from an extensive search of published studies. All studies located in North America that met minimum criteria of having sufficient site-level information and experimental designs were used, including C stock estimates, texture data, experimental designs with control plots, and land-use and management records for the experimental time period and pre-experiment condition. The inputs to the model were essentially known in the simulations for the long-term experiments, and, therefore, the analysis was designed to evaluate uncertainties associated with the model structure (i.e., model algorithms and parameterization).

The relationship between modeled soil C stocks and field measurements was statistically analyzed using linear-mixed effect modeling techniques. Additional fixed effects were included in the mixed effect model if they explained significant variation in the relationship between modeled and measured stocks (i.e., if they met an alpha level of 0.05 for significance). Several variables were tested including: land-use class; type of tillage; cropping system; geographic location; climate; soil texture; time since the management change; original land cover (i.e., forest or grassland); grain harvest as predicted by the model compared to the experimental values; and variation in fertilizer and residue management. The final model included variables for organic matter amendments, fertilizer rates, inclusion of hay/pasture in cropping rotations, use of no-till, and inclusion of bare fallow in the rotation, which were significant at an alpha level of 0.05. These fixed effects were used to make an adjustment to modeled values due to biases that were creating significant mismatches between the modeled and measured stock values. Random effects captured the statistical dependence (i.e., the data are not fully independent) in time series and data collected from the same long-term experimental site. Accounting for this statistical dependency is needed to estimate appropriate standard deviations for parameter coefficients.

A Monte Carlo approach was used to apply the uncertainty estimator (Ogle et al. 2010). Parameter values for the statistical equation (i.e., fixed effects) were selected from their joint probability distribution, as well as random error associated with fine-scale estimates at NRI points, and the residual or unexplained error associated with the linear mixed-effect model. The stock estimate and associated management information was then used as input into the equation, and adjusted stock values were computed for each C stock estimate produced in the evaluation of input uncertainty for *Cropland Remaining Cropland* (Component 1 of the uncertainty analysis). Note that the uncertainty estimator needs further development for application to *Grassland Remaining Grassland* and the land-use change categories. This development is a planned improvement for the soil C inventory. The variance of the adjusted C stock estimates were computed from the 100 simulated values from the Monte Carlo analysis.

The third element was the uncertainty associated with scaling the Century results for each NRI point to the entire land base, using the expansion factors provided with the NRI database. The expansion factors represent the number of hectares associated with the land-use and management history for a particular point. This uncertainty was determined by computing the variances of the expanded estimates, accounting for the two-stage sampling design of the NRI.

For the land base that was simulated with the Century model, soil organic C stocks ranged from losses of 4.25 Tg CO₂ Eq. to gains of 68.05 Tg CO₂ Eq. annually, depending on the land-use/land-use change category and inventory time period. Estimates and uncertainties are provided in Table A-236.

Table A-236: Annual Change in Soil Organic Carbon Stocks (95% Confidence Interval) for the Land Base Simulated with the Tier 3 Century Model-Based Approach (Tg CO₂ Eq.)

Year	Cropland Remaining Cropland		Land Converted to Cropland		Grassland Remaining Grassland		Land Converted to Grassland	
	Estimate	95% CI	Estimate	95% CI	Estimate	95% CI	Estimate	95% CI
1990	(55.19)	(111.72) to 1.33	(4.43)	(5.06) to (3.80)	(55.10)	(57.18) to (53.01) (29.87) to	(15.75)	(18.43) to (13.07)
1991	(57.50)	(90.49) to (24.51)	(4.30)	(4.93) to (3.68)	(28.04)	(26.21)	(15.06)	(17.58) to (12.54)
1992	(68.05)	(99.81) to (36.28)	(4.75)	(5.38) to (4.13)	(9.84)	(10.82) to (8.85)	(13.83)	(16.23) to (11.44)
1993	(64.25)	(95.93) to (32.56)	(8.66)	(9.34) to (7.98) (13.42) to	(1.48)	(3.29) to 0.33 (68.28) to	(13.52)	(16.09) to (10.94)
1994	(62.38)	(94.48) to (30.29)	(12.61)	(11.80)	(66.74)	(65.20)	(17.87)	(20.62) to (15.12)
1995	(47.58)	(83.91) to (11.25)	(3.84)	(4.51) to (3.17)	(29.45)	(30.78) to (28.13)	(18.21)	(20.80) to (15.61)

1996	(54.99)	(83.65) to (26.32)	(4.55)	(5.24) to (3.85)	4.25	3.00 to 5.50	(15.19)	(17.78) to (12.60)
1997	(54.08)	(81.53) to (26.63)	(4.21)	(4.94) to (3.48)	(20.44)	(21.73) to (19.14)	(19.90)	(22.64) to (17.16)
1998	(44.34)	(77.06) to (11.61)	(10.77)	(11.60) to (9.94)	1.46	2.49 to 0.43	(17.33)	(20.33) to (14.33)
1999	(29.72)	(58.21) to (1.23)	(3.30)	(4.02) to (2.59)	(18.92)	(19.78) to (18.06)	(23.95)	(26.64) to (21.26)
2000	(54.83)	(85.86) to (23.80)	(4.41)	(5.15) to (3.67)	(55.15)	(56.04) to (54.26)	(23.11)	(26.26) to (19.97)
2001	(37.57)	(68.05) to (7.08)	(2.53)	(3.24) to (1.83)	(27.34)	(28.17) to (26.51)	(24.03)	(27.01) to (21.05)
2002	(36.14)	(67.43) to (4.85)	(1.97)	(2.68) to (1.25)	(46.81)	(47.62) to (46.00)	(22.72)	(25.70) to (19.73)
2003	(42.32)	(69.67) to (14.98)	(0.84)	(1.54) to (0.13)	(11.65)	(12.50) to (10.79)	(20.69)	(23.50) to (17.89)
2004	(42.32)	(69.67) to (14.98)	(0.84)	(1.54) to (0.13)	(11.49)	(12.34) to (10.64)	(20.51)	(23.31) to (17.70)
2005	(42.32)	(69.67) to (14.98)	(0.84)	(1.54) to (0.13)	(11.32)	(12.17) to (10.47)	(20.31)	(23.11) to (17.50)
2006	(42.32)	(69.67) to (14.98)	(0.84)	(1.54) to (0.13)	(11.14)	(11.99) to (10.29)	(20.10)	(22.90) to (17.30)
2007	(42.32)	(69.67) to (14.98)	(0.84)	(1.54) to (0.13)	(10.97)	(11.82) to (10.12)	(19.90)	(22.70) to (17.09)
2008	(42.32)	(69.67) to (14.98)	(0.84)	(1.54) to (0.13)	(10.79)	(11.65) to (9.94)	(19.69)	(22.49) to (16.89)
2009	(42.32)	(69.67) to (14.98)	(0.84)	(1.54) to (0.13)	(10.62)	(11.47) to (9.77)	(19.48)	(22.29) to (16.68)

Note: Does not include the change in storage resulting from the annual application of sewage sludge, or the additional Conservation Reserve Program enrollment.

Step 3: Estimate C Stock Changes in Agricultural Lands on Mineral Soils Approximated with the Tier 2 Approach, in Addition to CO₂ Emissions from Agricultural Lands on Drained Organic Soils

Mineral and organic soil calculations were made for each climate by soil zone across the United States. Mineral stock values were derived for non-major crop rotations and land converted from non-agricultural uses to cropland in 1982, 1992, and 1997 based on the land-use and management activity data in conjunction with appropriate reference C stocks, land-use change, tillage, input, and wetland restoration factors. C losses from organic soils were computed based on 1992 and 1997 land use and management in conjunction with the appropriate C loss rate. Each input to the inventory calculations for the Tier 2 approach had some level of uncertainty that was quantified in PDFs, including the land-use and management activity data, reference C stocks, and management factors. A Monte Carlo Analysis was used to quantify uncertainty in SOC change for the inventory period based on uncertainty in the inputs. Input values were randomly selected from PDFs in an iterative process to estimate SOC change for 50,000 times and produce a 95 percent confidence interval for the inventory results.

Step 3a: Derive Mineral Soil Stock Change and Organic Soil Emission Factors

Stock change factors representative of U.S. conditions were estimated from published studies (Ogle et al. 2003, Ogle et al. 2006). The numerical factors quantify the impact of changing land use and management on SOC storage in mineral soils, including tillage practices, cropping rotation or intensification, and land conversions between cultivated and native conditions (including set-asides in the Conservation Reserve Program), as well as the net loss of SOC from organic soils attributed to agricultural production on drained soils. Studies from the United States and Canada were used in this analysis under the assumption that they would best represent management impacts for the Inventory.

For mineral soils, studies had to report SOC stocks (or information to compute stocks), depth of sampling, and the number of years since a management change to be included in the analysis. The data were analyzed using linear mixed-effect modeling, accounting for both fixed and random effects. Fixed effects included depth, number of years since a management change, climate, and the type of management change (e.g., reduced tillage vs. no-till). For depth increments, the data were not aggregated for the C stock measurements; each depth increment (e.g., 0-5 cm, 5-10 cm, and 10-30 cm) was included as a separate point in the dataset. Similarly, time series data were not aggregated in these datasets. Consequently, random effects were needed to account for the dependence in time series data and the dependence among data points representing different depth increments from the same study. Factors were estimated for the effect of management practices at 20 years for the top 30 cm of the soil (Table A-237). Variance was calculated for each of the U.S. factor values, and used to construct PDFs with a normal density. In the IPCC method, specific factor values are given for improved grassland, high input cropland with organic amendments, and for wetland rice, each of which

influences the C balance of soils. Specifically, higher stocks are associated with increased productivity and C inputs (relative to native grassland) on improved grassland with both medium and high input.⁷² Organic amendments in annual cropping systems also increase SOC stocks due to greater C inputs, while high SOC stocks in rice cultivation are associated with reduced decomposition due to periodic flooding. There were insufficient field studies to derive factor values for these systems from the published literature, and, thus, estimates from IPCC (2003) were used under the assumption that they would best approximate the impacts, given the lack of sufficient data to derive U.S.-specific factors. A measure of uncertainty was provided for these factors in IPCC (2003), which was used to construct PDFs.

Table A-237: Soil Organic Carbon Stock Change Factors for the United States and the IPCC Default Values Associated with Management Impacts on Mineral Soils

	IPCC default	Warm Moist Climate	U.S. Factor		
			Warm Dry Climate	Cool Moist Climate	Cool Dry Climate
Land-Use Change Factors					
Cultivated ^a	1	1	1	1	1
General Uncult. ^{a,b} (n=251)	1.4	1.42±0.06	1.37±0.05	1.24±0.06	1.20±0.06
Set-Aside ^a (n=142)	1.25	1.31±0.06	1.26±0.04	1.14±0.06	1.10±0.05
Improved Grassland Factors ^c					
Medium Input	1.1	1.14±0.06	1.14±0.06	1.14±0.06	1.14±0.06
High Input	Na	1.11±0.04	1.11±0.04	1.11±0.04	1.11±0.04
Wetland Rice Production Factor ^c	1.1	1.1	1.1	1.1	1.1
Tillage Factors					
Conv. Till	1	1	1	1	1
Red. Till (n=93)	1.05	1.08±0.03	1.01±0.03	1.08±0.03	1.01±0.03
No-till (n=212)	1.1	1.13±0.02	1.05±0.03	1.13±0.02	1.05±0.03
Cropland Input Factors					
Low (n=85)	0.9	0.94±0.01	0.94±0.01	0.94±0.01	0.94±0.01
Medium	1	1	1	1	1
High (n=22)	1.1	1.07±0.02	1.07±0.02	1.07±0.02	1.07±0.02
High with amendment ^c	1.2	1.38±0.06	1.34±0.08	1.38±0.06	1.34±0.08

Note: The “n” values refer to sample size.

^a Factors in the IPCC documentation (IPCC 2006) were converted to represent changes in SOC storage from a cultivated condition rather than a native condition.

^b Default factor was higher for aquatic soils at 1.7. The U.S. analysis showed no significant differences between aquatic and non-aquatic soils, so a single U.S. factor was estimated for all soil types.

^c U.S.-specific factors were not estimated for land improvements, rice production, or high input with amendment because of few studies addressing the impact of legume mixtures, irrigation, or manure applications for crop and grassland in the United States, or the impact of wetland rice production in the US. Factors provided in IPCC (2003) were used as the best estimates of these impacts.

Wetland restoration management also influences SOC storage in mineral soils, because restoration leads to higher water tables and inundation of the soil for at least part of the year. A stock change factor was estimated assessing the difference in SOC storage between restored and unrestored wetlands enrolled in the Conservation Reserve Program (Euliss and Gleason 2002), which represents an initial increase of C in the restored soils over the first 10 years (Table A-238). A PDF with a normal density was constructed from these data based on results from a linear regression model. Following the initial increase of C, natural erosion and deposition leads to additional accretion of C in these wetlands. The mass accumulation rate of organic C was estimated using annual sedimentation rates (cm/yr) in combination with percent organic C, and soil bulk density (g/cm³) (Euliss and Gleason 2002). Procedures for calculation of mass accumulation rate are described in Dean and Gorham (1998); the resulting rate and variance were used to construct a PDF with a normal density (Table A-238).

Table A-238: Factor Estimate for the Initial and Subsequent Increase in Organic Soil C Following Wetland Restoration of Conservation Reserve Program

Variable	Value
Factor (Initial Increase—First 10 Years)	1.22±0.18
Mass Accumulation (After Initial 10 Years)	0.79±0.05 Mg C/ha-yr

Note: Mass accumulation rate represents additional gains in C for mineral soils after the first 10 years (Euliss and Gleason 2002).

In addition, C loss rates were estimated for cultivated organic soils based on subsidence studies in the United States and Canada (Table A-239). PDFs were constructed as normal densities based on the mean C loss rates and associated variances.

⁷² Improved grasslands are identified in the 1997 *National Resources Inventory* as grasslands that were irrigated or seeded with legumes, in addition to those reclassified as improved with manure amendments.

Table A-239: Carbon Loss Rates for Organic Soils Under Agricultural Management in the United States, and IPCC Default Rates (Metric Ton C/ha-yr)

Region	Cropland		Grassland	
	IPCC	U.S. Revised	IPCC	U.S. Revised
Cold Temperate, Dry & Cold Temperate, Moist	1	11.2±2.5	0.25	2.8±0.5 ^a
Warm Temperate, Dry & Warm Temperate, Moist	10	14.0±2.5	2.5	3.5±0.8 ^a
Sub-Tropical, Dry & Sub-Tropical, Moist	20	14.0±3.3	5	3.5±0.8 ^a

^a There were not enough data available to estimate a U.S. value for C losses from grassland. Consequently, estimates are 25 percent of the values for cropland, which was an assumption used for the IPCC default organic soil C losses on grassland.

Step 3b: Estimate Annual Changes in Mineral Soil Organic C Stocks and CO₂ Emissions from Organic Soils

In accordance with IPCC methodology, annual changes in mineral soil C were calculated by subtracting the beginning stock from the ending stock and then dividing by 20.⁷³ For this analysis, the base inventory estimate for 1990 through 1992 is the annual average of 1992 stock minus the 1982 stock. The annual average change between 1993 and 2009 is the difference between the 1997 and 1992 C stocks. Using the Monte Carlo approach, SOC stock change for mineral soils was estimated 50,000 times between 1982 and 1992, and between 1992 and 1997. From the final distribution of 50,000 values, a 95 percent confidence interval was generated based on the simulated values at the 2.5 and 97.5 percentiles in the distribution (Ogle et al. 2003).

For organic soils, annual losses of CO₂ were estimated for 1992 and 1997 by applying the Monte Carlo approach to 1992 and 1997 land-use data in the United States. The results for 1992 were applied to the years 1990 through 1992, and the results for 1997 were applied to the years 1993 through 2009.

Mineral soils for the land base estimated with the Tier 2 approach accumulated about 1.7 to 3.0 Tg CO₂ Eq. annually in *Cropland Remaining Cropland*, while mineral soils in *Land Converted to Cropland* lost C at a rate of about 4.1 to 4.2 Tg CO₂ Eq. annually. Minerals soils in *Grassland Remaining Grassland* had small gains of about 0.2 to 0.3 Tg CO₂ Eq. annually and sequestered from 4.6 to 5.0 Tg CO₂ Eq. annually in *Land Converted to Grassland*. Organic soils lost about 27.4 to 27.7 Tg CO₂ Eq. annually in *Cropland Remaining Cropland* and 2.4 to 2.6 Tg CO₂ Eq. annually in *Land Converted to Cropland*, as well as an additional 3.7 to 3.9 Tg CO₂ Eq. annually in *Grassland Remaining Grassland* (Table A-240) and 0.5 to 0.9 Tg CO₂ Eq. annually in *Land Converted to Grassland*. Estimates and uncertainties are provided in Table A-240.

Table A-240: Annual Change in Soil Organic Carbon Stocks (95% Confidence Interval) for the Land Base Estimated with the Tier 2 Analysis using U.S. Factor Values, Reference Carbon Stocks, and Carbon Loss Rates (Tg CO₂ Eq./yr)

Year	Cropland Remaining Cropland		Land Converted to Cropland		Grassland Remaining Grassland*		Land Converted to Grassland*	
	Estimate	95% CI	Estimate	95% CI	Estimate	95% CI	Estimate	95% CI
Mineral Soils								
1990-1992	(1.65)	(2.6) to 5.8	4.18	2.5 to 6.0	(0.33)	(0.6) to (0.1)	(4.55)	(6.5) to (2.7)
1993-2009	(3.01)	(6.9) to 0.8	4.14	2.5 to 6.0	(0.15)	(0.4) to 0.04	(4.99)	(7.2) to (2.9)
Organic Soils								
1990-1992	27.43	18.3 to 39.4	2.42	1.4 to 3.8	3.85	1.97 to 6.4	0.47	0.22 to 0.8
		18.5 to						
1993-2009	27.68	39.5	2.64	1.5 to 4.0	3.69	1.9 to 6.1	0.88	0.4 to 1.5

* Preliminary estimates that will be finalized after public review period following completion of quality control measures.

Step 4: Compute Additional Changes in Soil Organic C Stocks Due to Organic Amendments and CRP Enrollment after 2003

There are two additional land-use and management activities in U.S. agricultural lands that were not estimated in Steps 2 and 3. The first activity involved the application of sewage sludge to agricultural lands. Minimal data exist on where and how much sewage sludge is applied to U.S. agricultural soils, but national estimates of mineral soil land area receiving sewage sludge can be approximated based on sewage sludge N production data, and the assumption that amendments are applied at a rate equivalent to the assimilative capacity from Kellogg et al. (2000). It was assumed that sewage sludge for agricultural land application was applied to grassland because of the high heavy metal content and other pollutants found in human waste, which limits its application to crops. The impact of organic amendments on SOC was

⁷³ The difference in C stocks is divided by 20 because the stock change factors represent change over a 20-year time period.

calculated as 0.38 metric tonnes C/ha-yr. This rate is based on the IPCC default method and country-specific factors (see Table A- 241), by calculating the effect of converting nominal, medium-input grassland to high input improved grassland (assuming a reference C stock of 50 metric tonnes C/ha, which represents a mid-range value for the dominant cropland soils in the United States, the land use factor for grassland (1.4) and the country-specific factor of 1.11 for high input improved grassland, with the change in stocks occurring over a 20 year (default value) time period; i.e., $[50 \times 1.4 \times 1.11 - 50 \times 1.4] / 20 = 0.38$). From 1990 through 2009, sewage sludge applications in agricultural lands increased SOC storage from 0.6 to 1.3 Tg CO₂ Eq./year (Table A- 241). A nominal ± 50 percent uncertainty was attached to these estimates due to limited information on application and the rate of change in soil C stock change with sewage sludge amendments.

The second activity was the change in enrollment for the Conservation Reserve Program after 2003 for mineral soils. Relative to the enrollment in 2003, the total area in the Conservation Reserve Program decreased from 2004 to 2009, leading to a reduction in enrollment of 0.16 million ha over the five-year period (USDA-FSA 2009). An average annual change in SOC of 0.5 metric tonnes C/ha-yr was used to estimate the effect of the enrollment changes. This rate is based on the IPCC default method and country-specific factors (see Table A-237) by calculating the impact of setting aside a medium input cropping system in the Conservation Reserve Program (assuming a reference C stock of 50 metric tonnes C/ha, which represents a mid-range value for the dominant cropland soils in the United States and the average country-specific factor of 1.2 for setting-aside cropland from production, with the change in stocks occurring over a 20 yr (default value) time period; i.e., $[50 \times 1.2 - 50] / 20 = 0.5$). While increases in enrollment from 2004 to 2009 generated additional accumulation of CO₂ Eq. annually, reductions in enrollment in 2009 caused emissions of 0.29 Tg CO₂ Eq (Table A-242). A nominal ± 50 percent uncertainty was also attached to these estimates due to limited information about the enrollment trends at subregional scales, which creates uncertainty in the rate of the soil C stock change (stock change factors for set-aside lands vary by climate region).

Step 5: Compute Net CO₂ Emissions and Removals from Agricultural Lands

The sum of total CO₂ emissions and removals from the Tier 3 Century Model Approach (Step 2), Tier 2 IPCC Methods (Step 3) and additional land-use and management considerations (Step 4) are presented in Table A-242. Overall, there was a net accumulation of 99.2 Tg CO₂ Eq. in 1990 for agricultural soils, and this rate had decreased by the end of the reporting period in 2009 to 43.4 Tg CO₂ Eq.

The total stock change (as seen in the Land Use, Land-Use Change, and Forestry chapter) as well as per hectare rate of change varies among the states (Figure A-17 and Figure A-18). On a per hectare basis, the highest rates of C accumulation occurred in the Northeast, Midwest, northern Great Plains, and Northwest. The states with highest total amounts of C sequestration were Iowa, Illinois, Missouri, Montana, Oklahoma, North Dakota, and South Dakota (Table A- 243). For organic soils, emission rates were highest in the regions that contain the majority of the drained organic soils, including California, Florida, Michigan, Minnesota, and New York. On a per hectare basis, the emission rate patterns were very similar to the total emissions in each state, with the highest rates in those regions with warmer climates and a larger proportion of the drained organic soil managed for crop production.

Figure A-17: Net C Stock Change, per Hectare, for Mineral Soils Under Agricultural Management, 2009

Figure A-18: Net C Stock Change, per Hectare, for Organic Soils Under Agricultural Management, 2009

Table A- 241: Assumptions and Calculations to Estimate the Contribution to Soil Organic Carbon Stocks from Application of Sewage Sludge to Mineral Soils

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Sewage Sludge N Applied to Agricultural Land (Mg N) ^a	52,198	55,658	59,250	62,977	65,966	69,001	72,081	75,195	78,353	80,932	83,523	86,124	88,736	91,358	93,991	98,081	100,887	103,682	106,468	109,245
Assimilative Capacity (Mg N/ha) ^b	0.120	0.120	0.120	0.122	0.122	0.122	0.122	0.122	0.122	0.122	0.122	0.122	0.122	0.122	0.122	0.122	0.122	0.122	0.122	0.122
Area covered by Available Sewage Sludge N (ha) ^c	434,985	463,816	493,746	516,202	540,707	565,583	590,828	616,357	642,240	663,381	684,612	705,932	727,341	748,836	770,418	803,942	826,940	849,851	872,686	895,452
Average Annual Rate of C storage (Mg C/ha-yr) ^d	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38
Contribution to Soil C (TgCO₂/yr)^{e,f}	(0.61)	(0.65)	(0.69)	(0.72)	(0.75)	(0.79)	(0.82)	(0.86)	(0.89)	(0.92)	(0.95)	(0.98)	(1.01)	(1.04)	(1.07)	(1.12)	(1.15)	(1.18)	(1.22)	(1.25)

Values in parentheses indicate net C storage.

^a N applied to soils described in Step 1d.

^b Assimilative Capacity is the national average amount of manure-derived N that can be applied on cropland without buildup of nutrients in the soil (Kellogg et al., 2000).

^c Area covered by sewage sludge N available for application to soils is the available N applied at the assimilative capacity rate. The 1992 assimilative capacity rate was applied to 1990 – 1992 and the 1997 rate was applied to 1993-2009.

^d Annual rate of C storage based on national average increase in C storage for grazing lands that is attributed to organic matter amendments (0.38 Mg/ha-yr)

^e Contribution to Soil C is estimated as the product of the area covered by the available sewage sludge N and the average annual C storage attributed to an organic matter amendment.

^f Some small, undetermined fraction of this applied N is probably not applied to agricultural soils, but instead is applied to forests, home gardens, and other lands.

Table A-242: Annual Soil C Stock Change in *Cropland Remaining Cropland* (CRC), *Land Converted to Cropland* (LCC), *Grassland Remaining Grassland* (GRG), and *Land Converted to Grassland* (LCG), in U.S. Agricultural Soils (Tg CO₂ Eq)

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Net emissions based on Tier 3 Century-based analysis (Step 2)																				
CRC	(55.2)	(57.5)	(68.0)	(64.2)	(62.4)	(47.6)	(55.0)	(54.1)	(44.3)	(29.7)	(54.8)	(37.6)	(36.1)	(42.3)	(42.3)	(42.3)	(42.3)	(42.3)	(42.3)	(42.3)
LCC	(4.4)	(4.3)	(4.8)	(8.7)	(12.6)	(3.8)	(4.5)	(4.2)	(10.8)	(3.3)	(4.4)	(2.5)	(2.0)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)
GRG	(55.1)	(28.0)	(9.8)	(1.5)	(66.7)	(29.5)	4.2	(20.4)	1.5	(18.9)	(55.2)	(27.3)	(46.8)	(11.7)	(11.5)	(11.3)	(11.1)	(11.0)	(10.8)	(10.6)
LCG	(15.8)	(15.1)	(13.8)	(13.5)	(17.9)	(18.2)	(15.2)	(19.9)	(17.3)	(24.0)	(23.1)	(24.0)	(22.7)	(20.7)	(20.5)	(20.3)	(20.1)	(19.9)	(19.7)	(19.5)
Net emissions based on the IPCC Tier 2 analysis (Step 3)																				
Mineral Soils																				
CRC	(1.6)	(1.6)	(1.6)	(3.0)	(3.0)	(3.0)	(3.0)	(3.0)	(3.0)	(3.0)	(3.0)	(3.0)	(3.0)	(3.0)	(3.0)	(3.0)	(3.0)	(3.0)	(3.0)	(3.0)
LCC	4.2	4.2	4.2	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1
GRG	(0.3)	(0.3)	(0.3)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)
LCG	(4.5)	(4.5)	(4.5)	(5.0)	(5.0)	(5.0)	(5.0)	(5.0)	(5.0)	(5.0)	(5.0)	(5.0)	(5.0)	(5.0)	(5.0)	(5.0)	(5.0)	(5.0)	(5.0)	(5.0)
Organic Soils																				
CRC	27.4	27.4	27.4	27.7	27.7	27.7	27.7	27.7	27.7	27.7	27.7	27.7	27.7	27.7	27.7	27.7	27.7	27.7	27.7	27.7
LCC	2.4	2.4	2.4	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6
GRG	3.9	3.9	3.9	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7
LCG	0.5	0.5	0.5	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Additional changes in net emissions from mineral soils based on application of sewage sludge to agricultural land (Step 4)																				
GRG	(0.6)	(0.6)	(0.7)	(0.7)	(0.8)	(0.8)	(0.8)	(0.9)	(0.9)	(0.9)	(1.0)	(1.0)	(1.0)	(1.0)	(1.1)	(1.1)	(1.2)	(1.2)	(1.2)	(1.3)
Additional changes in net emissions from mineral soils based on additional enrollment of CRP land (Step 4)																				
CRC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0.4)	(0.6)	(1.4)	(2.0)	(0.4)	0.3
Total Stock Changes by Land Use/Land-Use Change Category (Step 5)																				

CRC	(29.4)	(31.7)	(42.3)	(39.6)	(37.7)	(22.9)	(30.3)	(29.4)	(19.7)	(5.1)	(30.2)	(12.9)	(11.5)	(17.7)	(18.1)	(18.3)	(19.1)	(19.7)	(18.1)	(17.4)
LCC	2.2	2.3	1.8	(1.9)	(5.8)	2.9	2.2	2.6	(4.0)	3.5	2.4	4.2	4.8	5.9	5.9	5.9	5.9	5.9	5.9	5.9
GRG	(52.2)	(25.2)	(7.0)	1.3	(64.0)	(26.7)	7.0	(17.8)	4.1	(16.3)	(52.6)	(24.8)	(44.3)	(9.2)	(9.0)	(8.9)	(8.8)	(8.6)	(8.5)	(8.3)
LCG	(19.8)	(19.1)	(17.9)	(17.6)	(22.0)	(22.3)	(19.3)	(24.0)	(21.4)	(28.0)	(27.2)	(28.1)	(26.8)	(24.8)	(24.6)	(24.4)	(24.2)	(24.0)	(23.8)	(23.6)
Total *	(99.2)	(73.7)	(65.3)	(57.8)	(129.5)	(69.0)	(40.4)	(68.6)	(41.0)	(46.0)	(107.6)	(61.6)	(77.8)	(45.7)	(45.8)	(45.6)	(46.1)	(46.3)	(44.4)	(43.4)

Table A- 243: Soil C Stock Change for Mineral and Organic Soils during 2009 within individual states (Tg CO₂ Eq.)

State	Mineral Soil	Organic Soil	Total
AL	(0.45)	-	(0.45)
AR	(1.09)	-	(1.09)
AZ	(0.80)	-	(0.80)
CA	(0.16)	2.29	2.14
CO	(0.54)	0.00	(0.54)
CT	(0.06)	-	(0.06)
DE	0.02	-	0.02
FL	0.26	10.84	11.10
GA	(0.21)	-	(0.21)
HI	(0.02)	0.25	0.24
IA	(4.67)	0.75	(3.92)
ID	(1.53)	0.11	(1.43)
IL	(5.16)	0.54	(4.61)
IN	(1.72)	2.93	1.21
KS	(2.34)	-	(2.34)
KY	(1.90)	-	(1.90)
LA	(0.93)	0.07	(0.86)
MA	(0.02)	0.03	0.01
MD	(0.19)	0.03	(0.16)
ME	(0.17)	-	(0.17)
MI	(2.28)	2.72	0.43
MN	(2.57)	7.30	4.73
MO	(9.54)	-	(9.54)
MS	(1.19)	0.00	(1.18)
MT	(6.10)	0.11	(5.99)
NC	(0.35)	2.25	1.90
ND	(6.03)	-	(6.03)
NE	(2.03)	-	(2.03)
NH	(0.04)	0.01	(0.03)
NJ	(0.09)	0.01	(0.08)
NM	(1.18)	-	(1.18)
NV	(0.23)	0.00	(0.23)
NY	(1.83)	0.61	(1.23)
OH	(2.91)	0.42	(2.49)
OK	(6.48)	-	(6.48)
OR	(2.13)	0.12	(2.00)
PA	(1.85)	0.01	(1.84)
RI	(0.01)	0.00	(0.00)
SC	0.05	0.04	0.09
SD	(5.86)	-	(5.86)
TN	(1.85)	-	(1.85)
TX	5.46	-	5.46
UT	(0.02)	-	(0.02)
VA	(0.50)	0.02	(0.48)
VT	(0.28)	0.00	(0.27)
WA	(2.19)	0.26	(1.93)
WI	(2.48)	2.88	0.41
WV	(0.41)	-	(0.41)
WY	0.17	0.01	0.18

Note: Parentheses indicate net C accumulation. Estimates do not include soil C stock change associated with CRP enrollment after 2003 or sewage sludge application to soils, which were only estimated at the national scale. The sum of state results will not match the national results because state results are generated in a separate programming package, the sewage sludge and CRP enrollment after 2003 are not included, and differences arise due to rounding of values in this table.

3.14. Methodology for Estimating CH₄ Emissions from Landfills

Landfill gas is a mixture of substances generated when bacteria decompose the organic materials contained in solid waste. By volume, landfill gas is about half CH₄ and half CO₂.⁷⁴ The amount and rate of CH₄ generation depends upon the quantity and composition of the landfilled material, as well as the surrounding landfill environment.

Not all CH₄ generated within a landfill is emitted to the atmosphere. The CH₄ can be extracted and either flared or utilized for energy, thus oxidizing to CO₂ during combustion. Of the remaining CH₄, a portion oxidizes to CO₂ as it travels through the top layer of the landfill cover. In general, landfill-related CO₂ emissions are of biogenic origin and primarily result from the decomposition, either aerobic or anaerobic, of organic matter such as food or yard wastes.⁷⁵ To estimate the amount of CH₄ produced in a landfill in a given year, information is needed on the type and quantity of waste in the landfill, as well as the landfill characteristics (e.g., size, aridity, waste density). This information is not available for the majority of landfills in the United States. Consequently, to estimate CH₄ generation, a methodology was developed based on the quantity of waste placed in landfills nationwide each year, the first order decay model, and model parameters from the analysis of measured CH₄ generation rates for U.S. landfills with gas recovery systems.

From various studies and surveys of the generation and disposal of solid waste, estimates of the amount of waste placed in MSW and industrial landfills were developed. A database of measured CH₄ generation rates at landfills with gas recovery systems was compiled and analyzed. The results of this analysis and other studies were used to develop an estimate of the CH₄ generation potential for use in the first order decay model. In addition, the analysis and other studies provided estimates of the CH₄ generation rate constant as a function of precipitation. The first order decay model was applied to annual waste disposal estimates for each year and for three ranges of precipitation to estimate CH₄ generation rates nationwide for the years of interest. Based on the organic content of industrial wastes and the estimates of the fraction of these wastes sent to industrial landfills, CH₄ emissions from industrial landfills were also estimated using the first order decay model. Total CH₄ emissions were estimated by adding the CH₄ from MSW and industrial landfills and subtracting the amounts recovered for energy or flaring and the amount oxidized in the soil. The steps taken to estimate CH₄ emissions from U.S. landfills for the years 1990 through 2009 are discussed in greater detail below.

Figure A-19 presents the CH₄ emissions process—from waste generation to emissions—in graphical format.

Step 1: Estimate Annual Quantities of Solid Waste Placed in Landfills

For 1989 to 2009, estimates of the annual quantity of waste placed in MSW landfills were developed from a survey of State agencies as reported in BioCycle's State of Garbage in America (BioCycle 2008), adjusted to include U.S. territories.⁷⁶ The BioCycle survey is the only continually updated nationwide survey of waste disposed in landfills in the United States.

Table A-244 shows estimates of waste quantities contributing to CH₄ emissions. The table shows BioCycle estimates of total waste landfilled each year from 1990 through 2000, 2002, 2004, and 2006 adjusted for U.S. territories. A linear interpolation was used for 2001, 2003, 2005, 2007, 2008, and 2009 because there are no BioCycle surveys for those years. The next BioCycle survey will be published in 2011 representing 2008 data, at which time, the waste landfilled for 2007, 2008, and 2009 will be updated.

Figure A-19: Methane Emissions Resulting from Landfilling Municipal and Industrial Waste

Table A-244: Solid Waste in MSW Landfills Contributing to CH₄ Emissions (Tg unless otherwise noted)

Description	1990	1995	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Total Waste Generated ^a	271	302	377	416	455	462	470	459	448	452	456	460
Percent of Wastes Landfilled ^a	77%	63%	61%	63%	66%	65%	64%	64%	65%	65%	65%	65%

⁷⁴ Typically, landfill gas also contains small amounts of nitrogen, oxygen, and hydrogen, less than 1 percent nonmethane volatile organic compounds (NMVOCs), and trace amounts of inorganic compounds.

⁷⁵ See Box 8-1 "Biogenic Emissions and Sinks of Carbon" in the Waste chapter for additional background on how biogenic emissions of landfill CO₂ are addressed in the U.S. Inventory.

⁷⁶ Since the BioCycle survey does not include U.S. territories, waste landfilled in U.S. territories was estimated using population data for the U.S. territories (U.S. Census Bureau 2010) and the per capita rate for waste landfilled from BioCycle (2008).

Total Wastes Landfilled ^a	209	190	230	263	298	300	301	285	289	291	294	297
Waste in Place (30 years) ^b	4,674	5,075	5,400	5,488	5,608	5,759	5,909	6,058	6,198	6,328	6,458	6,587
Waste Contributing to Emissions ^c	6,815	7,796	8,828	9,092	9,390	9,690	9,991	10,286	10,574	10,866	11,160	11,457

^a Source: *BioCycle* (2008), adjusted for missing U.S. territories using U.S. Census Bureau (2010) population data and per capita disposal rate from *BioCycle*. The data, originally reported in short tons, are converted to metric tons. Estimates shown for 2001 and 2003 are based on an interpolation because there were no surveys in 2001 and 2003; estimates shown for 2005, 2007, 2008, and 2009 based on the increase in population.

^b This estimate represents the waste that has been in place for 30 years or less, which contributes about 90 percent of the CH₄ generation. Values are based on EPA (1993).

^c This estimate represents the cumulative amount of waste that has been placed in landfills from 1940 to the year indicated and is the sum of the annual disposal rates used in the first order decay model. Values are based on EPA (1993).

Estimates of the annual quantity of waste placed in landfills from 1960 through 1988 were developed from EPA's 1993 Report to Congress (EPA 1993) and a 1986 survey of MSW landfills (EPA 1988). Based on the national survey and estimates of the growth of commercial, residential and other wastes, the annual quantity of waste placed in landfills averaged 127 million metric tons in the 1960s, 154 million metric tons in the 1970s, 190 million metric tons in the 1990s, and 285 million metric tons in the 2000's. Estimates of waste placed in landfills in the 1940s and 1950s were developed based on U.S. population for each year and the per capital disposal rates from the 1960s.

Step 2: Estimate CH₄ Generation at Municipal Solid Waste Landfills

The CH₄ generation was estimated from the integrated form of the first order decay (FOD) model using the procedures and spreadsheets from IPCC (2006) for estimating CH₄ emissions from solid waste disposal. The form of the FOD model that was applied incorporates a time delay of 6 months after waste disposal before the generation of CH₄ begins.

The input parameters needed for the FOD model equations are the mass of waste disposed each year, which was discussed in the previous section, degradable organic carbon (DOC), and the decay rate constant (k). The DOC is determined from the CH₄ generation potential (L₀ in m³ CH₄/Mg waste), which is discussed in more detail in subsequent paragraphs, and the following equation:

$$\text{DOC} = [L_0 \times 6.74 \times 10^{-4}] \div [F \times 16/12 \times \text{DOC}_f \times \text{MCF}]$$

Where,

- DOC = degradable organic carbon (fraction, Gg C/Gg waste),
- L₀ = CH₄ generation potential (m³ CH₄/Mg waste),
- 6.74 × 10⁻⁴ = CH₄ density (Mg/m³),
- F = fraction of CH₄ by volume in generated landfill gas (equal to 0.5)
- 16/12 = molecular weight ratio CH₄/C,
- DOC_f = fraction of DOC that can decompose in the anaerobic conditions in the landfill (fraction equal to 0.5 for MSW), and
- MCF = methane correction factor for year of disposal (fraction equal to 1 for anaerobic managed sites).

The DOC value used in the CH₄ generation estimates from MSW landfills is 0.203 based on the CH₄ generation potential of 100 m³ CH₄/Mg waste as described below. Data from a set of 52 representative landfills across the U.S. in different precipitation ranges were chosen to evaluate L₀, and ultimately the country-specific DOC value. The 2004 Chartwell Municipal Solid Waste Facility Directory confirmed that each of the 52 landfills chosen accepted or accepts both MSW and construction and demolition (C&D) waste (Chartwell 2004; RTI 2009).

The methane generation potential (L₀) varies with the amount of organic content of the waste material. A higher L₀ occurs with a higher content of organic waste. Waste composition data is not collected for all landfills nationwide; thus a default value must be used. Values for L₀ were evaluated from landfill gas recovery data for this set of 52 landfills, which resulted in a best fit value for L₀ of 99 m³/Mg of waste (RTI 2004). This value compares favorably with a range of 50 to 162 (midrange of 106) m³/Mg presented by Peer, Thorneloe, and Epperson (1993); a range of 87 to 91 m³/Mg from a detailed analysis of 18 landfills sponsored by the Solid Waste Association of North America (SWANA 1998); and a value of 100 m³/Mg recommended in EPA's compilation of emission factors (EPA 1998; EPA 2008) based on data from 21 landfills. Based on the results from these studies, a value of 100 m³/Mg appears to be a reasonable best estimate to use in the FOD model for the national inventory.

The FOD model was applied to the gas recovery data for the 52 landfills to calculate the rate constant (k) directly for $L_0 = 100 \text{ m}^3/\text{Mg}$. The rate constant was found to increase with annual average precipitation; consequently, average values of k were developed for three ranges of precipitation, shown in Table A- 245 and recommended in EPA's compilation of emission factors (EPA 2008).

Table A- 245. Average Values for Rate Constant (k) by Precipitation Range (yr⁻¹)

Precipitation range (inches/year)	k (yr ⁻¹)
<20	0.020
20-40	0.038
>40	0.057

These values for k show reasonable agreement with the results of other studies. For example, EPA's compilation of emission factors (EPA 1998; EPA, 2008) recommends a value of 0.02 yr^{-1} for arid areas (less than 20 inches/year of precipitation) and 0.04 yr^{-1} for non-arid areas. The SWANA study of 18 landfills reported a range in values of k from 0.03 to 0.06 yr^{-1} based on CH₄ recovery data collected generally in the time frame of 1986 to 1995.

Using data collected primarily for the year 2000, the distribution of waste in place versus precipitation was developed from over 400 landfills (RTI 2004). A distribution was also developed for population vs. precipitation for comparison. The two distributions were very similar and indicated that population in areas or regions with a given precipitation range was a reasonable proxy for waste landfilled in regions with the same range of precipitation. Using U.S. Census data and rainfall data, the distributions of population versus rainfall were developed for each Census decade from 1950 through 2000. The distributions showed that the U.S. population has shifted to more arid areas over the past several decades. Consequently, the population distribution was used to apportion the waste landfilled in each decade according to the precipitation ranges developed for k, as shown in Table A-246.

Table A-246. Percent of U.S. Population within Precipitation Ranges (%)

Precipitation Range (inches/year)	1950	1960	1970	1980	1990	2000
<20	11	13	14	16	19	20
20-40	40	39	38	36	34	33
>40	49	48	48	48	47	47

Source: RTI (2004) using population data from the U.S. Bureau of Census and precipitation data from the National Climatic Data Center's National Oceanic and Atmospheric Administration.

In developing the Inventory, the proportion of waste disposed of in managed landfills versus open dumps prior to 1980 was re-evaluated. Based on the historical data presented by Mintz et al. (2003), a timeline was developed for the transition from the use of open dumps for solid waste disposed to the use of managed landfills. Based on this timeline, it was estimated that 6 percent of the waste that was land disposed in 1940 was disposed of in managed landfills and 94 percent was managed in open dumps. Between 1940 and 1980, the fraction of waste land disposed transitioned towards managed landfills until 100 percent of the waste was disposed of in managed landfills in 1980. For wastes disposed of in dumps, a methane correction factor (MCF) of 0.6 was used based on the recommended IPCC default value for uncharacterized land disposal (IPCC 2006); this MCF is equivalent to assuming 50 percent of the open dumps are deep and 50 percent are shallow. The recommended IPCC default value for the MCF for managed landfills of 1 was used for the managed landfills (IPCC 2006).

Step 3: Estimate CH₄ Generation at Industrial Landfills

Industrial landfills receive waste from factories, processing plants, and other manufacturing activities. In national inventories prior to the 1990 through 2005 inventory, CH₄ generation at industrial landfills was estimated as seven percent of the total CH₄ generation from MSW landfills, based on a study conducted by EPA (1993). For the 1990 through 2007 and current inventories, the methodology was updated and improved by using activity factors (industrial production levels) to estimate the amount of industrial waste landfilled each year and by applying the FOD model to estimate CH₄ generation. A nationwide survey of industrial waste landfills found that over 99 percent of the organic waste placed in industrial landfills originated from two industries: food processing (meat, vegetables, fruits) and pulp and paper (EPA 1993). Data for annual nationwide production for the food processing and pulp and paper industries were taken from industry and government sources for recent years; estimates were developed for production for the earlier years for which data were not available. For the pulp and paper industry, production data published by the Lockwood-Post's Directory (ERG 2010) and U.S. Department of Agriculture (2010) were the primary sources for years 1965 through 2009. An extrapolation based on U.S. real gross domestic product was used for years 1940 through 1964. For the food processing industry, production levels were obtained or developed from the U.S. Department of Agriculture (2010) for the

years 1990 through 2009 (ERG 2010). An extrapolation based on U.S. population was used for the years 1940 through 1989.

In addition to production data for the pulp and paper and food processing industries, the following inputs were needed to use the FOD model for estimating CH₄ generation from industrial landfills: 1) quantity of waste that is disposed in industrial landfills (as a function of production), 2) CH₄ generation potential (L_0) or DOC, and 3) FOD decay constant (k). Research into waste generation and disposal in landfills for the pulp and paper industry indicated that the quantity of waste landfilled was about 0.050 Mg/Mg of product compared to 0.046 Mg/Mg product for the food processing industry (Weitz and Bahner 2006). These factors were applied to estimates of annual production to estimate annual waste disposal in landfills. Estimates for DOC were derived from available data (Kraft and Orender, 1993; NCASI 2008; Flores et al. 1999). The DOC value for industrial pulp and paper waste is estimated as 0.20 (L_0 of 99 m³/Mg); the DOC value for industrial food waste is estimated as 0.26 (L_0 of 128 m³/Mg) (Coburn 2008). Estimates for k were taken from the default values in the 2006 IPCC Guidelines; the value of k given for food waste with disposal in a wet temperate climate is 0.19 yr⁻¹, and the value given for paper waste is 0.06 yr⁻¹. A literature review was conducted for the current inventory year with the intent of updating values for L_0 and k in the pulp and paper industry. Insufficient data was obtained to warrant a change for the current inventory year, but ongoing efforts may result in a U.S. industry-specific value rather than a default IPCC value in future inventory years.

As with MSW landfills, a similar trend in disposal practices from open dumps to managed landfills was expected for industrial landfills; therefore, the same time line that was developed for MSW landfills was applied to the industrial landfills to estimate the average MCF. That is, between 1940 and 1980, the fraction of waste land disposed transitioned from 6 percent managed landfills in 1940 and 94 percent open dumps to 100 percent managed landfills in 1980 and on. For wastes disposed of in dumps, an MCF of 0.6 was used and for wastes disposed of in managed landfills, an MCF of 1 was used, based on the recommended IPCC default values (IPCC 2006).

The parameters discussed above were used in the integrated form of the FOD model to estimate CH₄ generation from industrial landfills.

Step 4: Estimate CH₄ Emissions Avoided

The estimate of CH₄ emissions avoided (e.g., combusted) was based on landfill-specific data on landfill gas-to-energy (LFGTE) projects and flares. A destruction efficiency of 99 percent was applied to CH₄ recovered to estimate CH₄ emissions avoided. The value for efficiency was selected based on the range of efficiencies (98 to 100 percent) recommended for flares in EPA's "AP-42 Compilation of Air Pollutant Emission Factors, Chapter 2.4," efficiencies used to establish new source performance standards (NSPS) for landfills, and in recommendations for closed flares used in the Landfill Methane Outreach Program (LMOP).

Step 4a: Estimate CH₄ Emissions Avoided Through Landfill Gas-to-Energy (LFGTE) Projects

The quantity of CH₄ avoided due to LFGTE systems was estimated based on information from two sources: (1) a database maintained by the Energy Information Administration (EIA) for the voluntary reporting of greenhouse gases (EIA 2007) and (2) a database compiled by LMOP (EPA 2009). The EIA database included location information for landfills with LFGTE projects, estimates of CH₄ reductions, descriptions of the projects, and information on the methodology used to determine the CH₄ reductions. Generally the CH₄ reductions for each reporting year were based on the measured amount of landfill gas collected and the percent CH₄ in the gas. For the LMOP database, data on landfill gas flow and energy generation (i.e., MW capacity) were used to estimate the total direct CH₄ emissions avoided due to the LFGTE project. Detailed information on the landfill name, owner or operator, city, and state were available for both the EIA and LMOP databases; consequently, it was straightforward to identify landfills that were in both databases. The EIA database was given priority because reductions were reported for each year and were based on direct measurements. Landfills in the LMOP database that were also in the EIA database were dropped to avoid double counting.

Step 4b: Estimate CH₄ Emissions Avoided Through Flaring

The quantity of CH₄ flared was based on data from the EIA database and on information provided by flaring equipment vendors. To avoid double-counting, flares associated with landfills in the EIA and LMOP databases were excluded from the flare vendor database. As with the LFGTE projects, reductions from flaring landfill gas in the EIA database were based on measuring the volume of gas collected and the percent of CH₄ in the gas. The information provided by the flare vendors included information on the number of flares, flare design flow rates or flare dimensions, year of installation, and generally the city and state location of the landfill. When a range of design flare flow rates was provided by the flare vendor, the median landfill gas flow rate was used to estimate CH₄ recovered from each remaining

flare (i.e., for each flare not associated with a landfill in the EIA or LMOP databases). Several vendors provided information on the size of the flare rather than the flare design gas flow rate. To estimate a median flare gas flow rate for flares associated with these vendors, the size of the flare was matched with the size and corresponding flow rates provided by other vendors. Some flare vendors reported the maximum capacity of the flare. An analysis of flare capacity versus measured CH₄ flow rates from the EIA database showed that the flares operated at 51 percent of capacity when averaged over the time series and at 72 percent of capacity for the highest flow rate for a given year. For those cases when the flare vendor supplied maximum capacity, the actual flow was estimated as 50 percent of capacity. Total CH₄ avoided through flaring from the flare vendor database was estimated by summing the estimates of CH₄ recovered by each flare for each year.

Step 4c: Reduce CH₄ Emissions Avoided Through Flaring

As mentioned in Step 4b, flares in the flare vendor database associated with landfills in the EIA and LMOP databases were excluded from the flare reduction estimates in the flare vendor database. If comprehensive data on flares were available, each LFGTE project in the EIA and LMOP databases would have an identified flare because it is assumed that most LFGTE projects have flares. However, given that the flare vendor data only covers approximately 50 to 75 percent of the flare population, an associated flare was not identified for all LFGTE projects. These LFGTE projects likely have flares, yet flares were unable to be identified for one of two reasons: 1) inadequate identifier information in the flare vendor data; or 2) a lack of the flare in the flare vendor database. For those projects for which a flare was not identified due to inadequate information, CH₄ avoided would be overestimated, as both the CH₄ avoided from flaring and the LFGTE project would be counted. To avoid overestimating emissions avoided from flaring, the CH₄ avoided from LFGTE projects with no identified flares was determined and the flaring estimate from the flare vendor database was reduced by this quantity (referred to as a flare correction factor) on a state-by-state basis. This step likely underestimates CH₄ avoided due to flaring but was applied to be conservative in the estimates of CH₄ emissions avoided.

Additional effort was undertaken to improve the methodology behind the flare correction factor for the 1990-2009 Inventory to reduce the total number of flares in the flare vendor database that were not matched (512) to landfills and/or LFGTE projects in the EIA and LMOP databases. Each flare in the flare vendor database not associated with a LFGTE project in the EIA or LMOP databases was investigated to determine if it could be matched to either a landfill in the EIA database or a LFGTE project in the LMOP database. For some unmatched flares, the location information was missing or incorrectly transferred to the flare vendor database. In other instances, the landfill names were slightly different between what the flare vendor provided and the actual landfill name as listed in the EIA and LMOP databases.

It was found that a large majority of the unmatched flares are associated with landfills in LMOP that are currently flaring, but are also considering LFGTE. These landfills projects considering a LFGTE project are labeled as candidate, potential, or construction in the LMOP database. The flare vendor database was improved to match flares with operational, shutdown as well as candidate, potential, and construction LFGTE projects, thereby reducing the total number of unidentified flares in the flare vendor database, all of which are used in the flare correction factor. The results of this effort significantly decreased the number of flares used in the flare correction factor, and consequently, increased recovered flare emissions, and decreased net emissions from landfills for the 1990-2009 Inventory. The revised state-by-state flare correction factors were applied to the entire 1990 to 2009 time series for the current Inventory year.

Step 5: Estimate CH₄ Oxidation

A portion of the CH₄ escaping from a landfill oxidizes to CO₂ in the top layer of the soil. The amount of oxidation depends upon the characteristics of the soil and the environment. For purposes of this analysis, it was assumed that of the CH₄ generated, minus the amount of gas recovered for flaring or LFGTE projects, 10 percent was oxidized in the soil (Jensen and Pipatti 2002; Mancinelli and McKay 1985; Czepiel et al 1996). The factor of 10 percent is consistent with the value recommended in the 2006 IPCC revised guidelines for managed and covered landfills, and was therefore applied to the estimates of CH₄ generation minus recovery for both MSW and industrial landfills

Literature reviews were conducted in 2006 and 2010 to provide recommendations for the most appropriate oxidation rate assumptions. It was found that oxidation values are highly variable and range from zero to over 100 percent (i.e., the landfill is considered to be an atmospheric sink by virtue of the landfill gas extraction system pulling atmospheric methane down through the cover). There is considerable uncertainty and variability surrounding estimates of oxidation because it is difficult to measure and varies considerably with the thickness and type of the cover material, climate, and the presence of cracks/fissures in the cover material through which methane can escape. IPCC (2006) notes that test results from field and laboratory studies may lead to over-estimations of oxidation in landfill cover soils, because they largely determine oxidation using uniform and homogeneous soil layers. In addition, a number of studies note that gas escapes

more readily through the side slopes of a landfill as compared to moving through the cover thus complicating the correlation between oxidation and cover type or gas recovery.

Spokas et al (2005), in particular, helps to illustrate expected patterns (e.g., seasonality of generation, effectiveness of gas recovery) associated with landfill methane production and flux through the cover system. This study also highlights the large variability in oxidation between and within sites and ultimately reports oxidation ranging between 4-50 percent. All but one of the test sites had an active gas recovery system in place. For landfills with gas collection systems, there have been studies to show that gas recovery increases oxidation because it slows the flux of methane through the cover system. Although this may be true, there does not appear to be enough data to support the premise that landfills with gas recovery systems increase oxidation. This is demonstrated by the Spokas et al (2005) data where the oxidation rates were about the same for a landfill site with and without gas recovery. However, the site also had a thin temporary cover so the oxidation would be less than a site with a final cover system. Based on this and other studies, there does not appear to be adequate justification for increasing the default oxidation value for landfills with gas recovery.

Changing the oxidation rate from 10 percent to 20 percent has a minimal impact on the overall inventory results. Changing the oxidation rate from 10 percent to 60 percent has a more significant impact on the overall inventory results, lowering the overall inventory by as much as 15 to 20 percent.

The current default oxidation factor of 10 percent is recommended for all landfills in the Inventory until more reliable, peer-reviewed data is available about the influence of climate, cover type, and gas recovery is better understood.

Step 6: Estimate Total CH₄ Emissions

Total CH₄ emissions were calculated by adding emissions from MSW and industrial landfills, and subtracting CH₄ recovered and oxidized, as shown in Table A- 247.

Table A- 247: CH₄ Emissions from Landfills (Gg)

Activity	1990		1995		2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
MSW Generation	8,219		9,132		9,854	10,068	10,367	10,754	11,127	11,486	11,813	12,107	12,395	12,679
Industrial Generation	549		611		682	695	710	710	716	724	727	732	738	744
Potential Emissions	8,768		9,742		10,536	10,763	11,069	11,464	11,842	12,210	12,540	12,839	13,133	13,423
Landfill Gas-to-Energy	(649)		(1,070)		(2,352)	(2,548)	(2,589)	(2,563)	(2,673)	(2,691)	(2,807)	(3,033)	(3,189)	(3,429)
Flare	(321)		(1,298)		(2,276)	(2,491)	(2,738)	(2,886)	(3,364)	(3,566)	(3,820)	(3,918)	(3,810)	(3,779)
Emissions Avoided	(970)		(2,368)		(4,628)	(5,039)	(5,326)	(5,448)	(6,037)	(6,257)	(6,628)	(6,951)	(7,000)	(7,208)
Oxidation at MSW Landfills	(725)		(676)		(523)	(503)	(504)	(531)	(509)	(523)	(518)	(516)	(540)	(547)
Oxidation at Industrial Landfills	(55)		(61)		(68)	(70)	(70)	(71)	(72)	(73)	(73)	(73)	(74)	(74)
Net Emissions	7,018		6,637		5,317	5,152	5,169	5,414	5,224	5,358	5,321	5,299	5,520	5,593

Note: Totals may not sum exactly to the last significant figure due to rounding.

Note: MSW generation in

represents emissions before oxidation. In other tables throughout the text, MSW generation estimates account for oxidation.

Note: Parentheses denote negative values.

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Figure A-4: Domestic Greenhouse Gas Emissions by Mode and Vehicle Type, 1990 to 2009 (Tg CO₂ Eq.)

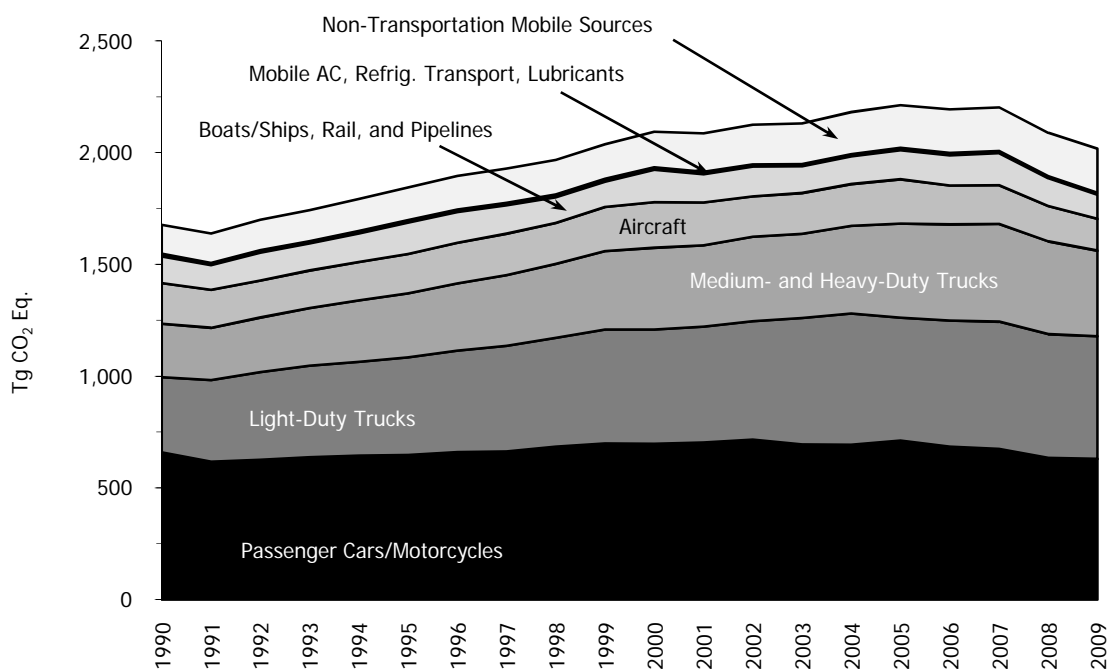


Figure A-5

Effect of Soil Temperature, Water-Filled Pore Space, and pH on Nitrification Rates

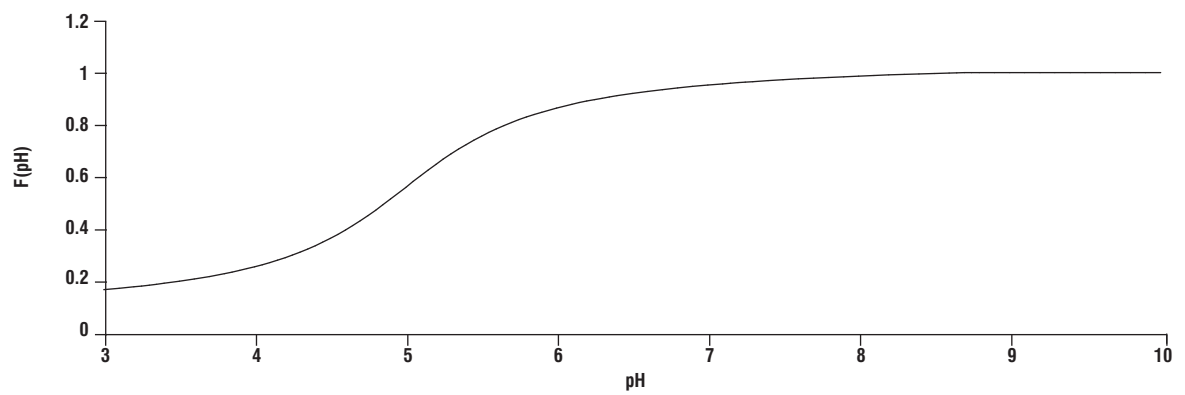
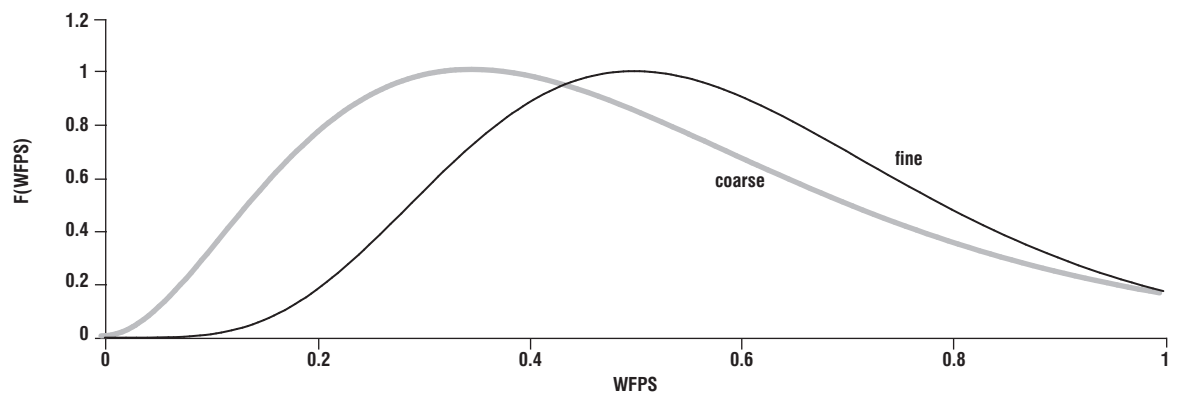
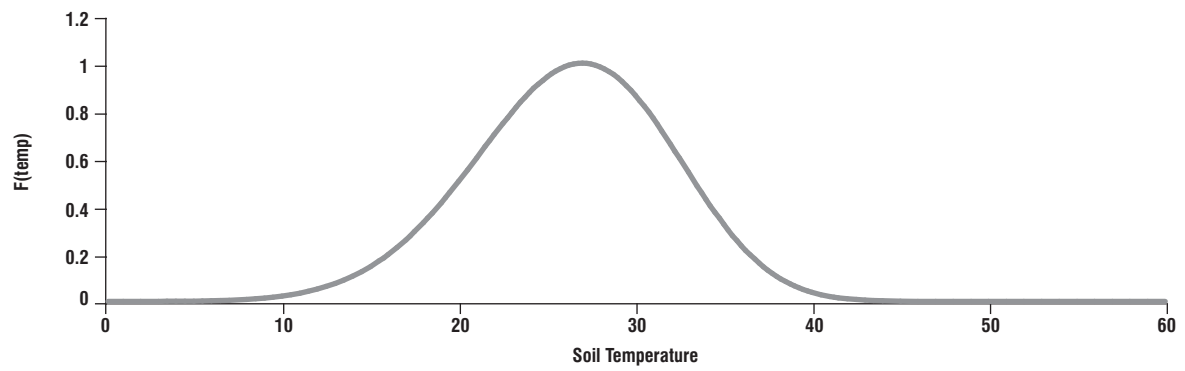
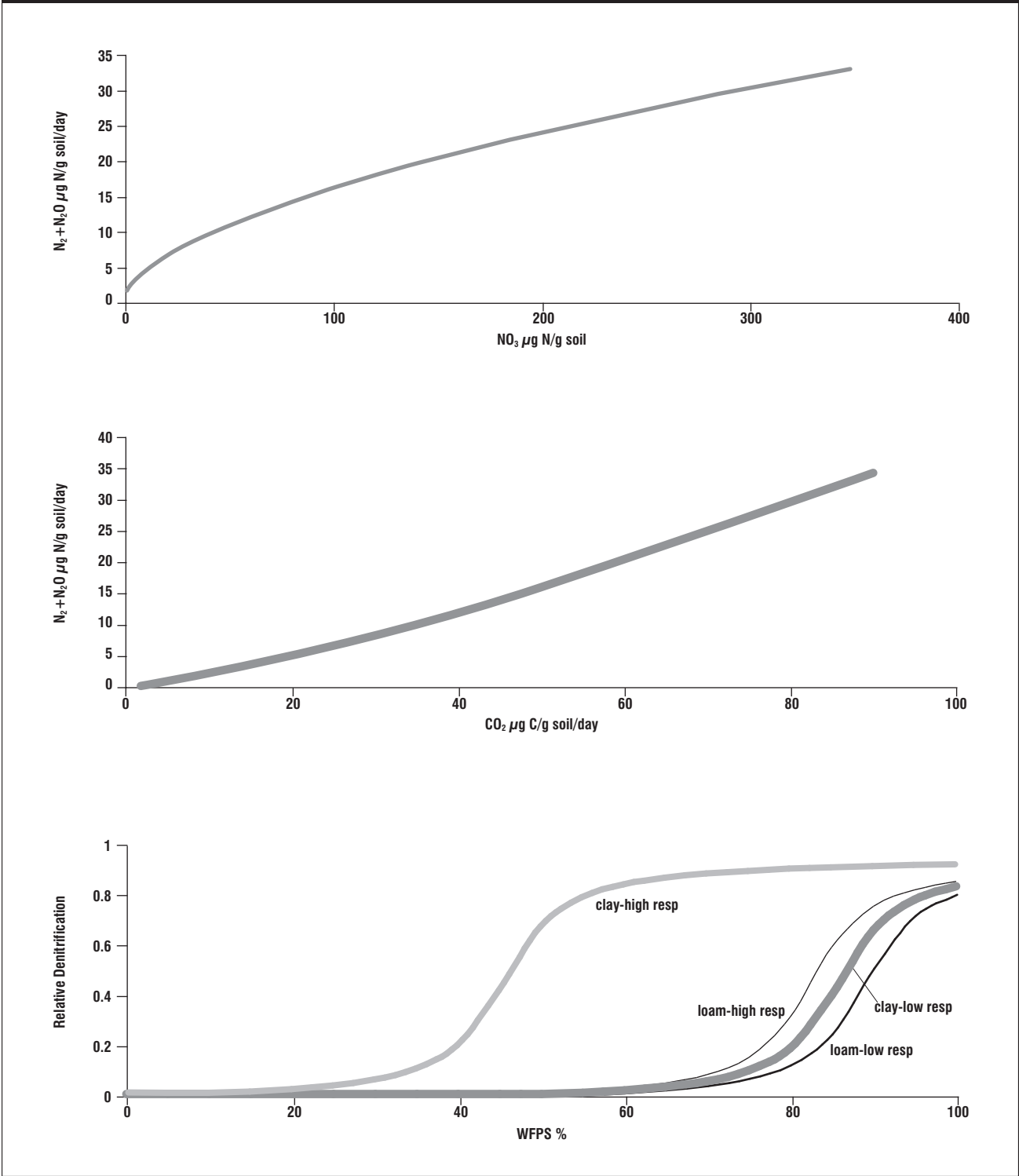


Figure A-6

Effect of Soil Nitrite Concentration, Heterotrophic Respiration Rates, and Water-Filled Pore Space on Denitrification Rates



DAYCENT MODEL

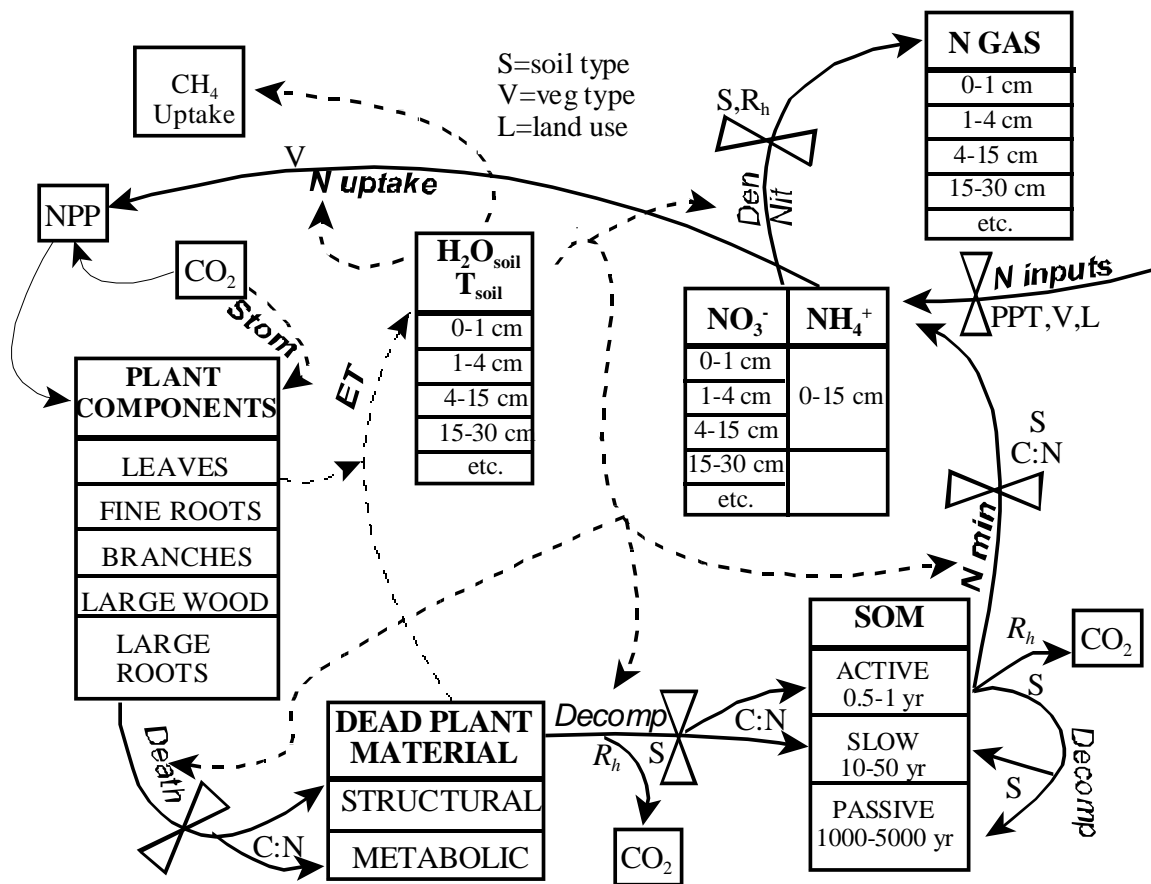


Figure A-7: DAYCENT model flow diagram

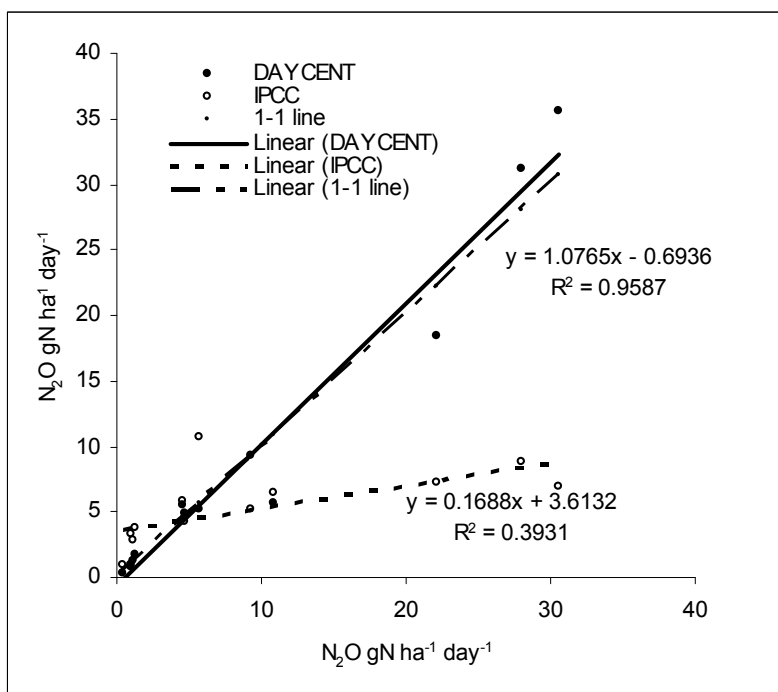


Figure A-8: Comparisons of Results from DAYCENT Model and IPCC Tier 1 Method with Measurements of Soil N₂O Emissions

Figure A-9

**Major Crops, Average Annual Direct N₂O Emissions Estimated Using the DAYCENT Model,
1990–2009 (Metric Tons CO₂ Eq./ha/year)**

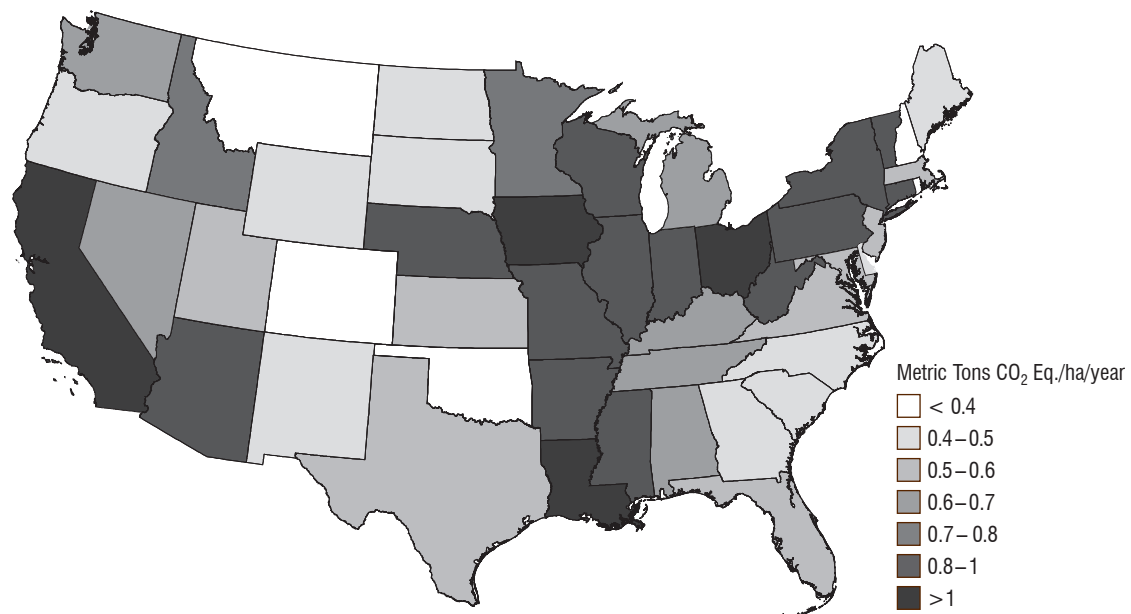


Figure A-10

Major Crops, Average Annual N losses Leading to Indirect N₂O Emissions Estimated Using the DAYCENT Model, 1990-2009 (kg N/ha/year)

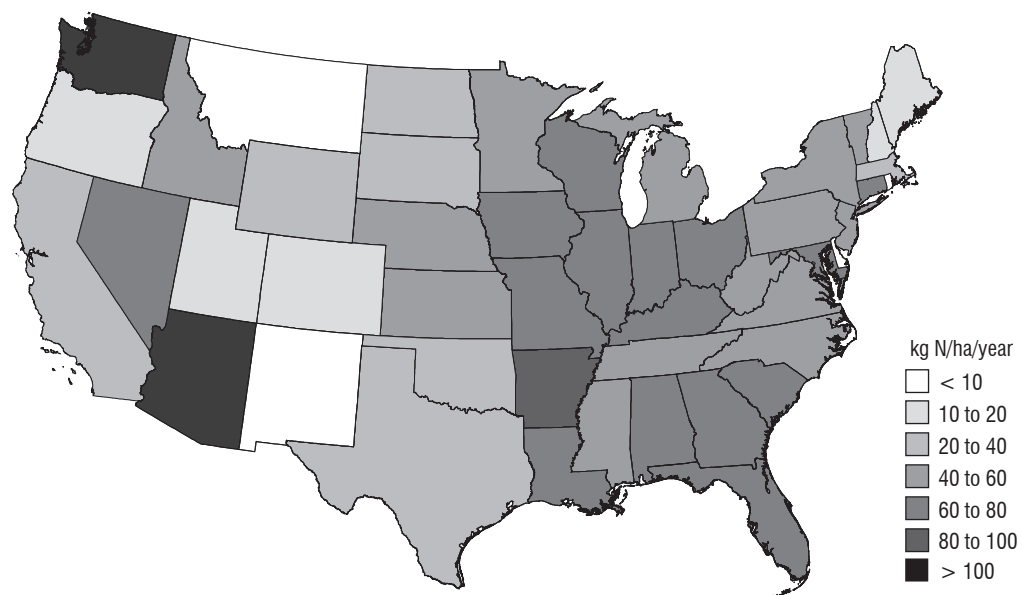


Figure A-11

**Grasslands, Average Annual Direct N₂O Emissions Estimated Using the DAYCENT Model,
1990–2009 (Metric Tons CO₂ Eq./ha/year)**

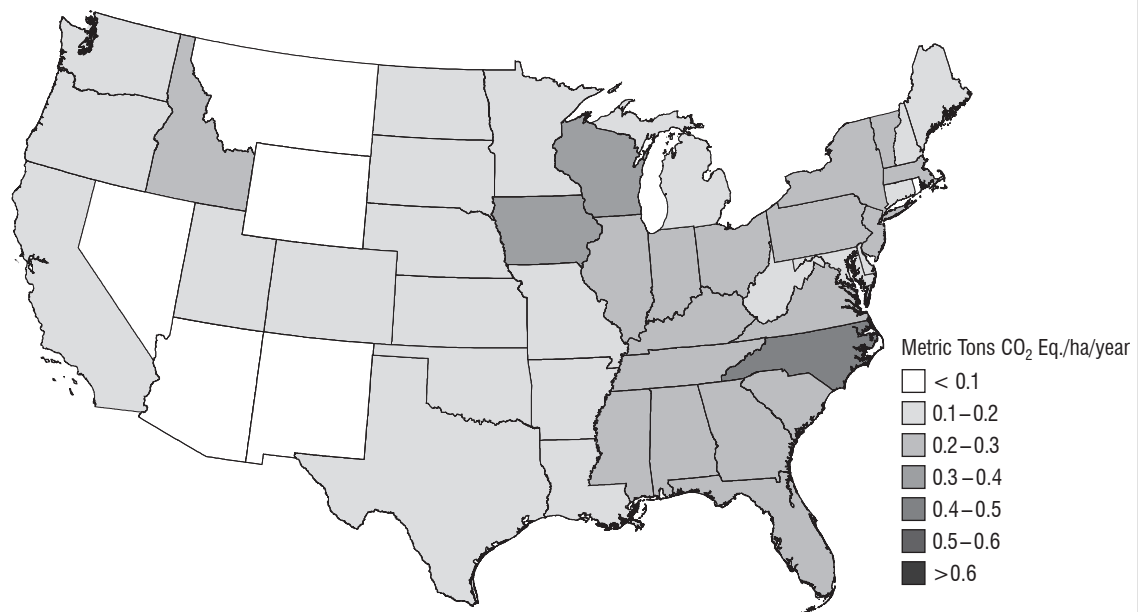


Figure A-12

Grasslands, Average Annual N Losses Leading to Indirect N₂O Emissions Estimated Using the DAYCENT Model, 1990-2009 (kg N/ha/year)

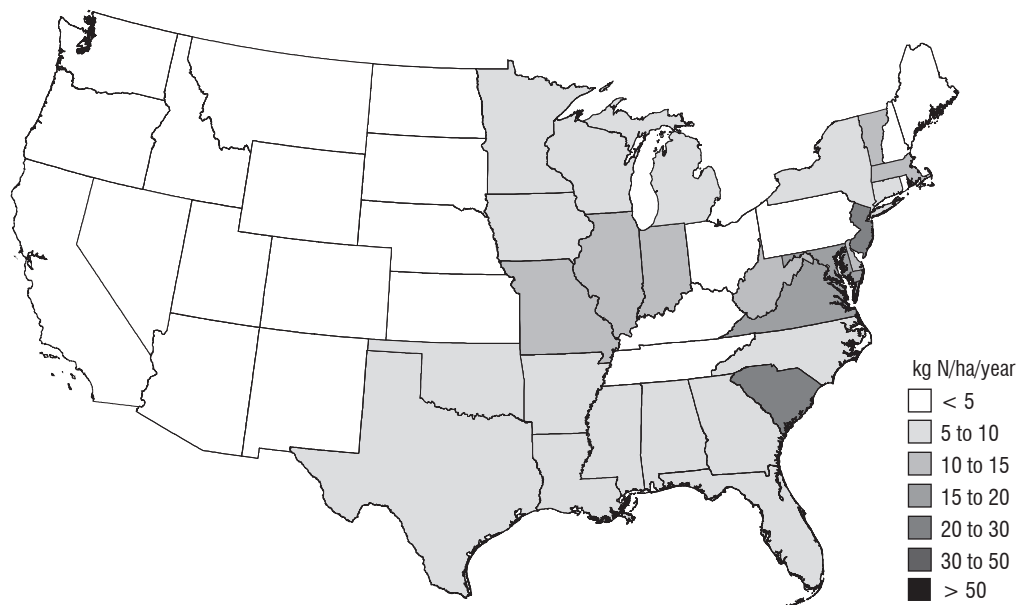


Figure A-13

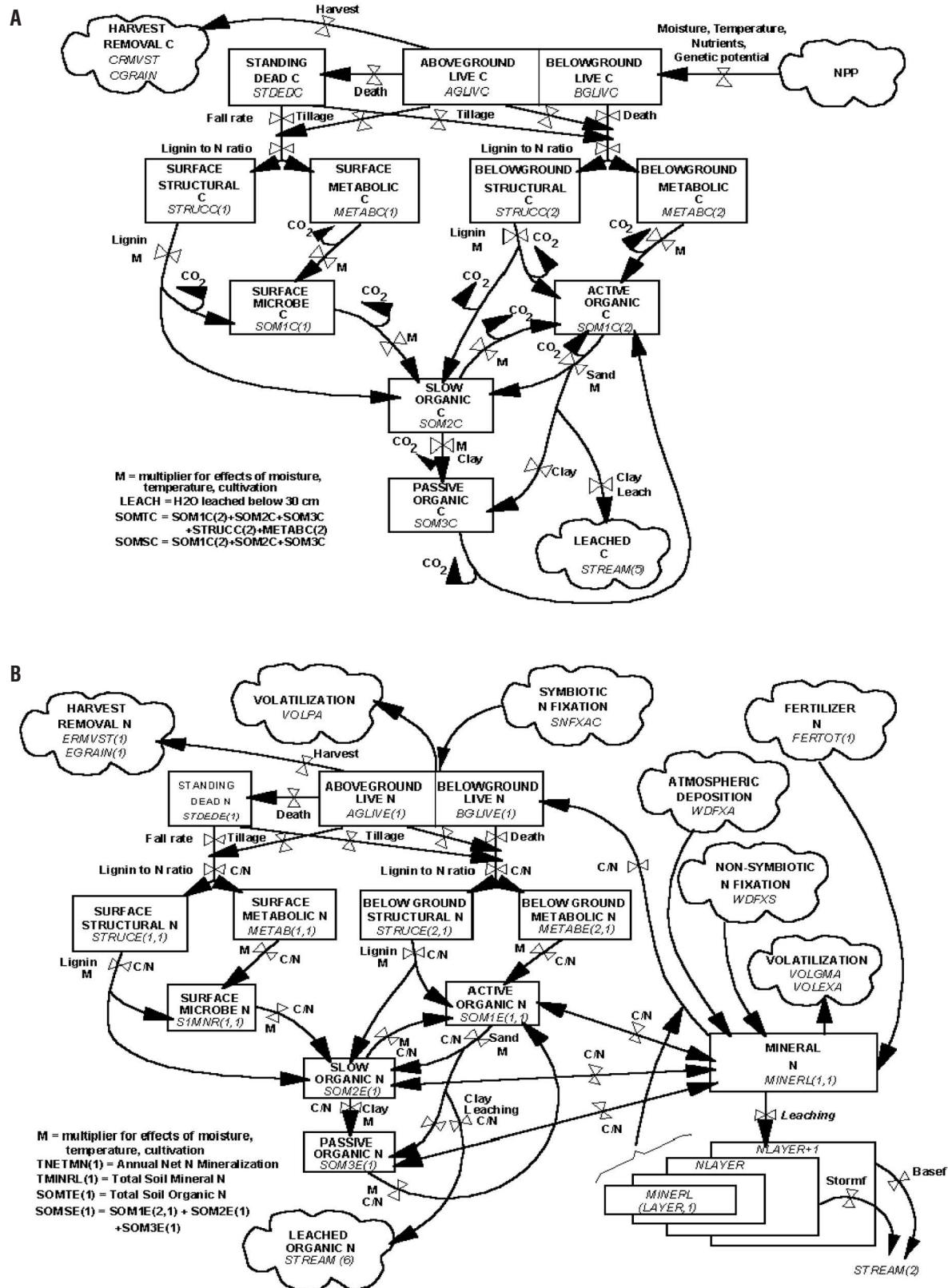


Figure A-14

Comparison of Measured Soil Organic C from Experimental Sites to Modeled Soil Organic C Using the Century Model

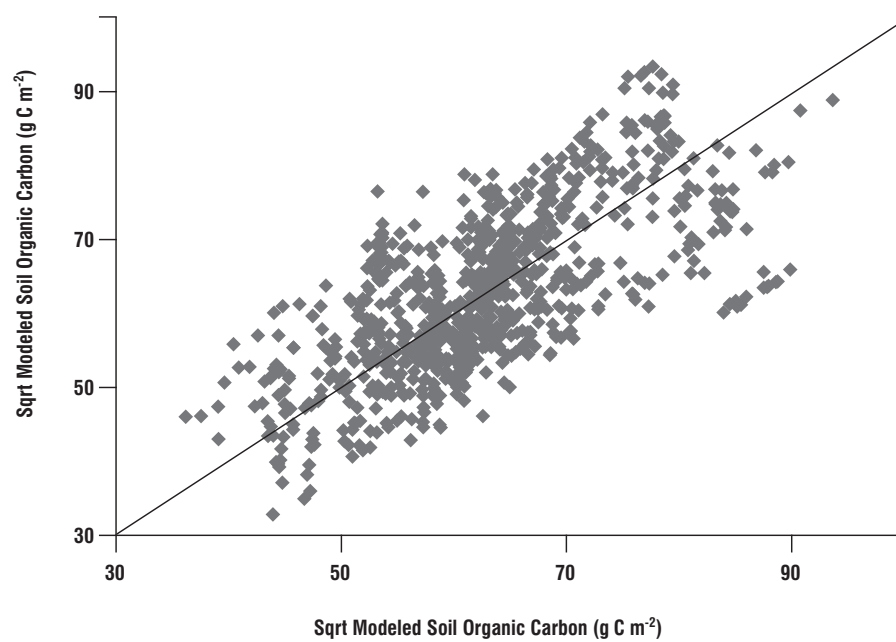
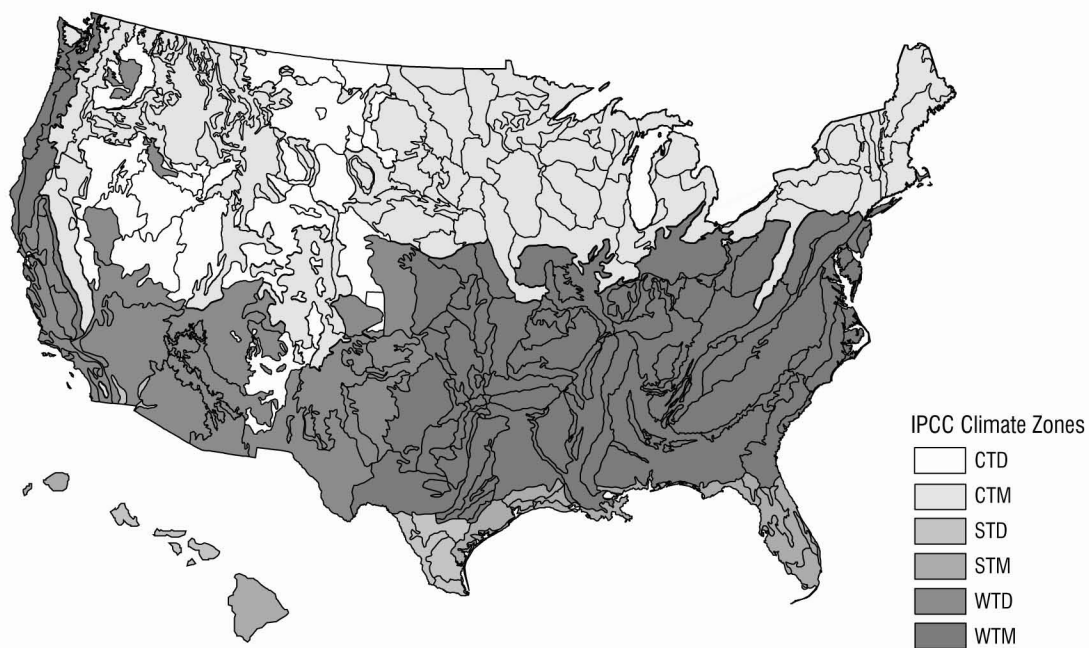
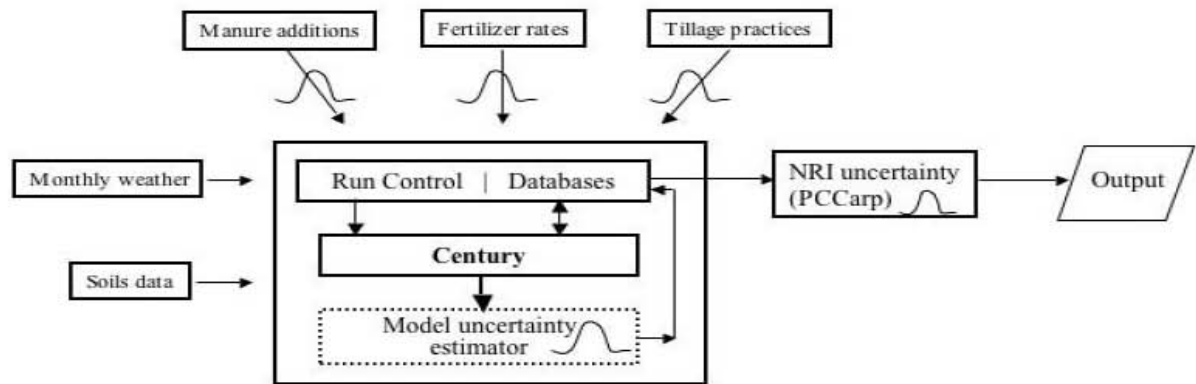


Figure A-15



This figure shows the IPCC climate zone assigned to each of the 180 Major Land Resource Areas (MLRAs) in the United States, based on PRISM climate data averaged for each MRLA.

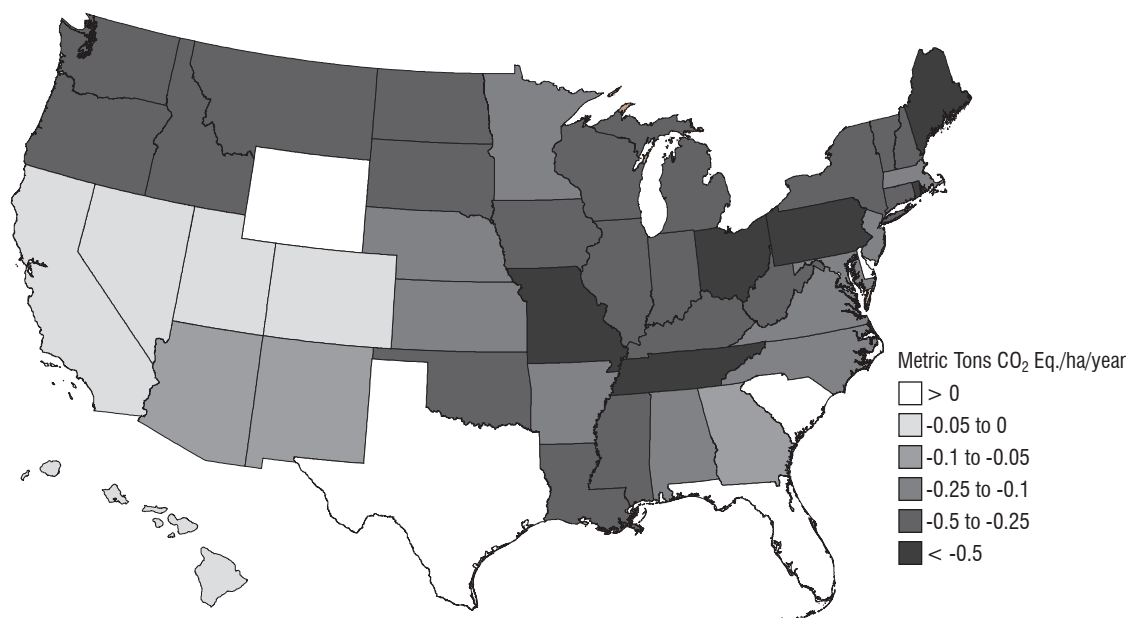
Figure A-16



Uncertainty in data inputs (i.e. fertilizer, manure and tillage practices) are estimated using a Monte-Carlo procedure with 100 random draws from input data probability distributions, for each NRI point simulated. Model uncertainty is estimated through an empirical-based approach. Uncertainty in the land representation of NRI is estimated from the statistics compiled from the NRI surveys to determine the land area expansion factors, which are used to upscale data to the national level.

Figure A-17

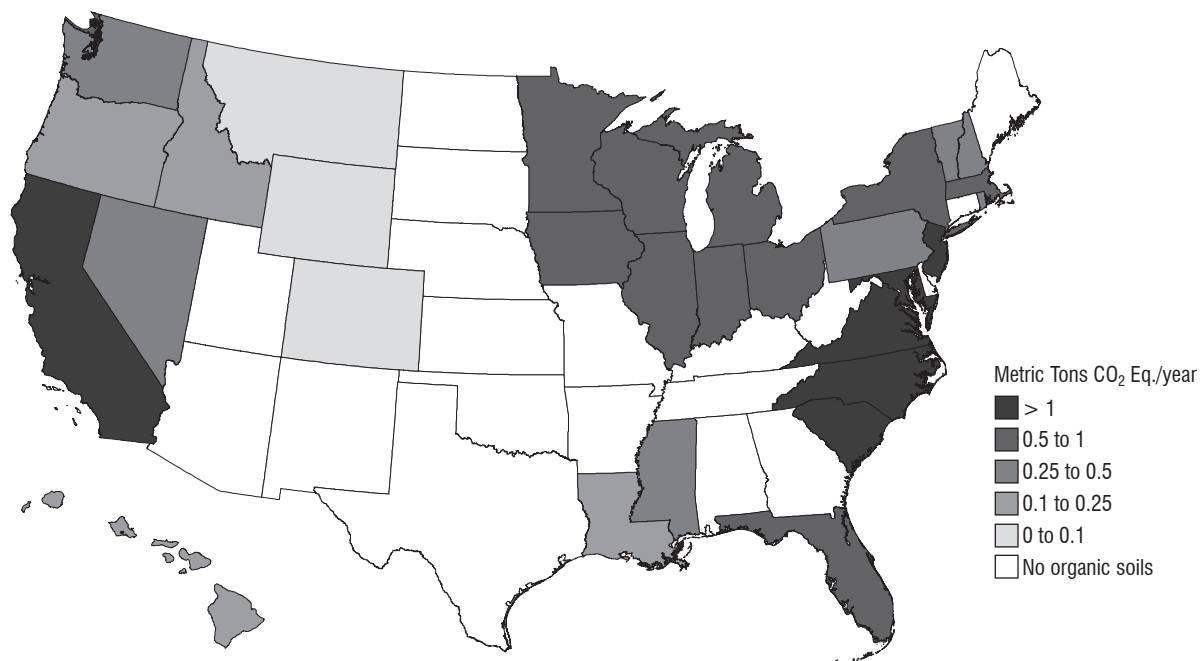
Net C Stock Change, per Hectare, for Mineral Soils Under Agricultural Management, 2009



Note: Values greater than zero represent emissions, and values less than zero represent sequestration. Map accounts for fluxes associated with the Tier 2 and 3 inventory computations. See Methodology for additional details.

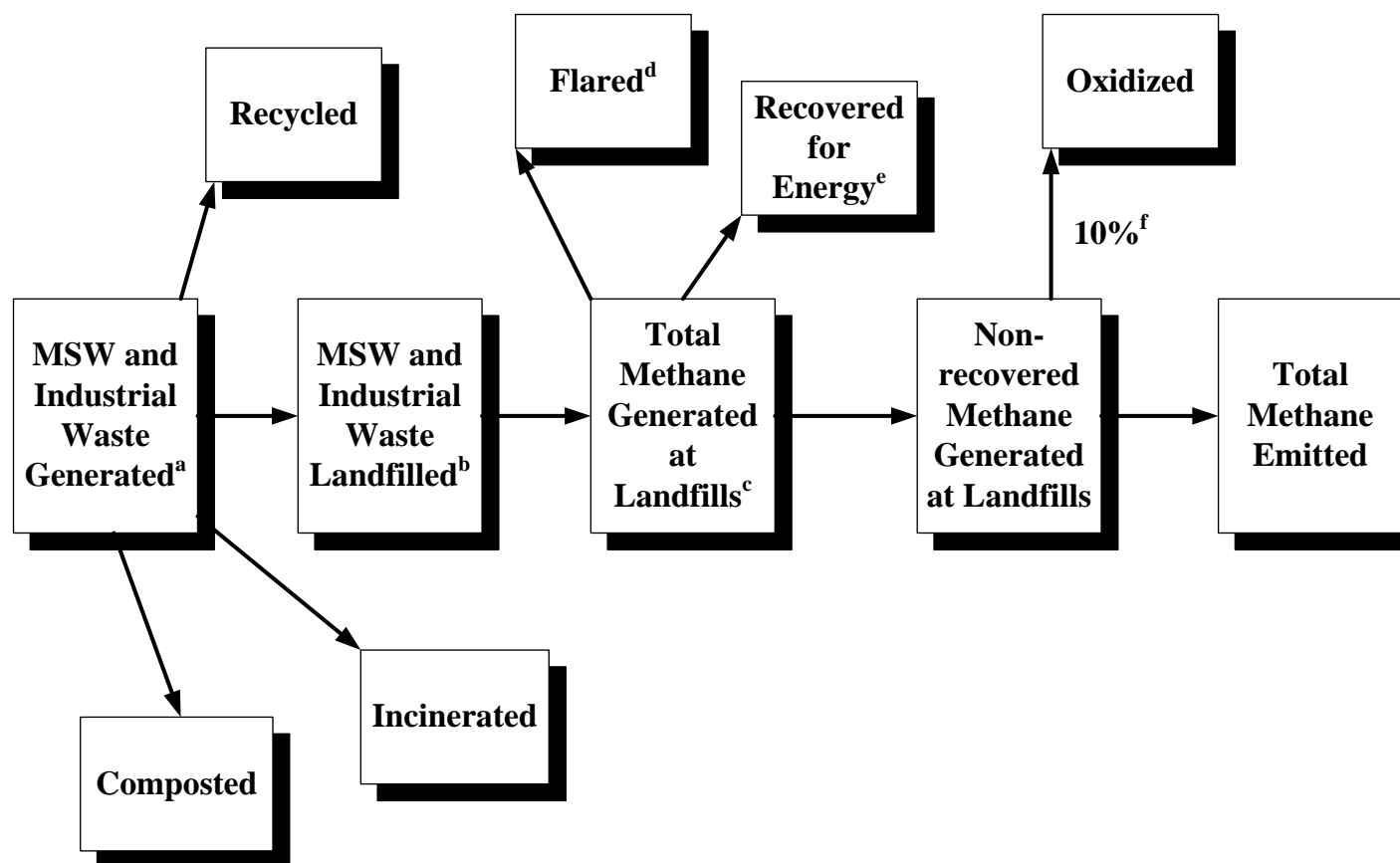
Figure A-18

Net C Stock Changes, per Hectare, for Organic Soils Under Agricultural Management, 2009



Note: Values greater than zero represent emissions.

Figure A-19: Methane Emissions Resulting from Landfilling Municipal and Industrial Waste



^a BioCycle 2006 for MSW and activity factors for industrial waste.

^b 1960 through 1988 based on EPA 1988 and EPA 1993; 1989 through 2006 based on BioCycle 2006.

^c 2006 IPCC Guidelines – First Order Decay Model.

^d EIA 2007 and flare vendor database.

^e EIA 2007 and EPA (LMOP) 2007.

^f 2006 IPCC Guidelines; Mancinelli and McKay 1985; Czepiel et al 1996

ANNEX 4 IPCC Reference Approach for Estimating CO₂ Emissions from Fossil Fuel Combustion

It is possible to estimate carbon dioxide (CO₂) emissions from fossil fuel consumption using alternative methodologies and different data sources than those described in the Estimating Emissions from Fossil Fuel Combustion Annex. For example, the UNFCCC reporting guidelines request that countries, in addition to their “bottom-up” sectoral methodology, complete a “top-down” Reference Approach for estimating CO₂ emissions from fossil fuel combustion. Section 1.3 of the *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories: Reporting Instructions* states, “If a detailed, Sectoral Approach for energy has been used for the estimation of CO₂ from fuel combustion you are still asked to complete...the Reference Approach...for verification purposes” (IPCC/UNEP/OECD/IEA 1997). This reference method estimates fossil fuel consumption by adjusting national aggregate fuel production data for imports, exports, and stock changes rather than relying on end-user consumption surveys. The basic principle is that once C-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 C 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. The following discussion provides the detailed calculations for estimating CO₂ emissions from fossil fuel combustion from the United States using the IPCC-recommended Reference Approach.

Step 1: Collect and Assemble Data in Proper Format

To ensure the comparability of national inventories, the IPCC has recommended that countries report energy data using the International Energy Agency (IEA) reporting convention. National energy statistics were collected in physical units from several EIA documents in order to obtain the necessary data on production, imports, exports, and stock changes.

It was necessary to make a number of modifications to these data to generate more accurate apparent consumption estimates of these fuels. The first modification adjusts for consumption of fossil fuel feedstocks accounted for in the Industrial Processes chapter, which include the following: unspecified coal for coal coke used in iron and steel production; natural gas, distillate fuel, and coal used in iron and steel production; natural gas used for ammonia production; petroleum coke used in the production of aluminum, ferroalloys, titanium dioxide, ammonia, and silicon carbide; and other oil and residual fuel oil used in the manufacture of C black. The second modification adjusts for the fact that EIA energy statistics include synthetic natural gas in coal and natural gas data. The third modification adjusts for the inclusion of ethanol in motor gasoline statistics. Ethanol is a biofuel, and net carbon fluxes from changes in biogenic carbon reservoirs in croplands are accounted for in the estimates for Land Use, Land-Use Change, and Forestry (see Chapter 7). The fourth modification adjusts for consumption of bunker fuels, which refer to quantities of fuels used for international transportation estimated separately from U.S. totals. The fifth modification consists of the addition of U.S. territories data that are typically excluded from the national aggregate energy statistics. The territories include Puerto Rico, U.S. Virgin Islands, Guam, American Samoa, Wake Island, and U.S. Pacific Islands. These data, as well as the production, import, export, and stock change statistics, are presented in Table A- 248.

The C content of fuel varies with the fuel's heat content. Therefore, for an accurate estimation of CO₂ emissions, fuel statistics were provided on an energy content basis (e.g., Btu or joules). Because detailed fuel production statistics are typically provided in physical units (as in Table A- 248 for 2009), they were converted to units of energy before CO₂ emissions were calculated. Fuel statistics were converted to their energy equivalents by using conversion factors provided by EIA. These factors and their data sources are displayed in Table A- 249. The resulting fuel type-specific energy data for 2009 are provided in Table A- 250.

Step 2: Estimate Apparent Fuel Consumption

The next step of the IPCC Reference Approach is to estimate “apparent consumption” of fuels within the country. This requires a balance of primary fuels produced, plus imports, minus exports, and adjusting for stock changes. In this way, C enters an economy through energy production and imports (and decreases in fuel stocks) and is transferred out of

the country through exports (and increases in fuel stocks). Thus, apparent consumption of primary fuels (including crude oil, natural gas liquids, anthracite, bituminous, subbituminous and lignite coal, and natural gas) can be calculated as follows:

$$\text{Apparent Consumption} = \text{Production} + \text{Imports} - \text{Exports} - \text{Stock Change}$$

Flows of secondary fuels (e.g., gasoline, residual fuel, coke) should be added to primary apparent consumption. The production of secondary fuels, however, should be ignored in the calculations of apparent consumption since the C contained in these fuels is already accounted for in the supply of primary fuels from which they were derived (e.g., the estimate for apparent consumption of crude oil already contains the C from which gasoline would be refined). Flows of secondary fuels should therefore be calculated as follows:

$$\text{Secondary Consumption} = \text{Imports} - \text{Exports} - \text{Stock Change}$$

Note that this calculation can result in negative numbers for apparent consumption of secondary fuels. This result is perfectly acceptable since it merely indicates a net export or stock increase in the country of that fuel when domestic production is not considered.

Next, the apparent consumption and secondary consumption need to be adjusted for feedstock uses of fuels accounted for in the Industrial Processes chapter, international bunker fuels, and U.S. territory fuel consumption. Bunker fuels and feedstocks accounted for in the Industrial Processes chapter are subtracted from these estimates, while fuel consumption in U.S. territories is added.

The IPCC Reference Approach calls for estimating apparent fuel consumption before converting to a common energy unit. However, certain primary fuels in the United States (e.g., natural gas and steam coal) have separate conversion factors for production, imports, exports, and stock changes. In these cases, it is not appropriate to multiply apparent consumption by a single conversion factor since each of its components has different heat contents. Therefore, United States fuel statistics were converted to their heat equivalents before estimating apparent consumption. Results are provided in Table A- 249.

Step 3: Estimate Carbon Emissions

Once apparent consumption is estimated, the remaining calculations are similar to those for the “bottom-up” Sectoral Approach (see Estimating Emissions from Fossil Fuel Combustion Annex). Potential CO₂ emissions were estimated using fuel-specific C coefficients (see Table A- 250).⁷⁷ The C in products from non-energy uses of fossil fuels (e.g., plastics or asphalt) was then estimated and subtracted (see Table A-252). This step differs from the Sectoral Approach in that emissions from both fuel combustion and non-energy uses are accounted for in this approach. Finally, to obtain actual CO₂ emissions, net emissions were adjusted for any C that remained unoxidized as a result of incomplete combustion (e.g., C contained in ash or soot).⁷⁸ The fraction oxidized was assumed to be 100 percent for petroleum, coal, and natural gas based on guidance in IPCC (2006) (see Estimating Emissions from Fossil Fuel Combustion Annex).

Step 4: Convert to CO₂ Emissions

Because the IPCC reporting guidelines recommend that countries report greenhouse gas emissions on a full molecular weight basis, the final step in estimating CO₂ emissions from fossil fuel consumption was converting from units of C to units of CO₂. Actual C emissions were multiplied by the molecular-to-atomic weight ratio of CO₂ to C (44/12) to obtain total CO₂ emitted from fossil fuel combustion in teragrams (Tg). The results are contained in Table A- 251.

Comparison Between Sectoral and Reference Approaches

These two alternative approaches can both produce reliable estimates that are comparable within a few percent. Note that the reference approach *includes* emissions from non-energy uses. Therefore, these totals should be compared to the aggregation of fuel use and emission totals from Emissions of CO₂ from Fossil Fuel Combustion and Carbon Emitted from Non-Energy Uses of Fossil Fuels Annexes. These two sections together are henceforth referred to as the Sectoral

⁷⁷ Carbon coefficients from EIA were used wherever possible. Because EIA did not provide coefficients for coal, the IPCC-recommended emission factors were used in the top-down calculations for these fuels. See notes in for more specific source information.

Approach. Other than this distinction, the major difference between methodologies employed by each approach lies in the energy data used to derive C emissions (i.e., the actual surveyed consumption for the Sectoral Approach versus apparent consumption derived for the Reference Approach). In theory, both approaches should yield identical results. In practice, however, slight discrepancies occur. For the United States, these differences are discussed below.

Differences in Total Amount of Energy Consumed

Table A-254 summarizes the differences between the Reference and Sectoral approaches in estimating total energy consumption in the United States. Although theoretically the two methods should arrive at the same estimate for U.S. energy consumption, the Reference Approach provides an energy total that is 1.2 percent lower than the Sectoral Approach for 2009. The greatest differences lie in lower estimates for petroleum consumption for the Reference Approach (4.2 percent) and higher estimates for natural gas consumption for the Reference Approach (2.5 percent).

There are several potential sources for the discrepancies in consumption estimates:

- *Product Definitions.* The fuel categories in the Reference Approach are different from those used in the Sectoral Approach, particularly for petroleum. For example, the Reference Approach estimates apparent consumption for crude oil. Crude oil is not typically consumed directly, but refined into other products. As a result, the United States does not focus on estimating the energy content of the various grades of crude oil, but rather estimating the energy content of the various products resulting from crude oil refining. The United States does not believe that estimating apparent consumption for crude oil, and the resulting energy content of the crude oil, is the most reliable method for the United States to estimate its energy consumption. Other differences in product definitions include using sector-specific coal statistics in the Sectoral Approach (i.e., residential, commercial, industrial coking, industrial other, and transportation coal), while the Reference Approach characterizes coal by rank (i.e. anthracite, bituminous, etc.). Also, the liquefied petroleum gas (LPG) statistics used in the bottom-up calculations are actually a composite category composed of natural gas liquids (NGL) and LPG.
- *Heat Equivalents.* It can be difficult to obtain heat equivalents for certain fuel types, particularly for categories such as "crude oil" where the key statistics are derived from thousands of producers in the United States and abroad.
- *Possible inconsistencies in U.S. Energy Data.* The United States has not focused its energy data collection efforts on obtaining the type of aggregated information used in the Reference Approach. Rather, the United States believes that its emphasis on collection of detailed energy consumption data is a more accurate methodology for the United States to obtain reliable energy data. Therefore, top-down statistics used in the Reference Approach may not be as accurately collected as bottom-up statistics applied to the Sectoral Approach.
- *Balancing Item.* The Reference Approach uses *apparent* consumption estimates while the Sectoral Approach uses *reported* consumption estimates. While these numbers should be equal, there always seems to be a slight difference that is often accounted for in energy statistics as a "balancing item."

Differences in Estimated CO₂ Emissions

Given these differences in energy consumption data, the next step for each methodology involved estimating emissions of CO₂. Table A-255 summarizes the differences between the two methods in estimated C emissions.

As mentioned above, for 2009, the Reference Approach resulted in a 1.2 percent lower estimate of energy consumption in the United States than the Sectoral Approach. The resulting emissions estimate for the Reference Approach was 0.8 percent lower. Estimates of natural gas emissions from the Reference Approach are higher (2.6 percent), and coal and petroleum emission estimates are lower (0.4 percent and 3.0 percent, respectively) than the Sectoral Approach. Potential reasons for these differences may include:

- *Product Definitions.* Coal data is aggregated differently in each methodology, as noted above. The format used for the Sectoral Approach likely results in more accurate estimates than in the Reference Approach. Also, the Reference Approach relies on a "crude oil" category for determining petroleum-related emissions. Given the many sources of crude oil in the United States, it is not an easy matter to track potential differences in C content between many different sources of crude; particularly since information on the C content of crude oil is not regularly collected.
- *Carbon Coefficients.* The Reference Approach relies on several default C coefficients by rank provided by IPCC (IPCC/UNEP/OECD/IEA 1997), while the Sectoral Approach uses annually updated category-specific coefficients by sector that are likely to be more accurate. Also, as noted above, the C coefficient for crude

oil is more uncertain than that for specific secondary petroleum products, given the many sources and grades of crude oil consumed in the United States.

Although the two approaches produce similar results, the United States believes that the “bottom-up” Sectoral Approach provides a more accurate assessment of CO₂ emissions at the fuel level. This improvement in accuracy is largely a result of the data collection techniques used in the United States, where there has been more emphasis on obtaining the detailed products-based information used in the Sectoral Approach than obtaining the aggregated energy flow data used in the Reference Approach. The United States believes that it is valuable to understand both methods.

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Table A- 248: 2009 U.S. Energy Statistics (Physical Units)

Fuel Category (Units)	Fuel Type	Production	Imports	Exports	Stock Change	Adjustment	Bunkers	U.S. Territories
Solid Fuels (Thousand Short Tons)	Anthracite Coal	1,934	a	a	a			
	Bituminous Coal	493,661	a	a	a			
	Sub-bituminous Coal	504,679	a	a	a	440		
	Lignite	72,477	a	a	a	4,643		
	Coke		347	1,307	(140)			
	Unspecified Coal		22,639	59,097	33,711	16,926		1,712
Gas Fuels (Million Cubic Feet)	Natural Gas	20,213,850	3,984,233	1,005,724	(34,253)	249,817		26,723
Liquid Fuels (Thousand Barrels)	Crude Oil	1,956,596	3,289,675	15,985	24,132			
	Nat Gas Liquids and LRGs	697,124	70,794	50,681	(14,281)			3,883
	Other Liquids		515,169	23,625	22,558			
	Motor Gasoline	53,635	81,536	71,326	(13,387)	171,416		38,289
	Aviation Gasoline		73		(158)			
	Kerosene		1,143	1,681	228			1,344
	Jet Fuel		29,488	25,230	5,428		173,089	7,360
	Distillate Fuel		82,172	214,411	19,951	552	19,286	12,755
	Residual Fuel		120,936	151,606	1,111	10,000	96,195	26,353
	Naphtha for petrochemical feedstocks		18,014		(297)			
	Petroleum Coke		6,543	142,821	(349)	10,355		
	Other Oil for petrochemical feedstocks		30,323		(115)	2,528		
	Special Naphthas		4,638	8,116	(317)			
	Lubricants		7,006	20,692	(1,805)			172
	Waxes		1,497	2,165	(71)			
	Asphalt/Road Oil		8,023	9,950	(2,303)			
	Still Gas							
	Misc. Products		80	515	(689)			9,522

[a] Included in Unspecified Coal

Data Sources: Solid and Gas Fuels: EIA (2011); Liquid Fuels: EIA (1995-2010).

Table A- 249: Conversion Factors to Energy Units (Heat Equivalents)

Fuel Category (Units)	Fuel Type	Production	Imports	Exports	Stock Change	Adjustment	Bunkers	U.S. Territories
Solid Fuels (Million Btu/Short Ton)	Anthracite Coal	22.57						
	Bituminous Coal	23.89						
	Sub-bituminous Coal	17.14				28.16		
	Lignite	12.87				12.87		
	Coke		25.00	25.63	25.00			
	Unspecified		25.00	25.97	20.86	25.85		25.14
Natural Gas (BTU/Cubic Foot)		1,026	1,025	1,009	1,026	1,025		1,026
Liquid Fuels (Million Btu/Barrel)	Crude Oil	5.80	5.99	5.80	5.80		5.80	5.80
	Nat Gas Liquids and LRGs	3.69	3.69	3.69	3.69		3.69	3.69
	Other Liquids	5.83	5.83	5.83	5.83		5.83	5.83
	Motor Gasoline	5.22	5.22	5.22	5.22	5.22	5.22	5.22
	Aviation Gasoline		5.05	5.05	5.05		5.05	5.05
	Kerosene		5.67	5.67	5.67		5.67	5.67
	Jet Fuel		5.67	5.67	5.67		5.55	5.67
	Distillate Fuel		5.83	5.83	5.83	5.83	5.83	5.83
	Residual Oil		6.29	6.29	6.29	6.29	6.29	6.29
	Naphtha for petrochemical feedstocks		5.25	5.25	5.25		5.25	5.25
	Petroleum Coke		6.02	6.02	6.02	6.02	6.02	6.02
	Other Oil for petrochemical feedstocks		5.83	5.83	5.83	5.83	5.83	5.83
	Special Naphthas		5.25	5.25	5.25		5.25	5.25
	Lubricants		6.07	6.07	6.07		6.07	6.07
	Waxes		5.54	5.54	5.54		5.54	5.54
	Asphalt/Road Oil		6.64	6.64	6.64		6.64	6.64
	Still Gas		6.00	6.00	6.00		6.00	6.00
	Misc. Products		5.80	5.80	5.80		5.80	5.80

Data Sources: Coal and lignite production: EIA (2010); Unspecified Solid Fuels: EIA (2011); Coke, Natural Gas and Petroleum Products: EIA (2011).

Table A- 250: 2009 Apparent Consumption of Fossil Fuels (TBtu)

Fuel Category	Fuel Type	Production	Imports	Exports	Stock Change	Adjustment	Bunkers	U.S. Territories	Apparent Consumption
Solid Fuels	Anthracite Coal	43.7							43.7
	Bituminous Coal	11,793.6							11,793.6
	Sub-bituminous Coal	8,650.2				12.4			8,637.8
	Lignite	932.5				59.7			872.8
	Coke		8.7	33.5	(3.5)				(21.3)
	Unspecified		566.0	1,534.9	703.2	437.4		43.0	(2,066.6)
Gas Fuels	Natural Gas	20,739.4	4,083.8	1,014.8	(35.1)	256.1		27.4	23,615.0
Liquid Fuels	Crude Oil	11,348.3	19,701.9	92.7	140.0				30,817.4
	Nat Gas Liquids and LRGs	2,572.4	261.2	187.0	(52.7)			14.3	2,713.6
	Other Liquids		3,000.9	137.6	131.4				2,731.8
	Motor Gasoline	279.9	425.5	372.2	(69.9)	894.5		199.8	(291.7)
	Aviation Gasoline		0.4		(0.8)				1.2
	Kerosene		6.5	9.5	1.3			7.6	3.3
	Jet Fuel		167.2	143.1	30.8		961.0	41.7	(925.9)
	Distillate Fuel		478.7	1,248.9	116.2	3.2	112.3	74.3	(927.8)
	Residual Oil		760.3	953.1	7.0	62.9	604.8	165.7	(701.8)
	Naphtha for petrochemical feedstocks		94.5	0.0	(1.6)				96.1
	Petroleum Coke		39.4	860.4	(2.1)	62.4			(881.2)
	Other Oil for petrochemical feedstocks		176.6		(0.7)	14.7			162.6
	Special Naphthas		24.3	42.6	(1.7)				(16.6)
	Lubricants		42.5	125.5	(10.9)			1.0	(71.0)
	Waxes		8.3	12.0	(0.4)				(3.3)
	Asphalt/Road Oil		53.2	66.0	(15.3)				2.5
	Still Gas								0.0
	Misc. Products		0.5	3.0	(4.0)			55.2	56.7
Total		56,359.8	29,900.3	6,836.8	931.3	1,803.3	1,678.1	630.1	75,640.9

Note: Totals may not sum due to independent rounding.

Table A- 251: 2009 Potential CO₂ Emissions

Fuel Category	Fuel Type	Apparent Consumption (QBtu)	Carbon Coefficients (Tg Carbon/QBtu)	Potential Emissions (Tg CO₂ Eq.)
Solid Fuels	Anthracite Coal	0.044	28.28	4.5
	Bituminous Coal	11.794	25.44	1,100.2
	Sub-bituminous Coal	8.638	26.50	839.3
	Lignite	0.873	26.65	85.3
	Coke	(0.021)	31.00	(2.4)
	Unspecified	(2.067)	25.34	(192.0)
Gas Fuels	Natural Gas	23.615	14.46	1,251.6
Liquid Fuels	Crude Oil	30.817	20.31	2,294.5
	Nat Gas Liquids and LRGs	2.714	16.90	168.2
	Other Liquids	2.732	20.31	203.4
	Motor Gasoline	(0.292)	19.46	(20.8)
	Aviation Gasoline	0.001	18.86	0.1
	Kerosene	0.003	19.96	0.2
	Jet Fuel	(0.926)	19.70	(66.9)
	Distillate Fuel	(0.928)	20.17	(68.6)
	Residual Oil	(0.702)	20.48	(52.7)
	Naphtha for petrochemical feedstocks	0.096	18.55	6.5
	Petroleum Coke	(0.881)	27.85	(90.0)
	Other Oil for petrochemical feedstocks	0.163	20.17	12.0
	Special Naphthas	(0.017)	19.74	(1.2)
	Lubricants	(0.071)	20.20	(5.3)
	Waxes	(0.003)	19.80	(0.2)
	Asphalt/Road Oil	0.002	20.55	0.2
	Still Gas	-	18.20	0.0
	Misc. Products	0.057	20.31	4.2
Total				5,470.2

Data Sources: C content coefficients by coal rank from USGS (1998) and SAIC (2004); Unspecified Solid Fuels, EIA (2011), Natural Gas and Liquid Fuels: EPA (2010).

Note: Totals may not sum due to independent rounding.

Table A-252: 2009 Non-Energy Carbon Stored in Products

Fuel Type	Consumption for Non- Energy Use (TBtu)	Carbon Coefficients (Tg Carbon/QBtu)	Carbon Content (Tg Carbon)	Fraction Sequestered	Carbon Stored (Tg CO₂ Eq.)
Coal	6.1	31.00	0.2	0.10	0.07
Natural Gas	366.0	14.46	5.3	0.58	11.26
Asphalt & Road Oil	873.1	20.55	17.9	1.00	65.51
LPG	1,446.2	17.06	24.7	0.58	52.53
Lubricants	262.6	20.20	5.3	0.09	1.79
Pentanes Plus	93.4	19.10	1.8	0.58	3.80
Petrochemical Feedstocks	[a]	[a]	[a]	[a]	40.33
Petroleum Coke	133.0	27.85	3.7	0.30	4.08
Special Naphtha	44.2	19.74	0.9	0.58	1.86
Waxes/Misc.	[a]	[a]	[a]	[a]	1.16
Misc. U.S. Territories Petroleum	[a]	[a]	[a]	[a]	0.41
Total					182.8

[a] Values for Misc. U.S. Territories Petroleum, Petrochemical Feedstocks and Waxes/Misc. are not shown because these categories are aggregates of numerous smaller components.

Note: Totals may not sum due to independent rounding.

Table A-253: 2009 Reference Approach CO₂ Emissions from Fossil Fuel Consumption (Tg CO₂ Eq. unless otherwise noted)

Fuel Category	Potential Emissions	Carbon Sequestered	Net Emissions	Fraction Oxidized	Total Emissions
Coal	1,834.9	0.1	1,834.8	100.0%	1,834.8
Petroleum	2,383.7	171.4	2,212.2	100.0%	2,212.2
Natural Gas	1,251.6	11.3	1,240.4	100.0%	1,240.4
Total	5,470.2	182.8	5,287.4	-	5,287.4

Note: Totals may not sum due to independent rounding.

Table A-254: Fuel Consumption in the United States by Estimating Approach (Tbtu)^a

Approach	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Sectoral	69,673.0	74,908.3	77,350.2	78,415.8	78,839.3	80,176.1	82,614.3	81,106.1	81,849.5	82,331.7	83,947.2	84,044.3	82,662.2	84,108.4	81,278.7	76,567.5
Coal	18,071.8	19,186.2	20,067.4	20,528.6	20,822.8	20,829.6	21,747.8	21,120.4	21,191.2	21,624.8	21,892.4	22,186.3	21,832.9	22,076.5	21,749.5	19,302.0
Natural Gas	19,184.0	22,169.5	22,589.0	22,722.9	22,323.2	22,365.5	23,391.9	22,466.2	23,211.4	22,561.3	22,609.4	22,278.5	21,945.6	23,412.6	23,536.9	23,046.2
Petroleum	32,417.2	33,552.6	34,693.8	35,164.4	35,693.3	36,981.0	37,474.6	37,519.6	37,446.9	38,145.6	39,445.4	39,579.5	38,883.7	38,619.3	35,992.3	34,219.4
Reference (Apparent)	68,941.1	73,951.5	76,275.2	77,822.5	77,838.5	79,082.3	81,543.6	80,610.7	81,307.1	81,732.9	83,416.2	83,495.8	81,854.4	83,727.5	79,932.4	75,640.9
Coal	17,572.2	18,566.7	19,424.8	20,104.6	19,980.4	20,029.1	20,956.8	20,709.5	20,796.7	21,080.5	21,734.5	21,985.5	21,532.4	21,586.3	21,388.5	19,259.9
Natural Gas	19,672.0	22,274.0	22,695.8	22,827.8	22,403.3	22,458.4	23,483.9	22,535.5	23,276.0	22,630.3	22,676.2	22,344.8	22,014.7	23,473.0	23,609.6	23,615.0
Petroleum	31,696.8	33,110.8	34,154.5	34,890.0	35,454.8	36,594.7	37,102.9	37,365.7	37,234.3	38,022.1	39,005.6	39,165.4	38,307.3	38,668.1	34,934.3	32,766.0
Difference	-1.1%	-1.3%	-1.4%	-0.8%	-1.3%	-1.4%	-1.3%	-0.6%	-0.7%	-0.7%	-0.6%	-0.7%	-1.0%	-0.5%	-1.7%	-1.2%
Coal	-2.8%	-3.2%	-3.2%	-2.1%	-4.0%	-3.8%	-3.6%	-1.9%	-1.9%	-2.5%	-0.7%	-0.9%	-1.4%	-2.2%	-1.7%	-0.2%
Natural Gas	2.5%	0.5%	0.5%	0.5%	0.4%	0.4%	0.4%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	2.5%
Petroleum	-2.2%	-1.3%	-1.6%	-0.8%	-0.7%	-1.0%	-1.0%	-0.4%	-0.6%	-0.3%	-1.1%	-1.0%	-1.5%	0.1%	-2.9%	-4.2%

* Includes U.S. territories. Does not include international bunker fuels.

Note: Totals may not sum due to independent rounding.

Table A-255: CO₂ Emissions from Fossil Fuel Combustion by Estimating Approach (Tg CO₂ Eq.)

Approach	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Sectoral	4,856.7	5,170.4	5,352.3	5,428.0	5,474.5	5,558.6	5,739.4	5,655.4	5,693.2	5,752.1	5,858.9	5,896.2	5,798.3	5,893.6	5,706.5	5,331.9
Coal	1,718.7	1,823.3	1,906.8	1,949.9	1,979.8	1,982.8	2,071.4	2,011.3	2,021.7	2,065.8	2,092.7	2,120.9	2,083.4	2,106.6	2,075.9	1,842.1
Natural Gas	1,006.8	1,164.7	1,186.5	1,193.1	1,169.3	1,172.4	1,226.4	1,177.7	1,217.6	1,181.8	1,184.9	1,167.5	1,149.9	1,226.6	1,234.8	1,209.1
Petroleum	2,131.1	2,182.4	2,259.0	2,285.0	2,325.4	2,403.4	2,441.7	2,466.5	2,453.9	2,504.6	2,581.3	2,607.9	2,565.0	2,560.4	2,395.8	2,280.8
Reference (Apparent)	4,802.2	5,130.6	5,303.0	5,421.9	5,427.4	5,501.3	5,686.5	5,650.1	5,690.1	5,741.1	5,872.1	5,891.3	5,770.6	5,880.8	5,630.2	5,287.4
Coal	1,654.1	1,756.2	1,837.0	1,901.8	1,894.4	1,902.9	1,989.0	1,967.6	1,976.4	2,002.2	2,065.2	2,088.1	2,049.5	2,054.3	2,036.7	1,834.8
Natural Gas	1,034.0	1,171.4	1,193.3	1,200.0	1,174.5	1,178.3	1,232.2	1,181.5	1,221.9	1,187.0	1,190.7	1,171.7	1,154.0	1,230.8	1,239.2	1,240.4
Petroleum	2,114.1	2,202.9	2,272.7	2,320.1	2,358.5	2,420.1	2,465.2	2,501.0	2,491.9	2,551.8	2,616.3	2,631.5	2,567.1	2,595.6	2,354.2	2,212.2
Difference	-1.1%	-0.8%	-0.9%	-0.1%	-0.9%	-1.0%	-0.9%	-0.1%	-0.1%	-0.2%	0.2%	-0.1%	-0.5%	-0.2%	-1.3%	-0.8%
Coal	-3.8%	-3.7%	-3.7%	-2.5%	-4.3%	-4.0%	-4.0%	-2.2%	-2.2%	-3.1%	-1.3%	-1.5%	-1.6%	-2.5%	-1.9%	-0.4%
Natural Gas	2.7%	0.6%	0.6%	0.6%	0.4%	0.5%	0.5%	0.3%	0.3%	0.4%	0.5%	0.4%	0.4%	0.3%	0.4%	2.6%
Petroleum	-0.8%	0.9%	0.6%	1.5%	1.4%	0.7%	1.0%	1.4%	1.5%	1.9%	1.4%	0.9%	0.1%	1.4%	-1.7%	-3.0%

* Includes U.S. territories. Does not include international bunker fuels.

Note: Totals may not sum due to independent rounding.

ANNEX 5 Assessment of the Sources and Sinks of Greenhouse Gas Emissions Not Included

Although this report is intended to be a comprehensive assessment of anthropogenic⁷⁹ sources and sinks of greenhouse gas emissions for the United States, certain sources have been identified but not included in the estimates presented for various reasons. Before discussing these sources, however, it is important to note that processes or activities that are not *anthropogenic in origin* or do not result in a *net source or sink* of greenhouse gas emissions are intentionally excluded from a national inventory of anthropogenic greenhouse gas emissions, in line with guidance from the IPCC in their guidelines for national inventories.

Given a source category that is both anthropogenic and results in net greenhouse gas emissions, reasons for not including a source related to an anthropogenic activity include one or more of the following:

- Though an estimating method has been developed, data were not adequately available to calculate emissions.
- Emissions were implicitly accounted for within another source category (e.g., CO₂ from Fossil Fuel Combustion).

It is also important to note that the United States believes that the sources discussed below are very low in comparison with the overall estimate of total U.S. greenhouse gas emissions, and not including them introduces a very minor bias. In general, the emission sources described in this annex are for source categories with methodologies introduced in the 2006 IPCC Guidelines for which data collection has not been sufficient to pursue an initial estimation of greenhouse gases.

N₂O from Caprolactam Production

Caprolactam is a widely used chemical intermediate, primarily to produce nylon-6. All processes for producing caprolactam involve the catalytic oxidation of ammonia, with N₂O being produced as a by-product.. More research is required to determine this source's significance because there is currently insufficient information available on caprolactam production to estimate emissions in the United States.

CO₂ and CH₄ from Calcium Carbide Production

CO₂ is formed by the oxidation of petroleum coke in the production of calcium carbide. These CO₂ emissions are implicitly accounted for in the storage factor calculation for the non-energy use of petroleum coke in the Energy chapter. There is currently not sufficient data on coke consumption for calcium carbide production to estimate emissions from this source.

CO₂ from Graphite Consumption in Ferroalloy and Steel Production

Emissions from "graphite," "wood," or "biomass" in calculating CO₂ emissions from ferroalloy production, iron and steel production or other "Industrial Processes" included in Chapter 4 of the inventory are not explicitly calculated. It is assumed that 100 percent of the C used in ferroalloy production is derived from petroleum coke and that all of the C used in iron and steel production is derived from coal coke or petroleum coke. It is also assumed that all of the C used in lead and zinc production is derived from coal coke. It is possible that some non-coke C is used in the production of ferroalloys, lead, zinc, and iron and steel, but no data are available to conduct inventory calculations for sources of C other than petroleum coke and coal coke used in these processes.

⁷⁹ 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 ("2006 IPCC Guidelines for National Greenhouse Gas Inventories").

Non-fuel uses of coal coke and petroleum coke are accounted for in the Industrial Process chapter, either directly for iron and steel, aluminum, ferroalloy, lead, zinc, and titanium dioxide production, or indirectly by applying a storage factor to "uncharacterized" non-fuel uses of petroleum coke and coal coke. Non-fuel uses of wood and biomass are not accounted for in the Energy or Industrial Process chapters, as all uses of wood and biomass are accounted for in the Land Use, Land-Use Change, and Forestry chapter. It is assumed for the purposes of the CO₂ emission calculation that no wood or other biogenic C is used in any of these industrial processes. Some biogenic C may be used in these industrial processes but sufficient data to estimate emissions are not available.

Consumption of either natural or synthetic graphite is not explicitly accounted for in the Industrial Process chapter. It is assumed that all of the C used in manufacturing C anodes for production of aluminum, ferroalloys, and electric arc furnace (EAF) steel are derived directly from petroleum coke and coal tar pitch (a coal coke byproduct), not from natural graphite or synthetic graphite sources. Some amount of C used in these industrial processes may be derived from natural or synthetic graphite sources, but sufficient data to estimate emissions are not currently available.

Miscellaneous SF₆ Uses

Sulfur hexafluoride (SF₆) is used in several applications for which estimates have not been provided in this inventory. Sulfur hexafluoride may be emitted from the production, leakage, and dismantling of radar, tracer, and night vision equipment. Emissions from this source are believed to be minor, and no data were available for estimating the emissions. Sulfur hexafluoride may be used in foam insulation, for dry etching, in laser systems, for indoor air quality testing, for laboratory hood testing, for chromatography, in tandem accelerators, in loudspeakers, in shock absorbers, and for certain biomedical applications. Emissions from this source are believed to be minor, and no data were available for estimating the emissions. Sulfur hexafluoride may be emitted from the production, breakage, or leakage of soundproof double-glazed windows. Emissions from this source are believed to be minor, and no data were available for estimating the emissions. Sulfur hexafluoride may be emitted from applications involving the production of sport shoes, tires, and tennis balls. Emissions from this source are believed to be minor, and no data were available for estimating the emissions. Sulfur hexafluoride may be emitted from applications involving tracer gasses to detect leakage from pressure vessels and as a tracer gas in the open air. Emissions from this source are believed to be minor, and no data were available for estimating the emissions.

CO₂ from Non-Hazardous Industrial Waste Incineration

Waste incineration is incorporated in two sections of the energy chapter of the inventory: in the section on CO₂ emissions from waste incineration, and in the calculation of emissions and storage from non-energy uses of fossil fuels. The former section addresses fossil-derived materials (such as plastics) that are discarded as part of the municipal wastestream and combusted (generally for energy recovery). The latter addresses two types of combustion: hazardous waste incineration of organic materials (assumed to be fossil-derived), in which regulated wastes are burned without energy recovery, and burning of fossil-derived materials for energy recovery. There is one potentially important category of waste incineration that is not included in our calculus: industrial non-hazardous waste, burned for disposal (rather than energy recovery). Data are not readily available for this source; further research is needed to estimate the magnitude of CO₂ emissions.

ANNEX 6 Additional Information

6.1. Global Warming Potential Values

Global Warming Potentials (GWPs) are intended as a quantified measure of the globally averaged relative radiative forcing impacts of a particular greenhouse gas. It is defined as the cumulative radiative forcing—both direct and indirect effects—integrated over a period of time from the emission of a unit mass of gas relative to some reference gas (IPCC 1996). Carbon dioxide (CO₂) was chosen as this reference gas. Direct effects occur when the gas itself is a greenhouse gas. Indirect radiative forcing occurs when chemical 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 relationship between gigagrams (Gg) of a gas and teragrams of CO₂ equivalents (Tg CO₂ Eq.) can be expressed as follows:

$$\text{Tg CO}_2 \text{ Eq} = (\text{Gg of gas}) \times (\text{GWP}) \times \left(\frac{\text{Tg}}{1,000 \text{ Gg}} \right)$$

Where,

Tg CO ₂ Eq.	= Teragrams of Carbon Dioxide Equivalents
Gg	= Gigagrams (equivalent to a thousand metric tons)
GWP	= Global Warming Potential
Tg	= Teragrams

GWP values allow policy makers to compare the impacts of emissions and reductions of different gases. According to the IPCC, GWPs typically have an uncertainty of ± 35 percent, though some GWPs have larger uncertainty than others, especially those in which lifetimes have not yet been ascertained. In the following decision, the parties to the UNFCCC have agreed to use consistent GWPs from the IPCC Second Assessment Report (SAR), based upon a 100 year time horizon, although other time horizon values are available (see Table A-256).

In addition to communicating emissions in units of mass, Parties may choose also to use global warming potentials (GWPs) to reflect their inventories and projections in carbon dioxide-equivalent terms, using information provided by the Intergovernmental Panel on Climate Change (IPCC) in its Second Assessment Report. Any use of GWPs should be based on the effects of the greenhouse gases over a 100-year time horizon. In addition, Parties may also use other time horizons.⁸⁰

Greenhouse gases with relatively long atmospheric lifetimes (e.g., CO₂, CH₄, N₂O, HFCs, PFCs, and SF₆) tend to be evenly distributed throughout the atmosphere, and consequently global average concentrations can be determined. However, the short-lived gases such as water vapor, carbon monoxide, tropospheric ozone, other indirect greenhouse gases (e.g., NO_x and NMVOCs), and tropospheric aerosols (e.g., SO₂ products and black carbon) vary spatially, and consequently it is difficult to quantify their global radiative forcing impacts. GWP values are generally not attributed to these gases that are short-lived and spatially inhomogeneous in the atmosphere.

Table A-256: Global Warming Potentials (GWP) and Atmospheric Lifetimes (Years) of Gases Used in this Report

Gas	Atmospheric Lifetime	100-year GWP ^a	20-year GWP	500-year GWP
Carbon dioxide (CO ₂)	50-200	1	1	1
Methane (CH ₄) ^b	12±3	21	56	6.5
Nitrous oxide (N ₂ O)	120	310	280	170
HFC-23	264	11,700	9,100	9,800
HFC-32	5.6	650	2,100	200
HFC-125	32.6	2,800	4,600	920
HFC-134a	14.6	1,300	3,400	420
HFC-143a	48.3	3,800	5,000	1,400

⁸⁰ Framework Convention on Climate Change; FCCC/CP/1996/15/Add.1; 29 October 1996; Report of the Conference of the Parties at its second session; held at Geneva from 8 to 19 July 1996; Addendum; Part Two: Action taken by the Conference of the Parties at its second session; Decision 9/CP.2; Communications from Parties included in Annex I to the Convention: guidelines, schedule and process for consideration; Annex: Revised Guidelines for the Preparation of National Communications by Parties Included in Annex I to the Convention; p. 18. FCCC (1996)

HFC-152a	1.5	140	460	42
HFC-227ea	36.5	2,900	4,300	950
HFC-236fa	209	6,300	5,100	4,700
HFC-43-10mee	17.1	1,300	3,000	400
CF ₄	50,000	6,500	4,400	10,000
C ₂ F ₆	10,000	9,200	6,200	14,000
C ₃ F ₈	2,600	7,000	4,800	10,100
C ₄ F ₁₀	2,600	7,000	4,800	10,100
c-C ₄ F ₈	3,200	8,700	6,000	12,700
C ₅ F ₁₂	4,100	7,500	5,100	11,000
C ₆ F ₁₄	3,200	7,400	5,000	10,700
SF ₆	3,200	23,900	16,300	34,900

Source: IPCC (1996)

^a GWPs used in this report are calculated over 100 year time horizon.

^b The methane 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 the production of CO₂ is not included.

Table A-257 presents direct and net (i.e., direct and indirect) GWPs for ozone-depleting substances (ODSs). Ozone-depleting substances directly absorb infrared radiation and contribute to positive radiative forcing; however, their effect as ozone-depleters also leads to a negative radiative forcing because ozone itself is a potent greenhouse gas. There is considerable uncertainty regarding this indirect effect; therefore, a range of net GWPs is provided for ozone depleting substances. The IPCC Guidelines and the UNFCCC do not include reporting instructions for estimating emissions of ODSs because their use is being phased-out under the Montreal Protocol (see note below Table A-257). The effects of these compounds on radiative forcing are not addressed in this report

Table A-257: Net 100-year Global Warming Potentials for Select Ozone Depleting Substances*

Gas	Direct	Net _{min}	Net _{max}
CFC-11	4,600	(600)	3,600
CFC-12	10,600	7,300	9,900
CFC-113	6,000	2,200	5,200
HCFC-22	1,700	1,400	1,700
HCFC-123	120	20	100
HCFC-124	620	480	590
HCFC-141b	700	(5)	570
HCFC-142b	2,400	1,900	2,300
CHCl ₃	140	(560)	0
CCl ₄	1,800	(3,900)	660
CH ₃ Br	5	(2,600)	(500)
Halon-1211	1,300	(24,000)	(3,600)
Halon-1301	6,900	(76,000)	(9,300)

Source: IPCC (2001)

Parentheses indicate negative values.

Note: Because these compounds have been shown to deplete stratospheric ozone, they are typically referred to as ozone depleting substances (ODSs). However, they are also potent greenhouse gases. Recognizing the harmful effects of these compounds on the ozone layer, in 1987 many governments signed the Montreal Protocol on Substances that Deplete the Ozone Layer to limit the production and importation of a number of CFCs and other halogenated compounds. The United States furthered its commitment to phase-out ODSs by signing and ratifying the Copenhagen Amendments to the Montreal Protocol in 1992. Under these amendments, the United States committed to ending the production and importation of halons by 1994, and CFCs by 1996.

The IPCC has published its Fourth Assessment Report (AR4), providing the most current and comprehensive scientific assessment of climate change (IPCC 2007). Within this report, the GWPs of several gases were revised relative to the SAR and the IPCC's Third Assessment Report (TAR) (IPCC 2001). Thus the GWPs used in this report have been updated twice by the IPCC; although the SAR GWPs are used throughout this report, it is informative to review the changes to the GWPs and the impact such improved understanding has on the total GWP-weighted emissions of the United States. All GWPs use CO₂ as a reference gas; a change in the radiative efficiency of CO₂ thus impacts the GWP of all other greenhouse gases. Since the SAR and TAR, the IPCC has applied an improved calculation of CO₂ radiative forcing and an improved CO₂ response function. The GWPs are drawn from IPCC/TEAP (2005) and the TAR, with updates for those cases where new laboratory or radiative transfer results have been published. Additionally, the atmospheric lifetimes of some gases have been recalculated. Because the revised radiative forcing of CO₂ is about 8 percent lower than that in the TAR, the GWPs of the other gases relative to CO₂ tend to be larger, taking into account revisions in lifetimes. However, there were some instances in which other variables, such as the radiative efficiency or the chemical lifetime, were altered that resulted in further increases or decreases in particular GWP values. In addition, the values for radiative forcing and lifetimes have been calculated for a variety of halocarbons, which were not presented in the SAR. Updates in some well-mixed HFC compounds (including HFC-23, HFC-32, HFC-134a, and HFC-227ea) for

AR4 result from investigation into radiative efficiencies in these compounds, with some GWPs changing by up to 40 percent; with this change, the uncertainties associated with these well-mixed HFCs are thought to be approximately 12 percent.

Table A- 258 compares the lifetimes and GWPs for the SAR, TAR, and AR4.

Table A- 258: Comparison of GWPs and lifetimes used in the SAR, TAR, and AR4

Gas	Lifetime (years)			GWP (100 year)			Difference (relative to SAR)			
	SAR	TAR	AR4	SAR	TAR	AR4	TAR	TAR (%)	AR4	AR4 (%)
Carbon dioxide (CO₂)	50-200	5-200 ^a	5-200 ^a	1	1	1	NC	NC	NC	NC
Methane (CH₄)^b	12±3	8.4/12 ^c	8.7/12 ^c	21	23	25	2	10%	4	19%
Nitrous oxide (N₂O)	120	120/114 ^c	120/114 ^c	310	296	298	(14)	(5%)	(12)	(4%)
Hydrofluorocarbons										
HFC-23	264	260	270	11,700	12,000	14,800	300	3%	3,100	26%
HFC-32	5.6	5.0	4.9	650	550	675	(100)	(15%)	25	4%
HFC-125	32.6	29	29	2,800	3,400	3,500	600	21%	700	25%
HFC-134a	14.6	13.8	14	1,300	1,300	1,430	NC	NC	130	10%
HFC-143a	48.3	52	52	3,800	4,300	4,470	500	13%	670	18%
HFC-152a	1.5	1.4	1.4	140	120	124	(20)	(14%)	(16)	(11%)
HFC-227ea	36.5	33.0	34.2	2,900	3,500	3,220	600	21%	320	11%
HFC-236fa	209	220	240	6,300	9,400	9,810	3,100	49%	3,510	56%
HFC-245fa	NA	7.2	7.6	NA	950	1,030	NA	NA	NA	NA
HFC-365mfc	NA	9.9	6.6	NA	890	794	NA	NA	NA	NA
HFC-43-10mee	17.1	15	15.9	1,300	1,500	1,640	200	15%	340	26%
Fully Fluorinated Species										
SF ₆	3,200	3,200	3200	23,900	22,200	22,800	(1,700)	(7%)	(1,100)	(5%)
CF ₄	50,000	50,000	50,000	6,500	5,700	7,390	(800)	(12%)	890	14%
C ₃ F ₆	10,000	10,000	10,000	9,200	11,900	12,200	2,700	29%	3,000	33%
C ₃ F ₈	2,600	2,600	2,600	7,000	8,600	8,830	1,600	23%	1,830	26%
C ₄ F ₁₀	2,600	2,600	2,600	7,000	8,600	8,860	1,600	23%	1,860	27%
c-C ₄ F ₈	3,200	3,200	3,200	8,700	10,000	10,300	1,300	15%	1,600	18%
C ₅ F ₁₂	4,100	4,100	4,100	7,500	8,900	9,160	1,400	19%	1,660	22%
C ₆ F ₁₄	3,200	3,200	3,200	7,400	9,000	9,300	1,600	22%	1,900	26%
Others^d										
NF ₃	NA	740	740	NA	10,800	17,200	NA	NA	NA	NA

NC (No Change)

NA (Not Applicable)

a No single lifetime can be determined for CO₂. (See IPCC 2001)

b The methane 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 the production of CO₂ is not included.

c Methane and nitrous oxide have chemical feedback systems that can alter the length of the atmospheric response, in these cases, global mean atmospheric lifetime (LT) is given first, followed by perturbation time (PT).

d Gases whose lifetime has been determined only via indirect means or for whom there is uncertainty over the loss process.

Note: Parentheses indicate negative values.

Source: IPCC (2001)

The choice of GWPs between the SAR, TAR, and AR4 has an impact on both the overall emissions estimated by the inventory, as well as the trend in emissions over time. To summarize, Table A-259 shows the overall trend in U.S. greenhouse gas emissions, by gas, from 1990 through 2009 using the three GWP sets. The table also presents the impact of TAR and AR4 GWPs on the total emissions for 1990 and for 2009.

Table A-259: Effects on U.S. Greenhouse Gas Emissions Using TAR, SAR, and AR4 GWPs (Tg CO₂Eq)

Gas	Trend from 1990 to 2009			Revisions to Annual Estimates (relative to SAR)			
	SAR	TAR	AR4	TAR	AR4	TAR	AR4
				1990		2009	
CO ₂	405.5	405.5	405.5	NC	NC	NC	NC
CH ₄	11.4	12.5	13.6	64.3	128.5	65.4	130.7
N ₂ O	(19.6)	(18.7)	(18.8)	(14.2)	(12.2)	(13.4)	(11.4)
HFCs, PFCs, and SF ₆ *	54.1	59.8	57.3	(2.3)	11.8	3.3	15.0
Total	451.4	459.1	457.6	47.7	128.1	55.3	134.3
Percent Change	7.3%	7.4%	7.3%	0.8%	2.1%	0.8%	2.0%

NC (No Change)

*Includes NF₃

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

When the GWPs from the AR4 are applied to the emission estimates presented in this report, total emissions for the year 2009 are 6,767.5 Tg CO₂ Eq., as compared to 6,633.2 Tg CO₂ Eq. when the GWPs from the SAR are used (a 2.0 percent difference). Table A-260 provides a detailed summary of U.S. greenhouse gas emissions and sinks for 1990 through 2009, using the GWPs from the AR4. The percent change in emissions is equal to the percent change in the GWP; however, in cases where multiple gases are emitted in varying amounts the percent change is variable over the years, such as with substitutes for ozone depleting substances. Table A-261 summarizes the resulting change in emissions from SAR to AR4 GWPs for 1990 through 2009 including the percent change for 2009.

Table A-260: Recent Trends in U.S. Greenhouse Gas Emissions and Sinks using the AR4 GWPs (Tg CO₂ Eq.)

Gas/Source	1990	2000	2005	2006	2007	2008	2009
CO₂	5,099.7	5,975.0	6,113.8	6,021.1	6,120.0	5,921.4	5,505.2
Fossil Fuel							
Combustion	4,738.4	5,594.8	5,735.2	5,653.1	5,756.7	5,565.9	5,209.0
Electricity							
Generation	1,820.8	2,296.9	2,402.1	2,346.4	2,412.8	2,360.9	2,154.0
Transportation	1,485.9	1,809.5	1,896.6	1,878.1	1,894.0	1,789.9	1,719.7
Industrial	846.5	851.1	823.1	848.2	842.0	802.9	730.4
Residential	338.3	370.7	357.9	321.5	342.4	348.2	339.2
Commercial	219.0	230.8	223.5	208.6	219.4	224.2	224.0
U.S. Territories	27.9	35.9	50.0	50.3	46.1	39.8	41.7
Non-Energy Use of							
Fuels	118.6	144.9	143.4	145.6	137.2	141.0	123.4
Iron and Steel							
Production & Metallurgical							
Coke Production	99.5	85.9	65.9	68.8	71.0	66.0	41.9
Natural Gas Systems	37.6	29.9	29.9	30.8	31.1	32.8	32.2
Cement Production	33.3	40.4	45.2	45.8	44.5	40.5	29.0
Incineration of Waste	8.0	11.1	12.5	12.5	12.7	12.2	12.3
Ammonia Production and Urea							
Consumption	16.8	16.4	12.8	12.3	14.0	11.9	11.8
Lime Production	11.5	14.1	14.4	15.1	14.6	14.3	11.2
Cropland Remaining							
Cropland	7.1	7.5	7.9	7.9	8.2	8.7	7.8
Limestone and							
Dolomite Use	5.1	5.1	6.8	8.0	7.7	6.3	7.6
Soda Ash Production and Consumption	4.1	4.2	4.2	4.2	4.1	4.1	4.3
Aluminum Production	6.8	6.1	4.1	3.8	4.3	4.5	3.0
Petrochemical							
Production	3.3	4.5	4.2	3.8	3.9	3.4	2.7
Carbon Dioxide							
Consumption	1.4	1.4	1.3	1.7	1.9	1.8	1.8
Titanium Dioxide							
Production	1.2	1.8	1.8	1.8	1.9	1.8	1.5
Ferroalloy Production	2.2	1.9	1.4	1.5	1.6	1.6	1.5
Wetlands Remaining							
Wetlands	1.0	1.2	1.1	0.9	1.0	1.0	1.1
Phosphoric Acid							
Production	1.5	1.4	1.4	1.2	1.2	1.2	1.0
Zinc Production	0.7	1.0	1.1	1.1	1.1	1.2	1.0
Lead Production	0.5	0.6	0.6	0.6	0.6	0.6	0.5
Petroleum Systems	0.6	0.5	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	0.1
Land Use, Land-Use Change, and Forestry (Sink) ^a	(861.5)	(576.6)	(1,056.5)	(1,064.3)	(1,060.9)	(1,040.5)	(1,015.1)
Wood Biomass and Ethanol Consumption ^b	219.4	227.4	229.8	234.8	242.3	253.1	245.0

<i>International Bunker Fuels^c</i>	<i>111.8</i>	<i>98.5</i>	<i>109.7</i>	<i>128.4</i>	<i>127.6</i>	<i>133.7</i>	<i>123.1</i>
CH₄	803.4	785.6	751.7	800.1	791.2	805.6	817.0
Natural Gas Systems	226.0	249.2	226.7	259.1	244.3	252.2	263.4
Enteric Fermentation	157.3	162.5	162.5	165.3	167.9	167.4	166.4
Landfills	175.5	132.9	133.9	133.0	132.5	138.0	139.8
Coal Mining	100.1	71.9	67.7	69.3	68.9	79.9	84.6
Manure Management	37.8	50.5	55.4	55.6	60.4	58.8	58.9
Petroleum Systems	42.1	37.5	35.0	34.9	35.7	36.0	36.8
Wastewater							
Treatment	28.0	30.0	29.0	29.2	29.1	29.2	29.2
Forest Land							
Remaining Forest							
Land	3.8	17.0	11.7	25.7	23.8	14.2	9.3
Rice Cultivation	8.5	8.9	8.2	7.0	7.4	8.6	8.7
Stationary							
Combustion	8.8	7.9	7.8	7.3	7.7	7.7	7.3
Abandoned							
Underground							
Coal Mines	7.2	8.8	6.6	6.5	6.7	7.0	6.6
Mobile Combustion	5.6	4.0	3.0	2.8	2.6	2.4	2.3
Composting	0.4	1.5	1.9	1.9	2.0	2.0	2.0
Petrochemical							
Production	1.0	1.5	1.3	1.2	1.2	1.1	1.0
Iron and Steel							
Production & Metallurgical							
Coke Production	1.1	1.1	0.9	0.9	0.8	0.8	0.4
Field Burning of							
Agricultural							
Residues	0.3	0.3	0.2	0.3	0.3	0.3	0.3
Ferroalloy Production	+	+	+	+	+	+	+
Silicon Carbide							
Production and							
Consumption	+	+	+	+	+	+	+
Incineration of Waste	+	+	+	+	+	+	+
<i>International Bunker Fuels^c</i>	<i>0.2</i>	<i>0.1</i>	<i>0.2</i>	<i>0.2</i>	<i>0.2</i>	<i>0.2</i>	<i>0.2</i>
N₂O	303.0	327.8	310.4	313.8	312.5	298.7	284.2
Agricultural Soil							
Management	190.1	198.8	203.2	200.8	201.3	202.6	196.7
Mobile Combustion	42.2	51.1	35.5	32.3	29.1	25.1	23.0
Manure Management	13.9	16.4	16.6	17.3	17.4	17.2	17.2
Nitric Acid							
Production	17.0	18.7	15.9	15.5	18.5	15.8	14.0
Stationary							
Combustion	12.3	14.0	14.1	13.9	14.0	13.6	12.3
Forest Land							
Remaining Forest							
Land	2.6	11.6	8.0	17.3	16.1	9.7	6.5
Wastewater							
Treatment	3.5	4.3	4.6	4.6	4.7	4.8	4.8
N ₂ O from Product							
Uses	4.2	4.7	4.2	4.2	4.2	4.2	4.2
Adipic Acid							
Production	15.2	5.3	4.8	4.1	3.5	2.0	1.9
Composting	0.3	1.3	1.7	1.7	1.8	1.8	1.8
Settlements							
Remaining							
Settlements	0.9	1.1	1.4	1.4	1.5	1.5	1.5
Incineration of Waste	0.5	0.4	0.4	0.4	0.4	0.4	0.4
Field Burning of							
Agricultural							
Residues	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Wetlands Remaining							
Wetlands	+	+	+	+	+	+	+

<i>International Bunker Fuels^c</i>	1.0	0.9	1.0	1.1	1.1	1.2	1.1
HFCs, PFCs, and SF6	103.8	152.4	160.1	162.5	170.4	168.6	161.1
HFCs	46.6	116.9	134.0	137.4	144.9	144.5	139.5
Substitution of Ozone Depleting Substances ^d	0.3	80.4	113.7	119.6	123.1	126.9	132.3
HCFC-22 Production	46.1	36.2	20.0	17.5	21.5	17.2	6.8
Semiconductor Manufacture	0.2	0.3	0.3	0.3	0.3	0.4	0.4
PFCs	24.4	16.2	7.9	8.0	9.6	8.7	7.5
Semiconductor Manufacture	2.9	6.3	4.5	5.1	5.1	5.5	5.6
Aluminum Production	21.6	9.9	3.4	2.9	4.5	3.2	1.9
SF₆	32.8	19.2	18.1	17.1	15.9	15.4	14.2
Electrical Transmission and Distribution	27.1	15.3	14.4	13.4	12.6	12.7	12.2
Magnesium Production and Processing	5.2	2.9	2.8	2.7	2.5	1.8	1.0
Semiconductor Manufacture	0.5	1.0	0.9	0.9	0.8	0.8	0.9
Total	6,309.9	7,240.7	7,336.0	7,297.5	7,394.1	7,194.4	6,767.5

+ Does not exceed 0.05 Tg CO₂ Eq.

^a The net CO₂ flux total includes both emissions and sequestration, and constitutes a sink in the United States. Sinks are only included in net emissions total. Parentheses indicate negative values or sequestration.

^b Emissions from Wood Biomass and Ethanol Consumption are not included specifically in summing energy sector totals.

^c Emissions from International Bunker Fuels are not included in totals.

^d Small amounts of PFC emissions also result from this source.

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

Table A-261: Change in U.S. Greenhouse Gas Emissions and Sinks Using SAR vs. AR4 GWPs (Tg CO₂ Eq.)

Gas/Source	1990	2000	2005	2006	2007	2008	2009	Percent Change in 2009
CO₂	NC	NC	NC	NC	NC	NC	NC	NC
CH₄	128.5	125.7	120.3	128.0	126.6	128.9	130.7	19%
Natural Gas Systems	36.2	39.9	36.3	41.5	39.1	40.3	42.1	19%
Enteric Fermentation	25.2	26.0	26.0	26.4	26.9	26.8	26.6	19%
Landfills	28.1	21.3	21.4	21.3	21.2	22.1	22.4	19%
Coal Mining	16.0	11.5	10.8	11.1	11.0	12.8	13.5	19%
Manure Management	6.0	8.1	8.9	8.9	9.7	9.4	9.4	19%
Petroleum Systems	6.7	6.0	5.6	5.6	5.7	5.8	5.9	19%
Wastewater Treatment	4.5	4.8	4.6	4.7	4.7	4.7	4.7	19%
Forest Land Remaining Forest								
Land	0.6	2.7	1.9	4.1	3.8	2.3	1.5	19%
Rice Cultivation	1.4	1.4	1.3	1.1	1.2	1.4	1.4	19%
Stationary Combustion	1.4	1.3	1.2	1.2	1.2	1.2	1.2	19%
Abandoned Underground Coal Mines	1.2	1.4	1.1	1.0	1.1	1.1	1.0	19%
Mobile Combustion	0.9	0.6	0.5	0.4	0.4	0.4	0.4	19%
Composting	0.1	0.2	0.3	0.3	0.3	0.3	0.3	19%
Petrochemical Production	0.2	0.2	0.2	0.2	0.2	0.2	0.2	19%
Iron and Steel Production & Metallurgical Coke Production	0.2	0.2	0.1	0.1	0.1	0.1	0.1	19%
Field Burning of Agricultural Residues	0.1	+	+	+	+	0.1	+	19%
Ferroalloy Production	+	+	+	+	+	+	+	19%
Silicon Carbide Production and Consumption	+	+	+	+	+	+	+	19%
Incineration of Waste	+	+	+	+	+	+	+	19%
<i>International Bunker Fuels^a</i>	+	+	+	+	+	+	+	19%
N₂O	(12.2)	(13.2)	(12.5)	(12.6)	(12.6)	(12.0)	(11.4)	(4%)

Agricultural Soil Management	(7.7)	(8.0)	(8.2)	(8.1)	(8.1)	(8.2)	(7.9)	(4%)
Mobile Combustion	(1.7)	(2.1)	(1.4)	(1.3)	(1.2)	(1.0)	(0.9)	(4%)
Manure Management	(0.6)	(0.7)	(0.7)	(0.7)	(0.7)	(0.7)	(0.7)	(4%)
Nitric Acid Production	(0.7)	(0.8)	(0.6)	(0.6)	(0.7)	(0.6)	(0.6)	(4%)
Stationary Combustion	(0.5)	(0.6)	(0.6)	(0.6)	(0.6)	(0.5)	(0.5)	(4%)
Forest Land Remaining Forest Land	(0.1)	(0.5)	(0.3)	(0.7)	(0.6)	(0.4)	(0.3)	(4%)
Wastewater Treatment	(0.1)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(4%)
N2O from Product Uses	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(4%)
Adipic Acid Production	(0.6)	(0.2)	(0.2)	(0.2)	(0.1)	(0.1)	(0.1)	(4%)
Composting	(+)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(4%)
Settlements Remaining								
Settlements	(+)	(+)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(4%)
Incineration of Waste	(+)	(+)	(+)	(+)	(+)	(+)	(+)	(4%)
Field Burning of Agricultural Residues	(+)	(+)	(+)	(+)	(+)	(+)	(+)	(4%)
Wetlands Remaining Wetlands	(+)	(+)	(+)	(+)	(+)	(+)	(+)	(4%)
<i>International Bunker Fuels^a</i>	(+)	(+)	(+)	(+)	(+)	(+)	(+)	(4%)
HFCs, PFCs, and SF₆	11.8	15.6	14.6	15.1	16.7	16.4	15.0	10%
HFCs	9.7	13.7	13.8	14.0	15.4	15.1	13.8	11%
Substitution of Ozone Depleting Substances	(+)	6.1	9.5	10.2	10.8	11.4	12.3	10%
HCFC-22 Production	9.7	7.6	4.2	3.7	4.5	3.6	1.4	26%
Semiconductor Manufacture	+	0.1	0.1	0.1	0.1	0.1	0.1	26%
PFCs	3.7	2.8	1.8	2.0	2.1	2.0	1.9	33%
Semiconductor Manufacture	0.6	1.4	1.3	1.6	1.5	1.6	1.6	40%
Aluminum Production	3.0	1.3	0.5	0.4	0.6	0.5	0.3	17%
SF₆	(1.6)	(0.9)	(0.9)	(0.8)	(0.8)	(0.7)	(0.7)	(5%)
Electrical Transmission and Distribution	(1.3)	(0.7)	(0.7)	(0.6)	(0.6)	(0.6)	(0.6)	(5%)
Magnesium Production and Processing	(0.3)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(+)	(5%)
Semiconductor Manufacture	(+)	(+)	(+)	(+)	(+)	(+)	(+)	(5%)
Total	128.1	128.1	122.4	130.5	130.7	133.3	134.3	2.0%

NC (No change)

+ Does not exceed 0.05 Tg CO₂ Eq.

^aEmissions from International Bunker Fuels are not included in totals.

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

Table A-262 below shows a comparison of total emissions estimates by sector using both the IPCC SAR and AR4 GWP values. For most sectors, the change in emissions was minimal. The effect on emissions from waste was by far the greatest (18 percent in 2009), due the predominance of CH₄ emissions in this sector. Emissions from all other sectors were comprised of mainly CO₂ or a mix of gases, which moderated the effect of the changes.

Table A-262: Comparison of Emissions by Sector using IPCC SAR and AR4 GWP Values (Tg CO₂ Eq.)

Sector	1990	2000	2005	2006	2007	2008	2009
Energy							
SAR GWP (Used in Inventory)	5,287.8	6,168.0	6,282.8	6,210.2	6,290.7	6,116.6	5,751.1
AR4 GWP, Updated	5,347.9	6,226.1	6,336.3	6,269.1	6,347.5	6,176.7	5,813.8
Difference (%)	1.1%	0.9%	0.9%	0.9%	0.9%	1.0%	1.1%
Industrial Processes							
SAR GWP (Used in Inventory)	315.8	348.8	334.1	339.4	350.9	331.7	282.9
AR4 GWP, Updated	326.6	363.9	348.2	354.1	367.1	347.7	297.5
Difference (%)	3.4%	4.3%	4.2%	4.3%	4.6%	4.8%	5.2%
Solvent and Other Product Use							
SAR GWP (Used in Inventory)	4.4	4.9	4.4	4.4	4.4	4.4	4.4
AR4 GWP, Updated	4.2	4.7	4.2	4.2	4.2	4.2	4.2
Difference (%)	(3.9%)	(3.9%)	(3.9%)	(3.9%)	(3.9%)	(3.9%)	(3.9%)
Agriculture							
SAR GWP (Used in Inventory)	383.6	410.6	418.8	418.8	425.8	426.3	419.3
AR4 GWP, Updated	408.0	437.5	446.1	446.5	454.7	455.0	448.2
Difference (%)	6.4%	6.5%	6.5%	6.6%	6.8%	6.7%	6.9%
Land Use, Land-Use Change, and Forestry							

SAR GWP (Used in Inventory)	(846.6)	(540.3)	(1,027.9)	(1,014.5)	(1,013.4)	(1,007.3)	(990.1)
AR4 GWP, Updated	(846.1)	(539.3)	(1,027.5)	(1,012.1)	(1,011.3)	(1,006.4)	(990.0)
Difference (%)	(0.1%)	(0.2%)	0.0%	(0.2%)	(0.2%)	(0.1%)	(0.0%)
Waste							
SAR GWP (Used in Inventory)	175.2	143.9	144.9	144.4	144.1	149.0	150.5
AR4 GWP, Updated	207.7	170.0	171.0	170.4	170.0	175.8	177.6
Difference (%)	18.5%	18.1%	18.0%	18.0%	18.0%	18.0%	18.0%
Net Emissions (Sources and Sinks)							
SAR GWP (Used in Inventory)	5,320.3	6,536.1	6,157.1	6,102.6	6,202.5	6,020.7	5,618.2
AR4 GWP	5,448.4	6,662.9	6,278.4	6,232.3	6,332.2	6,153.0	5,751.3
Difference (%)	2.4%	1.9%	2.0%	2.1%	2.1%	2.2%	2.4%

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

Overall, these revisions to GWP values do not have a significant effect on U.S. emission trends, as shown in Table A-263 and Table A-264.

Table A-263: Change in U.S. Greenhouse Gas Emissions and Sinks Using TAR vs. AR4 GWPs (Tg CO₂ Eq)

Gas	1990	2000	2005	2006	2007	2008	2009
CO ₂	NC	NC	NC	NC	NC	NC	NC
CH ₄	64.3	62.8	60.1	64.0	63.3	64.4	65.4
N ₂ O	2.0	2.2	2.1	2.1	2.1	2.0	1.9
HFCs	8.8	13.4	12.5	12.2	13.0	12.2	10.3
PFCs*	4.5	2.7	1.2	1.2	1.5	1.2	1.0
SF ₆	0.9	0.5	0.5	0.4	0.4	0.4	0.4
Total	80.4	81.7	76.3	80.0	80.2	80.3	78.9

NC (No change)

*Includes NF₃

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

Table A-264: Change in U.S. Greenhouse Gas Emissions Using TAR vs. AR4 GWPs (Percent)

Gas/Source	1990	2000	2005	2006	2007	2008	2009
CO ₂	NC	NC	NC	NC	NC	NC	NC
CH ₄	8.7%	8.7%	8.7%	8.7%	8.7%	8.7%	8.7%
N ₂ O	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%
HFCs	23.2%	13.0%	10.2%	9.8%	9.8%	9.2%	7.9%
Substitution of Ozone Depleting Substances	3.3%	8.8%	8.2%	8.0%	7.7%	7.5%	7.2%
HCFC-22 Production ^b	23.3%	23.3%	23.3%	23.3%	23.3%	23.3%	23.3%
Semiconductor Manufacture ^c	23.3%	23.3%	23.3%	23.3%	23.3%	23.3%	23.3%
PFCs	22.4%	19.9%	17.7%	17.6%	17.8%	16.8%	15.8%
Semiconductor Manufacture ^c	10.0%	11.3%	13.1%	14.2%	13.4%	13.6%	13.7%
Aluminum Production ^a	24.2%	26.0%	24.4%	24.2%	23.4%	22.9%	22.8%
SF ₆	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%
Total	1.3%	1.8%	1.7%	1.8%	1.8%	1.9%	2.0%

NC (No change)

a PFC emissions from CF₄ and C₂F₆

b HFC-23 emitted

c Emissions from HFC-23, CF₄, C₂F₆, C₃F₈, SF₆, and the addition of NF₃

Note: Excludes Sinks. Parentheses indicate negative values.

References

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6.2. Ozone Depleting Substance Emissions

Ozone is present in both the stratosphere,⁸¹ where it shields the earth from harmful levels of ultraviolet radiation, and at lower concentrations in the troposphere,⁸² where it is the main component of anthropogenic photochemical “smog.” Chlorofluorocarbons (CFCs), halons, carbon tetrachloride, methyl chloroform, and hydrochlorofluorocarbons (HCFCs), along with certain other chlorine and bromine containing compounds, have been found to deplete the ozone levels in the stratosphere. These compounds are commonly referred to as ozone depleting substances (ODSs). If left unchecked, stratospheric ozone depletion could result in a dangerous increase of ultraviolet radiation reaching the earth’s surface. In 1987, nations around the world signed the *Montreal Protocol on Substances that Deplete the Ozone Layer*. This landmark agreement created an international framework for limiting, and ultimately eliminating, the production of most ozone depleting substances. ODSs have historically been used in a variety of industrial applications, including refrigeration and air conditioning, foam blowing, fire extinguishing, as an aerosol propellant, sterilization, and solvent cleaning.

In the United States, the Clean Air Act Amendments of 1990 provide the legal instrument for implementation of the *Montreal Protocol* controls. The Clean Air Act classifies ozone depleting substances as either Class I or Class II, depending upon the ozone depletion potential (ODP) of the compound.⁸³ The production of CFCs, halons, carbon tetrachloride, and methyl chloroform—all Class I substances—has already ended in the United States. However, large amounts of these chemicals remain in existing equipment,⁸⁴ and stockpiles of the ODSs, as well as material recovered from equipment being decommissioned, are used for maintaining the existing equipment. As a result, emissions of Class I compounds will continue, albeit in ever decreasing amounts, for many more years. Class II designated substances, all of which are hydrochlorofluorocarbons (HCFCs), have been, or are being, phased out at later dates than Class I compounds because they have lower ozone depletion potentials. These compounds served, and in some cases continue to serve, as interim replacements for Class I compounds in many industrial applications. The use and emissions of HCFCs in the United States is anticipated to continue for several decades as equipment that use Class I as equipment that use Class I substances and Class II substances are retired from use. Under current controls, however, the production for domestic use of all HCFCs in the United States will end by the year 2030.

In addition to contributing to ozone depletion, CFCs, halons, carbon tetrachloride, methyl chloroform, and HCFCs are also potent greenhouse gases. However, the depletion of the ozone layer has a cooling effect on the climate that counteracts the direct warming from tropospheric emissions of ODSs. Stratospheric ozone influences the earth’s radiative balance by absorption and emission of longwave radiation from the troposphere as well as absorption of shortwave radiation from the sun; overall, stratospheric ozone has a warming effect.

The IPCC has prepared both direct GWPs and net (combined direct warming and indirect cooling) GWP ranges for some of the most common ozone depleting substances (IPCC 1996). See Global Warming Potential Values Annex for a listing of the net GWP values for ODS.

Although the IPCC emission inventory guidelines do not require the reporting of emissions of ozone depleting substances, the United States believes that no inventory is complete without the inclusion of these compounds. Emission estimates for several ozone depleting substances are provided in Table A- 265.

Table A- 265: Emissions of Ozone Depleting Substances (Gg)

Compound	1990	1995	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Class I												
CFC-11	29.0	12.1	12.7	12.7	12.6	12.7	12.4	12.2	12.2	11.1	9.9	8.6

⁸¹ The stratosphere is the layer from the top of the troposphere up to about 50 kilometers. Approximately 90 percent of atmospheric ozone is within the stratosphere. The greatest concentration of ozone occurs in the middle of the stratosphere, in a region commonly called the ozone layer.

⁸² The troposphere is the layer from the ground up to about 11 kilometers near the poles and 16 kilometers in equatorial regions (i.e., the lowest layer of the atmosphere, where humans live). It contains roughly 80 percent of the mass of all gases in the atmosphere and is the site for weather processes including most of the water vapor and clouds.

⁸³ Substances with an ozone depletion potential of 0.2 or greater are designated as Class I. All other substances that may deplete stratospheric ozone but which have an ODP of less than 0.2 are Class II.

⁸⁴ Older refrigeration and air-conditioning equipment, fire extinguishing systems, meter-dose inhalers, and foam products blown with CFCs/HCFCs may still contain ODS.

CFC-12	106.5	65.0	32.9	26.7	21.3	16.6	12.4	8.6	6.3	5.8	4.9	4.0
CFC-113	59.4	11.5	+	+	+	+	+	+	+	+	+	+
CFC-114	5.4	1.1	0.5	0.4	0.4	0.3	0.3	0.2	0.2	0.2	0.1	0.1
CFC-115	5.5	5.3	4.1	3.6	3.2	2.7	2.0	1.3	0.6	0.2	0.1	0.1
Carbon Tetrachloride	4.3	0.9	+	+	+	+	+	+	+	+	+	+
Methyl Chloroform	222.5	72.1	+	+	+	+	+	+	+	+	+	+
Halon-1211	1.6	1.6	1.1	0.9	0.8	0.7	0.7	0.7	0.7	0.6	0.6	0.6
Halon-1301	1.6	1.6	1.5	1.5	1.5	1.5	1.5	1.4	1.3	1.1	0.9	0.8
Class II												
HCFC-22	44.4	55.0	71.9	74.8	77.9	79.4	81.3	81.7	83.2	83.7	84.7	84.5
HCFC-123	+	0.3	0.6	0.6	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8
HCFC-124	+	1.2	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.6	1.6	1.6
HCFC-141b	1.0	4.0	7.0	6.7	5.6	4.0	4.1	4.2	4.3	5.5	6.9	8.4
HCFC-142b	2.1	3.6	2.7	2.8	2.9	3.0	3.2	3.3	3.4	3.5	3.7	2.5
HCFC-225ca/cb	+	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3

+ Does not exceed 0.05 Gg.

Methodology and Data Sources

Emissions of ozone depleting substances were estimated using the EPA's Vintaging Model. The model, named for its method of tracking the emissions of annual "vintages" of new equipment that enter into service, is a "bottom-up" model. It models the consumption of chemicals based on estimates of the quantity of equipment or products sold, serviced, and retired each year, and the amount of the chemical required to manufacture and/or maintain the equipment. The Vintaging Model makes use of this market information to build an inventory of the in-use stocks of the equipment in each of the end-uses. Emissions are estimated by applying annual leak rates, service emission rates, and disposal emission rates to each population of equipment. By aggregating the emission and consumption output from the different end-uses, the model produces estimates of total annual use and emissions of each chemical. Please see HFC and PFC Emissions from Substitution of Ozone Depleting Substances Annex of this Inventory for a more detailed discussion of the Vintaging Model.

Uncertainties

Uncertainties exist with regard to the levels of chemical production, equipment sales, equipment characteristics, and end-use emissions profiles that are used by these models. Please see the ODS Substitutes section of this report for a more detailed description of the uncertainties that exist in the Vintaging Model.

References

IPCC (1996) Climate Change 1995: The Science of Climate Change. Intergovernmental Panel on Climate Change, J.T. Houghton, L.G. Meira Filho, B.A. Callander, N. Harris, A. Kattenberg, and K. Maskell. (eds.). Cambridge University Press. Cambridge, United Kingdom.

6.3. Sulfur Dioxide Emissions

Sulfur dioxide (SO₂), emitted into the atmosphere through natural and anthropogenic processes, affects the Earth's radiative budget through photochemical transformation into sulfate aerosols that can (1) scatter sunlight back to space, thereby reducing the radiation reaching the Earth's surface; (2) affect cloud formation; and (3) affect atmospheric chemical composition (e.g., stratospheric ozone, by providing surfaces for heterogeneous chemical reactions). The overall effect of SO₂-derived aerosols on radiative forcing is believed to be negative (IPCC 2007). However, because SO₂ is short-lived and unevenly distributed through the atmosphere, its radiative forcing impacts are highly uncertain. Sulfur dioxide emissions have been provided below in Table A-266.

The major source of SO₂ emissions in the United States is the burning of sulfur containing fuels, mainly coal. Metal smelting and other industrial processes also release significant quantities of SO₂. The largest contributor to U.S. emissions of SO₂ is electricity generation, accounting for 60 percent of total SO₂ emissions in 2009 (see Table A-267); coal combustion accounted for approximately 92 percent of that total. The second largest source was industrial fuel combustion, which produced 18 percent of 2009 SO₂ emissions. Overall, SO₂ emissions in the United States decreased by 59 percent from 1990 to 2009. The majority of this decline came from reductions from electricity generation, primarily due to increased consumption of low sulfur coal from surface mines in western states.

Sulfur dioxide is important for reasons other than its effect on radiative forcing. It is a major contributor to the formation of urban smog and acid rain. As a contributor to urban smog, high concentrations of SO₂ can cause significant increases in acute and chronic respiratory diseases. In addition, once SO₂ is emitted, it is chemically transformed in the atmosphere and returns to earth as the primary contributor to acid deposition, or acid rain. Acid rain has been found to accelerate the decay of building materials and paints, and to cause the acidification of lakes and streams and damage trees. As a result of these harmful effects, the United States has regulated the emissions of SO₂ under the Clean Air Act. The EPA has also developed a strategy to control these emissions via four programs: (1) the National Ambient Air Quality Standards program,⁸⁵ (2) New Source Performance Standards,⁸⁶ (3) the New Source Review/Prevention of Significant Deterioration Program,⁸⁷ and (4) the sulfur dioxide allowance program.⁸⁸

Table A-266: SO₂ Emissions (Gg)

Sector/Source	1990	2000	2005	2006	2007	2008	2009
Energy	19,628	13,797	12,634	11,568	10,991	9,573	7,800
Stationary Combustion	18,407	12,849	11,541	10,612	10,172	8,891	7,167
Mobile Combustion	793	632	889	750	611	472	455
Oil and Gas Activities	390	287	181	182	184	187	154
Waste Combustion	38	29	24	24	24	23	24
Industrial Processes	1,307	1,031	831	818	807	795	798
Chemical Manufacturing	269	307	228	230	230	231	222
Metals Processing	659	284	159	167	176	184	158
Storage and Transport	6	5	3	3	4	4	2
Other Industrial Processes	362	372	327	318	308	298	324
Miscellaneous*	11	64	114	102	89	77	91
Solvent Use	+	1	+	+	+	+	+
Degreasing	+	+	+	+	+	+	+
Graphic Arts	+	+	+	+	+	+	+
Dry Cleaning	NA	+	+	+	+	+	+
Surface Coating	+	+	+	+	+	+	+
Other Industrial	+	1	+	+	+	+	+
Non-industrial	NA	NA	NA	NA	NA	NA	NA
Agriculture	NA	NA	NA	NA	NA	NA	NA
Agricultural Burning	NA	NA	NA	NA	NA	NA	NA
Waste	+	1	1	1	1	1	1
Landfills	+	1	1	1	1	1	1
Wastewater Treatment	+	+	+	+	+	+	+
Miscellaneous Waste	+	+	+	+	+	+	+
Total	20,935	14,830	13,466	12,388	11,799	10,368	8,599

⁸⁵ [42 U.S.C § 7409, CAA § 109]

⁸⁶ [42 U.S.C § 7411, CAA § 111]

⁸⁷ [42 U.S.C § 7473, CAA § 163]

⁸⁸ [42 U.S.C § 7651, CAA § 401]

Source: Data taken from EPA (2005) and disaggregated based on EPA (2003).

* Miscellaneous includes other combustion and fugitive dust categories.

+ Does not exceed 0.5 Gg

NA (Not Available)

Note: Totals may not sum due to independent rounding.

Table A-267: SO₂ Emissions from Electricity Generation (Gg)

Fuel Type	1990	2000	2005	2006	2007	2008	2009
Coal	13,808	9,620	8,680	7,846	7,459	6,300	4,718
Petroleum	580	428	458	414	393	332	249
Natural Gas	1	157	174	157	149	126	94
Misc. Internal Combustion	45	54	57	52	49	41	31
Other	NA	78	71	64	61	51	38
Total	14,433	10,338	9,439	8,532	8,111	6,851	5,131

Source: Data taken from EPA (2009 and 2010) and disaggregated based on EPA (2003).

Note: Totals may not sum due to independent rounding.

References

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6.4. Complete List of Source Categories

Chapter/Source	Gas(es)
Energy	
Fossil Fuel Combustion	CO ₂
Non-Energy Use of Fossil Fuels	CO ₂
Stationary Combustion (excluding CO ₂)	CH ₄ , N ₂ O, CO, NO _x , NMVOC
Mobile Combustion (excluding CO ₂)	CH ₄ , N ₂ O, CO, NO _x , NMVOC
Coal Mining	CH ₄
Abandoned Underground Coal Mines	CH ₄
Natural Gas Systems	CH ₄
Petroleum Systems	CH ₄
Incineration of Waste	CO ₂ , CH ₄ , N ₂ O
Industrial Processes	
Titanium Dioxide Production	CO ₂
Aluminum Production	CO ₂ , CF ₄ , C ₂ F ₆
Iron and Steel Production	CO ₂ , CH ₄
Ferroalloy Production	CO ₂ , CH ₄
Ammonia Production and Urea Consumption	CO ₂
Cement Production	CO ₂
Lime Production	CO ₂
Limestone and Dolomite Use	CO ₂
Soda Ash Production and Consumption	CO ₂
Carbon Dioxide Consumption	CO ₂
Phosphoric Acid Production	CO ₂
Petrochemical Production	CH ₄ , CO ₂
Silicon Carbide Production and Consumption	CH ₄ , CO ₂
Lead Production	CO ₂
Zinc Production	CO ₂
Adipic Acid Production	N ₂ O
Nitric Acid Production	N ₂ O
Substitution of Ozone Depleting Substances	HFCs, PFCs ^a
HCFC-22 Production	HFC-23
Semiconductor Manufacture	HFCs, PFCs, SF ₆ ^b
Electrical Transmission and Distributing	SF ₆
Magnesium Production and Processing	SF ₆
Solvent and Other Product Use	CO, NO _x , NMVOC
N ₂ O Product Usage	N ₂ O
Agriculture	
Enteric Fermentation	CH ₄
Manure Management	CH ₄ , N ₂ O
Rice Cultivation	CH ₄
Field Burning of Agricultural Residues	CH ₄ , N ₂ O
Agricultural Soil Management	N ₂ O, CO, NO _x
Land Use, Land-Use Change, and Forestry	
CO ₂ Flux	CO ₂ (sink)
Cropland Remaining Cropland	CO ₂
Settlements Remaining Settlements	N ₂ O
Forestland Remaining Forestland	CH ₄ , N ₂ O
Wetlands Remaining Wetlands	CO ₂ , N ₂ O
Waste	
Landfills	CH ₄
Wastewater Treatment	CH ₄ , N ₂ O
Composting	CH ₄ , N ₂ O

^a Includes HFC-23, HFC-32, HFC-125, HFC-134a, HFC-143a, HFC-236fa, CF₄, HFC-152a, HFC-227ea, HFC-245fa, HFC-4310mee, and PFC/PFPEs.

^b Includes such gases as HFC-23, CF₄, C₂F₆, SF₆.

6.5. Constants, Units, and Conversions

Metric Prefixes

Although most activity data for the United States is gathered in customary U.S. units, these units are converted into metric units per international reporting guidelines. Table A- 268 provides a guide for determining the magnitude of metric units.

Table A- 268: Guide to Metric Unit Prefixes

Prefix/Symbol	Factor
atto (a)	10^{-18}
femto (f)	10^{-15}
pico (p)	10^{-12}
nano (n)	10^{-9}
micro (μ)	10^{-6}
milli (m)	10^{-3}
centi (c)	10^{-2}
deci (d)	10^{-1}
deca (da)	10
hecto (h)	10^2
kilo (k)	10^3
mega (M)	10^6
giga (G)	10^9
tera (T)	10^{12}
peta (P)	10^{15}
exa (E)	10^{18}

Unit Conversions

1 kilogram = 2.205 pounds
1 pound = 0.454 kilograms
1 short ton = 2,000 pounds = 0.9072 metric tons
1 metric ton = 1,000 kilograms = 1.1023 short tons

1 cubic meter = 35.315 cubic feet
1 cubic foot = 0.02832 cubic meters
1 U.S. gallon = 3.785412 liters
1 barrel (bbl) = 0.159 cubic meters
1 barrel (bbl) = 42 U.S. gallons
1 liter = 0.001 cubic meters

1 foot = 0.3048 meters
1 meter = 3.28 feet
1 mile = 1.609 kilometers
1 kilometer = 0.622 miles

1 acre = 43,560 square feet = 0.4047 hectares = 4,047 square meters
1 square mile = 2.589988 square kilometers

To convert degrees Fahrenheit to degrees Celsius, subtract 32 and multiply by 5/9

To convert degrees Celsius to Kelvin, add 273.15 to the number of Celsius degrees

Density Conversions⁸⁹

Methane	1 cubic meter	=	0.67606 kilograms
Carbon dioxide	1 cubic meter	=	1.85387 kilograms
Natural gas liquids	1 metric ton	=	11.6 barrels = 1,844.2 liters
Unfinished oils	1 metric ton	=	7.46 barrels = 1,186.04 liters
Alcohol	1 metric ton	=	7.94 barrels = 1,262.36 liters
Liquefied petroleum gas	1 metric ton	=	11.6 barrels = 1,844.2 liters
Aviation gasoline	1 metric ton	=	8.9 barrels = 1,415.0 liters
Naphtha jet fuel	1 metric ton	=	8.27 barrels = 1,314.82 liters
Kerosene jet fuel	1 metric ton	=	7.93 barrels = 1,260.72 liters
Motor gasoline	1 metric ton	=	8.53 barrels = 1,356.16 liters
Kerosene	1 metric ton	=	7.73 barrels = 1,228.97 liters
Naphtha	1 metric ton	=	8.22 barrels = 1,306.87 liters
Distillate	1 metric ton	=	7.46 barrels = 1,186.04 liters
Residual oil	1 metric ton	=	6.66 barrels = 1,058.85 liters
Lubricants	1 metric ton	=	7.06 barrels = 1,122.45 liters
Bitumen	1 metric ton	=	6.06 barrels = 963.46 liters
Waxes	1 metric ton	=	7.87 barrels = 1,251.23 liters
Petroleum coke	1 metric ton	=	5.51 barrels = 876.02 liters
Petrochemical feedstocks	1 metric ton	=	7.46 barrels = 1,186.04 liters
Special naphtha	1 metric ton	=	8.53 barrels = 1,356.16 liters
Miscellaneous products	1 metric ton	=	8.00 barrels = 1,271.90 liters

Energy Conversions

Converting Various Energy Units to Joules

The common energy unit used in international reports of greenhouse gas emissions is the joule. A joule is the energy required to push with a force of one Newton for one meter. A terajoule (TJ) is one trillion (10^{12}) joules. A British thermal unit (Btu, the customary U.S. energy unit) is the quantity of heat required to raise the temperature of one pound of water one degree Fahrenheit at or near 39.2 Fahrenheit.

1 TJ =	2.388×10 ¹¹ calories
	23.88 metric tons of crude oil equivalent
	947.8 million Btus
	277,800 kilowatt-hours

Converting Various Physical Units to Energy Units

Data on the production and consumption of fuels are first gathered in physical units. These units must be converted to their energy equivalents. The conversion factors in Table A-269 can be used as default factors, if local data are not available. See Appendix A of EIA's *Annual Energy Review 2009* (EIA 2010) for more detailed information on the energy content of various fuels.

⁸⁹ Reference: EIA (2007)

Table A-269: Conversion Factors to Energy Units (Heat Equivalents)

Fuel Type (Units)	Factor
Solid Fuels (Million Btu/Short ton)	
Anthracite coal	22.573
Bituminous coal	23.89
Sub-bituminous coal	17.14
Lignite	12.866
Coke	24.8
Natural Gas (Btu/Cubic foot)	
	1,027
Liquid Fuels (Million Btu/Barrel)	
Motor gasoline	5.150
Aviation gasoline	5.048
Kerosene	5.670
Jet fuel, kerosene-type	5.670
Distillate fuel	5.825
Residual oil	6.287
Naphtha for petrochemicals	5.248
Petroleum coke	6.024
Other oil for petrochemicals	5.825
Special naphthas	5.248
Lubricants	6.065
Waxes	5.537
Asphalt	6.636
Still gas	6.000
Misc. products	5.796

Note: For petroleum and natural gas, *Annual Energy Review 2009* (EIA 2010). For coal ranks, *State Energy Data Report 1992* (EIA 1993). All values are given in higher heating values (gross calorific values).

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6.6. Abbreviations

AAPFCO	American Association of Plant Food Control Officials
ABS	Acrylonitrile Butadiene Styrene
AFEAS	Alternative Fluorocarbon Environmental Acceptability Study
AFV	Alternative Fuel Vehicle
AGA	American Gas Association
AHEF	Atmospheric and Health Effect Framework
AISI	American Iron and Steel Institute
ANL	Argonne National Laboratory
APC	American Plastics Council
API	American Petroleum Institute
ASAE	American Society of Agricultural Engineers
ASTM	American Society for Testing and Materials
BCEF	Biomass conversion and expansion factors
BEA	Bureau of Economic Analysis, U.S. Department of Commerce
BoC	Bureau of Census
BOD5	Biochemical oxygen demand over a 5-day period
BOF	Basic Oxygen Furnace
BRS	Biennial Reporting System
BTS	Bureau of Transportation Statistics, U.S. Department of Transportation
Btu	British thermal unit
C&EN	Chemical and Engineering News
CAAA	Clean Air Act Amendments of 1990
CAPP	Canadian Association of Petroleum Producers
CARB	California Air Resources Board
CBI	Confidential Business Information
CEFM	Cattle Enteric Fermentation Model
CFC	Chlorofluorocarbon
CFR	Code of Federal Regulations
CKD	Cement Kiln Dust
CMA	Chemical Manufacturer's Association
CMOP	Coalbed Methane Outreach Program
CNG	Compressed Natural Gas
CRF	Common Reporting Format
CRP	Conservation Reserve Program
CTIC	Conservation Technology Information Center
CVD	Chemical vapor deposition
DE	Digestible Energy
DESC	Defense Energy Support Center-DoD's defense logistics agency
DFAMS	Defense Fuels Automated Management System
DM	Dry Matter
DOC	U.S. Department of Commerce
DoD	U.S. Department of Defense
DOE	U.S. Department of Energy
DOI	U.S. Department of the Interior
DOT	U.S. Department of Transportation
EAF	Electric Arc Furnace
EF	Emission Factor
EFMA	European Fertilizer Manufacturers Association
EJ	Exajoule
EGR	Exhaust Gas Recirculation
EIA	Energy Information Administration, U.S. Department of Energy
EIIP	Emissions Inventory Improvement Program
EOR	Enhanced oil recovery
EPA	U.S. Environmental Protection Agency
ERS	Economic Research Service
FAA	Federal Aviation Administration
FAO	Food and Agricultural Organization
FCCC	Framework Convention on Climate Change
FEB	Fiber Economics Bureau
FGD	Flue Gas Desulphurization
FHWA	Federal Highway Administration
FIA	Forest Inventory and Analysis
FIPR	Florida Institute of Phosphate Research

FTP	Federal Test Procedure
GCV	Gross calorific value
GDP	Gross domestic product
Gg	Gigagram
GHG	Greenhouse gas
GRI	Gas Research Institute
GSAM	Gas Systems Analysis Model
GWP	Global warming potential
HBFC	Hydrobromofluorocarbon
HC	Hydrocarbon
HCFC	Hydrochlorofluorocarbon
HDDV	Heavy duty diesel vehicle
HDGV	Heavy duty gas vehicle
HDPE	High density polyethylene
HFC	Hydrofluorocarbon
HFE	Hydrofluoroethers
HHV	Higher Heating Value
HMA	Hot Mix Asphalt
HTF	Heat Transfer Fluid
HTS	Harmonized Tariff Schedule
HWP	Harvested wood product
ICAO	International Civil Aviation Organization
IEA	International Energy Association
IFO	Intermediate Fuel Oil
IISRP	International Institute of Synthetic Rubber Products
ILENR	Illinois Department of Energy and Natural Resources
IMO	International Maritime Organization
IPAA	Independent Petroleum Association of America
IPCC	Intergovernmental Panel on Climate Change
JWR	Jim Walters Resources
LDDT	Light duty diesel truck
LDDV	Light duty diesel vehicle
LDGT	Light duty gas truck
LDGV	Light duty gas vehicle
LDPE	Low density polyethylene
LEV	Low emission vehicles
LFG	Landfill gas
LFGTE	Landfill gas-to-energy
LHV	Lower Heating Value
LLDPE	Linear low density polyethylene
LMOP	EPA's Landfill Methane Outreach Program
LNG	Liquefied Natural Gas
LPG	Liquefied petroleum gas(es)
LTO	Landing and take-off
LULUCF	Land use, land-use change, and forestry
MC	Motorcycle
MCF	Methane conversion factor
MCFD	Thousand Cubic Feet Per Day
MGO	Marine Gas Oil
MLRA	Major Land Resource Area
MMCFD	Million Cubic Feet Per Day
MMS	Minerals Management Service
MMTCE	Million metric tons carbon equivalent
MSHA	Mine Safety and Health Administration
MSW	Municipal solid waste
MTBE	Methyl Tertiary Butyl Ether
NAHMS	National Animal Health Monitoring System
NAICS	North American Industry Classification System
NAPAP	National Acid Precipitation and Assessment Program
NASS	USDA's National Agriculture Statistics Service
NCV	Net calorific value
NEU	Non-Energy Use
NEV	Neighborhood Electric Vehicle
NGL	Natural Gas Liquids
NIR	National Inventory Report
NMVOC	Non-methane volatile organic compound

NO _x	Nitrogen Oxides
NPRA	National Petroleum and Refiners Association
NRC	National Research Council
NRCS	Natural Resources Conservation Service
NRI	National Resources Inventory
NSCEP	National Service Center for Environmental Publications
NSCR	Non-selective catalytic reduction
NWS	National Weather Service
OAP	EPA Office of Atmospheric Programs
OAQPS	EPA Office of Air Quality Planning and Standards
ODP	Ozone Depleting Potential
ODS	Ozone depleting substances
OECD	Organization of Economic Co-operation and Development
OEM	Original equipment manufacturers
OMS	EPA Office of Mobile Sources
ORNL	Oak Ridge National Laboratory
OSHA	Occupational Safety and Health Administration
OTA	Office of Technology Assessment
OTAQ	EPA Office of Transportation and Air-Quality
PAH	Polycyclic Aromatic Hydrocarbons
PCC	Precipitate calcium carbonate
PDF	Probability Density Function
PECVD	Plasma enhanced chemical vapor deposition
PET	Polyethylene Terephthalate
PEVM	PFC Emissions Vintage Model
PFC	Perfluorocarbon
PFPE	Perfluoropolyether
POTW	Publicly Owned Treatment Works
Ppbv	Parts per billion (10 ⁹) by volume
Ppmv	Parts per million (10 ⁶) by volume
Pptv	Parts per trillion (10 ¹²) by volume
PRP	Pasture/Range/Paddock
PS	Polystyrene
PSU	Primary Sample Unit
PU	Polyurethane
PVC	Polyvinyl chloride
QA/QC	Quality Assurance and Quality Control
QBtu	Quadrillion Btu
RCRA	Resource Conservation and Recovery Act
SAE	Society of Automotive Engineers
SAGE	System for assessing Aviation's Global Emissions
SAN	Styrene Acrylonitrile
SAR	IPCC Second Assessment Report
SCR	Selective catalytic reduction
SNAP	Significant New Alternative Policy Program
SNG	Synthetic natural gas
SOC	Soil Organic Carbon
STMC	Scrap Tire Management Council
SULEV	Super Ultra Low Emissions Vehicle
SWANA	Solid Waste Association of North America
TAM	Typical Animal Mass
TAME	Tertiary Amyl Methyl Ether
TAR	IPCC Third Assessment Report
TBtu	Trillion Btu
TDN	Total Digestible Nutrients
TFI	The Fertilizer Institute
Tg CO ₂ Eq.	Teragrams carbon dioxide equivalent
TJ	Terajoule
TLEV	Traditional Low Emissions Vehicle
TMLA	Total Manufactured Layer Area
TRI	Toxic Release Inventory
TSDF	Hazardous waste treatment, storage, and disposal facility
TVA	Tennessee Valley Authority
UDA	Utility Data Institute
U.S.	United States
U.S. ITC	United States International Trade Commission

UEP	United Egg Producers
ULEV	Ultra Low Emission Vehicle
UNEP	United Nations Environmental Programme
UNFCCC	United Nations Framework Convention on Climate Change
USAF	United States Air Force
USDA	United States Department of Agriculture
USFS	United States Forest Service
USGS	United States Geological Survey
VAIP	EPA's Voluntary Aluminum Industrial Partnership
VKT	Vehicle kilometers traveled
VMT	Vehicle miles traveled
VOCs	Volatile Organic Compounds
VS	Volatile Solids
WIP	Waste In Place
WMO	World Meteorological Organization
WMS	Waste Management Systems
ZEVs	Zero Emissions Vehicles

6.7. Chemical Formulas

Table A-270: Guide to Chemical Formulas

Symbol	Name
Al	Aluminum
Al ₂ O ₃	Aluminum Oxide
Br	Bromine
C	Carbon
CH ₄	Methane
C ₂ H ₆	Ethane
C ₃ H ₈	Propane
CF ₄	Perfluoromethane
C ₂ F ₆	Perfluoroethane, hexafluoroethane
c-C ₃ F ₆	Perfluorocyclopropane
C ₃ F ₈	Perfluoropropane
c-C ₄ F ₈	Perfluorocyclobutane
C ₄ F ₁₀	Perfluorobutane
C ₅ F ₁₂	Perfluoropentane
C ₆ F ₁₄	Perfluorohexane
CF ₃ I	Trifluoroiodomethane
CFCl ₃	Trichlorofluoromethane (CFC-11)
CF ₂ Cl ₂	Dichlorodifluoromethane (CFC-12)
CF ₃ Cl	Chlorotrifluoromethane (CFC-13)
C ₂ F ₃ Cl ₃	Trichlorotrifluoroethane (CFC-113)*
CCl ₃ CF ₃	CFC-113a*
C ₂ F ₄ Cl ₂	Dichlorotetrafluoroethane (CFC-114)
C ₂ F ₅ Cl	Chloropentafluoroethane (CFC-115)
CHCl ₂ F	HCFC-21
CHF ₂ Cl	Chlorodifluoromethane (HCFC-22)
C ₂ F ₃ HCl ₂	HCFC-123
C ₂ F ₄ HCl	HCFC-124
C ₂ FH ₃ Cl ₂	HCFC-141b
C ₂ H ₃ F ₂ Cl	HCFC-142b
CF ₃ CF ₂ CHCl ₂	HCFC-225ca
CClF ₂ CF ₂ CHClF	HCFC-225cb
CCl ₄	Carbon tetrachloride
CHClCCl ₂	Trichloroethylene
CCl ₂ CCl ₂	Perchloroethylene, tetrachloroethene
CH ₃ Cl	Methylchloride
CH ₃ CCl ₃	Methylchloroform
CH ₂ Cl ₂	Methylenechloride
CHCl ₃	Chloroform, trichloromethane
CHF ₃	HFC-23
CH ₂ F ₂	HFC-32
CH ₃ F	HFC-41
C ₂ HF ₅	HFC-125
C ₂ H ₂ F ₄	HFC-134
CH ₂ FCF ₃	HFC-134a
C ₂ H ₃ F ₃	HFC-143*
C ₂ H ₃ F ₃	HFC-143a*
CH ₂ FCH ₂ F	HFC-152*
C ₂ H ₄ F ₂	HFC-152a*
CH ₃ CH ₂ F	HFC-161
C ₃ HF ₇	HFC-227ea
CF ₃ CF ₂ CH ₂ F	HFC-236cb
CF ₃ CHFCHF ₂	HFC-236ea
C ₃ H ₂ F ₆	HFC-236fa
C ₃ H ₃ F ₅	HFC-245ca
CHF ₂ CH ₂ CF ₃	HFC-245fa
CF ₃ CH ₂ CF ₂ CH ₃	HFC-365mfc
C ₅ H ₂ F ₁₀	HFC-43-10mee
CF ₃ OCHF ₂	HFE-125
CF ₃ HOCHF ₂ H	HFE-134
CH ₃ OCF ₃	HFE-143a
CF ₃ CHFOCF ₃	HFE-227ea

CF ₃ CHClOCHF ₂	HCFE-235da2
CF ₃ CHFOCHF ₂	HFE-236ea2
CF ₃ CH ₂ OCF ₃	HFE-236fa
CF ₃ CF ₂ OCH ₃	HFE-245cb2
CHF ₂ CH ₂ OCF ₃	HFE-245fa1
CF ₃ CH ₂ OCHF ₂	HFE-245fa2
CHF ₂ CF ₂ OCH ₃	HFE-254cb2
CF ₃ CH ₂ OCH ₃	HFE-263fb2
CF ₃ CF ₂ OCF ₂ CHF ₂	HFE-329mcc2
CF ₃ CF ₂ OCH ₂ CF ₃	HFE-338mcf2
CF ₃ CF ₂ CF ₂ OCH ₃	HFE-347mcc3
CF ₃ CF ₂ OCH ₂ CHF ₂	HFE-347mcf2
CF ₃ CHFCF ₂ OCH ₃	HFE-356mec3
CHF ₂ CF ₂ CF ₂ OCH ₃	HFE-356pcc3
CHF ₂ CF ₂ OCH ₂ CHF ₂	HFE-356pcf2
CHF ₂ CF ₂ CH ₂ OCHF ₂	HFE-356pcf3
CF ₃ CF ₂ CH ₂ OCH ₃	HFE-365mcf3
CHF ₂ CF ₂ OCH ₂ CH ₃	HFE-374pcf2
C ₄ F ₉ OCH ₃	HFE-7100
C ₄ F ₉ OC ₂ H ₅	HFE-7200
CHF ₂ OCF ₂ OC ₂ F ₄ OCHF ₂	H-Galden 1040x
CHF ₂ OCF ₂ OCHF ₂	HG-10
CHF ₂ OCF ₂ CF ₂ OCHF ₂	HG-01
CH ₃ OCH ₃	Dimethyl ether
CH ₂ Br ₂	Dibromomethane
CH ₂ BrCl	Dibromochloromethane
CHBr ₃	Tribromomethane
CHBrF ₂	Bromodifluoromethane
CH ₃ Br	Methylbromide
CF ₂ BrCl	Bromodichloromethane (Halon 1211)
CF ₃ Br(CBrF ₃)	Bromotrifluoromethane (Halon 1301)
CF ₃ I	FIC-131I
CO	Carbon monoxide
CO ₂	Carbon dioxide
CaCO ₃	Calcium carbonate, Limestone
CaMg(CO ₃) ₂	Dolomite
CaO	Calcium oxide, Lime
Cl	atomic Chlorine
F	Fluorine
Fe	Iron
Fe ₂ O ₃	Ferric oxide
FeSi	Ferrosilicon
H, H ₂	atomic Hydrogen, molecular Hydrogen
H ₂ O	Water
H ₂ O ₂	Hydrogen peroxide
OH	Hydroxyl
N, N ₂	atomic Nitrogen, molecular Nitrogen
NH ₃	Ammonia
NH ₄ ⁺	Ammonium ion
HNO ₃	Nitric acid
NF ₃	Nitrogen trifluoride
N ₂ O	Nitrous oxide
NO	Nitric oxide
NO ₂	Nitrogen dioxide
NO ₃	Nitrate radical
Na	Sodium
Na ₂ CO ₃	Sodium carbonate, soda ash
Na ₃ AlF ₆	Synthetic cryolite
O, O ₂	atomic Oxygen, molecular Oxygen
O ₃	Ozone
S	atomic Sulfur
H ₂ SO ₄	Sulfuric acid
SF ₆	Sulfur hexafluoride
SF ₃ CF ₃	Trifluoromethylsulphur pentafluoride
SO ₂	Sulfur dioxide
Si	Silicon

SiC	Silicon carbide
SiO ₂	Quartz

* Distinct isomers.

ANNEX 7 Uncertainty

The annual U.S. Inventory presents the best effort to produce estimates for greenhouse gas source and sink categories in the United States. These estimates were generated according to the UNFCCC reporting guidelines, following the recommendations set forth in the *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories* (IPCC/UNEP/OECD/IEA 1997), the *IPCC Good Practice Guidance* (IPCC 2000), the *Good Practice Guidance for Land Use, Land-Use Change and Forestry* (IPCC 2003), and the *2006 Guidelines for National Greenhouse Gas Inventories* (IPCC 2006). This Annex provides an overview of the uncertainty analysis conducted to support the U.S. Inventory, describes the sources of uncertainty characterized throughout the Inventory associated with various source categories (including emissions and sinks), and describes the methods through which uncertainty information was collected, quantified, and presented.

7.1. Overview

The current inventory emission estimates for some source categories, such as for CO₂ Emissions from Fossil Fuel Combustion, have relatively low level of uncertainty associated with them. However, for some other source categories, the inventory emission estimates are considered less certain. The two major types of uncertainty associated with these emission estimates are (1) model uncertainty, which arises when the emission and/or removal estimation models used in developing the inventory estimates do not fully and accurately characterize the respective emission and/or removal processes (due to a lack of technical details or other resources), resulting in the use of incorrect or incomplete estimation methodologies and (2) parameter uncertainty, which arises due to a lack of precise input data such as emission factors and activity data.

The model uncertainty can be partially analyzed by comparing the model results with those of other models developed to characterize the same emission (or removal) process, after taking into account the differences in their conceptual framework, capabilities, data and assumptions. However, it would be very difficult—if not impossible—to quantify the model uncertainty associated with the emission estimates (primarily because, in most cases, only a single model has been developed to estimate emissions from any one source). Therefore, model uncertainty was not quantified in this report. Nonetheless, it has been discussed qualitatively, where appropriate, along with the individual source category description and inventory estimation methodology.

Parameter uncertainty is, therefore, the principal type and source of uncertainty associated with the national inventory emission estimates and is the main focus of the quantitative uncertainty analyses in this report. Parameter uncertainty has been quantified for all of the emission sources and sinks in the U.S. Inventory, with the exception of one very small emission source category, CH₄ emissions from Incineration of Waste, which was included in the 1990-2008 National GHG Inventory for the first time, and two other source categories International Bunker Fuels and biomass energy consumption) whose emissions are not included in the Inventory totals.

The primary purpose of the uncertainty analysis conducted in support of the U.S. Inventory is (i) to determine the quantitative uncertainty associated with the emission (and removal) estimates presented in the main body of this report [based on the uncertainty associated with the input parameters used in the emission (and removal) estimation methodologies] and (ii) to evaluate the relative importance of the input parameters in contributing to uncertainty in the associated source category inventory estimate and in the overall inventory estimate. Thus, the U.S. Inventory uncertainty analysis provides a strong foundation for developing future improvements and revisions to the Inventory estimation process. For each source category, the analysis highlights opportunities for changes to data measurement, data collection, and calculation methodologies. These are presented in the “Planned Improvements” sections of each source category’s discussion in the main body of the report.

7.2. Methodology and Results

The United States has developed a quality assurance and quality control (QA/QC) and uncertainty management plan (EPA 2002) in accordance with the *IPCC Good Practice Guidance* (IPCC 2000). Like the QA/QC plan, the uncertainty management plan is part of a continually evolving process. The uncertainty management plan provides for a quantitative assessment of the inventory analysis itself, thereby contributing to continuing efforts to understand both what causes uncertainty and how to improve inventory quality. Although the plan provides both general and specific guidelines for implementing quantitative uncertainty analysis, its components are intended to evolve over time, consistent with the

inventory estimation process. The U.S. plan includes procedures and guidelines, and forms and templates, for developing quantitative assessments of uncertainty in the national Inventory estimates (EPA 2002).

The IPCC *Good Practice Guidance* recommends two approaches—Tier 1 and Tier 2—for developing quantitative estimates of uncertainty in the inventory estimate of individual source categories and the overall inventory. Of these, the Tier 2 approach is both more flexible and reliable than Tier 1; both methods are described in the next section. The United States is in the process of implementing a multi-year strategy to develop quantitative estimates of uncertainty for all source categories using the Tier 2 approach. For the current Inventory, a Tier 2 approach was implemented for all source categories with the exception of Composting and parts of Agricultural Soil Management source categories.

The current Inventory reflects significant improvements over the previous publication in the extent to which the Tier 2 approach to uncertainty analysis was adopted. Each of the new Tier 2 analyses reflects additional detail and characterization of input parameters using statistical data collection, expert elicitation methods and more informed judgment. In following the UNFCCC requirement under Article 4.1, emissions from International Bunker Fuels and Indirect Greenhouse Gas Emissions are not included in the total emissions estimated for the U.S. Inventory; therefore, no quantitative uncertainty estimates have been developed for these source categories.⁹⁰ Emissions from biomass combustion are accounted for implicitly in the LULUCF chapter through the calculation of changes in carbon stocks. The Energy sector does provide an estimate of CO₂ emissions from bioenergy consumption provided as a memo item for informational purposes in line with the UNFCCC reporting requirements.

Tier 1 and Tier 2 Approach

The Tier 1 method for estimating uncertainty is based on the error propagation equation. This equation combines the uncertainty associated with the activity data and the uncertainty associated with the emission (or the other) factors. The Tier 1 approach is applicable where emissions (or removals) are usually estimated as the product of an activity value and an emission factor or as the sum of individual sub-source category values. Inherent in employing the Tier 1 method are the assumptions that, for each source category, (i) both the activity data and the emission factor values are approximately normally distributed, (ii) the coefficient of variation (i.e., the ratio of the standard deviation to the mean) associated with each input variable is less than 30 percent, and (iii) the input variables within and across (sub-) source categories are not correlated (i.e., value of each variable is independent of the values of other variables).

The Tier 2 method is preferred (i) if the uncertainty associated with the input variables is significantly large, (ii) if the distributions underlying the input variables are not normal, (iii) if the estimates of uncertainty associated with the input variables are correlated, and/or (iv) if a sophisticated estimation methodology and/or several input variables are used to characterize the emission (or removal) process correctly. In practice, the Tier 2 is the preferred method of uncertainty analysis for all source categories where sufficient and reliable data are available to characterize the uncertainty of the input variables.

The Tier 2 method employs the Monte Carlo Stochastic Simulation technique (also referred to as the Monte Carlo method). Under this method, estimates of emissions (or removals) for a particular source category are generated many times (equal to the number of simulations specified) using an uncertainty model, which is an emission (or removal) estimation equation that imitates or is the same as the inventory estimation model for a particular source category. These estimates are generated using the respective, randomly-selected values for the constituent input variables using commercially available simulation software such as *@RISK* or *Crystal Ball*.

Characterization of Uncertainty in Input Variables

Both Tier 1 and Tier 2 uncertainty analyses require that all the input variables are well-characterized in terms of their Probability Density Functions (PDFs). In the absence of particularly convincing data measurements, sufficient data samples, or expert judgments that determined otherwise, the PDFs incorporated in the current source category uncertainty analyses were limited to normal, lognormal, uniform, triangular, and beta distributions. The choice among these five PDFs depended largely on the observed or measured data and expert judgment.

⁹⁰ However, because the input variables that determine the emissions from the Fossil Fuel Combustion and the International Bunker Fuels source categories are correlated, uncertainty associated with the activity variables in the International Bunker Fuels was taken into account in estimating the uncertainty associated with the Fossil Fuel Combustion.

Source Category Inventory Uncertainty Estimates

Discussion surrounding the input parameters and sources of uncertainty for each source category appears in the body of this report. Table A-271 summarizes results based on assessments of source category-level uncertainty. The table presents base year (1990 or 1995) and current year (2009) emissions for each source category. The combined uncertainty (at the 95 percent confidence interval) for each source category is expressed as the percentage deviation above and below the total 2009 emissions estimated for that source category. Source category trend uncertainty is described subsequently in this Appendix.

Table A-271: Summary Results of Source Category Uncertainty Analyses

Source Category	Base Year Emissions ^a	2009 Emissions ^a	2009 Uncertainty ^b	
	Tg CO ₂ Eq.	Tg CO ₂ Eq.	Low	High
CO₂	5,099.3	5,504.8	-1%	6%
Fossil Fuel Combustion ^c	4,738.0	5,208.6	-1%	6%
Non-Energy Use of Fuels	118.6	123.4	-	10%
Natural Gas Systems	37.6	32.2	-	30%
Cement Production	33.3	29.0	-	14%
Lime Production	11.5	11.2	-7%	10%
Limestone and Dolomite Use	5.1	7.6	-	19%
Soda Ash Production and Consumption	4.1	4.3	-7%	7%
Carbon Dioxide Consumption	1.4	1.8	-	30%
Incineration of Waste	8.0	12.3	-	24%
Titanium Dioxide Production	1.2	1.5	-	13%
Aluminum Production	6.8	3.0	-4%	4%
Iron and Steel Production and Metallurgical Coke Production	99.5	41.9	16%	16%
Ferroalloy Production	2.2	1.5	-	13%
Ammonia Production and Urea Consumption	16.8	11.8	-7%	8%
Phosphoric Acid Production	1.5	1.0	-	19%
Petrochemical Production	3.3	2.7	-	31%
Silicon Carbide Production and Consumption	0.4	0.1	-9%	9%
Lead Production	0.5	0.5	-	15%
Zinc Production	0.7	1.0	-	18%
Cropland Remaining Cropland	7.1	7.8	-	50%
Wetlands Remaining Wetlands	1.0	1.1	-	34%
Petroleum Systems	0.6	0.5	-	149%
<i>Land Use, Land-Use Change, and Forestry (Sink)^d</i>	<i>(861.5)</i>	<i>(1,015.1)</i>	<i>15%</i>	<i>-15%</i>
<i>Biomass - Wood^e</i>	<i>215.2</i>	<i>183.8</i>	<i>NE</i>	<i>NE</i>
<i>International Bunker Fuels^e</i>	<i>111.8</i>	<i>123.1</i>	<i>NE</i>	<i>NE</i>
<i>Biomass - Ethanol^f</i>	<i>4.2</i>	<i>61.2</i>	<i>NE</i>	<i>NE</i>
CH₄	674.9	686.3	-9%	17%
Stationary Combustion	7.4	6.2	-	127%
Mobile Combustion	4.7	2.0	-9%	15%
Coal Mining	84.1	71.0	-	16%
Abandoned Underground Coal Mines	6.0	5.5	-	32%
Natural Gas Systems	189.8	221.2	-	30%
Petroleum Systems	35.4	30.9	-	149%
Petrochemical Production	0.9	0.8	-	27%
Silicon Carbide Production and Consumption	+	+	-9%	9%
Iron and Steel Production and Metallurgical Coke Production	1.0	0.4	21%	23%
Ferroalloy Production	+	+	-	12%
Enteric Fermentation	132.1	139.8	-	18%
Manure Management	31.7	49.5	-	20%
Rice Cultivation	7.1	7.3	-	146%
Field Burning of Agricultural Residues	0.3	0.2	-	42%
Forest Land Remaining Forest Land	3.2	7.8	-	145%
Landfills	147.4	117.5	-	40%
Wastewater Treatment	23.5	24.5	-	47%

Composting	0.3	1.7	-	50%
Incineration of Waste	+	+	NE	NE
<i>International Bunker Fuels^e</i>	<i>0.2</i>	<i>0.1</i>	<i>NE</i>	<i>NE</i>
N₂O	315.2	295.6	-	44%
Stationary Combustion	12.8	12.8	-	187%
Mobile Combustion	43.9	23.9	-	17%
Adipic Acid Production	15.8	1.9	-	42%
Nitric Acid Production	17.7	14.6	-	42%
Manure Management	14.5	17.9	-	24%
Agricultural Soil Management	197.8	204.6	-	54%
Field Burning of Agricultural Residues	0.1	0.1	-	31%
Wastewater Treatment	3.7	5.0	-	93%
N ₂ O from Product Uses	4.4	4.4	-8%	8%
Incineration of Waste	0.5	0.4	-	320%
Settlements Remaining Settlements	1.0	1.5	-	163%
Forest Land Remaining Forest Land	2.7	6.7	-	139%
Composting	0.4	1.8	-	50%
Wetlands Remaining Wetlands	+	+	-	41%
<i>International Bunker Fuels^e</i>	<i>1.1</i>	<i>1.1</i>	<i>NE</i>	<i>NE</i>
HFCs, PFCs, and SF₆	120.7	143.3	-6%	7%
Substitution of Ozone Depleting Substances ^g	29.0	117.1	-7%	8%
HCFC-22 Production	36.4	5.4	-7%	10%
Semiconductor Manufacture	2.9	5.3	-	11%
Aluminum Production	18.5	1.6	-	11%
Electrical Transmission and Distribution	28.4	12.8	-	22%
Magnesium Production and Processing	5.4	1.1	-3%	4%
Total^h	6,210.0	6,630.0	-1%	6%
Net Emissions (Sources and Sinks)^h	5,348.5	5,614.9	-2%	8%

Notes:

Totals may not sum due to independent rounding.

*Base Year is 1990 for all sources except Substitution of Ozone Depleting Substances, for which the United States has chosen 1995.

+ Does not exceed 0.05 Tg CO₂ Eq.

NE Not Estimated

^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 for 2009 in this table exclude approximately 3.2 Tg CO₂ 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. All uncertainty estimates correspond only to the totals reported in this table.

^b The uncertainty 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 This source category's inventory estimates exclude CO₂ emissions from geothermal sources, as quantitative uncertainty analysis was not performed for that sub-source category. Hence, for this source category, the emissions reported in this table do not match the emission estimates presented in the Energy chapter of the Inventory.

^d Sinks are only included in Net Emissions.

^e Emissions from International Bunker Fuels are not included in the totals.

^f Emissions from Wood Biomass and Ethanol Consumption are not included specifically in summing energy sector totals.

^g This source category's inventory estimate for 2009 excludes 2.9 Tg of CO₂ Eq. from several very small emission sources, as uncertainty associated with those sources was not assessed. Hence, for this source category, the emissions reported in this table do not match the emission estimates presented in the Industrial Processes chapter of the Inventory.

^h Totals exclude emissions for which uncertainty was not quantified. The Base Year emissions correspond to 1990 estimates for all source categories, with the exception of Substitution of ODS, for which the estimates correspond to 1995. Similarly, the total for HFCs, PFCs, and SF₆ for the Base Year includes 1995 emission estimates for Substitution of ODS and 1990 emission estimates for all other source categories.

Overall (Aggregate) Inventory Level Uncertainty Estimates

The overall level uncertainty estimate for the U.S. greenhouse gas emissions inventory was developed using the IPCC Tier 2 uncertainty estimation methodology. The uncertainty models of all the emission source categories could not be directly integrated to develop the overall uncertainty estimates due to software constraints in integrating multiple, large uncertainty models. Therefore, an alternative approach was adopted to develop the overall uncertainty estimates. The Monte Carlo simulation output data for each emission source category uncertainty analysis were combined by type of gas and the probability distributions were fitted to the combined simulation output data, where such simulated output data were available. If such detailed output data were not available for particular emissions sources, individual probability

distributions were assigned to those source category emission estimates based on the most detailed data available from the quantitative uncertainty analysis performed.

For the Composting and for parts of Agricultural Soil Management source categories, Tier 1 uncertainty results were used in the overall uncertainty analysis estimation. However, for all other emission sources (excluding international bunker fuels, CO₂ from biomass combustion, and CH₄ from incineration of waste), Tier 2 uncertainty results were used in the overall uncertainty estimation.

The overall uncertainty model results indicate that the 2009 U.S. greenhouse gas emissions are estimated to be within the range of approximately 6,584 to 7,034 Tg CO₂ Eq., reflecting a relative 95 percent confidence interval uncertainty range of -1 percent to 6 percent with respect to the total U.S. greenhouse gas emission estimate of approximately 6,630 Tg CO₂ Eq. The uncertainty interval associated with total CO₂ emissions, which constitute about 83 percent of the total U.S. greenhouse gas emissions in 2009, ranges from -1 percent to 6 percent of total CO₂ emissions estimated. The results indicate that the uncertainty associated with the inventory estimate of the total CH₄ emissions ranges from -9 percent to 17 percent, uncertainty associated with the total inventory N₂O emission estimate ranges from -11 percent to 44 percent, and uncertainty associated with high GWP gas emissions ranges from -6 percent to 7 percent.

A summary of the overall quantitative uncertainty estimates is shown below.

Table A-272. Quantitative Uncertainty Assessment of Overall National Inventory Emissions (Tg CO₂ Eq. and Percent)

Gas	2009 Emission Estimate ^a (Tg CO ₂ Eq.)	Uncertainty Range Relative to Emission Estimate ^b				Standard Deviation ^c	
		Uncertainty Range Relative to Emission Estimate ^b		Mean ^c		Deviation ^c	
		(Tg CO ₂ Eq.)	(%)	(Tg CO ₂ Eq.)	(%)	(Tg CO ₂ Eq.)	(%)
		Lower Bound ^d	Upper Bound ^d	Lower Bound	Upper Bound		
CO ₂	5,504.8	5,436.6	5,813.8	-1%	6%	5,622.5	97.5
CH ₄ ^e	686.3	623.9	805.4	-9%	17%	702.8	45.3
N ₂ O ^e	295.6	261.7	425.3	-11%	44%	334.2	42.1
PFC, HFC & SF ₆ ^e	143.3	134.5	153.4	-6%	7%	143.7	4.8
Total	6,630.0	6,584.2	7,033.6	-1%	6%	6,803.2	115.0
Net Emissions (Sources and Sinks)	5,614.9	5,512.3	6,055.1	-2%	8%	5,785.4	139.1

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 3.2 Tg CO₂ 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 CH₄, N₂O and high GWP gases used in the inventory emission calculations for 2009.

Trend Uncertainty

In addition to the estimates of uncertainty associated with the current year's emission estimates, this Annex also presents the estimates of trend uncertainty. The *IPCC Good Practice Guidance* defines trend as the difference in emissions between the base year (i.e., 1990) and the current year (i.e., 2009) inventory estimates. However, for purposes of understanding the concept of trend uncertainty, the emission trend is defined in this Inventory as the percentage change in the emissions (or removal) estimated for the current year, relative to the emission (or removal) estimated for the base year. The uncertainty associated with this emission trend is referred to as trend uncertainty.

Under the Tier 1 approach, the trend uncertainty for a source category is estimated using the sensitivity of the calculated difference between the base year and the current year (i.e., 2009) emissions to an incremental (i.e., 1 percent) increase in one or both of these values for that source category. The two sensitivities are expressed as percentages: Type A sensitivity highlights the effect on the difference between the base and the current year emissions caused by a 1 percent change in both, while Type B sensitivity highlights the effect caused by a change to only the current year's emissions. Both sensitivities are simplifications introduced in order to analyze the correlation between the base and the current year estimates. Once calculated, the two sensitivities are combined using the error propagation equation to estimate the overall trend uncertainty.

Under the Tier 2 approach, the trend uncertainty is estimated using Monte Carlo Stochastic Simulation technique. The trend uncertainty analysis takes into account the fact that the base and the current year estimates often share input variables. For purposes of the current Inventory, a simple approach has been adopted, under which the base year source category emissions (or removals) are assumed to exhibit the same uncertainty characteristics as the current year emissions (or removals). Source category-specific PDFs for base year estimates were developed using current year (i.e., 2009) uncertainty output data. These were adjusted to account for differences in magnitude between the two years' inventory estimates. Then, for each source category, a trend uncertainty estimate was developed using the Monte Carlo method. The overall inventory trend uncertainty estimate was developed by combining all source category-specific trend uncertainty estimates. These preliminary trend uncertainty estimates present the range of likely change from base year to 2009, and are shown in Table A- 273.

Table A- 273. Quantitative Assessment of Trend Uncertainty (Tg CO₂ Eq. and Percent)

Gas/Source	Base Year Emissions ^a	2009 Emissions ^a	Emissions Trend ^a	Trend Range ^{a,b}	
	(Tg CO ₂ Eq.)		(%)	(%)	
				Lower Bound	Upper Bound
CO₂	5,099.3	5,504.8	8%	3%	13%
Fossil Fuel Combustion ^c	4,738.0	5,208.6	10%	5%	16%
Non-Energy Use of Fuels	118.6	123.4	4%	-17%	31%
Iron and Steel Production and Metallurgical Coke Production	99.5	41.9	-58%	-67%	-47%
Natural Gas Systems	37.6	32.2	-14%	-39%	20%
Cement Production	33.3	29.0	-13%	-28%	5%
Incineration of Waste	8.0	12.3	54%	12%	111%
Ammonia Production and Urea Consumption	16.8	11.8	-30%	-37%	-22%
Lime Production	11.5	11.2	-3%	-14%	10%
Cropland Remaining Cropland	7.1	7.8	11%	-56%	181%
Limestone and Dolomite Use	5.1	7.6	49%	20%	85%
Soda Ash Production and Consumption	4.1	4.3	3%	-7%	14%
Aluminum Production	6.8	3.0	-56%	-58%	-53%
Petrochemical Production	3.3	2.7	-17%	-46%	27%
Carbon Dioxide Consumption	1.4	1.8	24%	-17%	88%
Ferroalloy Production	2.2	1.5	-32%	-43%	-18%
Titanium Dioxide Production	1.2	1.5	29%	7%	55%
Wetlands Remaining Wetlands	1.0	1.1	5%	-33%	67%
Phosphoric Acid Production	1.5	1.0	-32%	-48%	-11%
Zinc Production	0.7	1.0	45%	12%	86%
Petroleum Systems	0.6	0.5	-17%	-64%	90%
Lead Production	0.5	0.5	2%	-18%	25%
Silicon Carbide Production and Consumption	0.4	0.1	-61%	-66%	-56%
<i>Land Use, Land-Use Change, and Forestry (Sink)^d</i>	<i>(861.5)</i>	<i>(1,015.1)</i>	<i>18%</i>	<i>-5%</i>	<i>46%</i>
<i>Biomass - Wood^f</i>	<i>215.2</i>	<i>183.8</i>	<i>-15%</i>	<i>NE</i>	<i>NE</i>
<i>International Bunker Fuels^e</i>	<i>111.8</i>	<i>123.1</i>	<i>10%</i>	<i>NE</i>	<i>NE</i>
<i>Biomass - Ethanol^f</i>	<i>4.2</i>	<i>61.2</i>	<i>1348%</i>	<i>NE</i>	<i>NE</i>
CH₄	674.9	686.3	2%	-15%	22%
Natural Gas Systems	189.8	221.2	17%	-17%	64%
Enteric Fermentation	132.1	139.8	6%	-14%	30%
Landfills	147.4	117.5	-20%	-61%	63%
Coal Mining	84.1	71.0	-16%	-32%	4%
Manure Management	31.7	49.5	56%	19%	105%
Petroleum Systems	35.4	30.9	-13%	-62%	98%
Wastewater Treatment	23.5	24.5	4%	-42%	91%
Forest Land Remaining Forest Land	3.2	7.8	144%	-50%	1110%
Rice Cultivation	7.1	7.3	3%	-75%	317%
Stationary Combustion	7.4	6.2	-17%	-67%	109%
Abandoned Underground Coal Mines	6.0	5.5	-9%	-40%	38%
Mobile Combustion	4.7	2.0	-58%	-65%	-51%
Composting	0.3	1.7	421%	131%	1061%
Petrochemical Production	0.9	0.8	-2%	-34%	44%
Iron and Steel Production and Metallurgical Coke Production	1.0	0.4	-62%	-72%	-48%
Field Burning of Agricultural Residues	0.3	0.2	-8%	-51%	72%
Ferroalloy Production	+	+	-40%	-99%	-99%
Silicon Carbide Production and Consumption	+	+	-67%	-71%	-62%

Incineration of Waste	+	+	-23%	NE	NE
<i>International Bunker Fuels^e</i>	<i>0.2</i>	<i>0.1</i>	<i>-14%</i>	<i>NE</i>	<i>NE</i>
N₂O^g	315.2	295.6	-6%	-32%	31%
Agricultural Soil Management	197.8	204.6	3%	-36%	65%
Mobile Combustion	43.9	23.9	-46%	-56%	-32%
Manure Management	14.5	17.9	23%	-7%	63%
Nitric Acid Production	17.7	14.6	-18%	-56%	50%
Stationary Combustion	12.8	12.8	0%	-65%	183%
Forest Land Remaining Forest Land	2.7	6.7	152%	-40%	977%
Wastewater Treatment	3.7	5.0	36%	-72%	499%
N ₂ O from Product Uses	4.4	4.4	0%	-12%	12%
Adipic Acid Production	15.8	1.9	-88%	-93%	-77%
Composting	0.4	1.8	421%	135%	1042%
Settlements Remaining Settlements	1.0	1.5	55%	-51%	392%
Incineration of Waste	0.5	0.4	-23%	-83%	245%
Field Burning of Agricultural Residues	0.1	0.1	3%	-33%	60%
Wetlands Remaining Wetlands	+	+	-7%	-72%	225%
<i>International Bunker Fuels^e</i>	<i>1.1</i>	<i>1.1</i>	<i>4%</i>	<i>NE</i>	<i>NE</i>
HFCs, PFCs, and SF₆	120.7	143.3	19%	9%	29%
Substitution of Ozone Depleting Substances ^g	29.0	117.1	304%	264%	349%
Electrical Transmission and Distribution	28.4	12.8	-55%	-66%	-39%
HCFC-22 Production	36.4	5.4	-85%	-87%	-83%
Semiconductor Manufacture	2.9	5.3	83%	58%	111%
Aluminum Production	18.5	1.6	-91%	-93%	-90%
Magnesium Production and Processing	5.4	1.1	-81%	-82%	-80%
Total^h	6,210.0	6,630.0	7%	2%	12%
Net Emissions (Sources and Sinks)^h	5,348.5	5,614.9	5%	-2%	12%

Notes:

Totals may not sum due to independent rounding.

*Base Year is 1990 for all sources except Substitution of Ozone Depleting Substances, for which the United States has chosen to use 1995.

+ Does not exceed 0.05 Tg CO₂ Eq.

NE Not Estimated

^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 for 2009 exclude approximately 3.2 Tg CO₂ 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. Emissions trends and the emission range were calculated based on the emissions estimates reported in this table and, therefore, may differ from the emissions trends reported elsewhere in this Inventory.

^b The trend range represents a 95 percent confidence interval for the emission trend, with the lower bound corresponding to 2.5th percentile value and the upper bound corresponding to 97.5th percentile value.

^c This source category's inventory estimates exclude CO₂ emissions from geothermal sources, as quantitative uncertainty analysis was not performed for that sub-source category. Hence, for this source category, the emissions reported in this table do not match the emission estimates presented in the Energy chapter of the Inventory.

^d Sinks are only included in Net Emissions.

^e Emissions from International Bunker Fuels are not included in the emission totals and emission trend estimates.

^f Emissions from Wood Biomass and Ethanol Consumption are not included specifically in summing energy sector totals.

^g This source category's inventory estimate for 2009 excludes about 2.9 Tg of CO₂ Eq. from several very small emission sources, as uncertainty associated with those sources was not assessed. Hence, for this source category, the emissions reported in this table do not match the emission estimates presented in the Industrial Processes chapter of the Inventory.

^h Totals exclude emissions for which uncertainty was not quantified. The Base Year emissions correspond to 1990 estimates for all source categories, with the exception of Substitution of ODS, for which the estimates correspond to 1995. Similarly, the total for HFCs, PFCs, and SF₆ for the Base Year includes 1995 emission estimates for Substitution of ODS and 1990 emission estimates for all other source categories.

7.3. Planned Improvements

Identifying the sources of uncertainty in the emission and sink estimates of the Inventory and quantifying the magnitude of the associated uncertainty is the crucial first step towards improving those estimates. Quantitative assessment of the parameter uncertainty may also provide information about the relative importance of input parameters (such as activity data and emission factors), based on their relative contribution to the uncertainty within the source category estimates. Such information can be used to prioritize resources with a goal of reducing uncertainty over time within or among inventory source categories and their input parameters. In the current Inventory, potential sources of model uncertainty have been identified for some emission source categories, and uncertainty estimates based on their parameters' uncertainty have been developed for all the emission source categories, with the exception of CH₄ from incineration of waste, which is a minor emission source category newly added to the Inventory starting with the 2008 business year, and the international bunker fuels and wood biomass and ethanol combustion source categories, which are

not included in the energy sector totals. Emissions from biomass and ethanol combustion however are accounted for implicitly in the LULUCF chapter through the calculation of changes in carbon stocks. The Energy sector does provide an estimate of CO₂ emissions from bioenergy consumption provided as a memo item for informational purposes.

Specific areas that require further research include:

- *Incorporating excluded emission sources.* Quantitative estimates for some of the sources and sinks of greenhouse gas emissions, such as from some land-use activities, industrial processes, and parts of mobile sources, could not be developed at this time 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. In the future, efforts will focus on estimating emissions from excluded emission sources and developing uncertainty estimates for all source categories for which emissions are estimated.
- *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 CH₄ and N₂O emissions from stationary and mobile combustion are 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 SF₆ from electrical transmission and distribution is limited due to a lack of activity data regarding national SF₆ consumption or average equipment leak rates.

In improving the quality of uncertainty estimates the following include areas that deserve further attention:

- *Refine Source Category and Overall Uncertainty Estimates.* For many individual source categories, further research is needed to more accurately characterize PDFs that surround emissions modeling input variables. This might involve using measured or published statistics or implementing rigorous elicitation protocol to elicit expert judgments, if published or measured data are not available.
- *Include GWP uncertainty in the estimation of Overall level and trend uncertainty.* The current year's Inventory does not include the uncertainty associated with the GWP values in the estimation of the overall uncertainty for the Inventory. Including this source would contribute to a better characterization of overall uncertainty and help assess the level of attention that this source of uncertainty warrants in the future.
- *Improve characterization of trend uncertainty associated with base year Inventory estimates.* The characterization of base year uncertainty estimates could be improved, by developing explicit uncertainty models for the base year. This would then improve the analysis of trend uncertainty. However, not all of the simplifying assumptions described in the "Trend Uncertainty" section above may be eliminated through this process due to a lack of availability of more appropriate data.

7.4. Additional Information on Uncertainty Analyses by Source

The quantitative uncertainty estimates associated with each emission and sink source category are reported in each chapter of this Inventory following the discussions of inventory estimates and their estimation methodology. This section provides additional descriptions of the uncertainty analyses performed for some of the sources, including the models and methods used to calculate the emission estimates and the potential sources of uncertainty surrounding them. These sources are organized below in the same order as the sources in each chapter of the main section of this Inventory. To avoid repetition, the following uncertainty analysis discussions of individual source categories do not include descriptions of these source categories. Hence, to better understand the details provided below, refer to the respective chapters and sections in the main section of this Inventory, as needed. All uncertainty estimates are reported relative to the 2009 Inventory estimates for the 95 percent confidence interval, unless otherwise specified.

Energy

The uncertainty analysis descriptions in this section correspond to some source categories included in the Energy Chapter of the Inventory.

Mobile Combustion (excluding CO₂)

Mobile combustion emissions of CH₄ and N₂O per vehicle mile traveled vary significantly due to fuel type and composition, technology type, operating speeds and conditions, type of emission control equipment, equipment age, and operating and maintenance practices.

The primary activity data for on-road vehicles, VMT, are collected and analyzed each year by government agencies. To determine the uncertainty associated with the activity data used in the calculations of CH₄ and N₂O emissions, the agencies and the experts that supply the data were contacted. Because few of these sources were able to provide quantitative estimates of uncertainty, expert judgment was used to assess the quantitative uncertainty associated with the activity data.

The estimates of VMT for on-road vehicles by vehicle type in the U.S. were provided by the FHWA (1996 through 2009), and were generated through a cooperative process between the FHWA and the state and the local governments. These estimates are subject to several possible sources of error, such as unregistered vehicles, and measurement and estimation errors. These VMT were apportioned by fuel type, based on data from DOE (1993 through 2009), and then allocated to individual model years using temporal profiles of both the vehicle fleet by age and vehicle usage by model year in the U.S. provided by EPA (2007c) and EPA (2000). While the uncertainty associated with the total national VMT is believed to be low, the uncertainty within individual source categories was considered to be higher due to the uncertainty associated with apportioning total VMT into individual vehicle categories, by fuel type, technology type, and by equipment age. It was assumed that smaller sources had greater percentage uncertainty and vice-versa. Another source of uncertainty in the estimates occurs due to differences in the FHWA and the EPA data sources. For example, the FHWA data are used for defining vehicle types and for developing the estimates of VMT by vehicle type; whereas, the estimates of VMT by fuel types are calculated using EPA's definition of vehicle categories (which differ from those of the FHWA).

The emission factors for on-road vehicles used in the Inventory were obtained from ICF (2006b) and ICF (2004). These factors were based on laboratory testing of vehicles. While the controlled testing environment simulates real driving conditions, emission results from such testing can only approximate real world conditions and emissions. For some vehicle and control technology types, because the testing did not yield statistically significant results within the 95 percent confidence interval, expert judgment was adopted in developing the emission factors. In those cases, the missing emission factors were extrapolated based on the data available on the other emission factors and the emissions factors available for similar vehicle and control technology type. For example, if light duty trucks with an oxidation catalyst has no testing (or not significant testing) results and if light duty cars with an oxidation catalyst had testing results, the CH₄ and the N₂O emission factors for the trucks were calculated from the corresponding emissions factors for the car based upon the ratio of CO₂ emissions per mile for the car to the truck.

A total of 111 highway data input variables were simulated through Monte Carlo Simulation technique using @RISK software. Variables included VMT and emission factors for individual conventional and alternative fuel vehicle categories and technologies. In developing the uncertainty estimation model, a normal distribution was assumed for all but two activity-related input variables (e.g., VMT); in the case of the two input variables, buses and percent of diesel combination trucks, triangular distributions were assumed. The dependencies and other correlations among the activity data were incorporated into the model to ensure consistency in the model specification and simulation. Emission factors were assigned uniform distributions, with the upper and the lower bounds assigned based on 95 percent confidence intervals of laboratory test data. In cases where data did not yield statistically significant results within the 95 percent confidence interval, estimates of upper and lower bounds were determined using expert judgments. For biodiesel vehicles, because no test data were available, consistent with the assumptions underlying the ANL GREET model, their N₂O and CH₄ emissions were assumed to be same as those for diesel vehicles of similar types. For other alternative fuel vehicles (AFVs), uncertainty estimates were developed based on conventional fuel vehicle emission factors and applicable multipliers, as described in the ICF's AFV emission factors memorandum to EPA (ICF 2006a). The results of the quantitative uncertainty analysis are reported as *quantitative uncertainty estimates* following the mobile source category emissions description in the Energy Chapter of this Inventory.

Emissions from non-road vehicles account for 23 percent of CH₄ emissions from mobile sources and 13 percent of N₂O emissions from mobile sources in 2009. A quantitative analysis of uncertainty in the inventory estimates of emissions from non-road vehicles was performed for the first time for the 2009 inventory. Sources of uncertainty for non-road vehicles were investigated by examining the underlying uncertainty of emission factors and fuel consumption data. A non-road uncertainty assessment module was developed independently and integrated with the highway mobile uncertainty model to facilitate a more comprehensive quantitative analysis of uncertainty for all mobile sources.

The fuel consumption data for non-road vehicles were obtained from several sources. Estimates of fuel consumption for non-road vehicles (i.e., equipment used for agriculture, construction, lawn and garden, railroad, airport ground support, etc., as well as recreational vehicles) were generated by the EPA's NONROAD model (EPA 2009). This model estimates fuel consumption based on estimated equipment/vehicle use (in hours) and average fuel consumed per hour of use. Since the fuel estimates are not based upon documented fuel sales or consumption, a fair degree of uncertainty accompanies these estimates. Estimates of distillate fuel sales for ships and boats were obtained from EIA's *Fuel Oil and Kerosene Sales* (EIA 1991 through 20010). These estimates have a moderate level of uncertainty since

EIA's estimates are based on survey data and reflect sales to economic sectors, which may include use by both mobile and non-mobile sources within a sector. Domestic consumption of residual fuel by ships and boats is obtained from EIA (20010a). These estimates fluctuate widely from year to year, and are believed to be highly uncertain. In addition, estimates of distillate and residual fuel sales for ships and boats are adjusted for bunker fuel consumption, which introduces an additional (and much higher) level of uncertainty. Jet fuel and aviation gasoline consumption data are obtained from DOT (1991 through 20010), EIA (2007a), FAA (20010), and FAA (2006). Additionally, all jet fuel consumption in the transportation sector is assumed to be consumed by aircraft. Some jet fuel may also be used for other purposes such as blending with diesel fuel or heating oil. In calculating CH₄ emissions from aircraft, an average emission factor is applied to total jet fuel consumption. This average emission factor takes into account the fact that CH₄ emissions occur only during the landing and take-off (LTO) cycles, with no CH₄ being emitted during the cruise cycle. However, a better approach would be to apply emission factors based on the number of LTO cycles.

Emission factors for non-road modes were taken from IPCC/UNEP/OECD/IEA (1997) and Browning (2009). These emission factors are based on laboratory test data and expert judgment, and have similar sources of uncertainty as the on-road emission factors for uncontrolled vehicles.

A total of 79 non-road data input variables were simulated in the non-road uncertainty assessment module using @RISK software. To determine the uncertainty associated with the non-road fuel consumption data, the agencies and experts that supply the data were contacted. Since few of these sources were able to provide quantitative estimates of uncertainty, expert judgment was used to assess the quantitative uncertainty associated with the fuel consumption data. A normal distribution was assumed for all non-road activity-related input (fuel use) variables, and the activity variables were assumed to be independent of each other. Uncertainty estimates for non-road emissions factors were developed based on laboratory test data and expert judgement. Beta-PERT distributions were assumed for the emissions factor variables, and correlations among the data were incorporated into the model to ensure consistency in model specification.

The results of the quantitative uncertainty analysis are reported as *quantitative uncertainty estimates* following the mobile source category emissions description in the Energy Chapter of this Inventory.

Incineration of Waste

The upper and lower bounds of uncertainty in the CO₂ emissions estimate for Incineration of Waste are 24 percent and -21 percent respectively, and in the N₂O emission estimates are 320 percent and -51 percent respectively, relative to the respective 2009 emission estimates, at the 95 percent confidence interval. The uncertainties in the waste combustion emission estimates arise from both the assumptions applied to the data and from the quality of the data. Key factors include MSW combustion rate, fraction oxidized, missing data on MSW composition, average carbon content of MSW components, assumptions on the synthetic/biogenic carbon ratio, and combustion conditions affecting N₂O emissions. For more information on emission estimates from MSW combustion, please refer to the Incineration of Waste section of the Energy chapter. The highest levels of uncertainty surround the variables, whose estimates were developed 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, carbon content of carbon black). Important sources of uncertainty are as follows:

- *MSW Combustion Rate.* A source of uncertainty affecting both fossil CO₂ and N₂O emissions is the estimate of the MSW combustion rate. The *BioCycle* (Glenn 1999, Goldstein and Matdes 2000, Goldstein and Matdes 2001, Kaufman et al. 2004a, Kaufman et al. 2004b, Simmons et al. 2006, Arsova et al. 2008, van Haaren et al. 2010) estimate of total waste combustion, used for the N₂O and CH₄ emissions estimates, and waste incineration rate, used for the CO₂ emissions estimate are based on a survey of state officials, who use differing definitions of solid waste and who draw from a variety of sources of varying reliability and accuracy. The survey methodology changed significantly in 2003 and thus the results reported for 2002 are not directly comparable to the earlier results (Kaufman et al. 2004a, 2004b), introducing further uncertainty.
- *Fraction Oxidized.* Another source of uncertainty for the CO₂ emissions estimate is fraction oxidized. Municipal waste combustors vary considerably in their efficiency as a function of waste type, moisture content, combustion conditions, and other factors. A value of 98 percent was assumed for this analysis.
- *Missing Data on Municipal Solid Waste Composition.* Disposal rates have been interpolated when there is an incomplete interval within a time series. Where data are not available for years at the end of a time series, they are set equal to the most recent years for which estimates are available.
- *Average Carbon Contents.* Average carbon contents were applied to the mass of "Other" plastics combusted, synthetic rubber in tires and municipal solid waste, and synthetic fibers. These average values were estimated from the average carbon content of the known products recently produced. The actual carbon content of the

combusted waste may differ from this estimate depending on differences in the chemical formulation between the known and unspecified materials, and differences between the composition of the material disposed and that produced. For rubber, this uncertainty ranges from 51 to 91 percent; for plastics, it may be more significant, as their carbon contents range from 38 to 92 percent. However, overall, this is a small source of uncertainty.

- *Synthetic/Biogenic Assumptions.* A portion of the fiber and rubber in municipal solid waste is biogenic in origin. Assumptions have been made concerning the allocation between synthetic and biogenic materials based primarily on expert judgment.
- *Combustion Conditions Affecting N₂O Emissions.* Because insufficient data exist to provide detailed estimates of N₂O emissions for individual combustion facilities, the estimates presented exhibit high uncertainty. The emission factor for N₂O from municipal solid waste combustion facilities used in the analysis corresponds to the default emission factor for continuously fed stoker units found in IPCC (2006). Using this emission factor assumes that all waste combustors in the United States use continuously fed stoker technology, which is uncertain. Due to a lack of information on the control of N₂O emissions from MSW combustion facilities in the United States, the estimate of zero percent for N₂O emissions control removal efficiency also exhibits uncertainty.

Industrial Processes

The uncertainty analysis descriptions in this section correspond to some source categories included in the Industrial Processes Chapter of the Inventory.

Ammonia Manufacture and Urea Consumption

The uncertainty upper and lower bounds of the emission estimate for Ammonia Manufacture and Urea Consumption were 8 percent and -7 percent, respectively, at the 95 percent confidence interval. The European Fertilizer Manufacturer's Association (EFMA) reported an emission factor range of 1.15 to 1.30 ton CO₂/ton NH₃, with 1.2 ton CO₂/ton NH₃ reported as a typical value. The actual emission factor depends upon the amount of air used in the ammonia production process, with 1.15 ton CO₂/ton NH₃ being the approximate stoichiometric minimum that is achievable for the conventional reforming process. By using natural gas consumption data for each ammonia plant, more accurate estimates of CO₂ emissions from ammonia production could be calculated. However, these consumption data are often considered confidential. Also, natural gas is consumed at ammonia plants both as a feedstock to the reforming process and for generating process heat and steam. Natural gas consumption data, if available, would need to be divided into feedstock use (non-energy) and process heat and steam (fuel) use, as CO₂ emissions from fuel use and non-energy use are calculated separately.⁹¹

Natural gas feedstock consumption data for the U.S. ammonia industry as a whole are available from the Energy Information Administration (EIA) *Manufacturers Energy Consumption Survey* (MECS) for the years 1985, 1988, 1991, 1994 and 1998 (EIA 1994, 1998). These feedstock consumption data collectively correspond to an effective average emission factor of 1.0 ton CO₂/ton NH₃, which appears to be below the stoichiometric minimum that is achievable for the conventional steam reforming process. The EIA data for natural gas consumption for the years 1994 and 1998 correspond more closely to the CO₂ emissions calculated using the EFMA emission factor than do data for previous years. The 1994 and 1998 data alone yield an effective emission factor of 1.1 ton CO₂/ton NH₃, corresponding to CO₂ emissions estimates that are approximately 1.5 Tg CO₂ Eq. below the estimates calculated using the EFMA emission factor of 1.2 ton CO₂/ton NH₃. Natural gas feedstock consumption data are not available from EIA for other years, and data for 1991 and previous

⁹¹ It appears that the IPCC emission factor for ammonia production of 1.5 ton CO₂ per ton ammonia may include both CO₂ emissions from the natural gas feedstock to the process and some CO₂ emissions from the natural gas used to generate process heat and steam for the process. Table 2-5, Ammonia Production Emission Factors, in Volume 3 of the *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories Reference Manual* (IPCC 1997) includes two emission factors, one reported for Norway and one reported for Canada. The footnotes to the table indicate that the factor for Norway does not include natural gas used as fuel but that it is unclear whether the factor for Canada includes natural gas used as fuel. However, the factors for Norway and Canada are nearly identical (1.5 and 1.6 tons CO₂ per ton ammonia, respectively) and it is likely that if one value does not include fuel use, the other value also does not. For the conventional steam reforming process, however, the EFMA reports an emission factor range for feedstock CO₂ of 1.15 to 1.30 ton per ton (with a typical value of 1.2 ton per ton) and an emission factor for fuel CO₂ of 0.5 tons per ton. This corresponds to a total CO₂ emission factor for the ammonia production process, including both feedstock CO₂ and process heat CO₂, of 1.7 ton per ton, which is closer to the emission factors reported in the *IPCC 1996 Reference Guidelines* than to the feedstock-only CO₂ emission factor of 1.2 ton CO₂ per ton ammonia reported by the EFMA. Because it appears that the emission factors cited in the *IPCC Guidelines* may actually include natural gas used as fuel, we use the 1.2 tons/ton emission factor developed by the EFMA.

years may underestimate feedstock natural gas consumption, and therefore the EFMA emission factor was used to estimate CO₂ emissions from ammonia production, rather than EIA data.

Research indicates that there is only one U.S. plant that manufactures ammonia from petroleum coke. CO₂ emissions from this plant are explicitly accounted for in the Inventory estimates. No data for ammonia plants using naphtha or other feedstocks other than natural gas have been identified. Therefore, all other CO₂ emissions from ammonia plants are calculated using the emission factor for natural gas feedstock. However, actual emissions may differ because processes other than catalytic steam reformation and feedstocks other than natural gas may have been used for ammonia production. Urea is also used for other purposes than as a nitrogenous fertilizer. Currently, urea used as a nitrogenous fertilizer is accounted for in the LULUCF chapter. Research has identified one ammonia production plant that is recovering byproduct CO₂ for use in EOR. Such CO₂ is currently assumed to remain sequestered (see the section of this chapter on CO₂ Consumption); however, time series data for the amount of CO₂ recovered from this plant are not available and therefore all of the CO₂ produced by this plant is assumed to be emitted to the atmosphere and allocated to Ammonia Manufacture.

Phosphoric Acid Production

The uncertainty upper and lower bounds of the emissions estimate for Phosphoric Acid Production were 19 percent and -18 percent, respectively, at the 95 percent confidence interval. Factors such as the composition of phosphate rock affect CO₂ emissions from phosphoric acid production. For more information on how emissions estimates were calculated, please refer to the Phosphoric Acid Production section of the Industrial Processes chapter. Only one set of data from the Florida Institute of Phosphate Research (FIPR) was available for the composition of phosphate rock mined domestically and imported, and data for uncalcined phosphate rock mined in North Carolina and Idaho were unavailable. Inorganic carbon content (as CO₂) of phosphate rock could vary ± 1 percent, resulting in a variation in CO₂ emissions of ± 20 percent.

Organic C is not included in the calculation of CO₂ emissions from phosphoric acid production. However, if, for example, 50 percent of the organic carbon content of the phosphate rock were to be emitted as CO₂ in the phosphoric acid production process, the CO₂ emission estimate would increase by approximately 50 percent. If it is assumed that 100 percent of the reported domestic production of phosphate rock for Idaho and Utah was first calcined, and it is assumed that 50 percent of the organic carbon content of the total production for Idaho and Utah was converted to CO₂ in the calcination process, the CO₂ emission estimate would increase on the order of 10 percent. If it were assumed that there are zero emissions from other uses of phosphate rock, CO₂ emissions would fall 10 percent.

Iron and Steel & Metallurgical Coke Production

The uncertainty upper and lower bounds of the CO₂ emission estimate for Iron and Steel & Metallurgical Coke Production were 16 percent and -16 percent, respectively, at the 95 percent confidence interval. Factors such as the composition of C anodes and the C content of pig iron and crude steel affect CO₂ emissions from Iron and Steel Production. For more information on emission estimates, please refer to the Iron and Steel Production section of the Industrial Processes chapter. Simplifying assumptions were made concerning the composition of C anodes, (80 percent petroleum coke and 20 percent coal tar). For example, within the aluminum industry, the coal tar pitch content of anodes can vary from 15 percent in prebaked anodes to 24 to 28 percent in Soderberg anode pastes (DOE 1997). An average value was assumed and applied to all carbon anodes utilized during aluminum and steel production. It was also assumed that the C contents of all pig iron and crude steel have carbon contents of 4 percent and 1 percent, respectively. The carbon content of pig iron can vary between 3.6 and 4.4 percent, while crude steel can have a carbon content of up to 2 percent, although it is typically less than 1 percent (IPCC 2000).

Aluminum Production

The uncertainty upper and lower bounds of the PFCs emission estimate for Aluminum Production were 11 percent and -11 percent, respectively, at the 95 percent confidence interval. The uncertainties associated with three variables were estimated for each smelter: (1) the quantity of aluminum produced, (2) the anode effect minutes per cell day (which may be reported directly or calculated as the product of anode effect frequency and anode effect duration), and (3) the smelter- or technology-specific slope coefficient (or weight fraction). For more information on the effect of these variables on PFC emissions, please refer the Aluminum Production section of the Industrial Processes chapter. All three types of data are assumed to be characterized by a normal distribution. The uncertainty in aluminum production estimates was assumed to be 1 percent for reported data (IPCC 2006). For reported anode effect frequency and duration data, the uncertainties were assumed to be 2 percent and 5 percent, respectively (Kantamaneni et al. 2001). For calculated smelter-specific CF₄ and C₂F₆ slope coefficients the uncertainties were assumed to be 15 percent (IPCC 2006). For smelters applying technology-specific slope coefficients or weight fractions, the uncertainty in the coefficients was based on the standard deviation of the individual measurements used to determine the average value given by the IPCC guidance for

technology-specific (Tier 2) slope coefficients. Consequently, the uncertainty value assigned to the technology-specific slope coefficients for CF₄ for CWPB was 0.036, and for C₂F₆ for CWPB was 0.060. (The uncertainty in the technology-specific CF₄ slope coefficient for CWPB is reported as 6 percent in IPCC (2006), but was increased to 50 percent in this analysis to better account for measurement uncertainty for an individual facility. The uncertainty in PFC emissions for CWPB facilities (the best behaved of the technology types) is about 50 percent for any given facility using the Tier 2 calculation.) In general, where precise quantitative information was not available on the uncertainty of a parameter, an upper-bound value was used.

Magnesium Production

The uncertainty information below pertains to the emission estimates presented in the Magnesium Production section of the Industrial Processes chapter. Please refer to that section for more information about this source. The uncertainty upper and lower bounds of the emissions estimate for Magnesium Production were 4 percent and -4 percent, respectively, at the 95 percent confidence interval. An uncertainty of 5 percent was assigned to the data reported by each participant in the Partnership. If Partners did not report emissions data during the current reporting year, SF₆ emissions data were estimated using available emission factor and production information reported in prior years; the extrapolation was based on the average trend for Partners reporting in the current reporting year and the year prior. The uncertainty associated with the SF₆ usage estimate generated from the extrapolated emission factor and production information was determined using a sum of squares method. A 5 percent uncertainty for the year the Partner last reported was assumed and a 30% uncertainty for each subsequent year was assumed. For those industry processes that are not represented in Partnership, such as permanent mold and wrought casting, SF₆ emissions were estimated using production and consumption statistics reported by USGS and estimated process-specific emission factors (see Table 4-73). The uncertainties associated with the emission factors and USGS-reported statistics were assumed to be 75 percent and 25 percent, respectively. Emissions associated with sand casting activities not entirely captured by the Partnership utilized a Partner-reported emission factor with an uncertainty of 75 percent. In general, where precise quantitative information was not available on the uncertainty of a parameter, a conservative (upper-bound) value was used.

Electrical Transmission and Distribution

The uncertainty upper and lower bounds of the emissions estimate for Electrical Transmission and Distribution at the 95 percent confidence interval were 22 percent and -21 percent, respectively. Uncertainty associated with emissions of SF₆ from electrical transmission and distribution stem from the following three quantities: (1) emissions from partners, (2) emissions from non-partners, and (3) emissions from manufacturers of electrical equipment. The uncertainty of partner emissions is related to whether the partner emissions are reported or estimated. For reported partner emissions, individual partner submitted SF₆ data was assumed to have an uncertainty of 10 percent. Based on a Monte Carlo analysis, the cumulative uncertainty of the total partner reported data was estimated to be 5.3 percent. For partner-estimated emissions, the uncertainty associated with emissions extrapolated or interpolated from reported emissions data was assumed to be 20 percent. There are two sources of uncertainty that contribute to the non-partner emissions uncertainty. The first is the uncertainty in the coefficients of the regression equations used to estimate emissions from non-partners, and the second is the uncertainty in the total transmission miles for non-partners—the independent variable in the regression equation. The uncertainty in the coefficients (as defined by the regression standard error estimate) is estimated to be ±20 percent for small utilities and ±64 percent for large utilities, while the uncertainty in the transmission miles is assumed to be 10 percent. For equipment manufacturers, the quantity of SF₆ charged into equipment by equipment manufacturers is estimated using partner reported new nameplate capacity data and the estimate for the total industry nameplate capacity. The quantity of SF₆ charged into equipment in 2009 is estimated to have an uncertainty of 70.2 percent, and is derived from the uncertainty in partner reported new nameplate capacity (estimated as 4.2 percent using error propagation) and the uncertainty in the estimate for U.S. total nameplate capacity (assumed to be 70 percent).

A Monte Carlo analysis was applied to estimate the overall uncertainty of the 2009 emission estimate for SF₆ from electrical transmission and distribution. For each defined parameter (i.e., regression coefficient, transmission mileage, partner-reported and partner-estimated SF₆ emissions data for electric power systems; and SF₆ emission rate and statistics for manufacturers), random variables were selected from probability density functions, all assumed to have normal distributions about the mean.

Agriculture

The uncertainty analysis descriptions in this section correspond to some source categories included in the Agriculture Chapter of the Inventory.

Manure Management

The uncertainty information below pertains to the emission estimates presented in the Manure Management section of the Agriculture chapter. Please refer to that section for information about various manure management systems and their effect on emissions from this source. The uncertainty upper and lower bounds of the CH₄ emissions estimate for Manure Management were 20 percent and -18 percent, respectively, at the 95 percent confidence interval. The primary factors that contribute to the uncertainty in the emission estimates are a lack of information on the usage of various manure management systems in each regional location and the exact CH₄ generating characteristics of each type of manure management system. Because of significant shifts in the swine and dairy sectors toward larger farms, it is believed that increasing amounts of manure are being managed in liquid manure management systems. The existing estimates reflect these shifts in the weighted MCFs based on 1992, 1997, and 2002 farm-size data. However, the assumption of a direct relationship between farm size and liquid system usage may not apply in all cases and may vary based on geographic location. In addition, the CH₄ generating characteristics of each manure management system type are based on relatively few laboratory and field measurements, and may not match the diversity of conditions under which manure is managed nationally.

Previously, IPCC published a default range of MCFs for anaerobic lagoon systems of 0 to 100 percent, reflecting the wide range in performance that may be achieved with these systems (IPCC 2000). There exist relatively few data points on which to determine country-specific MCFs for these systems. In the United States, many livestock waste treatment systems classified as anaerobic lagoons are actually holding ponds that are substantially organically overloaded and therefore not producing CH₄ at the same rate as a properly designed lagoon. In addition, these systems may not be well operated, contributing to higher loading rates when sludge is allowed to enter the treatment portion of the lagoon or the lagoon volume is pumped too low to allow treatment to occur. Rather than setting the MCF for all anaerobic lagoon systems in the United States based on data available from optimized lagoon systems, a MCF methodology utilizing the van't Hoff-Arrhenius equation was developed to more closely match observed system performance and account for the affect of temperature on system performance.

The MCF methodology used in the inventory includes a factor to account for management and design practices that result in the loss of VS from the management system. This factor is currently estimated based on data from anaerobic lagoons in temperate climates, and from only three systems. However, this methodology is intended to account for systems across a range of management practices.

Uncertainty also exists with the maximum CH₄ producing potential of VS excreted by different animal groups (i.e., B₀). The B₀ values used in the CH₄ calculations are published values for U.S. animal waste. However, there are several studies that provide a range of B₀ values for certain animals, including dairy and swine. The B₀ values chosen for dairy assign separate values for dairy cows and dairy heifers to better represent the feeding regimens of these animal groups. For example, dairy heifers do not receive an abundance of high energy feed and consequently, dairy heifer manure will not produce as much CH₄ as manure from a milking cow. However, the data available for B₀ values are sparse, and do not necessarily reflect the rapid changes that have occurred in this industry with respect to feed regimens.

Rice Cultivation

The uncertainty upper and lower bounds of the emission estimate for Rice Cultivation were 146 percent and -65 percent, respectively, at the 95 percent confidence interval. Factors such as primary rice-cropped area, ratooning, and flooding affect greenhouse gas emissions from this source. For more information on emissions estimates for Rice Cultivation, please refer to that section in the Agriculture Chapter. Uncertainty associated with primary rice-cropped area for each state was assumed to range from 1 percent to 5 percent of the mean area based on expert judgment. A normal distribution of uncertainty, truncated to avoid negative values, was assumed about the mean for areas.

Ratooned area data are an additional source of uncertainty. Although ratooning accounts for only 5 to 10 percent of the total rice-cropped area, it is responsible for about 15 to 30 percent of total emissions. For states that have never reported any ratooning, it is assumed with complete certainty that no ratooning occurred in 2009. For states that regularly report ratooning, uncertainty is estimated to be between 3 percent and 5 percent (based on expert judgment) and is assumed to have a normal distribution, truncated to avoid negative values. For Arkansas, which reported significant ratooning in 1998 and 1999 only, a triangular distribution was assumed, with a lower boundary of 0 percent ratooning and an upper boundary of 0.034 percent ratooning based on the maximum ratooned area reported in 1998 and 1999.

The practice of flooding outside of the normal rice season is also an uncertainty. According to agricultural extension agents, all of the rice-growing states practice this on some part of their rice acreage. Estimates of these areas range from 5 to 68 percent of the rice acreage. Fields are flooded for a variety of reasons: to provide habitat for waterfowl, to provide ponds for crawfish production, and to aid in rice straw decomposition. To date, however, CH₄ flux

measurements have not been undertaken over a sufficient geographic range or under a broad enough range of representative conditions to account for this source in the emission estimates or its associated uncertainty.

Agricultural Soil Management

The uncertainty information below pertains to the emission estimates presented in the Agricultural Soil Management section of the Agriculture chapter. Please refer to that section for information about this source. For direct emissions calculated using DAYCENT, uncertainty in the results was attributed to model inputs (i.e., activity data, weather and soil conditions) and the structure of the model (i.e., underlying model equations and parameterization). A Monte Carlo analysis was implemented to address these uncertainties and propagate errors through the modeling process (Del Grosso et al., 2010). The analysis was conducted using probability distribution functions (PDFs) for weather, soil characteristics, and N inputs to simulate direct N₂O emissions for each crop- or grassland type in a county. A joint PDF was used to address the structural uncertainty for direct N₂O emissions from crops, which was derived using an empirically-based method (Ogle et al. 2007). This same Monte Carlo analysis was used to derive uncertainty for the volatilization, runoff, and leaching of N that had been estimated with DAYCENT. County-scale PDFs for weather were based on the variation in temperature and precipitation as represented in DAYMET weather data grid cells (1x1 km) occurring in croplands and grasslands in a county. The National Land Cover Dataset (Vogelman et al. 2001) provided the data on distribution of croplands and grasslands. Similarly, county-scale PDFs for soil characteristics were based on STATSGO Soil Map Units (Soil Survey Staff 2005), that occurred in croplands and grasslands. PDFs for fertilizer were derived from survey data for major U.S. crops, both irrigated and rainfed (ERS 1997; NASS 2004, 1999, 1992; Grant and Krenz 1985). State-level PDFs were developed for each crop if a minimum of 15 data points existed for each of the two categories (irrigated and rainfed). Where data were insufficient at the state-level, PDFs were developed for multi-state Farm Production Regions. Uncertainty in manure application for specific crops was incorporated into the analysis based on total manure available for application in each county, a weighted average application rate, and the crop-specific land area amended with manure for 1997 (compiled from USDA data on animal numbers, manure production, storage practices, application rates and associated land areas receiving manure amendments; see Edmonds et al. 2003). Together with the total area for each crop within a county, the result yielded a probability that a given crop in a specific county would either receive manure or not in the Monte Carlo analysis. A ratio of manure N available for application in each year of the inventory relative to 1997 was used to adjust the amount of area amended with manure, under the assumption that changing the amount of manure N available for application would lead to a proportional change in amended area (see the section on Major Crop Types on Mineral Soils for data sources on manure N availability). If soils were amended with manure, a reduction factor was applied to the N fertilization rate accounting for the interaction between fertilization and manure N amendments (i.e., producers reduce mineral fertilization rates if applying manure). Reduction factors were randomly selected from probability distribution factors based on relationships between manure N application and fertilizer rates from USDA cropping survey data (ERS 1997).

An empirically-based uncertainty estimator was developed to assess the uncertainty in model structure associated with its' algorithms and parameterization, using a method described by Ogle et al. (2007). This estimator was based on a linear mixed-effect modeling analysis comparing N₂O emission estimates from eight agricultural experiments with 50 treatments. Although the dataset was relatively small, modeled emissions were significantly related to measurements with a p-value of less than 0.01. Random effects were included to capture the dependence in time series and data collected from the same experimental site, which were needed to estimate appropriate standard deviations for parameter coefficients. The model structural uncertainty estimator, accounted for bias and prediction error in the DAYCENT model results, as well as random error associated with fine-scale emission predictions in counties over a time series from 1990 to 2009. Note that the current application only addresses structural uncertainty in cropland estimates; further development will be needed to address this uncertainty in model estimates for grasslands, which is a planned improvement as more soil N₂O measurement data become available for grassland sites. In general, DAYCENT tended to underestimate emissions if the rates were above 6 g N₂O/ha/day (Del Grosso et al., 2010). Model structural uncertainty was not assessed for N volatilization and leaching/runoff, because sufficient data from field experiments were not available.

A simple error propagation method (IPCC 2006) was used to estimate uncertainties for direct emissions estimated with Tier 1 methods, including management of non-major crops (mineral fertilization, crop residues, organic fertilizers) and N inputs that were not addressed in the DAYCENT simulations (i.e., sewage sludge N, PRP manure N excreted on federal grasslands). Similarly, indirect emissions from N inputs that were not simulated with DAYCENT were calculated according to the IPCC methodology using the simple error propagation method (IPCC 2006). PDFs for the proportion of N subject to volatilization, leaching and runoff, as well as indirect N₂O emission factors were based on IPCC (2006), and PDFs for the activity data were based on the uncertainties associated underlying survey information and

calculations.⁹² For lands simulated by DAYCENT, uncertainty in indirect emissions was derived using the simple error propagation approach, combining uncertainty from the DAYCENT outputs for N volatilization and leaching/runoff with uncertainty in the indirect N₂O emission factors (IPCC 2006).

Field Burning of Agricultural Residues

The uncertainty upper and lower bounds of the CH₄ emission estimate for Field Burning of Agricultural Residues were 42 percent and -40 percent, respectively, and of the N₂O emissions estimate were 31 percent and -30 percent respectively, at the 95 percent confidence interval. Variables such as crop production, residue/crop product ratios, and burning and combustion efficiencies affect greenhouse gas emission estimates for Field Burning of Agricultural Residues. For more information on emission estimates, please refer to the Field Burning of Agricultural Residues section of the Agriculture Chapter. The uncertainty in production for all crops considered here is estimated to be 5 percent, based on expert judgment. The uncertainty in area burned was 7 percent, based on McCarty (2009). Residue/crop product ratios can vary among cultivars. Generic residue/crop product ratios, rather than ratios specific to the United States, have been used for all crops except sugarcane. An uncertainty of 10 percent was applied to the residue/crop product ratios for all crops except for cotton, which was 55 percent. Based on the range given for measurements of soybean dry matter fraction (Strehler and Stützel 1987), residue dry matter contents were assigned an uncertainty of 3.1 percent for all crop types, except for cotton and lentils, which were 10 and 4.4 percent, respectively. Burning and combustion efficiencies were assigned an uncertainty of 5 percent based on expert judgment.

The N₂O emission ratio was estimated to have an uncertainty of 28.6 percent based on the range reported in IPCC/UNEP/OECD/IEA (1997). The uncertainty estimated for the CH₄ emission ratio was 40 percent based on the range of ratios reported in IPCC/UNEP/OECD/IEA (1997).

Land Use, Land-Use Change, and Forestry

Forest Land Remaining Forest Land

Changes in Forest Carbon Stocks

Forest area data from the USDA Forest Service and C density data affect total net flux of forest C estimates. For more information on net forest C flux, please refer to the Changes in Forest Carbon Stocks section of the Land Use, Land-Use Change, and Forestry (LULUCF) chapter. The USDA Forest Service inventories are designed to be accurate within 3 percent at the 67 percent confidence level (one standard error) per 405,000 ha (1 million acres) of timberland (USDA Forest Service 2006c). For larger areas, the uncertainty in area is concomitantly less, and precision at plot levels is greater. An analysis of uncertainty in growing stock volume data for timber producing land in the Southeast by Phillips et al. (2000) found that nearly all of the uncertainty in their analysis was due to sampling rather than the regression equations used to estimate volume from tree height and diameter. The quantitative uncertainty analysis summarized here primarily focuses on uncertainties associated with the estimates of specific C stocks at the plot level and does not address error in tree diameters or volumes.

Estimates for stand-level C pools are derived from extrapolations of site-specific studies to all forest land, because survey data on these pools are not generally available. Such extrapolation introduces uncertainty because available studies may not adequately represent regional or national averages. Uncertainty may also arise due to: (1) modeling errors (e.g., relying on coefficients or relationships that are not well known); and (2) errors in converting estimates from one reporting unit to another (Birdsey and Heath 1995). An important source of uncertainty is that there is little consensus from available data sets on the effect of land-use change and forest management activities (such as harvest) on soil C stocks. For example, while Johnson and Curtis (2001) found little or no net change in soil C following harvest, on average, across a number of studies, many of the individual studies did show differences. Heath and Smith (2000) noted that the experimental design in a number of soil studies limited their usefulness for determining effects of harvesting on soil C. Because soil C stocks are large, estimates need to be very precise, since even small relative changes in soil C sum to large differences when integrated over large areas. The soil C stock and stock change estimates presented here are based on the assumption that soil C density for each broad forest type group stays constant over time. The state of information and modeling are improving in this regard (Woodbury et al. 2006, 2007); the effects of land use and of changes in land use and forest management will be better accounted for in future estimates of soil C.

Uncertainty in estimates about the HWP Contribution is based on Monte Carlo simulation of the production approach. The uncertainty analysis is based on Skog et al. (2004), with later revisions made in conjunction with overall revisions in the HWP model (Skog in preparation). The uncertainty analysis for HWP includes an evaluation of the effect

⁹² With the exception of organic fertilizers and crop yields, which were assumed to have a default ±50 percent uncertainty.

of uncertainty in 13 sources including production and trade data, factors to convert products to quantities of C, rates at which wood and paper are discarded, and rates and limits for decay of wood and paper in SWDS.

Direct N₂O fluxes from Forest Soils

The uncertainty upper and lower bounds of the emissions estimate for Direct N₂O Fluxes from Forest Soils were 211 percent and -59 percent, respectively, at the 95 percent confidence interval. Variables such as the emission factor for synthetic fertilizer applied to soil, and the area of forest land receiving fertilizer affect Direct N₂O fluxes from Forest Soils. For more information, please refer to that section of the LULUCF chapter. The uncertainty range of the IPCC (2006) default emission factor for synthetic fertilizer applied to soil, ranges from 0.3 to 3 percent. Because IPCC does not provide further information on whether this range represents the 95 percent confidence interval or the absolute minimum and maximum values, a triangular distribution was used to represent the uncertainty of the emission factor. The uncertainty in the area of forest land receiving fertilizer was conservatively estimated at ± 20 percent and in fertilization rates at ± 50 percent (Binkley 2004).

Cropland Remaining Cropland

The uncertainty information below pertains to the emission estimates presented in the Cropland Remaining Cropland section of the LULUCF chapter. Please refer to that section for information about this source. The uncertainty upper and lower bounds of the emissions estimate for Cropland Remaining Cropland were -172 percent and 167 percent, respectively, at the 95 percent confidence interval. Probability Distribution Functions (PDFs) for fertilizer were based on survey data for major U.S. crops, both irrigated and rainfed (ERS 1997; NASS 2004, 1999, 1992; Grant and Krenz 1985). State-level PDFs were developed for each crop if a minimum of 15 data points existed for each of the two categories (irrigated and rainfed). Where data were insufficient at the state-level, PDFs were developed for multi-state Farm Production Regions. Uncertainty in manure applications for specific crops was incorporated in the analysis based on total manure available for use in each county, a weighted average application rate, and the crop-specific land area amended with manure (compiled from USDA data on animal numbers, manure production, storage practices, application rates and associated land areas receiving manure amendments; see Edmonds et al. 2003). Together with the total area for each crop within a county, this yielded a probability that a given crop at a specific NRI point would either receive manure or not. A ratio of managed manure N production in each year of the inventory relative to 1997 was used to adjust the probability of an area receiving an amendment, under the assumption that greater or less managed manure N production would lead to a proportional change in amended area (see Tier 3 Methods Section for data sources on manure N production). Manure amendment areas were averaged across decades to produce the PDF for the Monte Carlo Analysis (i.e., 1980-1989, 1990-2000). If soils were amended with manure, a reduction factor was applied to the N fertilization rate accounting for the interaction between fertilization and manure N amendments (i.e., producers often reduce mineral fertilization rates if applying manure). Reduction factors were randomly selected from probability distribution factors based on relationships between manure N application and fertilizer rates (ERS 1997). For tillage uncertainty, transition matrices were constructed from CTIC data to represent tillage changes for two time periods, combining the first two and the second two management blocks (i.e., 1980-1989, 1990-2000). A Monte Carlo analysis was conducted with 100 iterations in which inputs values were randomly drawn from the PDFs to simulate the soil C stocks for each NRI cluster of points (i.e., inventory points in the same county were grouped into clusters if they had the same land-use/management history and soil type) using the Century model.

An empirically-based uncertainty estimator was developed to assess uncertainty in model structure associated with the algorithms and parameterization. The estimator was based on a linear mixed effect modeling analysis comparing modeled soil C stocks with field measurements from 45 long-term agricultural experiments with over 800 treatments, representing a variety of tillage, cropping, and fertilizer management practices (Ogle et al. 2006b). The final model included variables for organic matter amendments, N fertilizer rates, inclusion of hay/pasture in cropping rotations, use of no-till, setting-aside cropland from production and inclusion of bare fallow in the rotation. Each of these variables were found to be significant at a 95 percent probability level, and accounted for statistically significant biases in the modeled estimates from Century. For example, Century tended to under-estimate the influence of organic amendments on soil C storage, so a variable was added to adjust the estimate from Century. Random effects captured the dependence in time series and data collected from the same long-term experimental site, which were needed to estimate appropriate standard deviations for parameter coefficients. For each C stock estimate from the Monte Carlo analysis, the structural uncertainty estimator was applied to adjust the value accounting for bias and prediction error in the modeled values. The structural uncertainty estimator was applied by randomly drawing parameter coefficients from their joint probability distribution, in addition to random draws from PDFs representing the uncertainty due to site and site by year random effects. Finally, uncertainty in the land-use and management statistics from the NRI were incorporated into the analysis based on the sampling variance for the clusters of NRI points.

The NRI has a two-stage sampling design that allowed PDFs to be constructed assuming a multivariate normal distribution accounting for dependencies in activity data. PDFs for the tillage activity data, as provided by the CTIC, were constructed on a bivariate normal distribution with a log-ratio scale, accounting for the negative dependence among the proportions of land under conventional and conservation tillage practices. PDFs for the agricultural areas receiving manure were derived assuming a normal distribution from county-scale area amendment estimates derived from the USDA Census of Agriculture (Edmonds et al. 2003). Lastly, enrollment in wetland restoration programs was estimated from contract agreements, but due to a lack of information on the margin of error, PDFs were constructed assuming a nominal ± 50 percent uncertainty range.

Mineral Soil Carbon Stock Changes

Tier 3 Approach

The uncertainty information below pertains to the emission estimates presented in the Mineral Soil Carbon Stock Changes section of the LULUCF chapter. Please refer to that section for information about this source. The uncertainty analysis for the Tier 3 Century inventory had three components: 1) a Monte Carlo approach to address uncertainties in model inputs, 2) an empirically-based approach for quantifying uncertainty inherent in the structure of the Century model, and 3) scaling uncertainty associated with the NRI survey (i.e., scaling from the individual NRI points to the entire U.S. agricultural land base using the expansion factors).

For the model input uncertainty, probability distribution functions (PDFs) were developed for fertilizer rates, manure application and tillage practices. An empirically-based uncertainty estimator was developed to assess uncertainty in model structure associated with the algorithms and parameterization. The estimator was based on a linear mixed effect modeling analysis comparing modeled soil C stocks with field measurements from 45 long-term agricultural experiments with over 800 treatments, representing a variety of tillage, cropping, and fertilizer management practices (Ogle et al. 2007). The final model included variables for organic matter amendments, N fertilizer rates, inclusion of hay/pasture in cropping rotations, use of no-till, setting-aside cropland from production, and inclusion of bare fallow in the rotation. Each of these variables were found to be significant at a 0.05 alpha level, and accounted for statistically significant biases in modeled estimates from the Century model. Uncertainty in land-use and management statistics from the NRI were incorporated into the analysis based on the sampling variance for the clusters of NRI points.

Tier 2 Approach

For the Tier 2 IPCC method, a Monte Carlo approach was used (Ogle et al. 2003). PDFs for stock change factors were derived from a synthesis of 91 published studies, which addressed the impact of management on SOC storage. Uncertainties in land-use and management activity data were also derived from a statistical analysis.

Additional Mineral C Stock Change Calculations

A ± 50 percent uncertainty was assumed for additional adjustments to the mineral soil C stocks between 1990 and 2006, accounting for additional C stock changes associated gains or losses in C sequestration after 1997 due to changes in Conservation Reserve Program enrollment.

Organic Soil Carbon Stock Changes

Uncertainty in C emissions from organic soils was estimated in the same manner described for mineral soil using the Tier 2 method and Monte Carlo analysis. PDFs for emission factors were derived from a synthesis of 10 studies, and combined with uncertainties in the NRI land use and management data for organic soils in the Monte Carlo analysis. Please refer to the Organic Soil C Stock Changes section of the LULUCF chapter for more information on C emissions from organic soils.

CO₂ Emissions from Liming

The uncertainty information below pertains to the emission estimates presented in the Mineral Soil Carbon Stock Changes section of the LULUCF chapter. Please refer to that section for information about liming activity data and the emission factors used for this source. A Monte Carlo (Tier 2) uncertainty analysis was applied to estimate the uncertainty of CO₂ emissions from liming. Uncertainties in the estimates of emissions from liming result from both the emission factors and the activity data. The emission factors used for limestone and dolomite take into account the fate of C following application to soils, including: dissolution of liming constituents; leaching of bicarbonates into the soil and transport to the ocean; and emissions to the atmosphere (West and McBride 2005). The C accounting behind these emission factors entails assumptions about several uncertain factors. First, it is uncertain what fraction of agricultural lime is dissolved by nitric acid (HNO₃)—a process that releases CO₂—and what portion reacts with carbonic acid (H₂CO₃), resulting in the uptake of CO₂. The fractions can vary depending on soil pH and N fertilizer use. The second major source of uncertainty is the fraction of bicarbonate (HCO₃⁻) that leaches through the soil profile and *is transported into*

groundwater, which can eventually be transferred into rivers and into the ocean. This fraction can vary depending on the soil pH and whether calcium (Ca^{2+}) and magnesium (Mg^{2+}) liming constituents that might otherwise accompany HCO_3^- , are taken up by crops, remain in the upper soil profile, or are transported through or out of the soil profile. Finally, the emission factors do not account for the time that is needed for leaching and transport processes to occur.

There are several sources of uncertainty in the limestone and dolomite activity data. When reporting data to the USGS (or U.S. Bureau of Mines), some producers do not distinguish between limestone and dolomite. In these cases, data are reported as limestone, so this reporting could lead to an overestimation of limestone and an underestimation of dolomite. In addition, the total quantity of crushed stone listed each year in the *Minerals Yearbook* excludes American Samoa, Guam, Puerto Rico, and the U.S. Virgin Islands.

Land Converted to Cropland

Tier 2 Approach

The uncertainty upper and lower bounds of the emissions estimate for Land Converted to Cropland were 36 percent and -40 percent, respectively, at the 95 percent confidence interval. The uncertainty analysis for *Land Converted to Cropland* using the Tier 2 approach was based on the same method described for *Cropland Remaining Cropland*.

Mineral and Organic Soil Carbon Stock Changes

The quantitative estimates of uncertainty presented above are missing several components. This section qualitatively describes these contributors to overall uncertainty. The agricultural soil C inventory has undergone several improvements during the past few years, such as the development of the Tier 3 inventory method to estimate mineral soil C stock changes for the majority of U.S. cropland. However, some limitations remain in the analysis. First, the current agricultural soil C inventory includes some points designated as non-agricultural land-uses in the NRI if the points were categorized as cropland in either 1992 or 1997, but were urban, water, or miscellaneous non-cropland (e.g., roads and barren areas) in another year. The impact on soil organic C storage that results from converting non-agricultural uses to cropland is not well-understood, and therefore, those points were not included in the calculations for mineral soils (emissions from organic soils, however, were computed for those points in the years that they were designated as an agricultural use). Similarly, the effect of aquaculture (e.g., rice cultivation followed by crayfish production in flooded fields) on soil C stocks has not been estimated due to a lack of experimental data. Second, the current estimates may underestimate losses of C from organic soils because the *1997 National Resources Inventory* was not designed as a soil survey and organic soils frequently occur as relatively small inclusions within major soil types. Lastly, the IPCC Tier 2 methodology does not take into account changes in SOC stocks due to pre-1982 land use and land-use change.

Grassland Remaining Grassland

Tier 2 Approach

The uncertainty upper and lower bounds of the emissions estimate for Grassland Remaining Grassland were -32 percent and 25 percent, respectively, at the 95 percent confidence interval. The uncertainty analysis for *Grassland Remaining Grassland* using the Tier 2 approach was based on the same method described for *Cropland Remaining Cropland*.

Additional Uncertainties in Mineral and Organic Soil C Stock Changes

The quantitative estimates of uncertainty presented above are missing several components. This section qualitatively describes these contributors to overall uncertainty. Minimal data exist on where and how much sewage sludge has been applied to U.S. agricultural land and the accounting of this activity appears to be much more difficult than the related-activity of using manure to amend agricultural soils. Consequently, there is considerable uncertainty in the application of sewage sludge, which is assumed to be applied to *Grassland Remaining Grassland*. However, some sludge may be applied to other agricultural land, but there is not sufficient information to further subdivide application among the agricultural land use/land-use change categories. Another limitation is that the current estimates may underestimate losses of C from organic soils because the *1997 National Resources Inventory* was not designed as a soil survey and organic soils frequently occur as relatively small inclusions within major soil types. Lastly, the IPCC Tier 2 methodology does not take into account changes in SOC stocks due to pre-1982 land use and land-use change.

Land Converted to Grassland

Tier 2 Approach

The uncertainty upper and lower bounds of the emissions estimate for Land Converted to Grassland were -15 percent and 15 percent, respectively, at the 95 percent confidence interval. The uncertainty analysis for *Land Converted to Grassland* using the Tier 2 approach was based on the same method described for *Cropland Remaining Cropland*. See the Tier 2 section under minerals soils in the *Cropland Remaining Cropland* section for additional discussion.

Additional Uncertainties in Mineral and Organic Soil Carbon Stock Changes

The quantitative estimates of uncertainty presented above are missing several components. This section qualitatively describes these contributors to overall uncertainty. The agricultural soil C inventory has undergone several improvements during the past few years, such as the development of the Tier 3 inventory method to estimate mineral soil C stock changes for the majority of U.S. grassland. However, some limitations remain in the analysis. First, the current agricultural soil C inventory includes some points designated as non-agricultural land-uses in the NRI if the points were categorized as agricultural land use in either 1992 or 1997, but were urban, water, or miscellaneous non-cropland (e.g., roads and barren areas) in another year. The impact on SOC storage that results from converting non-agricultural uses to grassland is not well-understood, and therefore, those points were not included in the calculations for mineral soils (emissions from organic soils, however, were computed for those points in the years that they were designated as grassland). Second, the current estimates may underestimate losses of C from organic soils because the *1997 National Resources Inventory* was not designed as a soil survey and organic soils frequently occur as relatively small inclusions within major soil types. Lastly, this IPCC Tier 2 methodology does not take into account changes in SOC stocks due to pre-1982 land use and land-use change.

Settlements Remaining Settlements

N₂O Fluxes from Settlement Soil

The uncertainty information below pertains to the emission estimates presented in the N₂O Fluxes from Settlement Soils section of the LULUCF chapter. Please refer to that section for information about synthetic fertilizer N, the amounts of sewage sludge applied to non-agricultural lands, and other variables that affect this source. The uncertainty upper and lower bounds of the emissions estimate for N₂O fluxes from Settlement Soil were 163 percent and -49 percent, respectively, at the 95 percent confidence interval. The uncertainty range for the IPCC's default emission factor for mineral and organic N additions applied to soil ranges from 0.3 to 3 percent (IPCC 2006). Because the IPCC does not provide further information on whether this range represents the 95 percent confidence interval or the absolute minimum and maximum values, a triangular distribution was used to represent the uncertainty of the emission factor.

The uncertainty in the total amount of synthetic fertilizer N applied in the United States was estimated to be ± 3 percent (Terry 2005). The uncertainty in the amount of synthetic fertilizer N applied to settlement soils was conservatively estimated to be ± 50 percent, since no uncertainty was provided in Ruddy et al. (2006). The uncertainty in the amounts of sewage sludge applied to non-agricultural lands and used in surface disposal was based on the uncertainty of the following data points: (1) N content of sewage sludge; (2) total sludge applied in 2000; (3) wastewater existing flow in 1996, 2000, and 2004; and (4) the sewage sludge disposal practice distributions to non-agricultural land application and surface disposal.

- (1) The value assumed for N content of sewage sludge could range from around 0.1 percent to around 17 percent (McFarland 2001). Because information was not available on the distribution, a triangular distribution was assumed based on IPCC guidelines.
- (2) The uncertainty in the total amount of sludge applied in 2000 was based on a comparison with similar data available from other publications, which were all within 3 percent of the value used in the Inventory calculations (BioCycle 2000, NRC 2002, WEF 1997, Bastian 1997). The distribution was estimated to be normal based on expert opinion (Boucher 2006).
- (3) The uncertainty in the wastewater existing flow values for 1996 and 2000 was estimated at 0.0625 percent with a lognormal distribution (Plastino 2006).
- (4) The uncertainty in the sewage sludge disposal practice distributions was based on a comparison with similar data available from other publications, which were at most 12 percent different than the distribution for non-agricultural land application used in the Inventory calculations and at most 69 percent different than the distribution for surface disposal used in the Inventory calculations (Biocycle 2000, NRC 2002).

Other

The uncertainty analysis descriptions in this section correspond to Changes in Yard Trimming and Food Scrap Carbon Stocks in Landfills source category included in the Other Chapter of the Inventory.

Changes in Yard Trimming and Food Scrap Carbon Stocks in Landfills

The uncertainty ranges were assigned based on expert judgment and are assumed to be normally distributed around the inventory estimate, except for the values for decomposition rate, proportion of C stored, and the decay rates. The uncertainty ranges associated with these values are highlighted separately in this section.

The uncertainty range selected for input variables for the proportions of both grass and leaves in yard trimmings was 20 to 60 percent. The initial C content for grass, leaves, and food scraps (all expressed as percentages in the calculations for the inventory) were plus or minus 10 percent. For the moisture content of branches (where the inventory estimate is 10 percent), the uncertainty range was assumed to be 5 to 30 percent, within a lognormal distribution.

The uncertainty ranges associated with the disposal of grass, leaves, branches, and food scraps were bound at 50 percent to 150 percent of the inventory estimates. The proportion of C stored in grass, leaves, branches, and food scraps was assumed to vary plus or minus 20 percent from the best estimate, with a uniform distribution. The proportion of C stored in food scraps was truncated at a lower bound of 2 percent.

Finally, the uncertainty ranges assigned to the decay rates of grass, leaves, branches, and food scraps were developed based on De la Cruz, 2010. The minimum value corresponds to projected conditions if all landfills are in a dry environment; the maximum value corresponds to bioreactor conditions. A triangular distribution is applied to each of these variables.

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