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 CO_2 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 CO_2 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.

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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) and IPCC's *Good Practice Guidance for Land Use, Land-Use Change, and Forestry (IPCC 2003)*, 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 based on the Tier 1 approach (including and not including LULUCF categories) using emissions data in this report, and ranked according to their sector and global warming potential-weighted emissions in 2006. The table also indicates the criteria used in identifying these source and sink categories (i.e., level, trend, and/or qualitative assessments).

Table A-1: Key Source Categories for the United States (1990-2006) Based on Tier 1 Approach

IPCC Source Categories	Gas	Level Without LULUCF	Trend Without LULUCF	Level With LULUCF	Trend With LULUCF	Qual	2006 Emissions (Tg CO_2 Eq.)
Energy							
CO_2 Emissions from Stationary Combustion - Coal	CO_2	✓	✓	✓	✓		2,065.3
Mobile Combustion: Road & Other	CO_2	✓	✓	✓	✓		1,643.0
CO_2 Emissions from Stationary Combustion - Gas	CO_2	✓	✓	✓			1,121.9
CO_2 Emissions from Stationary Combustion - Oil	CO_2	✓	✓	✓	✓		594.3
Mobile Combustion: Aviation	CO_2	✓	✓	✓	✓		170.6
CO_2 Emissions from Non-Energy Use of Fuels	CO_2	✓		✓			138.0
Mobile Combustion: Marine	CO_2	✓	✓	✓	✓		42.4
CO_2 Emissions from Natural Gas Systems	CO_2	✓	✓	✓	✓		28.5
CO_2 Emissions from Municipal Solid Waste Combustion	CO_2		✓		✓		20.9
Fugitive Emissions from Natural Gas Systems	CH_4	✓	✓	✓	✓		102.4
Fugitive Emissions from Coal Mining	CH_4	✓	✓	✓	✓		58.5
Fugitive Emissions from Petroleum Systems	CH_4	✓	✓	✓	✓		28.4
Mobile Combustion: Road & Other	N_2O	✓	✓	✓	✓		31.1
International Bunker Fuels[b]	Several					✓	128.4

IPCC Source Categories	Gas	Level Without LULUCF	Trend Without LULUCF	Level With LULUCF	Trend With LULUCF	Qual	2006 Emissions (Tg CO_2 Eq.)
Industrial Processes							
CO_2 Emissions from Iron and Steel Production	CO_2	✓	✓	✓	✓		49.1
CO_2 Emissions from Cement Manufacture	CO_2	✓	✓	✓	✓		45.7
CO_2 Emissions from Ammonia Manufacture and Urea Application	CO_2		✓		✓		12.4
N_2O Emissions from Adipic Acid Production	N_2O		✓		✓		5.9
Emissions from Substitutes for Ozone Depleting Substances	Several	✓	✓	✓	✓		110.4
HFC-23 Emissions from HCFC-22 Production	HFCs	✓	✓	✓	✓		13.8
SF_6 Emissions from Electrical Transmission and Distribution	SF_6		✓		✓		13.2
PFC Emissions from Aluminum Production	PFCs		✓		✓		2.5
Agriculture							
CH_4 Emissions from Enteric Fermentation	CH_4	✓	✓	✓	✓		126.2
CH_4 Emissions from Manure Management	CH_4	✓		✓	✓		41.4
Direct N_2O Emissions from Agricultural Soil Management	N_2O	✓	✓	✓	✓		214.7
Indirect N_2O Emissions from Applied Nitrogen	N_2O	✓	✓	✓	✓		50.3
Waste							
CH_4 Emissions from Landfills	CH_4	✓	✓	✓	✓		125.7
Land Use, Land Use Change, and Forestry							
CO_2 Emissions from Forest Land Remaining Forest Land	CO_2			✓	✓		(745.1)
CO_2 Emissions from Settlements Remaining Settlements	CO_2			✓	✓		(95.5)
CO_2 Emissions from Cropland Remaining Cropland	CO_2			✓	✓		(33.8)
CO_2 Emissions from Grassland Remaining Grassland	CO_2				✓		16.2
CO_2 Emissions from Landfilled Yard Trimmings and Food Scraps	CO_2				✓		(10.5)
CO_2 Emissions from Land Converted to Cropland	CO_2				✓		9.4
CH_4 Emissions from Forest Land Remaining Forest Land	CH_4				✓		24.6
Subtotal Without LULUCF							**6,807.6**
Total Emissions Without LULUCF							**7,017.3**
Percent of Total Without LULUCF							**97.0%**
Subtotal With LULUCF							**5,972.8**
Total Emissions With LULUCF							**6,170.5**
Percent of Total With LULUCF							**96.8%**

[a]Qualitative criteria.
[b]Emissions from this source not included in totals.
Note: The Tier 1 approach for identifying key source categories does not directly include assessment of uncertainty in emissions estimates.

Table A-2 provides a complete listing of source categories by IPCC sector, along with comments 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 comments on the criteria used in identifying key categories, including LULUCF sources and sinks. The comments refer specifically to the year(s) over the course of the entire inventory time series (i.e., 1990 to 2006) in which each source category reached the threshold for being a key source based on a Tier 1 level assessment.

In addition to conducting Tier 1 level and trend assessments, a qualitative assessment of the source and sink 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.

Following the text of this Annex, Table A-3 through Table A- 7 contain the 1990 and 2006 level assessments for both with and without LULUCF sources and sinks, and contain further detail on where each source falls within the analysis.

Table A- 8 and Table A- 9 detail the "with LULUCF" and "without LULUCF" trend assessments for 1990 through 2006.

Table A-2: U.S Greenhouse Gas Inventory Source Categories without LULUCF

IPCC Source Categories	Direct GHG	2006 Emissions (Tg CO_2 Eq.)	Key Category	ID Criteria	Comments
Energy					
CO_2 Emissions from Stationary Combustion - Coal	CO_2	2,065.3	✓	L,T	Level 1990 and 2006
Mobile Combustion: Road & Other	CO_2	1,643.0	✓	L,T	Level 1990 and 2006
CO_2 Emissions from Stationary Combustion - Gas	CO_2	1,121.9	✓	L,T	Level 1990 and 2006
CO_2 Emissions from Stationary Combustion - Oil	CO_2	594.3	✓	L,T	Level 1990 and 2006
Mobile Combustion: Aviation	CO_2	170.6	✓	L,T	Level 1990 and 2006
CO_2 Emissions from Non-Energy Use of Fuels	CO_2	138.0	✓	L	Level 1990 and 2006
Mobile Combustion: Marine	CO_2	42.4	✓	L,T	Level 1990 and 2006
CO_2 Emissions from Natural Gas Systems	CO_2	28.5	✓	L,T	Level 1990
CO_2 Emissions from Municipal Solid Waste Combustion	CO_2	20.9	✓	T	
CO_2 Emissions from Stationary Combustion - Geothermal Energy	CO_2	0.4			
CO_2 Emissions from Petroleum Systems	CO_2	0.3			
Fugitive Emissions from Natural Gas Systems	CH_4	102.4	✓	L,T	Level 1990 and 2006
Fugitive Emissions from Coal Mining	CH_4	58.5	✓	L,T	Level 1990 and 2006
Fugitive Emissions from Petroleum Systems	CH_4	28.4	✓	L,T	Level 1990
Non-CO_2 Emissions from Stationary Combustion	CH_4	6.2			
Fugitive Emissions from Abandoned Underground Coal Mines	CH_4	5.4			
Mobile Combustion: Road & Other	CH_4	2.1			
Mobile Combustion: Aviation	CH_4	0.1			
Mobile Combustion: Marine	CH_4	0.1			
Mobile Combustion: Road & Other	N_2O	31.1	✓	L,T	Level 1990
Non-CO_2 Emissions from Stationary Combustion	N_2O	14.5			
Mobile Combustion: Aviation	N_2O	1.6			
N_2O Emissions from Municipal Solid Waste Combustion	N_2O	0.4			
Mobile Combustion: Marine	N_2O	0.4			
International Bunker Fuels[a]	Several	128.4	✓	Q	
Industrial Processes					
CO_2 Emissions from Iron and Steel Production	CO_2	49.1	✓	L,T	Level 1990 and 2006
CO_2 Emissions from Cement Manufacture	CO_2	45.7	✓	L,T	Level 2006
CO_2 Emissions from Lime Manufacture	CO_2	15.8			
CO_2 Emissions from Ammonia Manufacture and Urea Application	CO_2	12.4	✓	T	
CO_2 Emissions from Limestone and Dolomite Use	CO_2	8.6			
CO_2 Emissions from Soda Ash Manufacture and Consumption	CO_2	4.2			
CO_2 Emissions from Aluminum Production	CO_2	3.9			
CO_2 Emissions from Petrochemical Production	CO_2	2.6			
CO_2 Emissions from Titanium Dioxide Production	CO_2	1.9			
CO_2 Emissions from CO_2 Consumption	CO_2	1.6			
CO_2 Emissions from Ferroalloy Production	CO_2	1.5			
CO_2 Emissions from Phosphoric Acid Production	CO_2	1.2			
CO_2 Emissions from Zinc Production	CO_2	0.5			
CO_2 Emissions from Lead Production	CO_2	0.3			
CO_2 Emissions from Silicon Carbide Production and Consumption	CO_2	0.2			

IPCC Source Categories	Direct GHG	2006 Emissions (Tg CO_2 Eq.)	Key Category	ID Criteria	Comments
CH_4 Emissions from Petrochemical Production	CH_4	1.0			
CH_4 Emissions from Iron and Steel Production	CH_4	0.9			
CH_4 Emissions from Ferroalloy Production	CH_4	+			
CH_4 Emissions from Silicon Carbide Production and Consumption	CH_4	+			
N_2O Emissions from Nitric Acid Production	N_2O	15.6			
N_2O Emissions from Adipic Acid Production	N_2O	5.9	✓	T	
N_2O Emissions from N_2O Product Usage	N_2O	4.4			
Emissions from Substitutes for Ozone Depleting Substances	HiGWP	110.4	✓	L,T	Level 2006
HFC-23 Emissions from HCFC-22 Production	HiGWP	13.8	✓	L,T	Level 1990
SF_6 Emissions from Electrical Transmission and Distribution	HiGWP	13.2	✓	T	
PFC, HFC, and SF_6 Emissions from Semiconductor Manufacture	HiGWP	4.8			
SF_6 Emissions from Magnesium Production and Processing	HiGWP	3.2			
PFC Emissions from Aluminum Production	HiGWP	2.5	✓	T	
Agriculture					
CH_4 Emissions from Enteric Fermentation	CH_4	126.2	✓	L,T	Level 1990 and 2006
CH_4 Emissions from Manure Management	CH_4	41.4	✓	L	Level 2006
CH_4 Emissions from Rice Cultivation	CH_4	5.9			
CH_4 Emissions from Field Burning of Agricultural Residues	CH_4	0.8			
Direct N_2O Emissions from Agricultural Soil Management	N_2O	214.7	✓	L,T	Level 1990 and 2006
Indirect N_2O Emissions from Applied Nitrogen	N_2O	50.3	✓	L,T	Level 1990 and 2006
N_2O Emissions from Manure Management	N_2O	14.3			
N_2O Emissions from Field Burning of Agricultural Residues	N_2O	0.5			
Waste					
CH_4 Emissions from Landfills	CH_4	125.7	✓	L,T	Level 1990 and 2006
CH_4 Emissions from Wastewater Treatment	CH_4	23.9			
CH_4 Emissions from Composting	CH_4	1.6			
N_2O Emissions from Wastewater Treatment	N_2O	8.1			
N_2O Emissions from Composting	N_2O	1.8			

[a] Emissions from these sources not included in totals.
+ Does not exceed 0.05 Tg CO_2 Eq.
Note: LULUCF sources and sinks are not included in this analysis.
Note: The Tier 1 approach for identifying key categories does not directly include assessment of uncertainty in emission estimates.

Table A-3: U.S Greenhouse Gas Inventory Source Categories with LULUCF

IPCC Source Categories	Gas	2006 Emissions (Tg CO_2 Eq.)	Key Category	ID Criteria	Comments
Energy					
CO_2 Emissions from Stationary Combustion - Coal	CO_2	2,065.3	✓	L,T	Level 1990 and 2006
Mobile Combustion: Road & Other	CO_2	1,643.0	✓	L,T	Level 1990 and 2006
CO_2 Emissions from Stationary Combustion - Gas	CO_2	1,121.9	✓	L	Level 1990 and 2006
CO_2 Emissions from Stationary Combustion - Oil	CO_2	594.3	✓	L,T	Level 1990 and 2006
Mobile Combustion: Aviation	CO_2	170.6	✓	L,T	Level 1990 and 2006
CO_2 Emissions from Non-Energy Use of Fuels	CO_2	138.0	✓	L	Level 1990 and 2006
Mobile Combustion: Marine	CO_2	42.4	✓	L,T	Level 1990 and 2006
CO_2 Emissions from Natural Gas Systems	CO_2	28.5	✓	L,T	Level 1990
CO_2 Emissions from Municipal Solid Waste Combustion	CO_2	20.9	✓	T	
CO_2 Emissions from Stationary Combustion - Geothermal Energy	CO_2	0.4			
CO_2 Emissions from Petroleum Systems	CO_2	0.3			
Fugitive Emissions from Natural Gas Systems	CH_4	102.4	✓	L,T	Level 1990 and 2006
Fugitive Emissions from Coal Mining	CH_4	58.5	✓	L,T	Level 1990 and 2006
Fugitive Emissions from Petroleum Systems	CH_4	28.4	✓	L,T	Level 1990

IPCC Source Categories	Gas	2006 Emissions (Tg CO_2 Eq.)	Key Category	ID Criteria	Comments
Non-CO_2 Emissions from Stationary Combustion	CH_4	6.2			
Fugitive Emissions from Abandoned Underground Coal Mines	CH_4	5.4			
Mobile Combustion: Road & Other	CH_4	2.1			
Mobile Combustion: Aviation	CH_4	0.1			
Mobile Combustion: Marine	CH_4	0.1			
Mobile Combustion: Road & Other	N_2O	31.1	✓	L,T	Level 1990 and 2006
Non-CO_2 Emissions from Stationary Combustion	N_2O	14.5			
Mobile Combustion: Aviation	N_2O	1.6			
N_2O Emissions from Municipal Waste Combustion	N_2O	0.4			
Mobile Combustion: Marine	N_2O	0.4			
International Bunker Fuels[a]	Several	128.4	✓	Q	
Industrial Processes					
CO_2 Emissions from Iron and Steel Production	CO_2	49.1	✓	L,T	Level 1990 and 2006
CO_2 Emissions from Cement Manufacture	CO_2	45.7	✓	L,T	Level 1990 and 2006
CO_2 Emissions from Lime Manufacture	CO_2	15.8			
CO_2 Emissions from Ammonia Manufacture and Urea Application	CO_2	12.4	✓	T	
CO_2 Emissions from Limestone and Dolomite Use	CO_2	8.6			
CO_2 Emissions from Soda Ash Manufacture and Consumption	CO_2	4.2			
CO_2 Emissions from Aluminum Production	CO_2	3.9			
CO_2 Emissions from Petrochemical Production	CO_2	2.6			
CO_2 Emissions from Titanium Dioxide Production	CO_2	1.9			
CO_2 Emissions from CO_2 Consumption	CO_2	1.6			
CO_2 Emissions from Ferroalloy Production	CO_2	1.5			
CO_2 Emissions from Phosphoric Acid Production	CO_2	1.2			
CO_2 Emissions from Zinc Production	CO_2	0.5			
CO_2 Emissions from Lead Production	CO_2	0.3			
CO_2 Emissions from Silicon Carbide Production and Consumption	CO_2	0.2			
CH_4 Emissions from Petrochemical Production	CH_4	1.0			
CH_4 Emissions from Iron and Steel Production	CH_4	0.9			
CH_4 Emissions from Ferroalloy Production	CH_4	+			
CH_4 Emissions from Silicon Carbide Production and Consumption	CH_4	+			
N_2O Emissions from Nitric Acid Production	N_2O	15.6			
N_2O Emissions from Adipic Acid Production	N_2O	5.9	✓	T	
N_2O Emissions from N_2O Product Usage	N_2O	4.4			
Emissions from Substitutes for Ozone Depleting Substances	HiGWP	110.4	✓	L,T	Level 2006
HFC-23 Emissions from HCFC-22 Production	HiGWP	13.8	✓	L,T	Level 1990
SF_6 Emissions from Electrical Transmission and Distribution	HiGWP	13.2	✓	T	
PFC, HFC, and SF_6 Emissions from Semiconductor Manufacture	HiGWP	4.8			
SF_6 Emissions from Magnesium Production and Processing	HiGWP	3.2			
PFC Emissions from Aluminum Production	HiGWP	2.5	✓	T	
Agriculture					
CH_4 Emissions from Enteric Fermentation	CH_4	126.2	✓	L,T	Level 1990 and 2006
CH_4 Emissions from Manure Management	CH_4	41.4	✓	L,T	Level 1990 and 2006
CH_4 Emissions from Rice Cultivation	CH_4	5.9			
CH_4 Emissions from Field Burning of Agricultural Residues	CH_4	0.8			
Direct N_2O Emissions from Agricultural Soil Management	N_2O	214.7	✓	L,T	Level 1990 and 2006
Indirect N_2O Emissions from Applied Nitrogen	N_2O	50.3	✓	L,T	Level 1990 and 2006
N_2O Emissions from Manure Management	N_2O	14.3			
N_2O Emissions from Field Burning of Agricultural Residues	N_2O	0.5			

IPCC Source Categories	Gas	2006 Emissions (Tg CO_2 Eq.)	Key Category	ID Criteria	Comments
Waste					
CH_4 Emissions from Landfills	CH_4	125.7	✓	L,T	Level 1990 and 2006
CH_4 Emissions from Wastewater Treatment	CH_4	23.9			
CH_4 Emissions form Composting	CH_4	1.6			
N_2O Emissions from Wastewater Treatment	N_2O	8.1			
N_2O Emissions from Composting	N_2O	1.8			
Land Use, Land Use Change, and Forestry					
CO_2 Emissions from Forest Land Remaining Forest Land	CO_2	(745.1)	✓	L,T	Level 1990 and 2006
CO_2 Emissions from Settlements Remaining Settlements	CO_2	(95.5)	✓	L,T	Level 1990 and 2006
CO_2 Emissions from Cropland Remaining Cropland	CO_2	(33.8)	✓	L,T	Level 2006
CO_2 Emissions from Land Converted to Grassland	CO_2	(16.3)			
CO_2 Emissions from Grassland Remaining Grassland	CO_2	16.2	✓	T	
CO_2 Emissions from Landfilled Yard Trimmings and Food Scraps	CO_2	(10.5)	✓	T	
CO_2 Emissions from Land Converted to Cropland	CO_2	9.4	✓	T	
CH_4 Emissions from Forest Land Remaining Forest Land	CH_4	24.6	✓	T	
N_2O Emissions from Forest Land Remaining Forest Land	N_2O	2.8			
N_2O Emissions from Settlements Remaining Settlements	N_2O	1.5			

[a] Emissions from these sources not included in totals.
+ Does not exceed 0.05 Tg CO_2 Eq.
Note: The Tier 1 approach for identifying key categories does not directly include assessment of uncertainty in emission estimates.

Evaluation of Tier 1 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.

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.

Trend Assessment

The United States is currently taking a Tier 1 approach to identify trend assessment key categories until a full and consistent inventory-wide uncertainty analysis is completed. 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.

Tier 2 Key Category Assessment

IPCC *Good Practice Guidance* (IPCC 2000) recommends using a Tier 2 method for identifying key source categories if nationally derived source-level uncertainties are measured. The Tier 2 approach is a more detailed analysis that builds on the Tier 1 approach by multiplying the results of the Tier 1 analysis by the relative uncertainty of each source category. This method is likely to reduce the number of key source categories under consideration. As part of its multi-year uncertainty assessment effort, the United States has already developed quantitative uncertainty estimates for most source and sink categories. When quantitative estimates of uncertainty become available for all source categories, future inventories can incorporate this Tier 2 approach.

Table A- 4: 1990 Key Source Category Tier 1 Analysis—Level Assessment, without LULUCF

IPCC Source Categories	Direct GHG	1990 Estimate (Tg CO_2 Eq.)	1990 Estimate (Tg CO_2 Eq.)	Level Assessment	Cumulative Total of Level Assessment
CO_2 Emissions from Stationary Combustion - Coal	CO_2	1698.9	1698.9	0.28	0.28
Mobile Combustion: Road & Other	CO_2	1258.5	1258.5	0.21	0.48
CO_2 Emissions from Stationary Combustion - Gas	CO_2	975.4	975.4	0.16	0.64
CO_2 Emissions from Stationary Combustion - Oil	CO_2	564.3	564.3	0.09	0.73
Direct N_2O Emissions from Agricultural Soil Management	N_2O	218.3	218.3	0.04	0.77
Mobile Combustion: Aviation	CO_2	180.0	180.0	0.03	0.80
CH_4 Emissions from Landfills	CH_4	149.6	149.6	0.02	0.82
CH_4 Emissions from Enteric Fermentation	CH_4	126.9	126.9	0.02	0.84
Fugitive Emissions from Natural Gas Systems	CH_4	124.7	124.7	0.02	0.86
CO_2 Emissions from Non-Energy Use of Fuels	CO_2	117.2	117.2	0.02	0.88
CO_2 Emissions from Iron and Steel Production	CO_2	86.2	86.2	0.01	0.90
Fugitive Emissions from Coal Mining	CH_4	84.1	84.1	0.01	0.91
Indirect N_2O Emissions from Applied Nitrogen	N_2O	51.1	51.1	0.01	0.92
Mobile Combustion: Marine	CO_2	46.5	46.5	0.01	0.93
Mobile Combustion: Road & Other	N_2O	41.4	41.4	0.01	0.93
HFC-23 Emissions from HCFC-22 Production	HFCs	36.4	36.4	0.01	0.94
Fugitive Emissions from Petroleum Systems	CH_4	33.9	33.9	0.01	0.94
CO_2 Emissions from Natural Gas Systems	CO_2	33.7	33.7	0.01	0.95
CO_2 Emissions from Cement Manufacture	CO_2	33.3	33.3	0.01	0.96
CH_4 Emissions from Manure Management	CH_4	31.0	31.0	0.01	0.96
SF_6 Emissions from Electrical Transmission and Distribution	SF_6	26.7	26.7	<0.01	0.96
CH_4 Emissions from Wastewater Treatment	CH_4	23.0	23.0	<0.01	0.97
PFC Emissions from Aluminum Production	PFCs	18.5	18.5	<0.01	0.97
N_2O Emissions from Nitric Acid Production	N_2O	17.0	17.0	<0.01	0.97
CO_2 Emissions from Ammonia Manufacture and Urea Application	CO_2	16.9	16.9	<0.01	0.98
N_2O Emissions from Adipic Acid Production	N_2O	15.3	15.3	<0.01	0.98
Non-CO_2 Emissions from Stationary Combustion	N_2O	12.8	12.8	<0.01	0.98
N_2O Emissions from Manure Management	N_2O	12.1	12.1	<0.01	0.98
CO_2 Emissions from Lime Manufacture	CO_2	12.0	12.0	<0.01	0.99
CO_2 Emissions from Municipal Solid Waste Combustion	CO_2	10.9	10.9	<0.01	0.99
Non-CO_2 Emissions from Stationary Combustion	CH_4	7.4	7.4	<0.01	0.99
CH_4 Emissions from Rice Cultivation	CH_4	7.1	7.1	<0.01	0.99
CO_2 Emissions from Aluminum Production	CO_2	6.8	6.8	<0.01	0.99
N_2O Emissions from Wastewater Treatment	N_2O	6.3	6.3	<0.01	0.99
Fugitive Emissions from Abandoned Underground Coal Mines	CH_4	6.0	6.0	<0.01	0.99
CO_2 Emissions from Limestone and Dolomite Use	CO_2	5.5	5.5	<0.01	0.99
SF_6 Emissions from Magnesium Production and Processing	SF_6	5.4	5.4	<0.01	0.99
Mobile Combustion: Road & Other	CH_4	4.5	4.5	<0.01	0.99

IPCC Source Categories	Direct GHG	1990 Estimate (Tg CO_2 Eq.)	1990 Estimate (Tg CO_2 Eq.)	Level Assessment	Cumulative Total of Level Assessment
N_2O Emissions from N_2O Product Usage	N_2O	4.4	4.4	<0.01	0.99
CO_2 Emissions from Soda Ash Manufacture and Consumption	CO_2	4.1	4.1	<0.01	0.99
PFC, HFC, and SF_6 Emissions from Semiconductor Manufacture	Several	2.9	2.9	<0.01	0.99
CO_2 Emissions from Petrochemical Production	CO_2	2.2	2.2	<0.01	0.99
CO_2 Emissions from Ferroalloy Production	CO_2	2.2	2.2	<0.01	0.99
Mobile Combustion: Aviation	N_2O	1.7	1.7	<0.01	1.00
CO_2 Emissions from Phosphoric Acid Production	CO_2	1.5	1.5	<0.01	1.00
CO_2 Emissions from Carbon Dioxide Consumption	CO_2	1.4	1.4	<0.01	1.00
CH_4 Emissions from Iron and Steel Production	CH_4	1.3	1.3	<0.01	1.00
CO_2 Emissions from Titanium Dioxide Production	CO_2	1.2	1.2	<0.01	1.00
CO_2 Emissions from Zinc Production	CO_2	0.9	0.9	<0.01	1.00
CH_4 Emissions from Petrochemical Production	CH_4	0.9	0.9	<0.01	1.00
CH_4 Emissions from Field Burning of Agricultural Residues	CH_4	0.7	0.7	<0.01	1.00
N_2O Emissions from Municipal Solid Waste Combustion	N_2O	0.5	0.5	<0.01	1.00
CO_2 Emissions from Stationary Combustion - Geothermal Energy	CO_2	0.4	0.4	<0.01	1.00
CO_2 Emissions from Petroleum Systems	CO_2	0.4	0.4	<0.01	1.00
Mobile Combustion: Marine	N_2O	0.4	0.4	<0.01	1.00
CO_2 Emissions from Silicon Carbide Production and Consumption	CO_2	0.4	0.4	<0.01	1.00
N_2O Emissions from Field Burning of Agricultural Residues	N_2O	0.4	0.4	<0.01	1.00
N_2O Emission from Composting	N_2O	0.4	0.4	<0.01	1.00
Emissions from Substitutes for Ozone Depleting Substances	Several	0.3	0.3	<0.01	1.00
CH_4 Emissions from Composting	CH_4	0.3	0.3	<0.01	1.00
CO_2 Emissions from Lead Production	CO_2	0.3	0.3	<0.01	1.00
Mobile Combustion: Aviation	CH_4	0.2	0.2	<0.01	1.00
Mobile Combustion: Marine	CH_4	0.1	0.1	<0.01	1.00
CH_4 Emissions from Silicon Carbide Production and Consumption	CH_4	<0.1	<0.1	<0.01	1.00
CH_4 Emissions from Ferroalloy Production	CH_4	<0.1	<0.1	<0.01	1.00

Note: LULUCF sources and sinks are not included in this analysis.

Table A- 5: 1990 Key Source Category Tier 1 Analysis—Level Assessment, with LULUCF

IPCC Source Categories	Direct GHG	1990 Estimate (Tg CO_2 Eq.)	1990 Estimate (Tg CO_2 Eq.)	Level Assessment	Cumulative Total of Level Assessment
CO_2 Emissions from Stationary Combustion - Coal	CO_2	1698.9	1698.9	0.25	0.25
Mobile Combustion: Road & Other	CO_2	1258.5	1258.5	0.18	0.43
CO_2 Emissions from Stationary Combustion - Gas	CO_2	975.4	975.4	0.14	0.57
CO_2 Emissions from Forest Land Remaining Forest Land	CO_2	621.7	621.7	0.09	0.66
CO_2 Emissions from Stationary Combustion - Oil	CO_2	564.3	564.3	0.08	0.74
Direct N_2O Emissions from Agricultural Soil Management	N_2O	218.3	218.3	0.03	0.77
Mobile Combustion: Aviation	CO_2	180.0	180.0	0.03	0.80
CH_4 Emissions from Landfills	CH_4	149.6	149.6	0.02	0.82
CH_4 Emissions from Enteric Fermentation	CH_4	126.9	126.9	0.02	0.84
Fugitive Emissions from Natural Gas Systems	CH_4	124.7	124.7	0.02	0.86
CO_2 Emissions from Non-Energy Use of Fuels	CO_2	117.2	117.2	0.02	0.87
CO_2 Emissions from Iron and Steel Production	CO_2	86.2	86.2	0.01	0.89
Fugitive Emissions from Coal Mining	CH_4	84.1	84.1	0.01	0.90
CO_2 Emissions from Settlements Remaining Settlements	CO_2	60.6	60.6	0.01	0.91
Indirect N_2O Emissions from Applied Nitrogen	N_2O	51.1	51.1	0.01	0.92
Mobile Combustion: Marine	CO_2	46.5	46.5	0.01	0.92
Mobile Combustion: Road & Other	N_2O	41.4	41.4	0.01	0.93
HFC-23 Emissions from HCFC-22 Production	HFCs	36.4	36.4	0.01	0.93
Fugitive Emissions from Petroleum Systems	CH_4	33.9	33.9	<0.01	0.94
CO_2 Emissions from Natural Gas Systems	CO_2	33.7	33.7	<0.01	0.94
CO_2 Emissions from Cement Manufacture	CO_2	33.3	33.3	<0.01	0.95

IPCC Source Categories	Direct GHG	1990 Estimate (Tg CO_2 Eq.)	1990 Estimate (Tg CO_2 Eq.)	Level Assessment	Cumulative Total of Level Assessment
CH_4 Emissions from Manure Management	CH_4	31.0	31.0	<0.01	0.95
SF_6 Emissions from Electrical Transmission and Distribution	SF_6	26.7	26.7	<0.01	0.96
CO_2 Emissions from Landfilled Yard Trimmings and Food Scraps	CO_2	23.9	23.9	<0.01	0.96
CH_4 Emissions from Wastewater Treatment	CH_4	23.0	23.0	<0.01	0.96
CO_2 Emissions from Cropland Remaining Cropland	CO_2	23.0	23.0	<0.01	0.97
PFC Emissions from Aluminum Production	PFCs	18.5	18.5	<0.01	0.97
N_2O Emissions from Nitric Acid Production	N_2O	17.0	17.0	<0.01	0.97
CO_2 Emissions from Ammonia Manufacture and Urea Application	CO_2	16.9	16.9	<0.01	0.97
N_2O Emissions from Adipic Acid Production	N_2O	15.3	15.3	<0.01	0.98
CO_2 Emissions from Land Converted to Cropland	CO_2	14.7	14.7	<0.01	0.98
CO_2 Emissions from Land Converted to Grassland	CO_2	14.3	14.3	<0.01	0.98
Non-CO_2 Emissions from Stationary Combustion	N_2O	12.8	12.8	<0.01	0.98
N_2O Emissions from Manure Management	N_2O	12.1	12.1	<0.01	0.98
CO_2 Emissions from Lime Manufacture	CO_2	12.0	12.0	<0.01	0.99
CO_2 Emissions from Municipal Solid Waste Combustion	CO_2	10.9	10.9	<0.01	0.99
Non-CO_2 Emissions from Stationary Combustion	CH_4	7.4	7.4	<0.01	0.99
CH_4 Emissions from Rice Cultivation	CH_4	7.1	7.1	<0.01	0.99
CO_2 Emissions from Aluminum Production	CO_2	6.8	6.8	<0.01	0.99
N_2O Emissions from Wastewater Treatment	N_2O	6.3	6.3	<0.01	0.99
Fugitive Emissions from Abandoned Underground Coal Mines	CH_4	6.0	6.0	<0.01	0.99
CO_2 Emissions from Limestone and Dolomite Use	CO_2	5.5	5.5	<0.01	0.99
SF_6 Emissions from Magnesium Production and Processing	SF_6	5.4	5.4	<0.01	0.99
CH_4 Emissions from Forest Land Remaining Forest Land	CH_4	4.5	4.5	<0.01	0.99
Mobile Combustion: Road & Other	CH_4	4.5	4.5	<0.01	1.00
N_2O Emissions from N_2O Product Usage	N_2O	4.4	4.4	<0.01	1.00
CO_2 Emissions from Soda Ash Manufacture and Consumption	CO_2	4.1	4.1	<0.01	1.00
PFC, HFC, and SF_6 Emissions from Semiconductor Manufacture	Several	2.9	2.9	<0.01	1.00
CO_2 Emissions from Petrochemical Production	CO_2	2.2	2.2	<0.01	1.00
CO_2 Emissions from Ferroalloy Production	CO_2	2.2	2.2	<0.01	1.00
CO_2 Emissions from Grassland Remaining Grassland	CO_2	1.9	1.9	<0.01	1.00
Mobile Combustion: Aviation	N_2O	1.7	1.7	<0.01	1.00
CO_2 Emissions from Phosphoric Acid Production	CO_2	1.5	1.5	<0.01	1.00
CO_2 Emissions from Carbon Dioxide Consumption	CO_2	1.4	1.4	<0.01	1.00
CH_4 Emissions from Iron and Steel Production	CH_4	1.3	1.3	<0.01	1.00
CO_2 Emissions from Titanium Dioxide Production	CO_2	1.2	1.2	<0.01	1.00
N_2O Emissions from Settlements Remaining Settlements	N_2O	1.0	1.0	<0.01	1.00
CO_2 Emissions from Zinc Production	CO_2	0.9	0.9	<0.01	1.00
CH_4 Emissions from Petrochemical Production	CH_4	0.9	0.9	<0.01	1.00
CH_4 Emissions from Field Burning of Agricultural Residues	CH_4	0.7	0.7	<0.01	1.00
N_2O Emissions from Forest Land Remaining Forest Land	N_2O	0.5	0.5	<0.01	1.00
N_2O Emissions from Municipal Solid Waste Combustion	N_2O	0.5	0.5	<0.01	1.00
CO_2 Emissions from Stationary Combustion - Geothermal Energy	CO_2	0.4	0.4	<0.01	1.00
CO_2 Emissions from Petroleum Systems	CO_2	0.4	0.4	<0.01	1.00
Mobile Combustion: Marine	N_2O	0.4	0.4	<0.01	1.00
CO_2 Emissions from Silicon Carbide Production and Consumption	CO_2	0.4	0.4	<0.01	1.00
N_2O Emissions from Field Burning of Agricultural Residues	N_2O	0.4	0.4	<0.01	1.00
N_2O Emission from Composting	N_2O	0.4	0.4	<0.01	1.00
Emissions from Substitutes for Ozone Depleting Substances	Several	0.3	0.3	<0.01	1.00
CH_4 Emissions from Composting	CH_4	0.3	0.3	<0.01	1.00
CO_2 Emissions from Lead Production	CO_2	0.3	0.3	<0.01	1.00
Mobile Combustion: Aviation	CH_4	0.2	0.2	<0.01	1.00
Mobile Combustion: Marine	CH_4	0.1	0.1	<0.01	1.00
CH_4 Emissions from Silicon Carbide Production and Consumption	CH_4	<0.1	<0.1	<0.01	1.00
CH_4 Emissions from Ferroalloy Production	CH_4	<0.1	<0.1	<0.01	1.00

Table A- 6: 2006 Key Source Category Tier 1 Analysis—Level Assessment, without LULUCF

IPCC Source Categories	Direct GHG	1990 Estimate (Tg CO_2 Eq.)	2006 Estimate (Tg CO_2 Eq.)	Level Assessment	Cumulative Total of Level Assessment
CO_2 Emissions from Stationary Combustion - Coal	CO_2	1698.9	2065.3	0.29	0.29
Mobile Combustion: Road & Other	CO_2	1258.5	1643.0	0.23	0.53
CO_2 Emissions from Stationary Combustion - Gas	CO_2	975.4	1121.9	0.16	0.69
CO_2 Emissions from Stationary Combustion - Oil	CO_2	564.3	594.3	0.08	0.77
Direct N_2O Emissions from Agricultural Soil Management	N_2O	218.3	214.7	0.03	0.80
Mobile Combustion: Aviation	CO_2	180.0	170.6	0.02	0.83
CO_2 Emissions from Non-Energy Use of Fuels	CO_2	117.2	138.0	0.02	0.85
CH_4 Emissions from Enteric Fermentation	CH_4	126.9	126.2	0.02	0.87
CH_4 Emissions from Landfills	CH_4	149.6	125.7	0.02	0.88
Emissions from Substitutes for Ozone Depleting Substances	Several	0.3	110.4	0.02	0.90
Fugitive Emissions from Natural Gas Systems	CH_4	124.7	102.4	0.01	0.91
Fugitive Emissions from Coal Mining	CH_4	84.1	58.5	0.01	0.92
Indirect N_2O Emissions from Applied Nitrogen	N_2O	51.1	50.3	0.01	0.93
CO_2 Emissions from Iron and Steel Production	CO_2	86.2	49.1	0.01	0.94
CO_2 Emissions from Cement Manufacture	CO_2	33.3	45.7	0.01	0.94
Mobile Combustion: Marine	CO_2	46.5	42.4	0.01	0.95
CH_4 Emissions from Manure Management	CH_4	31.0	41.4	0.01	0.95
Mobile Combustion: Road & Other	N_2O	41.4	31.1	<0.01	0.96
CO_2 Emissions from Natural Gas Systems	CO_2	33.7	28.5	<0.01	0.96
Fugitive Emissions from Petroleum Systems	CH_4	33.9	28.4	<0.01	0.97
CH_4 Emissions from Wastewater Treatment	CH_4	23.0	23.9	<0.01	0.97
CO_2 Emissions from Municipal Solid Waste Combustion	CO_2	10.9	20.9	<0.01	0.97
CO_2 Emissions from Lime Manufacture	CO_2	12.0	15.8	<0.01	0.98
N_2O Emissions from Nitric Acid Production	N_2O	17.0	15.6	<0.01	0.98
Non-CO_2 Emissions from Stationary Combustion	N_2O	12.8	14.5	<0.01	0.98
N_2O Emissions from Manure Management	N_2O	12.1	14.3	<0.01	0.98
HFC-23 Emissions from HCFC-22 Production	HFCs	36.4	13.8	<0.01	0.98
SF_6 Emissions from Electrical Transmission and Distribution	SF_6	26.7	13.2	<0.01	0.99
CO_2 Emissions from Ammonia Manufacture and Urea Application	CO_2	16.9	12.4	<0.01	0.99
CO_2 Emissions from Limestone and Dolomite Use	CO_2	5.5	8.6	<0.01	0.99
N_2O Emissions from Wastewater Treatment	N_2O	6.3	8.1	<0.01	0.99
Non-CO_2 Emissions from Stationary Combustion	CH_4	7.4	6.2	<0.01	0.99
N_2O Emissions from Adipic Acid Production	N_2O	15.3	5.9	<0.01	0.99
CH_4 Emissions from Rice Cultivation	CH_4	7.1	5.9	<0.01	0.99
Fugitive Emissions from Abandoned Underground Coal Mines	CH_4	6.0	5.4	<0.01	0.99
PFC, HFC, and SF_6 Emissions from Semiconductor Manufacture	Several	2.9	4.8	<0.01	0.99
N_2O Emissions from N_2O Product Usage	N_2O	4.4	4.4	<0.01	0.99
CO_2 Emissions from Soda Ash Manufacture and Consumption	CO_2	4.1	4.2	<0.01	1.00
CO_2 Emissions from Aluminum Production	CO_2	6.8	3.9	<0.01	1.00
SF_6 Emissions from Magnesium Production and Processing	SF_6	5.4	3.2	<0.01	1.00
CO_2 Emissions from Petrochemical Production	CO_2	2.2	2.6	<0.01	1.00
PFC Emissions from Aluminum Production	PFCs	18.5	2.5	<0.01	1.00
Mobile Combustion: Road & Other	CH_4	4.5	2.1	<0.01	1.00
CO_2 Emissions from Titanium Dioxide Production	CO_2	1.2	1.9	<0.01	1.00
N_2O Emission from Composting	N_2O	0.4	1.8	<0.01	1.00
Mobile Combustion: Aviation	N_2O	1.7	1.6	<0.01	1.00
CH_4 Emissions from Composting	CH_4	0.3	1.6	<0.01	1.00
CO_2 Emissions from Carbon Dioxide Consumption	CO_2	1.4	1.6	<0.01	1.00
CO_2 Emissions from Ferroalloy Production	CO_2	2.2	1.5	<0.01	1.00
CO_2 Emissions from Phosphoric Acid Production	CO_2	1.5	1.2	<0.01	1.00
CH_4 Emissions from Petrochemical Production	CH_4	0.9	1.0	<0.01	1.00
CH_4 Emissions from Iron and Steel Production	CH_4	1.3	0.9	<0.01	1.00
CH_4 Emissions from Field Burning of Agricultural Residues	CH_4	0.7	0.8	<0.01	1.00
CO_2 Emissions from Zinc Production	CO_2	0.9	0.5	<0.01	1.00
N_2O Emissions from Field Burning of Agricultural Residues	N_2O	0.4	0.5	<0.01	1.00
N_2O Emissions from Municipal Solid Waste Combustion	N_2O	0.5	0.4	<0.01	1.00
CO_2 Emissions from Stationary Combustion - Geothermal Energy	CO_2	0.4	0.4	<0.01	1.00
Mobile Combustion: Marine	N_2O	0.4	0.4	<0.01	1.00

IPCC Source Categories	Direct GHG	1990 Estimate (Tg CO_2 Eq.)	2006 Estimate (Tg CO_2 Eq.)	Level Assessment	Cumulative Total of Level Assessment
CO_2 Emissions from Petroleum Systems	CO_2	0.4	0.3	<0.01	1.00
CO_2 Emissions from Lead Production	CO_2	0.3	0.3	<0.01	1.00
CO_2 Emissions from Silicon Carbide Production and Consumption	CO_2	0.4	0.2	<0.01	1.00
Mobile Combustion: Aviation	CH_4	0.2	0.1	<0.01	1.00
Mobile Combustion: Marine	CH_4	0.1	0.1	<0.01	1.00
CH_4 Emissions from Ferroalloy Production	CH_4	<0.1	<0.1	<0.01	1.00
CH_4 Emissions from Silicon Carbide Production and Consumption	CH_4	<0.1	<0.1	<0.01	1.00

Note: LULUCF sources and sinks are not included in this analysis.

Table A- 7: 2006 Key Source Category Tier 1 Analysis—Level Assessment with LULUCF

IPCC Source Categories	Direct GHG	1990 Estimate (Tg CO_2 Eq.)	2006 Estimate (Tg CO_2 Eq.)	Level Assessment	Cumulative Total of Level Assessment
CO_2 Emissions from Stationary Combustion - Coal	CO_2	1698.9	2065.3	0.26	0.26
Mobile Combustion: Road & Other	CO_2	1258.5	1643.0	0.21	0.47
CO_2 Emissions from Stationary Combustion - Gas	CO_2	975.4	1121.9	0.14	0.61
CO_2 Emissions from Forest Land Remaining Forest Land	CO_2	621.7	745.1	0.09	0.70
CO_2 Emissions from Stationary Combustion - Oil	CO_2	564.3	594.3	0.07	0.77
Direct N_2O Emissions from Agricultural Soil Management	N_2O	218.3	214.7	0.03	0.80
Mobile Combustion: Aviation	CO_2	180.0	170.6	0.02	0.82
CO_2 Emissions from Non-Energy Use of Fuels	CO_2	117.2	138.0	0.02	0.84
CH_4 Emissions from Enteric Fermentation	CH_4	126.9	126.2	0.02	0.86
CH_4 Emissions from Landfills	CH_4	149.6	125.7	0.02	0.87
Emissions from Substitutes for Ozone Depleting Substances	Several	0.3	110.4	0.01	0.88
Fugitive Emissions from Natural Gas Systems	CH_4	124.7	102.4	0.01	0.90
CO_2 Emissions from Settlements Remaining Settlements	CO_2	60.6	95.5	0.01	0.91
Fugitive Emissions from Coal Mining	CH_4	84.1	58.5	0.01	0.92
Indirect N_2O Emissions from Applied Nitrogen	N_2O	51.1	50.3	0.01	0.92
CO_2 Emissions from Iron and Steel Production	CO_2	86.2	49.1	0.01	0.93
CO_2 Emissions from Cement Manufacture	CO_2	33.3	45.7	0.01	0.94
Mobile Combustion: Marine	CO_2	46.5	42.4	0.01	0.94
CH_4 Emissions from Manure Management	CH_4	31.0	41.4	0.01	0.95
CO_2 Emissions from Cropland Remaining Cropland	CO_2	23.0	33.8	<0.01	0.95
Mobile Combustion: Road & Other	N_2O	41.4	31.1	<0.01	0.95
CO_2 Emissions from Natural Gas Systems	CO_2	33.7	28.5	<0.01	0.96
Fugitive Emissions from Petroleum Systems	CH_4	33.9	28.4	<0.01	0.96
CH_4 Emissions from Forest Land Remaining Forest Land	CH_4	4.5	24.6	<0.01	0.96
CH_4 Emissions from Wastewater Treatment	CH_4	23.0	23.9	<0.01	0.97
CO_2 Emissions from Municipal Solid Waste Combustion	CO_2	10.9	20.9	<0.01	0.97
CO_2 Emissions from Land Converted to Grassland	CO_2	14.3	16.3	<0.01	0.97
CO_2 Emissions from Grassland Remaining Grassland	CO_2	1.9	16.2	<0.01	0.97
CO_2 Emissions from Lime Manufacture	CO_2	12.0	15.8	<0.01	0.98
N_2O Emissions from Nitric Acid Production	N_2O	17.0	15.6	<0.01	0.98
Non-CO_2 Emissions from Stationary Combustion	N_2O	12.8	14.5	<0.01	0.98
N_2O Emissions from Manure Management	N_2O	12.1	14.3	<0.01	0.98
HFC-23 Emissions from HCFC-22 Production	HFCs	36.4	13.8	<0.01	0.98
SF_6 Emissions from Electrical Transmission and Distribution	SF_6	26.7	13.2	<0.01	0.98
CO_2 Emissions from Ammonia Manufacture and Urea Application	CO_2	16.9	12.4	<0.01	0.99
CO_2 Emissions from Landfilled Yard Trimmings and Food Scraps	CO_2	23.9	10.5	<0.01	0.99
CO_2 Emissions from Land Converted to Cropland	CO_2	14.7	9.4	<0.01	0.99
CO_2 Emissions from Limestone and Dolomite Use	CO_2	5.5	8.6	<0.01	0.99
N2O Emissions from Wastewater Treatment	N_2O	6.3	8.1	<0.01	0.99
Non-CO_2 Emissions from Stationary Combustion	CH_4	7.4	6.2	<0.01	0.99
N_2O Emissions from Adipic Acid Production	N_2O	15.3	5.9	<0.01	0.99
CH_4 Emissions from Rice Cultivation	CH_4	7.1	5.9	<0.01	0.99

IPCC Source Categories	Direct GHG	1990 Estimate (Tg CO_2 Eq.)	2006 Estimate (Tg CO_2 Eq.)	Level Assessment	Cumulative Total of Level Assessment
Fugitive Emissions from Abandoned Underground Coal Mines	CH_4	6.0	5.4	<0.01	0.99
PFC, HFC, and SF_6 Emissions from Semiconductor Manufacture	Several	2.9	4.8	<0.01	0.99
N_2O Emissions from N_2O Product Usage	N_2O	4.4	4.4	<0.01	1.00
CO_2 Emissions from Soda Ash Manufacture and Consumption	CO_2	4.1	4.2	<0.01	1.00
CO_2 Emissions from Aluminum Production	CO_2	6.8	3.9	<0.01	1.00
SF_6 Emissions from Magnesium Production and Processing	SF_6	5.4	3.2	<0.01	1.00
N_2O Emissions from Forest Land Remaining Forest Land	N_2O	0.5	2.8	<0.01	1.00
CO_2 Emissions from Petrochemical Production	CO_2	2.2	2.6	<0.01	1.00
PFC Emissions from Aluminum Production	PFCs	18.5	2.5	<0.01	1.00
Mobile Combustion: Road & Other	CH_4	4.5	2.1	<0.01	1.00
CO_2 Emissions from Titanium Dioxide Production	CO_2	1.2	1.9	<0.01	1.00
N_2O Emission from Composting	N_2O	0.4	1.8	<0.01	1.00
Mobile Combustion: Aviation	N_2O	1.7	1.6	<0.01	1.00
CH_4 Emissions from Composting	CH_4	0.3	1.6	<0.01	1.00
CO_2 Emissions from Carbon Dioxide Consumption	CO_2	1.4	1.6	<0.01	1.00
CO_2 Emissions from Ferroalloy Production	CO_2	2.2	1.5	<0.01	1.00
N_2O Emissions from Settlements Remaining Settlements	N_2O	1.0	1.5	<0.01	1.00
CO_2 Emissions from Phosphoric Acid Production	CO_2	1.5	1.2	<0.01	1.00
CH_4 Emissions from Petrochemical Production	CH_4	0.9	1.0	<0.01	1.00
CH_4 Emissions from Iron and Steel Production	CH_4	1.3	0.9	<0.01	1.00
CH_4 Emissions from Field Burning of Agricultural Residues	CH_4	0.7	0.8	<0.01	1.00
CO_2 Emissions from Zinc Production	CO_2	0.9	0.5	<0.01	1.00
N_2O Emissions from Field Burning of Agricultural Residues	N_2O	0.4	0.5	<0.01	1.00
N_2O Emissions from Municipal Solid Waste Combustion	N_2O	0.5	0.4	<0.01	1.00
CO_2 Emissions from Stationary Combustion - Geothermal Energy	CO_2	0.4	0.4	<0.01	1.00
Mobile Combustion: Marine	N_2O	0.4	0.4	<0.01	1.00
CO_2 Emissions from Petroleum Systems	CO_2	0.4	0.3	<0.01	1.00
CO_2 Emissions from Lead Production	CO_2	0.3	0.3	<0.01	1.00
CO_2 Emissions from Silicon Carbide Production and Consumption	CO_2	0.4	0.2	<0.01	1.00
Mobile Combustion: Aviation	CH_4	0.2	0.1	<0.01	1.00
Mobile Combustion: Marine	CH_4	0.1	0.1	<0.01	1.00
CH_4 Emissions from Ferroalloy Production	CH_4	<0.1	<0.1	<0.01	1.00
CH_4 Emissions from Silicon Carbide Production and Consumption	CH_4	<0.1	<0.1	<0.01	1.00

Table A- 8: 1990-2006 Key Source Category Tier 1 Analysis—Trend Assessment, without LULUCF

IPCC Source Categories	Direct GHG	1990 Estimate (Tg CO_2 Eq.)	2006 Estimate (Tg CO_2 Eq.)	Trend Assessment	Percent Contribution to Trend (%)	Cumulative Contribution to Trend (%)
Mobile Combustion: Road & Other	CO_2	1258.5	1643.0	0.03	21.3	21
CO_2 Emissions from Stationary Combustion - Coal	CO_2	1698.9	2065.3	0.02	12.8	34
Emissions from Substitutes for Ozone Depleting Substances	Several	0.3	110.4	0.01	11.5	46
CO_2 Emissions from Stationary Combustion - Oil	CO_2	564.3	594.3	0.01	5.3	51
CO_2 Emissions from Iron and Steel Production	CO_2	86.2	49.1	0.01	5.2	56
CH_4 Emissions from Landfills	CH_4	149.6	125.7	0.01	4.7	61
Fugitive Emissions from Natural Gas Systems	CH_4	124.7	102.4	0.01	4.2	65
Fugitive Emissions from Coal Mining	CH_4	84.1	58.5	<0.01	3.9	69
Mobile Combustion: Aviation	CO_2	180.0	170.6	<0.01	3.7	73
Direct N_2O Emissions from Agricultural Soil Management	N_2O	218.3	214.7	<0.01	3.7	76
HFC-23 Emissions from HCFC-22 Production	HFCs	36.4	13.8	<0.01	2.9	79
CH_4 Emissions from Enteric Fermentation	CH_4	126.9	126.2	<0.01	2.0	81
PFC Emissions from Aluminum Production	PFCs	18.5	2.5	<0.01	2.0	83
SF_6 Emissions from Electrical Transmission and Distribution	SF_6	26.7	13.2	<0.01	1.8	85
Mobile Combustion: Road & Other	N_2O	41.4	31.1	<0.01	1.7	87

IPCC Source Categories	Direct GHG	1990 Estimate (Tg CO_2 Eq.)	2006 Estimate (Tg CO_2 Eq.)	Trend Assessment	Percent Contribution to Trend (%)	Cumulative Contribution to Trend (%)
N_2O Emissions from Adipic Acid Production	N_2O	15.3	5.9	<0.01	1.2	88
Mobile Combustion: Marine	CO_2	46.5	42.4	<0.01	1.1	89
Fugitive Emissions from Petroleum Systems	CH_4	33.9	28.4	<0.01	1.1	90
CO_2 Emissions from Natural Gas Systems	CO_2	33.7	28.5	<0.01	1.1	91
CO_2 Emissions from Municipal Solid Waste Combustion	CO_2	10.9	20.9	<0.01	0.9	92
Indirect N_2O Emissions from Applied Nitrogen	N_2O	51.1	50.3	<0.01	0.9	93
CO_2 Emissions from Cement Manufacture	CO_2	33.3	45.7	<0.01	0.8	94
CO_2 Emissions from Ammonia Manufacture and Urea Application	CO_2	16.9	12.4	<0.01	0.7	94
CO_2 Emissions from Stationary Combustion - Gas	CO_2	975.4	1121.9	<0.01	0.7	95
CH_4 Emissions from Manure Management	CH_4	31.0	41.4	<0.01	0.6	96
CO_2 Emissions from Non-Energy Use of Fuels	CO_2	117.2	138.0	<0.01	0.4	96
CO_2 Emissions from Aluminum Production	CO_2	6.8	3.9	<0.01	0.4	96
N_2O Emissions from Nitric Acid Production	N_2O	17.0	15.6	<0.01	0.4	97
SF_6 Emissions from Magnesium Production and Processing	SF_6	5.4	3.2	<0.01	0.3	97
Mobile Combustion: Road & Other	CH_4	4.5	2.1	<0.01	0.3	97
CH_4 Emissions from Wastewater Treatment	CH_4	23.0	23.9	<0.01	0.3	98
CO_2 Emissions from Limestone and Dolomite Use	CO_2	5.5	8.6	<0.01	0.2	98
Non-CO_2 Emissions from Stationary Combustion	CH_4	7.4	6.2	<0.01	0.2	98
CH_4 Emissions from Rice Cultivation	CH_4	7.1	5.9	<0.01	0.2	98
CO_2 Emissions from Lime Manufacture	CO_2	12.0	15.8	<0.01	0.2	99
Fugitive Emissions from Abandoned Underground Coal Mines	CH_4	6.0	5.4	<0.01	0.2	99
PFC, HFC, and SF_6 Emissions from Semiconductor Manufacture	Several	2.9	4.8	<0.01	0.2	99
N_2O Emission from Composting	N_2O	0.4	1.8	<0.01	0.1	99
CH_4 Emissions from Composting	CH_4	0.3	1.6	<0.01	0.1	99
CO_2 Emissions from Ferroalloy Production	CO_2	2.2	1.5	<0.01	0.1	99
N_2O Emissions from Wastewater Treatment	N_2O	6.3	8.1	<0.01	0.1	99
N_2O Emissions from N_2O Product Usage	N_2O	4.4	4.4	<0.01	0.1	100
CO_2 Emissions from Phosphoric Acid Production	CO_2	1.5	1.2	<0.01	0.1	100
CO_2 Emissions from Soda Ash Manufacture and Consumption	CO_2	4.1	4.2	<0.01	0.1	100
CH_4 Emissions from Iron and Steel Production	CH_4	1.3	0.9	<0.01	0.1	100
CO_2 Emissions from Zinc Production	CO_2	0.9	0.5	<0.01	0.1	100
CO_2 Emissions from Titanium Dioxide Production	CO_2	1.2	1.9	<0.01	0.1	100
N_2O Emissions from Manure Management	N_2O	12.1	14.3	<0.01	0.1	100
Mobile Combustion: Aviation	N_2O	1.7	1.6	<0.01	<0.1	100
CO_2 Emissions from Silicon Carbide Production and Consumption	CO_2	0.4	0.2	<0.01	<0.1	100
N_2O Emissions from Municipal Solid Waste Combustion	N_2O	0.5	0.4	<0.01	<0.1	100
CO_2 Emissions from Petroleum Systems	CO_2	0.4	0.3	<0.01	<0.1	100
Non-CO_2 Emissions from Stationary Combustion	N_2O	12.8	14.5	<0.01	<0.1	100
N_2O Emissions from Field Burning of Agricultural Residues	N_2O	0.4	0.5	<0.01	<0.1	100
Mobile Combustion: Marine	N_2O	0.4	0.4	<0.01	<0.1	100
CO_2 Emissions from Stationary Combustion - Geothermal Energy	CO_2	0.4	0.4	<0.01	<0.1	100
CO_2 Emissions from Lead Production	CO_2	0.3	0.3	<0.01	<0.1	100
Mobile Combustion: Aviation	CH_4	0.2	0.1	<0.01	<0.1	100
CO_2 Emissions from Carbon Dioxide Consumption	CO_2	1.4	1.6	<0.01	<0.1	100
CH_4 Emissions from Field Burning of Agricultural Residues	CH_4	0.7	0.8	<0.01	<0.1	100
CO_2 Emissions from Petrochemical Production	CO_2	2.2	2.6	<0.01	<0.1	100
CH_4 Emissions from Silicon Carbide Production and Consumption	CH_4	0.0	0.0	<0.01	<0.1	100
CH_4 Emissions from Petrochemical Production	CH_4	0.9	1.0	<0.01	<0.1	100

IPCC Source Categories	Direct GHG	1990 Estimate (Tg CO_2 Eq.)	2006 Estimate (Tg CO_2 Eq.)	Trend Assessment	Percent Contribution to Trend (%)	Cumulative Contribution to Trend (%)
Mobile Combustion: Marine	CH_4	0.1	0.1	<0.01	<0.1	100
CH_4 Emissions from Ferroalloy Production	CH_4	<0.1	<0.1	<0.01	<0.1	100

Note: LULUCF sources and sinks are not included in this analysis.

Table A- 9: 1990-2006 Key Source Category Tier 1 Analysis—Trend Assessment, with LULUCF

IPCC Source Categories	Direct GHG	1990 Estimate (Tg CO_2 Eq.)	2006 Estimate (Tg CO_2 Eq.)	Trend Assessment	Percent Contribution to Trend (%)	Cumulative Contribution to Trend (%)
Mobile Combustion: Road & Other	CO_2	1258.5	1643.0	0.02	17.8	18
Emissions from Substitutes for Ozone Depleting Substances	Several	0.3	110.4	0.01	10.4	28
CO_2 Emissions from Stationary Combustion - Coal	CO_2	1698.9	2065.3	0.01	9.7	38
CO_2 Emissions from Stationary Combustion - Oil	CO_2	564.3	594.3	0.01	5.4	43
CO_2 Emissions from Iron and Steel Production	CO_2	86.2	49.1	0.01	4.8	48
CH_4 Emissions from Landfills	CH_4	149.6	125.7	0.01	4.4	52
Fugitive Emissions from Natural Gas Systems	CH_4	124.7	102.4	<0.01	3.9	56
Fugitive Emissions from Coal Mining	CH_4	84.1	58.5	<0.01	3.6	60
Direct N_2O Emissions from Agricultural Soil Management	N_2O	218.3	214.7	<0.01	3.5	64
Mobile Combustion: Aviation	CO_2	180.0	170.6	<0.01	3.5	67
HFC-23 Emissions from HCFC-22 Production	HFCs	36.4	13.8	<0.01	2.7	70
CO_2 Emissions from Forest Land Remaining Forest Land	CO_2	621.7	745.1	<0.01	2.5	72
CO_2 Emissions from Settlements Remaining Settlements	CO_2	60.6	95.5	<0.01	2.4	75
CH_4 Emissions from Enteric Fermentation	CH_4	126.9	126.2	<0.01	1.9	77
CH_4 Emissions from Forest Land Remaining Forest Land	CH_4	4.5	24.6	<0.01	1.8	78
PFC Emissions from Aluminum Production	PFCs	18.5	2.5	<0.01	1.8	80
SF_6 Emissions from Electrical Transmission and Distribution	SF_6	26.7	13.2	<0.01	1.7	82
CO_2 Emissions from Landfilled Yard Trimmings and Food Scraps	CO_2	23.9	10.5	<0.01	1.6	83
Mobile Combustion: Road & Other	N_2O	41.4	31.1	<0.01	1.6	85
CO_2 Emissions from Grassland Remaining Grassland	CO_2	1.9	16.2	<0.01	1.3	86
N_2O Emissions from Adipic Acid Production	N_2O	15.3	5.9	<0.01	1.1	87
Mobile Combustion: Marine	CO_2	46.5	42.4	<0.01	1.1	89
Fugitive Emissions from Petroleum Systems	CH_4	33.9	28.4	<0.01	1.0	90
CO_2 Emissions from Natural Gas Systems	CO_2	33.7	28.5	<0.01	1.0	90
Indirect N_2O Emissions from Applied Nitrogen	N_2O	51.1	50.3	<0.01	0.8	91
CO_2 Emissions from Municipal Solid Waste Combustion	CO_2	10.9	20.9	<0.01	0.8	92
CO_2 Emissions from Land Converted to Cropland	CO_2	14.7	9.4	<0.01	0.7	93
CO_2 Emissions from Cement Manufacture	CO_2	33.3	45.7	<0.01	0.7	94
CO_2 Emissions from Cropland Remaining Cropland	CO_2	23.0	33.8	<0.01	0.7	94
CO_2 Emissions from Ammonia Manufacture and Urea Application	CO_2	16.9	12.4	<0.01	0.7	95
CH_4 Emissions from Manure Management	CH_4	31.0	41.4	<0.01	0.5	95
CO_2 Emissions from Stationary Combustion - Gas	CO_2	975.4	1121.9	<0.01	0.5	96
CO_2 Emissions from Aluminum Production	CO_2	6.8	3.9	<0.01	0.4	96
N_2O Emissions from Nitric Acid Production	N_2O	17.0	15.6	<0.01	0.4	97
SF_6 Emissions from Magnesium Production and Processing	SF_6	5.4	3.2	<0.01	0.3	97
Mobile Combustion: Road & Other	CH_4	4.5	2.1	<0.01	0.3	97
CH_4 Emissions from Wastewater Treatment	CH_4	23.0	23.9	<0.01	0.3	97
CO_2 Emissions from Non-Energy Use of Fuels	CO_2	117.2	138.0	<0.01	0.2	98
Non-CO_2 Emissions from Stationary Combustion	CH_4	7.4	6.2	<0.01	0.2	98
CH_4 Emissions from Rice Cultivation	CH_4	7.1	5.9	<0.01	0.2	98
N_2O Emissions from Forest Land Remaining Forest Land	N_2O	0.5	2.8	<0.01	0.2	98
CO_2 Emissions from Limestone and Dolomite Use	CO_2	5.5	8.6	<0.01	0.2	99
CO_2 Emissions from Lime Manufacture	CO_2	12.0	15.8	<0.01	0.2	99
Fugitive Emissions from Abandoned Underground Coal Mines	CH_4	6.0	5.4	<0.01	0.1	99
PFC, HFC, and SF_6 Emissions from Semiconductor	Several	2.9	4.8	<0.01	0.1	99

IPCC Source Categories	Direct GHG	1990 Estimate (Tg CO_2 Eq.)	2006 Estimate (Tg CO_2 Eq.)	Trend Assessment	Percent Contribution to Trend (%)	Cumulative Contribution to Trend (%)
Manufacture						
N_2O Emission from Composting	N_2O	0.4	1.8	<0.01	0.1	99
CH_4 Emissions from Composting	CH_4	0.3	1.6	<0.01	0.1	99
CO_2 Emissions from Ferroalloy Production	CO_2	2.2	1.5	<0.01	0.1	99
N_2O Emissions from Wastewater Treatment	N_2O	6.3	8.1	<0.01	0.1	99
N_2O Emissions from N_2O Product Usage	N_2O	4.4	4.4	<0.01	0.1	100
CO_2 Emissions from Soda Ash Manufacture and Consumption	CO_2	4.1	4.2	<0.01	0.1	100
CO_2 Emissions from Phosphoric Acid Production	CO_2	1.5	1.2	<0.01	0.1	100
CH_4 Emissions from Iron and Steel Production	CH_4	1.3	0.9	<0.01	0.1	100
CO_2 Emissions from Zinc Production	CO_2	0.9	0.5	<0.01	0.1	100
CO_2 Emissions from Titanium Dioxide Production	CO_2	1.2	1.9	<0.01	<0.1	100
N_2O Emissions from Manure Management	N_2O	12.1	14.3	<0.01	<0.1	100
Mobile Combustion: Aviation	N_2O	1.7	1.6	<0.01	<0.1	100
N_2O Emissions from Settlements Remaining Settlements	N_2O	1.0	1.5	<0.01	<0.1	100
Non-CO_2 Emissions from Stationary Combustion	N_2O	12.8	14.5	<0.01	<0.1	100
CO_2 Emissions from Silicon Carbide Production and Consumption	CO_2	0.4	0.2	<0.01	<0.1	100
CO_2 Emissions from Land Converted to Grassland	CO_2	14.3	16.3	<0.01	<0.1	100
N_2O Emissions from Municipal Solid Waste Combustion	N_2O	0.5	0.4	<0.01	<0.1	100
CO_2 Emissions from Petroleum Systems	CO_2	0.4	0.3	<0.01	<0.1	100
Mobile Combustion: Marine	N_2O	0.4	0.4	<0.01	<0.1	100
CO_2 Emissions from Stationary Combustion - Geothermal Energy	CO_2	0.4	0.4	<0.01	<0.1	100
N_2O Emissions from Field Burning of Agricultural Residues	N_2O	0.4	0.5	<0.01	<0.1	100
CO_2 Emissions from Lead Production	CO_2	0.3	0.3	<0.01	<0.1	100
CO_2 Emissions from Carbon Dioxide Consumption	CO_2	1.4	1.6	<0.01	<0.1	100
Mobile Combustion: Aviation	CH_4	0.2	0.1	<0.01	<0.1	100
CH_4 Emissions from Field Burning of Agricultural Residues	CH_4	0.7	0.8	<0.01	<0.1	100
CH_4 Emissions from Silicon Carbide Production and Consumption	CH_4	0.0	0.0	<0.01	<0.1	100
Mobile Combustion: Marine	CH_4	0.1	0.1	<0.01	<0.1	100
CH_4 Emissions from Petrochemical Production	CH_4	0.9	1.0	<0.01	<0.1	100
CO_2 Emissions from Petrochemical Production	CO_2	2.2	2.6	<0.01	<0.1	100
CH_4 Emissions from Ferroalloy Production	CH_4	<0.1	<0.1	<0.01	<0.1	100

References

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IPCC (2000) *Good Practice Guidance* and Uncertainty Management in National Greenhouse Gas Inventories, Intergovernmental Panel on Climate Change, National Greenhouse Gas Inventories Programme.

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

Carbon dioxide (CO_2) emissions from fossil fuel combustion were estimated using a "bottom-up" methodology characterized by nine 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 CO_2 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). Adjusted consumption data are presented in Columns 2 through 8 of Table A-1 through Table A-17, 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 2006 total adjusted energy consumption across all sectors, including territories, and energy types was 77,259.5 trillion British thermal units (TBtu), as indicated in the last entry of Column 8 in Table A-1. 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 2007a).

There are also three basic differences between the consumption data presented in Table A-1 through Table A-18 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.

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[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 Framework Convention on Climate Change are to include energy consumption within territories. Therefore, consumption estimates for U.S. territories were added to domestic consumption of fossil fuels. Energy consumption data from U.S. territories are presented in Column 7 of Table A-1 through Table A-17. 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 (>401F) for processes accounted for in the Industrial Processes chapter, (2) corrections for synthetic natural gas production, (3) corrections for ethanol added to motor gasoline, and (4) corrections for biogas in natural gas, (5) subtraction of other fuels used for non-energy purposes, and (6) 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 six fuel categories—coking coal, 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 is 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.

Step 3: Adjust for Biofuels and Conversion of Fossil Fuels

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 CO_2. The synthetic natural gas enters the natural gas distribution system. Since October 2000, a portion of the CO_2 produced by the coal gasification plant has been exported to Canada by pipeline. The remainder of the CO_2 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 CO_2 is not emitted to the atmosphere in the United States, and therefore the energy used to produce this amount of CO_2 is subtracted from industrial other coal.

Second, ethanol has been added to the motor gasoline stream for several years, but prior to 1993 this addition was not captured in EIA motor gasoline statistics. Starting in 1993, ethanol was included in gasoline statistics. However, because ethanol is a biofuel, which is assumed to result in no net CO_2 emissions, the amount of ethanol added is subtracted from total gasoline consumption. Thus, motor gasoline consumption statistics given in this report may be slightly lower than in EIA sources.

Third, EIA natural gas consumption statistics include "biomass gas," which is upgraded landfill methane that is sold to pipelines. However, because this gas is biogenic, the biomass gas total is deducted from natural gas consumption. The subtraction is done only from natural gas in the industrial sector, as opposed to all end-sectors, because the biogas amount is small. Due to this adjustment—and the ammonia adjustment mentioned previously—industrial natural gas consumption in this report is slightly lower than in EIA sources.

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 some of this C when they are used and/or burned as waste.[3] 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-18, 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-19). Emissions from international bunker fuels have been estimated separately and not included in national totals.[4]

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-1 through Table A-17) by fuel-specific C content coefficients (see Table A-20 and Table A-21) 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 CO_2 Emissions

Actual CO_2 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 CO_2 Eq.). To convert from C content to CO_2 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-22). 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.

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[3] See Waste Combustion section of the Energy chapter and the Municipal Solid Waste Annex for a discussion of emissions from the combustion of plastics in the municipal solid waste stream.

[4] 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-1: 2006 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

	Adjusted Consumption (TBtu)[a]							[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	6.0	65.0	1,298.3	NE	20,462.0	44.2	21,875.5	0.6	6.2	122.0	NE	1,932.4	4.1	2,065.3
Residential Coal	6.0						6.0	0.6						0.6
Commercial Coal		65.0					65.0		6.2					6.2
Industrial Other Coal			1,298.3				1,298.3			122.0				122.0
Transportation Coal				NE										NE
Electric Power Coal					20,462.0		20,462.0					1,932.4		1,932.4
U.S. Territory Coal (bit)						44.2	44.2						4.1	4.1
Natural Gas	4,476.0	2,905.0	7,336.9	626.0	6,401.5	26.2	21,771.5	237.5	154.1	389.3	33.2	339.6	1.4	1,155.1
Total Petroleum	1,280.4	687.0	4,788.1	25,492.6	649.0	664.8	33,561.8	88.5	49.8	350.9	1,822.8	55.7	49.4	2,417.1
Asphalt & Road Oil														
Aviation Gasoline				33.0			33.0				2.3			2.3
Distillate Fuel Oil	701.4	395.2	1,232.2	6,334.7	74.0	134.8	8,872.3	51.3	28.9	90.1	463.4	5.4	9.9	649.0
Jet Fuel				2,375.3	NA	69.5	2,444.8				168.4		4.9	173.3
Kerosene	71.0	17.1	23.5			5.5	117.0	5.1	1.2	1.7			0.4	8.5
LPG	508.0	90.0	559.8	17.2		0.7	1,175.7	32.0	5.7	35.3	1.1		0.0	74.1
Lubricants														
Motor Gasoline		71.2	545.9	16,507.8		203.4	17,328.3		5.0	38.7	1,170.0		14.4	1,228.2
Residual Fuel		113.2	231.0	224.6	361.0	250.9	1,180.8		8.9	18.2	17.7	28.4	19.8	93.0
Other Petroleum														
AvGas Blend Components			8.1				8.1			0.6				0.6
Crude Oil														
MoGas Blend Components														
Misc. Products														
Naphtha (<401 deg. F)														
Other Oil (>401 deg. F)														
Pentanes Plus			32.6				32.6			2.2				2.2
Petroleum Coke		0.3	662.8		214.0		877.1		0.0	67.7		21.9		89.6
Still Gas			1,429.4				1,429.4			91.8				91.8
Special Naphtha														
Unfinished Oils			62.8				62.8			4.7				4.7
Waxes														
Geothermal					50.6		50.6					0.4		0.4
TOTAL (All Fuels)	5,762.4	3,657.0	13,423.2	26,118.6	27,563.1	735.2	77,259.5	326.5	210.1	862.2	1,856.0	2,328.2	54.9	5,637.9

[a] Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-18), and international bunker fuel consumption (see Table A-19).
[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-2: 2005 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

	Adjusted Consumption (TBtu)[a]							[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	9.0	96.0	1,297.6	NE	20,737.2	40.1	22,179.9	0.9	9.2	122.0	NE	1,958.4	3.7	2,094.1
Residential Coal	9.0						9.0	0.9						0.9
Commercial Coal		96.0					96.0		9.2					9.2
Industrial Other Coal			1,297.6				1,297.6			122.0				122.0
Transportation Coal				NE										NE
Electric Power Coal					20,737.2		20,737.2					1,958.4		1,958.4
U.S. Territory Coal (bit)						40.1	40.1						3.7	3.7
Natural Gas	4,951.0	3,076.0	7,434.5	625.0	6,014.8	24.3	22,125.6	262.7	163.2	394.5	33.2	319.1	1.3	1,173.9
Total Petroleum	1,369.0	682.6	4,516.2	25,689.2	1,234.5	648.8	34,140.4	95.0	49.6	330.9	1,836.7	102.3	48.2	2,462.7
Asphalt & Road Oil														
Aviation Gasoline				35.4			35.4				2.4			2.4
Distillate Fuel Oil	773.1	405.0	1,131.9	6,192.2	114.6	131.7	8,748.5	56.6	29.6	82.8	453.0	8.4	9.6	640.0
Jet Fuel				2,522.2	NA	68.0	2,590.2				178.8		4.8	183.6
Kerosene	91.7	22.2	30.5			5.3	149.8	6.6	1.6	2.2			0.4	10.8
LPG	504.2	89.0	583.5	17.1		0.7	1,194.4	31.8	5.6	36.8	1.1		0.0	75.3
Lubricants														
Motor Gasoline		50.4	386.3	16,665.8		198.5	17,300.9		3.6	27.4	1,181.2		14.1	1,226.2
Residual Fuel		115.8	237.4	256.4	876.5	244.7	1,730.8		9.1	18.7	20.2	69.1	19.3	136.4
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			3.1				3.1
Petroleum Coke		0.3	660.1		243.5		903.9		0.0	67.4		24.9		92.3
Still Gas			1,429.4				1,429.4			91.8				91.8
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)	6,329.0	3,854.6	13,248.3	26,314.2	28,036.7	713.3	78,496.1	358.5	221.9	847.3	1,869.8	2,380.2	53.2	5,731.0

[a] Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-18), and international bunker fuel consumption (see Table A-19).
[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-3: 2004 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

	Adjusted Consumption (TBtu)[a]							[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	13.0	102.0	1,343.0	NE	20,305.0	39.1	21,802.1	1.2	9.7	126.2	NE	1,917.6	3.6	2,058.4
Residential Coal	13.0						13.0	1.2						1.2
Commercial Coal		102.0							9.7					9.7
Industrial Other Coal			1,343.0				1,343.0			126.2				126.2
Transportation Coal				NE										NE
Electric Power Coal					20,305.0		20,305.0					1,917.6		1,917.6
U.S. Territory Coal (bit)						39.1	39.1						3.6	3.6
Natural Gas	4,986.0	3,204.0	7,830.5	603.0	5,594.9	24.7	22,243.0	264.5	170.0	415.5	32.0	296.8	1.3	1,180.1
Total Petroleum	1,475.2	700.2	4,310.1	25,530.5	1,212.4	653.6	33,882.0	102.5	50.9	316.0	1,824.4	100.1	48.6	2,442.5
Asphalt & Road Oil														
Aviation Gasoline				31.2			31.2				2.2			2.2
Distillate Fuel Oil	859.6	437.6	1,118.3	5,970.0	111.3	134.4	8,631.2	62.9	32.0	81.8	436.7	8.1	9.8	631.4
Jet Fuel				2,467.0	NA	68.8	2,535.8				174.9		4.9	179.7
Kerosene	84.8	20.5	28.2			6.0	139.5	6.1	1.5	2.0			0.4	10.1
LPG	530.9	93.7	604.8	18.0		0.8	1,248.2	33.5	5.9	38.1	1.1		0.1	78.7
Lubricants														
Motor Gasoline		25.6	196.7	16,857.8		198.6	17,278.7		1.8	13.9	1,194.8		14.1	1,224.7
Residual Fuel		122.5	204.7	186.4	879.0	245.0	1,637.6		9.7	16.1	14.7	69.3	19.3	129.0
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			3.5				3.5
Petroleum Coke		0.3	687.7		222.1		910.0		0.0	70.2		22.7		92.9
Still Gas			1,482.6				1,482.6			95.2				95.2
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)	6,474.2	4,006.2	13,483.5	26,133.5	27,162.9	717.4	77,977.6	368.3	230.6	857.7	1,856.4	2,314.9	53.5	5,681.4

[a] Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-18), and international bunker fuel consumption (see Table A-19).
[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-4: 2003 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

	Adjusted Consumption (TBtu)[a]							[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	12.4	82.9	1,319.0	NE	20,184.7	41.1	21,640.1	1.2	7.9	124.0	NE	1,906.2	3.8	2,043.1
Residential Coal	12.4						12.4	1.2						1.2
Commercial Coal		82.9					82.9		7.9					7.9
Industrial Other Coal			1,319.0				1,319.0			124.0				124.0
Transportation Coal				NE										NE
Electric Power Coal					20,184.7		20,184.7					1,906.2		1,906.2
U.S. Territory Coal (bit)						41.1	41.1						3.8	3.8
Natural Gas	5,229.5	3,330.6	8,160.3	630.0	5,246.2	26.9	22,623.5	277.5	176.7	433.0	33.4	278.3	1.4	1,200.3
Total Petroleum	1,503.2	714.6	4,075.0	24,841.3	1,205.0	621.8	32,960.9	104.2	51.8	299.1	1,774.2	98.1	45.8	2,373.3
Asphalt & Road Oil														
Aviation Gasoline				30.2			30.2				2.1			2.1
Distillate Fuel Oil	868.9	462.4	1,079.7	5,661.8	161.0	120.5	8,354.4	63.6	33.8	79.0	414.2	11.8	8.8	611.1
Jet Fuel				2,435.8	NA	76.1	2,511.9				172.7		5.4	178.0
Kerosene	70.3	18.6	24.1			10.7	123.7	5.1	1.3	1.7			0.8	8.9
LPG	564.0	99.5	523.1	15.7		10.5	1,212.8	35.6	6.3	33.0	1.0		0.7	76.5
Lubricants														
Motor Gasoline		22.5	121.9	16,598.7		210.1	16,953.2		1.6	8.6	1,176.5		14.9	1,201.6
Residual Fuel		111.1	176.4	99.1	869.4	193.9	1,450.0		8.8	13.9	7.8	68.5	15.3	114.3
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			3.5				3.5
Petroleum Coke		0.3	663.7		174.7		838.7		0.0	67.8		17.8		85.6
Still Gas			1,477.3				1,477.3			94.8				94.8
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)	6,745.0	4,128.0	13,554.3	25,471.3	26,685.2	689.8	77,273.7	382.9	236.5	856.0	1,807.6	2,283.1	51.0	5,617.0

[a] Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-18), and international bunker fuel consumption (see Table A-19).
[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-5: 2002 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

	Adjusted Consumption (TBtu)[a]							[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	87.8	1,312.8	NE	19,782.8	17.9	21,213.3	1.1	8.4	123.4	NE	1,868.3	1.7	2,002.8
Residential Coal	12.0						12.0	1.1						1.1
Commercial Coal		87.8					87.8		8.4					8.4
Industrial Other Coal			1,312.8				1,312.8			123.4				123.4
Transportation Coal				NE										NE
Electric Power Coal					19,782.8		19,782.8					1,868.3		1,868.3
U.S. Territory Coal (bit)						17.9	17.9						1.7	1.7
Natural Gas	4,994.3	3,223.6	8,428.5	702.0	5,766.8	22.8	23,138.1	265.0	171.0	447.2	37.2	306.0	1.2	1,227.6
Total Petroleum	1,365.5	601.2	3,879.3	25,040.6	961.3	556.8	32,404.7	94.4	43.4	284.3	1,791.7	79.1	41.1	2,334.0
Asphalt & Road Oil														
Aviation Gasoline				33.7			33.7				2.3			2.3
Distillate Fuel Oil	762.8	394.0	1,056.8	5,605.1	127.4	92.8	8,038.9	55.8	28.8	77.3	410.0	9.3	6.8	588.0
Jet Fuel				2,478.0	NA	61.8	2,539.8				175.6		4.4	180.0
Kerosene	59.9	15.9	13.8			8.2	97.8	4.3	1.2	1.0			0.6	7.1
LPG	542.8	95.8	579.5	13.5		11.2	1,242.7	34.2	6.0	36.6	0.8		0.7	78.4
Lubricants														
Motor Gasoline		15.4	105.5	16,523.5		189.4	16,833.7		1.1	7.5	1,172.3		13.4	1,194.4
Residual Fuel		79.8	146.1	386.9	658.7	193.6	1,465.1		6.3	11.5	30.5	51.9	15.3	115.4
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			3.5				3.5
Petroleum Coke		0.2	650.0		175.2		825.4		0.0	66.4		17.9		84.3
Still Gas			1,403.3				1,403.3			90.1				90.1
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)	6,371.8	3,912.6	13,620.6	25,742.6	26,560.3	597.6	76,805.6	360.5	222.8	854.8	1,828.9	2,253.7	44.0	5,564.8

[a] Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-18), and international bunker fuel consumption (see Table A-19).
[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-6: 2001 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

	Adjusted Consumption (TBtu)[a]							[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	10.9	88.3	1,420.6	NE	19,613.7	10.8	21,144.2	1.0	8.4	133.5	NE	1,852.3	1.0	1,996.3
Residential Coal	10.9						10.9	1.0						1.0
Commercial Coal		88.3					88.3		8.4					8.4
Industrial Other Coal			1,420.6				1,420.6			133.5				133.5
Transportation Coal				NE										NE
Electric Power Coal					19,613.7		19,613.7					1,852.3		1,852.3
U.S. Territory Coal (bit)						10.8	10.8						1.0	1.0
Natural Gas	4,906.9	3,111.6	8,009.6	642.0	5,458.1	22.9	22,151.2	260.3	165.1	425.0	34.1	289.6	1.2	1,175.3
Total Petroleum	1,472.4	675.7	4,003.6	24,374.1	1,276.6	632.2	32,434.5	102.2	48.8	294.0	1,741.6	102.0	46.8	2,335.5
Asphalt & Road Oil														
Aviation Gasoline				34.9			34.9				2.4			2.4
Distillate Fuel Oil	842.1	471.3	1,193.4	5,417.4	170.5	109.4	8,204.2	61.6	34.5	87.3	396.3	12.5	8.0	600.1
Jet Fuel				2,597.9	NA	98.9	2,696.7				184.1		7.0	191.1
Kerosene	95.1	31.4	23.2			0.9	150.6	6.9	2.3	1.7			0.1	10.9
LPG	535.2	94.5	500.6	12.9		7.0	1,150.2	33.8	6.0	31.6	0.8		0.4	72.6
Lubricants														
Motor Gasoline		8.5	66.7	16,151.4		187.6	16,414.2		0.6	4.7	1,145.4		13.3	1,164.0
Residual Fuel		69.9	146.7	159.5	1,002.8	228.4	1,607.2		5.5	11.6	12.6	79.0	18.0	126.6
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			4.1				4.1
Petroleum Coke		0.2	650.0		103.2		753.4		0.0	66.4		10.5		76.9
Still Gas			1,430.7				1,430.7			91.9				91.9
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)	6,390.2	3,875.6	13,433.8	25,016.1	26,395.2	665.9	75,776.8	363.6	222.3	852.5	1,775.6	2,244.3	49.0	5,507.4

[a] Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-18), and international bunker fuel consumption (see Table A-19).
[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-7: 2000 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

	Adjusted Consumption (TBtu)[a]							[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	10.6	85.8	1,420.6	NE	20,220.2	10.3	21,747.5	1.0	8.2	133.5	NE	1,909.6	0.9	2,053.2
Residential Coal	10.6						10.6	1.0						1.0
Commercial Coal		85.8					85.8		8.2					8.2
Industrial Other Coal			1,420.6				1,420.6			133.5				133.5
Transportation Coal				NE										NE
Electric Power Coal					20,220.2		20,220.2					1,909.6		1,909.6
U.S. Territory Coal (bit)						10.3	10.3						0.9	0.9
Natural Gas	5,099.8	3,254.4	8,670.8	672.0	5,293.4	12.7	23,003.1	270.6	172.7	460.0	35.7	280.9	0.7	1,220.5
Total Petroleum	1,452.6	651.9	3,647.2	24,638.3	1,144.3	471.7	32,006.0	100.5	47.2	266.8	1,762.5	91.5	34.6	2,303.0
Asphalt & Road Oil														
Aviation Gasoline				36.3			36.3				2.5			2.5
Distillate Fuel Oil	794.3	431.0	1,042.1	5,395.7	174.8	71.3	7,909.3	58.1	31.5	76.2	394.7	12.8	5.2	578.6
Jet Fuel				2,735.9	NA	74.1	2,810.0				193.9		5.2	199.2
Kerosene	94.6	29.7	15.6			2.4	142.2	6.8	2.1	1.1			0.2	10.3
LPG	563.7	99.5	605.3	11.2		8.0	1,287.7	35.6	6.3	38.2	0.7		0.5	81.2
Lubricants														
Motor Gasoline				16,015.7		185.1	16,200.8				1,135.7		13.1	1,148.9
Residual Fuel		91.6	184.1	443.5	870.8	130.9	1,720.8		7.2	14.5	34.9	68.6	10.3	135.6
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			7.1				7.1
Petroleum Coke		0.2	655.4		98.6		754.2		0.0	66.9		10.1		77.0
Still Gas			1,435.6				1,435.6			92.2				92.2
Special Naphtha														
Unfinished Oils			(401.2)				(401.2)			(29.8)				(29.8)
Waxes														
Geothermal					48.1		48.1					0.4		0.4
TOTAL (All Fuels)	6,563.0	3,992.1	13,738.7	25,310.3	26,706.0	494.6	76,804.6	372.1	228.0	860.3	1,798.2	2,282.3	36.2	5,577.1

[a] Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-18), and international bunker fuel consumption (see Table A-19).
[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-8: 1999 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

	Adjusted Consumption (TBtu)[a]							[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	13.9	101.6	1,362.2	NE	19,279.5	10.2	20,767.3	1.3	9.7	128.0	NE	1,820.7	0.9	1,960.7
Residential Coal	13.9						13.9	1.3						1.3
Commercial Coal		101.6					101.6		9.7					9.7
Industrial Other Coal			1,362.2				1,362.2			128.0				128.0
Transportation Coal				NE										NE
Electric Power Coal					19,279.5		19,279.5					1,820.7		1,820.7
U.S. Territory Coal (bit)						10.2	10.2						0.9	0.9
Natural Gas	4,856.8	3,131.9	8,621.8	674.0	4,902.1	-	22,186.7	257.7	166.2	457.4	35.8	260.1		1,177.2
Total Petroleum	1,377.4	582.5	3,532.7	23,953.3	1,211.4	461.0	31,118.2	95.4	42.1	260.2	1,710.7	97.3	34.0	2,239.6
Asphalt & Road Oil														
Aviation Gasoline				39.2			39.2				2.7			2.7
Distillate Fuel Oil	732.5	388.0	1,038.9	5,169.8	140.1	79.4	7,548.7	53.6	28.4	76.0	378.2	10.3	5.8	552.2
Jet Fuel				2,641.2	NA	59.5	2,700.7				187.2		4.2	191.4
Kerosene	111.2	26.9	12.8			3.7	154.7	8.0	1.9	0.9			0.3	11.2
LPG	533.7	94.2	435.0	13.5		8.3	1,084.7	33.8	6.0	27.5	0.9		0.5	68.6
Lubricants														
Motor Gasoline				15,913.9		164.0	16,078.0				1,127.9		11.6	1,139.6
Residual Fuel		73.3	150.9	175.7	958.7	146.0	1,504.6		5.8	11.9	13.8	75.5	11.5	118.6
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			6.9				6.9
Petroleum Coke		0.1	652.0		112.5		764.6		0.0	66.6		11.5		78.1
Still Gas			1,421.1				1,421.1			91.2				91.2
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)	6,248.1	3,816.1	13,516.6	24,627.3	25,443.6	471.2	74,122.8	354.4	217.9	845.7	1,746.5	2,178.5	34.9	5,377.9

[a] Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-18), and international bunker fuel consumption (see Table A-19).
[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-9: 1998 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

	Adjusted Consumption (TBtu)[a]							[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	12.4	100.6	1,409.4	NE	19,215.7	10.5	20,748.6	1.2	9.6	132.5	NE	1,814.7	1.0	1,958.9
Residential Coal	12.4						12.4	1.2						1.2
Commercial Coal		100.6					100.6		9.6					9.6
Industrial Other Coal			1,409.4				1,409.4			132.5				132.5
Transportation Coal				NE										NE
Electric Power Coal					19,215.7		19,215.7					1,814.7		1,814.7
U.S. Territory Coal (bit)						10.5	10.5						1.0	1.0
Natural Gas	4,671.0	3,098.1	9,056.9	665.0	4,674.9	-	22,165.9	247.8	164.4	480.5	35.3	248.0		1,176.1
Total Petroleum	1,242.9	585.4	3,464.6	23,137.5	1,306.2	445.4	30,182.2	86.5	42.5	256.2	1,651.4	105.0	32.8	2,174.5
Asphalt & Road Oil														
Aviation Gasoline				35.5			35.5				2.5			2.5
Distillate Fuel Oil	701.0	389.5	1,088.5	4,874.3	135.7	71.9	7,260.9	51.3	28.5	79.6	356.6	9.9	5.3	531.1
Jet Fuel				2,566.1	NA	59.9	2,626.0				181.9		4.2	186.1
Kerosene	108.3	31.2	22.1			6.3	167.8	7.8	2.3	1.6			0.5	12.1
LPG	433.6	76.5	303.9	16.6		5.9	836.6	27.4	4.8	19.2	1.1		0.4	52.8
Lubricants														
Motor Gasoline		3.0	15.1	15,566.1		160.3	15,744.6		0.2	1.1	1,103.3		11.4	1,115.9
Residual Fuel		85.2	173.3	78.9	1,047.0	141.1	1,525.5		6.7	13.7	6.2	82.5	11.1	120.2
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			6.0				6.0
Petroleum Coke		0.1	644.8		123.6		768.4		0.0	65.8		12.6		78.5
Still Gas			1,437.3				1,437.3			92.3				92.3
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)	5,926.4	3,784.1	13,930.9	23,802.5	25,247.2	456.0	73,147.1	335.5	216.5	869.2	1,686.7	2,168.2	33.8	5,309.9

[a] Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-18), and international bunker fuel consumption (see Table A-19).
[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-10: 1997 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

	Adjusted Consumption (TBtu)[a]							[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	15.9	128.7	1,462.6	NE	18,904.5	10.4	20,522.2	1.5	12.3	137.5	NE	1,785.3	1.0	1,937.6
Residential Coal	15.9						15.9	1.5						1.5
Commercial Coal		128.7					128.7		12.3					12.3
Industrial Other Coal			1,462.6				1,462.6			137.5				137.5
Transportation Coal				NE										NE
Electric Power Coal					18,904.5		18,904.5					1,785.3		1,785.3
U.S. Territory Coal (bit)						10.4	10.4						1.0	1.0
Natural Gas	5,125.0	3,306.4	9,335.6	779.0	4,146.0	-	22,691.9	271.9	175.4	495.3	41.3	220.0		1,204.0
Total Petroleum	1,343.4	623.9	3,818.4	22,622.4	926.8	445.3	29,780.3	93.5	45.4	280.3	1,616.3	74.8	32.8	2,143.0
Asphalt & Road Oil														
Aviation Gasoline				39.7			39.7				2.7			2.7
Distillate Fuel Oil	789.8	400.9	1,076.1	4,790.8	110.6	81.6	7,249.8	57.8	29.3	78.7	350.4	8.1	6.0	530.3
Jet Fuel				2,528.1	NA	62.1	2,590.2				179.2		4.4	183.6
Kerosene	92.9	24.6	18.8			4.0	140.3	6.7	1.8	1.4			0.3	10.1
LPG	460.7	81.3	463.7	13.4		6.5	1,025.7	29.0	5.1	29.2	0.8		0.4	64.6
Lubricants														
Motor Gasoline		5.8	28.5	15,113.9		160.0	15,308.2		0.4	2.0	1,072.3		11.4	1,086.1
Residual Fuel		111.2	235.6	136.5	714.6	131.1	1,329.0		8.8	18.6	10.8	56.3	10.3	104.7
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			2.0				2.0
Petroleum Coke		0.1	609.7		101.6		711.4		0.0	62.3		10.4		72.6
Still Gas			1,445.1				1,445.1			92.8				92.8
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)	6,484.3	4,059.1	14,616.5	23,401.4	24,027.6	455.7	73,044.6	366.9	233.1	913.0	1,657.7	2,080.5	33.7	5,284.9

[a] Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-18), and international bunker fuel consumption (see Table A-19).
[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-11: 1996 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

	Adjusted Consumption (TBtu)[a]							[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	16.4	120.1	1,498.9	NE	18,429.0	10.3	20,074.7	1.6	11.4	140.7	NE	1,739.6	1.0	1,894.2
Residential Coal	16.4						16.4	1.6						1.6
Commercial Coal		120.1					120.1		11.4					11.4
Industrial Other Coal			1,498.9				1,498.9			140.7				140.7
Transportation Coal				NE										NE
Electric Power Coal					18,429.0		18,429.0					1,739.6		1,739.6
U.S. Territory Coal (bit)						10.3	10.3						1.0	1.0
Natural Gas	5,390.5	3,250.9	9,249.4	736.0	3,883.0	-	22,509.8	286.0	172.5	490.7	39.0	206.0		1,194.3
Total Petroleum	1,436.3	699.3	3,851.5	22,380.6	817.4	434.6	29,619.5	100.2	51.1	283.3	1,600.5	65.6	31.9	2,132.5
Asphalt & Road Oil														
Aviation Gasoline				37.4			37.4				2.6			2.6
Distillate Fuel Oil	874.2	455.9	1,111.3	4,500.4	109.4	76.5	7,127.6	63.9	33.4	81.3	329.2	8.0	5.6	521.4
Jet Fuel				2,545.9	NA	78.5	2,624.4				180.5		5.6	186.0
Kerosene	88.8	21.0	18.3			3.0	131.1	6.4	1.5	1.3			0.2	9.5
LPG	473.2	83.5	436.9	14.7		7.3	1,015.7	29.8	5.3	27.5	0.9		0.5	64.1
Lubricants														
Motor Gasoline		1.5	11.2	14,967.3		151.4	15,131.4		0.1	0.8	1,062.5		10.7	1,074.1
Residual Fuel		137.2	281.7	314.9	628.4	118.0	1,480.1		10.8	22.2	24.8	49.5	9.3	116.6
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			2.6				2.6
Petroleum Coke		0.1	608.7		79.6		688.4		0.0	62.2		8.1		70.3
Still Gas			1,437.1				1,437.1			92.3				92.3
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)	6,843.2	4,070.3	14,599.7	23,116.6	23,178.3	445.0	72,252.9	387.8	235.0	914.8	1,639.5	2,011.6	32.8	5,221.4

[a] Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-18), and international bunker fuel consumption (see Table A-19).
[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-12: 1995 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

	Adjusted Consumption (TBtu)[a]							[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	17.4	116.3	1,521.7	NE	17,466.3	10.2	19,131.9	1.7	11.1	143.0	NE	1,648.7	0.9	1,805.4
Residential Coal	17.4						17.4	1.7						1.7
Commercial Coal		116.3					116.3		11.1					11.1
Industrial Other Coal			1,521.7				1,521.7			143.0				143.0
Transportation Coal				NE										NE
Electric Power Coal					17,466.3		17,466.3					1,648.7		1,648.7
U.S. Territory Coal (bit)						10.2	10.2						0.9	0.9
Natural Gas	4,983.5	3,116.5	8,941.6	723.0	4,325.0	-	22,089.6	264.4	165.4	474.4	38.4	229.5		1,172.0
Total Petroleum	1,293.5	673.7	3,523.9	21,807.2	754.6	461.8	28,514.7	90.5	49.3	259.0	1,561.0	60.7	34.0	2,054.7
Asphalt & Road Oil														
Aviation Gasoline				39.6			39.6				2.7			2.7
Distillate Fuel Oil	814.9	431.3	1,010.7	4,318.9	108.1	89.5	6,773.4	59.6	31.6	73.9	315.9	7.9	6.5	495.5
Jet Fuel				2,424.1	NA	75.7	2,499.9				171.9		5.4	177.2
Kerosene	74.3	22.1	15.4			3.6	115.4	5.4	1.6	1.1			0.3	8.3
LPG	404.2	71.3	432.5	16.7		5.6	930.5	25.5	4.5	27.3	1.1		0.4	58.7
Lubricants														
Motor Gasoline		7.3	81.2	14,620.5		146.7	14,855.7		0.5	5.8	1,038.9		10.4	1,055.6
Residual Fuel		141.5	284.7	387.3	566.0	140.7	1,520.1		11.1	22.4	30.5	44.6	11.1	119.8
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			2.3				2.3
Petroleum Coke		0.1	588.7		80.6		669.4		0.0	60.1		8.2		68.4
Still Gas			1,377.3				1,377.3			88.4				88.4
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)	6,294.4	3,906.6	13,987.2	22,530.2	22,591.5	472.0	69,781.8	356.5	225.8	876.5	1,599.4	1,939.3	35.0	5,032.4

[a] Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-18), and international bunker fuel consumption (see Table A-19).
[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-13: 1994 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

	Adjusted Consumption (TBtu)[a]							[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	20.7	117.1	1,575.0	NE	17,260.9	10.0	18,983.7	2.0	11.1	148.0	NE	1,627.8	0.9	1,789.8
Residential Coal	20.7						20.7	2.0						2.0
Commercial Coal		117.1					117.1		11.1					11.1
Industrial Other Coal			1,575.0				1,575.0			148.0				148.0
Transportation Coal				NE										NE
Electric Power Coal					17,260.9		17,260.9					1,627.8		1,627.8
U.S. Territory Coal (bit)						10.0	10.0						0.9	0.9
Natural Gas	4,981.0	2,978.1	8,453.6	708.0	4,000.0	-	21,120.8	264.3	158.0	448.5	37.6	212.2		1,120.6
Total Petroleum	1,325.5	712.9	3,660.8	21,479.6	1,058.8	506.3	28,743.9	92.9	52.4	268.9	1,540.9	84.4	37.5	2,077.0
Asphalt & Road Oil														
Aviation Gasoline				38.1			38.1				2.6			2.6
Distillate Fuel Oil	865.1	451.5	994.1	4,164.4	120.1	118.8	6,714.1	63.3	33.0	72.7	304.6	8.8	8.7	491.1
Jet Fuel				2,484.7	NA	65.8	2,550.5				176.3		4.7	180.9
Kerosene	64.9	19.5	16.9			3.0	104.3	4.7	1.4	1.2			0.2	7.5
LPG	395.4	69.8	450.8	32.2		7.3	955.5	25.0	4.4	28.5	2.0		0.5	60.3
Lubricants														
Motor Gasoline				14,402.0		147.4	14,549.4				1,027.1		10.5	1,037.6
Residual Fuel		171.9	368.4	358.1	869.0	164.1	1,931.5		13.5	29.0	28.2	68.5	12.9	152.2
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			5.4				5.4
Petroleum Coke		0.1	586.8		69.7		656.6		0.0	59.9		7.1		67.1
Still Gas			1,417.5				1,417.5			91.0				91.0
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)	6,327.2	3,808.1	13,689.4	22,187.7	22,372.7	516.3	68,901.3	359.2	221.6	865.4	1,578.5	1,924.8	38.4	4,987.8

[a] Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-18), and international bunker fuel consumption (see Table A-19).
[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: 1993 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

	Adjusted Consumption (TBtu)[a]							[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	25.6	116.5	1,574.7	NE	17,195.9	9.6	18,922.3	2.4	11.1	147.9	NE	1,620.9	0.9	1,783.1
Residential Coal	25.6						25.6	2.4						2.4
Commercial Coal		116.5					116.5		11.1					11.1
Industrial Other Coal			1,574.7				1,574.7			147.9				147.9
Transportation Coal				NE										NE
Electric Power Coal					17,195.9		17,195.9					1,620.9		1,620.9
U.S. Territory Coal (bit)						9.6	9.6						0.9	0.9
Natural Gas	5,097.8	2,944.3	8,454.2	644.0	3,560.0	-	20,700.3	270.5	156.2	448.6	34.2	188.9		1,098.3
Total Petroleum	1,358.4	704.9	3,540.3	20,916.4	1,123.8	459.9	28,103.6	95.3	51.8	260.9	1,499.6	89.9	34.1	2,031.6
Asphalt & Road Oil														
Aviation Gasoline				38.4			38.4				2.7			2.7
Distillate Fuel Oil	884.2	447.7	1,007.2	3,886.9	86.5	104.9	6,417.3	64.7	32.7	73.7	284.3	6.3	7.7	469.4
Jet Fuel				2,366.9	NA	62.1	2,429.0				168.1		4.4	172.6
Kerosene	75.6	14.0	13.1			3.8	106.5	5.5	1.0	0.9			0.3	7.7
LPG	398.6	70.3	443.3	19.0		4.9	936.2	25.2	4.4	28.0	1.2		0.3	59.1
Lubricants														
Motor Gasoline				14,237.7		128.3	14,365.9				1,014.3		9.1	1,023.5
Residual Fuel		172.7	391.5	367.5	958.6	155.9	2,046.3		13.6	30.8	29.0	75.5	12.3	161.2
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			3.8				3.8
Petroleum Coke		0.2	601.8		78.6		680.6		0.0	61.5		8.0		69.5
Still Gas			1,401.8				1,401.8			90.0				90.0
Special Naphtha														
Unfinished Oils			(396.0)				(396.0)			(29.4)				(29.4)
Waxes														
Geothermal					57.3		57.3					0.4		0.4
TOTAL (All Fuels)	6,481.7	3,765.7	13,569.1	21,560.4	21,937.0	469.5	67,783.4	368.2	219.1	857.3	1,533.8	1,900.1	35.0	4,913.5

[a] Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-18), and international bunker fuel consumption (see Table A-19).
[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: 1992 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

	Adjusted Consumption (TBtu)[a]							[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	25.6	116.8	1,536.4	NE	16,465.6	8.8	18,153.2	2.5	11.2	144.3	NE	1,551.3	0.8	1,710.1
Residential Coal	25.6						25.6	2.5						2.5
Commercial Coal		116.8					116.8		11.2					11.2
Industrial Other Coal			1,536.4				1,536.4			144.3				144.3
Transportation Coal				NE										NE
Electric Power Coal					16,465.6		16,465.6					1,551.3		1,551.3
U.S. Territory Coal (bit)						8.8	8.8						0.8	0.8
Natural Gas	4,819.7	2,882.8	8,348.6	608.0	3,534.0	-	20,193.1	255.7	153.0	442.9	32.3	187.5		1,071.4
Total Petroleum	1,381.9	751.0	3,867.9	20,355.5	990.7	444.9	27,792.0	97.2	55.3	281.5	1,459.1	78.7	32.9	2,004.8
Asphalt & Road Oil														
Aviation Gasoline				41.1			41.1				2.8			2.8
Distillate Fuel Oil	934.4	483.3	1,049.0	3,657.7	73.5	91.8	6,289.7	68.4	35.4	76.7	267.6	5.4	6.7	460.1
Jet Fuel				2,348.7	NA	61.3	2,410.0				167.0		4.4	171.3
Kerosene	65.0	11.1	9.8			3.3	89.2	4.7	0.8	0.7			0.2	6.4
LPG	382.5	67.5	469.1	18.3		11.9	949.3	24.1	4.3	29.6	1.2		0.7	59.9
Lubricants														
Motor Gasoline				13,889.5		122.1	14,011.7				989.0		8.7	997.7
Residual Fuel		189.1	328.4	400.1	872.2	154.6	1,944.3		14.9	25.9	31.5	68.7	12.2	153.2
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			17.5				17.5
Petroleum Coke		0.1	566.6		45.0		611.7		0.0	57.9		4.6		62.5
Still Gas			1,435.7				1,435.7			92.2				92.2
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)	6,227.2	3,750.6	13,752.9	20,963.5	21,045.4	453.7	66,193.3	355.4	219.5	868.8	1,491.3	1,817.9	33.7	4,786.6

[a] Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-18), and international bunker fuel consumption (see Table A-19).
[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: 1991 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

	Adjusted Consumption (TBtu)[a]							[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	25.3	115.4	1,577.4	NE	16,249.7	7.7	17,975.6	2.4	11.0	148.0	NE	1,530.9	0.7	1,693.1
Residential Coal	25.3						25.3	2.4						2.4
Commercial Coal		115.4					115.4		11.0					11.0
Industrial Other Coal			1,577.4				1,577.4			148.0				148.0
Transportation Coal				NE										NE
Electric Power Coal					16,249.7		16,249.7					1,530.9		1,530.9
U.S. Territory Coal (bit)						7.7	7.7						0.7	0.7
Natural Gas	4,683.7	2,806.6	7,959.8	620.0	3,399.0	-	19,469.1	248.5	148.9	422.3	32.9	180.3		1,033.0
Total Petroleum	1,386.6	837.8	3,544.1	19,737.8	1,198.3	425.4	27,130.1	97.5	61.7	258.1	1,413.0	94.6	31.3	1,956.2
Asphalt & Road Oil														
Aviation Gasoline				41.7			41.7				2.9			2.9
Distillate Fuel Oil	924.8	514.3	1,064.4	3,466.5	83.6	71.4	6,124.9	67.6	37.6	77.9	253.6	6.1	5.2	448.0
Jet Fuel				2,378.1	NA	78.2	2,456.3				169.2		5.6	174.7
Kerosene	72.3	12.1	11.4			2.8	98.6	5.2	0.9	0.8			0.2	7.1
LPG	389.5	68.7	371.4	19.9		13.8	863.3	24.6	4.3	23.4	1.3		0.9	54.5
Lubricants														
Motor Gasoline		30.8	70.0	13,607.2		124.7	13,832.6		2.2	5.0	968.4		8.9	984.5
Residual Fuel		211.9	270.9	224.4	1,085.3	134.6	1,927.1		16.7	21.3	17.7	85.5	10.6	151.9
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			16.7				16.7
Petroleum Coke			539.6		29.3		569.0			55.1		3.0		58.1
Still Gas			1,404.5				1,404.5			90.2				90.2
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)	6,095.6	3,759.9	13,081.3	20,357.8	20,901.4	433.2	64,629.3	348.4	221.6	828.5	1,445.9	1,806.3	32.0	4,682.7

[a] Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-18), and international bunker fuel consumption (see Table A-19).
[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: 1990 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

	Adjusted Consumption (TBtu)[a]							[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	31.0	123.8	1,624.0	NE	16,261.0	7.0	18,046.8	2.9	11.8	152.3	NE	1,531.3	0.6	1,698.9
Residential Coal	31.0						31.0	2.9						2.9
Commercial Coal		123.8					123.8		11.8					11.8
Industrial Other Coal			1,624.0				1,624.0			152.3				152.3
Transportation Coal				NE										NE
Electric Power Coal					16,261.0		16,261.0					1,531.3		1,531.3
U.S. Territory Coal (bit)						7.0	7.0						0.6	0.6
Natural Gas	4,519.1	2,697.8	7,846.8	680.0	3,321.0	-	19,064.7	239.8	143.1	416.3	36.1	176.2		1,011.5
Total Petroleum	1,382.3	828.4	3,789.0	20,232.8	1,289.4	374.8	27,896.7	97.4	61.2	276.3	1,449.0	101.8	27.6	2,013.3
Asphalt & Road Oil														
Aviation Gasoline				45.0			45.0				3.1			3.1
Distillate Fuel Oil	953.4	522.3	1,114.4	3,570.5	96.5	74.0	6,331.1	69.7	38.2	81.5	261.2	7.1	5.4	463.1
Jet Fuel				2,486.6	NA	61.0	2,547.6				176.9		4.3	181.2
Kerosene	63.9	11.8	12.3			2.6	90.6	4.6	0.9	0.9			0.2	6.6
LPG	365.0	64.4	406.4	21.6		14.4	871.9	23.0	4.1	25.7	1.4		0.9	55.0
Lubricants														
Motor Gasoline				13,808.8		101.0	13,909.8				982.8		7.2	990.0
Residual Fuel		229.8	364.1	300.3	1,162.6	121.8	2,178.7		18.1	28.7	23.7	91.6	9.6	171.7
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			11.2				11.2
Petroleum Coke			536.2		30.4		566.6			54.8		3.1		57.9
Still Gas			1,451.9				1,451.9			93.2				93.2
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)	5,932.3	3,650.1	13,259.7	20,912.8	20,924.0	381.9	65,060.8	340.1	216.1	844.9	1,485.1	1,809.6	28.3	4,724.1

[a] Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-18), and international bunker fuel consumption (see Table A-19).
[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: Unadjusted Non-Energy Fuel Consumption (TBtu)

Sector/Fuel Type	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Industry	4,535	4,560	4,676	4,844	5,162	5,222	5,293	5,515	5,744	6,013	5,633	5,286	5,387	5,341	5,885	5,570	5,505
Industrial Coking Coal	0	0	0	0	10	44	26	0	9	46	63	26	47	72	215	110	86
Industrial Other Coal	8	8	10	10	11	11	11	11	10	11	12	11	12	12	12	12	12
Natural Gas to Chemical Plants, Other Uses	300	301	259	292	354	357	360	387	427	437	440	412	380	383	402	405	411
Asphalt & Road Oil	1,170	1,077	1,102	1,149	1,173	1,178	1,176	1,224	1,263	1,324	1,276	1,257	1,240	1,220	1,304	1,323	1,226
LPG	1,201	1,378	1,391	1,351	1,546	1,587	1,652	1,670	1,744	1,821	1,665	1,553	1,620	1,545	1,576	1,488	1,517
Lubricants	186	167	170	173	181	178	173	182	191	193	190	174	172	159	161	160	131
Pentanes Plus	83	45	62	276	258	303	316	299	204	261	237	202	171	169	170	150	107
Naphtha (<401 deg. F)	348	299	377	351	398	373	479	536	584	502	614	494	583	613	749	699	602
Other Oil (>401 deg. F)	754	827	815	844	839	801	730	861	819	811	722	662	632	699	779	708	791
Still Gas	21	22	11	28	22	40	0	2	0	16	13	36	58	59	64	68	122
Petroleum Coke	178	153	231	124	136	133	148	118	214	284	141	208	192	161	246	229	261
Special Naphtha	107	88	105	105	81	71	75	72	107	145	97	78	102	80	51	63	70
Other (Wax/Misc.)																	
Distillate Fuel Oil	7	7	7	7	7	8	9	10	12	12	12	12	12	12	12	12	12
Waxes	33	35	37	40	41	41	49	44	42	37	33	36	32	31	31	31	25
Miscellaneous Products	138	153	100	95	106	97	89	98	119	112	119	125	134	126	113	113	133
Transportation	176	157	161	163	171	168	163	172	180	182	179	164	162	150	152	151	147
Lubricants	176	157	161	163	171	168	163	172	180	182	179	164	162	150	152	151	147
U.S. Territories	87	114	63	74	55	91	121	132	135	139	165	80	139	128	111	108	110
Lubricants	1	1	1	3	2	2	1	2	1	1	16	0	1	9	5	5	5
Other Petroleum (Misc. Prod.)	86	114	61	71	53	89	120	129	134	138	149	80	137	119	106	102	105
Total	4,798	4,831	4,899	5,082	5,388	5,481	5,577	5,818	6,060	6,335	5,978	5,530	5,688	5,619	6,148	5,829	5,763

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.

Table A-19: International Bunker Fuel Consumption (TBtu)

Fuel Type	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Marine Residual Fuel Oil	716	802	670	534	524	523	536	575	595	490	444	426	290	472	553	581	599
Marine Distillate Fuel Oil & Other	158	149	146	147	121	126	114	126	159	114	86	72	70	104	144	127	119
Aviation Jet Fuel	643	647	653	661	670	708	728	780	791	821	844	828	862	830	915	953	1,004
Total	1,517	1,598	1,468	1,342	1,315	1,357	1,379	1,481	1,544	1,424	1,374	1,327	1,222	1,405	1,612	1,660	1,722

Table A-20: Key Assumptions for Estimating CO_2 Emissions

Fuel Type	C Content Coefficient (Tg C/QBtu)
Coal	
Residential Coal	[a]
Commercial Coal	[a]
Industrial Coking Coal	31.00
Industrial Other Coal	[a]
Electric Power Coal	[a]
U.S. Territory Coal (bit)	25.14
Natural Gas	14.47
Petroleum	
Asphalt & Road Oil	20.62
Aviation Gasoline	18.87
Distillate Fuel Oil	19.95
Jet Fuel	[a]
Kerosene	19.72
LPG (energy use)	[a]
LPG (non-energy use)	[a]
Lubricants	20.24
Motor Gasoline	[a]
Residual Fuel Oil	21.49
Other Petroleum	
AvGas Blend Components	18.87
Crude Oil	[a]
MoGas Blend Components	[a]
Misc. Products	[a]
Misc. Products (Territories)	20.00
Naphtha (<401 deg. F)	18.14
Other Oil (>401 deg. F)	19.95
Pentanes Plus	18.24
Petrochemical Feedstocks	19.37
Petroleum Coke	27.85
Still Gas	17.51
Special Naphtha	19.86
Unfinished Oils	[a]
Waxes	19.81
Geothermal	2.05

Sources: C coefficients from EIA (2007b).
[a] These coefficients vary annually due to fluctuations in fuel quality (see Table A-21).

Table A-21: Annually Variable C Content Coefficients by Year (Tg C/QBtu)

Fuel Type	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Residential Coal	25.92	26.00	26.13	25.97	25.95	26.00	25.92	26.00	26.00	26.00	26.00	26.00	26.00	26.00	26.00	26.00	26.00
Commercial Coal	25.92	26.00	26.13	25.97	25.95	26.00	25.92	26.00	26.00	26.00	26.00	26.00	26.00	26.00	26.00	26.00	26.00
Industrial Other Coal	25.58	25.60	25.62	25.61	25.63	25.63	25.61	25.63	25.63	25.63	25.63	25.63	25.63	25.63	25.63	25.63	25.63
Electric Power Coal	25.68	25.69	25.69	25.71	25.72	25.74	25.74	25.76	25.76	25.76	25.76	25.76	25.76	25.76	25.76	25.76	25.76
LPG (energy use)	17.21	17.21	17.21	17.22	17.22	17.20	17.20	17.18	17.23	17.25	17.20	17.21	17.20	17.21	17.20	17.19	17.19
LPG (non-energy use)	16.83	16.84	16.84	16.80	16.88	16.87	16.86	16.88	16.88	16.84	16.81	16.83	16.82	16.84	16.81	16.81	16.78
Motor Gasoline	19.41	19.41	19.42	19.43	19.45	19.38	19.36	19.35	19.33	19.33	19.34	19.34	19.35	19.33	19.33	19.33	19.33
Jet Fuel	19.40	19.40	19.39	19.37	19.35	19.34	19.33	19.33	19.33	19.33	19.33	19.33	19.33	19.33	19.33	19.33	19.33
MoGas Blend Components	19.41	19.41	19.42	19.43	19.45	19.38	19.36	19.35	19.33	19.33	19.34	19.34	19.35	19.33	19.33	19.33	19.33
Misc. Products	20.16	20.18	20.22	20.22	20.21	20.23	20.25	20.24	20.24	20.19	20.23	20.29	20.30	20.28	20.33	20.33	20.33
Unfinished Oils	20.16	20.18	20.22	20.22	20.21	20.23	20.25	20.24	20.24	20.19	20.23	20.29	20.30	20.28	20.33	20.33	20.33
Crude Oil	20.16	20.18	20.22	20.22	20.21	20.23	20.25	20.24	20.24	20.19	20.23	20.29	20.30	20.28	20.33	20.33	20.33

Source: EIA (2007b)

Table A-22: Electricity Consumption by End-Use Sector (Billion Kilowatt-Hours)

End-Use Sector	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Residential	924	955	936	995	1,008	1,043	1,083	1,076	1,130	1,145	1,192	1,202	1,265	1,276	1,292	1,359	1,354
Commercial	838	855	850	885	913	953	980	1,027	1,078	1,104	1,159	1,191	1,205	1,199	1,230	1,275	1,301
Industrial	1,070	1,071	1,107	1,116	1,154	1,163	1,186	1,194	1,212	1,230	1,235	1,159	1,156	1,181	1,186	1,174	1,157
Transportation	5	5	5	5	5	5	5	5	5	5	5	6	6	7	7	8	8
Total	2,837	2,886	2,897	3,001	3,081	3,164	3,254	3,302	3,425	3,484	3,592	3,557	3,632	3,662	3,716	3,816	3,820

Note: Does not include the U.S. territories.
Source: EIA (2007a)

2.2. Methodology for Estimating the Carbon Content of Fossil Fuels

This subannex 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 this report were developed using methods first outlined in EIA's *Emissions of Greenhouse Gases in the United States: 1987-1992* (1994) and were developed primarily by EIA. This annex describes an updated methodology for estimating the C content of coal, and presents a time-series analysis of changes in U.S. C content coefficients. A summary of C content coefficients used in this report appears in Table A- 23.

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 subannex examines C contents of petroleum products. U.S. energy consumption statistics account for more than 20 different petroleum products.

Table A- 23: Carbon Content Coefficients Used in this Report (Tg Carbon/QBtu)

Fuel Type	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Coal																	
Residential Coal[a]	25.92	26.00	26.13	25.97	25.95	26.00	25.92	26.00	26.00	26.00	26.00	26.00	26.00	26.00	26.00	26.00	26.00
Commercial Coal[a]	25.92	26.00	26.13	25.97	25.95	26.00	25.92	26.00	26.00	26.00	26.00	26.00	26.00	26.00	26.00	26.00	26.00
Industrial Coking Coal[a]	25.51	25.51	25.51	25.51	25.52	25.53	25.55	25.56	25.56	25.56	25.56	25.56	25.56	25.56	25.56	25.56	25.56
Industrial Other Coal[a]	25.58	25.60	25.62	25.61	25.63	25.63	25.61	25.63	25.63	25.63	25.63	25.63	25.63	25.63	25.63	25.63	25.63
Utility Coal[a,b]	25.68	25.69	25.69	25.71	25.72	25.74	25.74	25.76	25.76	25.76	25.76	25.76	25.76	25.76	25.76	25.76	25.76
Natural Gas	14.47	14.47	14.47	14.47	14.47	14.47	14.47	14.47	14.47	14.47	14.47	14.47	14.47	14.47	14.47	14.47	14.47
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	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	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	19.95	19.95	19.95
Jet Fuel[a]	19.40	19.40	19.39	19.37	19.35	19.34	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	19.72	19.72	19.72
LPG (energy use)[a]	17.21	17.21	17.21	17.22	17.22	17.20	17.20	17.18	17.23	17.25	17.20	17.21	17.20	17.21	17.20	17.19	17.19
LPG (non-energy use)[a]	16.83	16.84	16.84	16.80	16.88	16.87	16.86	16.88	16.88	16.84	16.81	16.83	16.82	16.84	16.81	16.81	16.78
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	20.24	20.24	20.24
Motor Gasoline[a]	19.41	19.41	19.42	19.43	19.45	19.38	19.36	19.35	19.33	19.33	19.34	19.34	19.35	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	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	18.87	18.87	18.87
Mo Gas Blend Comp[a]	19.41	19.41	19.42	19.43	19.45	19.38	19.36	19.35	19.33	19.33	19.34	19.34	19.35	19.33	19.33	19.33	19.33
Crude Oil[a]	20.16	20.18	20.22	20.22	20.21	20.23	20.25	20.24	20.24	20.19	20.23	20.29	20.30	20.28	20.33	20.33	20.33
Misc. Products[a]	20.16	20.18	20.22	20.22	20.21	20.23	20.25	20.24	20.24	20.19	20.23	20.29	20.30	20.28	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	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	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	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	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	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	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	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	19.86	19.86	19.86
Unfinished Oils[a]	20.16	20.18	20.22	20.22	20.21	20.23	20.25	20.24	20.24	20.19	20.23	20.29	20.30	20.28	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	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	19.81	19.81	19.81
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	2.05

[a]C contents vary annually based on changes in fuel composition.

[b]C 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 CO_2 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.

Coal

Approximately one-third of all U.S. CO_2 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-24.[1]

Methodology

The methodology for developing C contents for coal by consuming sector consists of four steps.

Step 1. Determine carbon contents by rank and by state of origin

C contents by rank are estimated on the basis of 6,588 coal samples collected by the U.S. Geological Survey between 1973 and 1989. 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. Dividing the C content (reported in pounds CO_2) 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. Allocate sectoral consumption by rank and state of origin

U.S. energy statistics 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. 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.

Step 3. 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 rank by the C content estimated in Step 1. The resulting partial C contents are then totaled across all states and ranks to generate a national sectoral C content.

$$C_{sector} = S_{rank1} \times C_{rank1} + S_{rank2} \times C_{rank2} + \ldots + S_{rank50} \times C_{rank50}$$

Where,

C_{sector} = The C content by consuming sector;
S_{rank} = The portion of consuming sector coal consumption attributed to a given rank in each state;
C_{rank} = The estimated C content of a given rank in each state.

[1] 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.

Table A-24: Carbon Content Coefficients for Coal by Consuming Sector and Coal Rank (Tg C/QBtu) (1990-2006)

Consuming Sector	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Electric Power	25.68	25.69	25.69	25.71	25.72	25.74	25.74	25.76	25.76	25.76	25.76	25.76	25.76	25.76	25.76	25.76	25.76
Industrial Coking	25.51	25.51	25.51	25.51	25.52	25.53	25.55	25.56	25.56	25.56	25.56	25.56	25.56	25.56	25.56	25.56	25.56
Other Industrial	25.58	25.60	25.62	25.61	25.63	25.63	25.61	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	26.13	25.97	25.95	26.00	25.92	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	28.26	28.26	28.26 [p]
Bituminous	25.43	25.45	25.44	25.45	25.46	25.47	25.47	25.48	25.47	25.48	25.49	25.49	25.49	25.49	25.49	25.49	25.49 [p]
Sub-bituminous	26.50	26.49	26.49	26.48	26.49	26.49	26.49	26.49	26.49	26.49	26.48	26.48	26.48	26.48	26.48	26.48	26.48 [p]
Lignite	26.19	26.21	26.22	26.21	26.52	26.51	26.47	26.50	26.53	26.55	26.57	26.57	26.57	26.57	26.57	26.57	26.57 [p]

[p] Preliminary

Sources: C content coefficients by consuming sector from EIA (2007a). C content coefficients by coal rank from USGS (1998) and SAIC (2007).

Step 4. 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 (consumption by rank is unavailable in U.S. energy statistics). 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.

$$N_{rank} = P_{rank1} \times C_{rank1} + P_{rank2} \times C_{rank2} + \ldots + P_{rankn} \times C_{rankn}$$

Where,

N_{rank} = The national C content by rank;
P_{rank} = The portion of U.S. coal production attributed to a given rank in 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 6,588 coal samples from USGS (1998). Data contained in the CoalQual Database are derived primarily from samples taken between 1973 and 1989, and were largely reported in State Geological Surveys.

Data on coal distribution by state and consumption by sector, as well as coal production by state and rank, was obtained from EIA (2002).

Uncertainty

C contents vary considerably by state. Bituminous coal production and sub-bituminous coal production represented 53.4 percent and 38.1 percent of total U.S. supply in 2000, respectively. C content coefficients for bituminous coal vary from a low of 90.94 kg CO_2 per MMBtu in Kansas to a high of 105.23 kg CO_2 per MMBtu in Montana. In 2000, however, just 200 tons of bituminous coal was produced in Kansas, and none was produced in Montana. In 2000, more than 60 percent of bituminous coal was produced in three states: West Virginia, Kentucky, 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-25).

Similarly, the C content coefficients for sub-bituminous coal range from 91.31 kg CO_2 per MMBtu in Utah to 98.66 kg CO_2 per MMBtu in Washington. Utah showed no sub-bituminous coal production in 2000, and Washington produced just 4,000 tons. Wyoming, however, has represented between 75 percent and 82 percent of total sub-bituminous coal production in the United States since 1990. Thus, the C content coefficient for Wyoming, based on 435 samples, dominates.

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 ±1.0 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 for U.S. coal suggest that the uncertainty in this factor is very low, on the order of ±1.0 percent.

Table A-25: Variability in Carbon Content Coefficients by Rank Across States (Kilograms CO_2 Per MMBtu)

State	Number of Samples	Bituminous	Sub-bituminous	Anthracite	Lignite
Alabama	946	92.85	-	-	99.11
Alaska	90	98.34	98.11	-	98.66
Arizona	11	-	97.52	-	-
Arkansas	70	96.52	-	-	94.98
Colorado	292	94.39	96.48	-	96.48
Georgia	35	95.03	-	-	-
Idaho	1	-	94.89	-	-
Illinois	16	93.35	-	-	-
Indiana	125	92.67	-	-	-

Iowa	89	91.94	-	-	-
Kansas	28	90.94	-	-	-
Kentucky	870	92.58	-	-	-
Louisiana	1	-	-	-	96.03
Maryland	46	94.35	-	-	-
Massachusetts	3	-	-	114.82	-
Michigan	3	92.85	-	-	-
Mississippi	8	-	-	-	98.20
Missouri	91	91.85	-	-	-
Montana	301	105.23	97.75	103.60	99.38
Nevada	2	94.39	-	-	99.84
New Mexico	167	95.25	94.89	103.92	-
North Dakota	186	-	-	-	99.56
Ohio	646	91.85	-	-	-
Oklahoma	46	92.67	-	-	-
Pennsylvania	739	93.39	-	103.65	-
Tennessee	58	92.80	-	-	-
Texas	48	-	-	-	94.76
Utah	152	96.07	91.31	-	-
Virginia	456	93.53	-	98.52	-
Washington	14	95.39	98.66	102.51	106.55
West Virginia	566	93.89	-	-	-
Wyoming	476	94.66	97.20	-	-

- No Sample Data Available
Sources: USGS (1998) and SAIC (2007).

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 (C_2H_6), propane (C_3H_8), butane (C_4H_{10}), and, to a lesser extent, pentane (C_5H_{12}) and hexane (C_6H_{14}). 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 gasoline[1] contributes to the gasoline/naphtha "octane pool," used primarily to make motor gasoline.

Raw natural gas can also contain varying amounts of non-hydrocarbon gases, such as CO_2, 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. Otherwise, inert gases will usually be left in the natural gas. Because the raw gas that is usually flared contains NGLs and CO_2, 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 natural gas can be described in five steps.

Step 1. Define pipeline-quality natural gas

In the United States, pipeline-quality natural gas is expected 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 1 percent is CO_2.

1 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.

However, there is 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 CO_2 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 CO_2). All natural gas flared for these reasons is probably "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 energy content of 1,130 Btu per standard cubic foot. 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 (and therefore 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 1,025 Btu per cubic foot, varying by less than 1 percent (1,025 to 1,031 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 appears in Table A-26.

Table A-26: 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	1,032

Source: Gas Technology Institute (1992)

C contents were then calculated for a series of sub samples stratified by heat content. C contents were developed for eight separate sub-samples based on heat content and are shown in Table A-27.

Table A-27: 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).

Step 4. Apply carbon content coefficients developed in Step 3 to pipeline natural gas

Because there is some regional variation in the energy content of natural gas consumed, 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. The result was a weighted national average of 14.47 Tg C/QBtu. This was identical to the average C content of all samples with more than 1,000 Btu per cubic foot and the average C content for all samples with a heat content between 1,025 and 1,050 Btu per cubic foot. Because those samples with a heat content below 1,000 Btu had an unusually high C content coefficient attributable to large portions of CO_2 (not seen in the median sample), they were excluded so as not to bias the C content coefficient upwards by including them in the final sample used to select a C content.

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 uncertainty 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, 14.92 Tg C/QBtu, was adopted as the coefficient for flare gas. It should be noted that the sample data set did not include any samples with more than 1,130 Btu per cubic foot.

Data Sources

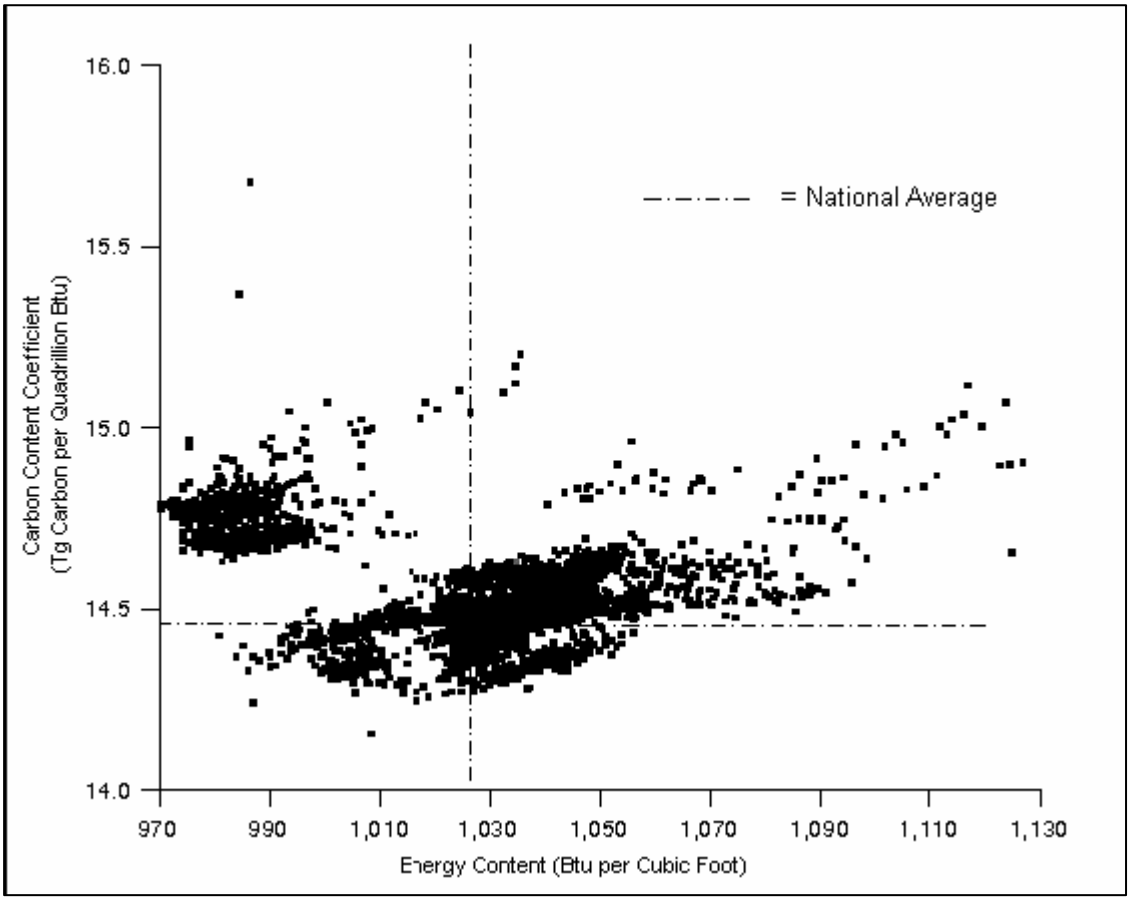
Natural gas samples were obtained from the Gas Technology Institute (1992). Average heat content data for natural gas consumed in the United States and on a state-by-state basis were taken from EIA (2007a) and EIA (2003), respectively.

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 contents 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



Source: EIA (1994).

Natural gas suppliers may achieve the same energy contents with 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 14.51 Tg C/QBtu (see Table A-27). However, this average was raised by both the samples with less than 1,000 Btu per cubic foot 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 weighted national average of 14.47 Tg C/QBtu that represents fuels more typically consumed is used.[2]

[2] The national average was weighted by applying the carbon content associated with the average heat content of natural gas consumed in each state by the portion of national natural gas consumption represented by that state.

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.

$$C_{fuel} = (D_{fuel} \times S_{fuel}) / E_{fuel}$$

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.

Petroleum products vary between 5.6 degrees API gravity (dense products such as asphalt and road oil) and 247 degrees (ethane).[3] 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): ethane is 80 percent C by weight, while petroleum coke is 90 to 92 percent C. The tightly bound range of C contents can be explained by basic petroleum chemistry.

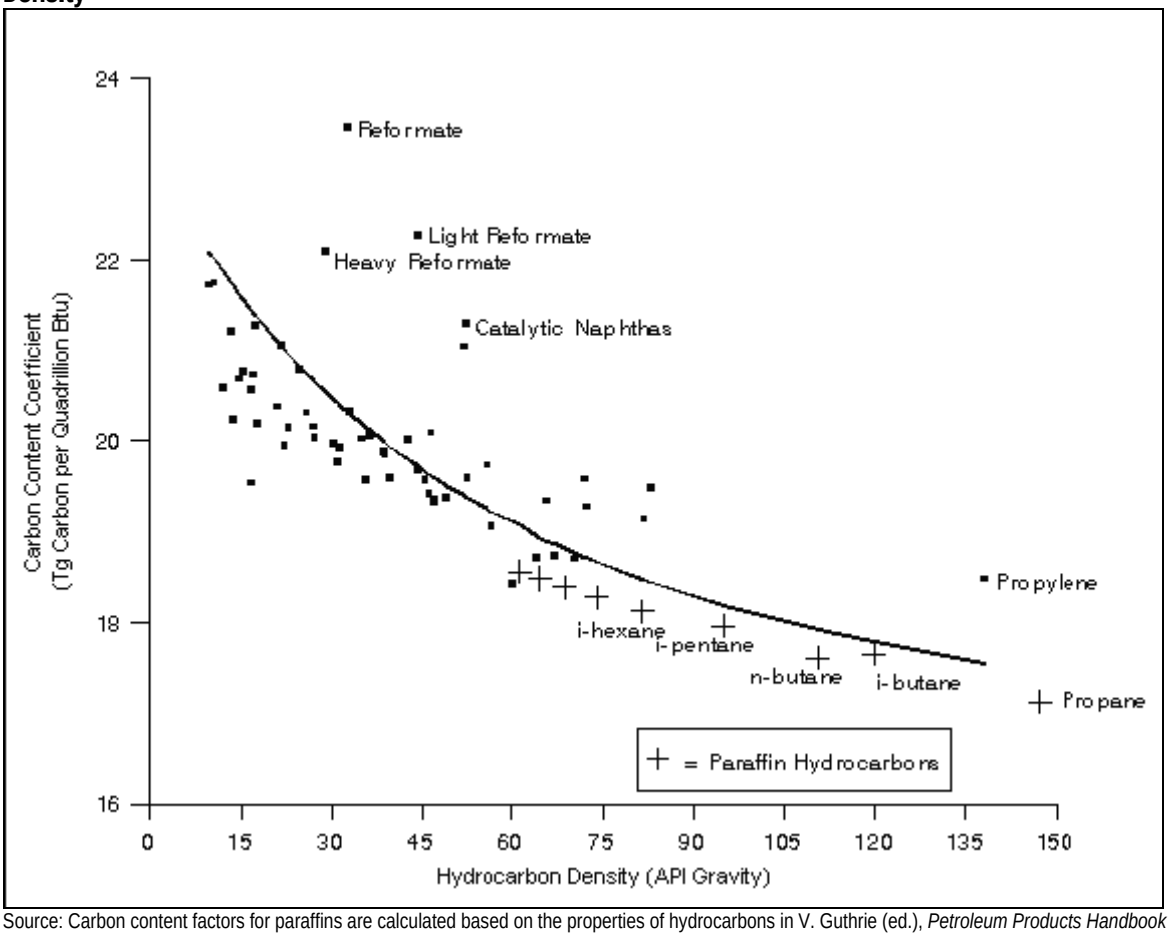
Petroleum Chemistry

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.

[3] 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: API Gravity = (141.5/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.

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.

The derived empirical relationship between C content per unit heat and density is based on the types of hydrocarbons most frequently encountered. Actual 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 80 percent C by weight, octane 84 percent. As the size of paraffin molecules increases, the C content approaches the limiting value of 85.7 percent asymptotically (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 85.7 percent C by mass, regardless of molecular size.

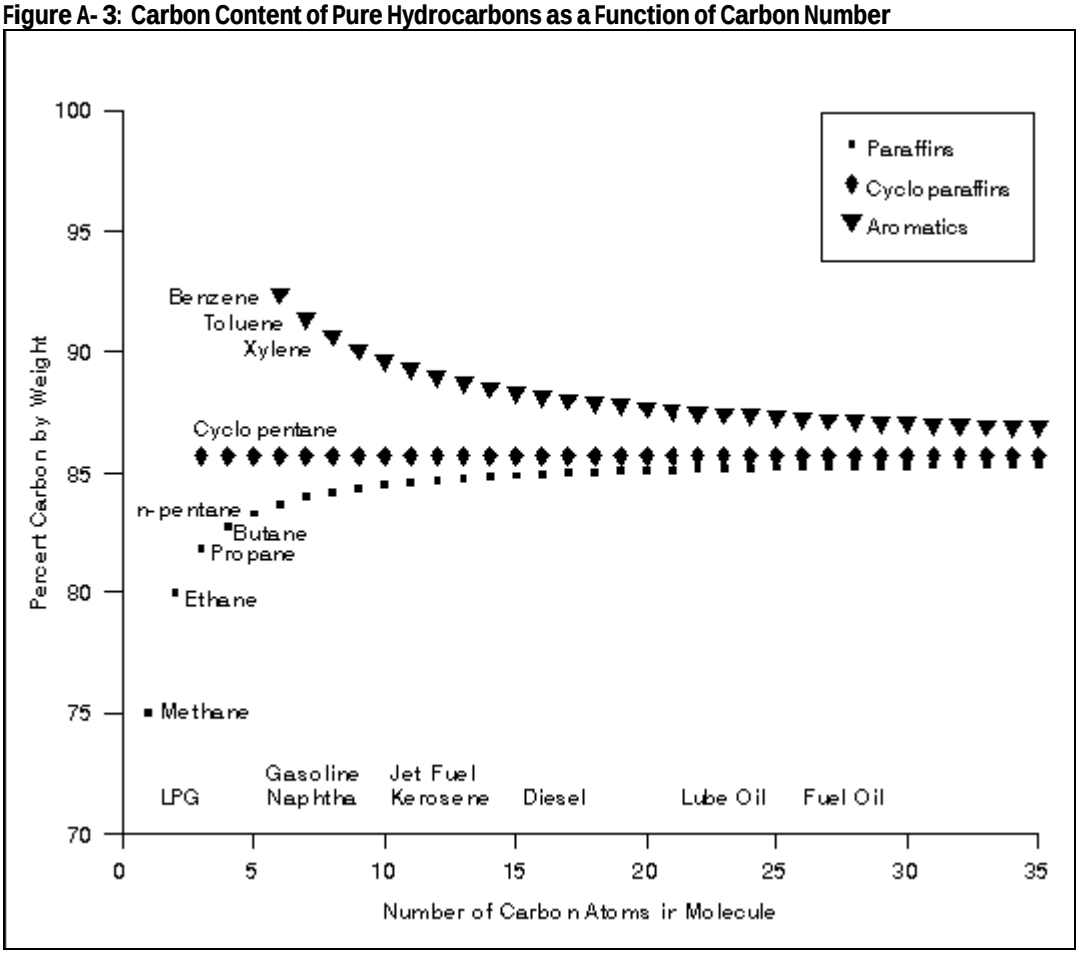
Olefins. Olefins are a reactive and unstable form of paraffin: a straight chain with the two hydrogen atoms at each end of the chain missing. They are never found in crude oil but are created in moderate quantities by the refining process. Thus, gasoline, for example, may contain 2 percent olefins. They also have the general formula C_nH_{2n}, and hence are also always 85.7 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 steam reforming of 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 percent C by mass, while xylene is 90.6 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 ($C_{10}H_2$ and 94.4 percent C by mass) and anthracene ($C_{14}H_4$ 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 are generally used as lubricants, waxes, and residual fuel oil.

Figure A- 3: Carbon Content of Pure Hydrocarbons as a Function of Carbon Number



Source: Hunt (1979).

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-28. A description of the methods and data sources for estimating the key parameters for each individual petroleum product appears below.

Table A-28: Carbon Content Coefficients and Underlying Data for Petroleum Products

Fuel	2006 Carbon Content	Gross Heat of Combustion	Density	Percent

	(Tg C/QBtu)	(MMBtu/Barrel)	(API Gravity)	Carbon
Motor Gasoline	19.33	5.218	59.1	86.60
LPG(total)	16.99	a	a	a
LPG (energy use)	17.19	a	a	a
LPG (non-energy use)	16.78	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	18.24	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-31.
[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 (2007a), and SAIC (2007).

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.[4] "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. CO_2 emissions. EIA collects consumption data (i.e., "petroleum products supplied" by wholesalers) for several types of gasoline: leaded regular, unleaded regular, and unleaded high octane. 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, which implies a range of possible C and energy contents per barrel. Table A-29 reflects changes in the density of gasoline over time and across grades of gasoline through 2006.

Table A-29: Motor Gasoline Density, 1990 – 2006 (Degrees API)

Fuel Grade	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Winter Grade																	
Low Octane	62.0	61.8	61.4	61.0	60.1	59.8	60.6	61.5	61.8	61.6	61.6	61.7	61.6	61.8	62.4	62.4	62.4
Mid Octane	60.8	60.4	60.2	59.9	59.4	59.1	59.9	60.7	61.2	61.3	61.2	61.2	61.2	61.2	61.2	61.2	61.2
High Octane	59.0	59.3	59.0	58.7	58.5	58.0	58.5	59.3	60.0	60.3	59.7	59.1	59.0	59.9	60.7	60.7	60.7
Summer Grade																	
Low Octane	58.2	58.0	57.4	56.1	55.7	56.1	56.9	57.1	57.6	57.7	56.8	57.2	56.5	56.8	57.4	57.4	57.4
Mid Octane	57.4	57.1	56.4	55.5	54.8	55.6	56.2	56.6	56.7	57.4	58.0	58.0	58.0	58.0	58.0	58.0	58.0
High Octane	55.5	55.7	55.6	54.4	53.8	55.1	55.3	56.4	55.7	57.4	55.8	55.5	55.7	56.0	57.0	57.0	57.0

Source: National Institute of Petroleum and Energy Research (1990 through 2006).

[4] 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.

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 used in gasoline 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. In reformulated gasoline, methyl tertiary butyl ether (MTBE) and tertiary amyl methyl ether (TAME) are often added to standard gasoline to boost its oxygen content. The increased oxygen reduces 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 2001 contained 8 percent MTBE and 0.5 percent TAME. The characteristics of reformulated fuel additives appear in Table A-30.

Table A-30: Characteristics of Major Reformulated Fuel Additives

Additive	Density (Degrees API)	Carbon Share (Percent)	Carbon Content (Tg C/QBtu)
MTBE	59.1	68.2	16.92
ETBE	59.1	70.5	17.07
TAME	52.8	70.5	17.00

Source: API (1988).

Methodology

Step 1. Disaggregate U.S. gasoline consumption by grade and type

U.S. gasoline consumption was divided by product grade and season for both standard gasoline and reformulated gasoline.

Step 2. Develop carbon content coefficients for each grade and type

C content coefficients for each grade and type are derived from three parameters: gasoline density, share of the gasoline mixture that is C; and the energy content of a gallon of gasoline. C content coefficients for reformulated fuels were calculated by applying the C content coefficient for the fuel additives listed in Table A-30 to the increased share of reformulated gasoline represented by these additives (standard gasoline contains small amounts of MTBE and TAME) and weighting the gasoline C content accordingly.

Step 3. Weight overall gasoline carbon content coefficient for consumption of each grade and type

The C content for each grade and type of fuel is multiplied by the share of overall consumption represented by the grade and fuel type. Individual coefficients are then summed and totaled to yield an overall C content coefficient.

Data Sources

Data for the density of motor gasoline were obtained from the National Institute for Petroleum and Energy Research (1990 through 2006). Data on the characteristics of reformulated gasoline were taken from API (1988). C contents of motor gasoline were obtained from the following: DeLuchi (1993), Applied Systems Corporation (1976), Ward, C.C. (1978), and Rose and Cooper (1977).

Standard heat contents for motor gasoline of 5.253 MMBtu per barrel conventional gasoline and 5.150 MMBtu per barrel reformulated gasoline were adopted from EIA (2007a).

Uncertainty

There are two primary contributors to the uncertainty of C content coefficients for motor gasoline. The first is the small number of motor gasoline samples and ultimate analyses from Deluchi et al. 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.

The second 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, which show a variation in density of ±1.5 percent.

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 represents a consumption-weighted combination of the naphtha-based and kerosene-based coefficients.

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 and C share of kerosene-based jet fuels was based on the average composition of 39 fuel samples taken by Boeing Corporation (the leading U.S. commercial airline manufacturer) in 1989. 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

The C content for each jet fuel type is multiplied by the share of overall consumption of that fuel type. Individual coefficients are then summed and totaled to yield an overall C content coefficient

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 (2007a). Data on the C content and density of kerosene-based jet fuel was taken from Hadallar and Momenthy (1990).

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.

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 the purposes of this report, the C content of No. 2 fuel oil is assumed to typify the C content of distillate fuel generally. The C share in No. 2 fuel oil was estimated based on the average of 11 ultimate analyses. This C share was combined with EIA's standard heat content of 5.825 MMBtu per barrel and the density of distillate assumed to be 35.5 degrees API, in accord with its heat content.

Data Sources

Data on C contents and density were derived from four samples from C. T. Hare and R.L. Bradow (1979). Samples were taken from the following sources: Funkenbush, et al. (1979), Mason (1981), and Black and High (1979).

A standard heat content was adopted from EIA (2007a).

Uncertainty

The primary source of uncertainty for the estimated C content of distillate fuel is the selection of No.2 fuel oil as the typical distillate fuel. No.2 fuel oil is generally consumed for home heating. No.1 fuel oil is generally less dense and if it is consumed in large portions for mobile sources, the C content estimated for this report is likely to be too high. The five No.1 fuel oil samples obtained by EIA contained an average of 86.01 percent C compared to the 86.34 percent contained in samples of No.2 fuel oil. A C content coefficient based on No.1 fuel oil would equal 19.72 Tg C/QBtu rather than the 19.95 Tg C/QBtu for No. 2 fuel oil. There is also small uncertainty in the share of C based on the limited sample size of ±1 percent.

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 a 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 and an average sulfur content of 1 percent (EIA 2001). This implies a density of about 17 degrees API.

Methodology

For this report, residual fuel was defined as No.6 fuel oil. The National Institute of Petroleum and Energy Research, Fuel Oil Survey shows an average density for fuel oil of 11.3 API gravity and anecdotal evidence suggests that marine residual fuel is also very dense, with typical gravity of 10.5 to 11.5 degrees API (EIA 1993). Because the largest share of fuel oil consumption is for marine vessels, a density of 11 degrees API was adopted when developing the C content coefficient for this report. An average share of C in residual fuel of 85.67 percent by mass was used based on ultimate analyses of a dozen samples.

Data Sources

Data on C content were derived from three samples of residual fuel from the Middle East and one sample from Texas. These data were found in Mosby, et al. (1976). Three samples of heavy fuel oils were taken from Longwell (1991); three samples from Ward (1978); two samples from Vorum (1974); and one sample from Rose and Cooper (1977). Density of residual fuel consumed for electric power generation was obtained from EIA (2001).

Density of residual fuel consumed in marine vessels was obtained from EIA (1993). A standard heat content was adopted from EIA (2007a).

Uncertainty

The largest source of uncertainty for estimating the C content of residual fuel centers on the estimates of density, which differ from power generation to marine vessel fuels. The difference between the density implied by the energy content of utility fuels and the density observed in the NIPER surveys is probably due to nonsulfur impurities, which reduce the energy content without greatly affecting the density of the product. Impurities of several percent are commonly observed in residual oil. The presence of these impurities also affects the share of the fuel that is C. 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) and the atomic weight of hydrogen (1). Thus, for example, the C share of propane, C_3H_8, is 81.8 percent. The densities and heat content of the compounds are also well known allowing C content coefficients to be calculated directly. Table A-31 summarizes the physical characteristic of LPG.

Table A-31: 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_2H_6	16.88	80.0	2.916	16.25
Propane	C_3H_8	12.44	81.8	3.824	17.20
Isobutane	C_4H_{10}	11.20	82.8	4.162	17.75
n-butane	C_4H_{10}	10.79	82.8	4.328	17.72

Source: Guthrie (1960).

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 compound 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 compound 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-32.

Data Sources

Data on C share, density, and heat content of LPG was obtained from Guthrie (1960). LPG consumption was based on data obtained from API (1990-2006) and EIA (2007b). Non-fuel use of LPG was obtained from API (1990 through 2006).

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 consumption data and non-fuel data in U.S. energy statistics. This uncertainty is probably less than ±3 percent.

Table A-32: Consumption and Carbon Content Coefficients of Liquefied Petroleum Gases, 1990-2006

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Energy Consumption (QBtu)																	
Fuel Use	0.86	0.86	0.94	0.94	0.96	0.93	1.02	1.03	0.84	1.09	1.29	1.15	1.24	1.21	1.25	1.20	1.17
Ethane	0.03	0.02	0.03	0.02	0.02	0.03	0.03	0.05	0.00	0.00	0.08	0.05	0.05	0.05	0.05	0.04	0.05
Propane	0.75	0.79	0.84	0.86	0.86	0.86	0.95	0.92	0.80	0.97	1.08	1.01	1.10	1.07	1.13	1.08	1.06
Butane	0.08	0.05	0.07	0.06	0.07	0.05	0.04	0.05	0.04	0.11	0.14	0.10	0.09	0.09	0.07	0.07	0.06
Non-Fuel Use	1.20	1.38	1.39	1.35	1.55	1.59	1.65	1.67	1.74	1.82	1.67	1.55	1.62	1.55	1.58	1.49	1.49
Ethane	0.55	0.62	0.62	0.65	0.65	0.68	0.74	0.71	0.73	0.82	0.80	0.73	0.77	0.70	0.74	0.70	0.75
Propane	0.53	0.59	0.61	0.55	0.65	0.67	0.65	0.71	0.77	0.77	0.66	0.59	0.65	0.63	0.66	0.64	0.62
Butane	0.13	0.17	0.16	0.15	0.25	0.24	0.26	0.25	0.24	0.22	0.21	0.23	0.21	0.22	0.17	0.15	0.15
Carbon Content (Tg C/QBtu)																	
Fuel Use	17.21	17.21	17.21	17.22	17.22	17.20	17.20	17.18	17.23	17.25	17.20	17.21	17.20	17.21	17.20	17.19	17.19
Non-Fuel Use	16.83	16.84	16.84	16.80	16.88	16.87	16.86	16.88	16.88	16.84	16.81	16.83	16.82	16.84	16.81	16.81	16.78

Sources: Fuel use of LPG based on data from EIA (2007b) and API (1990 through 2006). Non-fuel use of LPG from API (1990 through 2006). C contents from EIA (2007a).

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. To estimate the share of C in the fuel, it was assumed that aviation gasoline is 87.5 percent isooctane, 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 percent and a C content coefficient of 18.87 Tg C/QBtu.

Data Sources

Data sources include ASTM (1985). A standard heat content for aviation gas was adopted from EIA (2007a).

Uncertainty

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. 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 EIA obtained data on four samples of still gas. Table A-33 below shows the composition of those samples.

Table A-33: 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

Because gas streams with a large free hydrogen content are likely to be used as refinery or chemical feedstocks, EIA selected the C content coefficient from the sample with the lowest hydrogen content as the representative value for still gas.

Data Sources

Data sources include one still gas sample from American Gas Association (1974) and three still gas samples from Guerra, et al. (1979).

Uncertainty

Because the composition of still gas is highly heterogeneous, the C content coefficient for this product is highly uncertain, with an accuracy of ±33 percent. The C content coefficient used for this report is probably at the high end of the plausible range.

Asphalt

Asphalt is used to pave roads. Because most of its C is retained in those roads, it is a small source of emissions. It is derived from a class of hydrocarbons called "asphaltenes," 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 other hydrocarbons.

Methodology

Ultimate analyses of twelve samples of asphalts showed an average C content of 83.5 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 20.62 Tg C/QBtu.

Data Sources

A standard heat content for asphalt was adopted from EIA (2007a). The density of asphalt was determined by the ASTM (1985).

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. Ultimate analysis of a single sample of motor oil yielded a C content of 85.8 percent. A standard heat content of 6.065 MMBtu per barrel was adopted from EIA. These factors produce a C content coefficient of 20.24 Tg C/QBtu.

Data Sources

A standard heat content was adopted from the EIA (2007a). The density of asphalt 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 just under 20.0 Tg C/QBtu to about 21.5 Tg C/QBtu or an uncertainty band from –1 percent to + 6 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 400 degrees Fahrenheit and above.

Methodology

The method for estimating the C content of petrochemical feedstocks includes three 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 and an average density of 67.1 degrees API gravity. The standard EIA heat content of 5.248 MMBtu per barrel is used to estimate a C content coefficient of 18.14 Tg C/QBtu.

Step 2. Estimate the carbon content coefficient for petrochemical feedstocks with a boiling temperature 400 degrees Fahrenheit and above

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. Thus, the C content coefficient of 19.95 Tg C/QBtu used for distillate fuel is also adopted for this portion of petrochemical feedstocks.

Step 3. Weight the carbon content coefficients for the two classes of petrochemical feedstock by consumption

The weighted average of the two C content coefficients for petroleum feedstocks equals 19.37 Tg C/QBtu.

Data Sources

Data on the C content and density of naphtha was taken from Unzelman (1992). A standard heat content for petrochemical feedstock was adopted from EIA (2007a).

Uncertainty

Petrochemical feedstocks are not so much distinguished on the basis of chemical composition as on the identity of the purchaser, who may be presumed to be a chemical company or a petrochemical unit co-located on the refinery grounds. This produces a considerable degree of uncertainty about the exact composition of petrochemical feedstocks. Since the C content coefficient for petrochemical feedstocks is a weighted average of the coefficients for naphtha and some class of middle distillates, the accurate coefficient is likely bounded by the two individual coefficients, suggesting an uncertainty of ±6 percent.

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 fuel oil.

Methodology

The average density of 41.4 degrees API and average C share of 86.01 percent found in five ultimate analyses of No. 1 fuel oil samples were applied to a standard heat content of 5.670 MMBtu per barrel to yield a C content coefficient of 19.72 Tg C/QBtu.

Data Sources

A standard heat content was adopted from EIA (2007a).

Uncertainty

Uncertainty in the estimated C content for kerosene is driven by the selection of No. 1 fuel oil as a proxy for kerosene. If kerosene is more like kerosene-based jet fuel, the true C content coefficient is likely to be some 2 percent lower. If kerosene is more aptly compared to No. 2 fuel oil, then the true C content coefficient is likely to be about 1 percent higher.

Petroleum Coke

Petroleum coke is the solid residue by-product of the extensive processing of crude oil. It is a coal-like solid, usually with a C content greater than 90 percent, that 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 92.3 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 (2007a).

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 83.7 percent C. Its density is 76.6 degrees API or 5.649 pounds per gallon and its derived C content coefficient is 17.17 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-34, below.

Table A-34: Characteristics of Non-hexane Special Naphthas

Special Naphtha	Aromatic Content (Percent)	Density (Degrees API)	Carbon Content (Percent)	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

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 19.86 Tg C/QBtu.

Data Sources

A standard heat content for special naphtha was adopted from EIA (2007a). 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 hexane and on the upper end by the C content of high solvency mineral spirits. This implies an uncertainty band of –15 percent to +6 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 85.29 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 19.81 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 (2007a).

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

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, 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.[1] When C content was adjusted to exclude sulfur, the R-squared value rose to 0.65. While sulfur is the most important nonhydrocarbon 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 2001 crude oil quality data (30.49 degrees API and 1.42 percent sulfur) produces an estimated C content of 85.81 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 20.33 Tg C/QBtu.

Data Sources

C content was derived from 150 crude oil samples from U.S. National Research Council (1927). A standard heat content for crude oil was adopted from EIA (2007a).

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

The estimates of C content coefficients for coal were updated and revised in 2006. The methodology employed for these estimates was unchanged from previous years; however, the underlying coal data sample set was updated. Previously a set of 5,426 coal samples from the EIA Coal Analysis File was used to develop C content estimates. The results from that sample set appear below in Table A-35. 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. The updated sample set included 6,588 coal samples collected by the U.S. Geological Survey between 1973 and 1989.

[1] R-squared represents the percentage of variation in the dependent variable (in this case carbon content) explained by variation in the independent variables.

Petroleum Products

Jet Fuel

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 Momenthy 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.

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 is about 2 percent higher than the coefficient for non-fuel use.

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.

Table A-35: Carbon Content Coefficients for Coal by Consuming Sector and Coal Rank [p], 1990-2006 (Tg C/QBtu)

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
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	25.76	25.76	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	25.56	25.56	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	25.63	25.63	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	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	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	25.49	25.49	25.49	25.49	25.49	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	26.48	26.48	26.48	26.48	26.48	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	26.30	26.30	26.30	26.30	26.30	26.30

[p] (Preliminary)

Sources: C content coefficients by consuming sector from EIA (2007a). C content coefficients by coal rank from USGS (1998) and SAIC (2007).

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2.3. Methodology for Estimating Carbon Emitted from Non-Energy Uses of Fossil Fuels

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-36. The remaining C—i.e., that which is not stored—is emitted. This subannex 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 factors[11] 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-36: 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]	62
Natural Gas to Chemical Plants [b]	62
Asphalt & Road Oil	100
LPG [b]	62
Lubricants	9
Pentanes Plus [b]	62
Naphtha (<401 deg. F) [b]	62
Other Oil (>401 deg. F) [b]	62
Still Gas [b]	62
Petroleum Coke[c]	50
Special Naphtha [b]	62
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 2006. As described in this annex, the factor varies over time.

[c] Includes processes for which specific petroleum coke consumption and emission factor data are not available (e.g., C fibers and textiles, refractory, electric motor parts, brake parts, batteries). 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.

[11] 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 CH_4) to heavier, more complex naphthas and other oils.[12]

After adjustments for (1) use in industrial processes and (2) net exports, these eight fuel categories constituted approximately 215.6 Tg CO_2 Eq., or 57 percent, of the 377.6 Tg CO_2 Eq. of non-energy fuel consumption in 2006. For 2006 the storage factor for the eight fuel categories was 62 percent. In other words, of the net consumption, 62 percent was destined for long-term storage in products—including products subsequently combusted for waste disposal—while the remaining 38 percent was emitted to the atmosphere directly as CO_2 (e.g., through combustion of industrial byproducts) or indirectly as CO_2 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 CO_2 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* (EIA 2007) 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 2006.

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.

[12] 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.

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 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 the mass balance already incorporated cross-boundary flows (through the use of consumption data) or not, and to adjust the import/export balance accordingly.

The BoC trade statistics are publicly available[13] and cover a complete time series from 1990 to 2006. 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-37. As shown in the table, the United States has been a net exporter of chemical intermediates and products throughout the 1990 to 2006 period.

Table A-37: Net Exports of Petrochemical Feedstocks, 1990 – 2006 (Tg CO_2 Eq.)

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Net Exports	11.8	13.4	12.7	15.0	12.6	13.9	11.5	13.6	8.9	8.7	8.5	1.9	7.3	15.0	20.4	6.7	3.5

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-37) 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-

[13] See the U.S International Trade Commission (USITC) Trade Dataweb at <http://dataweb.usitc.gov/>.

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.[14]

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 (the inputs to the system) for some years in the time series.[15] 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 CO_2 from waste combustion are accounted for separately in the Inventory and are discussed in the Waste Combustion 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-38. Summing the C stored and dividing it by total C outputs yields the overall storage factor, as shown in the following equation for 2006:

$$\text{Overall Storage Factor} = \text{C Stored} / (\text{C Stored} + \text{C Emitted}) =$$

$$150.3 \text{ Tg } CO_2 \text{ Eq.} / (150.3 + 94.0) \text{ Tg } CO_2 \text{ Eq.} = 62\%$$

Table A-38: C Stored and Emitted by Products from Feedstocks in 2006 (Tg CO_2 Eq.)

Product/Waste Type	C Stored (Tg CO_2 Eq.)	C Emitted (Tg CO_2 Eq.)
Industrial Releases	0.4	5.5
TRI Releases	0.4	1.0
Industrial VOCs		2.3
Non-combustion CO		0.7
Hazardous Waste Incin.		1.5
Energy Recovery		71.9
Products	149.9	16.6
Plastics	127.7	-
Synthetic Rubber	12.0	-
Abraded tire rubber	-	0.7
Synthetic Fiber	9.4	-
Pesticides	0.3	0.2
Soaps, shampoos, detergents	-	5.7
Food additives	-	0.9

[14] 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.

[15] Overall, there was fairly close agreement between inputs and outputs; for the entire 1990 through 2006 time series, inputs exceeded outputs by 0.5 percent. During the period 1990 through 1999, carbon inputs exceeded carbon outputs (i.e., the sum of carbon stored and carbon emitted), and for those years, the assumption was made that the "missing" carbon was lost through fates leading to emissions.

Antifreeze and deicers	-	1.2
Silicones	0.5	-
Solvent VOCs	-	7.9
Total	150.3	94.0

- 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.

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 2000). 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."[16] The C released in each disposal location is provided in Table A-39.

Each on-site classification was assigned a storage factor. A one hundred 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 CO_2 (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 2006 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-39: 1998 TRI Releases by Disposal Location (Gg CO_2 Eq.)

Disposal Location	Carbon Stored (Gg CO_2 Eq.)	Carbon Emitted (Gg CO_2 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

[16] 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).

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 the Air Emissions Trends Report data (EPA 2006a). The 1990-2006 Trends Report data include information on NMVOC emissions by end-use category; some of these fall into the heading of "industrial releases" in Table A-39 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 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-40 for 1990 through 2006. Solvent evaporation emissions in 2006 were 7.9 Tg CO_2 Eq., and industrial NMVOC emissions in 2006 were 2.3 Tg CO_2 Eq. In 2006, NMVOC and solvent activity data were revised across the entire time series to reflect updated information from the 2006 National Air Quality and Emissions Trends Report.

Table A-40: Industrial and Solvent NMVOC Emissions

	1990	1995	2000	2001	2002	2003	2004	2005	2006
Industrial NMVOCs[a]									
NMVOCs ('000 Short Tons)	909	1,352	791	804	838	849	810	828	815
Carbon Content (%)	85%	85%	85%	85%	85%	85%	85%	85%	85%
Carbon Emitted (Tg CO_2 Eq.)	2.6	3.8	2.2	2.3	2.4	2.4	2.3	2.3	2.3
Solvent Evaporation[b]									
Solvents ('000 Short Tons)	5,750	6,183	4,832	5,012	4,278	4,257	4,248	4,240	4,231
Carbon Content (%)	56%	56%	56%	56%	56%	56%	56%	56%	56%
Carbon Emitted (Tg CO_2 Eq.)	10.8	11.6	9.0	9.4	8.0	8.0	8.0	7.9	7.9

[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 Air Emissions Trends Report data (EPA 2006a). 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 CO_2) emissions from oil and gas production, petroleum refining, and asphalt manufacturing are also accounted for elsewhere in this Inventory. Sustainably harvested biogenic emissions (e.g., pulp and paper process emissions) are also 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 included in the calculation of the petrochemical feedstocks storage factor. Table A-41 lists the CO emissions that remain after taking into account the exclusions listed above.

Table A-41: Non-Combustion Carbon Monoxide Emissions[a]

Year	CO Emitted (Thousand Short Tons)	Carbon Emitted (Tg CO_2 Eq.)
1990	489	0.7
1991	441	0.6
1992	454	0.6
1993	486	0.7
1994	481	0.7
1995	481	0.7
1996	552	0.8
1997	570	0.8
1998	567	0.8
1999	605	0.9
2000	623	0.9
2001	650	0.9
2002	492	0.7
2003	492	0.7
2004	492	0.7
2005	492	0.7
2006	492	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).[17] 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.

[17] [42 U.S.C. §6924, SDWA §3004]

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, 2004, 2006b, 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 Comubstion 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, and 2005 (EPA 2000a, 2004, 2006b, 2007a). Values for 2006 were held constant at the 2005 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-42). 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 2005 were 1.5 Tg CO_2 Eq. Table A-43 lists the CO_2 emissions from hazardous waste incineration.

Table A-42: 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-43: CO_2 Emitted from Hazardous Waste Incineration (Tg CO_2 Eq.)

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
CO_2 Emissions	1.1	1.1	1.1	1.2	1.5	1.7	1.7	1.8	1.6	1.4	1.4	1.4	1.4	1.5	1.5	1.5	1.5

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, and 2002 (EIA 1994, 1997, 2001b, 2004). 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 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; 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. 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-44). 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 CO_2. Petrochemical feedstocks combusted for energy recovery corresponded to 42.7 Tg CO_2 Eq. in 1991, 35.8 Tg CO_2 Eq. in 1994, 58.7 Tg CO_2 Eq. in 1998, and 71.9 Tg CO_2 in 2002. Values for petrochemical feedstocks burned for energy recovery for years between 1991 and 1994, between 1994 and 1998, and between 1998 and 2002 have been estimated by interpolation. The value for 1990 is assumed to be the same as the value for 1991, and values for years subsequent to 2002 are assumed to be the same as the value for 2002 (Table A-45).

Table A-44: Summary of 2002 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	1
Petroleum and Coal Products	324	0	2	1396	89	67
Chemicals	325	483	10	0	261	394
Plastics and Rubber Products	326	0	0	0	4	1
Nonmetallic Mineral Products	327	0	0	0	0	43
Primary Metals	331	1	1	0	31	4
Fabricated Metal Products	332	0	0	0	0	2
Machinery	333	0	0	0	2	2
Computer and Electronic Products	334	0	0	0	1	1
Electrical Equip., Appliances, Components	335	0	0	0	1	0
Transportation Equipment	336	1	0	0	7	18
Furniture and Related Products	337	0	8	0	1	2
Miscellaneous	339	0	0	0	1	1
Total (Trillion Btu)		485	21	1396	397	536
Average C Content (Tg/QBtu)		18.14	20.62	17.51	0	19.37
Fraction Oxidized		1	1	1	0	1
Total C (Tg)		8.80	0.43	24.44		10.38
Total C (Tg) (ex. still gas from refining)		8.80	0.43	0.00		10.38

[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-45: Carbon Emitted from Fuels Burned for Energy Recovery (Tg CO_2 Eq.)

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
C Emissions	42.7	42.7	40.4	38.1	35.8	41.5	47.2	53.0	58.7	62.0	65.3	68.6	71.9	71.9	71.9	71.9	71.9

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 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). Production was organized by resin type (see Table A-46) 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 formulas and are listed in Table A-47 and Table A-48. 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 engineering resins and 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. However, an estimate of emissions related to the combustion of these plastics in the municipal solid waste stream can be found in the Waste Combustion section of the Energy chapter.

Table A-46: 2006 Plastic Resin Production (Tg dry weight) and C Stored (Tg CO_2 Eq.)

Resin Type	2006 Production[a] (Tg dry weight)	Carbon Stored (Tg CO_2 Eq.)
Epoxy	0.28	0.8
Urea	0.71	0.9
Melamine	0.71	0.8
Phenolic	1.99	5.6
Low-Density Polyethylene (LDPE)	3.25	10.2
Linear Low-Density Polyethylene (LLDPE)	5.41	17.0
High Density Polyethylene (HDPE)	7.30	22.9
Polypropylene (PP)	7.57	23.8
Acrylonitrile-butadiene-styrene (ABS)	0.51	1.6
Other Styrenics [c]	0.72	2.4
Polystyrene (PS)	2.59	8.8
Nylon	0.5	1.2
Polyvinyl chloride (PVC) [b]	6.17	8.7
Thermoplastic Polyester	3.29	7.5
Engineering Resins	1.10	2.7
All Other (including Polyester (unsaturated))	5.13	12.8
Total	47.23	127.7

[a] Originally included production from Canada for Urea, Melamine, LDPE, LLDPE, HDPE, PP, ABS, SAN, Phenolic, Other Styrenics, PS, Nylon, PVC, Thermoplastic Polyester, and Engineering Resins, and production from Mexico for 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-47: 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-48)
Polyvinyl Chloride (PVC)	38%	Polyvinyl chloride
Thermoplastic Polyester	63%	Polyethylene terephthalate
Engineering Resins	68%	Weighted average of other resin production

All Other	68%	Weighted average of other resin production

*Does not include alcoholic hydrogens.

Table A-48: 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's (RMA) Scrap Tire Management Council (STMC). The market information is presented in the report *Scrap Tire Markets in the United States 2005 Edition* (RMA 2006), while the tire composition information is from the "Scrap Tires, Facts and Figures" section of the organization's website (STMC 2003). 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 2003, 2005, and 2007b) 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 5 lbs per scrap tire, while the abraded rubber from scrap truck tires was assumed to be 20 lbs per scrap tire. Data on abraded rubber weight were obtained by calculating the average weight difference between new and scrap tires (STMC 2003).

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-49). 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 Waste Combustion section of the Energy chapter.

Table A-49: 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* (APC 2001, 2003, 2005 through 2007). These data are organized by year and fiber type. For each fiber, a C content was assigned based on molecular formula (see Table A-50). 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 because much of their C is of biogenic origin. 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 Waste Combustion section of the Energy chapter.

Table A-50: 2006 Fiber Production (Tg), C Content (%), and C Stored (Tg CO_2 Eq.)

Fiber Type	Production (Tg)	C Content	C Stored (Tg CO_2 Eq.)
Polyester	1.3	63%	2.87
Nylon	1.0	64%	2.39
Olefin	1.3	86%	4.06
Acrylic	+	68%	0.06
Total	3.6	-	9.38

+ 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 1998b, 1999b, 2002c, 2004b) reports. The most recent data available were for 2001, so it was assumed that the 2002 through 2006 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 2002 total pesticide active ingredient consumption was not specified by chemical type in the *Sales and Usage* report (EPA 2004b). 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-51: Active Ingredient Consumption in Pesticides (Million lbs.) and C Emitted and Stored (Tg CO_2 Eq.) in 2001

Pesticide Use*	Active Ingredient (Million lbs.)	C Emitted (Tg CO_2 Eq.)	C Stored (Tg CO_2 Eq.)
Agricultural Uses [a]	458.5	0.1	0.2
Non-Agricultural Uses [b]	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 CO_2 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, and 2002 Economic Census. Consumption values for 1990 and 1991 were assumed to be the same as the 1992 value; consumption was interpolated between 1992 and 1997 and between 1997 and 2002; consumption for 2003 through 2006 was assumed to equal the 2002 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 liquid[18] cleanser categories, respectively.

Next, the total tonnage of cleansers was calculated (wet and dry combined). Multiplying the mean C content (21.9 percent) by this value yielded an estimate of 4.5 Tg CO_2 Eq. in cleansers for 1997. For 1992 and 2002 the estimates are 3.6 Tg CO_2 Eq. and 5.1 Tg CO_2 Eq. Estimates for other years are based on these values as described above, and are shown in Table A-52.

Table A-52: C Emitted from Utilization of Soaps, Shampoos, and Detergents (Tg CO_2 Eq.)

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
C Emissions	3.6	3.6	3.6	3.8	4.0	4.2	4.3	4.5	4.5	4.2	4.3	4.7	5.1	4.8	4.7	4.7	5.7

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 CO_2 or to otherwise biodegrade to CO_2. 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 2005, 2006, 2007). 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.

The consumption of glycol compounds in antifreeze and deicing applications is assumed to be 100 percent emitted as CO_2. Emissions of CO_2 from utilization of antifreeze and deicers are summarized in Table A-53.

[18] A density of 1.05 g/mL—slightly denser than water—was assumed for liquid cleansers.

Table A-53: C Emitted from Utilization of Antifreeze and Deicers (Tg CO_2 Eq.)

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
C Emissions	1.1	1.1	1.1	1.1	1.2	1.2	1.2	1.3	1.3	1.3	1.3	1.1	1.1	1.2	1.3	1.1	1.2

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 CO_2 or to otherwise biodegrade to CO_2. 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 not considered in this analysis.

Annual production data for food additive compounds were obtained from the Guide to the Business of Chemistry (ACC 2005, 2006, 2007). 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 website.[19] The consumption of synthetic food additives is assumed to be 100 percent emitted as CO_2. Emissions of CO_2 from utilization of synthetic food additives are summarized in Table A-54.

Table A-54: C Emitted from Utilization of Food Additives (Tg CO_2 Eq.)

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
C Emissions	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.8	0.7	0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.9

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 CO_2 in the manufacturing process. It is also assumed that the C contained in the silicone products is stored, and not emitted as CO_2.

Annual production data for each silicone manufacturing compound were obtained from the Guide to the Business of Chemistry (ACC 2005, 2006, 2007). 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. The consumption of silicone manufacturing compounds is assumed to be 100 percent stored, and not emitted as CO_2. Storage of silicone manufacturing compounds is summarized in Table A-55.

Table A-55: C Stored in Silicone Products (Tg CO_2 Eq.)

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
C Storage	0.3	0.3	0.3	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	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 2006. 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

[19] http://www.the-innovation-group.com/ChemProfiles

underlying EIA estimates, plus an additional ±15 percent to account for uncertainty in the assignment of imports and 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 ±10 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 around a mean of 61 percent, with a standard deviation of 1 percent, and 95 percent confidence limits of 59 percent and 64 percent. This compares to the calculated estimate, used in the Inventory, of 62 percent. The analysis produced a C emission distribution approximating a normal curve with a mean of 82.7 Tg CO_2 Eq., standard deviation of 8.4 Tg CO_2 Eq., and 95 percent confidence limits of 66.4 and 99.5 Tg CO_2 Eq. This compares with a calculated estimate of 83.0 Tg CO_2 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 both 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 CO_2 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 are the possibility of double counting of 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 CO_2 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, and 2002 (EIA 1994, 1997, 2001b, 2004). 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 three factors. First, 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. Second, 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). Lastly, 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; 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. According to EPA (2000e), approximately 100 Tg CO_2 Eq. has been used in the production of asphalt cement annually. 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 2000c), 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 2000c, EIIP 1998) 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 (2000e) and total HMA production.[20] 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 5 percent asphalt cement content based on personal communication with an expert from the National Asphalt Paving Association (Connolly 2000), 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 (i.e., rapid, medium and slow cure). All three forms emit C only from the volatile petroleum distillate used to thin the asphalt cement (EPA 1995). Because the petroleum distillates are not included in the EIA fuel use statistics for asphalt, the storage factor for cut-back is assumed to be 100 percent.

It was also 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 were obtained from "Hot Mix Asphalt Plants Emissions Assessment Report" from EPA's *AP-42* (EPA 2000e) publication. The asphalt cement content of HMA was provided by Una Connolly of National Asphalt Paving Association (Connolly 2000). 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 1998). "Asphalt Paving Operation" *AP-42* (EPA 1995) 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 2006. 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 around the mean, was applied to the C content coefficient.

The Monte Carlo analysis, given a 95 percent confidence interval, produced a storage factor distribution that approximates a normal curve skewed to the right, around a mean of 99.6 percent, with a standard deviation less than 0.05 percent and boundaries between 99.3 and 99.8 percent. This compares to the storage factor value used in the Inventory of 100 percent. The analysis produced an emission

[20] The emission factors are expressed as a function of asphalt paving tonnage (i.e., including the rock aggregate as well as the asphalt cement).

distribution, skewed to the left, with an uncertainty range slightly below 100 percent. The emission uncertainty range is not applicable since the Inventory calculation estimates that zero C is emitted from asphalts and road oil.

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 CO_2 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. However, because the C storage factor of each is 100 percent, use of more recent data would not affect the overall result.

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 (2006), the C content from U.S. production of lubricants in 2006 was approximately 20.2 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 percent; thus, emissions in 2006 were about 5.2 Tg C, or 19.1 Tg CO_2 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.[21] 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-56 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 CO_2 (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 CO_2 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

[21] 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.

anaerobic within municipal landfills, it is assumed that 90 percent of the oil persists in an underrated form, based on analogy with the persistence of petroleum in native petroleum-bearing strata, which are both 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 CO_2, only about 3 percent of the C in oil lubricants goes into long-term storage.

Table A-56: Commercial and Environmental Fate of Oil Lubricants (Percent)

Fate of Oil	Portion of Total Oil	C Stored
Combusted During Use	20	1
Not Combusted During Use	80	-
Combusted as Used Oil *	64	1
Dumped on the ground or in storm sewers	6	0
Landfilled	2	90
Re-refined into lube oil base stock and other products	8	3
Weighted Average	-	2.9

* (e.g., in boilers or space heaters)
- Not applicable

Greases

Table A-57 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.

Table A-57: Commercial and Environmental Fate of Grease Lubricants (Percent)

Fate of Grease	Portion of Total Grease	C Stored
Combusted During Use	5	1
Not Combusted During Use	95	-
Landfilled	85.5	90
Dumped on the ground or in storm sewers	9.5	50
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 (1999) does maintain records of the value of production of lubricating oils and lubricating greases. 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 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 2006. 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 maximum 6% uncertainty around the mean, was applied to the lubricant C content coefficient.

The Monte Carlo analysis, given a 95 percent confidence interval, produced a storage factor distribution that approximates a normal curve, around a mean of 10 percent (with individual storage factors for oil and grease at 3 and 82 percent), with a standard deviation of 4 percent and 95 percent confidence limits of 4 and 18 percent. This compares to the calculated estimate, used in the Inventory, of 9 percent. The analysis produced an emission distribution approximating a normal curve with a mean of 18.9 Tg CO_2, standard deviation of 1.6 and 95 percent confidence limits of 15.7 and 22.1 Tg CO_2. This compares with a calculated estimate of 19.1 Tg CO_2.

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

At present, 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-23 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-58: 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%	0%
Cosmetics	1%	2%
Plastics	1%	2%
Tires/Rubber	1%	1%
Hot Melts	1%	1%
Chemically Modified	0%	1%
Other	2%	9%
Total	42%	58%

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-59 categorizes wax end uses identified by the NPRA, and lists each end use's estimated C storage factor.

Table A-59: 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
Candles	20%	10%	2%
Firelogs	7%	1%	+
Hotmelts	3%	50%	1%
Packaging	30%	79%	24%
Construction Materials	18%	79%	14%
Cosmetics	3%	79%	2%
Plastics	3%	79%	2%
Tires/Rubber	3%	47%	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 CO_2. 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 CO_2 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 CO_2 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 CO_2; 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 most remaining end uses is ultimately to enter the municipal solid waste (MSW) stream, where they are 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 2006. 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 that approximates a normal curve around a mean of 58 percent, with a standard deviation of 6 percent and 95 percent confidence limits of 44 percent and 69 percent. This compares to the calculated estimate, used in the Inventory, of 58 percent. The analysis produced an emission distribution approximating a normal curve with a mean of 0.9 Tg CO_2, standard deviation of 0.2 Tg CO_2, and 95 percent confidence limits of 0.6 and 1.2 Tg CO_2. This compares with a calculated estimate of 0.8 Tg CO_2. This value is 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 would be 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 (2007), the C content of miscellaneous petroleum products in 2006 was approximately 20.3 Tg C. One hundred percent of the C content is assumed to be emitted to the atmosphere, where it is oxidized to CO_2.

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). 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 NEUs. 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 2006. 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, 10 percent, was applied to coking coal and miscellaneous products. C coefficients for distillate fuel oil ranged from 19.52 to 20.15 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 that approximates a normal curve around a mean of 41 percent, with a standard deviation of 11 percent and 95 percent confidence limits of 20 percent and 64 percent. This compares to the calculated, weighted average (across the various fuels) storage factor of 24 percent. The analysis produced an emission distribution approximating a normal curve with a mean of 27.2 Tg CO_2 and a standard deviation of 5.6 Tg CO_2, and 95 percent confidence limits of 16.5 Tg CO_2 and 38.3 Tg CO_2. This compares with the Inventory estimate of 35.2 Tg CO_2, which falls closer to the upper boundary of the confidence limit. The uncertainty analysis results are driven primarily by the very broad uncertainty inputs for the storage factors.

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ANNEX 3 Methodological Descriptions for Additional Source or Sink Categories

3.1. Methodology for Estimating Emissions of CH_4, N_2O, and Indirect Greenhouse Gases from Stationary Combustion

Estimates of CH_4 and N_2O Emissions

Methane (CH_4) and nitrous oxide (N_2O) 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-69 through Table A-73.

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 CH_4 and N_2O, 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, December 2007* and Published Supplemental Tables on Petroleum Product detail (EIA 2007a). Wood consumption data for the United States was obtained from EIA's *Annual Energy Review* (EIA 2007b). 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 Grillot (2007).[22] Fuel consumption for the industrial sector was adjusted to subtract out construction and agricultural use, which is reported under mobile sources.[23] Construction and agricultural fuel use was obtained from EPA (2004). 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-69 provides annual energy consumption data for the years 1990 through 2006.

Step 2: Determine the Amount of CH_4 and N_2O 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 N_2O emission factors by fuel type (consistent across sectors) were also assumed for U.S. territories. The CH_4 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-70 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 2008) 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. Due to lack of data availability, emissions were held constant from 2005 to 2006.

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

[23] 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.

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 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-71 through Table A-73 present indirect greenhouse gas emission estimates for 1990 through 2006.

The basic calculation procedure for most source categories presented in EPA (2003) and EPA (2008) 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-69: Fuel Consumption by Stationary Combustion for Calculating CH_4 and N_2O Emissions (TBtu)

Fuel/End-Use Sector	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Coal	**18,047**	**17,976**	**18,153**	**18,922**	**18,984**	**19,132**	**20,075**	**20,522**	**20,749**	**20,767**	**21,747**	**21,144**	**21,213**	**21,640**	**21,802**	**22,180**	**21,876**
Residential	31	25	26	26	21	17	16	16	12	14	11	11	12	12	13	9	6
Commercial	124	115	117	117	117	116	120	129	101	102	86	88	88	83	102	96	65
Industrial	1,624	1,577	1,536	1,575	1,575	1,522	1,499	1,463	1,409	1,362	1,421	1,421	1,313	1,319	1,343	1,298	1,298
Electric Power	16,261	16,250	16,466	17,196	17,261	17,466	18,429	18,905	19,216	19,279	20,220	19,614	19,783	20,185	20,305	20,737	20,462
U.S. Territories	7	8	9	10	10	10	10	10	11	10	10	11	18	41	39	40	44
Petroleum	**6,868**	**6,565**	**6,573**	**6,291**	**6,300**	**5,714**	**6,203**	**6,092**	**5,999**	**6,076**	**6,224**	**6,810**	**6,073**	**6,803**	**6,984**	**7,063**	**6,634**
Residential	1,440	1,442	1,437	1,414	1,371	1,339	1,477	1,387	1,294	1,416	1,482	1,497	1,390	1,533	1,509	1,402	1,310
Commercial	860	868	780	733	736	698	720	646	614	603	668	689	614	730	718	700	704
Industrial	2,903	2,631	2,920	2,561	2,628	2,461	2,754	2,687	2,340	2,385	2,458	2,715	2,552	2,713	2,891	3,078	3,306
Electric Power	1,289	1,198	991	1,124	1,059	755	817	927	1,306	1,211	1,144	1,277	961	1,205	1,212	1,235	649
U.S. Territories	375	425	445	460	506	462	435	445	445	461	472	632	557	622	654	649	665
Natural Gas	**18,385**	**18,849**	**19,585**	**20,056**	**20,413**	**21,367**	**21,774**	**21,913**	**21,501**	**21,513**	**22,331**	**21,509**	**22,436**	**21,994**	**21,640**	**21,501**	**21,145**
Residential	4,519	4,684	4,820	5,098	4,981	4,984	5,391	5,125	4,671	4,857	5,100	4,907	4,994	5,229	4,986	4,951	4,476
Commercial	2,698	2,807	2,883	2,944	2,978	3,117	3,251	3,306	3,098	3,132	3,254	3,112	3,224	3,331	3,204	3,076	2,905
Industrial	7,847	7,960	8,349	8,454	8,454	8,942	9,249	9,336	9,057	8,622	8,671	8,010	8,428	8,160	7,830	7,435	7,337
Electric Power	3,321	3,399	3,534	3,560	4,000	4,325	3,883	4,146	4,675	4,902	5,293	5,458	5,767	5,246	5,595	6,015	6,401
U.S. Territories	0	0	0	0	0	0	0	0	0	0	13	23	23	27	25	24	26
Wood	**2,216**	**2,214**	**2,313**	**2,260**	**2,324**	**2,370**	**2,437**	**2,371**	**2,184**	**2,214**	**2,262**	**2,006**	**1,995**	**2,002**	**2,121**	**2,116**	**2,114**
Residential	580	610	640	550	520	520	540	430	380	390	420	370	380	400	410	410	390
Commercial	66	68	72	76	72	72	76	73	64	67	71	67	69	71	70	70	65
Industrial	1,442	1,410	1,461	1,484	1,580	1,652	1,683	1,731	1,603	1,620	1,636	1,443	1,396	1,363	1,476	1,452	1,469
Electric Power	129	126	140	150	152	125	138	137	137	138	134	126	150	167	165	185	190
U.S. Territories	NE	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-70: CH_4 and N_2O Emission Factors by Fuel Type and Sector (g/GJ)[24]

Fuel/End-Use Sector	CH_4	N_2O
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)

[24] GJ (Gigajoule) = 10^9 joules. One joule = 9.486×10^{-4} Btu

Table A-71: NO_x Emissions from Stationary Combustion (Gg)

Sector/Fuel Type	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Electric Power	**6,045**	**5,914**	**5,900**	**6,034**	**5,956**	**5,792**	**5,592**	**5,695**	**5,654**	**5,190**	**4,836**	**4,461**	**4,272**	**3,982**	**3,593**	**3,469**	**3,252**
Coal	5,119	5,043	5,061	5,211	5,113	5,061	5,079	5,118	4,932	4,437	4,130	3,802	3,634	3,387	3,057	2,951	2,766
Fuel Oil	200	192	154	163	148	87	107	131	202	179	147	149	142	132	120	115	108
Natural gas	513	526	526	500	536	510	258	289	346	400	383	332	317	296	267	258	242
Wood	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other Fuels[a]	NA	NA	NA	NA	NA	NA	5	6	24	33	36	37	36	33	30	29	27
Internal Combustion	213	152	159	160	159	134	142	150	149	141	140	140	143	133	120	116	109
Industrial	**2,753**	**2,703**	**2,786**	**2,859**	**2,855**	**2,852**	**2,859**	**2,812**	**2,767**	**2,458**	**2,470**	**2,499**	**1,850**	**1,775**	**1,750**	**1,725**	**1,700**
Coal	530	517	521	534	546	541	490	487	475	475	484	518	384	368	363	358	353
Fuel Oil	240	215	222	222	219	224	203	196	190	190	166	153	114	109	107	106	104
Natural gas	1,072	1,134	1,180	1,207	1,210	1,201	1,092	1,078	1,066	880	902	914	677	649	640	631	622
Wood	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other Fuels[a]	119	117	115	113	113	111	109	103	104	100	109	116	86	82	81	80	79
Internal Combustion	792	720	749	783	767	774	965	948	932	813	809	798	591	566	559	551	543
Commercial	**336**	**333**	**348**	**360**	**365**	**365**	**360**	**369**	**347**	**255**	**256**	**261**	**247**	**244**	**244**	**243**	**242**
Coal	36	33	35	37	36	35	30	32	34	23	21	21	19	19	19	19	19
Fuel Oil	88	80	84	84	86	94	86	88	73	54	52	52	50	49	49	49	49
Natural gas	181	191	204	211	215	210	224	229	220	156	161	165	157	155	155	154	154
Wood	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other Fuels[a]	31	29	25	28	28	27	20	21	21	22	22	23	21	21	21	21	21
Residential	**749**	**829**	**879**	**827**	**817**	**813**	**726**	**699**	**651**	**441**	**439**	**446**	**422**	**418**	**417**	**416**	**415**
Coal[b]	NA	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	NA
Natural Gas[b]	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Wood	42	45	48	40	40	44	27	27	27	25	21	22	21	20	20	20	20
Other Fuels[a]	707	784	831	786	778	769	699	671	624	416	417	424	402	397	396	395	395
Total	**9,883**	**9,779**	**9,914**	**10,079**	**9,993**	**9,821**	**9,537**	**9,575**	**9,419**	**8,344**	**8,002**	**7,667**	**6,791**	**6,419**	**6,004**	**5,853**	**5,610**

NA (Not Applicable)

[a] "Other Fuels" include LPG, waste oil, coke oven gas, coke, and non-residential wood (EPA 2003, 2008).

[b] Residential coal, fuel oil, and natural gas emissions are included in the "Other Fuels" category (EPA 2003, 2008).

Note: Totals may not sum due to independent rounding.

Table A-72: CO Emissions from Stationary Combustion (Gg)

Sector/Fuel Type	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Electric Power	**329**	**317**	**318**	**329**	**336**	**337**	**369**	**384**	**410**	**450**	**439**	**439**	**594**	**589**	**598**	**606**	**615**
Coal	213	212	214	224	224	227	228	233	220	187	221	220	298	295	299	304	308
Fuel Oil	18	17	14	15	13	9	11	13	17	36	27	28	38	37	38	38	39
Natural gas	46	46	47	45	48	49	72	76	88	151	96	92	125	124	125	127	129
Wood	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other Fuels[a]	NA	NA	NA	NA	NA	NA	7	8	30	24	31	32	44	43	44	44	45
Internal Combustion	52	41	43	46	50	52	52	54	55	52	63	67	91	90	91	93	94
Industrial	**797**	**835**	**866**	**946**	**944**	**958**	**1,078**	**1,055**	**1,044**	**1,100**	**1,106**	**1,137**	**1,150**	**1,128**	**1,125**	**1,121**	**1,118**
Coal	95	92	92	92	91	88	100	99	96	114	118	125	127	124	124	123	123
Fuel Oil	67	54	58	60	60	64	49	47	46	54	48	45	46	45	45	45	44
Natural gas	205	257	272	292	306	313	307	307	305	350	355	366	370	363	362	361	360
Wood	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other Fuels[a]	253	242	239	259	260	270	316	302	303	286	300	321	325	319	318	317	316
Internal Combustion	177	189	205	244	228	222	305	299	294	296	285	279	282	277	276	275	275
Commercial	**205**	**196**	**204**	**207**	**212**	**211**	**122**	**126**	**122**	**151**	**151**	**154**	**177**	**174**	**173**	**172**	**170**
Coal	13	13	13	14	13	14	13	13	14	16	14	13	15	15	15	15	15
Fuel Oil	16	16	16	16	16	17	17	18	15	17	17	17	20	20	19	19	19
Natural gas	40	40	46	48	49	49	58	59	57	81	83	84	97	96	95	94	94
Wood	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other Fuels[a]	136	128	128	129	134	132	34	36	36	36	36	38	44	44	43	43	43
Residential	**3,668**	**3,965**	**4,195**	**3,586**	**3,515**	**3,877**	**2,364**	**2,362**	**2,353**	**3,323**	**2,644**	**2,648**	**3,044**	**3,002**	**2,981**	**2,961**	**2,940**
Coal[b]	NA	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	NA
Natural Gas[b]	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Wood	3,430	3,710	3,930	3,337	3,272	3,629	2,132	2,133	2,133	3,094	2,416	2,424	2,787	2,748	2,730	2,711	2,692
Other Fuels[a]	238	255	265	249	243	248	231	229	220	229	228	224	257	254	252	250	248
Total	**5,000**	**5,313**	**5,583**	**5,069**	**5,007**	**5,383**	**3,933**	**3,927**	**3,928**	**5,024**	**4,340**	**4,377**	**4,965**	**4,893**	**4,876**	**4,860**	**4,844**

NA (Not Applicable)

[a] "Other Fuels" include LPG, waste oil, coke oven gas, coke, and non-residential wood (EPA 2003, 2008).

[b] Residential coal, fuel oil, and natural gas emissions are included in the "Other Fuels" category (EPA 2003, 2008).

Note: Totals may not sum due to independent rounding.

Table A-73: NMVOC Emissions from Stationary Combustion (Gg)

Sector/Fuel Type	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Electric Power	**43**	**40**	**40**	**41**	**41**	**40**	**44**	**47**	**51**	**49**	**56**	**55**	**45**	**44**	**44**	**44**	**45**
Coal	24	24	25	26	26	26	25	26	26	25	27	26	21	21	21	21	21
Fuel Oil	5	5	4	4	4	2	3	4	5	4	4	4	4	3	3	4	4
Natural gas	2	2	2	2	2	2	7	7	9	9	12	12	10	10	10	10	10
Wood	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other Fuels[a]	NA	NA	NA	NA	NA	NA	+	+	1	2	2	2	1	1	1	1	1
Internal Combustion	11	9	9	9	9	9	9	10	10	10	11	10	9	8	8	8	8
Industrial	**165**	**178**	**170**	**169**	**178**	**187**	**163**	**160**	**159**	**156**	**157**	**159**	**138**	**134**	**131**	**128**	**125**
Coal	7	5	7	5	7	5	6	6	6	9	9	10	9	9	9	8	8
Fuel Oil	11	10	11	11	11	11	8	7	7	10	9	9	7	7	7	7	7
Natural gas	52	54	48	46	57	66	54	54	53	52	53	54	47	45	44	43	42
Wood	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other Fuels[a]	46	47	45	46	45	45	33	31	31	26	27	29	25	25	24	24	23
Internal Combustion	49	61	60	60	58	60	63	62	61	60	58	57	49	48	47	46	45
Commercial	**18**	**18**	**20**	**22**	**21**	**21**	**22**	**22**	**21**	**25**	**28**	**29**	**61**	**49**	**48**	**47**	**46**
Coal	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Fuel Oil	3	2	3	3	3	3	3	3	3	3	4	4	6	6	6	6	6
Natural gas	7	8	9	10	10	10	13	13	12	11	14	14	23	23	23	23	23
Wood	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other Fuels[a]	8	7	7	8	8	8	5	5	5	10	9	10	31	19	18	17	16
Residential	**686**	**739**	**782**	**670**	**657**	**725**	**789**	**788**	**786**	**815**	**837**	**836**	**1,341**	**1,333**	**1,329**	**1,326**	**1,323**
Coal[b]	NA	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	NA
Natural Gas[b]	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Wood	651	704	746	633	621	688	756	756	756	794	809	809	1,297	1,290	1,286	1,283	1,280
Other Fuels[a]	35	35	36	36	36	37	33	32	30	21	27	27	43	43	43	43	43
Total	**912**	**975**	**1,012**	**901**	**897**	**973**	**1,018**	**1,017**	**1,017**	**1,045**	**1,077**	**1,080**	**1,585**	**1,560**	**1,553**	**1,545**	**1,538**

NA (Not Applicable)

[a] "Other Fuels" include LPG, waste oil, coke oven gas, coke, and non-residential wood (EPA 2003, 2008).

[b] Residential coal, fuel oil, and natural gas emissions are included in the "Other Fuels" category (EPA 2003, 2008).

Note: Totals may not sum due to independent rounding.

3.2. Methodology for Estimating Emissions of CH_4, N_2O, and Indirect Greenhouse Gases from Mobile Combustion and Methodology for and Supplemental Information on Transportation-Related GHG Emissions

Estimating CO_2 Emissions by Transportation Mode

Transportation-related CO_2 emissions, as presented in Table 3-7 of Chapter 3, 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, CO_2 emissions estimates for the transportation sector were calculated directly for diesel fuel (all sources) and on-road motor gasoline based on data sources for individual modes of transportation (considered a "bottom up" approach). For all other fuel and energy types (i.e., jet fuel, aviation gasoline, residual fuel oil, natural gas, LPG, and electricity), CO_2 emissions were calculated based on transportation sector-wide fuel consumption estimates from the Energy Information Administration (EIA 2007a and EIA 2007d) 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 1990-2004 inventory, and a bottom-up gasoline calculation was introduced in this year's 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 2007), 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 2007) to develop an estimate of fuel consumption for each vehicle type (i.e., passenger cars, light-duty trucks, buses, heavy-duty trucks, motorcycles). The highway 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 with the fuel consumption estimates in *Highway Statistics'* Table MF-21 (FHWA 1996 through 2007). 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 2007) for Class I railroads, the American Public Transportation Association (APTA 2006 and 2007) and Gaffney (2007) for commuter rail, the Upper Great Plains Transportation Institute (Benson 2002 through 2004) and Whorton (2006 through 2007) for Class II and III railroads, and DOE's *Transportation Energy Data Book* (DOE 1993 through 2007) for passenger rail. Estimates of diesel from ships and boats were taken from EIA's *Fuel Oil and Kerosene Sales* (1991 through 2007).

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 2006b), 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 2007) and FAA (2006) for commercial aircraft, FAA (2007) for general aviation aircraft, and DESC (2007) for military aircraft.

Table A- 74 displays estimated fuel consumption by fuel and vehicle type. Table A- 75 displays estimated energy consumption by fuel and vehicle type. The values in both of these tables correspond to the figures used to calculate CO_2 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 subtracted out to calculate CO_2 emissions.

Table A- 74: Fuel Consumption by Fuel and Vehicle Type (million gallons unless otherwise specified)

Fuel/Vehicle Type	1990	1995	2000	2001	2002	2003	2004	2005	2006
Motor Gasoline[a]	**110,407.4**	**117,748.8**	**129,109.4**	**130,203.6**	**133,253.7**	**133,886.4**	**135,767.3**	**134,144.3**	**132,872.6**
Passenger Cars	69,761.8	67,667.1	72,747.5	73,236.3	74,895.8	72,602.5	72,241.6	74,297.9	71,596.2
Light-Duty Trucks	34,698.1	44,185.8	50,695.6	51,091.4	52,430.8	55,935.0	58,133.4	54,054.7	55,419.0
Motorcycles	194.0	199.5	209.5	192.9	190.5	185.2	194.9	182.8	212.0
Buses	38.9	41.6	43.5	40.0	38.1	35.9	49.8	40.6	41.4
Medium- and Heavy-Duty Trucks	4,349.8	4,054.7	4,089.2	3,977.7	4,037.3	3,478.0	3,511.2	3,945.7	4,002.6
Recreational Boats[b]	1,364.8	1,600.1	1,324.1	1,665.3	1,661.2	1,649.8	1,636.4	1,622.5	1,601.4
Distillate Fuel Oil (Diesel Fuel)	**25,744.2**	**31,140.8**	**38,904.8**	**39,060.8**	**40,414.2**	**40,823.4**	**43,045.5**	**44,647.7**	**45,675.0**
Passenger Cars	770.5	762.0	354.8	356.9	364.5	411.7	421.6	413.7	402.8
Light Trucks	1,117.5	1,446.3	1,953.8	2,025.7	2,133.5	2,652.0	2,836.9	2,516.9	2,607.0
Buses	780.2	847.8	993.1	904.5	855.8	930.0	1,323.4	1,040.7	1,071.3
Medium- and Heavy-Duty Trucks	18,557.4	23,149.7	30,074.9	30,077.6	31,421.8	31,539.6	32,772.5	35,139.6	36,013.0
Recreational Boats	190.4	228.1	265.6	275.7	283.8	291.8	299.8	307.8	315.9
Ships and Other Boats – Domestic	867.4	843.4	1,156.8	1,301.3	1,266.3	822.3	984.4	782.8	727.0
Rail	3,460.6	3,863.5	4,105.9	4,119.0	4,088.7	4,176.1	4,406.8	4,446.1	4,538.0
Jet Fuel – Domestic[c]	**18,419.4**	**17,956.6**	**20,266.1**	**19,243.5**	**18,355.8**	**18,043.1**	**18,274.4**	**18,683.0**	**17,595.1**
Commercial Air craft – Domestic	14,235.0	14,950.2	17,161.7	15,975.8	15,270.1	15,043.1	14,937.0	15,720.3	14,854.4
General Aviation Aircraft	653.2	551.0	961.3	915.8	949.7	915.4	1,202.7	1,193.6	1,190.3
Military Aircraft	3,531.2	2,455.4	2,143.2	2,352.0	2,136.0	2,084.6	2,134.7	1,769.1	1,550.3
Aviation Gasoline[b]	**374.2**	**329.3**	**301.9**	**290.7**	**280.6**	**251.4**	**259.9**	**294.3**	**274.6**
General Aviation Aircraft	374.2	329.3	301.9	290.7	280.6	251.4	259.9	294.3	274.6
Residual Fuel Oil - Domestic[c, d]	**2,006.2**	**2,587.4**	**2,962.6**	**1,065.5**	**2,584.7**	**662.1**	**1,245.3**	**1,713.1**	**1,500.6**
Ships and Other Boats - Domestic	2,006.2	2,587.4	2,962.6	1,065.5	2,584.7	662.1	1,245.3	1,713.1	1,500.6
Natural Gas[c] (cubic feet)	**0.7**	**0.7**	**0.7**	**0.6**	**0.7**	**0.6**	**0.6**	**0.6**	**0.6**
Passenger Cars	-	+	-	-	-	-	-	-	-
Light-Duty Trucks	-	+	-	-	-	-	-	-	-
Buses	-	+	+	+	+	+	+	+	+
Pipelines	0.7	0.7	0.6	0.6	0.7	0.6	0.6	0.6	0.6
LPG[c]	**250.6**	**194.1**	**130.1**	**150.2**	**156.4**	**181.1**	**209.2**	**198.5**	**199.9**
Buses	-	1.5	2.5	0.6	1.2	1.3	1.7	1.6	1.6
Light Trucks	100.2	92.9	47.9	56.5	58.1	66.3	82.7	78.2	78.7
Medium- and Heavy-Duty Trucks	150.3	99.7	79.8	93.2	97.1	113.5	124.9	118.8	119.6
Electricity[c]	**4,751.2**	**4,974.5**	**5,381.9**	**5,724.2**	**5,517.3**	**6,809.8**	**7,223.6**	**7,506.4**	**8,086.2**
Locomotives & Transit Cars	4,751.2	4,974.5	5,381.9	5,724.2	5,517.3	6,809.8	7,223.6	7,506.4	8,086.2

Note: Emission estimates for passenger cars, light-duty trucks and medium- and heavy-duty trucks are calculated using fuel consumption data from FHWA's Highway Statistics, which used an updated methodology to develop the 2005 and 2006 estimates. This causes some discontinuity in the emissions estimates between 2004 and 2005.

[a] Figures do not include ethanol blended in motor gasoline.

[b] Fluctuations in recreational boat gasoline estimates reflect the use of this category to reconcile bottom-up values with EIA total gasoline estimates.

[c] Estimated based on EIA transportation sector energy estimates by fuel type, with bottom-up activity data used for apportionment to modes.

[d] Fluctuations in reported fuel consumption may reflect data collection problems.

+ Less than 0.05 million

- Unreported or zero

Table A- 75: Energy Consumption by Fuel and Vehicle Type (TBtu)

Fuel/Vehicle Type	1990	1995	2000	2001	2002	2003	2004	2005	2006
Motor Gasoline[a]	**13,809**	**14,620**	**16,016**	**16,151**	**16,523**	**16,599**	**16,858**	**16,666**	**16,508**
Passenger Cars	8,725	8,402	9,024	9,085	9,287	9,001	8,970	9,231	8,895
Light-Duty Trucks	4,340	5,486	6,289	6,338	6,501	6,935	7,218	6,716	6,885
Motorcycles	24	25	26	24	24	23	24	23	26
Buses	5	5	5	5	5	4	6	5	5
Medium- and Heavy-Duty Trucks	544	503	507	493	501	431	436	490	497
Recreational Boats[b]	171	199	164	207	206	205	203	202	199
Distillate Fuel Oil (Diesel Fuel)	**3,570**	**4,319**	**5,396**	**5,417**	**5,605**	**5,662**	**5,970**	**6,192**	**6,335**
Passenger Cars	107	106	49	50	51	57	58	57	56
Light Trucks	155	201	271	281	296	368	393	349	362
Buses	108	118	138	125	119	129	184	144	149
Medium- and Heavy-Duty Trucks	2,574	3,211	4,171	4,171	4,358	4,374	4,545	4,874	4,995
Recreational Boats	26	32	37	38	39	40	42	43	44
Ships and Other Boats - Domestic	120	117	160	180	176	114	137	109	101
Rail	480	536	569	571	567	579	611	617	629
Jet Fuel - Domestic[c]	**2,487**	**2,424**	**2,736**	**2,598**	**2,478**	**2,436**	**2,467**	**2,522**	**2,375**
Commercial Aircraft - Domestic	1,922	2,018	2,317	2,157	2,061	2,031	2,016	2,122	2,005
General Aviation Aircraft	88	74	130	124	128	124	162	161	161
Military Aircraft	477	331	289	318	288	281	288	239	209
Aviation Gasoline[c]	**45**	**40**	**36**	**35**	**34**	**30**	**31**	**35**	**33**
General Aviation Aircraft	45	40	36	35	34	30	31	35	33
Residual Fuel Oil – Domestic[c, d]	**300**	**387**	**443**	**160**	**387**	**99**	**186**	**256**	**225**
Ships and Other Boats - Domestic	300	387	443	160	387	99	186	256	225
Natural Gas[c]	**680**	**723**	**672**	**642**	**702**	**630**	**603**	**625**	**626**
Passenger Cars	0	2	0	0	0	0	0	0	0
Light-Duty Trucks	0	0	0	0	0	0	0	0	0
Buses	0	1	8	9	12	14	16	16	16
Pipelines	680	720	664	633	690	616	587	609	610
LPG[c]	**22**	**17**	**11**	**13**	**13**	**16**	**18**	**17**	**17**
Buses	0	0	0	0	0	0	0	0	0
Light Trucks	9	8	4	5	5	6	7	7	7
Medium- and Heavy-Duty Trucks	13	9	7	8	8	10	11	10	10
Electricity[c]	**16**	**17**	**18**	**20**	**19**	**23**	**25**	**26**	**28**
Locomotives & Transit Cars	16	17	18	20	19	23	25	26	28
Total	**20,929**	**22,547**	**25,329**	**25,036**	**25,761**	**25,495**	**26,158**	**26,340**	**26,146**

Note: Emissions estimates for passenger cars, light-duty trucks and heavy-duty trucks are calculated using fuel consumption data from FHWA's Highway Statistics, which used an updated methodology to develop the 2006 estimates. In the most recent Highway Statistics, FHWA also updated 2005 fuel consumption estimates, but did not revise other prior years. This causes some discontinuity in the emissions estimates between 2004 and 2005.

[a] Figures do not include ethanol blended in motor gasoline.

[b] Fluctuations in recreational boat gasoline estimates reflect the use of this category to reconcile bottom-up values with EIA total gasoline estimates.

[c] Estimated based on EIA transportation sector energy estimates, with bottom-up data used for apportionment to modes

[d] Fluctuations in reported fuel consumption may reflect data collection problems.

Estimates of CH_4 and N_2O Emissions

Mobile source emissions of greenhouse gases other than CO_2 are reported by transport mode (e.g., road, rail, aviation, and waterborne), vehicle type, and fuel type. Emissions estimates of CH_4 and N_2O 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 Highway 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,[25] buses, and motorcycles) were obtained from the Federal Highway Administration's (FHWA) *Highway Statistics* (FHWA 1996 through 2007). 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 2007) 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 2007). 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.[26] The resulting national VMT estimates for gasoline and diesel highway vehicles are presented in Table A- 76 and Table A- 77, respectively.

Total VMT for each highway category (i.e., gasoline passenger cars, light-duty gasoline trucks, heavy-duty gasoline vehicles, diesel passenger cars, light-duty diesel trucks, heavy-duty diesel vehicles, and motorcycles) were distributed across 31 model years shown for 2006 in Table A- 80. Distributions for 1990 - 2005 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 2007c).[27] 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- 84 through Table A- 87. 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*

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[25] 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.

[26] 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.

[27] Age distributions were held constant for the period 1990-1998, and reflect a 25-year vehicle age span. EPA (2007c) provides a variable age distribution and 31-year vehicle age span beginning in year 1999.

IPCC Guidelines, roughly correspond to the introduction of EPA Tier 0 and EPA Tier 1 regulations (EPA 1998).[28] EPA Tier 2 regulations affect vehicles produced starting in 2004 and are responsible for a noticeable decrease in N_2O emissions compared EPA Tier 1 emissions technology (EPA 1999b).

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 2004 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 CH_4 and N_2O Emission Factors by Vehicle, Fuel, and Control Technology Type

Emission factors for gasoline and diesel highway 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 CH_4 and N_2O Emitted by Vehicle, Fuel, and Control Technology Type

Emissions of CH_4 and N_2O 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.[29] The data obtained include vehicle fuel use and total number of vehicles in use from 1992 through 2006. 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

[28] For further description, see "Definitions of Emission Control Technologies and Standards" section of this annex.

[29] 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.

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- 78, while more detailed estimates of VMT by control technology are shown in Table A- 79.

Step 2: Determine CH_4 and N_2O Emission Factors by Vehicle and Alternative Fuel Type

CH_4 and N_2O 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, N_2O and CH_4 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- 89.

Step 3: Determine the Amount of CH_4 and N_2O Emitted by Vehicle and Fuel Type

Emissions of CH_4 and N_2O were calculated by multiplying total VMT for each vehicle and fuel type (Step 1) by the appropriate emission factors (Step 2).

Methodology for Non-Highway Mobile Sources

CH_4 and N_2O emissions from non-highway mobile sources were estimated by applying emission factors to the amount of fuel consumed by mode and vehicle type.

Activity data for non-highway vehicles include annual fuel consumption statistics by transportation mode and fuel type, as shown in Table A- 83. Consumption data for ships and other boats (i.e., vessel bunkering) were obtained from DHS (2008) and EIA (1991 through 2007) for distillate fuel, and DHS (2008) and EIA (2007a) for residual fuel; marine transport fuel consumption data for U.S. territories (EIA 2007b, EIA 1991 through 2007) were added to domestic consumption, and this total was reduced by the amount of fuel used for international bunkers.[30] Gasoline consumption by recreational boats was obtained from EPA's NONROAD model (EPA 2006b). Annual diesel consumption for Class I rail was obtained from the Association of American Railroads (AAR) (2007), diesel consumption from commuter rail was obtained from APTA (2006 and 2007) and Gaffney (2007), and consumption by Class II and III rail was provided by Benson (2002 through 2004) and Whorton (2006 through 2007). Diesel consumption by commuter and intercity rail was obtained from DOE (1993 through 2007). Data on the consumption of jet fuel and aviation gasoline in aircraft were obtained from EIA (2007a), as described in Annex 2.1: Methodology for Estimating Emissions of CO_2 from Fossil Fuel Combustion, and were reduced by the amount allocated to international bunker fuels. Pipeline fuel consumption was obtained from EIA (2007d) (note: pipelines are a transportation source but are stationary, not mobile, sources). Data on fuel consumption by all non-transportation mobile sources[31] were obtained from EPA's NONROAD model (EPA 2006b) and from FHWA (1996 through 2007 for gasoline consumption for trucks used off-road.

Emissions of CH_4 and N_2O from non-highway 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- 90). Table A- 91 and Table A- 92 provide complete estimates of CH_4 and N_2O emissions, respectively, for 1990 through 2006.

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[30] See International Bunker Fuels section of the Energy Chapter.

[31] "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.

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 (2006a), EPA (2005) and EPA (2003)), 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- 93 through Table A- 95 provide complete emissions estimates for 1990 through 2006.

Table A- 76: Vehicle Miles Traveled for Gasoline Highway Vehicles (10^9 Miles)

Year	Passenger Cars	Light-Duty Trucks	Heavy-Duty Vehicles	Motorcycles
1990	1,391.1	554.3	25.4	9.6
1991	1,341.6	627.2	25.0	9.2
1992	1,354.8	682.9	24.8	9.6
1993	1,356.5	720.4	24.5	9.9
1994	1,387.5	738.8	24.9	10.2
1995	1,420.6	762.5	24.7	9.8
1996	1,454.6	788.0	24.0	9.9
1997	1,488.4	820.8	23.6	10.1
1998	1,536.5	836.8	23.6	10.3
1999	1,559.0	867.4	23.8	10.6
2000	1,591.4	886.6	23.7	10.5
2001	1,619.2	904.8	23.2	9.6
2002	1,649.0	925.6	23.1	9.6
2003	1,662.4	942.8	23.5	9.6
2004	1,690.0	984.1	23.7	10.1
2005	1,698.4	997.3	23.8	10.5
2006	1,672.6	1,043.1	23.9	12.4

Source: Derived from FHWA (1996 through 2007).

Table A- 77: Vehicle Miles Traveled for Diesel Highway Vehicles (10^9 Miles)

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	198.9
2004	8.4	41.3	201.3
2005	8.5	41.9	202.9
2006	8.3	43.8	203.2

Source: Derived from FHWA (1996 through 2007).

Table A- 78: Vehicle Miles Traveled for Alternative Fuel Highway Vehicles (10^9 Miles)

Year	Passenger Cars	Light-Duty Trucks	Heavy-Duty Vehicles
1990	0.2	0.0	0.1
1991	0.3	0.0	0.1
1992	0.3	0.0	0.1
1993	0.3	0.0	0.1

1994	0.4	0.0	0.1
1995	0.5	0.0	0.1
1996	0.5	0.0	0.1
1997	0.6	0.0	0.1
1998	0.7	0.0	0.1
1999	0.7	0.0	0.1
2000	0.9	0.0	0.1
2001	1.0	0.0	0.1
2002	1.2	0.0	0.1
2003	1.3	0.0	0.1
2004	1.5	0.0	0.1
2005	1.6	0.0	0.1
2006	1.8	0.0	0.1

Source: Derived from Browning (2003).

Table A- 79: Detailed Vehicle Miles Traveled for Alternative Fuel Highway Vehicles (10^6 Miles)

Vehicle Type	1990	1995	2000	2001	2002	2003	2004	2005	2006
Passenger Cars	229.6	450.1	886.3	1,016.7	1,209.3	1,307.9	1,451.0	1,579.8	1,752.2
Methanol-Flex Fuel ICE	0.0	44.2	14.3	10.8	8.4	6.9	3.8	0.0	0.0
Ethanol-Flex Fuel ICE	0.0	1.7	125.6	158.7	189.2	224.9	243.0	271.7	295.1
CNG ICE	15.9	41.5	119.8	142.0	149.5	156.2	160.7	160.9	174.8
CNG Bi-fuel	31.8	109.2	227.5	256.1	271.5	292.7	298.4	298.9	325.5
LPG ICE	20.6	44.8	41.9	45.0	48.8	43.1	49.8	55.7	62.0
LPG Bi-fuel	161.3	194.9	197.6	224.8	244.0	221.9	249.2	272.3	297.6
Biodiesel (BD20)	0.0	0.0	8.4	8.6	18.3	30.8	62.5	86.6	111.6
NEVs	0.0	6.5	88.9	104.0	182.0	208.2	234.0	260.6	287.1
Electric Vehicle	0.0	7.4	62.3	66.8	97.6	123.3	149.5	173.3	198.4
Light-Duty Trucks	660.7	626.4	1,219.1	1,368.9	1,498.6	1,620.6	1,778.1	1,904.8	2,139.1
Ethanol-Flex Fuel ICE	0.0	1.8	125.4	150.3	189.4	210.1	246.4	284.5	323.8
CNG ICE	10.9	29.6	163.4	196.6	201.7	204.9	218.1	225.1	241.9
CNG Bi-fuel	24.2	68.0	280.1	344.5	361.7	381.2	390.1	390.7	425.6
LPG ICE	56.9	46.8	58.4	64.4	68.2	62.1	67.1	71.4	76.2
LPG Bi-fuel	568.7	473.1	525.2	537.8	568.2	620.8	671.1	700.2	785.9
Biodiesel (BD20)	0.0	0.0	8.2	8.1	23.9	39.5	67.1	100.2	134.5
Electric Vehicle	0.0	7.1	58.4	67.2	85.4	102.1	118.3	132.8	151.3
Medium-Duty Trucks	508.0	449.9	612.7	832.6	922.0	873.2	1,032.9	1,069.6	1,024.4
CNG Bi-fuel	2.3	12.5	107.1	181.0	201.9	245.3	312.3	323.1	344.2
LPG ICE	24.3	19.3	29.7	41.9	48.3	47.9	52.2	53.2	60.1
LPG Bi-fuel	481.4	418.1	475.9	609.7	671.8	580.0	668.4	693.3	620.0
Biodiesel (BD20)	0.0	0.0	7.1	7.9	29.5	33.9	44.6	61.9	80.6
Heavy-Duty Trucks	521.0	628.0	684.0	777.3	792.0	1,084.0	1,138.5	1,160.0	1,264.2
Neat Methanol ICE	0.1	7.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Neat Ethanol ICE	0.0	4.4	0.1	0.0	0.0	0.0	0.0	0.0	0.0
CNG ICE	12.7	32.2	83.7	135.4	154.0	312.1	371.8	395.9	437.5
LPG ICE	36.3	45.6	48.3	57.1	60.9	73.4	77.9	82.6	87.5
LPG Bi-fuel	471.9	531.0	529.7	558.0	548.5	661.7	650.8	636.8	689.5
LNG	0.0	6.9	22.2	26.9	28.6	36.7	38.0	44.7	49.7
Biodiesel (BD20)	0.0	0.0	32.2	33.9	76.3	124.1	163.4	201.0	234.2
Buses	43.2	79.0	108.6	121.9	148.6	185.6	226.3	252.9	290.8
Neat Methanol ICE	3.7	3.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Neat Ethanol ICE	0.1	0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CNG ICE	11.2	37.5	53.4	51.3	54.0	64.3	75.4	78.2	87.1
LPG ICE	28.2	30.9	35.6	36.9	36.4	35.3	38.9	38.7	41.3
LNG	0.0	4.3	13.3	21.0	22.3	22.7	24.0	26.5	28.4
Biodiesel (BD20)	0.0	0.0	5.2	5.3	11.2	21.8	29.9	37.1	46.8
Electric	0.0	2.0	1.0	7.5	24.7	41.5	58.2	72.5	87.1
Total VMT	1,962.4	2,233.4	3,510.6	4,117.5	4,570.6	5,071.4	5,626.8	5,967.1	6,470.6

Source: Derived from Browning (2003).

[a] 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.

Table A- 80: Age Distribution by Vehicle/Fuel Type for Highway Vehicles,[a] 2006

Vehicle Age	LDGV	LDGT	HDGV	LDDV	LDDT	HDDV	MC
0	6.19%	7.53%	6.30%	6.19%	7.53%	6.30%	8.64%
1	5.84%	8.11%	6.28%	5.84%	8.11%	6.28%	8.08%
2	5.72%	8.19%	5.73%	5.72%	8.19%	5.73%	7.70%
3	5.75%	7.62%	4.76%	5.75%	7.62%	4.76%	7.45%
4	6.08%	7.32%	4.49%	6.08%	7.32%	4.49%	7.12%
5	6.25%	7.17%	4.98%	6.25%	7.17%	4.98%	7.04%
6	6.48%	6.75%	6.15%	6.48%	6.75%	6.15%	7.10%
7	6.25%	6.30%	6.61%	6.25%	6.30%	6.61%	6.64%
8	5.72%	5.47%	5.15%	5.72%	5.47%	5.15%	6.22%
9	5.56%	4.73%	4.45%	5.56%	4.73%	4.45%	4.72%
10	5.50%	4.40%	4.14%	5.50%	4.40%	4.14%	3.99%
11	5.40%	3.84%	4.75%	5.40%	3.84%	4.75%	3.41%
12	5.28%	3.58%	4.15%	5.28%	3.58%	4.15%	3.00%
13	4.58%	2.94%	3.22%	4.58%	2.94%	3.22%	2.57%
14	3.72%	2.35%	2.36%	3.72%	2.35%	2.36%	2.00%
15	3.06%	1.91%	2.37%	3.06%	1.91%	2.37%	1.62%
16	2.85%	1.90%	2.89%	2.85%	1.90%	2.89%	1.47%
17	2.40%	1.72%	3.27%	2.40%	1.72%	3.27%	1.32%
18	2.00%	1.60%	2.99%	2.00%	1.60%	2.99%	1.42%
19	1.45%	1.37%	2.54%	1.45%	1.37%	2.54%	1.58%
20	1.16%	1.21%	2.67%	1.16%	1.21%	2.67%	1.37%
21	0.84%	1.02%	2.14%	0.84%	1.02%	2.14%	1.17%
22	0.59%	0.77%	1.48%	0.59%	0.77%	1.48%	0.98%
23	0.39%	0.53%	1.47%	0.39%	0.53%	1.47%	0.82%
24	0.24%	0.39%	0.84%	0.24%	0.39%	0.84%	0.68%
25	0.20%	0.30%	0.77%	0.20%	0.30%	0.77%	0.55%
26	0.15%	0.29%	0.76%	0.15%	0.29%	0.76%	0.44%
27	0.12%	0.23%	0.63%	0.12%	0.23%	0.63%	0.34%
28	0.09%	0.20%	0.72%	0.09%	0.20%	0.72%	0.25%
29	0.07%	0.14%	0.41%	0.07%	0.14%	0.41%	0.17%
30	0.06%	0.15%	0.53%	0.06%	0.15%	0.53%	0.15%
Total	100%	100%	100%	100%	100%	100%	100%

Source: EPA (2007c).

[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).

Table A- 81: Annual Average Vehicle Mileage Accumulation per Vehicle (miles)

Vehicle Age	LDGV	LDGT	HDGV	LDDV	LDDT	HDDV	MC[a]
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

ource: EPA (2000).

Because 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 n aggregate.

able A- 82: VMT Distribution by Vehicle Age and Vehicle/Fuel Type, 2006

Vehicle Age	LDGV	LDGT	HDGV	LDDV	LDDT	HDDV	MC
0	9.09%	11.62%	10.84%	9.09%	12.87%	12.68%	14.30%
1	8.16%	11.77%	10.12%	8.16%	12.69%	11.55%	12.50%
2	7.60%	11.15%	8.34%	7.60%	11.72%	9.64%	11.08%
3	7.26%	9.72%	6.73%	7.26%	9.98%	7.31%	9.92%
4	7.29%	8.75%	5.94%	7.29%	8.78%	6.30%	8.72%
5	7.14%	8.01%	6.18%	7.14%	7.88%	6.39%	7.87%
6	7.02%	7.04%	7.14%	7.02%	6.79%	7.21%	7.17%
7	6.44%	6.12%	7.19%	6.44%	5.81%	7.08%	5.99%
8	5.61%	4.95%	5.25%	5.61%	4.62%	5.05%	4.94%
9	5.18%	3.98%	4.26%	5.18%	3.66%	3.99%	3.24%
10	4.87%	3.43%	3.71%	4.87%	3.12%	3.39%	2.32%
11	4.55%	2.77%	3.99%	4.55%	2.50%	3.56%	1.61%
12	4.23%	2.39%	3.27%	4.23%	2.13%	2.84%	1.42%
13	3.49%	1.81%	2.38%	3.49%	1.60%	2.02%	1.21%
14	2.69%	1.33%	1.61%	2.69%	1.17%	1.35%	0.95%
15	2.10%	0.99%	1.53%	2.10%	0.88%	1.24%	0.77%
16	1.86%	0.90%	1.76%	1.86%	0.80%	1.39%	0.70%
17	1.49%	0.75%	1.86%	1.49%	0.66%	1.43%	0.62%
18	1.18%	0.63%	1.59%	1.18%	0.56%	1.20%	0.67%
19	0.81%	0.49%	1.27%	0.81%	0.45%	0.93%	0.75%
20	0.62%	0.39%	1.25%	0.62%	0.36%	0.90%	0.65%
21	0.43%	0.30%	0.94%	0.43%	0.28%	0.66%	0.55%
22	0.28%	0.21%	0.61%	0.28%	0.19%	0.42%	0.46%
23	0.18%	0.13%	0.57%	0.18%	0.12%	0.38%	0.39%
24	0.11%	0.09%	0.30%	0.11%	0.08%	0.20%	0.32%
25	0.09%	0.06%	0.28%	0.09%	0.06%	0.18%	0.26%
26	0.07%	0.06%	0.28%	0.07%	0.06%	0.18%	0.21%
27	0.05%	0.05%	0.23%	0.05%	0.05%	0.15%	0.16%
28	0.04%	0.04%	0.26%	0.04%	0.04%	0.17%	0.12%
29	0.03%	0.03%	0.15%	0.03%	0.03%	0.10%	0.08%
30	0.03%	0.03%	0.19%	0.03%	0.03%	0.13%	0.07%
	100%	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

ote: Estimated by weighting data in Table A- 80 by data in Table A- 81.

able A- 83: Fuel Consumption for Non-Highway Vehicles by Fuel Type (million gallons)

Vehicle Type/Year	1990	1995	2000	2001	2002	2003	2004	2005	2006
Aircraft – Domestic									
Gasoline[a]	374.2	329.3	301.9	290.7	280.6	251.4	259.9	294.3	274.6
Jet Fuel	18,692.0	18,243.2	20,491.8	19,297.4	18,136.8	18,376.5	18,703.5	19,648.5	19,050.3
Ships and Boats – Domestic									
Diesel	1,175.2	1,184.8	1,525.5	1,680.4	1,653.8	1,352.0	1,523.2	1,329.7	1,281.9
Gasoline	1,429.0	1,612.7	1,678.0	1,680.2	1,678.4	1,673.0	1,664.8	1,655.0	1,644.9

Residual	2,060.7	2,646.1	3,027.6	1,130.7	2,649.8	730.3	1,313.5	1,781.3	1,568.9
Construction/Mining Equipment									
Diesel	3,508.2	4,189.5	4,866.5	5,045.9	5,186.3	5,326.7	5,467.1	5,607.5	5,747.0
Gasoline	392.5	354.3	260.1	574.1	599.1	635.4	672.5	621.4	614.7
Agricultural Equipment									
Diesel	2,291.5	2,736.6	3,181.6	3,265.6	3,347.6	3,429.6	3,511.6	3,593.6	3,674.5
Gasoline	812.8	926.7	652.3	801.6	831.8	851.3	1,093.8	1,077.8	1,228.7
Locomotives									
Diesel	3,460.6	3,863.5	4,105.9	4,119.0	4,088.7	4,176.1	4,406.8	4,446.4	4,538.0
Other[b]									
Diesel	671.0	777.6	883.9	914.2	939.6	965.0	990.4	1,015.8	1,041.2
Gasoline	2,743.2	2,785.9	2,865.2	3,621.8	3,727.7	3,859.1	4,003.9	3,958.8	4,000.2

Sources: AAR (2007), APTA (2007 and 2006), BEA (1991 through 2005), Benson (2002 through 2004), DHS (2008), DOC (1991 through 2007), DOE (1993 through 2007), DESC (2007), DOT (1991 through 2007), EIA (2002), EIA (2007a), EIA (2007b), EIA (2007d), EIA (1991 through 2007), EPA (2006b), FAA (2007 and 2006), Gaffney (2007), Lou (2007) and Whorton (2006 through 2007).

[a] For aircraft, this is aviation gasoline. For all other categories, this is motor gasoline.

[b] "Other" includes snowmobiles and other recreational equipment, logging equipment, lawn and garden equipment, railroad equipment, airport equipment, commercial equipment, and industrial equipment.

Table A- 84: 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%

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-85: 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%

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- 86: 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%

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- 87: Control Technology Assignments for Diesel Highway 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	1996-2006
Diesel Medium- and Heavy-Duty Trucks and Buses	
Uncontrolled	1960-1982
Moderate control	1983-1995
Advanced control	1996-2006
Motorcycles	
Uncontrolled	1960-1995
Non-catalyst controls	1996-2006

Source: EPA (1998) and Browning (2005)
Note: Detailed descriptions of emissions control technologies are provided in the following section of this annex.

Table A- 88: Emission Factors for CH_4 and N_2O for Highway Vehicles

Vehicle Type/Control Technology	N_2O (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[b]	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		
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).

[a] The 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- 89: Emission Factors for CH_4 and N_2O for Alternative Fuel Vehicles

	N_2O (g/mi)	CH_4 (g/mi)
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	0.000
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- 90: Emission Factors for CH_4 and N_2O Emissions from Non-Highway Mobile Combustion (g gas/kg fuel)

Vehicle Type/Fuel Type	N_2O	CH_4
Ships and Boats		
Residual	0.08	0.230
Distillate	0.08	0.230
Gasoline	0.08	0.230
Rail		
Diesel	0.08	0.250
Agricultural Equipment		
Gas	0.08	0.450
Diesel	0.08	0.450
Construction/Mining Equipment		
Gas	0.08	0.180
Diesel	0.08	0.180
Other Non-Highway		
All "Other" Categories*	0.08	0.180
Aircraft		
Jet Fuel	0.10	0.087
Aviation Gasoline	0.04	2.640

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

* "Other" includes snowmobiles and other recreational equipment, logging equipment, lawn and garden equipment, railroad equipment, airport equipment, commercial equipment, and industrial equipment.

Table A- 91: CH_4 Emissions from Mobile Combustion (Tg CO_2 Eq.)

Fuel Type/Vehicle Type	1990	1995	2000	2001	2002	2003	2004	2005	2006
Gasoline Highway	**4.2**	**3.8**	**2.8**	**2.7**	**2.4**	**2.2**	**2.0**	**1.9**	**1.7**
Passenger Cars	2.6	2.1	1.6	1.5	1.4	1.3	1.2	1.1	1.0
Light-Duty Trucks	1.4	1.4	1.1	1.1	0.9	0.8	0.7	0.7	0.7
Medium- and Heavy-Duty Trucks and Buses	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Motorcycles	+	+	+	+	+	+	+	+	+
Diesel Highway	**+**	**+**	**+**	**+**	**+**	**+**	**+**	**+**	**+**
Passenger Cars	+	+	+	+	+	+	+	+	+
Light-Duty Trucks	+	+	+	+	+	+	+	+	+
Medium- and Heavy-Duty Trucks and Buses	+	+	+	+	+	+	+	+	+
Alternative Fuel Highway	**+**	**+**	**+**	**+**	**+**	**+**	**0.1**	**0.1**	**0.1**
Non-Highway	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.6**	**0.6**
Ships and Boats – Domestic	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Rail	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Aircraft – Domestic	0.2	0.1	0.2	0.1	0.1	0.1	0.1	0.1	0.1
Agricultural Equipment	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Construction/Mining Equipment	+	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Other*	+	+	+	+	0.1	0.1	0.1	0.1	0.1
Total	4.7	4.3	3.4	3.3	3.0	2.7	2.6	2.5	2.4

+ Less than 0.05 Tg CO_2 Eq.

Note: Totals may not sum due to independent rounding.

[a] "Other" includes snowmobiles and other recreational equipment, logging equipment, lawn and garden equipment, railroad equipment, airport equipment, commercial equipment, and industrial equipment.

Table A- 92: N_2O Emissions from Mobile Combustion (Tg CO_2 Eq.)

Fuel Type/Vehicle Type	1990	1995	2000	2001	2002	2003	2004	2005	2006
Gasoline Highway	**40.1**	**49.8**	**48.4**	**45.9**	**41.8**	**38.4**	**35.6**	**32.1**	**29.0**
Passenger Cars	25.4	26.9	25.2	23.8	22.5	21.0	19.5	17.7	15.6
Light-Duty Trucks	14.1	22.1	22.4	21.2	18.5	16.5	15.3	13.6	12.6
Medium- and Heavy-Duty Trucks and Buses	0.6	0.7	0.9	0.9	0.9	0.9	0.8	0.8	0.7
Motorcycles	+	+	+	+	+	+	+	+	+
Diesel Highway	**0.2**	**0.3**	**0.3**	**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	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Alternative Fuel Highway	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.2**	**0.2**	**0.2**	**0.2**
Non-Highway	**3.2**	**3.3**	**3.7**	**3.6**	**3.6**	**3.4**	**3.6**	**3.7**	**3.6**
Ships and Boats – Domestic	0.4	0.4	0.5	0.3	0.5	0.3	0.4	0.4	0.4
Rail	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4
Aircraft – Domestic	1.7	1.7	1.9	1.8	1.7	1.7	1.7	1.7	1.6
Agricultural Equipment	0.2	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4
Construction/Mining Equipment	0.3	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.5
Other*	0.2	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4
Total	**43.5**	**53.4**	**52.5**	**49.9**	**45.9**	**42.3**	**39.7**	**36.3**	**33.1**

+ Less than 0.05 Tg CO_2 Eq.
Note: Totals may not sum due to independent rounding.
[a] "Other" includes snowmobiles and other recreational equipment, logging equipment, lawn and garden equipment, railroad equipment, airport equipment, commercial equipment, and industrial equipment.

Table A- 93: NO_x Emissions from Mobile Combustion (Gg)

Fuel Type/Vehicle Type	1990	1995	2000	2001	2002	2003	2004	2005	2006
Gasoline Highway	**5,746**	**4,560**	**3,812**	**3,715**	**3,761**	**3,533**	**3,322**	**3,112**	**2,901**
Passenger Cars	3,847	2,752	2,084	2,027	2,052	1,927	1,813	1,698	1,583
Light-Duty Trucks	1,364	1,325	1,303	1,285	1,301	1,222	1,149	1,076	1,003
Medium- and Heavy-Duty Trucks and Buses	515	469	411	390	395	371	349	327	304
Motorcycles	20	14	13	14	14	13	12	11	11
Diesel Highway	**2,956**	**3,493**	**3,803**	**3,338**	**3,379**	**3,174**	**2,985**	**2,796**	**2,607**
Passenger Cars	39	19	7	6	6	6	5	5	5
Light-Duty Trucks	20	12	6	5	6	5	5	5	4
Medium- and Heavy-Duty Trucks and Buses	2,897	3,462	3,791	3,326	3,368	3,164	2,975	2,787	2,598
Alternative Fuel Highway	**IE**	**IE**	**IE**	**IE**	**IE**	**IE**	**IE**	**IE**	**IE**
Non-Highway	**2,218**	**2,569**	**2,695**	**2,766**	**3,014**	**2,935**	**2,883**	**2,831**	**2,779**
Ships and Boats – Domestic	402	488	506	544	595	580	570	559	549
Rail	338	433	451	485	531	518	508	499	490
Aircraft – Domestic	25	31	40	39	43	42	41	40	40
Agricultural Equipment	437	478	484	480	521	507	498	489	480
Construction/Mining Equipment	641	697	697	690	748	728	715	702	689
Other*	376	442	518	529	576	561	551	541	531
Total	**10,920**	**10,622**	**10,310**	**9,819**	**10,154**	**9,642**	**9,191**	**8,739**	**8,287**

IE = Included Elsewhere
[a] NO_x emissions from alternative fuel highway vehicles are included under gasoline and diesel highway.
[b] Aircraft estimates include only emissions related to LTO cycles, and therefore do not include cruise altitude emissions.
[c] "Other" includes gasoline powered recreational, industrial, lawn and garden, light commercial, logging, airport service, other equipment; and diesel powered recreational, industrial, lawn and garden, light construction, airport service.
Note: Totals may not sum due to independent rounding.

Table A- 94: CO Emissions from Mobile Combustion (Gg)

Fuel Type/Vehicle Type	1990	1995	2000	2001	2002	2003	2004	2005	2006
Gasoline Highway	**98,328**	**74,673**	**60,657**	**56,716**	**54,143**	**50,683**	**47,498**	**44,314**	**41,129**
Passenger Cars	60,757	42,065	32,867	31,600	30,166	28,238	26,464	24,689	22,915
Light-Duty Trucks	29,237	27,048	24,532	22,574	21,550	20,173	18,905	17,638	16,370
Medium- and Heavy-Duty Trucks and Buses	8,093	5,404	3,104	2,411	2,302	2,155	2,019	1,884	1,748
Motorcycles	240	155	154	131	125	117	110	103	95
Diesel Highway	**1,696**	**1,424**	**1,088**	**869**	**830**	**777**	**728**	**679**	**630**
Passenger Cars	35	18	7	6	6	5	5	5	4
Light-Duty Trucks	22	16	6	5	5	5	4	4	4
Medium- and Heavy-Duty Trucks and Buses	1,639	1,391	1,075	858	819	767	719	670	622
Alternative Fuel Highway	**IE**	**IE**	**IE**	**IE**	**IE**	**IE**	**IE**	**IE**	**IE**
Non-Highway	**19,337**	**21,533**	**21,814**	**22,266**	**20,448**	**19,579**	**18,870**	**18,162**	**17,453**
Ships and Boats – Domestic	1,559	1,781	1,825	1,831	1,682	1,610	1,552	1,494	1,436
Rail	85	93	90	90	82	79	76	73	70
Aircraft – Domestic	217	224	245	233	214	205	198	190	183
Agricultural Equipment	581	628	626	621	570	546	526	507	487
Construction/Mining Equipment	1,090	1,132	1,047	1,041	956	915	882	849	816
Other*	15,805	17,676	17,981	18,449	16,943	16,222	15,635	15,048	14,461
Total	**119,360**	**97,630**	**83,559**	**79,851**	**75,421**	**71,038**	**67,096**	**63,154**	**59,213**

IE = Included Elsewhere

[a] CO emissions from alternative fuel highway vehicles are included under gasoline and diesel highway.

[b] Aircraft estimates include only emissions related to LTO cycles, and therefore do not include cruise altitude emissions.

[c] "Other" includes gasoline powered recreational, industrial, lawn and garden, light commercial, logging, airport service, other equipment; and diesel powered recreational, industrial, lawn and garden, light construction, airport service.

Note: Totals may not sum due to independent rounding.

Table A- 95: NMVOCs Emissions from Mobile Combustion (Gg)

Fuel Type/Vehicle Type	1990	1995	2000	2001	2002	2003	2004	2005	2006
Gasoline Highway	**8,110**	**5,819**	**4,615**	**4,285**	**4,255**	**4,017**	**3,803**	**3,589**	**3,375**
Passenger Cars	5,120	3,394	2,610	2,393	2,376	2,243	2,124	2,004	1,885
Light-Duty Trucks	2,374	2,019	1,750	1,664	1,652	1,560	1,477	1,394	1,310
Medium- and Heavy-Duty Trucks and Buses	575	382	232	206	205	193	183	173	162
Motorcycles	42	24	23	22	22	21	19	18	17
Diesel Highway	**406**	**304**	**216**	**207**	**206**	**194**	**184**	**174**	**163**
Passenger Cars	16	8	3	3	3	3	3	3	2
Light-Duty Trucks	14	9	4	4	4	3	3	3	3
Medium- and Heavy-Duty Trucks and Buses	377	286	209	201	199	188	178	168	158
Alternative Fuel Highway	**IE**	**IE**	**IE**	**IE**	**IE**	**IE**	**IE**	**IE**	**IE**
Non-Highway	**2,415**	**2,622**	**2,398**	**2,379**	**2,774**	**2,674**	**2,600**	**2,527**	**2,453**
Ships and Boats – Domestic	608	739	744	730	851	820	798	775	753
Rail	33	36	35	35	41	40	39	38	36
Aircraft – Domestic	28	28	24	19	22	22	21	20	20
Agricultural Equipment	85	86	76	72	84	81	79	77	75
Construction/Mining Equipment	149	152	130	125	146	140	137	133	129
Other*	1,512	1,580	1,390	1,397	1,629	1,570	1,527	1,484	1,441
Total	**10,932**	**8,745**	**7,230**	**6,872**	**7,235**	**6,885**	**6,587**	**6,289**	**5,991**

IE = Included Elsewhere

[a] NMVOC emissions from alternative fuel highway vehicles are included under gasoline and diesel highway.

[b] Aircraft estimates include only emissions related to LTO cycles, and therefore do not include cruise altitude emissions.

[c] "Other" includes gasoline powered recreational, industrial, lawn and garden, light commercial, logging, airport service, other equipment; and diesel powered recreational, industrial, lawn and garden, light construction, airport service.

Note: Totals may not sum due to independent rounding.

Definitions of Emission Control Technologies and Standards

The N_2O and CH_4 emission factors used depend on the emission standards in place and the corresponding level of control technology for each vehicle type. Table A- 84 through Table A- 87 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 CO_2 and H_2O, 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 CH_4 or N_2O 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.

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 CO_2, N_2O, CH_4, 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 subannex, within the annex that details the calculation methods and data used for non-CO_2 calculations, is to provide all transportation estimates presented throughout the repot in one place.

This section of this Annex reports total greenhouse gas emissions from transportation and other (non-transportation) mobile sources in CO_2 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 CO_2 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 CO_2 from Non-Transportation Mobile Sources

The estimates of N_2O and CH_4 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 CO_2 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- 96 provides estimates of CO_2 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 N_2O and CH_4 estimates.

Table A- 96: CO_2 Emissions from Non-Transportation Mobile Sources (Tg CO_2 Eq.)

Fuel Type/Vehicle Type	1990	1995	2000	2001	2002	2003	2004	2005	2006
Agricultural Equipment	30.5	35.9	38.0	40.2	41.3	42.3	45.3	45.9	48.1
Construction/Mining Equipment	39.1	45.6	51.7	56.2	57.9	59.6	61.4	62.4	63.7
Other Sources	31.2	32.4	34.1	41.1	42.3	43.7	45.3	45.1	45.8
Total	**100.8**	**114.0**	**123.8**	**137.5**	**141.5**	**145.6**	**151.9**	**153.4**	**157.6**

Estimation of HFC Emissions from Transportation Sources

In addition to CO_2, N_2O and CH_4 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- 97 below presents these HFC emissions. Table A- 98 presents all transportation and mobile source greenhouse gas emissions, including HFC emissions.

Table A- 97: HFC Emissions from Transportation Sources

Vehicle Type	1990	1995	2000	2001	2002	2003	2004	2005	2006
Mobile AC	**+**	**16.2**	**42.9**	**46.6**	**49.7**	**52.2**	**54.8**	**56.2**	**55.6**
Passenger Cars	+	10.1	24.3	25.9	27.2	28.0	28.8	28.5	27.2
Light-Duty Trucks	+	6.1	18.6	20.6	22.5	24.2	26.1	27.7	28.3
Comfort Cooling for Trains and Buses	**+**	**+**	**0.1**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.3**
School and Tour Buses	+	+	0.1	0.1	0.2	0.2	0.2	0.2	0.3
Transit Buses	+	+	+	+	+	+	+	+	+
Rail	+	+	+	+	+	+	+	+	+
Refrigerated Transport	**+**	**2.3**	**9.6**	**10.5**	**11.2**	**12.0**	**12.8**	**13.2**	**13.6**
Medium- and Heavy-Duty Trucks	+	0.3	1.6	1.7	1.8	1.9	2.1	2.1	2.2
Rail	+	1.4	4.6	5.0	5.4	5.8	6.1	6.4	6.5
Ships and Other Boats - Domestic	+	0.6	3.4	3.7	4.0	4.3	4.6	4.7	4.9
Total	**+**	**18.6**	**52.6**	**57.2**	**61.1**	**64.4**	**67.8**	**69.7**	**69.5**

+ Less than 0.05 Tg CO_2 Eq.

Note: Totals may not sum due to independent rounding.

Contribution of Transportation and Mobile Sources to Greenhouse Gas Emissions, by Mode/Vehicle Type/Fuel Type

Table A- 98 presents estimates of greenhouse gas emissions from all transportation and other mobile sources in CO_2 equivalents. In total, transportation and mobile sources emitted 2,126.0 Tg CO_2 Eq. in 2006, an increase of 30 percent from 1990. These estimates were generated using the estimates of CO_2 emissions from transportation sources reported in Table 3-7, CH_4 emissions reported in Table 3-21, and N_2O emissions reported in Table 3-22 of Chapter 3; information on HFCs from mobile air conditioners, comfort cooling for trains and buses, and refrigerated transportation from Chapter 4; and estimates of CO_2 emitted from non-transportation mobile sources reported in Table A- 96 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 N_2O and CH_4, 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 CO_2 emissions. N_2O and CH_4 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 2007 and 2006). Similarly, N_2O and CH_4 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 Table 3-21 and Table 3-22 of Chapter 3 by the portion of fuel used by each vehicle type (from DOE 1993-2007). 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 CO_2), Chapter 4, and Annex 3.8 (for HFCs), and earlier in this Annex (for CH_4 and N_2O).

Transportation sources include highway (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 CO_2 from lubricants (such as motor oil) used in transportation. Together, transportation sources were responsible for 1,974.3 Tg CO_2 Eq. in 2006.

On-road vehicles were responsible for about 78 percent of transportation GHG emissions in 2006. 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 2006, greenhouse gas emissions from passenger cars increased 3 percent, while emissions from light-duty trucks increased 66 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 77 percent, reflecting the increased volume of total freight movement and an increasing share transported by trucks.

Greenhouse gas emissions from aircraft decreased 5 percent between 1990 and 2006, despite a substantial rise in passenger miles traveled. The overall decrease in emissions was caused by a large decline in emissions from military aircraft (56 percent) and a 4 percent increase in emissions from commercial aircraft. Greenhouse gas emissions from commercial aircraft rose 20 percent between 1990 and 2000, but then declined in 2001, 2002, 2003 and 2004, due largely to a decrease in air travel following the September 11, 2001 terrorist attacks.

Non-transportation mobile sources, such as construction/mining equipment, agricultural equipment, and industrial/commercial equipment, emitted approximately 159.1 Tg CO_2 Eq. in 2006. Together, these sources emitted more greenhouse gases than ships and boats (domestic travel in the United States), rail, and pipelines combined. Emissions from non-transportation mobile sources increased rapidly, growing approximately 56 percent between 1990 and 2006. CH_4 and N_2O emissions from these sources are included in the "Mobile Combustion" section and CO_2 emissions are included in the relevant economic sectors.

Contribution of Transportation and Mobile Sources to Greenhouse Gas Emissions, by Gas

Table A- 99 presents estimates of greenhouse gas emissions from transportation and other mobile sources broken down by greenhouse gas. As this table shows, CO_2 accounts for the vast majority of transportation greenhouse gas emissions (approximately 95 percent in 2006). Emissions of CO_2 from transportation and mobile sources increased by 427.8 Tg CO_2 Eq. between 1990 and 2006. In contrast, the combined emissions of CH_4 and N_2O decreased by 12.8 Tg CO_2 Eq. over the same period, due largely to the introduction of control technologies designed to reduce criteria pollutant emissions.[32] Meanwhile, HFC emissions from mobile air conditioners and refrigerated transport increased from virtually no emissions in 1990 to 69.5 Tg CO_2 Eq. in 2006 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.

[32] The decline in CFC emissions is not captured in the official transportation estimates.

Greenhouse Gas Emissions from Freight and Passenger Transportation

Table A- 100 and Table A- 101 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-100. 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- 101. 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- 98. In addition, estimates of fuel consumption from DOE (1993 through 2007) were used to allocate rail emissions between passenger and freight categories.

In 2006, passenger transportation modes emitted 1,408.0 Tg CO_2 Eq., while freight transportation modes emitted 541.3 Tg CO_2 Eq. The rate of growth of greenhouse gas emissions from freight sources, however, was more than three times as fast, due largely to the rapid increase in emissions associated with medium- and heavy-duty trucks.

Table A- 98: Total U.S. Greenhouse Gas Emissions from Transportation and Mobile Sources (Tg CO_2 Eq.)

Mode / Vehicle Type / Fuel Type	1990	1995	2000	2001	2002	2003	2004	2005	2006	Percent Change 1990-2006
Transportation Total[a]	**1,547.2**	**1,688.9**	**1,921.0**	**1,899.4**	**1,952.0**	**1,930.2**	**1,980.0**	**1,992.0**	**1,974.5**	**28%**
On-Road Vehicles	**1,231.9**	**1,362.4**	**1,560.1**	**1,568.0**	**1,608.4**	**1,619.7**	**1,656.7**	**1,658.8**	**1,653.9**	**34%**
Passenger Cars	656.9	644.1	694.6	699.1	713.7	692.4	689.5	705.8	678.4	3%
Gasoline	649.0	626.1	666.7	669.5	682.8	660.2	656.4	673.1	647.0	0%
Diesel	7.8	7.7	3.6	3.6	3.7	4.2	4.3	4.2	4.1	-48%
AFVs	+	0.1	+	+	+	+	+	+	+	452%
HFCs from Mobile AC	+	10.1	24.3	25.9	27.2	28.0	28.8	28.5	27.2	N/A
Light-Duty Trucks	336.2	434.7	508.1	513.3	525.1	560.4	583.0	544.0	556.6	66%
Gasoline	324.3	413.4	469.4	471.8	480.6	508.8	527.6	490.3	501.3	55%
Diesel	11.3	14.7	19.8	20.6	21.7	26.9	28.8	25.6	26.5	133%
AFVs	0.6	0.5	0.3	0.3	0.4	0.4	0.5	0.5	0.5	-16%
HFCs from Mobile AC	+	6.1	18.6	20.6	22.5	24.2	26.1	27.7	28.3	N/A
Medium- and Heavy-Duty Trucks	228.6	272.5	344.3	343.6	357.9	354.4	367.4	395.2	404.6	77%
Gasoline	39.3	36.5	36.8	35.8	36.4	31.4	31.7	35.5	35.9	-8%
Diesel	188.5	235.1	305.4	305.4	319.1	320.3	332.8	356.8	365.7	94%
AFVs	0.9	0.6	0.5	0.6	0.6	0.8	0.8	0.8	0.8	-8%
HFCs from Refrigerated Transport	+	0.3	1.6	1.7	1.8	1.9	2.1	2.1	2.2	N/A
Buses	8.5	9.3	11.2	10.3	10.0	10.8	15.1	12.1	12.5	47%
Gasoline	0.6	0.6	0.5	0.5	0.4	0.4	0.5	0.4	0.4	-23%
Diesel	7.9	8.6	10.1	9.2	8.7	9.5	13.5	10.6	10.9	37%
AFVs	+	0.1	0.5	0.5	0.6	0.7	0.9	0.9	0.9	30104%
HFCs from Comfort Cooling	+	+	0.1	0.2	0.2	0.2	0.2	0.2	0.3	N/A
Motorcycles	1.8	1.8	1.9	1.7	1.7	1.7	1.8	1.6	1.9	8%
Gasoline	1.8	1.8	1.9	1.7	1.7	1.7	1.8	1.6	1.9	8%

Aircraft - Domestic	**181.9**	**176.4**	**198.5**	**188.5**	**179.8**	**176.6**	**178.9**	**183.1**	**172.4**	**-5%**
Commercial Aircraft	138.1	144.6	165.9	154.4	147.6	145.4	144.4	152.0	143.6	4%
Jet Fuel	138.1	144.6	165.9	154.4	147.6	145.4	144.4	152.0	143.6	4%
General Aviation Aircraft	9.5	8.1	11.9	11.3	11.6	11.0	13.8	14.0	13.8	45%
Jet Fuel	6.3	5.3	9.3	8.9	9.2	8.8	11.6	11.5	11.5	82%
Aviation Gasoline	3.2	2.8	2.6	2.5	2.4	2.1	2.2	2.5	2.3	-27%
Military Aircraft (Jet Fuel)	34.3	23.7	20.7	22.7	20.6	20.2	20.6	17.1	15.0	-56%
Jet Fuel	34.3	23.7	20.7	22.7	20.6	20.2	20.6	17.1	15.0	-56%
Ships and Boats – Domestic[b]	**47.0**	**56.6**	**65.1**	**47.4**	**65.4**	**38.3**	**47.1**	**50.8**	**47.7**	**1%**
Gasoline	12.3	14.3	11.8	14.8	14.8	14.6	14.5	14.4	14.2	16%
Distillate Fuel	10.8	11.0	14.6	16.2	15.9	11.4	13.2	11.2	10.7	-1%
Residual Fuel	23.9	30.8	35.3	12.7	30.8	7.9	14.8	20.4	17.9	-25%
HFCs from Refrigerated Transport	+	0.6	3.4	3.7	4.0	4.3	4.6	4.7	4.9	N/A
Rail	**38.5**	**44.0**	**50.1**	**50.8**	**50.7**	**52.8**	**55.8**	**56.6**	**57.9**	**51%**
Distillate Fuel	35.4	39.6	42.0	42.2	41.9	42.8	45.1	45.5	46.5	31%
Electricity	3.0	3.1	3.4	3.6	3.4	4.3	4.5	4.7	5.0	63%
HFCs from Comfort Cooling	+	+	+	+	+	+	+	+	+	N/A
HFCs from Refrigerated Transport	+	1.4	4.6	5.0	5.4	5.8	6.1	6.4	6.5	N/A
Pipelines[c]	**36.1**	**38.2**	**35.2**	**33.6**	**36.6**	**32.7**	**31.2**	**32.3**	**32.4**	**-10%**
Natural Gas	36.1	38.2	35.2	33.6	36.6	32.7	31.2	32.3	32.4	-10%
Other Transportation	**11.9**	**11.3**	**12.1**	**11.1**	**10.9**	**10.1**	**10.2**	**10.2**	**9.9**	**-16%**
Lubricants	11.9	11.3	12.1	11.1	10.9	10.1	10.2	10.2	9.9	-16%
Unspecified[d]	+	+	+	+	+	0.1	0.1	0.2	0.2	N/A
Non-Trans Mobile Total	**101.7**	**115.1**	**125.0**	**138.8**	**142.8**	**147.0**	**153.3**	**154.9**	**159.1**	**56%**
Agricultural Equipment	**30.8**	**36.3**	**38.4**	**40.6**	**41.7**	**42.7**	**45.7**	**46.4**	**48.6**	**58%**
Gasoline	7.3	8.3	5.8	7.1	7.4	7.6	9.7	9.6	10.9	50%
Diesel	23.5	28.1	32.6	33.5	34.3	35.2	36.0	36.9	37.7	60%
Construction/ Mining Equipment	**39.4**	**46.0**	**52.1**	**56.7**	**58.4**	**60.2**	**61.9**	**62.9**	**64.3**	**63%**
Gasoline	3.5	3.2	2.3	5.1	5.3	5.6	6.0	5.5	5.5	55%
Diesel	35.9	42.9	49.8	51.7	53.1	54.5	56.0	57.4	58.8	64%
Other Equipment[e]	**31.5**	**32.7**	**34.5**	**41.5**	**42.7**	**44.1**	**45.7**	**45.5**	**46.2**	**47%**
Gasoline	24.6	24.8	25.4	32.1	33.1	34.2	35.5	35.1	35.5	44%
Diesel	6.9	8.0	9.0	9.4	9.6	9.9	10.1	10.4	10.7	55%
Total Transportation & Mobile	**1,648.9**	**1,804.1**	**2,046.0**	**2,038.2**	**2,094.8**	**2,077.1**	**2,133.2**	**2,146.7**	**2,133.4**	**29%**

Note: Emissions estimates for passenger cars, light-duty trucks and heavy-duty trucks are calculated using fuel consumption data from FHWA's Highway Statistics, which used an updated methodology to develop the 2006 estimates. In the most recent Highway Statistics, FHWA also updated 2005 fuel consumption estimates, but did not revise other prior years. This causes some discontinuity in the emissions estimates between 2004 and 2005. HFC emissions primarily reflect HFC-134a.

[a] Not including emissions from international bunker fuels.

[b] Fluctuations in emission estimates reflect data collection problems.

[c] Includes only CO_2 from natural gas used to power pipelines; does not include emissions from electricity use or non-CO_2 gases.

[d] Combination of gases; balancing item for transportation emissions not specifically identified in table but which are included in transportation economic sector emissions.

[e] "Other" includes snowmobiles and other recreational equipment, logging equipment, lawn and garden equipment, railroad equipment, airport equipment, commercial equipment, and industrial equipment.

+ Less than 0.05 Tg CO_2 Eq.

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- 99: Transportation and Mobile Source Emissions by Gas (Tg CO_2 Eq.)

Gas	1990	1995	2000	2001	2002	2003	2004	2005	2006
CO_2	1,600.7	1,727.8	1,937.5	1,927.8	1,984.7	1,967.5	2,023.0	2,038.2	2,028.5
N_2O	43.5	53.4	52.5	49.9	45.9	42.3	39.7	36.3	33.1
CH_4	4.7	4.3	3.4	3.3	3.0	2.7	2.6	2.5	2.4
HFC	+	18.6	52.6	57.2	61.1	64.4	67.8	69.7	69.5
Total	**1,648.9**	**1,804.1**	**2,046.0**	**2,038.2**	**2,094.8**	**2,077.0**	**2,133.2**	**2,146.7**	**2,133.3**

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 2006 (Tg CO_2 Eq.)

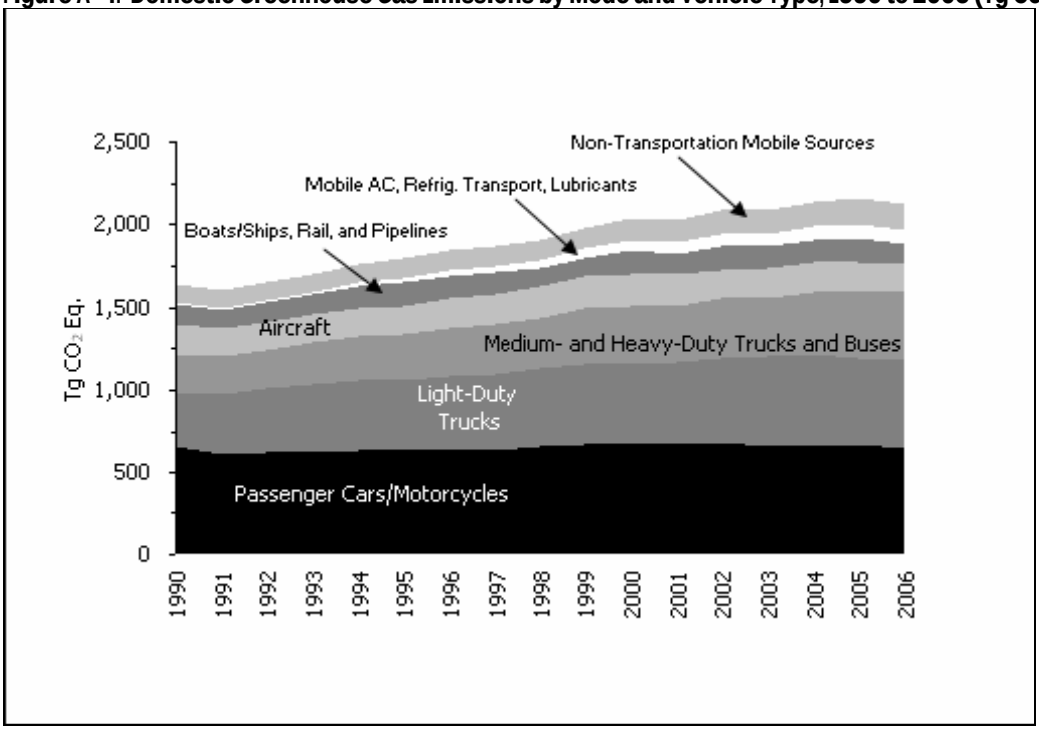

Table A- 100: Greenhouse Gas Emissions from Passenger Transportation (Tg CO_2 Eq.)

Vehicle Type	1990	1995	2000	2001	2002	2003	2004	2005	2006	% Change 1990-2006
Highway Vehicles	**1,003.3**	**1,089.9**	**1,215.8**	**1,224.4**	**1,250.5**	**1,265.3**	**1,289.3**	**1,263.6**	**1,249.3**	**25%**
Passenger Cars	656.9	644.1	694.6	699.1	713.7	692.4	689.5	705.8	678.4	3%
Light-duty Trucks	336.2	434.7	508.1	513.3	525.1	560.4	583.0	544.0	556.6	66%
Buses	8.5	9.3	11.2	10.3	10.0	10.8	15.1	12.1	12.5	47%
Motorcycles	1.8	1.8	1.9	1.7	1.7	1.7	1.8	1.6	1.9	8%
Aircraft – Domestic	**123.7**	**127.7**	**149.0**	**139.0**	**133.6**	**131.2**	**134.0**	**141.8**	**134.8**	**9%**
General Aviation	9.5	8.1	11.9	11.3	11.6	11.0	13.8	14.0	13.8	45%
Commercial Aircraft	114.2	119.5	137.2	127.7	122.1	120.3	120.2	127.7	121.0	6%
Recreational Boats	**14.2**	**16.6**	**14.5**	**17.6**	**17.6**	**17.6**	**17.6**	**17.5**	**17.4**	**23%**
Passenger Rail	**4.3**	**4.5**	**5.1**	**5.4**	**5.1**	**5.8**	**6.0**	**6.2**	**6.4**	**48%**
Total	**1,145.6**	**1,238.5**	**1,384.4**	**1,386.4**	**1,406.8**	**1,419.9**	**1,446.8**	**1,429.1**	**1,408.0**	**23%**

Note: Data from DOE (1993 through 2007) were used to disaggregate emissions from rail and buses. Emissions from HFCs have been included in these estimates.

Table A- 101: Greenhouse Gas Emissions from Domestic Freight Transportation (Tg CO_2 Eq.)

By Mode	1990	1995	2000	2001	2002	2003	2004	2005	2006	% Change 1990-2006
Trucking	228.6	272.5	344.3	343.6	357.9	354.4	367.4	395.2	404.6	77%
Freight Rail	34.1	39.6	44.9	45.5	45.6	47.0	49.8	50.4	51.5	51%
Ships and Other Boats – Domestic	32.8	40.1	50.6	29.8	47.8	20.7	29.5	33.2	30.2	-8%
Pipelines	36.1	38.2	35.2	33.6	36.6	32.7	31.2	32.3	32.4	-10%
Commercial Aircraft – Domestic	23.9	25.0	28.7	26.7	25.6	25.2	24.2	24.3	22.6	-5%
Total	**355.5**	**415.4**	**503.7**	**479.2**	**513.5**	**480.0**	**502.1**	**535.5**	**541.3**	**52%**

+ Less than 0.05 Tg CO_2 Eq.

NA = Not Applicable, as there were no HFC emissions allocated to the transport sector in 1990, and thus a growth rate cannot be calculated.

Note: Data from DOE (1993 through 2007) were used to allocate the passenger/freight split of rail emissions. Emissions from HFCs have been included in these estimates.

3.3. Methodology for Estimating CH_4 Emissions from Coal Mining

The methodology for estimating CH_4 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 CH_4 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 CH_4 Liberated and CH_4 Emitted from Underground Mines

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

Step 1.1: Estimate CH_4 Liberated from Ventilation Systems

All coal mines with detectable CH_4 emissions[33] use ventilation systems to ensure that CH_4 levels remain within safe concentrations. Many coal mines do not have detectable levels of CH_4, 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 CH_4 emissions levels at underground mines. MSHA maintains a database of measurement data from all underground mines with detectable levels of CH_4 in their ventilation air. Based on the four quarterly measurements, MSHA estimates average daily CH_4 liberated at each of the underground mines with detectable emissions.

For the years 1990 through 1996 and 1998 through 2006, 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- 102. Well over 90 percent of all ventilation emissions were concentrated in these subsets. For 1997, the complete MSHA database for all 586 mines with detectable CH_4 emissions was obtained. These mines were assumed to account for 100 percent of CH_4 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- 102). The proportion was then applied to the years 1990 through 2006 to account for the less than 10 percent of ventilation emissions coming from mines without MSHA data.

For 1990 through 1999, average daily CH_4 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 2006, MSHA provided quarterly emissions. The average daily CH_4 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 CH_4 emissions were multiplied by 92 days. Total ventilation emissions for a particular year were estimated by summing emissions from individual mines.

[33] 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- 102: 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)*

* Factor derived from a complete set of individual mine data collected for 1997.

Step 1.2: Estimate CH_4 Liberated from Degasification Systems

Coal mines use several different types of degasification systems to remove CH_4, including vertical wells and horizontal boreholes to recover CH_4 prior to mining of the coal seam. Gob wells and cross-measure boreholes recover CH_4 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 CH_4 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 CH_4 liberated from their degasification systems. For these mines, this reported information was used as the estimate. In other cases in which mines sell CH_4 recovered from degasification systems to a pipeline, gas sales were used to estimate CH_4 liberated from degasification systems (see Step 1.3). Finally, for those mines that do not sell CH_4 to a pipeline and have not provided information to EPA, CH_4 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 CH_4 liberated from the mine.

Step 1.3: Estimate CH_4 Recovered from Degasification Systems and Utilized (Emissions Avoided)

In 2006, fourteen active coal mines had CH_4 recovery and use projects, thirteen sold the recovered CH_4 to a pipeline and one used the CH_4 on site to heat mine ventilation air. Two of the coal mines that sold gas to pipelines also used CH_4 to generate electricity or 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. One mining company provided their 1605b reports, which they file annually with the Department of Energy as part of the voluntary reporting program. Emissions avoided were attributed to the year in which the coal seam was mined. For example, if a coal mine recovered and sold CH_4 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 CH_4 Emitted from Surface Mines and Post-Mining Activities

Mine-specific data were not available for estimating CH_4 emissions from surface coal mines or for post-mining activities. For surface mines and post-mining activities, basin-specific coal production was multiplied by a basin-specific emission factor to determine CH_4 emissions.

Step 2.1: Define the Geographic Resolution of the Analysis and Collect Coal Production Data

The first step in estimating CH_4 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- 103, 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- 103. 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- 104 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* CH_4 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* CH_4 content in the basin. For this analysis, the surface mining emission factor was determined to be twice the *in situ* CH_4 content in the basin. Furthermore, the post-mining emission factors used were estimated to be 25 to 40 percent of the average *in situ* CH_4 content in the basin. For this analysis, the post-mining emission factor was determined to be 32.5 percent of the *in situ* CH_4 content in the basin. Table A- 105 presents the average *in situ* content for each basin, along with the resulting emission factor estimates.

Step 2.3: Estimate CH_4 Emitted

The total amount of CH_4 emitted was calculated by multiplying the coal production in each basin by the appropriate emission factors.

Total annual CH_4 emissions are equal to the sum of underground mine emissions plus surface mine emissions plus post-mining emissions. Table A- 106 and Table A- 107 present estimates of CH_4 liberated, used, and emitted for 1990 through 2006. Table A- 108 provides emissions by state.

Table A- 103: 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-104: Annual Coal Production (Thousand Short Tons)

Basin	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Underground Coal Production	**423,556**	**406,344**	**406,335**	**351,056**	**399,102**	**396,249**	**409,850**	**420,657**	**417,729**	**391,791**	**372,766**	**380,627**	**357,384**	**352,785**	**367,531**	**368,611**	**359,020**
N. Appalachia	103,865	103,450	105,220	77,032	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
Cent. Appalachia	198,412	181,873	177,777	164,845	170,893	166,495	171,845	177,720	171,279	157,058	150,584	152,457	137,224	130,724	128,560	123,083	117,738
Warrior	17,531	17,062	15,944	15,557	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
Illinois	69,167	69,947	73,154	55,967	69,050	69,009	67,046	64,728	64,463	63,529	53,720	54,364	54,016	51,780	56,319	59,180	61,726
S. West/Rockies	32,754	31,568	31,670	35,409	41,681	42,994	43,088	44,503	45,983	46,957	45,742	51,193	52,121	56,111	59,012	60,865	59,670
N. Great Plains	1,722	2,418	2,511	2,146	2,738	2,018	2,788	2,854	1,723	1,673	1,210	0	0	32	201	572	840
West Interior	105	26	59	100	147	25	137	212	247	200	241	416	464	394	410	465	482
Northwest	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Surface Coal Production	**602,753**	**587,143**	**588,944**	**594,372**	**634,401**	**636,726**	**654,007**	**669,271**	**699,608**	**708,639**	**700,608**	**745,306**	**735,912**	**717,689**	**743,553**	**762,191**	**802,975**
N. Appalachia	60,761	51,124	50,512	48,641	44,960	39,372	39,788	40,179	41,043	33,928	34,908	35,334	30,008	27,370	28,174	28,873	28,376
Cent. Appalachia	94,343	91,785	95,163	94,433	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
Warrior	11,413	10,104	9,775	9,211	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
Illinois	72,000	63,483	58,814	50,535	51,868	40,376	44,754	46,862	47,715	40,474	33,631	40,894	39,380	36,675	34,016	33,702	33,362
S. West/Rockies	43,863	42,985	46,052	48,765	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
N. Great Plains	249,356	259,194	258,281	275,873	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
West Interior	64,310	61,889	63,562	60,574	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
Northwest	6,707	6,579	6,785	6,340	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
Total Coal Production	**1,026,309**	**993,487**	**995,279**	**945,428**	**1,033,503**	**1,032,975**	**1,063,857**	**1,089,928**	**1,118,132**	**1,093,975**	**1,073,374**	**1,127,689**	**1,093,296**	**1,070,654**	**1,111,111**	**1,130,802**	**1,161,995**
N. Appalachia	164,626	154,574	155,732	125,673	145,082	137,475	146,517	152,314	157,761	141,145	140,282	142,360	128,731	125,739	135,089	140,024	136,203
Cent. Appalachia	292,755	273,658	272,940	259,278	277,022	272,745	280,714	290,995	279,624	262,660	261,063	269,440	248,564	230,143	232,528	235,305	236,126
Warrior	28,944	27,166	25,719	24,768	23,266	24,641	24,637	24,468	23,013	19,499	20,147	19,967	21,236	23,812	25,856	24,894	22,626
Illinois	141,167	133,430	131,968	106,502	120,918	109,385	111,800	111,590	110,176	103,966	87,351	95,258	93,396	88,455	90,335	92,882	95,088
S. West/Rockies	76,617	74,553	77,722	84,174	90,800	89,637	86,902	92,877	95,618	96,207	95,239	103,373	102,127	97,348	101,570	103,621	96,468
N. Great Plains	251,078	261,612	260,792	278,019	311,017	333,385	346,192	352,466	387,161	406,324	408,880	438,367	441,346	444,039	466,425	474,628	518,976
West Interior	64,415	61,915	63,621	60,674	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
Northwest	6,707	6,579	6,785	6,340	6,460	6,566	6,046	5,945	5,982	5,665	5,911	6,138	6,973	7,313	7,165	6,720	4,005

Source for 1990-2006 data: EIA (1990 through 06), Annual Coal Report. U.S. Department of Energy, Washington, DC, Table 1.
Note: Totals may not sum due to independent rounding.

Table A-105: Coal Surface and Post-Mining CH_4 Emission Factors (ft^3 per Short Ton)

Basin	Surface Average *in situ* Content	Underground Average *In situ* 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- 106: Underground Coal Mining CH_4 Emissions (Billion Cubic Feet)

Activity	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Ventilation Output	112	NA	NA	95	96	100	90	96	94	92	87	84	79	76	83	75	79
Adjustment Factor for Mine Data*	97.8%	NA	NA	97.8%	97.8%	91.4%	91.4%	100%	97.8%	97.8%	97.8%	97.8%	97.8%	97.8%	97.8%	97.8%	97.8%
Adjusted Ventilation Output	114	NA	NA	97	98	109	99	96	96	94	89	86	80	77	84	77	81
Degasification System Liberated	54	NA	NA	45	46	47	49	42	49	40	45	49	50	50	50	48	54
Total Underground Liberated	168	164	162	142	144	153	148	139	146	134	134	135	131	127	132	129	135
Recovered & Used	(14)	(14)	(16)	(23)	(27)	(31)	(35)	(28)	(35)	(31)	(37)	(41)	(43)	(38)	(40)	(37)	(46)
Total	**154**	**150**	**145**	**120**	**117**	**116**	**113**	**115**	**111**	**103**	**97**	**94**	**88**	**89**	**94**	**89**	**89**

* Refer to Table A- 102.

Note: Totals may not sum due to independent rounding.

Table A- 107: Total Coal Mining CH_4 Emissions (Billion Cubic Feet)

Activity	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Underground Mining	154	150	145	120	117	116	113	115	111	103	97	94	88	89	94	87	89
Surface Mining	30	28	29	28	29	28	29	31	30	31	30	33	32	31	32	33	35
Post-Mining (Underground)	19	18	18	16	17	17	18	18	18	17	17	17	16	16	16	16	15
Post-Mining (Surface)	5	5	5	4	5	5	5	5	5	5	5	5	5	5	5	5	6
Total	**208**	**200**	**196**	**167**	**168**	**166**	**155**	**169**	**166**	**156**	**149**	**149**	**141**	**141**	**148**	**141**	**145**

Note: Totals may not sum due to independent rounding.

Table A- 108: Total Coal Mining CH_4 Emissions by State (Million Cubic Feet)

State	1990		1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Alabama	32,272		29,618	33,735	29,556	54,629	27,111	25,702	23,342	18,661	18,686	19,288	22,330	16,384	14,255
Alaska	63		58	63	55	54	50	58	61	56	43	40	56	54	53
Arizona	192		222	203	177	199	192	200	223	228	217	205	216	205	139
Arkansas	7		8	5	4	3	4	4	2	2	2	1	1	1	3
California	1		-	-	-	-	0	0	0	0	0	0	0	0	0
Colorado	10,325		9,192	7,582	5,972	16,499	9,181	9,390	10,808	10,620	12,082	13,216	12,582	13,608	13,102
Illinois	10,502		10,585	11,563	10,876	15,836	7,847	7,810	8,542	10,024	5,972	4,744	5,798	6,586	6,954
Indiana	2,795		2,495	2,025	2,192	2,861	2,878	2,650	2,231	3,373	3,496	3,821	3,531	3,702	4,029
Iowa	30		4	-	-	-	0	0	0	0	0	0	0	0	0
Kansas	57		23	23	19	29	27	33	16	14	16	12	6	14	34
Kentucky	10,956		11,259	10,269	8,987	15,237	10,005	9,561	9,105	9,397	8,464	8,028	7,926	7,494	8,599
Louisiana	81		89	95	82	91	82	76	94	95	97	103	97	106	627
Maryland	519		237	237	259	267	251	225	331	340	401	391	411	421	280
Mississippi	-		-	-	-	-	0	1	57	43	165	264	256	254	403
Missouri	211		67	44	57	32	30	31	35	29	20	43	46	48	65
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	1,664
New Mexico	451		679	586	408	459	489	497	464	630	1,280	1,864	2,052	3,001	2,959
North Dakota	1,358		1,501	1,400	1,389	1,375	1,391	1,448	1,454	1,417	1,432	1,431	1,392	1,393	1,500
Ohio	5,065		4,583	4,189	4,068	6,247	4,350	3,914	3,519	3,619	2,831	2,649	3,183	3,385	2,749
Oklahoma	285		359	323	286	503	395	469	454	620	660	620	849	877	1,398
Pennsylvania	22,735		24,024	25,611	26,440	47,795	29,491	24,867	24,830	23,659	19,668	20,281	20,020	18,191	15,911
Tennessee	296		101	112	143	158	116	119	99	142	142	124	136	140	2,737
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	1,039
Utah	3,587		2,626	2,570	2,810	6,270	3,859	3,633	2,816	2,080	2,709	3,408	5,253	4,787	4,768
Virginia	46,137		26,742	20,059	19,771	28,553	13,978	13,321	12,065	-14,309	11,227	11,906	11,389	8,790	8,770
Washington	186		182	181	170	167	173	153	159	172	217	232	210	196	2,595
West Virginia	49,039		30,664	30,552	36,384	52,332	36,962	33,660	30,827	54,110	31,482	28,599	29,550	30,612	25,778
Wyoming	8,496		10,912	12,185	12,838	12,999	14,549	15,607	15,725	17,147	17,352	17,497	18,435	18,784	20,505
Total	**208.822**		**169,503**	**166,793**	**166,109**	**265,864**	**166,748**	**156,697**	**150,282**	**145,142**	**141,557**	**141,699**	**148,752**	**142,075**	**140,915**

+ 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 CH_4 and CO_2 Emissions from Natural Gas Systems

The following steps were used to estimate CH_4 and non-energy CO_2 emissions from natural gas systems.

Step 1: Calculate Emission Estimates for Base Year 1992 Using GRI/EPA Study

The first step in estimating CH_4 and non-energy related (i.e., fugitive, vented and flared) CO_2 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 80 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, the EPA has updated activity data for some of the components in the system. Table A- 109 displays the 1992 GRI/EPA activity levels and CH_4 emission factors for the natural gas distribution stage, and the current EPA activity levels and emission factors. These data are shown to illustrate the kind of data used to calculate CH_4 and non-energy CO_2 emissions from all stages. For most sources, the CH_4 emission factors were adjusted for CO_2 content when estimating fugitive and vented non-energy CO_2 emissions. In the case of non-energy CO_2 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.

Step 2: Collect Aggregate Statistics on Main Driver Variables

As detailed data on each of the over 80 sources were not available for the period 1990 through 2006, activity levels were estimated using aggregate statistics on key drivers, including: number of producing wells (EIA 2007a-b, New Mexico 2007a-b, Texas 2007a-b), number of gas plants (AGA 1991-1998; OGJ 1997-2007), number of shallow and deep offshore platforms (MMS 2007a-e), miles of transmission pipeline (OPS 2007a), miles of distribution pipeline (OPS 2007b), miles of distribution services (OPS 2007b), energy consumption (EIA 2007c). Data on the distribution of gas mains and services by material type was not available for 1990 through 1992 from OPS. For those years, the distribution by type was back calculated from 1993 using compound growth rates determined for the years 1993 through 2000. Table A- 110 provides the activity levels of some of the key drivers in the natural gas analysis.

Step 3: Estimate CH_4 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 CH_4 reductions reported to the Natural Gas STAR Program and CH_4 reductions resulting from National Emission Standards for Hazardous Air Pollutants (NESHAP) regulations.

Industry partners report CH_4 emission reductions by project to the Natural Gas STAR Program. The reductions are estimates using actual measurement data or equipment-specific emission factors. Before incorporating the reductions into the Inventory, quality assurance and quality control checks are undertaken to identify errors, inconsistencies, or irregular data. The 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 were 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 sunsetting time period, which removes reductions from the accounting system after a set time period. In future inventories, the sunsetting may be replaced with a technological lifetime. Methane emission reductions from the Natural Gas STAR Program beyond the efforts reflected in the 1992 base year are summarized in Table A- 111.

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 a part of secondary emission reductions. These emission reductions are estimated in Table A- 112.

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.

Step 4: Estimate CO_2 Emissions for Each Year and Stage

The same procedure for estimating CH_4 emissions holds true for estimating non-energy related CO_2 emissions, except the emissions estimates are not corrected for reductions due to the Natural Gas STAR program or the NESHAP regulations.

Produced natural gas is composed of primarily methane, but as shown in Table A- 117, the natural gas contains, in some cases, as much as 8 percent CO_2. The same vented and fugitive emissions of natural gas that led to CH_4 emissions also contain a certain volume of CO_2. Accordingly, the CO_2 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 CO_2 content in each sector.

Using the default methane content of produced natural gas from EPA/GRI (1996) of 78.8 percent, the corresponding amount of CO_2 emissions from the production sector can be estimated. Each sector of the natural gas system has varying CO_2 contents, similar to the way the methane content varies among the sectors. Table A- 118 shows the CO_2 content for the different well types in the production sector of the natural gas system. In the estimation of CO_2 emissions from the production sector, the production sector methane emission factors were used as a basis to estimate CO_2 emissions; however, they were converted to CO_2 emissions factors by multiplication with a conversion factor. This conversion factor is the ratio of CO_2 content in the gas stream (in this case the production concentrations provided in Table A- 117) to the corresponding CH_4 content of the same gas stream. The three exceptions to this methodology are CO_2 emissions from flares, acid gas removal units, and condensate tanks. In the case of flare emissions a direct CO_2 emissions 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 is reported as vented and flared onshore by EIA. The amount of CO_2 emissions from an acid gas unit in a processing plant is equal to the difference in CO_2 concentrations between produced natural gas and pipeline quality gas applied to the thoughput of the plant. This methodology was applied to the national gas throughput using national average CO_2 concentrations in produced gas (3.45 percent) and transmission quality gas (1 percent). For condensate tanks, a series of API Tankcalc (EPA 1999) simulations provide the total CO_2 vented per barrel of condensate throughput from fixed roof tank flash gas for condensate gravities of API 44 degree and higher. The ratios of emissions to throughput were used to estimate the CO_2 emissions factor for condensate passing through fixed roof tanks. The detailed source emission estimates for CH_4 and CO_2 from the production sector are presented in Table A- 113 and Table A- 118 respectively.

In the processing sector, the CO_2 content of the natural gas remains the same as the CO_2 content in the production sector for the equipment upstream of 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 CO_2 content in gas for the remaining equipment that is downstream of acid gas removal is the same as in pipeline quality gas. The EPA/GRI study estimates the average methane content of natural gas in the processing sector to be 87 percent methane. Consequently, the processing sector methane emission factors were proportioned to reflect the CO_2 content of either produced natural gas or pipeline quality gas using the same methodology as the production

sector. The detailed source emissions estimates for CH_4 and CO_2 from the processing sector are presented in Table A- 114 and Table A- 119 respectively.[34]

For the transmission sector, CO_2 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 CO_2 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 CO_2 emissions for the transmission sector the methane emission factors were proportioned from the 93.4 percent CH_4 reported in EPA/GRI (1996) to reflect the 1 percent CO_2 content found in transmission quality natural gas. The detailed source emission estimates for CH_4 and CO_2 for the transmission sector are presented in Table A- 115 and Table A- 120 respectively.

The natural gas in the distribution sector of the system has the same characteristics as the natural gas in the transmission sector. The CH_4 content (93.4 percent) and CO_2 content (1 percent) are identical due to the absence of any further treatment between sector boundaries. Thus, the CH_4 emissions factors were converted to CO_2 emissions factors using the same methodology as discussed for the transmission sector. The detailed source emission estimates for CH_4 and CO_2 for the distribution sector are presented in Table A- 116 and Table A- 121 respectively.

Because Partners report only CH_4 emission reductions to the Natural Gas STAR Program, there was no need to adjust for the Natural Gas STAR program in the CO_2 emissions estimates for any of the sectors in the natural gas system. The impact of NESHAP regulations on CO_2 emission reductions are not currently addressed in the CO_2 emission estimates.

[34] This methodology assumes that anthropogenic CO_2 emitted from natural gas processing plants is emitted to the atmosphere. CO_2 capture for enhanced oil recovery is currently not accounted for in the Inventory.

Table A-109: 1992 Data and CH_4 Emissions (Mg) for the Natural Gas Distribution Stage

	GRI/EPA Values			*EPA Adjusted Values*		
Activity	**Activity Data**	**Emission Factor**	**Emissions**	**Activity Data**	**Emission Factor**	**Emissions**
Pipeline Leaks						
Mains—Cast Iron	55,288 miles	238.70 Mscf/mile-yr	254,178.95	55,288 miles	238.70 Mscf/mile-yr	254,178.95
Mains—Unprotected steel	174,657 equiv leaks	51.80 Mscf/leak-yr	174,249.70	82,109 miles	110.19 Mscf/mile-yr	179,256.43
Mains—Protected steel	68,308 equiv leaks	20.30 Mscf/leak-yr	26,706.93	451,466 miles	3.07 Mscf/mile-yr	26,667.46
Mains—Plastic	49,226 equiv leaks	99.80 Mscf/leak-yr	94,619.66	299,421 miles	9.91 Mscf/mile-yr	57,149.47
Services—Unprotected steel	458,476 equiv leaks	20.20 Mscf/leak-yr	178,371.00	5,446,393 services	1.70 Mscf/service	178,406.33
Services Protected steel	390,628 equiv leaks	9.20 Mscf/leak-yr	69,216.16	20,352,983 services	0.18 Mscf/service	69,186.06
Services—Plastic	68,903 equiv leaks	2.39 Mscf/leak-yr	3,171.70	17,681,238 services	0.01 Mscf/service	3,166.39
Services—Copper	7,720 equiv leaks	7.68 Mscf/leak-yr	1,141.92	233,246 services	0.25 Mscf/service	1,142.51
Meter/Regulator (City Gates)						
M&R >300	3,460 stations	179.80 scfh/station	104,960.57	3,460 stations	179.80 scfh/station	104,960.57
M&R 100-300	13,335 stations	95.60 scfh/station	215,085.58	13,335 stations	95.60 scfh/station	215,085.58
M&R <100	7,127 stations	4.31 scfh/station	5,182.56	7,127 stations	4.31 scfh/station	5,182.56
Reg >300	3,995 stations	161.90 scfh/station	109,124.94	3,995 stations	161.90 scfh/station	109,124.94
R-Vault >300	2,346 stations	1.30 scfh/station	514.55	2,346 stations	1.30 scfh/station	514.55
Reg 100-300	12,273 stations	40.50 scfh/station	83,862.18	12,273 stations	40.50 scfh/station	83,862.18
R-Vault 100-300	5,514 stations	0.18 scfh/station	167.46	5,514 stations	0.18 scfh/station	167.46
Reg 40-100	36,328 stations	1.04 scfh/station	6,374.34	36,328 stations	1.04 scfh/station	6,374.34
R-Vault 40-100	32,215 stations	0.09 scfh/station	470.15	32,215 stations	0.09 scfh/station	470.15
Reg <40	15,377 stations	0.13 scfh/station	345.05	15,377 stations	0.13 scfh/station	345.05
Customer Meters						
Residential	40,049,306 outdoor meters	138.50 scfy/meter	106,831.92	40,049,306 outdoor meters	143.27 scfy/meter	110,511.83
Commercial/Industry	4,608,000 meters	47.90 scfy/meter	4,251.13	4,607,983 meters	47.90 scfy/meter	4,251.11
Routine Maintenance						
Pressure Relief Valve Releases	836,760 mile main	0.05 Mscf/mile	805.80	888,284 mile main	0.05 Mscf/mile	855.42
Pipeline Blowdown	1,297,569 miles	0.10 Mscfy/mile	2,549.10	1,297,569 miles	0.10 Mscfy/mile	2,549.10
Upsets						
Mishaps (Dig-ins)	1,297,569 miles	1.59 mscfy/mile	39,735.97	1,297,569 miles	1.59 mscfy/mile	39,735.97

Table A- 110: Key Activity Data Drivers

Variable	Units	1990	1995	2000	2001	2002	2003	2004	2005	2006
Transmission Pipelines Length	**miles**	291,990	296,947	298,957	290,462	303,528	301,961	302,948	300,556	300,620
Wells										
NE—Associated Gas Wells*	# wells	68,261	66,102	58,671	54,727	52,928	47,803	47,412	46,471	47,034
NE—Non-associated Gas Wells*	# wells	124,241	129,789	143,922	149,436	154,590	156,320	155,257	153,103	164,319
MC—Associated Gas Wells*	# wells	64,379	72,483	67,880	67,278	65,786	65,864	65,902	64,861	65,903
MC—Non-associated Gas Wells*	# wells	53,940	65,033	51,217	63,595	67,861	70,377	72,809	76,411	73,914
RM—Associated Gas Wells*	# wells	13,749	13,745	12,328	12,148	12,446	12,495	12,723	13,495	13,579
RM—Non-associated Gas Wells*	# wells	24,339	32,347	64,539	70,450	72,438	71,239	70,770	72,025	75,614
SW—Associated Gas Wells*	# wells	69,339	59,954	54,830	57,188	60,623	60,315	59,381	59,409	55,301
SW—Non-associated Gas Wells*	# wells	24,217	27,086	32,346	33,936	35,025	36,648	37,219	34,606	36,159
WC—Associated Gas Wells*	# wells	20,672	19,109	20,494	20,808	22,503	22,263	22,584	21,562	22,189
WC—Non-associated Gas Wells*	# wells	1,292	1,114	1,338	1,434	1,415	1,459	1,388	1,410	1,503
GC—Associated Gas Wells*	# wells	36,279	34,729	32,497	32,549	29,880	28,078	27,675	28,104	27,319
GC—Non-associated Gas Wells*	# wells	41,753	41,978	48,316	51,182	53,198	54,245	54,544	57,600	60,715
Platforms										
Gulf of Mexico and Pacific OCS Off-shore Platforms	# platforms	3,939	3,981	4,027	4,075	4,057	4,013	3,940	3,913	3,913
GoM and Pacific OCS Deep Water Platforms	# platforms	17	23	38	40	44	46	50	59	67
Gas Plants	**# gas plants**	761	675	585	570	590	574	572	566	571
Distribution Services	**# of services**	47,883,083	54,644,033	56,761,042	57,461,795	58,876,416	58,537,395	61,089,889	58,556,335	62,255,435
Steel—Unprotected	# of services	7,633,526	6,151,653	5,675,520	5,449,653	5,186,134	4,840,347	4,791,652	5,308,375	5,642,470
Steel—Protected	# of services	19,781,581	21,002,455	17,855,560	17,911,402	17,778,463	17,258,710	18,147,587	15,883,423	15,732,037
Plastic	# of services	18,879,865	26,044,545	31,795,871	32,706,753	34,547,274	35,071,961	36,811,107	36,152,277	39,632,313
Copper	# of services	1,588,111	1,445,380	1,434,091	1,393,987	1,364,545	1,366,377	1,339,543	1,212,260	1,248,615
Distribution Mains	**miles**	944,157	1,001,706	1,048,485	1,099,137	1,133,625	1,104,683	1,151,995	1,093,909	1,209,419
Cast Iron	miles	58,292	50,625	44,750	44,283	42,025	41,091	40,600	37,371	36,977
Steel—Unprotected	miles	108,941	94,058	82,800	81,291	78,119	74,042	75,859	69,291	71,738
Steel—Protected	miles	465,538	503,288	471,510	475,329	480,982	483,782	495,861	461,459	481,811
Plastic	miles	311,386	353,735	449,425	498,234	532,499	505,768	539,675	525,788	618,893

* 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- 111: CH_4 reductions derived from the Natural Gas STAR program (Gg)

Process	1992	1995	2000	2001	2002	2003	2004	2005	2006
Production	0	75	319	384	422	568	920	1,307	1,284
Processing	0	5	17	22	28	58	49	109	119
Transmission and Storage	0	120	262	339	346	332	417	509	484
Distribution	0	20	27	33	163	111	96	39	123
Total	**0**	**219**	**624**	**778**	**958**	**1,070**	**1,483**	**1,964**	**2,010**

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 sunsetting period.

Table A- 112: CH_4 reductions derived from NESHAP regulations (Gg)

Process	1999	2000	2001	2002	2003	2004	2005	2006
Production	24.1	25.4	27.7	28.6	28.7	28.4	29.0	29.9
Processing	11.3	11.5	11.7	11.3	11.4	11.1	10.8	11.1
Transmission and Storage	0	0	0	0	0	0	0	0
Distribution	0	0	0	0	0	0	0	0
Total	**35.3**	**36.9**	**39.4**	**40.0**	**40.1**	**39.5**	**39.8**	**41.0**

Note: NESHAP regulations went into effect in 1999.

Table A- 113: CH_4 Emission Estimates from the Natural Gas Production Stage (Gg)

Activity	1990	1992	1995	2000	2001	2002	2003	2004	2005	2006
Normal Fugitives										
Gas Wells										
Associated Gas Wells	30.81	31.73	37.68	48.23	50.69	51.59	51.15	50.50	49.78	51.66
Unconventional Gas Wells	0.01	0.02	0.04	0.26	0.47	0.67	0.85	0.99	1.20	1.32
Field Separation Equipment										
Heaters	12.57	13.28	16.48	23.56	25.61	26.44	26.61	26.67	26.93	28.17
Separators	43.83	44.16	54.81	76.54	81.59	84.19	85.11	85.30	86.57	90.88
Dehydrators	14.75	15.76	17.90	20.78	22.43	23.29	23.64	23.74	23.97	24.99
Meter/ Piping	43.61	44.96	54.91	73.82	79.37	82.00	82.79	83.11	83.84	87.75
Gathering Compressors										
Small Reciprocating Comp.	30.22	32.15	38.28	45.58	50.63	52.54	53.55	54.01	53.91	56.35
Large Reciprocating Comp.	7.50	8.57	9.87	11.85	12.78	12.78	12.78	12.79	12.78	12.78
Large Reciprocating Stations	0.51	0.58	0.67	0.80	0.87	0.87	0.87	0.87	0.87	0.87
Pipeline Leaks	98.00	102.40	115.52	135.09	143.27	147.35	148.92	149.55	150.58	155.76
Vented and Combusted										
Drillling and Well Completion										
Completion Flaring	.0055	0.0058	.0064	0.01	0.008	0.008	0.008	0.01	0.01	0.01
Well Drilling	0.74	0.560	0.58	0.99	1.28	1.01	1.16	1.27	1.56	1.86
Coal Bed Methane										
Powder River	0.04	0.47	1.47	28.60	40.35	46.90	46.58	44.48	46.10	56.31
Black Warrior	2.72	4.84	6.25	6.82	7.32	7.81	8.53	9.22	9.87	10.45
Normal Operations										
Pneumatic Device Vents	569.61	607.00	703.98	820.38	906.26	943.88	959.11	968.30	968.73	1009.64
Chemical Injection Pumps	26.89	29.38	35.09	43.51	48.94	49.41	51.44	51.89	52.03	54.20
Kimray Pumps	131.81	140.68	159.62	185.28	200.04	207.73	210.83	211.75	213.80	222.87
Dehydrator Vents	41.10	43.56	49.77	57.77	62.38	64.77	65.74	66.03	66.67	69.49
Condensate Tank Vents										
Condensate Tanks without Control Device	23.59	21.69	20.22	21.48	23.80	24.43	23.59	22.53	23.59	23.59
Condensate Tanks with Control Devices	4.72	4.34	4.04	4.30	4.76	4.89	4.71	4.50	4.72	4.72
Compressor Exhaust Vented Gas Engines	119.06	125.48	151.42	180.03	200.20	208.50	212.13	214.63	215.26	224.96
Well Workovers										
Gas Wells	0.56	0.581	0.65	0.75	0.81	0.84	0.85	0.86	0.87	0.90
Well Clean Ups (LP Gas Wells)	106.74	111.85	124.46	143.88	155.43	161.61	164.12	164.96	166.45	173.50
Blowdowns										

Vessel BD	0.36	0.38	0.42	0.50	0.53	0.56	0.57	0.57	0.57	0.60
Pipeline BD	1.56	1.63	1.84	2.15	2.28	2.37	2.37	2.38	2.40	2.48
Compressor BD	1.17	1.24	1.48	1.76	1.96	2.03	2.07	2.09	2.08	2.18
Compressor Starts	2.61	2.78	3.31	3.94	4.37	4.53	4.62	4.67	4.66	4.87
Upsets										
Pressure Relief Valves	0.34	0.36	0.42	0.46	0.494	0.51	0.52	0.52	0.53	0.55
Mishaps	0.84	0.88	1.00	1.16	1.24	1.28	1.28	1.29	1.30	1.34
Offshore										
Offshore water Gas Platforms (GoM & Pacific)	219.57	225.19	232.59	245.51	250.58	251.45	250.77	245.90	243.63	243.08
Deepwater Gas Platforms (GoM &Pacific)	2.73	3.11	3.87	6.70	7.12	7.90	8.33	9.06	10.69	12.14
Total	**1,539**	**1,622**	**1,849**	**2,192**	**2,388**	**2,474**	**2,506**	**2,514**	**2,526**	**2,630**

Table A- 114: CH_4 Emission Estimates from the Natural Gas Processing Plants (Gg)

Activity	1990	1992	1995	2000	2001	2002	2003	2004	2005	2006
Normal Fugitives										
Plants	41.95	40.35	37.21	32.25	31.42	32.52	31.64	31.53	31.20	31.48
Reciprocating Compressors	322.06	322.07	334.99	345.96	353.75	341.19	343.86	334.80	324.97	334.18
Centrifugal Compressors	108.35	108.35	112.70	116.39	119.01	114.78	115.68	112.64	109.32	112.43
Vented and Combusted										
Normal Operations										
Compressor Exhaust										
Gas Engines	128.32	128.32	133.47	137.84	140.94	135.94	137	129.47	129.47	133.14
Gas Turbines	3.61	3.61	3.76	3.88	3.97	3.83	3.86	3.65	3.65	3.75
AGR Vents	16.49	15.87	14.62	12.68	12.35	12.79	12.44	12.27	12.27	12.38
Kimray Pumps	3.28	3.28	3.41	3.52	3.60	3.47	3.50	3.31	3.31	3.40
Dehydrator Vents	20.20	20.2	21.01	21.70	22.19	21.40	21.57	20.39	20.39	20.96
Pneumatic Devices	2.39	2.30	2.12	1.84	1.79	1.86	1.81	1.78	1.78	1.80
Routine Maintenance										
Blowdowns/Venting	59.02	56.77	52.35	45.37	44.20	45.76	44.51	43.90	43.90	44.28
Total	**706**	**701**	**716**	**721**	**733**	**714**	**716**	**699**	**680**	**698**

Table A- 115: CH_4 Emission Estimates from the Natural Gas Transmission and Storage (Gg)

Activity	1990	1992	1995	2000	2001	2002	2003	2004	2005	2006
Fugitives										
Pipelines Leaks	3.11	3.11	3.17	3.19	3.10	3.24	3.22	3.23	3.20	3.21
Compressor Stations (Transmission)										
Station	105.12	104.93	106.90	107.63	104.57	109.27	108.71	109.06	108.20	108.23
Recip Compressor	728.04	726.74	740.40	745.42	724.23	756.81	752.91	755.37	749.40	749.56
Centrifugal Compressor	145.34	145.08	147.81	148.81	144.58	151.08	150.30	150.80	149.60	149.64
Compressor Stations (Storage)										
Station	54.64	58.36	60.35	62.17	59.37	60.84	63.20	60.59	59.80	53.94
Recip Compressor	157.80	168.48	174.27	179.62	171.45	175.76	182.59	175.01	172.79	155.87
Centrifugal Compressor	22.35	23.86	24.72	25.58	24.29	24.93	26.01	24.93	24.50	22.14
Wells (Storage)	13.56	14.49	14.98	15.43	14.74	15.10	15.69	15.04	14.85	13.39
M&R (Trans. Co. Interconnect)	71.04	70.92	72.25	72.74	70.67	73.85	73.47	73.71	73.13	73.14
M&R (Farm Taps + Direct Sales)	15.96	15.93	16.23	16.34	15.88	16.59	16.50	16.56	16.43	16.43
Vented and Combusted										
Normal Operation										
Dehydrator Vents (Transmission)	1.96	1.96	1.99	2.01	1.95	2.04	2.03	2.03	2.02	2.02
Dehydrator Vents (Storage)	4.23	4.51	4.67	4.81	4.59	4.71	4.89	4.69	4.63	4.17
Compressor Exhaust Engines (Transmission)	178.73	186.65	206.10	222.84	212.39	219.72	212.75	213.82	212.41	208.39

Turbines (Transmission)	1.01	1.06	1.17	1.26	1.20	1.25	1.21	1.21	1.20	1.18
Engines (Storage)	21.30	22.75	23.53	24.24	23.14	23.72	24.64	23.62	23.31	21.03
Turbines (Storage)	0.18	0.19	0.20	0.20	0.19	0.20	0.21	0.20	0.19	0.18
Generators (Engines)	8.75	9.13	10.09	10.90	10.39	10.75	10.41	10.46	10.39	10.20
Generators (Turbines)	0.00	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	212.01	221.55	220.41	221.13	219.38	219.43
Pneumatic Devices Storage	45.22	48.30	49.95	51.44	49.13	50.35	52.30	50.14	49.49	44.64
Routine Maintenance/Upsets										
Pipeline Venting	173.74	173.43	176.69	177.88	172.83	180.60	179.67	180.26	178.83	178.87
Station venting Trans+Storage										
Station Venting Transmission	143.02	142.76	145.44	146.43	142.27	148.67	147.90	148.38	147.21	147.24
Station Venting Storage	30.34	32.41	33.51	34.52	32.97	33.78	35.09	33.64	33.21	29.95
LNG Storage										
LNG Stations	9.24	9.45	9.77	10.30	10.41	10.52	10.62	10.62	10.62	10.62
LNG Reciprocating Compressors	34.50	35.37	36.67	38.84	39.28	39.71	40.15	40.15	40.15	40.15
LNG Centrifugal Compressors	11.78	12.09	12.55	13.31	13.46	13.61	13.77	13.77	13.77	13.77
LNG Compressor Exhaust										
LNG Engines	3.21	3.23	3.25	3.30	3.30	3.31	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	0.01
LNG Station Venting	5.13	5.25	5.43	5.72	5.78	5.84	5.90	5.90	5.90	5.90
LNG Import Terminals										
LNG Stations	0.21	0.21	0.21	0.21	0.32	0.32	0.42	0.42	0.42	0.42
LNG Reciprocating Compressors	1.01	1.01	1.01	1.01	1.51	1.51	2.02	2.02	2.02	2.02
LNG Centrifugal Compressors	0.26	0.26	0.26	0.26	0.39	0.39	0.52	0.52	0.52	0.52
LNG Compressor Exhaust										
LNG Engines	1.74	0.96	0.49	4.41	4.70	4.52	9.83	12.57	12.18	11.28
LNG Turbines	0.01	0.00	0.00	0.03	0.03	0.03	0.06	0.07	0.07	0.07
LNG Station Venting	0.12	0.12	0.12	0.12	0.18	0.18	0.24	0.24	0.24	0.24
Total	**2,206**	**2,236**	**2,301**	**2,349**	**2,275**	**2,365**	**2,371**	**2,363**	**2,343**	**2,301**

Table A- 116: CH_4 Emission Estimates from the Natural Gas Distribution Stage (Gg)

Activity	1990	1992	1995	2000	2001	2002	2003	2004	2005	2006
Pipeline Leaks										
Mains—Cast Iron	280.00	254.18	243.17	214.95	212.71	201.86	197.37	195.02	179.50	177.62
Mains—Unprotected steel	190.56	174.26	164.53	144.84	142.20	136.65	129.52	132.69	121.21	125.49
Mains—Protected steel	26.46	26.67	28.61	26.80	27.02	27.34	27.50	28.19	26.23	27.39
Mains—Plastic	66.58	57.15	75.63	96.09	106.53	113.86	108.14	115.39	112.42	132.33
Services—Unprotected steel	190.78	178.41	153.74	141.84	136.20	129.61	120.97	119.75	132.67	141.02
Services Protected steel	69.32	69.19	73.60	62.57	62.77	62.30	60.48	63.60	55.66	55.13
Services—Plastic	2.89	3.17	3.99	4.87	5.00	5.29	5.37	5.63	5.53	6.06
Services—Copper	1.16	1.14	1.05	1.04	1.02	0.99	1.00	0.98	0.88	0.91
Meter/Regulator (City Gates)				-						
M&R >300	98.27	104.96	108.55	111.81	106.77	109.41	113.66	108.97	107.56	97.01
M&R 100-300	201.39	215.09	222.43	229.12	218.80	224.21	232.92	223.29	220.40	198.80
M&R <100	4.85	5.18	5.36	5.52	5.27	5.40	5.61	5.38	5.31	4.79
Reg >300	102.17	109.12	112.85	116.24	111.01	113.75	118.17	113.29	111.82	100.86
R-Vault >300	0.48	0.51	0.53	0.55	0.52	0.54	0.56	0.53	0.53	0.48
Reg 100-300	78.52	83.86	86.73	89.33	85.31	87.42	90.82	87.06	85.94	77.51
R-Vault 100-300	0.16	0.17	0.17	0.18	0.17	0.17	0.18	0.17	0.17	0.15
Reg 40-100	5.97	6.37	6.59	6.79	6.48	6.64	6.90	6.62	6.53	5.89
R-Vault 40-100	0.44	0.47	0.49	0.50	0.48	0.49	0.51	0.49	0.48	0.43
Reg <40	0.32	0.35	0.36	0.37	0.35	0.36	0.37	0.36	0.35	0.32
Customer Meters										
Residential	103.47	110.51	114.29	117.72	112.42	115.20	119.68	114.73	113.24	102.15
Commercial/Industry	3.97	4.25	4.78	4.66	4.27	4.38	4.25	4.27	4.05	3.90

Routine Maintenance										
Pressure Relief Valve Releases	0.91	0.86	0.97	1.03	1.09	1.12	1.09	1.14	1.09	1.21
Pipeline Blowdown	2.39	2.55	2.64	2.72	2.59	2.66	2.76	2.65	2.61	2.36
Upsets										
Mishaps (Dig-ins)	37.20	39.74	41.09	42.33	40.42	41.42	43.03	41.25	40.72	36.73
Total	**1,468**	**1,448**	**1,452**	**1,422**	**1,389**	**1,391**	**1,391**	**1,371**	**1,335**	**1,299**

Table A- 117: U.S. Production Sector CO_2 Content in Natural Gas by NEMS Region and Natural Gas Well type

	U.S. Region						
Well Types	**North East**	**Mid-Central**	**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- 118: CO_2 Emission Estimates from the Natural Gas Production Stage (Gg)

Activity	**1990**	**1992**	**1995**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**
Normal Fugitives										
Gas Wells										
Associated Gas Wells	3.56	3.57	4.25	6.43	6.69	6.67	6.43	6.26	6.02	6.22
Unconventional Gas Wells	0.00	0.00	0.00	0.01	0.01	0.01	0.02	0.02	0.03	0.03
Field Separation Equipment										
Heaters	1.86	1.91	2.32	3.95	4.29	4.42	4.39	4.38	4.44	4.64
Separators	6.04	5.97	7.17	11.29	12.17	12.55	12.56	12.56	12.70	13.29
Dehydrators	1.50	1.54	1.73	2.58	2.73	2.81	2.81	2.79	2.83	2.96
Meter/ Piping	5.85	5.85	6.95	10.90	11.76	12.12	12.12	12.11	12.23	12.78
Gathering Compressors										
Small Reciprocating Comp.	2.95	2.98	3.57	5.46	5.94	6.13	6.15	6.16	6.18	6.46
Large Reciprocating Comp.	0.69	0.91	1.02	1.33	1.40	1.40	1.40	1.40	1.40	1.40
Large Reciprocating Stations	0.05	0.06	0.07	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Pipeline Leaks	10.75	10.85	11.99	16.04	17.02	17.47	17.50	17.49	17.66	18.30
Vented and Combusted										
Drillling and Well Completion										
Completion Flaring	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Well Drilling	0.07	0.05	0.06	0.11	0.14	0.11	0.13	0.14	0.17	0.20
Coal Bed Methane										
Powder River[1]	-	-	-		-	-	-	-	-	-
Black Warrior[1]	-	-	-		-	-	-	-	-	-
Normal Operations										
Pneumatic Device Vents	58.49	60.24	69.38	101.86	110.26	113.87	114.04	114.00	115.02	120.01
Chemical Injection Pumps	2.95	3.11	3.75	6.33	6.93	7.00	7.09	7.08	7.19	7.50
Kimray Pumps	13.41	13.71	15.43	22.91	24.22	24.94	24.93	24.78	25.18	26.25
Dehydrator Vents	4.18	4.28	4.81	7.14	7.55	7.78	7.77	7.73	7.85	8.19
Condensate Tank Vents										
Condensate Tanks without Control Device	10.25	9.43	8.79	9.34	10.34	10.62	10.25	9.79	10.25	10.25
Condensate Tanks with Control Devices	2.05	1.89	1.76	1.87	2.07	2.12	2.05	1.96	2.05	2.05
Compressor Exhaust Vented Gas Engines[1]	-	-	-		-	-	-	-	-	-
Well Workovers										
Gas Wells	0.06	0.06	0.06	0.08	0.09	0.09	0.09	0.09	0.09	0.10
Well Clean Ups (LP Gas Wells)	10.64	10.89	12.02	16.15	17.28	17.86	17.95	17.92	18.15	18.93
Blowdowns										
Vessel BD	0.04	0.04	0.04	0.06	0.06	0.06	0.06	0.06	0.07	0.07
Pipeline BD	0.17	0.17	0.19	0.26	0.27	0.28	0.28	0.28	0.28	0.29
Compressor BD	0.11	0.12	0.14	0.21	0.23	0.24	0.24	0.24	0.24	0.25
Compressor Starts	0.25	0.26	0.31	0.47	0.51	0.53	0.53	0.53	0.53	0.56

Upsets										
Pressure Relief Valves	0.03	0.03	0.04	0.05	0.05	0.06	0.06	0.06	0.06	0.06
Mishaps	0.09	0.09	0.10	0.14	0.15	0.15	0.15	0.15	0.15	0.16
Flaring Emissions - Onshore	5,509	5,062	8,729	5,525.04	5,858	6,001	5,936	5,828	7,193	6,779
Offshore										
Offshore water Gas Platforms (GoM & Pacific)	1.11	1.14	1.18	1.25	1.27	1.28	1.27	1.25	1.24	1.23
Deepwater Gas Platforms (GoM & Pacific)	0.01	0.02	0.02	0.03	0.04	0.04	0.04	0.05	0.05	0.06
Flaring Emissions - Offshore	230	163	197	204	205	211	155	165	182	162
Total	**5,876**	**5,364**	**9,083**	**5,956**	**6,307**	**6,463**	**6,342**	**6,242**	**7,627**	**7,203**

[1] Energy use CO_2 emissions not estimated to avoid double counting.

Table A- 119: CO_2 Emission Estimates from the Natural Gas Processing Plants (Gg)

Activity	1990	1992	1995	2000	2001	2002	2003	2004	2005	2006
Normal Fugitives										
Plants – Before CO_2 removal	2.54	2.44	2.25	1.95	1.90	1.97	1.92	1.91	1.89	1.91
Plants – After CO_2 removal	0.56	0.54	0.50	0.43	0.42	0.44	0.43	0.42	0.42	0.42
Reciprocating Compressors – Before CO_2 removal	19.49	19.50	20.28	20.94	21.41	20.65	20.81	20.27	19.67	20.23
Reciprocating Compressors – After CO_2 removal	4.33	4.33	4.50	4.65	4.75	4.59	4.62	4.50	4.37	4.49
Centrifugal Compressors – Before CO_2 removal	6.56	6.56	6.82	7.05	7.20	6.95	7.00	6.82	6.62	6.81
Centrifugal Compressors – After CO_2 removal	1.46	1.46	1.51	1.56	1.60	1.54	1.55	1.51	1.47	1.51
Vented and Combusted										
Normal Operations										
Compressor Exhaust										
Gas Engines[1]	-	-	-	-	-	-	-	-	-	-
Gas Turbines[1]	-	-	-	-	-	-	-	-	-	-
AGR Vents	27,708	26,652	24,577	23,288	22,342	23,022	21,958	21,737	21,694	21,161
Kimray Pumps	0.35	0.35	0.36	0.38	0.39	0.37	0.37	0.36	0.35	0.36
Dehydrator Vents	2.16	2.16	2.25	2.32	2.37	2.29	2.31	2.25	2.18	2.24
Pneumatic Devices	0.28	0.27	0.25	0.22	0.21	0.22	0.21	0.21	0.21	0.21
Routine Maintenance										
Blowdowns/Venting	6.31	6.07	5.60	4.85	4.73	4.89	4.76	4.74	4.69	4.74
Total	**27,752**	**26,696**	**24,621**	**23,333**	**22,387**	**23,066**	**22,002**	**21,780**	**21,736**	**21,204**

[1] Energy use CO_2 emissions not estimated to avoid double counting.

Table A- 120: CO_2 Emission Estimates from the Natural Gas Transmission and Storage (Gg)

Activity	1990	1992	1995	2000	2001	2002	2003	2004	2005	2006
Fugitives										
Pipelines Leaks	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Compressor Stations (Transmission)										
Station	3.03	3.03	3.08	3.10	3.02	3.15	3.14	3.15	3.12	3.12
Recip Compressor	21.00	20.96	21.36	21.50	20.89	21.83	21.72	21.79	21.62	21.62
Centrifugal Compressor	4.19	4.18	4.26	4.29	4.17	4.36	4.34	4.35	4.32	4.32
Compressor Stations (Storage)										
Station	1.58	1.68	1.74	1.79	1.71	1.75	1.82	1.75	1.73	1.56
Recip Compressor	4.55	4.86	5.03	5.18	4.95	5.07	5.27	5.05	4.98	4.50
Centrifugal Compressor	0.64	0.69	0.71	0.74	0.70	0.72	0.75	0.72	0.71	0.64
Wells (Storage)	0.39	0.42	0.43	0.45	0.43	0.44	0.45	0.43	0.43	0.39
M&R (Trans. Co. Interconnect)	2.05	2.05	2.08	2.10	2.04	2.13	2.12	2.13	2.11	2.11
M&R (Farm Taps + Direct Sales)	0.46	0.46	0.47	0.47	0.46	0.48	0.48	0.48	0.47	0.47
Vented and Combusted										
Normal Operation										
Dehydrator Vents	0.06	0.06	0.06		0.06	0.06	0.06	0.06	0.06	0.06
(Transmission)				0.06						
Dehydrator Vents (Storage)	0.12	0.13	0.13	0.14	0.13	0.14	0.14	0.14	0.13	0.12
Compressor Exhaust										
Engines (Transmission)[1]	-	-	-	-	-	-	-	-	-	-
Turbines (Transmission)[1]	-	-	-	-	-	-	-	-	-	-
Engines (Storage)[1]	-	-	-	-	-	-	-	-	-	-
Turbines (Storage)[1]	-	-	-	-	-	-	-	-	-	-
Generators (Engines)[1]	-	-	-	-	-	-	-	-	-	-
Generators (Turbines)[1]	-	-	-	-	-	-	-	-	-	-
Pneumatic Devices Trans+Stor				-						
Pneumatic Devices Trans	6.15	6.14	6.25	6.29	6.12	6.39	6.36	6.38	6.33	6.33
Pneumatic Devices Storage	1.30	1.39	1.44	1.48	1.42	1.45	1.51	1.45	1.43	1.29
Routine Maintenance/Upsets										
Pipeline Venting	5.01	5.00	5.10	5.13	4.99	5.21	5.18	5.20	5.16	5.16
Station venting Trans+Storage										
Station Venting Transmission	4.13	4.12	4.20	4.22	4.10	4.29	4.27	4.28	4.25	4.25
Station Venting Storage	0.88	0.93	0.97	1.00	0.95	0.97	1.01	0.97	0.96	0.86
LNG Storage										
LNG Stations	0.31	0.32	0.33	0.35	0.35	0.35	0.36	0.36	0.36	0.36
LNG Reciprocating Compressors	1.16	1.18	1.23	1.30	1.32	1.33	1.34	1.34	1.34	1.34
LNG Centrifugal Compressors	0.39	0.41	0.42	0.45	0.45	0.46	0.46	0.46	0.46	0.46
LNG Compressor Exhaust										
LNG Engines[1]	-	-	-	-	-	-	-	-	-	-
LNG Turbines[1]	-	-	-	-	-	-	-	-	-	-
LNG Station Venting	0.17	0.18	0.18	0.19	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	0.01	0.01	0.01
LNG Reciprocating Compressors	0.03	0.03	0.03	0.03	0.05	0.05	0.07	0.07	0.07	0.07
LNG Centrifugal Compressors	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.02
LNG Compressor Exhaust										
LNG Engines[1]	-	-	-	-	-	-	-	-	-	-
LNG Turbines[1]	-	-	-	-	-	-	-	-	-	-
LNG Station Venting	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01
Total	**58**	**58**	**60**	**60**	**59**	**61**	**61**	**61**	**60**	**59**

[1] Energy use CO_2 emissions not estimated to avoid double counting.

Table A- 121: CO_2 Emission Estimates from the Natural Gas Distribution Stage (Gg)

Activity	1990	1992	1995	2000	2001	2002	2003	2004	2005	2006
Pipeline Leaks										
Mains—Cast Iron	8.08	7.33	7.01	6.20	6.14	5.82	5.69	5.63	5.18	5.12
Mains—Unprotected steel	5.50	5.03	4.75	4.18	4.10	3.94	3.74	3.83	3.50	3.62
Mains—Protected steel	0.76	0.77	0.83	0.77	0.78	0.79	0.79	0.81	0.76	0.79
Mains—Plastic	1.92	1.65	2.18	2.77	3.07	3.28	3.12	3.33	3.24	3.82
Services—Unprotected steel	5.50	5.15	4.43	4.09	3.93	3.74	3.49	3.45	3.83	4.07
Services Protected steel	2.00	2.00	2.12	1.81	1.81	1.80	1.74	1.83	1.61	1.59
Services—Plastic	0.08	0.09	0.11	0.14	0.14	0.15	0.15	0.16	0.16	0.17
Services—Copper	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Meter/Regulator (City Gates)										
M&R >300	2.83	3.03	3.13	3.23	3.08	3.16	3.28	3.14	3.10	2.80
M&R 100-300	5.81	6.20	6.42	6.61	6.31	6.47	6.72	6.44	6.36	5.73
M&R <100	0.14	0.15	0.15	0.16	0.15	0.16	0.16	0.16	0.15	0.14
Reg >300	2.95	3.15	3.26	3.35	3.20	3.28	3.41	3.27	3.23	2.91
R-Vault >300	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01
Reg 100-300	2.26	2.42	2.50	2.58	2.46	2.52	2.62	2.51	2.48	2.24
R-Vault 100-300	0.00	0.00	0.00	0.01	0.00	0.01	0.01	0.01	0.00	0.00
Reg 40-100	0.17	0.18	0.19	0.20	0.19	0.19	0.20	0.19	0.19	0.17
R-Vault 40-100	0.01	0.01	0.01	0.01	0.01	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	0.01
Customer Meters										
Residential	2.98	3.19	3.30	3.40	3.24	3.32	3.45	3.31	3.27	2.95
Commercial/Industry	0.11	0.12	0.14	0.13	0.12	0.13	0.12	0.12	0.12	0.11
Routine Maintenance										
Pressure Relief Valve Releases	0.03	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Pipeline Blowdown	0.07	0.07	0.08	0.08	0.07	0.08	0.08	0.08	0.08	0.07
Upsets										
Mishaps (Dig-ins)	1.07	1.15	1.19	1.22	1.17	1.19	1.24	1.19	1.17	1.06
Total	**42**	**42**	**42**	**41**	**40**	**40**	**40**	**40**	**39**	**37**

3.5. Methodology for Estimating CH_4 and CO_2 Emissions from Petroleum Systems

The methodology for estimating CH_4 and non-combustion CO_2 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 CH_4 and twenty-nine activities that emit non-combustion CO_2 from petroleum systems were examined from these reports. Most of the activities analyzed involve crude oil production field operations, which accounted for about 97.6 percent of total oil industry CH_4 emissions. Crude transportation and refining accounted for the remaining CH_4 emissions of less than one half and just over two percent, respectively. Non-combustion CO_2 emissions were analyzed for the production operations only, because the emissions from transportation and refining operations are negligible. The following steps were taken to estimate CH_4 and CO_2 emissions from petroleum systems.

Step 1: Determine Emission Factors for all Activities

The CH_4 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 CH_4 emission factors for the 64 CH_4-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 1996 study. The gas engine emission factor is taken from (EPA/GRI 1996b). The oil tank venting emission factor is taken from the API E&P Tank Calc average for API gravity less than 44 API degrees. 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 2006, MMS 2005c). The emission factors determined for 1995 were assumed to be representative of emissions from each source type over the period 1990 through 2006. Therefore, the same emission factors are used for each year throughout this period.

The CO_2 emission factors were derived from the corresponding source CH_4 emission factors. The amount of CO_2 in the crude oil stream changes as it passes through various equipment in petroleum production operations. As a result, three distinct stages/streams with varying CO_2 contents exist. The three streams that are used to estimate the emissons factors are the associated gas stream separated from crude oil, hydrocarbons flashed out from crude oil (such as in storage tanks), and whole crude oil itself when it leaks downstream. The standard approach used to estimate CO_2 emission factors was to use the existing CH_4 emissions factors and multiply them by a conversion factor, which is the ratio of CO_2 content to CH_4 content for the particular stream (Table A- 122). Only the emissions factor for storage tanks is estimated using API E&P Tank Calc simulation runs of tank emissions for crude oil of different gravity less than 44 API degrees.

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 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 Minerals Management Service (MMS), Energy Information Administration (EIA), American Petroleum Institute (API), and the Oil & Gas Journal (O&GJ) were used to extrapolate the activity levels from the base year to each year between 1990 and 2006. Data used include total domestic crude oil production, number of domestic crude oil wells, total imports and exports of crude oil, and total petroleum refinery crude runs. The activity data for the transportation sector are 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, such as average stripper well production, oil industry data based on expert judgment was used. In the case of non-combustion CO_2 emission sources, the activity factors remain the same as for CH_4 emission sources.

Step 3: Estimate Methane and Carbon Dioxide Emissions for Each Activity for Each Year

Annual CH_4 emissions from each of the 64 petroleum system activities and CO_2 emissions from the 29 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 CH_4 and CO_2 emissions, respectively.

Table A- 122, Table A- 123, Table A- 124 and Table A- 124 provide 2006 activity factors, emission factors, and emission estimates.[35] Table A- 126 and Table A- 127 provide a summary of emission estimates for the years 1990 through 2006.

Table A- 122: Ratio of CO_2 to CH_4 Content

%CO2 / %CH4 (whole crude post-separator)	0.052
% CO2 / % CH4 (associated gas)	0.020
% CO2 / % CH4 (flash gas)	0.017
% CO2 / % CH4 (offshore)	0.004

[1] Ratios for separators, associated gas and flash gas are from API Tankcalc runs. Offshore from MMS - Gulf of Mexico Air Quality Study, Final Report: Vol. 3 Inventory Preparation Appendices N-P

Table A- 123 : 2006 CH_4 Emissions from Petroleum Production Field Operations

Activity/Equipment	Emission Factor	Units	Activity Factor	Units	Emissions (Bcf/yr)
Vented Emissions					**62.649**
Oil Tanks	5.28	scf of CH_4/bbl crude	1,358	MMbbl/yr (non stripper wells)	7.171
Pneumatic Devices, High Bleed	330	scfd CH_4/device	133,232	No. of high-bleed devices	16.067
Pneumatic Devices, Low Bleed	52	scfd CH_4/device	247,430	No. of low-bleed devices	4.696
Chemical Injection Pumps	248	scfd CH_4/pump	26,828	No. of pumps	2.429
Vessel Blowdowns	78	scfy CH_4/vessel	173,889	No. of vessels	0.014
Compressor Blowdowns	3,775	scf/yr of CH_4/compressor	2,357	No. of compressors	0.009
Compressor Starts	8,443	scf/yr. of CH_4/compressor	2,357	No. of compressors	0.020
Stripper wells	2,345	scf/yr of CH_4/stripper well	320,858	No. of stripper wells vented	0.752
Well Completion Venting	733	scf/completion	12,339	Oil well completions	0.009
Well Workovers	96	scf CH_4/workover	37,575	Oil well workovers	0.004
Pipeline Pigging	2.40	scfd of CH_4/pig station	0	No. of crude pig stations	0.000
Offshore Platforms, Shallow water Oil, fugitive, vented and combusted	54,795	scfd CH_4/platform	1,464	No. of oil platforms	29.275
Offshore Platforms, Deepwater oil, fugitive, vented and combusted	260,274	scfd CH_4/platform	23	No. of oil platforms	2.202
Fugitive Emissions					**2.314**
Oil Wellheads (heavy crude)	0.13	scfd/well	12,700	No. of hvy. crude wells	0.001
Oil Wellheads (light crude)	16.6	scfd/well	167,442	No. of lt. crude wells	1.016
Separators (heavy crude)	0.15	scfd CH_4/separator	10,235	No. of hvy. crude seps.	0.001
Separators (light crude)	14	scfd CH_4/separator	93,151	No. of lt. crude seps.	0.471
Heater/Treaters (light crude)	19	scfd CH_4/heater	70,502	No. of heater treaters	0.494
Headers (heavy crude)[1]	0.08	scfd CH_4/header	13,069	No. of hvy. crude hdrs.	0.000
Headers (light crude)	11	scfd CH_4/header	40,514	No. of lt. crude hdrs.	0.161
Floating Roof Tanks	338,306	scf CH_4/floating roof tank/yr.	24	No. of floating roof tanks	0.008
Compressors	100	scfd CH_4/compressor	2,357	No. of compressors	0.086
Large Compressors	16,360	scfd CH_4/compressor	0	No. of large comprs.	0.000
Sales Areas	41	scf CH_4/loading	1,561,950	Loadings/year	0.063
Pipelines	0	scfd of CH_4/mile of pipeline	12,141	Miles of gathering line	0.000
Well Drilling	0	scfd of CH_4/oil well drilled	13,907	No. of oil wells drilled	0.000

[35] Emissions are not actually zero, but too small to show at this level of precision

Activity/Equipment	Emission Factor	Units	Activity Factor	Units	Emissions (Bcf/yr)
Battery Pumps	0.24	scfd of CH_4/pump	150,300	No. of battery pumps	0.013
Combustion Emissions					**3.602**
Gas Engines	0.24	scf CH_4/HP-hr	14,848	MMHP-hr	3.564
Heaters	0.52	scf CH_4/bbl	1,874.6	MMbbl/yr	0.001
Well Drilling	2,453	scf CH_4/well drilled	13,907	Oil wells drilled	0.034
Flares	20	scf CH_4/Mcf flared	157,773	Mcf flared/yr	0.003
Process Upset Emissions					**0.121**
Pressure Relief Valves	35	scf/yr/PR valve	156,589	No. of PR valves	0.005
Well Blowouts Onshore	2.5	MMscf/blowout	46.4	No. of blowouts/yr	0.116
Total					**68.69**

[1] Emissions are not actually 0, but too small to show at this level of precision.

Table A- 124: 2006 CH_4 Emissions from Petroleum Transportation

Activity/Equipment	Emission Factor	Units	Activity Factor	Units	Emissions (Bcf/yr)
Vented Emissions					**0.218**
Tanks	0.021	scf CH_4/yr/bbl of crude delivered to refineries	5,563	MMbbl crude feed/yr	0.115
Truck Loading	0.520	scf CH_4/yr/bbl of crude transported by truck	57.8	MMbbl trans. by truck	0.030
Marine Loading	2.544	scf CH_4/1000 gal. crude marine loadings	22,563,301	1,000 gal./yr loaded	0.057
Rail Loading	0.520	scf CH_4/yr/bbl of crude transported by rail	4.5	MMbbl. Crude by rail/yr	0.002
Pump Station Maintenance[1]	36.80	scf CH_4/station/yr	476	No. of pump stations	0.000
Pipeline Pigging	39	scfd of CH_4/pig station	952	No. of pig stations	0.014
Fugitive Emissions					**0.050**
Pump Stations	25	scf CH_4/mile/yr.	47,617	No. of miles of crude p/l	0.001
Pipelines	0	scf CH_4/bbl crude transported by pipeline	6,668	MM bbl crude piped	0.000
Floating Roof Tanks	58,965	scf CH_4/floating roof tank/yr.	824	No. of floating roof tanks	0.049
Combustion Emissions					**0.000**
Pump Engine Drivers	0.24	scf CH_4/hp-hr	NE	No. of hp-hrs	NE
Heaters	0.521	scf CH_4/bbl.burned	NE	No. of bbl. Burned	NE
Total					**0.268**

[1] Emissions are not actually 0, but too small to show at this level of precision.
NE: Not estimated for lack of activity factor data

Table A- 125: 2006 CH_4 Emissions from Petroleum Refining

Activity/Equipment	Emission Factor	Units	Activity Factor	Units	Emissions (Bcf/yr)
Vented Emissions					**1.248**
Tanks	20.6	scfCH_4/Mbbl	1,956	Mbbl/cd heavy crude feed	0.015
System Blowdowns	137	scfCH_4/Mbbl	15,242	Mbbl/cd refinery feed	0.761
Asphalt Blowing	2,555	scfCH_4/Mbbl	506	Mbbl/cd production	0.472
Fugitive Emissions					**0.088**
Fuel Gas System	439	McfCH_4/refinery/yr	145	Refineries	0.064
Floating Roof Tanks[1]	587	scf CH_4/floating roof tank/yr.	767	No. of floating roof tanks	0.000
Wastewater Treating	1.88	scfCH_4/Mbbl	15,242	Mbbl/cd refinery feed	0.010
Cooling Towers	2.36	scfCH_4/Mbbl	15,242	Mbbl/cd refinery feed	0.013
Combustion Emissions					**0.095**
Atmospheric Distillation	3.61	scfCH_4/Mbbl	15,602	Mbbl/cd refinery feed	0.021
Vacuum Distillation	3.61	scfCH_4/Mbbl	6,848	Mbbl/cd feed	0.009
Thermal Operations	6.01	scfCH_4/Mbbl	2,147	Mbbl/cd feed	0.005
Catalytic Cracking	5.17	scfCH_4/Mbbl	5,141	Mbbl/cd feed	0.010
Catalytic Reforming	7.22	scfCH_4/Mbbl	3,172	Mbbl/cd feed	0.008
Catalytic Hydrocracking	7.22	scfCH_4/Mbbl	1,360	Mbbl/cd feed	0.004
Hydrorefining	2.17	scfCH_4/Mbbl	2,169	Mbbl/cd feed	0.002
Hydrotreating	6.50	scfCH_4/Mbbl	9,948	Mbbl/cd feed	0.024
Alkylation/Polymerization	12.6	scfCH_4/Mbbl	1,106	Mbbl/cd feed	0.005
Aromatics/Isomeration	1.80	scfCH_4/Mbbl	979	Mbbl/cd feed	0.001
Lube Oil Processing	0.00	scfCH_4/Mbbl	183	Mbbl/cd feed	0.000
Engines	0.006	scfCH_4/hp-hr	1,172	MMhp-hr/yr	0.007
Flares	0.189	scfCH_4/Mbbl	15,242	Mbbl/cd refinery feed	0.001
Total					**1.430**

[1] Emissions are not actually 0, but too small to show at this level of precision.

Table A- 126: Summary of CH_4 Emissions from Petroleum Systems (Bcf)

Activity	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Production Field Operations	**82.20**	**82.82**	**80.70**	**78.78**	**78.27**	**77.62**	**77.51**	**77.03**	**76.41**	**74.23**	**73.25**	**73.02**	**72.28**	**70.57**	**69.42**	**68.31**	**68.69**
Pneumatic device venting	25.44	25.91	25.06	24.56	24.41	24.07	24.03	23.99	23.49	22.75	22.27	22.12	22.06	21.43	21.22	20.67	20.76
Tank venting	9.29	9.33	9.02	8.68	8.37	8.38	8.39	8.57	8.47	7.98	8.02	8.02	7.88	7.80	7.41	7.03	7.17
Combustion & process upsets	4.59	4.66	4.47	4.37	4.32	4.27	4.27	4.28	4.15	3.98	3.94	3.92	3.88	3.79	3.75	3.67	3.72
Misc. venting & fugitives	41.53	41.55	40.89	39.92	39.94	39.62	39.53	38.85	38.96	38.30	37.86	37.80	37.30	36.43	35.97	35.93	36.01
Wellhead fugitives	1.35	1.37	1.26	1.25	1.24	1.28	1.30	1.33	1.34	1.23	1.16	1.17	1.17	1.12	1.08	1.02	1.02
Crude Oil Transportation	**0.34**	**0.34**	**0.33**	**0.32**	**0.32**	**0.31**	**0.31**	**0.31**	**0.31**	**0.29**	**0.27**	**0.27**	**0.27**	**0.27**	**0.27**	**0.27**	**0.27**
Refining	**1.29**	**1.26**	**1.26**	**1.29**	**1.31**	**1.33**	**1.33**	**1.38**	**1.40**	**1.41**	**1.44**	**1.40**	**1.40**	**1.42**	**1.45**	**1.43**	**1.43**
Total	**83.83**	**84.42**	**82.28**	**80.39**	**79.90**	**79.26**	**79.16**	**78.72**	**78.12**	**75.93**	**74.96**	**74.69**	**73.95**	**72.27**	**71.14**	**70.01**	**70.38**

Table A- 127 : 2006 CO_2 Emissions from Petroleum Production Field Operations

Activity/Equipment	Emission Factor	Units	Activity Factor	Units	Emissions (Bcf/yr)
Vented Emissions					**5.485**
Oil Tanks	3.53	scf of CO_2/bbl crude	1,358	MMbbl/yr (non stripper wells)	4.792
Pneumatic Devices, High Bleed	6.704	scfd CO_2/device	133,232	No. of high-bleed devices	0.326
Pneumatic Devices, Low Bleed	1.055	scfd CO_2/device	247,430	No. of low-bleed devices	0.095
Chemical Injection Pumps	5.033	scfd CO_2/pump	26,828	No. of pumps	0.049
Vessel Blowdowns[1]	1.583	scfy CO_2/vessel	173,889	No. of vessels	0.000
Compressor Blowdowns[1]	77	scf/yr of CH_4/compressor	2,357	No. of compressors	0.000
Compressor Starts[1]	171	scf/yr. of CH_4/compressor	2,357	No. of compressors	0.000
Stripper wells	48	scf/yr of CH_4/stripper well	320,858	No. of stripper wells vented	0.015
Well Completion Venting[1]	14.87	scf/completion	12,339	Oil well completions	0.000
Well Workovers[1]	1.95	scf CO_2/workover	37,575	Oil well workovers	0.000
Pipeline Pigging[1]	0	scfd of CO_2/pig station	0	No. of crude pig stations	0.000
Offshore Platforms, Shallow water Oil, fugitive, vented and combusted	358	scfd CO_2/platform	1,464	No. of oil platforms	0.191
Offshore Platforms, Deepwater oil, fugitive, vented and combusted	1,701	scfd CO_2/platform	23	No. of oil platforms	0.014
Fugitive Emissions					**0.048**
Oil Wellheads (heavy crude)[1]	0.003	scfd/well	12,700	No. of hvy. crude wells	0.000
Oil Wellheads (light crude)	0.337	scfd/well	167,442	No. of lt. crude wells	0.021
Separators (heavy crude)[1]	0.003	scfd CO_2/separator	10,235	No. of hvy. crude seps.	0.000
Separators (light crude)	0.281	scfd CO_2/separator	93,151	No. of lt. crude seps.	0.010
Heater/Treaters (light crude)	0.319	scfd CO_2/heater	70,502	No. of heater treaters	0.008
Headers (heavy crude)[1]	0.002	scfd CO_2/header	13,069	No. of hvy. crude hdrs.	0.000
Headers (light crude)	0.220	scfd CO_2/header	40,514	No. of lt. crude hdrs.	0.003
Floating Roof Tanks[1]	17,490	scf CO_2/floating roof tank/yr.	24	No. of floating roof tanks	0.000
Compressors	2.029	scfd CO_2/compressor	2,357	No. of compressors	0.002
Large Compressors	332	scfd CO_2/compressor	0	No. of large comprs.	0.000
Sales Areas	2.096	scf CO_2/loading	1,561,950	Loadings/year	0.003
Pipelines	0	scfd of CO_2/mile of pipeline	12,141	Miles of gathering line	0.000
Well Drilling	0	scfd of CO_2/oil well drilled	13,907	No. of oil wells drilled	0.000
Battery Pumps	0.012	scfd of CO_2/pump	150,300	No. of battery pumps	0.001
Process Upset Emissions					**0.003**
Pressure Relief Valves[1]	1.794	scf/yr/PR valve	156,589	No. of PR valves	0.000
Well Blowouts Onshore	0.051	MMscf/blowout	46.4	No. of blowouts/yr	0.002
Total					**5.535**

[1] Emissions are not actually 0, but too small to show at this level of precision.

[2] Combustion emissions not estimated to avoid double accounting with CO_2 from fossil fuel combustion inventory.

3.6. Methodology for Estimating CO_2 and N_2O Emissions from Municipal Solid Waste Combustion

Emissions of CO_2 from municipal solid waste (MSW) combustion include CO_2 generated by the combustion of plastics, synthetic rubber and synthetic fibers in MSW, and combustion of synthetic rubber and C black in tires. Combustion of MSW also results in emissions of N_2O. The methodology for calculating emissions from each of these waste combustion sources is described in this Annex.

CO_2 from Plastics Combustion

In the *Municipal Solid Waste Generation, Recycling, and Disposal in the United States: Facts and Figures* reports (EPA 1997, 1998, 1999, 2000b, 2002, 2003, 2005a, 2006b, 2007), the flows of plastics in the U.S. waste stream are reported for seven resin categories. For 2006, the most recent year for which these data are reported, the quantity generated, recovered, and discarded for each resin is shown in Table A- 128. The data set for 1990 through 2005 is incomplete, and several assumptions were employed to bridge the data gaps. The EPA reports do not provide estimates for individual materials landfilled and combusted, although they do provide such an estimate for the waste stream as a whole. To estimate the quantity of plastics landfilled and combusted, total discards were apportioned based on the proportions of landfilling and combustion for the entire U.S. waste stream for each year in the time series. For those years when distribution by resin category was not reported (1990-1994), 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- 128: 2006 Plastics in the Municipal Solid Waste Stream by Resin (Gg)

Waste Pathway	PET	HDPE	PVC	LDPE/ LLDPE	PP	PS	Other	Total
Generation	2,776	5,479	1,515	5,951	3,674	2,313	5,044	**26,753**
Recovery	562	526	0	254	18	9	481	**1,851**
Discard	2,214	4,953	1,515	5,697	3,656	2,304	4,563	**24,902**
Landfill	1,776	3,975	1,216	4,571	2,934	1,849	3,662	**19,982**
Combustion	437	979	299	1,126	722	455	902	**4,921**
Recovery*	20%	10%	0%	4%	0%	0%	10%	**7%**
Discard*	80%	90%	100%	96%	100%	100%	90%	**93%**
Landfill*	64%	73%	80%	77%	80%	80%	73%	**75%**
Combustion*	16%	18%	20%	19%	20%	20%	18%	**18%**

*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 CO_2 emissions were calculated as the product of plastic combusted, C content, and fraction oxidized (see Table A- 129). 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- 129: 2006 Plastics Combusted (Gg), Carbon Content (%), Fraction Oxidized (%) and Carbon Combusted (Gg)

Factor	PET	HDPE	PVC	LDPE/ LLDPE	PP	PS	Other	Total
Quantity Combusted	437	979	299	1,126	722	455	902	**4,921**
Carbon Content of Resin	63%	86%	38%	86%	86%	92%	66%	**-**
Fraction Oxidized	98%	98%	98%	98%	98%	98%	98%	**-**
Carbon in Resin Combusted	268	822	113	946	607	412	582	**3,749**
Emissions (Tg CO_2 Eq.)	1.0	3.0	0.4	3.5	2.2	1.5	2.1	**13.7**

[a] Weighted average of other plastics produced.
Note: Totals may not sum due to independent rounding.

CO_2 from Combustion of Synthetic Rubber and Carbon Black in Tires

Emissions from tire combustion require two pieces of information: the amount of tires combusted and the C content of the tires. *U.S. Scrap Tire Markets in the United States 2005* (RMA 2006) reports that 155.1 million of the

299.2 million scrap tires generated in 2005 (approximately 52 percent of generation) were used for fuel purposes. Using RMA's Scrap Tire Management Council (STMC) 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.[36] Table A- 130 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 (Miller 1999).

Multiplying the mass of scrap tires combusted by the total C content of the synthetic rubber and C black portions of scrap tires and by a 98 percent oxidation factor yielded CO_2 emissions, as shown in Table A- 131. The disposal rate of rubber in tires (0.3 Tg C/yr) is smaller than the consumption rate for tires based on summing the elastomers listed in Table A- 130 (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 2001 were taken from RMA 2004; 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.

Table A- 130: 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.

Table A- 131: Scrap Tire Constituents and CO_2 Emissions from Scrap Tire Combustion in 2006

Material	Weight of Material (Tg)	Fraction Oxidized	Carbon Content	Emissions (Tg CO_2 Eq.)
Synthetic Rubber	0.4	98%	90%	1.2
Carbon Black	0.4	98%	100%	1.6
Total	**0.8**	**-**	**-**	**2.8**

- Not applicable

[36] The carbon content of tires (1,158 Gg C) divided by the mass of rubber in tires (1,285 Gg) equals 90 percent.

CO_2 from Combustion of Synthetic Rubber in Municipal Solid Waste

Similar to the methodology for scrap tires, CO_2 emissions from synthetic rubber in MSW were estimated by multiplying the amount of rubber combusted by an average rubber C content. The amount of rubber 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 1996, 1997, 1998, 1999, 2000b, 2002, 2003, 2005a, 2006b, 2007) 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. Since there was negligible recovery for these product types, all the waste generated can be considered discarded. Similar to the plastics method, discards were apportioned into landfilling and combustion 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 was assigned to each product type, as shown in Table A-132.[37] 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-132: Rubber and Leather in Municipal Solid Waste in 2006

Product Type	Combustion (Gg)	Synthetic Rubber (%)	Carbon Content (%)	Fraction Oxidized (%)	Emissions (Tg CO_2 Eq.)
Durables (not Tires)	528.8	100%	85%	98%	1.7
Non-Durables	72.6	-			0.2
Clothing and Footwear	35.0	25%	85%	98%	0.1
Other Non-Durables	37.6	75%	85%	98%	0.1
Containers and Packaging	7.2	100%	85%	98%	+
Total	**608.6**	**-**	**-**	**-**	**1.9**

+ Less than 0.05 Tg CO_2 Eq.
- Not applicable

CO_2 from Combustion of Synthetic Fibers

CO_2 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 2000b, 2002, 2003, 2005a, 2006b, 2007) for textiles. Production data for the synthetic fibers was based on data from the American Chemical Society (FEB 2006). The amount of synthetic fiber in MSW was estimated by subtracting (a) the amount recovered from (b) the waste generated (see Table A-133). As with the other materials in the MSW stream, discards were apportioned based on the annually variable proportions of landfilling and combustion for the entire U.S. waste stream. 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 types (polyester, nylon, olefin, and acrylic) produced in 1998 (see Table A-134). The equation relating CO_2 emissions to the amount of textiles combusted is shown below.

$$CO_2 \text{ Emissions from the Combustion of Synthetic Fibers} = \text{Annual Textile Combustion (Gg)} \times (\text{Percent of Total Fiber that is Synthetic}) \times (\text{Average C Content of Synthetic Fiber}) \times (44\text{g } CO_2/12 \text{ g C})$$

[37] As a sustainably harvested biogenic material, the combustion of leather is assumed to have no net CO_2 emissions.

Table A-133: Synthetic Textiles in MSW (Gg)

Year	Generation	Recovery	Discards	Combustion
1990	2,884	328	2,557	474
1991	3,008	347	2,661	530
1992	3,286	387	2,899	556
1993	3,386	397	2,988	578
1994	3,604	432	3,172	619
1995	3,674	447	3,227	723
1996	3,832	472	3,361	789
1997	4,090	526	3,564	810
1998	4,269	556	3,713	781
1999	4,498	611	3,887	789
2000	4,686	655	4,031	802
2001	4,870	715	4,155	826
2002	5,123	750	4,373	864
2003	5,257	755	4,503	892
2004	5,426	874	4,552	914
2005	5,600	894	4,706	930
2006	5,878	899	4,979	984

Table A-134: Synthetic Fiber Production in 1998

Fiber	Production (Tg)	Carbon Content
Polyester	1.8	63%
Nylon	1.2	64%
Olefin	1.3	86%
Acrylic	0.2	68%
Total	**4.5**	**70%**

N_2O from Municipal Solid Waste Combustion

Estimates of N_2O emissions from MSW combustion 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 (2000a, 2002, 2003, 2005a, 2006b, 2007) and unpublished backup data (Schneider 2007). According to this methodology, emissions of N_2O from MSW combustion are the product of the mass of MSW combusted, an emission factor of N_2O emitted per unit mass of waste combusted, and an N_2O emissions control removal efficiency. The mass of waste combusted was derived from the information published in *BioCycle* (Simmons et al 2006). For MSW combustion in the United States, an emission factor of 44 g N_2O/metric ton MSW (the average of the values provided for hearth/grate combustors as listed in the IPCC *Good Practice Guidance*, 2000) and an estimated emissions control removal efficiency of zero percent were used. No information was available on the mass of waste combusted in 2005 or 2006, so the value was assumed to remain constant at the 2004 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 combusted that are relatively consistent (see Table A-135).

Table A-135: U.S. Municipal Solid Waste Combusted, as Reported by EPA and BioCycle (Metric Tons)

Year	EPA	BioCycle
1990	28,939,680	30,632,057
1991	30,209,760	25,462,836
1992	29,656,368	29,086,574
1993	29,865,024	27,838,884
1994	29,474,928	29,291,583
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	25,951,892[a]
2002	30,255,120	25,802,917
2003	30,527,280	25,932,940[b]
2004	31,198,608	26,037,823
2005	30,300,480	NA
2006	28,467,936	NA

NA (Not Available)

[a] Interpolated between 2000 and 2002 values.

[b] Interpolated between 2002 and 2004 values.

3.7. Methodology for Estimating Emissions from International Bunker Fuels used by the U.S. Military

Bunker fuel emission estimates for the Department of Defense (DoD) are developed using data generated by the Defense Energy Support Center for aviation and naval fuels. The Defense Energy Support Center (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 2006, 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 the DoD between 1992 and 1995.

Step 1: Omit Extra-Territorial Fuel Deliveries

Beginning with the complete DFAMS 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 extra-territorial fuel transactions/deliveries (i.e., sales abroad).

Step 2: Allocate JP-8 between Aviation and Land-based Vehicles

As a result of DoD[38] and NATO[39] 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. 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-136 displays DoD's consumption of fuels that remain at the completion of Step 1, summarized by fuel type. Table A-136 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 were considered potential DoD international bunker fuels, including those listed below.

- Marine: naval distillate fuel (F76), marine gas oil (MGO), and intermediate fuel oil (IFO).
- Aviation: jet fuels (JP8, JP5, JP4, JAA, JA1, and JAB).

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[38] DoD Directive 4140.43, Fuel Standardization, 1998; DoD Directive 4140.25, DoD Management Policy for Energy Commodities and Related Services, 1999.

[39] NATO Standard Agreement NATO STANAG 4362, Fuels for Future Ground Equipments Using Compression Ignition or Turbine Engines, 1987.

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.

- 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-137 and Table A-138 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. CO_2 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" within Table 3-51 and Table 3-52 in the Energy Chapter were based on the international bunker fuel totals provided in Table A-137 and Table A-138, below. CO_2 emissions from aviation bunkers and distillate marine bunkers presented in Table A-141, and are based on emissions from fuels tallied in Table A-137 and Table A-138.

Table A-136: Transportation Fuels from Domestic Fuel Deliveries[a] (Million Gallons)

Vehicle Type/Fuel	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Aviation	**4,598.4**	**4,562.8**	**3,734.5**	**3,610.8**	**3,246.2**	**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**
Total Jet Fuels	4,598.4	4,562.8	3,734.5	3,610.8	3,246.2	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
JP8	285.7	283.5	234.5	989.4	1,598.1	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
JP5	1,025.4	1,017.4	832.7	805.1	723.8	691.2	615.8	552.8	515.6	505.5	472.1	503.2	442.2	409.1	433.7	421.6	325.5
Other Jet Fuels	3,287.3	3,261.9	2,667.3	1,816.3	924.3	225.9	72.9	60.9	103.3	63.3	69.6	71.2	76.1	111.4	143.2	77.6	57.0
Aviation Gasoline	+	+	+	+	+	+	+	+	+	+	+	+	0.1	0.1	+	0.1	0.1
Marine	**686.8**	**632.6**	**646.2**	**589.4**	**478.6**	**438.9**	**493.3**	**639.8**	**674.2**	**598.9**	**454.4**	**418.4**	**455.8**	**609.1**	**704.5**	**604.9**	**531.6**
Middle Distillate (MGO)	0.0	0.0	0.0	0.0	0.0	0.0	38.5	47.5	51.1	49.2	48.3	33.0	41.2	88.1	71.2	54.0	45.8
Naval Distillate (F76)	686.8	632.6	646.2	589.4	478.6	438.9	449.0	583.4	608.4	542.9	398.0	369.1	395.1	460.9	583.5	525.9	453.6
Intermediate Fuel Oil (IFO)[b]	0.0	0.0	0.0	0.0	0.0	0.0	5.9	9.0	14.7	6.7	8.1	16.3	19.5	60.2	49.9	25.0	32.2
Other[c]	**717.1**	**590.4**	**491.7**	**415.1**	**356.1**	**310.9**	**276.9**	**263.3**	**256.8**	**256.0**	**248.2**	**109.8**	**211.1**	**221.2**	**170.9**	**205.6**	**107.3**
Diesel	93.0	97.9	103.0	108.3	113.9	119.9	126.1	132.6	139.5	146.8	126.6	26.6	57.7	60.8	46.4	56.8	30.6
Gasoline	624.1	492.5	388.7	306.8	242.1	191.1	150.8	119.0	93.9	74.1	74.8	24.7	27.5	26.5	19.4	24.3	11.7
Jet Fuel[d]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11.7	23.4	35.0	46.7	58.4	125.9	133.9	105.1	124.4	65.0
Total (Including Bunkers)	**6,002.4**	**5,785.9**	**4,872.3**	**4,615.3**	**4,080.9**	**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**

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-137: Total U.S. Military Aviation Bunker Fuel (Million Gallons)

Fuel Type/Service	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
JP8	**56.7**	**56.3**	**46.4**	**145.3**	**224.0**	**300.4**	**308.8**	**292.0**	**306.4**	**301.4**	**307.6**	**341.2**	**309.5**	**305.1**	**309.8**	**285.6**	**262.5**
Navy	56.7	56.3	46.1	44.6	40.1	38.3	39.8	46.9	53.8	55.5	53.4	73.8	86.6	76.3	79.2	70.9	64.7
Air Force	+	+	0.3	100.8	183.9	262.2	269.0	245.1	252.6	245.9	254.2	267.4	222.9	228.7	230.6	214.7	197.8
JP5	**370.5**	**367.7**	**300.9**	**291.0**	**261.6**	**249.8**	**219.4**	**194.2**	**184.4**	**175.4**	**160.3**	**169.7**	**158.3**	**146.1**	**157.9**	**160.6**	**125.0**
Navy	365.3	362.5	296.7	286.8	257.9	246.3	216.1	191.2	181.4	170.6	155.6	163.7	153.0	141.3	153.8	156.9	122.8
Air Force	5.3	5.2	4.3	4.1	3.7	3.5	3.3	3.0	3.0	4.8	4.7	6.1	5.3	4.9	4.1	3.7	2.3
JP4	**420.8**	**417.5**	**341.4**	**229.6**	**113.1**	**21.5**	**1.1**	**0.1**	**+**	**+**	**+**	**+**	**+**	**+**	**+**	**+**	**+**
Navy	+	+	+	+	+	+	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	+	0.0
Air Force	420.8	417.5	341.4	229.6	113.1	21.5	1.1	0.1	+	+	+	+	+	+	+	+	+
JAA	**13.7**	**13.6**	**11.1**	**10.8**	**9.7**	**9.2**	**10.3**	**9.4**	**10.8**	**10.8**	**12.5**	**12.6**	**13.7**	**21.7**	**30.0**	**15.5**	**11.7**
Navy	8.5	8.4	6.9	6.6	6.0	5.7	6.6	5.9	6.6	6.3	7.9	8.0	9.8	15.5	21.5	11.6	9.1
Air Force	5.3	5.2	4.3	4.1	3.7	3.5	3.7	3.5	4.2	4.5	4.5	4.6	3.8	6.2	8.6	3.9	2.6
JA1	**+**	**+**	**+**	**+**	**+**	**+**	**+**	**+**	**+**	**+**	**+**	**0.1**	**0.6**	**0.2**	**0.5**	**0.5**	**0.4**
Navy	+	+	+	+	+	+	+	+	+	0.0	+	+	+	+	+	+	+
Air Force	+	+	+	+	+	+	+	+	+	0.0	+	0.1	0.6	0.2	0.5	0.5	0.4
JAB	**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**	**0.0**
Navy	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	0.0
Air Force	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	0.0
Navy Subtotal	**430.5**	**427.2**	**349.6**	**338.1**	**303.9**	**290.2**	**262.5**	**244.0**	**241.8**	**232.4**	**216.9**	**245.5**	**249.4**	**233.1**	**254.4**	**239.4**	**196.6**
Air Force Subtotal	**431.3**	**427.9**	**350.2**	**338.6**	**304.4**	**290.7**	**277.0**	**251.7**	**259.9**	**255.2**	**263.5**	**278.1**	**232.7**	**239.9**	**243.7**	**222.9**	**203.1**
Total	**861.8**	**855.1**	**699.9**	**676.7**	**608.4**	**580.9**	**539.5**	**495.6**	**501.7**	**487.5**	**480.4**	**523.6**	**482.1**	**473.0**	**498.1**	**462.3**	**399.7**

+ Does not exceed 0.05 million gallons.

Note: Totals may not sum due to independent rounding.

Table A-138: Total U.S. DoD Maritime Bunker Fuel (Million Gallons)

Marine Distillates	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Navy—MGO	0.0	0.0	0.0	0.0	0.0	0.0	30.3	35.6	31.9	39.7	23.8	22.5	27.1	63.7	56.2	38.0	33.0
Navy—F76	522.4	481.2	491.5	448.3	364.0	333.8	331.9	441.7	474.2	466.0	298.6	282.6	305.6	347.8	434.4	413.1	355.9
Navy—IFO	0.0	0.0	0.0	0.0	0.0	0.0	4.6	7.1	11.6	5.3	6.4	12.9	15.4	47.5	39.4	19.7	25.4
Total	**522.4**	**481.2**	**491.5**	**448.3**	**364.0**	**333.8**	**366.8**	**484.3**	**517.7**	**511.0**	**328.8**	**318.0**	**348.2**	**459.0**	**530.0**	**470.7**	**414.3**

+ Does not exceed 0.005 million gallons.

Note: Totals may not sum due to independent rounding.

Table A-139: 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)	19.95	1.00
Marine (Residual)	21.49	1.00

Source: EIA (2006) and IPCC (2006)

Table A-140: Annual Variable Carbon Content Coefficient for Jet Fuel (Tg Carbon/QBtu)

Fuel	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Jet Fuel	19.40	19.40	19.39	19.37	19.35	19.34	19.33	19.33	19.33	19.33	19.33	19.33	19.33	19.33	19.33	19.33	19.33

Source: EIA (2006)

Table A-141: Total U.S. DoD CO_2 Emissions from Bunker Fuels (Tg CO_2 Eq.)

Mode	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Aviation	8.1	8.0	6.5	6.4	5.8	5.5	5.1	4.7	4.8	4.6	4.6	5.0	4.6	4.5	4.7	4.4	3.8
Marine	5.3	4.9	5.0	4.5	3.7	3.4	3.7	4.9	5.3	5.2	3.3	3.2	3.5	4.7	5.4	4.8	4.2
Total	**13.4**	**12.9**	**11.5**	**10.9**	**9.5**	**8.9**	**8.9**	**9.6**	**10.0**	**9.8**	**7.9**	**8.2**	**8.1**	**9.2**	**10.1**	**9.2**	**8.0**

Note: Totals may not sum due to independent rounding.

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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. production 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 61 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 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 extrapolating forward in time from the amount of regulated ODS used in the early 1990s. Using data gleaned from a variety of sources, assessments are made regarding which alternatives will likely be used, and what fraction of the ODS market in each end-use will be 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 emissions 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 ODSs, as well as data on how the substitutes are replacing the ODSs, to simulate the implementation of new technologies that ensure 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 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. These lifetime emissions and disposal emissions 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:

$$Es_j = (l_a + l_s) \times \sum Qc_{j-i+1} \quad for\ i = 1 \rightarrow k$$

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.

Qc = 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 normal leakage and servicing (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- 142, 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-142: 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	
Chillers													
CFC-11	HCFC-123	1993	1993	45%	None								0.5%
	HCFC-22	1991	1993	16%	HCFC-22	1996	1996	100%	HFC-134a	2000	2010	100%	
	HFC-134a	1992	1993	39%	None								
CFC-12	HFC-134a	1992	1994	53%	None								0.5%
	HCFC-22	1991	1994	16%	HCFC-22	1996	1996	100%	HFC-134a	2000	2010	100%	
	HCFC-123	1993	1994	31%	None								
R-500	HFC-134a	1992	1994	53%	None								0.5%
	HCFC-22	1991	1994	16%	HCFC-22	1996	1996	100%	HFC-134a	2000	2010	100%	
	HCFC-123	1993	1994	31%	None								
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%	R-404A	2010	2010	100%	2.5%
					R-507	1996	2010	25%	R-507	2010	2010	100%	
	R-404A	1994	1996	26%	None								
	R-507	1994	1996	9%	None								
HCFC-22	HCFC-22	1992	1993	100%	R-404A	1996	2009	8%	R-404A	2010	2010	100%	2.5%
					R-507	1996	2009	3%	R-507	2010	2010	100%	
					R-404A	2009	2010	68%	R-404A	2010	2010	100%	
					R-507	2009	2010	23%	R-507	2010	2010	100%	
R-502	HCFC-22	1990	1993	40%	R-404A	1996	2010	38%	R-404A	2010	2010	100%	2.5%
					R-507	1996	2010	12%	R-507	2010	2010	100%	
					Non-ODP/GWP	1996	2010	50%	Non-ODP/GWP	2010	2010	100%	
	R-404A	1993	1996	45%	R-404A	2010	2010	100%	None				
	R-507	1994	1996	15%	R-507	2010	2010	100%	None				
Commercial Unitary Air Conditioners													

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	HCFC-22	1992	1993	100%	R-410A	1996	2000	3%	None				2.5%
					R-410A	2001	2005	18%	None				
					R-410A	2006	2009	8%	None				
					R-410A	2009	2010	71%	None				
HCFC-22	HCFC-22	1992	1993	100%	R-410A	2001	2005	5%	None				2.5%
					R-407C	2006	2009	1%	None				
					R-410A	2006	2009	9%	None				
					R-407C	2009	2010	5%	None				
					R-410A	2009	2010	81%	None				
Dehumidifiers													
HCFC-22	HFC-134a	1997	1997	89%	None								0.2%
	R-410A	2007	2010	11%	None								
Displacement Chillers													
HCFC-22	HCFC-22	1996	1996	100%	HFC-134a	2000	2009	9%	R-407C	2010	2020	60%	0.5%
									R-410A	2010	2020	40%	
					R-407C	2000	2009	1%	None				
					HFC-134a	2009	2010	81%	R-407C	2010	2020	60%	
									R-410A	2010	2020	40%	
					R-407C	2009	2010	9%	None				
HCFC-22	HCFC-22	1996	1996	100%	HFC-134a	2000	2009	9%	R-407C	2010	2020	60%	0.5%
									R-410A	2010	2020	40%	
					R-407C	2000	2009	1%	None				
					HFC-134a	2009	2010	81%	R-407C	2010	2020	60%	
									R-410A	2010	2020	40%	
					R-407C	2009	2010	9%	None				
CFC-12	HCFC-22	1993	1993	100%	HCFC-22	1999	1999	100%	R-410A	2010	2020	40%	0.2%
Ice Makers													

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	HFC-134a	1993	1995	100%	HFC-134a	2005	2005	100%	None				2.5%
Industrial Process Refrigeration													
CFC-11	HCFC-123	1992	1994	70%	HCFC-123	2005	2005	100%	None				2.5%
	HFC-134a	1992	1994	15%	HFC-134a	2005	2005	100%	None				
	HCFC-22	1991	1994	15%	HFC-134a	1995	2010	100%	HFC-134a	2010	2010	100%	
CFC-12	HCFC-22	1991	1994	10%	HFC-134a	1995	2010	15%	HFC-134a	2010	2010	100%	2.5%
					R-404A	1995	2010	50%	R-404A	2010	2010	100%	
					R-410A	1999	2010	20%	R-410A	2010	2010	100%	
					R-507	1995	2010	15%	R-507	2010	2010	100%	
	HCFC-123	1992	1994	35%	HCFC-123	2005	2005	100%	None				
	HFC-134a	1992	1994	50%	HFC-134a	2005	2005	100%	None				
	R-401	1995	1996	5%	HFC-134a	1997	2000	100%	None				
HCFC-22	HCFC-22	1992	1993	100%	HFC-134a	1995	2009	2%	HFC-134a	2010	2010	100%	2.5%
					R-404A	1995	2009	5%	R-404A	2010	2010	100%	
					R-410A	1999	2009	2%	R-410A	2010	2010	100%	
					R-507	1995	2009	2%	R-507	2010	2010	100%	
					HFC-134a	2009	2010	14%	HFC-134a	2010	2010	100%	
					R-404A	2009	2010	45%	R-404A	2010	2010	100%	
					R-410A	2009	2010	18%	R-410A	2010	2010	100%	
					R-507	2009	2010	14%	R-507	2010	2010	100%	
Mobile Air Conditioners													
CFC-12	HFC-134a	1992	1994	100%									2.8%
CFC-12	HFC-134a	1993	1994	100%									
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	1992	1993	100%	HCFC-22	2006	2006	70%	R-410A	2007	2010	29%	1.9%
									R-407C	2010	2010	14%	

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	2011	2015	100%	
									R-410A	2010	2010	57%	
					R-410A	2000	2005	5%	R-410A	2006	2006	100%	
					R-410A	2000	2006	5%	None				
					R-410A	2006	2006	20%	None				
Retail Food													
CFC-12	R-502	1988	1990	100%	HCFC-22	1991	1993	100%	R-404A	1995	2000	18%	1.7%
									R-507	1995	2000	8%	
									R-404A	2000	2005	32%	
									R-507	2000	2005	14%	
									R-404A	2005	2010	18%	
									R-507	2005	2010	12%	
HCFC-22	R-404A	1995	2000	18%	None								1.7%
	R-507	1995	2000	8%	None								
	R-404A	2000	2005	32%	None								
	R-507	2000	2005	14%	None								
	R-404A	2005	2010	18%	None								
	R-507	2005	2010	12%	None								
CFC-12	HCFC-22	1990	1993	90%	HFC-134a	1993	1995	90%	CO_2	2010	2010	5%	1.7%
					R-404A	2000	2009	8%	None				
					R-507	2000	2009	3%	None				
	R-404A	1993	1996	8%	None								
	R-507	1993	1996	3%	None								
R-502	HCFC-22	1990	1993	100%	R-404A	1995	2000	18%	None				1.7%
					R-507	1995	2000	8%	None				
					R-404A	2000	2005	32%	None				
					R-507	2000	2005	14%	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	
					R-404A	2005	2010	18%	None				
					R-507	2005	2010	12%	None				
Transport Refrigeration													
CFC-12	HFC-134a	1993	1995	98%	HFC-134a	2005	2005	100%	None				2.
	HCFC-22	1993	1995	2%	HFC-134a	1995	1999	100%	HFC-134a	2005	2005	100%	
R-502	HFC-134a	1993	1995	55%	HFC-134a	2005	2005	100%	None				2.
	R-404A	1993	1995	45%	R-404A	2005	2005	100%	None				
Water-Source, Ground-Source and Unitary Heat Pumps; Packaged Terminal Air Conditioners and Heat Pumps													
HCFC-22	HCFC-22	1992	1993	100%	R-407C	2000	2006	5%	None				2.
					R-410A	2000	2006	5%	None				
					HFC-134a	2000	2009	2%	None				
					R-407C	2006	2009	3%	None				
					R-410A	2006	2009	5%	None				
					HFC-134a	2009	2010	18%	None				
					R-407C	2009	2010	23%	None				
					R-410A	2009	2010	41%	None				
HCFC-22	HCFC-22	1992	1993	100%	R-410A	2006	2009	10%	None				2.
					R-410A	2009	2010	90%	None				
Window Units													
HCFC-22	R-407C	2003	2009	3%	None								5.
	R-407C	2009	2010	35%	None								
	R-410A	2003	2009	7%	None								
	R-410A	2009	2010	55%	None								

Table A- 143 presents the average equipment lifetimes for each end use assumed by the Vintaging Model.

Table A- 143. Refrigeration and Air-conditioning Lifetime Assumptions

End Use	Lifetime (Years)
Mobile Air Conditioners	5-12
Chillers	20 - 27
Retail Food	15 - 20
Cold Storage	20 - 25
Industrial Process Refrigeration	25
Transport Refrigeration	12
Dehumidifiers	11
Ice Makers	20
Refrigerated Appliances	20
Residential Unitary A/C	15
Commercial Unitary A/C	15
Water & Ground Source Heat Pumps	20
PTAC/PTHP	12
Cold Storage	20 - 25
Displacement Chillers	20
Window Units	12

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 ODSs in consumer aerosols was banned in 1977, and many products transitioned to "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.

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- 144.

Table A- 144. 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-11	HFC-134a	1997	2008	9%	None				1.5%

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	
	HFC-227ea	1997	2008	1%	None				
	HFC-134a	2009	2009	27%	None				
	HFC-227ea	2009	2009	3%	None				
	HFC-134a	2009	2015	54%	None				
	HFC-227ea	2009	2015	6%	None				
CFC-12	HFC-134a	1997	2008	9%	None				1.5%
	HFC-227ea	1997	2008	1%	None				
	HFC-134a	2009	2009	27%	None				
	HFC-227ea	2009	2009	3%	None				
	HFC-134a	2009	2015	54%	None				
	HFC-227ea	2009	2015	6%	None				
CFC-114	HFC-134a	1997	2008	9%	None				1.5%
	HFC-227ea	1997	2008	1%	None				
	HFC-134a	2009	2009	27%	None				
	HFC-227ea	2009	2009	3%	None				
	HFC-134a	2009	2015	54%	None				
	HFC-227ea	2009	2015	6%	None				
Non-MDIs									
NA*	HFC-152a	1990	1991	50%	None				2.0%
	HFC-134a	1995	1995	50%	HFC-152a	1997	1998	44%	
					HFC-134a	1997	1998	56%	

*Consumer Aerosols transitioned away from ODS prior to the beginning of the Vintaging Model, which begins in 1985. 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.

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- 145.

Table A-145. 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									
CH3CCl3	Non-ODP/GWP	1994	1995	100%	None				2.0%
Electronics									
CFC-113	Non-ODP/GWP	1994	1995	52%	None				2.0%
	HCFC-225ca/cb	1994	1995	0%	None				
	HFC-4310mee	1995	1996	1%	None				
	HFE-7100	1994	1995	1%	None				
	Non-ODP/GWP	1992	1996	6%	None				
	Non-ODP/GWP	1992	1996	40%	None				
CH3CCl3	Non-ODP/GWP	1996	1997	29%	None				2.0%
	Non-ODP/GWP	1996	1997	7%	None				
	Non-ODP/GWP	1996	1997	9%	None				
	PFC/PFPE	1996	1997	0%	Non-ODP/GWP	2000	2003	90%	
					Non-ODP/GWP	2005	2009	10%	
	Non-ODP/GWP	1996	1997	56%	None				
Metals									
CH3CCl3	Non-ODP/GWP	1992	1996	100%	None				2.0%
CFC-113	Non-ODP/GWP	1992	1996	100%	None				2.0%
CCl4	Non-ODP/GWP	1992	1996	100%	None				2.0%
Precision									
CH3CCl3	Non-ODP/GWP	1995	1996	15%	None				2.0%
	Non-ODP/GWP	1995	1996	10%	None				
	Non-ODP/GWP	1995	1996	29%	None				
	Non-ODP/GWP	1995	1996	12%	None				
	HFC-4310mee	1995	1996	1%	None				
	PFC/PFPE	1995	1996	0%	Non-ODP/GWP	2000	2003	90%	
					Non-ODP/GWP	2005	2009	10%	
	Non-ODP/GWP	1995	1996	34%	None				
CFC-113	Non-ODP/GWP	1995	1996	90%	None				2.0%
	HCFC-225ca/cb	1995	1996	1%	None				
	HFE-7100	1995	1996	3%	None				
	Non-ODP/GWP	1995	1996	6%	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, 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. 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.

$$E_j = \mathrm{r} \times \sum Qc_{j-i+1} \quad for\ i=1 \rightarrow k$$

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.

Qc = 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.

Assumptions

Transition assumptions and growth rates for these two fire extinguishing types are presented in Table A-146.

Table A-146. 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%	None				2.2%
	HFC-23	1994	1999	0%	None				
	HFC-227ea	1994	1999	18%	Novec 1230	2003	2010	10%	
					HFC-125	2001	2008	10%	
	Non-ODP/GWP	1994	1994	46%	Novec 1230	2003	2010	7%	
	Non-ODP/GWP	1995	2034	10%	None				
	Non-ODP/GWP	1998	2027	10%	None				
	C_4F_{10}	1994	1999	1%	Novec 1230	2003	2003	100%	
	HFC-125	1997	2006	11%	None				
Streaming Agents									
Halon-1211	Halon-1211	1992	1992	5%	None				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				

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 or PFC content upon manufacture, a portion at a constant rate over the lifetime of the foam, and a portion at disposal.

Step 1: Calculate emissions from open-cell foam

Emissions from open-cell foams are calculated using the following equation.

$$E_j = Qc_j$$

Where:

E = Emissions. Total emissions of a specific chemical in year j used for open-cell foam blowing, by weight.

Qc = Quantity of Chemical. Total amount of a specific chemical used for open-cell foam blowing in year j, by weight.

j = Year of emission.

Step 2: Calculate emissions from closed-cell foam

Emissions from foams occur at many different stages, including manufacturing, lifetime, disposal and post-disposal. 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.

Qc = Quantity of Chemical. Total amount of a specific chemical used to manufacture closed-cell foams in a given year.

j = Year of emission.

Lifetime emissions occur annually from closed cell foams throughout the lifetime of the foam, as calculated as presented in the following equation.

$$Eu_j = \mathrm{lu} \times \sum Qc_{j-i+1} \quad for\ i=1 \rightarrow k$$

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 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.

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.

Post-Disposal emissions occur in the years after the foam is disposed, and are assumed to occur while the disposed foam is in a landfill. Currently, the only foam type assumed to have post-disposal emissions is polyurethane appliance foam, which is expected to continue to emit for 32 years post-disposal, and are calculated as presented in the following equation.

$$Ep_j = lp \times \sum Qc_{j-m} \quad for\ m=k \rightarrow k+32$$

Where:

Ep_j = Emissions from post disposal. Total 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+32).

j = Year of emission.

To calculate total emissions from foams in any given year, emissions from all foam stages must be summed, as presented in the following equation.

$$E_j = Em_j + Eu_j + Eu_j + Ed_j + Ep_j$$

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 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- 147. The emission profiles of the foam types estimating in the Vintaging Model are shown inTable A- 148.

Table A- 147. Foam Blowing 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	
Commercial Refrigeration Foam									
CFC-11	HCFC-141b	1989	1996	40%	HFC-245fa	2002	2003	80%	6.0%
					Non-ODS/GWP	2002	2003	20%	
	HCFC-142b	1989	1996	8%	Non-ODS/GWP	2009	2010	80%	
					HFC-245fa	2009	2010	20%	
	HCFC-22	1989	1996	52%	Non-ODS/GWP	2009	2010	80%	
					HFC-245fa	2009	2010	20%	
Flexible PU Foam: Integral Skin Foam									
CFC-11	HCFC-141b	1989	1990	100%	HFC-134a	1993	1996	25%	2.0%
					HFC-134a	1994	1996	25%	
					CO_2	1993	1996	25%	
					CO_2	1994	1996	25%	
Flexible PU Foam: Slabstock Foam, Moulded Foam									
CFC-11	Non-ODS/GWP	1992	1992	100%	None				2.0%
Phenolic Foam									
CFC-11	HCFC-141b	1989	1990	100%	Non-ODS/GWP	1992	1992	100%	2.0%
Polyolefin Foam									
CFC-114	HFC-152a	1989	1993	10%	Non-ODS/GWP	2005	2010	100%	2.0%
	HCFC-142b	1989	1993	90%	Non-ODS/GWP	1994	1996	100%	
PU and PIR Rigid: Boardstock									
CFC-11	HCFC-141b	1993	1996	100%	Non-ODS/GWP	2000	2003	95%	6.0%
					HFC Blend	2000	2003	5%	
PU Rigid: Domestic Refrigerator and Freezer Insulation									
CFC-11	HCFC-141b	1993	1996	89%	HFC-134a	1996	2003	10%	3.0%
					HFC-245fa	2002	2003	85%	
					Non-ODS/GWP	2002	2003	5%	
	HCFC Blend	1993	1996	1%	HFC-245fa	2009	2010	50%	
					HFC-134a	2009	2010	50%	
	HCFC-22	1993	1996	10%	HFC-134a	2009	2010	100%	
PU Rigid: One Component Foam									
CFC-12	HCFC Blend	1989	1996	70%	Non-ODS/GWP	2009	2010	80%	4.0%
					HFC-134a	2009	2010	10%	
					HFC-152a	2009	2010	10%	
	HCFC-22	1989	1996	30%	Non-ODS/GWP	2009	2010	80%	
					HFC-134a	2009	2010	10%	
					HFC-152a	2009	2010	10%	
PU Rigid: Other: Slabstock Foam									
CFC-11*	HCFC-141b	1989	1996	100%	CO_2	1999	2003	45%	2.0%
					Non-ODS/GWP	2001	2003	45%	

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	
					HCFC-22	2003	2003	10%	
PU Rigid: Sandwich Panels: Continuous and Discontinuous									
CFC-11**	HCFC-141b	1989	1996	82%	HCFC Blend	2001	2003	20%	6.0%
					HFC Blend	2002	2004	20%	
					Non-ODS/GWP	2001	2004	40%	
					HFC-134a	2002	2004	20%	
	HCFC-22	1989	1996	18%	HFC Blend	2009	2010	40%	
					Non-ODS/GWP	2009	2010	20%	
					CO_2	2009	2010	20%	
					HFC-134a	2009	2010	20%	
PU Rigid: Spray Foam									
CFC-11	HCFC-141b	1989	1996	100%	HFC-245fa	2002	2003	30%	6.0%
					HFC Blend	2002	2003	60%	
					Non-ODS/GWP	2001	2003	10%	
XPS: Boardstock Foam									
CFC-12	HCFC Blend	1989	1994	10%	HFC-134a	2009	2010	70%	2.5%
					HFC-152a	2009	2010	10%	
					CO_2	2009	2010	10%	
					Non-ODS/GWP	2009	2010	10%	
	HCFC-142b	1989	1994	90%	HFC-134a	2009	2010	70%	
					HFC-152a	2009	2010	10%	
					CO_2	2009	2010	10%	
					Non-ODS/GWP	2009	2010	10%	
XPS: Sheet Foam									
CFC-12	CO_2	1989	1994	1%	None				2.0%
	Non-ODS/GWP	1989	1994	99%	CO_2	1995	1999	9%	
					HFC-152a	1995	1999	10%	

* Polyurethane Slabstock and Other Foam has a tertiary substitution; HCFC-22 is substituted with a non-ODP/GWP substitute in 2009, with 100% penetration in new equipment in 2010.

** Polyurethane Sandwich Panel Foam has a tertiary substitution; The portion of theHCFC Blend that is substituted for HCFC-141b, is substituted with a blend of 50/50 HFC Blend and a non-ODS/GWP substituted in 200- with 100% penetration in new equipment in 2010.

Table A- 148. 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	20	27.3	36.3
PU and PIR Rigid: Boardstock	6	1	50	44	100
PU Sandwich Panels: Continuous and Discontinuous	5.5	0.5	50	69.5	100

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 32 years.

Sterilization

Sterilization is used to control microorganisms and pathogens during the growing, collecting, storing and distribution of flowers as well as various foods including grains, vegetables and fruits. Currently, the Vintaging Model assumes that the sterilization sector has not transitioned to any HFC or PFC as an ODS substitute, however, the modeling methodology is provided below for completeness.

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.

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 basis. Values for use and emissions are calculated both in metric tons and in teragrams of CO_2 equivalents (Tg CO_2 Eq.). The conversion of metric tons of chemical to Tg CO_2 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.

3.9. Methodology for Estimating CH_4 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; consequently, the more detailed IPCC Tier 2 methodology was used to estimate emissions from cattle and the IPCC Tier 1 methodology was used to estimate emissions from 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).[40] 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.[41] 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 2007). A summary of the annual average populations upon which all livestock-related emissions are based is provided in **Table A- 163** of the Manure Management Annex. Actual cattle populations used in the Enteric Fermentation sector were estimated using the cattle transition matrix in the Cattle Enteric Fermentation Model (CEFM), which uses USDA population 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 means that the cattle population estimates for Enteric Fermentation differ slightly from the USDA point estimates used in the Manure Management Estimates in the Agriculture Chapter and the cattle population data obtained from the Food and Agriculture Organization of the United Nations (FAO).

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 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).

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[40] Emissions from bulls are estimated using a Tier 1 approach based on published population statistics and national average emission factors because it is assumed there is minimal variation in population and diets. Calves younger than 7 months are not included because it is assumed they emit little or no CH_4.

[41] Additional information on the Cattle Enteric Fermentation Model can be found in ICF (2006)

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 CH_4 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 CH_4 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-149.

Table A-149: Cattle Population Categories Used for Estimating CH_4 Emissions

Dairy Cattle	Beef Cattle
Calves	Calves
Heifer Replacements	Heifer Replacements
Cows	Heifer and Steer Stockers
	Animals in Feedlots (Heifers & Steers)
	Cows
	Bulls[42]

The key variables tracked for each of these cattle population categories (except bulls[40]) 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 (2007). For dairy cows it is assumed that the number of births is distributed equally throughout the year (approximately 8.3 percent per month), beef births are distributed according to Table A-150, 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 (varies depending on birth 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-151. 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-150: 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-151: Example of Calf Transition Matrix

Age (month)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
7		597	593	707	839	802	796	1,313	2,500	4,384	3,540	1,623
6	598	593	708	839	802	796	1,313	2,501	4,386	3,542	1,624	791
5	594	708	839	802	796	1,314	2,501	4,388	3,544	1,625	791	578
4	742	870	836	827	1,343	2,531	4,418	3,577	1,656	819	606	601
3	871	837	827	1,343	2,532	4,420	3,578	1,657	820	607	601	750
2	837	828	1,344	2,533	4,422	3,580	1,657	820	607	602	750	879
1	828	1,345	2,534	4,423	3,581	1,658	820	607	602	751	879	844
0	1,346	2,536	4,425	3,582	1,658	820	607	602	751	880	845	835

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

[42] Note all bulls (beef and dairy) are accounted for in a single category.

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 (2007).

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-152) and subtraction through death loss and animals placed in feedlots. Eventually, an entire cohort population of stockers will 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-152.

Table A-152: Example of Stocker Transition Matrix

Age (month)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
24		123	112	0	0	0	0	0	0	0	0	0
23	198	214	58	0	0	0	0	0	0	1	1	0
22	346	173	27	0	0	0	0	0	2	2	20	0
21	280	80	13	0	0	0	0	4	4	46	27	0
20	130	40	10	0	0	0	5	8	94	63	58	0
19	64	29	10	0	0	8	11	170	127	137	61	0
18	48	29	14	0	11	16	247	231	278	143	34	0
17	47	41	27	17	22	353	335	504	291	80	107	0
16	59	49	36	30	491	479	731	526	169	263	4	0
15	69	58	51	686	699	1,047	756	303	762	11	0	0
14	66	57	813	955	1,502	1,026	420	1,356	115	5	0	0
13	65	910	1,382	2,095	1,302	526	1,828	203	69	8	4	18
12	1,042	1,547	2,403	1,582	639	2,291	280	126	80	27	54	267
11	1,764	2,689	1,815	756	2,830	424	201	172	158	92	371	500
10	3,079	2,108	855	3,077	538	396	343	410	380	440	570	1,387
9	2,492	1,037	3,514	616	504	594	711	648	662	694	1,579	2,895
8	1,154	3,840	763	664	763	958	866	868	827	1,894	3,298	2,573
7	4,187	829	822	1,007	1,230	1,168	1,159	1,084	2,256	4,120	3,286	1,396

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 are discussed individually below:

- Total Available Table. This table sums the number of animals available to be placed in feedlots by weight group.
- Planned Placements Table. This table presents the USDA NASS feedlot placement statistics.
- Placements from this Population Table. This table draws the lowest value from either the "Total Available" or "Planned Placements" tables.
- Imports Required Table. Subtracts the "Placements from this Population" value from the "Planned Placements" data to determine if additional imports are required for each weight class.
- Placed % of Available Table. This table calculates the number of animals that are placed as a percentage of the animals that could be placed.

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 to range from 480 to 575 pounds, depending on the birth month. Other reported target weights were available for 12, 15, 24, and 36 month-old animals. Live slaughter weights were derived from dressed slaughter weight data for each year (USDA 2007). Live slaughter weight was estimated as dressed weight divided by 0.63 USDA (1999c). 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-153 provides the target weights used to track average weights of cattle by animal type.

Table A-153: Target Weights for Use in Estimating Average Weights and Weight Gains (lbs)

Cattle Type	Typical Weights (lbs)
Beef Replacement Heifer Data	
Replacement Weight at 15 months	715
Replacement Weight at 24 months	1,078
Mature Weight at 36 months	1,172
Dairy Replacement Heifer Data	
Replacement Weight at 15 months	800
Replacement Weight at 24 months	1,225
Mature Weight at 36 months	1,350
Stockers Data—Grazing/Forage Based Only	
Steer Weight Gain/Month to 12 months	45
Steer Weight Gain/Month to 24 months	35
Heifer Weight Gain/Month to 12 months	35
Heifer Weight Gain/Month to 24 months	30

Source: Feedstuffs (1998), Western Dairyman (1998), Johnson (1999), NRC (1999).

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-154) 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 onwards. Table A-154 provides a summary of the reported feedlot placement statistics for 2006.

Table A-154: Feedlot Placements in the United States for 2006 (Number of animals placed in Thousand Head)

Weight When Placed	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
< 600 lbs	530	355	380	385	440	565	570	680	720	840	555	470	**6,490**
600 – 700 lbs	447	300	342	265	370	430	403	430	412	650	560	504	**5,113**
700 – 800 lbs	702	505	565	444	498	456	490	535	450	485	404	420	**5,954**
> 800 lbs	520	428	550	525	595	495	495	645	645	455	365	320	**6,038**
Total	**2199**	**1588**	**1837**	**1619**	**1903**	**1946**	**1958**	**2290**	**2227**	**2430**	**1884**	**1714**	**23,595**

Source: USDA (2007).
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 CH_4 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. Monthly estimates for dairy cattle were taken from USDA monthly milk production statistics. Dairy lactation estimates for 1990 through 2006 are shown in Table A-155. Beef and dairy cow populations are assumed to remain static throughout the year, as it is assumed that there are not large fluctuations in population size. These estimates are taken from the USDA beginning of year population datasets.

Table A-155: Dairy Lactation by State (lbs· year/cow)*

State/Year	1990	1995	2000	2001	2002	2003	2004	2005	2006
Alabama	12,214	14,176	13,920	14,286	13,850	14,000	14,412	14,000	14,500
Alaska	14,000	17,000	14,500	13,055	13,600	12,846	12,167	12,273	12,250
Arizona	17,500	19,735	21,820	22,036	23,333	22,916	22,788	22,679	22,855
Arkansas	11,841	12,150	12,436	12,343	12,281	12,207	13,458	13,545	13,250
California	18,456	19,573	21,130	20,904	21,277	20,993	21,139	21,404	21,815
Colorado	17,182	18,687	21,618	21,413	21,590	21,530	21,412	22,577	23,155
Connecticut	15,606	16,438	17,778	18,240	18,625	18,773	19,600	19,200	19,316
Delaware	13,667	14,500	14,747	16,667	16,667	15,904	17,230	17,662	17,429
Florida	14,033	14,698	15,688	15,758	15,387	15,218	16,326	16,591	16,417
Georgia	12,973	15,550	16,284	16,663	17,294	16,988	16,857	17,259	18,234
Hawaii	13,604	13,654	14,358	14,107	14,667	14,154	13,197	12,889	13,256
Idaho	16,475	18,147	20,816	21,194	21,018	21,718	21,446	22,332	22,326
Illinois	14,707	15,887	17,450	17,414	17,835	18,441	18,486	18,827	19,204
Indiana	14,590	15,375	16,568	16,778	17,603	19,725	20,046	20,295	19,994
Iowa	15,118	16,124	18,298	18,024	18,201	18,955	19,953	20,641	20,146
Kansas	12,576	14,390	16,923	17,312	18,972	19,189	19,611	20,505	20,920
Kentucky	10,947	12,469	12,841	12,969	13,230	12,629	12,927	12,896	13,276
Louisiana	11,605	11,908	12,034	11,704	12,063	12,070	12,605	12,400	12,375
Maine	14,619	16,025	17,128	17,211	17,730	17,829	18,000	18,030	17,938
Maryland	13,461	14,725	16,083	15,780	16,062	15,577	15,703	15,986	17,078
Massachusetts	14,871	16,000	17,091	17,000	17,190	17,474	17,412	17,059	17,375
Michigan	15,394	17,071	19,017	19,373	20,332	21,109	20,891	21,635	22,188
Minnesota	14,127	15,894	17,777	17,278	17,368	17,459	17,499	18,091	18,587
Mississippi	12,081	12,909	15,028	14,200	14,059	13,645	14,037	15,280	14,826
Missouri	13,632	14,158	14,662	13,441	14,204	14,620	15,139	16,026	16,000
Montana	13,542	15,000	17,789	18,211	18,944	19,167	19,333	19,579	18,632
Nebraska	13,866	14,797	16,513	16,194	17,418	17,641	17,197	17,950	18,328
Nevada	16,400	18,128	19,000	19,412	20,040	19,400	20,360	21,680	20,667
New Hampshire	15,100	16,300	17,333	17,889	18,222	19,063	18,938	18,875	19,533
New Jersey	13,538	13,913	15,250	16,643	18,154	16,615	16,667	16,000	16,182
New Mexico	18,815	18,969	20,944	20,750	20,983	21,028	20,666	21,192	21,515
New York	14,658	16,501	17,378	17,530	18,101	17,812	17,786	18,639	18,879
North Carolina	15,220	16,314	16,746	17,224	17,766	17,115	17,649	18,741	18,510
North Dakota	12,624	13,094	14,292	14,000	14,825	14,857	15,471	14,182	14,688
Ohio	13,767	15,917	17,027	16,519	17,080	17,269	17,338	17,567	17,737
Oklahoma	12,327	13,611	14,440	15,407	15,560	16,000	16,192	16,480	16,630
Oregon	16,273	17,289	18,222	18,074	18,360	18,294	18,917	18,876	19,000
Pennsylvania	14,726	16,492	18,081	18,112	18,419	17,979	17,904	18,722	19,390
Rhode Island	14,250	14,773	15,667	16,571	16,357	17,000	16,333	17,000	17,273
South Carolina	12,771	14,481	16,087	17,476	18,200	16,737	16,882	16,000	16,353
South Dakota	12,257	13,398	15,516	15,393	14,988	16,220	16,838	17,741	18,580
Tennessee	11,825	13,740	14,789	14,511	14,943	15,253	15,400	15,743	15,657
Texas	14,350	15,244	16,503	15,666	16,719	17,649	18,837	20,131	21,328
Utah	15,838	16,739	17,573	17,211	17,914	17,824	18,284	18,875	20,291
Vermont	14,528	16,210	17,199	17,444	17,552	17,698	17,890	18,469	18,383
Virginia	14,213	15,116	15,833	15,975	15,891	15,319	16,486	16,990	17,363
Washington	18,532	20,091	22,644	22,324	22,753	22,780	22,852	23,270	23,055
West Virginia	11,250	12,667	15,588	15,563	15,188	14,400	14,923	14,923	15,385
Wisconsin	13,973	15,397	17,306	17,182	17,367	17,728	17,796	18,500	18,824
Wyoming	12,337	13,197	13,571	14,000	14,409	14,211	14,744	14,878	17,612

Source: USDA (2007).

* 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 CH_4 conversion rate (Y_m, the fraction of gross energy converted to CH_4) 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. Additional detail on the regional diet characterization is provided in EPA (2000).

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 States[43] 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.

DE and Y_m values for dairy cows were estimated using a model (Donovan and Baldwin 1999) that represents physiological processes in the ruminant animals. The three major categories of input required by the model 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 (USDA 1996)). 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 model accounts for differing diets (i.e., grain-based, forage-based, range-based), so that Y_m values for the variable feeding characteristics within the U.S. cattle population can be estimated.

To calculate the DE values for grazing beef cattle, the diet descriptions were used to estimate weighted DE values for a combination of forage only and supplemented 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. For forage diets, two separate regional DE values were used to account for the generally lower forage quality in the western United States. For non-western grazing animals, the forage DE was an average of the seasonal "TDN as a percent of DM" for Grass Pasture diets listed in Appendix Table 1 of the NRC (2000). This average digestible energy for the non-western grazing animals was 64.7 percent. This value was used for all regions except the west. For western grazing animals, the forage digestible energy was calculated as the average "TDN as a percent of DM" for meadow and range diets listed in Appendix Table 1 of the NRC (2000). The calculated DE for western grazing animals was 58.5 percent. The DE values of supplemental diets were estimated for each specific feed component, as shown in Table A-156, along with the percent of each feed type in each region. Finally, weighted averages were developed for DE values for each region using both the supplemented diet and the forage diet.[44] 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). The percent of each diet that is assumed to be supplemental and the DE values for each region are shown in Table A-157. 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 1996 through 2006 were taken from Johnson (1999). Values for 1990 through 1995 were linearly extrapolated from the 1996 value based on Johnson (1999). 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. In response to peer reviewer comments (Johnson 2000), values for dairy replacement heifers are based on EPA (1993).

Table A-158 shows the regional DE and Y_m for U.S. cattle in each region based on 2006 data.

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[43] 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.

[44] 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.

Table A-156: 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	California [a]	West	Northern Great Plains	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 Supplement	Table 11-1, feed #70	83.1%		5%	5%				5%
Sorghum	Table 11-1, feed #67	81.3%							20%
Soybean Hulls	Table 11-1, feed #69	76.4%						7%	
Timothy Hay	Table 11-1, feed #77	55.5%					50%		
Whole Cotton Seed	Table 11-1, feed #41	89.2%	5%				5%		
Wheat Middlings	Table 1a, feed #433	83.0%			15%	13%			
Wheat	Table 11-1, feed #83	87.2%	10%						
Weighted Total			**69%**	**65%**	**74%**	**62%**	**65%**	**65%**	**59%**

Source of representative regional diets: Donovan (1999).

[a] 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.

Table A-157: Percent of Each Diet that is Supplemental, and the Resulting DE Values for Each Region

Region[a]	Percent Supplement	Percent Forage	Calculated Weighted Average DE
West	10	90	59
Northeast	15	85	65
Southcentral	10	90	64
Midwest	15	85	65
Northern Great Plains	15	85	66
Southeast	5	95	64
California	5	95	65

Source of percent of total diet that is supplemental diet: Donovan (1999).

[a] 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.

Table A-158: Regional Digestible Energy (DE) and CH_4 Conversion Rates (Y_m) for Cattle in 2006

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	66	66	66	64	68	66	66
	Y_m	5.9%	5.9%	5.6%	6.4%	6.3%	5.6%	6.9%
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	85	85	85	85	85	85	85
	Y_m	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
Heifer Feedlot	DE	85	85	85	85	85	85	85
	Y_m	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
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	69	66	69	68	69	69	68
	Y_m	4.8%	5.8%	5.8%	5.7%	5.8%	5.8%	5.6%
Steer Step-Up	DE	73	73	73	73	73	73	73
	Y_m	4.8%	4.8%	4.8%	4.8%	4.8%	4.8%	4.8%
Heifer Step-Up	DE	73	73	73	73	73	73	73
	Y_m	4.8%	4.8%	4.8%	4.8%	4.8%	4.8%	4.8%

[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 CH_4 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 emissions 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)[45]
- Standard Reference Weight[46] (Dairy = 1,324 lbs; Beef = 1,195 lbs)
- 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 CH_4)
- Population

Step 3a: 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).

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[45] 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.

[46] Standard Reference Weight is 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 percentage of gross energy (percent)

Step 3b: 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, weight, and state.

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:

$$Emissions_{state} = DayEmit_{state} \times Days/Month \times SubPop_{state}$$

Where,

DayEmit	= The emission factor for the subcategory and state (kg CH_4/head/day)
Days/Month	= The number of days in the month
SubPop	= 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-159. The emissions for each subcategory were then summed to estimate total emissions from beef cattle and dairy cattle for the entire year.

Table A-159: CH_4 Emissions from Cattle (Gg)

Cattle Type	1990	1995	2000	2001	2002	2003	2004	2005	2006
Dairy	**1,488**	**1,422**	**1,377**	**1,374**	**1,381**	**1,393**	**1,377**	**1,411**	**1,441**
Cows	1,241	1,177	1,139	1,133	1,140	1,150	1,138	1,165	1,187
Replacements 7-11 months	51	51	51	51	51	50	51	53	54
Replacements 12-23 months	195	194	188	190	190	192	188	193	200
Beef	**4,281**	**4,616**	**4,304**	**4,257**	**4,251**	**4,260**	**4,155**	**4,198**	**4,249**
Cows	2,814	3,047	2,906	2,889	2,866	2,853	2,843	2,848	2,854
Replacements 7-11 months	54	63	55	56	56	55	56	58	59
Replacements 12-23 months	200	244	208	211	210	212	208	215	223
Steer Stockers	431	480	362	352	355	361	325	337	347
Heifer Stockers	243	262	218	214	216	221	199	210	209
Feedlot Cattle	423	392	438	420	432	441	410	417	442
Bulls	116	127	116	116	115	115	113	114	116
Total	**5,769**	**6,038**	**5,682**	**5,631**	**5,632**	**5,652**	**5,531**	**5,609**	**5,689**

Notes: Totals may not sum due to independent rounding. Emissions from calves less than 7 months are not included because it is assumed that they emit little or no methane.

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 2007). **Table A-163** 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 2007). The Food and Agriculture Organization (FAO) publishes horse population data. These data were accessed from the FAOSTAT database (FAO 2007). 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-160 shows the emission factors used for these other livestock.

Enteric fermentation emissions from all livestock types are shown in Table A-161 and Table A-162.

Table A-160: Emission Factors for Other Livestock (kg CH_4/head/year)

Livestock Type	Emission Factor
Sheep	8
Goats	5
Horses	18
Swine	1.5

Source: IPCC (2006)

Table A-161: CH_4 Emissions from Enteric Fermentation (Tg CO_2 Eq.)

Livestock Type	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Beef Cattle	89.9	89.0	91.5	92.3	94.2	96.9	96.1	93.7	92.0	91.9	90.4	89.4	89.3	89.5	87.2	88.2	89.2
Dairy Cattle	31.2	31.3	31.2	29.8	29.7	29.9	28.4	28.4	28.3	28.5	28.9	28.8	29.0	29.2	28.9	29.6	30.3
Horses	1.9	1.9	1.9	1.9	1.9	1.9	1.9	2.0	2.0	2.0	2.0	2.1	2.3	2.6	3.0	3.5	3.5
Sheep	1.9	1.9	1.8	1.7	1.7	1.5	1.4	1.3	1.3	1.2	1.2	1.2	1.1	1.1	1.0	1.0	1.0
Swine	1.7	1.8	1.8	1.8	1.9	1.9	1.8	1.8	2.0	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9
Goats	0.3	0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Total	126.9	126.1	128.5	127.9	129.7	132.3	129.8	127.4	125.7	125.8	124.6	123.6	123.8	124.6	122.4	124.5	126.2

Note: Totals may not sum due to independent rounding.

Table A-162: CH_4 Emissions from Enteric Fermentation (Gg)

Livestock Type	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Beef Cattle	4,281	4,239	4,355	4,397	4,487	4,616	4,574	4,461	4,380	4,377	4,304	4,257	4,251	4,260	4,155	4,198	4,249
Dairy Cattle	1,488	1,490	1,485	1,419	1,417	1,422	1,351	1,350	1,345	1,358	1,377	1,374	1,381	1,393	1,377	1,411	1,441
Horses	91	92	92	92	92	92	93	93	94	93	94	99	108	126	144	166	166
Sheep	91	89	86	82	79	72	68	64	63	58	56	55	53	51	49	49	50
Swine	81	85	88	87	90	88	84	88	93	90	88	88	90	90	91	92	93
Goats	13	13	13	12	12	12	12	11	12	12	12	12	13	13	13	13	13
Total	**6,044**	**6,007**	**6,119**	**6,090**	**6,176**	**6,302**	**6,181**	**6,068**	**5,987**	**5,989**	**5,933**	**5,886**	**5,896**	**5,931**	**5,828**	**5,928**	**6,010**

Note: Totals may not sum due to independent rounding.

3.10. Methodology for Estimating CH_4 and N_2O Emissions from Manure Management

The following steps were used to estimate methane (CH_4) and nitrous oxide (N_2O) 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 2006 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 2007a). Poultry population data were obtained from USDA NASS reports (USDA 1995a, 1995b, 1998a, 1999, 2004a, 2004b, 2006a, 2006b, 2007b, 2007c). Horse population data were obtained from the Food and Agriculture Organization (FAO) FAOSTAT database (FAO 2007). Goat population data for 1992, 1997, and 2002 were obtained from the Census of Agriculture (USDA 2005). Additional data sources used and adjustments to these data sets are described below.

Beef Cattle: Additional information regarding the percent of beef steers and heifers in feedlots was obtained from contacts with the national USDA office (Milton 2000). Data for beef feedlots were also obtained from EPA's Office of Water (ERG 2000a, EPA 2002a, 2002b).

For all beef 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 fattened cattle are slaughtered; therefore, to develop the best estimate for the annual animal population, the average inventory of cattle by state was calculated. In order to estimate average annual populations by state, a "scaling factor" was developed that adjusts the January state-level data to reflect July inventory changes. This factor, as shown in the equation below, equals the average of the U.S. January and July data divided by the January data. The scaling factor is derived for each cattle group and is then applied to the January state-level data to arrive at the state-level annual population estimates.

$$\text{Cattle Scaling Factor} \equiv \left(\frac{\text{January}_{\text{US Cattle}} + \text{July}_{\text{US Cattle}}}{2} \right) \div \text{January}_{\text{US Cattle}}$$

Swine: The USDA provides quarterly data for each swine subcategory: breeding, market under 60 pounds (less than 27 kg), market 60 to 119 pounds (27 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 2006 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 only available for 1992, 1997, and 2002 (USDA 2005). The data for 1992 were used for 1990 through 1992 and the data for 2002 were used for 2002 through 2006. Data for 1993 through 1996 were estimated based on the 1992 and 1997 Census data. Data for 1998 through 2001 were extrapolated using the 1997 and 2002 Census data.

Poultry: The USDA provides population data for hens, pullets, broilers, other chickens, and turkeys (USDA 1995a, 1995b, 1998a, 1999, 2004a, 2004b, 2006a, 2006b, 2007b, 2007c). The annual population data for boilers 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 2007). 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. FAO horse population estimates for recent years have been updated since the 1990 to 2005 inventory. For example, the 2005 U.S. horse population was previously estimated at 5,300,000, and the updated 2005 horse population is now estimated at 9,200,000. The FAO has been contacted about the changes in horse population, but no explanation has been supplied. These changes in horse population estimates have affected the emissions estimates for the 1990 to 2006 inventory.

A summary of the livestock population characterization data used to calculate CH_4 and N_2O emissions is presented in Table A- 163.

Step 2: Waste Characteristics Data

Methane and N_2O emissions calculations are based on the following animal characteristics for each relevant livestock population:

- Volatile solids (VS) excretion rate;
- Maximum methane producing capacity (B_o) for U.S. animal waste;
- Nitrogen excretion rate (Nex); and
- Typical animal mass (TAM).

Table A-164 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 (USDA 1996a) is one of the primary sources of waste characteristics. In some cases, data from the American Society of Agricultural Engineers, Standard D384.1 (ASAE 1999) were used to supplement the USDA data. The dairy cow populations are assumed to be comprised of both lactating and dry cows: 17 percent of a dairy herd is assumed to be dry and 83 percent is assumed to be lactating. Nex rates were collected from the sources indicated in Table A-164 and are based on measurement data from excreted manure. 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, and the 2004 inventory VS and Nex values of 10.8 (hens) and 9.7 (pullets) kg VS/day per 1,000 kg mass, and 0.83 (hens) and 0.62 (pullets) kg Total Kjeldahl Nitrogen/day per 1,000 kg mass. The new hen and pullet VS and Nex values were applied to hens and pullets for all years of the inventory.

The method for calculating VS production from beef and dairy cows, heifers, and steers is based on the relationship between animal diet and energy utilization, which is modeled in the enteric fermentation portion of the inventory. 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 CH_4 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 an additional two percent of gross energy for urinary energy excretion per animal unit. This value is then converted to VS production per animal unit using the typical conversion of dietary gross energy to dry organic matter of 20.1 MJ/kg (Garrett and Johnson 1983). The equation used for calculating VS is as follows:

$$\text{VS production (kg)} = \frac{\text{GE} - \text{DE} + (0.02 \times \text{GE})}{20.1\,\text{MJ/kg}}$$

Where,

GE = Gross energy intake (MJ)
DE = Digestible energy (MJ)

This equation is used to calculate VS rates for each state, cattle type, and year. (Pederson et al., 2007). Table A- 165 presents the state-specific VS production rates used for 2006.

Step 3: Waste Management System Usage Data

Table A- 166 summarizes 2006 manure distribution data among waste management systems (WMS) at beef feedlots, dairies, dairy heifer facilities, and swine, layer, broiler, and turkey operations. Table A- 167 describes each WMS.

Manure from 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.

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 2005). 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 2006. 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 (2000b). 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 2005) 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 2006, which were obtained from the USDA NASS (USDA 2007a).

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: Based on data collected during site visits for EPA's Office of Water (ERG 2000a), manure from swine at large (greater than 2000 head) and medium (200 through 2000 head) operations are primarily managed using deep pit systems, liquid/slurry systems, or anaerobic lagoons. For operations with less than 200 head, manure management system data were obtained from USDA (USDA 1998b). It was assumed that those operations use pasture, range, or paddock systems. The percent of waste by 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 2005) 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 2006. 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.

Sheep: 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 2006 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—Layers: 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 2000c). 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 2005 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 N_2O 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- 168. A U.S.-specific methodology was used to develop MCFs for all lagoon and liquid systems.

Based on annual average temperature data, each state and year in the inventory was assigned a climate classification of cool, temperate or warm, and the appropriate IPCC default MCF was applied for animal waste managed in dry systems.

A climate-based approach based on the van't Hoff-Arrhenius equation was developed to estimate MCFs for anaerobic lagoons and other liquid systems 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 CH_4 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 2007). 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 2005). 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 2006 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 and, for lagoon systems, adjusted for a management and design practices factor. This factor accounts for other mechanisms by which VS are removed from the management system prior to conversion to CH_4, such as solids being removed from the system for application to cropland. This factor, equal to 0.8, has been estimated using currently available CH_4 measurement data from anaerobic lagoon systems in the United States (ERG 2001).

- The amount of VS available for conversion to CH_4 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 CH_4 generated during the month is equal to the monthly VS consumed multiplied by the maximum CH_4 potential of the waste (B_o).

The annual MCF is then calculated as:

$$MCF_{annual} = \frac{CH_4 \text{ generated}_{annual}}{VS \text{ produced}_{annual} \times B_0}$$

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 CH_4. 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-7 by state, WMS, and animal group for 2006.

Nitrous Oxide Emission Factors

Direct N_2O emission factors for manure management systems (kg N_2O-N/kg excreted N) were set equal to the most recent default IPCC factors (IPCC 2006), presented in Table A- 170.

Indirect N_2O emission factors account for two fractions of nitrogen losses: volatilization of ammonia (NH_3) and NO_X ($Frac_{gas}$) and runoff/leaching ($Frac_{runoff/leach}$). IPCC default indirect N_2O emission factors were used to estimate indirect N_2O emissions. These factors are 0.010 kg N_2O-N/kg N for volatilization and 0.0075 kg N_2O/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 NH_3. 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 NH_3 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- 171.

Step 5: CH_4 and N_2O Emission Calculations

Methane emissions were calculated as follows:

$$CH_4 = \sum_{\text{State, animal, WMS}} \left(\text{Population}_{\text{state}} \times \text{WMS} \times \frac{\text{TAM}}{1000} \times \text{VS} \times B_0 \times \text{MCF} \times 0.662 \times 365.25 \right)$$

Where,

CH_4	=	CH_4 emissions (kg CH_4/yr)
$\text{Population}_{\text{state}}$	=	Annual average state animal population (head)
WMS	=	Distribution of manure by waste management system for each animal type in a state (percent)
TAM	=	Typical animal mass (kg)
VS	=	Volatile solids production rate (kg VS/1000 kg animal mass/day)
B_o	=	Maximum CH_4 producing capacity (m^3 CH_4/kg VS)
$\text{MCF}_{\text{animal, state, WMS}}$	=	MCF for the animal group, state and WMS (percent)
0.662	=	Conversion factor of m^3 CH_4 to kilograms CH_4 (kg CH_4 /m^3 CH_4)
365.25	=	Days per year

Total N_2O emissions were calculated by summing the direct and indirect N_2O emissions. Direct N_2O emissions were calculated using the following equation:

$$\text{Direct N2O} = \sum_{\text{State, animal, WMS}} \left(\text{Population}_{\text{state}} \times \text{WMS} \times \text{TAM} \times \text{N}_{\text{excreted}} \times \text{EF}_{\text{WMS}} \times \frac{44}{28} \right)$$

Where,

Direct N_2O	=	Direct N_2O emissions (kg N_2O/yr)
$\text{Population}_{\text{state}}$	=	Annual average state animal population (head)
WMS	=	Distribution of manure by waste management system for each animal type in a state (percent)
TAM	=	Typical animal mass (kg)
N excreted	=	Total Kjeldahl nitrogen excretion rate (kg N/1000 kg animal mass/day)
EF_{WMS}	=	Direct N_2O emission factor from IPCC guidelines (kg N_2O-N /kg N)
44/28	=	Conversion factor of N_2O-N to N_2O

Indirect N_2O emissions were calculated for each animal group as follows:

$$\text{Indirect N2O} = \sum_{\text{State, animal, WMS}} \left(\text{Population}_{\text{state}} \times \text{WMS} \times \text{TAM} \times \text{N}_{\text{excreted}} \times \frac{\text{Frac}_{\text{gas, WMS}}}{100} \times \text{EF}_{\text{volatilization}} \times \frac{44}{28} \right) + \left(\text{Population}_{\text{state}} \times \text{WMS} \times \text{TAM} \times \text{N}_{\text{excreted}} \times \frac{\text{Frac}_{\text{runoff/leach, WMS}}}{100} \times \text{EF}_{\text{runnoff/leach}} \times \frac{44}{28} \right)$$

Where,

Indirect N_2O	=	Indirect N_2O emissions (kg N_2O/yr)
$\text{Population}_{\text{state}}$	=	Annual average state animal population (head)
WMS	=	Distribution of manure by waste management system for each animal type in a state (percent)
TAM	=	Typical animal mass (kg)
$N_{excreted}$	=	Total Kjeldahl nitrogen excretion rate (kg N/1000 kg animal mass/day)
$Frac_{gas,WMS}$	=	Nitrogen lost through volatilization in each WMS
$Frac_{runoff/leach,WMS}$	=	Nitrogen lost through runoff and leaching in each WMS
$EF_{volatilization}$	=	Emission factor for volatilization (0.010 kg N_2O-N/kg N)
$EF_{runoff/leach}$	=	Emission factor for runoff/leaching (0.0075 kg N_2O-N/kg N)
44/28	=	Conversion factor of N_2O-N to N_2O

Emission estimates of CH_4 and N_2O by animal type are presented for all years of the inventory in Table A- 172 and Table A- 173, respectively. Emission estimates for 2006 are presented by animal type and state in Table A- 174 and Table A- 175, respectively.

Table A-163: Livestock Population (1,000 Head)

Animal Type	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Dairy Cattle	**14,143**	**13,980**	**13,830**	**13,767**	**13,566**	**13,502**	**13,305**	**13,138**	**12,992**	**13,023**	**13,066**	**12,964**	**13,005**	**12,978**	**12,805**	**12,937**	**13,144**
Dairy Cows	10,007	9,883	9,714	9,679	9,504	9,491	9,410	9,309	9,200	9,139	9,216	9,136	9,128	9,121	8,995	9,027	9,106
Dairy Heifer	4,135	4,097	4,116	4,088	4,062	4,011	3,895	3,829	3,793	3,884	3,850	3,828	3,877	3,857	3,810	3,909	4,038
Swine	**53,941**	**56,478**	**58,532**	**58,016**	**59,951**	**58,899**	**56,220**	**58,728**	**61,989**	**60,238**	**58,864**	**58,913**	**60,028**	**59,817**	**60,717**	**61,055**	**61,759**
Market <60 lbs.	18,359	19,212	19,851	19,434	20,157	19,656	18,851	19,886	20,692	19,928	19,574	19,659	19,863	19,929	20,216	20,232	20,455
Market 60-119 lbs.	11,734	12,374	12,839	12,656	13,017	12,836	12,157	12,754	13,551	13,255	12,926	12,900	13,284	13,138	13,400	13,513	13,682
Market 120-179 lbs.	9,440	9,840	10,253	10,334	10,671	10,545	10,110	10,480	11,234	11,041	10,748	10,708	11,013	11,046	11,228	11,338	11,439
Market >180 lbs.	7,510	7,822	8,333	8,435	8,824	8,937	8,463	8,768	9,671	9,641	9,385	9,465	9,738	9,701	9,921	9,995	10,113
Breeding	6,899	7,231	7,255	7,157	7,282	6,926	6,639	6,840	6,841	6,373	6,231	6,181	6,129	6,004	5,952	5,978	6,069
Beef Cattle	**86,087**	**87,267**	**88,548**	**90,321**	**92,571**	**94,391**	**94,269**	**92,290**	**90,730**	**90,034**	**89,220**	**88,621**	**87,927**	**87,040**	**86,349**	**86,882**	**87,807**
Feedlot Steers	7,338	7,920	7,581	7,984	7,797	7,763	7,380	7,644	7,845	7,805	8,338	8,622	8,423	7,944	8,174	8,298	8,609
Feedlot Heifers	3,621	4,035	3,626	3,971	3,965	4,047	3,999	4,396	4,459	4,587	4,899	5,066	4,852	4,571	4,633	4,574	4,706
NOF Bulls[2]	2,180	2,198	2,220	2,239	2,306	2,392	2,392	2,325	2,235	2,241	2,197	2,187	2,172	2,174	2,128	2,160	2,181
NOF Calves[2]	23,909	23,853	24,118	24,209	24,586	25,170	25,042	24,363	24,001	23,895	23,508	22,958	22,577	22,273	22,005	22,075	22,183
NOF Heifers[2]	8,872	8,938	9,520	9,850	10,469	10,680	10,869	10,481	9,998	9,716	9,326	9,194	9,212	9,336	9,205	9,403	9,548
NOF Steers[2]	7,490	7,364	8,031	7,935	8,346	8,693	9,077	8,452	8,050	7,840	7,190	6,946	7,249	7,451	7,075	7,190	7,357
NOF Cows[2]	32,677	32,960	33,453	34,132	35,101	35,645	35,509	34,629	34,143	33,950	33,763	33,649	33,442	33,292	33,131	33,183	33,222
Sheep	**11,358**	**11,174**	**10,797**	**10,201**	**9,836**	**8,989**	**8,465**	**8,024**	**7,825**	**7,247**	**7,036**	**6,908**	**6,623**	**6,321**	**6,105**	**6,135**	**6,230**
Sheep NOF	1,180	1,115	1,187	1,195	1,015	909	872	854	836	803	804	797	752	730	664	673	694
Sheep on Feed	10,178	10,058	9,610	9,006	8,820	8,081	7,592	7,169	6,990	6,444	6,232	6,111	5,871	5,591	5,441	5,462	5,536
Goats	**2,516**	**2,516**	**2,516**	**2,463**	**2,410**	**2,357**	**2,304**	**2,252**	**2,307**	**2,363**	**2,419**	**2,475**	**2,530**	**2,530**	**2,530**	**2,530**	**2,530**
Poultry	**1,537,074**	**1,594,944**	**1,649,998**	**1,707,422**	**1,769,135**	**1,826,977**	**1,882,078**	**1,926,790**	**1,965,312**	**2,008,632**	**2,033,123**	**2,060,398**	**2,097,691**	**2,085,268**	**2,130,877**	**2,150,410**	**2,154,928**
Hens >1 yr.	273,467	280,121	284,500	290,626	298,527	299,071	303,922	312,137	321,828	330,180	333,593	340,317	340,209	340,979	343,922	348,203	348,719
Pullets[1]	73,167	76,616	79,870	81,774	79,853	81,369	81,572	90,344	95,845	97,562	95,159	95,656	95,289	100,346	101,429	96,809	96,087
Chickens	6,545	6,857	7,113	7,240	7,369	7,637	7,243	7,549	7,682	9,661	8,088	8,126	8,353	8,439	8,248	8,289	7,893
Broilers	1,066,209	1,115,845	1,164,089	1,217,147	1,275,916	1,331,940	1,381,229	1,411,673	1,442,593	1,481,165	1,506,127	1,525,413	1,562,015	1,544,155	1,589,209	1,613,091	1,614,909
Turkeys	117,685	115,504	114,426	110,635	107,469	106,960	108,112	105,088	97,365	90,064	90,155	90,887	91,826	91,349	88,069	84,018	87,320
Horses	**5,069**	**5,100**	**5,121**	**5,130**	**5,110**	**5,130**	**5,150**	**5,170**	**5,237**	**5,170**	**5,240**	**5,500**	**6,000**	**7,000**	**8,000**	**9,200**	**9,200**

Note: Totals may not sum due to independent rounding.

[1]Pullets includes laying pullets, pullets younger than 3 months, and pullets older than 3 months.

[2]NOF = Not on Feed

Table A-164: Waste Characteristics Data

Animal Group	Average TAM (kg)	Source	Total Kjeldahl Nitrogen, N_{ex} (kg/day per 1,000 kg mass)	Source	Maximum Methane Generation Potential, B_o (m^3 CH_4/kg VS added)	Source	Volatile Solids, VS (kg/day per 1,000 kg mass)	Source
Dairy Cows	604	Safley 2000	0.44	USDA 1996a	0.24	Morris 1976	Table A- 165	Pederson, Moffroid, and Pape, 2007
Dairy Heifers	476	Safley 2000	0.31	USDA 1996a	0.17	Bryant et. al. 1976	Table A- 165	Pederson, Moffroid, and Pape, 2007
Feedlot Steers	420	USDA 1996a	0.30	USDA 1996a	0.33	Hashimoto 1981	Table A- 165	Pederson, Moffroid, and Pape, 2007
Feedlot Heifers	420	USDA 1996a	0.30	USDA 1996a	0.33	Hashimoto 1981	Table A- 165	Pederson, Moffroid, and Pape, 2007
NOF Bulls	750	Shuyler 2000	0.31	USDA 1996a	0.17	Hashimoto 1981	6.04	USDA 1996a
NOF Calves	118	USDA 1996a	0.30	USDA 1996a	0.17	Hashimoto 1981	6.41	USDA 1996a
NOF Heifers	420	USDA 1996a	0.31	USDA 1996a	0.17	Hashimoto 1981	Table A- 165	Pederson, Moffroid, and Pape, 2007
NOF Steers	318	Safley 2000	0.31	USDA 1996a	0.17	Hashimoto 1981	Table A- 165	Pederson, Moffroid, and Pape, 2007
NOF Cows	533	Safley 2000	0.33	USDA 1996a	0.17	Hashimoto 1981	Table A- 165	Pederson, Moffroid, and Pape, 2007
Market Swine <60 lbs.	16	Safley 2000	0.60	USDA 1996a	0.48	Hashimoto 1984	8.80	USDA 1996a
Market Swine 60-119 lbs.	41	Safley 2000	0.42	USDA 1996a	0.48	Hashimoto 1984	5.40	USDA 1996a
Market Swine 120-179 lbs.	68	Safley 2000	0.42	USDA 1996a	0.48	Hashimoto 1984	5.40	USDA 1996a
Market Swine >180 lbs.	91	Safley 2000	0.42	USDA 1996a	0.48	Hashimoto 1984	5.40	USDA 1996a
Breeding Swine	198	Safley 2000	0.24	USDA 1996a	0.48	Hashimoto 1984	2.60	USDA 1996a
Feedlot Sheep	25	EPA 1992	0.42	ASAE 1999	0.36	EPA 1992	9.20	ASAE 1999
NOF Sheep	80	EPA 1992	0.42	ASAE 1999	0.19	EPA 1992	9.20	ASAE 1999
Goats	64	ASAE 1999	0.45	ASAE 1999	0.17	EPA 1992	9.50	ASAE 1999
Horses	450	ASAE 1999	0.30	ASAE 1999	0.33	EPA 1992	10.0	ASAE 1999
Hens >/= 1 yr	1.8	ASAE 1999	0.83	USDA 1996a	0.39	Hill 1982	10.8	USDA 1996a
Pullets	1.8	ASAE 1999	0.62	USDA 1996a	0.39	Hill 1982	9.7	USDA 1996a
Other Chickens	1.8	ASAE 1999	0.83	USDA 1996a	0.39	Hill 1982	10.8	USDA 1996a
Broilers	0.9	ASAE 1999	1.10	USDA 1996a	0.36	Hill 1984	15.0	USDA 1996a
Turkeys	6.8	ASAE 1999	0.74	USDA 1996a	0.36	Hill 1984	9.7	USDA 1996a

Table A-165: Estimated Volatile Solids Production Rate by State for 2006 (kg/day/1000 kg animal mass)

State	Dairy Cow	Dairy Heifers	Beef NOF Cow	Beef NOF Heifers	Beef NOF Steer	Beef OF Heifers	Beef OF Steer
Alabama	8.28	6.64	6.74	7.55	7.63	3.45	3.44
Alaska	7.87	7.09	8.71	9.96	10.09	3.57	3.55
Arizona	11.41	7.09	8.71	9.99	10.09	3.59	3.56
Arkansas	7.55	6.48	6.72	7.53	7.61	4.15	4.05
California	9.59	6.13	6.57	7.37	7.42	3.58	3.55
Colorado	9.98	6.10	6.19	6.93	6.96	3.58	3.56
Connecticut	8.87	6.10	6.62	7.42	7.49	3.73	3.69
Delaware	8.33	6.10	6.62	7.43	7.49	3.60	3.57
Florida	8.88	6.64	6.74	7.55	7.63	3.53	3.51
Georgia	9.45	6.64	6.74	7.56	7.63	3.62	3.59
Hawaii	8.20	7.09	8.71	9.97	10.09	3.53	3.51
Idaho	11.23	7.09	8.71	10.02	10.09	3.63	3.60
Illinois	8.84	6.10	6.63	7.45	7.49	3.61	3.58
Indiana	9.07	6.10	6.63	7.44	7.49	3.64	3.61
Iowa	9.11	6.10	6.63	7.46	7.49	3.59	3.56
Kansas	9.34	6.10	6.19	6.93	6.96	3.57	3.55
Kentucky	7.89	6.64	6.74	7.56	7.63	3.41	3.40
Louisiana	7.28	6.48	6.72	7.52	7.61	3.56	3.53
Maine	8.47	6.10	6.62	7.42	7.49	3.45	3.44
Maryland	8.23	6.10	6.62	7.43	7.49	3.59	3.56
Massachusetts	8.31	6.10	6.62	7.41	7.49	3.53	3.51
Michigan	9.70	6.10	6.63	7.44	7.49	3.59	3.56
Minnesota	8.66	6.10	6.63	7.45	7.49	3.59	3.56
Mississippi	8.38	6.64	6.74	7.55	7.63	3.65	3.61
Missouri	7.91	6.10	6.63	7.43	7.49	3.59	3.56
Montana	8.67	6.10	6.19	6.90	6.96	3.64	3.61
Nebraska	8.59	6.10	6.19	6.93	6.96	3.57	3.54
Nevada	10.68	7.09	8.71	9.99	10.09	3.73	3.69
New Hampshire	8.94	6.10	6.62	7.42	7.49	3.53	3.51
New Jersey	7.97	6.10	6.62	7.43	7.49	3.53	3.51
New Mexico	10.96	7.09	8.71	10.00	10.09	3.53	3.51
New York	8.75	6.10	6.62	7.44	7.49	3.75	3.70
North Carolina	9.53	6.64	6.74	7.56	7.63	3.59	3.56
North Dakota	7.53	6.10	6.19	6.91	6.96	3.59	3.56
Ohio	8.42	6.10	6.63	7.44	7.49	3.66	3.62
Oklahoma	8.58	6.48	6.72	7.55	7.61	3.56	3.54
Oregon	10.12	7.09	8.71	9.99	10.09	3.72	3.68
Pennsylvania	8.89	6.10	6.62	7.44	7.49	3.59	3.56
Rhode Island	8.28	6.10	6.62	7.42	7.49	3.62	3.58
South Carolina	8.86	6.64	6.74	7.55	7.63	3.73	3.69
South Dakota	8.66	6.10	6.19	6.92	6.96	3.59	3.56
Tennessee	8.64	6.64	6.74	7.56	7.63	3.39	3.38
Texas	10.02	6.48	6.72	7.56	7.61	3.55	3.53
Utah	10.55	7.09	8.71	10.00	10.09	3.69	3.65
Vermont	8.60	6.10	6.62	7.43	7.49	3.47	3.46
Virginia	9.17	6.64	6.74	7.56	7.63	3.63	3.60
Washington	11.47	7.09	8.71	10.01	10.09	3.74	3.69
West Virginia	7.73	6.10	6.62	7.43	7.49	3.47	3.46
Wisconsin	8.73	6.10	6.63	7.44	7.49	3.58	3.55
Wyoming	8.38	6.10	6.19	6.91	6.96	3.59	3.56

Source: Lieberman and Pape 2005.

Table A-166: 2006 Manure Distribution Among Waste Management Systems by Operation (Percent)

	Beef Feedlots		Dairies						Dairy Heifer Facilities		Swine Operations					Layer Operations		Broiler and Turkey Operations	
State	Dry Lot[1]	Liquid/ Slurry[1]	Pasture	Daily Spread	Solid Storage	Liquid/ Slurry	Anaerobic Lagoon	Deep Pit	Dry Lot[2]	Liquid/ Slurry[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	100	1.0	5	4	8	51	32	42	58	1	99
Alaska	100	1.3	4	6	28	24	30	8	100	1.0	53	2	13	10	22	25	75	1	99
Arizona	100	0.4	0	10	9	20	61	0	100	0.3	14	3	5	50	27	60	40	1	99
Arkansas	100	1.3	57	15	11	7	10	1	100	1.0	4	4	12	46	35	0	100	1	99
California	100	1.3	1	11	9	21	58	0	100	1.0	13	3	8	47	29	12	88	1	99
Colorado	100	0.4	1	1	12	24	62	1	100	0.3	2	5	26	17	50	60	40	1	99
Connecticut	100	1.0	6	43	17	20	12	2	100	0.8	57	2	12	9	20	5	95	1	99
Delaware	100	1.0	6	44	19	19	10	2	100	0.8	12	4	24	18	42	5	95	1	99
Florida	100	1.3	17	22	8	15	39	0	100	1.0	71	1	8	6	14	42	58	1	99
Georgia	100	1.3	40	18	10	11	21	0	100	1.0	8	4	10	47	32	42	58	1	99
Hawaii	100	1.3	1	0	11	21	67	0	100	1.0	23	3	18	21	34	25	75	1	99
Idaho	100	0.4	0	1	12	23	63	1	100	0.3	46	3	15	10	26	60	40	1	99
Illinois	100	0.6	5	8	43	26	13	5	100	0.5	2	5	28	15	50	2	98	1	99
Indiana	100	0.6	8	13	35	24	16	3	100	0.5	3	5	28	15	50	0	100	1	99
Iowa	100	0.6	6	10	41	25	14	4	100	0.5	1	4	12	48	35	0	100	1	99
Kansas	100	0.6	3	5	28	33	29	3	100	0.5	2	5	28	13	51	2	98	1	99
Kentucky	100	1.0	61	14	14	6	2	2	100	0.8	5	4	12	45	34	5	95	1	99
Louisiana	100	1.3	60	14	10	6	9	1	100	1.0	54	2	13	10	22	60	40	1	99
Maine	100	1.0	7	45	20	17	9	2	100	0.8	73	1	7	6	13	5	95	1	99
Maryland	100	1.0	7	44	23	15	8	3	100	0.8	21	4	21	16	38	5	95	1	99
Mass.	100	1.0	7	45	24	15	6	3	100	0.8	31	3	19	14	32	5	95	1	99
Michigan	100	0.6	3	6	32	33	22	4	100	0.5	5	5	25	17	48	2	98	1	99
Minnesota	100	0.6	6	10	44	24	12	5	100	0.5	2	5	26	18	49	0	100	1	99
Mississippi	100	1.3	57	15	10	7	10	0	100	1.0	2	4	6	57	31	60	40	1	99
Missouri	100	0.6	8	14	48	18	6	5	100	0.5	3	5	28	14	51	0	100	1	99
Montana	100	0.4	3	4	25	26	36	6	100	0.3	6	5	25	17	47	60	40	1	99
Nebraska	100	0.6	4	6	35	30	21	4	100	0.5	3	5	28	15	50	2	98	1	99
Nevada	100	0.4	0	0	11	24	64	0	100	0.3	35	2	4	39	20	0	100	1	99
New Hampshire	100	1.0	7	44	21	16	9	3	100	0.8	57	2	12	9	20	5	95	1	99
New Jersey	100	1.0	8	45	24	14	6	3	100	0.8	31	3	19	14	33	5	95	1	99
New Mexico	100	0.4	0	10	9	19	61	0	100	0.3	92	0	2	2	4	60	40	1	99
New York	100	1.0	7	45	20	16	10	2	100	0.8	20	4	21	15	40	5	95	1	99
North Carolina	100	1.0	54	15	12	11	6	1	100	0.8	0	4	6	58	31	42	58	1	99
North Dakota	100	0.6	6	11	45	22	12	4	100	0.5	9	5	24	17	45	2	98	1	99
Ohio	100	0.6	8	14	41	23	11	4	100	0.5	7	4	27	15	47	0	100	1	99

	Beef Feedlots		Dairies						Dairy Heifer Facilities		Swine Operations					Layer Operations		Broiler and Turkey Operations	
State	Dry Lot[1]	Liquid/ Slurry[1]	Pasture	Daily Spread	Solid Storage	Liquid/ Slurry	Anaerobic Lagoon	Deep Pit	Dry Lot[2]	Liquid/ Slurry[2]	Pasture	Solid Storage	Liquid/ Slurry	Anaerobic Lagoon	Deep Pit	Anaerobic Lagoon	Poultry without Litter	Pasture	Poultry with Litter
Oklahoma	100	0.4	0	6	25	23	40	6	100	0.3	1	4	6	58	31	60	40	1	99
Oregon	100	1.3	20	0	13	21	44	2	100	1.0	58	2	12	9	20	25	75	1	99
Pennsylvania	100	1.0	9	47	25	12	5	2	100	0.8	5	5	25	18	47	0	100	1	99
Rhode Island	100	1.0	9	47	26	12	4	3	100	0.8	56	2	12	9	21	5	95	1	99
South Carolina	100	1.3	54	15	8	9	13	0	100	1.0	6	4	9	50	32	60	40	1	99
South Dakota	100	0.6	5	8	38	28	18	4	100	0.5	3	5	26	18	48	2	98	1	99
Tennessee	100	1.0	59	15	12	9	4	2	100	0.8	10	4	12	41	33	5	95	1	99
Texas	100	0.4	0	8	13	24	53	2	100	0.3	7	3	6	54	29	12	88	1	99
Utah	100	0.4	1	1	17	26	51	3	100	0.3	1	6	26	17	51	60	40	1	99
Vermont	100	1.0	7	44	19	17	10	2	100	0.8	86	1	4	3	7	5	95	1	99
Virginia	100	1.0	57	15	12	9	4	2	100	0.8	3	4	7	55	31	5	95	1	99
Washington	100	1.3	17	0	11	22	49	1	100	1.0	37	3	17	12	31	12	88	1	99
West Virginia	100	1.0	7	45	23	16	7	3	100	0.8	58	2	11	8	21	5	95	1	99
Wisconsin	100	0.6	7	12	42	24	12	4	100	0.5	13	4	24	17	42	2	98	1	99
Wyoming	100	0.4	7	12	22	23	30	6	100	0.3	3	5	26	17	49	60	40	1	99

[1] Because manure at beef feedlots 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.
[2] Because manure from 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- 167: 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_2O emissions from deposited manure are covered under the N_2O 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_2O emissions during storage and treatment are assumed to be zero. N_2O 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.
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- 168: Methane Conversion Factors (percent) for Dry Systems

Waste Management System	Cool Climate MCF	Temperate Climate MCF	Warm Climate MCF
Aerobic Treatment	0	0	0
Anaerobic Digester	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
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- 169: Methane Conversion Factors by State for Liquid Systems for 2006 (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	0.77	0.41	0.76	0.40	0.42	0.76
Alaska	0.48	0.15	0.48	0.13	0.15	0.48
Arizona	0.78	0.62	0.75	0.39	0.50	0.75
Arkansas	0.75	0.37	0.76	0.40	0.38	0.76
California	0.74	0.35	0.73	0.32	0.40	0.74
Colorado	0.64	0.22	0.68	0.24	0.24	0.64
Connecticut	0.69	0.25	0.69	0.24	0.26	0.69
Delaware	0.74	0.32	0.74	0.32	0.32	0.74
Florida	0.79	0.53	0.78	0.52	0.53	0.79
Georgia	0.76	0.41	0.76	0.40	0.40	0.76
Hawaii	0.77	0.59	0.77	0.59	0.59	0.77
Idaho	0.68	0.24	0.67	0.22	0.23	0.66
Illinois	0.72	0.29	0.72	0.28	0.28	0.72
Indiana	0.70	0.27	0.70	0.26	0.27	0.70
Iowa	0.69	0.26	0.70	0.25	0.27	0.70
Kansas	0.74	0.33	0.74	0.32	0.33	0.74
Kentucky	0.73	0.31	0.73	0.31	0.31	0.73
Louisiana	0.77	0.48	0.78	0.49	0.49	0.77
Maine	0.63	0.21	0.63	0.20	0.20	0.64
Maryland	0.73	0.30	0.73	0.30	0.30	0.73
Massachusetts	0.67	0.23	0.68	0.23	0.24	0.67
Michigan	0.67	0.24	0.68	0.23	0.24	0.68
Minnesota	0.68	0.25	0.68	0.24	0.25	0.68
Mississippi	0.77	0.44	0.77	0.42	0.43	0.77
Missouri	0.74	0.33	0.74	0.32	0.32	0.74
Montana	0.62	0.20	0.65	0.20	0.22	0.65
Nebraska	0.71	0.28	0.71	0.27	0.28	0.71
Nevada	0.71	0.27	0.71	0.27	0.27	0.71
New Hampshire	0.64	0.22	0.66	0.21	0.21	0.65
New Jersey	0.72	0.29	0.73	0.29	0.29	0.72
New Mexico	0.71	0.31	0.71	0.28	0.30	0.69
New York	0.66	0.22	0.66	0.22	0.23	0.67
North Carolina	0.73	0.32	0.76	0.37	0.32	0.74
North Dakota	0.67	0.24	0.67	0.22	0.23	0.66
Ohio	0.69	0.26	0.70	0.25	0.26	0.70
Oklahoma	0.76	0.42	0.75	0.38	0.38	0.76
Oregon	0.64	0.21	0.65	0.21	0.24	0.65
Pennsylvania	0.69	0.26	0.71	0.26	0.26	0.71
Rhode Island	0.69	0.26	0.69	0.25	0.26	0.69
South Carolina	0.76	0.39	0.76	0.40	0.39	0.76
South Dakota	0.69	0.26	0.70	0.25	0.26	0.70
Tennessee	0.74	0.33	0.75	0.36	0.34	0.74
Texas	0.77	0.48	0.77	0.46	0.39	0.78
Utah	0.67	0.23	0.66	0.22	0.24	0.66
Vermont	0.64	0.21	0.64	0.20	0.21	0.64
Virginia	0.71	0.28	0.73	0.31	0.29	0.72
Washington	0.64	0.22	0.66	0.22	0.24	0.65
West Virginia	0.69	0.26	0.70	0.25	0.26	0.70
Wisconsin	0.67	0.23	0.68	0.23	0.24	0.68
Wyoming	0.61	0.20	0.66	0.22	0.23	0.64

Table A- 170: Direct Nitrous Oxide Emission Factors for 2006 (kg N_2O-N/kg KjdI N)

Waste Management System	Direct N2O 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- 171: 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

Table A- 172: 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
Dairy Cattle	**574**	**585**	**574**	**566**	**611**	**640**	**611**	**640**	**682**	**713**	**755**	**800**	**839**	**865**	**847**	**896**	**920**
Dairy Cows	566	578	566	559	604	633	605	634	676	706	748	794	832	859	840	890	913
Dairy Heifer	8	7	7	7	7	7	6	6	6	6	6	6	6	6	6	6	7
Swine	**624**	**676**	**639**	**680**	**741**	**764**	**730**	**783**	**891**	**848**	**832**	**851**	**875**	**844**	**838**	**890**	**876**
Market Swine	484	524	500	534	585	609	582	626	721	693	680	697	721	696	694	738	726
Market <60 lbs.	102	110	104	109	119	121	116	125	141	133	131	134	137	133	133	140	138
Market 60-119 lbs.	102	111	105	110	120	124	117	127	145	138	136	138	144	138	139	147	144
Market 120-179 lbs.	136	147	140	151	164	170	164	175	201	193	189	192	200	194	193	206	202
Market >180 lbs.	145	156	152	165	182	194	185	198	235	229	225	232	240	231	230	246	242
Breeding Swine	140	152	139	146	157	155	148	157	170	155	152	154	154	147	143	152	151
Beef Cattle	**120**	**121**	**118**	**119**	**121**	**121**	**119**	**117**	**120**	**119**	**114**	**117**	**113**	**112**	**111**	112	117
Feedlot Steers	18	18	16	16	15	14	12	12	13	13	13	14	13	12	13	13	14
Feedlot Heifers	9	9	8	8	7	7	6	7	7	7	8	8	8	7	7	7	7
NOF Bulls	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
NOF Calves	9	9	9	9	9	9	9	9	9	9	9	9	8	8	8	8	9
NOF Heifers	13	13	14	14	15	16	16	15	15	15	14	14	14	14	14	14	15
NOF Steers	8	8	9	8	9	9	10	9	9	9	8	8	8	8	8	8	8
NOF Cows	58	58	58	59	61	62	61	60	61	61	58	60	58	57	57	57	60
Sheep	**7**	**7**	**7**	**6**	**6**	**5**	**5**	**5**	**5**	**4**	**4**	**4**	**4**	**4**	**4**	**4**	**4**
Goats	**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**	**127**	**130**	**125**	**126**	**130**	**128**	**128**	**127**	**127**	**127**
Hens >1 yr.	73	72	70	73	72	69	68	67	70	66	66	70	67	68	65	65	65
Total Pullets	25	26	23	23	23	22	21	23	23	21	22	22	22	22	23	22	23
Chickens	4	4	4	4	4	4	3	3	4	3	3	3	4	4	3	3	3
Broilers	19	20	20	21	22	23	24	25	25	26	27	27	28	27	28	28	28
Turkeys	10	10	10	10	9	9	9	9	8	8	8	8	8	8	8	7	8
Horses	**22**	**22**	**21**	**21**	**21**	**21**	**21**	**21**	**22**	**22**	**22**	**23**	**25**	**29**	**34**	**39**	**39**

[a] Methane emissions estimates presented in this table do not account for anaerobic digestion reductions and therefore totals for dairy cattle, swine, and poultry may be slightly higher than the summary values in the Manure Management chapter text.

Table A- 173: 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
Dairy Cattle	**11.2**	**11.1**	**11.2**	**11.2**	**11.2**	**11.3**	**11.2**	**11.2**	**11.3**	**11.5**	**11.7**	**11.7**	**11.9**	**11.9**	**11.8**	**12.0**	**12.3**
Dairy Cows	6.4	6.4	6.3	6.3	6.3	6.3	6.4	6.4	6.4	6.4	6.5	6.5	6.6	6.6	6.5	6.6	6.6
Dairy Heifer	4.8	4.7	4.9	4.9	4.9	5.0	4.9	4.8	4.9	5.1	5.1	5.2	5.4	5.3	5.3	5.5	5.7
Swine	**4.0**	**4.2**	**4.4**	**4.4**	**4.6**	**4.5**	**4.4**	**4.6**	**4.9**	**4.8**	**4.7**	**4.7**	**4.8**	**4.7**	**4.8**	**4.8**	**4.9**
Market Swine	3.0	3.1	3.3	3.3	3.5	3.5	3.3	3.5	3.8	3.7	3.7	3.7	3.8	3.8	3.9	3.9	3.9
Market <60 lbs.	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.7	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.7
Market 60-119 lbs.	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Market 120-179 lbs.	0.9	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.1	1.1	1.0	1.0	1.1	1.1	1.1	1.1	1.1
Market >180 lbs.	0.9	1.0	1.0	1.0	1.1	1.1	1.1	1.1	1.3	1.3	1.2	1.2	1.3	1.3	1.3	1.3	1.3
Breeding Swine	1.0	1.1	1.1	1.1	1.1	1.1	1.0	1.1	1.1	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Beef Cattle	**17.8**	**19.4**	**19.4**	**19.4**	**19.1**	**19.2**	**18.5**	**19.6**	**20.0**	**20.1**	**21.5**	**22.2**	**21.6**	**20.3**	**20.8**	**20.9**	**21.6**
Feedlot Steers	11.9	12.9	13.0	13.0	12.7	12.6	12.0	12.4	12.7	12.7	13.5	14.0	13.7	12.9	13.3	13.5	14.0
Feedlot Heifers	5.9	6.6	6.5	6.5	6.4	6.6	6.5	7.1	7.2	7.5	8.0	8.2	7.9	7.4	7.5	7.4	7.6
Sheep	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.2**	**0.2**	**0.3**
Goats	**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**	**0.1**
Poultry	**4.7**	**4.8**	**5.0**	**5.0**	**5.1**	**5.1**	**5.3**	**5.3**	**5.3**	**5.4**	**5.4**	**5.5**	**5.6**	**5.5**	**5.6**	**5.6**	**5.7**
Hens >1 yr.	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Total Pullets	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	0.3
Chickens	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	0.0
Broilers	2.2	2.3	2.5	2.5	2.6	2.7	2.8	2.9	2.9	3.0	3.1	3.1	3.2	3.1	3.2	3.3	3.3
Turkeys	1.2	1.2	1.1	1.1	1.1	1.1	1.1	1.1	1.0	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Horses	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**	**0.8**	**0.8**	**1.0**	**1.1**	**1.3**	**1.3**

Table A- 174: Methane Emissions by State from Livestock Manure Management for 2006 (Gg)[a]

State	Beef on Feedlots	Beef Not on Feed	Dairy Cow	Dairy Heifer	Swine—Market	Swine—Breeding	Layer	Broiler	Turkey	Sheep	Goats	Horses
Alabama	0.0127	2.1882	0.7586	0.0141	2.4896	0.6231	8.0762	3.3760	+	0.0079	0.0190	0.8905
Alaska	0.0001	0.0211	0.0436	0.0005	0.0018	0.0018	0.1860	+	+	0.0053	0.0001	0.0174
Arizona	0.6393	0.7968	41.2941	0.0972	2.1616	0.4706	0.6533	+	+	0.0820	0.0133	0.6372
Arkansas	0.0128	2.9494	0.6331	0.0179	2.3322	2.7241	0.6041	3.7991	0.8612	0.0079	0.0122	0.9828
California	1.2495	3.0698	302.9132	1.6533	1.8123	0.5647	4.0273	0.3060	0.4536	0.5078	0.0387	1.7941
Colorado	1.3722	1.5374	16.6967	0.0660	5.9691	2.6662	3.0750	+	0.1106	0.2031	0.0046	0.9707
Connecticut	0.0002	0.0181	0.8795	0.0149	0.0118	0.0060	0.3315	+	+	0.0041	0.0006	0.0861
Delaware	0.0003	0.0126	0.3049	0.0042	0.0792	0.0510	0.0731	0.8596	+	0.0053	0.0004	0.0313
Florida	0.0059	2.7503	16.2979	0.0996	0.0754	0.0412	7.9397	0.2404	+	0.0079	0.0150	1.3585
Georgia	0.0098	1.8642	5.6144	0.0538	3.1153	1.1904	15.6483	4.4295	+	0.0079	0.0261	1.0063
Hawaii	0.0018	0.3475	0.8591	0.0055	0.1568	0.1163	0.1640	+	+	0.0079	0.0020	0.0623
Idaho	0.3458	1.5398	91.5063	0.3516	0.0938	0.0491	0.5777	+	+	0.1354	0.0029	0.7544
Illinois	0.2700	1.0822	6.2669	0.0672	39.5295	8.5334	0.2795	+	0.0773	0.0359	0.0043	0.5407
Indiana	0.1522	0.5699	9.8318	0.0830	27.8184	5.9593	0.8142	0.3050	0.3948	0.0260	0.0069	0.8919
Iowa	1.1934	2.8613	10.7352	0.1526	231.9080	29.4283	1.5829	0.3050	0.2346	0.1224	0.0047	0.6991
Kansas	3.4196	4.0945	12.1210	0.0723	20.2372	3.5237	0.0421	+	0.1106	0.0521	0.0062	0.6112
Kentucky	0.0210	2.5535	1.4252	0.0765	4.2688	0.9876	0.5769	0.9231	+	0.0182	0.0171	1.3548
Louisiana	0.0055	1.4286	0.9465	0.0214	0.1007	0.0301	2.0095	0.3060	+	0.0079	0.0055	0.6498
Maine	0.0005	0.0388	0.9993	0.0237	0.0084	0.0055	0.4492	+	+	0.0041	0.0008	0.1155
Maryland	0.0176	0.1248	2.3710	0.0419	0.2485	0.1236	0.3069	0.8682	0.0209	0.0115	0.0024	0.2352
Massachusetts	0.0002	0.0221	0.4132	0.0114	0.0760	0.0198	0.0202	+	0.0018	0.0041	0.0015	0.1405
Michigan	0.2418	0.3494	25.4315	0.1726	8.0901	1.7614	0.5507	0.3050	0.1316	0.0432	0.0053	0.9513
Minnesota	0.3709	1.2907	21.4901	0.3353	56.4038	10.6138	0.3656	0.1466	1.2875	0.0807	0.0049	0.8409
Mississippi	0.0103	1.6919	0.9029	0.0262	5.4068	1.2525	8.5597	2.5761	+	0.0079	0.0100	0.9085
Missouri	0.0941	4.9190	4.2613	0.0919	24.0210	7.3942	0.2417	0.3050	0.5722	0.0391	0.0122	1.2814
Montana	0.0681	2.9317	1.7054	0.0096	1.3517	0.2740	0.3306	+	+	0.1536	0.0022	0.8557
Nebraska	3.3750	4.3508	4.6216	0.0193	24.8930	6.7848	0.6505	0.0163	0.1106	0.0552	0.0029	0.5342
Nevada	0.0103	0.6914	5.3216	0.0170	0.0373	0.0077	0.0214	+	+	0.0385	0.0016	0.1462
New Hampshire	0.0002	0.0133	0.5377	0.0112	0.0112	0.0040	0.0179	+	+	0.0041	0.0009	0.0718
New Jersey	0.0004	0.0259	0.3125	0.0083	0.0619	0.0076	0.1195	+	0.0009	0.0053	0.0021	0.2438
New Mexico	0.1771	1.3992	65.5459	0.1504	0.0023	0.0005	0.5982	+	+	0.0807	0.0048	0.4232
New York	0.0258	0.3313	22.0908	0.4317	0.6811	0.1655	0.4564	0.3050	0.0180	0.0365	0.0083	0.6823
North Carolina	0.0082	1.3212	1.6346	0.0338	151.7877	35.4564	10.5152	2.4005	1.0765	0.0141	0.0252	0.8728
North Dakota	0.0764	1.9412	1.3265	0.0240	1.0508	0.5269	0.0400	+	0.0372	0.0542	0.0006	0.3935
Ohio	0.2372	0.7395	12.3500	0.1527	12.8757	2.9391	0.8610	0.1457	0.1459	0.0734	0.0113	1.2180
Oklahoma	0.6927	8.4337	9.9159	0.0389	35.5865	12.3902	3.5765	0.7993	0.1109	0.0625	0.0310	2.0415
Oregon	0.0982	1.8014	14.3688	0.1192	0.0814	0.0386	1.0102	0.3050	+	0.1146	0.0077	0.8378
Pennsylvania	0.1058	0.5846	13.4497	0.3735	9.9966	1.9117	0.7274	0.4628	0.3004	0.0573	0.0100	1.0279
Rhode Island	0.0001	0.0036	0.0213	0.0010	0.0064	0.0045	0.0699	+	+	0.0041	0.0001	0.0177
South Carolina	0.0028	0.6798	0.7935	0.0139	4.9838	0.9716	5.3862	0.7278	0.2756	0.0079	0.0154	0.5537
South Dakota	0.5172	3.7276	5.2301	0.0572	12.6203	2.8244	0.1744	+	0.1202	0.2005	0.0018	0.6306
Tennessee	0.0157	3.6926	1.5486	0.0618	3.0513	0.6074	0.1669	0.6842	+	0.0211	0.0430	2.0212
Texas	5.4234	18.6846	62.1187	0.2556	16.2671	3.4771	4.5367	2.0136	0.1109	0.8516	0.4477	5.0627
Utah	0.0377	0.9878	13.0736	0.0631	4.4608	1.7440	3.0464	+	0.1106	0.1458	0.0023	0.5563
Vermont	0.0006	0.0544	4.7817	0.0765	0.0033	0.0014	0.0186	+	0.0016	0.0041	0.0010	0.1019
Virginia	0.0409	1.6835	2.3625	0.0600	5.5767	0.9411	0.3914	0.8184	0.6152	0.0349	0.0103	0.7374
Washington	0.2348	0.8854	35.1221	0.1561	0.2012	0.0442	0.9511	0.3050	+	0.0260	0.0058	0.6885
West Virginia	0.0123	0.4558	0.3610	0.0054	0.0483	0.0171	0.1783	0.2865	0.1030	0.0167	0.0044	0.2887
Wisconsin	0.2917	1.0045	59.0787	0.8436	3.0649	0.8579	0.3158	0.1223	0.1106	0.0464	0.0088	0.9246
Wyoming	0.0981	1.6065	0.5004	0.0060	0.6427	0.4074	0.0107	+	+	0.2344	0.0013	0.5703

+ Emission estimate is less than 0.00005 Gg.

[a] Methane emissions estimates presented in this table do not account for anaerobic digestion reductions and therefore totals for dairy cattle, swine, and poultry may be slightly higher than the summary values in the Manure Management chapter text.

Table A- 175: Total (Direct and Indirect) Nitrous Oxide Emissions by State from Livestock Manure Management for 2006 (Gg)

State	Beef Feedlot-Heifer	Beef Feedlot-Steers	Dairy Cow	Dairy Heifer	Swine—Market	Swine—Breeding	Layer	Broiler	Turkey	Sheep	Goats	Horses
Alabama	0.0026	0.0062	0.0049	0.0040	0.0095	0.0029	0.0503	0.3879	+	0.0017	0.0015	0.0229
Alaska	+	0.0001	0.0007	0.0005	+	+	0.0028	+	+	0.0017	+	0.0007
Arizona	0.0257	0.4843	0.1265	0.0684	0.0083	0.0022	0.0029	+	+	+	0.0010	0.0164
Arkansas	0.0026	0.0051	0.0060	0.0039	0.0094	0.0132	0.0749	0.4365	0.1029	0.0021	0.0010	0.0252
California	0.1807	0.6693	1.3134	1.2120	0.0077	0.0028	0.0746	0.0352	0.0542	0.0012	0.0031	0.0460
Colorado	0.6415	1.0688	0.0874	0.0932	0.0456	0.0250	0.0165	+	0.0133	0.0598	0.0005	0.0374
Connecticut	+	0.0002	0.0106	0.0097	+	+	0.0126	+	+	+	0.0001	0.0033
Delaware	0.0001	0.0003	0.0037	0.0026	0.0002	0.0004	0.0026	0.0991	+	0.0021	+	0.0012
Florida	0.0018	0.0019	0.0701	0.0425	+	0.0002	0.0477	0.0276	+	0.0021	0.0012	0.0349
Georgia	0.0027	0.0039	0.0302	0.0169	0.0122	0.0057	0.0985	0.5089	+	0.0021	0.0021	0.0258
Hawaii	0.0005	0.0007	0.0038	0.0034	0.0004	0.0005	0.0016	+	+	0.0021	0.0002	0.0016
Idaho	0.1602	0.2674	0.3949	0.4269	0.0008	0.0004	0.0031	+	+	0.0039	0.0003	0.0290
Illinois	0.1180	0.1960	0.0970	0.0782	0.2792	0.0712	0.0178	+	0.0093	0.0034	0.0005	0.0208
Indiana	0.0583	0.1178	0.1303	0.0884	0.2075	0.0528	0.1001	0.0352	0.0474	0.0014	0.0008	0.0343
Iowa	0.5025	0.9070	0.1663	0.1728	1.1565	0.1734	0.1947	0.0352	0.0281	0.0193	0.0006	0.0269
Kansas	1.6389	2.2677	0.1009	0.0874	0.1314	0.0270	0.0027	+	0.0133	0.0085	0.0007	0.0235
Kentucky	0.0073	0.0158	0.0273	0.0212	0.0196	0.0054	0.0213	0.1064	+	+	0.0020	0.0522
Louisiana	0.0016	0.0019	0.0082	0.0040	0.0002	0.0002	0.0091	0.0352	+	0.0017	0.0004	0.0167
Maine	0.0002	0.0004	0.0163	0.0150	+	+	0.0182	+	+	+	0.0001	0.0044
Maryland	0.0064	0.0121	0.0366	0.0256	0.0015	0.0010	0.0113	0.1001	0.0025	+	0.0003	0.0091
Massachusetts	+	0.0002	0.0083	0.0070	0.0004	0.0002	0.0007	+	0.0002	+	0.0002	0.0054
Michigan	0.0524	0.2386	0.2916	0.2146	0.0634	0.0164	0.0361	0.0352	0.0158	0.0049	0.0006	0.0366
Minnesota	0.1175	0.3268	0.4028	0.3847	0.4330	0.0971	0.0449	0.0169	0.1544	0.0142	0.0006	0.0324
Mississippi	0.0019	0.0048	0.0067	0.0054	0.0195	0.0055	0.0389	0.2960	+	0.0017	0.0008	0.0233
Missouri	0.0381	0.0692	0.0971	0.0934	0.1548	0.0576	0.0298	0.0352	0.0686	0.0026	0.0014	0.0493
Montana	0.0381	0.0459	0.0166	0.0128	0.0118	0.0028	0.0017	+	+	0.0042	0.0003	0.0329
Nebraska	1.5028	2.4805	0.0560	0.0234	0.1796	0.0585	0.0417	0.0019	0.0133	0.0102	0.0003	0.0206
Nevada	0.0049	0.0073	0.0226	0.0205	+	+	0.0027	+	+	0.0019	0.0002	0.0056
New Hampshire	+	0.0001	0.0083	0.0072	+	+	0.0006	+	+	+	0.0001	0.0028
New Jersey	0.0002	0.0003	0.0058	0.0049	0.0002	+	0.0044	+	0.0001	0.0017	0.0002	0.0094
New Mexico	0.0753	0.1431	0.2528	0.1632	+	+	0.0029	+	+	0.0020	0.0006	0.0163
New York	0.0160	0.0117	0.3299	0.2715	0.0056	0.0016	0.0178	0.0352	0.0022	0.0028	0.0010	0.0263
North Carolina	0.0022	0.0040	0.0166	0.0116	0.5772	0.1612	0.0673	0.2758	0.1287	+	0.0020	0.0224
North Dakota	0.0410	0.0510	0.0293	0.0270	0.0085	0.0051	0.0027	+	0.0045	0.0077	0.0001	0.0152
Ohio	0.0776	0.1981	0.2310	0.1625	0.0958	0.0261	0.1059	0.0168	0.0175	0.0080	0.0013	0.0469
Oklahoma	0.1705	0.4021	0.0646	0.0322	0.1355	0.0560	0.0163	0.0918	0.0133	0.0026	0.0025	0.0524
Oregon	0.0369	0.0635	0.0854	0.1041	0.0006	0.0003	0.0114	0.0352	+	0.0054	0.0009	0.0323
Pennsylvania	0.0257	0.0900	0.2703	0.2113	0.0711	0.0164	0.0894	0.0534	0.0360	0.0032	0.0012	0.0396
Rhode Island	+	+	0.0004	0.0005	+	+	0.0026	+	+	+	+	0.0007
South Carolina	0.0009	0.0010	0.0049	0.0032	0.0197	0.0046	0.0246	0.0836	0.0329	0.0017	0.0012	0.0142
South Dakota	0.2480	0.3647	0.0741	0.0679	0.0931	0.0248	0.0112	+	0.0144	0.0173	0.0002	0.0243
Tennessee	0.0048	0.0075	0.0198	0.0183	0.0132	0.0031	0.0061	0.0786	+	+	0.0034	0.0519
Texas	1.6022	2.8720	0.2593	0.2064	0.0583	0.0148	0.0810	0.2313	0.0133	0.0267	0.0353	0.1299
Utah	0.0170	0.0288	0.0739	0.0759	0.0371	0.0171	0.0159	+	0.0133	0.0039	0.0003	0.0214
Vermont	0.0004	0.0004	0.0735	0.0492	+	+	0.0007	+	0.0002	+	0.0001	0.0039
Virginia	0.0115	0.0317	0.0305	0.0193	0.0233	0.0046	0.0146	0.0943	0.0738	0.0020	0.0012	0.0284
Washington	0.0950	0.1445	0.1721	0.1420	0.0015	0.0004	0.0197	0.0352	+	+	0.0007	0.0265
West Virginia	0.0053	0.0085	0.0067	0.0033	0.0002	0.0001	0.0067	0.0330	0.0124	+	0.0005	0.0111
Wisconsin	0.0564	0.2960	1.0892	0.9452	0.0237	0.0079	0.0207	0.0141	0.0133	0.0034	0.0010	0.0356
Wyoming	0.0519	0.0703	0.0054	0.0069	0.0054	0.0041	+	+	+	0.0165	0.0002	0.0220

+ Emission estimate is less than +5 Gg.

3.11. Methodology for Estimating N_2O Emissions from Agricultural Soil Management

Nitrous oxide (N_2O) emissions from agricultural soils on managed lands 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 N_2O. The *Revised 1996 IPCC Guidelines* (IPCC/UNEP/OECD/IEA 1997) focus on five specific practices: synthetic mineral N fertilization, organic amendments, crop residue N added to soils, cultivation of N fixing crops, and drainage and cultivation of organic cropland soils. The *IPCC Good Practice Guidance for LULUCF* (IPCC 2003) also recommends accounting for emissions resulting from decomposition of soil organic matter, particularly following land-use change. More recently, the *2006 IPCC Guidelines* (IPCC 2006) have taken the guidance a step further by recommending reporting of all emissions from managed land, because of the close linkage between natural and anthropogenic factors and the difficulty of separating out the portion of emissions only influenced by anthropogenic activity (IPCC 2006, see Volume IV, Chapter 1). Given the recent advancements and improvements in methods and emission factors for soil N_2O, this Inventory has adopted recommendations from IPCC (2006), which includes a number of changes from IPCC/UNEP/OECD/IEA (1997). For example, the emission factor for direct N_2O emissions from N inputs in IPCC/UNEP/OECD/IEA (1997) was too high according to a recent global analysis of experimental measurements (Bouwman et al. 2002a, 2002b, Rochette et al. 2004). Thus, the approaches described in this section are based on the original methods from IPCC/UNEP/OECD/IEA (1997), as amended in the IPCC Good Practice Guidance Documents (IPCC 2000, 2003), and further refined in IPCC (2006).

A combination of Tier 1 and Tier 3 approaches was used to estimate direct and indirect N_2O emissions from agricultural soils. The process-based biogeochemical model DAYCENT (a Tier 3 approach) was used to estimate N_2O emissions resulting from mineral soil croplands that were used to produce major crops, while the IPCC Tier 1 methodology was applied to estimate N_2O emissions for non-major crop types on mineral soils. The Tier 1 method was also used to estimate direct N_2O emissions due to drainage and cultivation of organic cropland soils. Direct N_2O emissions from grasslands were estimated by using a combination of DAYCENT and IPCC Tier 1 methods. A combination of DAYCENT and Tier 1 methods was also used to estimate indirect emissions from all managed lands. Specifically, the amount of N volatilized from soils and managed manure systems and leached or transported 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 N_2O emissions resulting from off-site transport of N were then computed using the Tier 1 method. Overall, the Tier 3 approach is used to estimate approximately 85 percent of direct soil emissions and 70 percent of total soil N_2O 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 N_2O 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 N_2O. Nutrient supply is a function of external nutrient additions as well as soil organic matter (SOM) decomposition rates, and increasing decomposition can lead to greater N_2O 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 a robust estimate of N_2O 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 N_2O emissions (Del Grosso et al. 2005). This is not surprising, since DAYCENT includes site-specific factors (climate, soil properties, and previous management) that influence N_2O emissions. Furthermore, DAYCENT also simulated NO_3 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 N_2O inventory for the United States relative to earlier reporting done using the IPCC Tier 1 method.

Text Box: DAYCENT model simulation of nitrification and denitrification

The DAYCENT model simulates the two biogeochemical processes, nitrification and denitrification, that result in N_2O 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 N_2O emissions from nitrification and denitrification are described below.

Nitrification is controlled by soil ammonium concentration (NH_4), water filled pore space (WFPS),

$$Nit = K_{max} \times NH_4 \times F(WFPS) \times F(t) \times F(pH)$$

where,

Nit	= the soil nitrification rate (g $N/m^2/d$)
NH_4	= the model-derived soil ammonium concentration (g N/m^2)
K_{max}	= the maximum fraction of NH_4^+ nitrified ($K_{max} = 0.10/d^1$)
F(t)	= the effect of soil temperature on nitrification (Figure A-5a)
F(WFPS)	= the effect of soil water content and soil texture on nitrification (Figure A-5b)
F(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 respiration, and texture. Denitrification is calculated for each soil layer, 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

$$Den = \min[F(NO_3), F(CO_2)] \times F(WFPS).$$

where,

Den	= the soil denitrification rate (µg N g $soil^{-1}$ d^{-1})
$F(CO_2)$	= a function relating N gas flux to soil respiration and nitrate levels
$F(NO_3)$	= a function relating N gas flux to soil respiration and nitrate levels
F(WFPS)	= a dimensionless multiplier (Figure A- 6).

The x inflection point of F(WFPS) is a function of respiration and soil gas diffusivity at field capacity (D_{FC}):

$$x \text{ inflection} = 0.90 - M(CO_2),$$

where,

M	= a multiplier that is a function of D_{FC}.

Respiration has a much stronger effect on the water curve in clay soils with low D_{FC} than 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 N_2/N_2O is estimated so that total N gas emissions can be

$$R_{N2/N2O} = F_r(NO_3/CO_2) \times F_r(WFPS)$$

where,

$R_{N2/N2O}$ = the ratio of N_2/N_2O

$F_r(NO_3/CO_2)$ = a function estimating the impact of the availability of electron donor relative to substrate

$F_r(WFPS)$ = a multiplier to account for the effect of soil water on N_2/N_2O.

For $F_r(NO_3/CO_2)$, 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 $F_r(WFPS)$, as WFPS increases, a higher portion of N gas is assumed to be in the form of N_2.

Figure A-5: Effect of Soil Temperature, Water-Filled Pore Space, and pH on Nitrification Rates

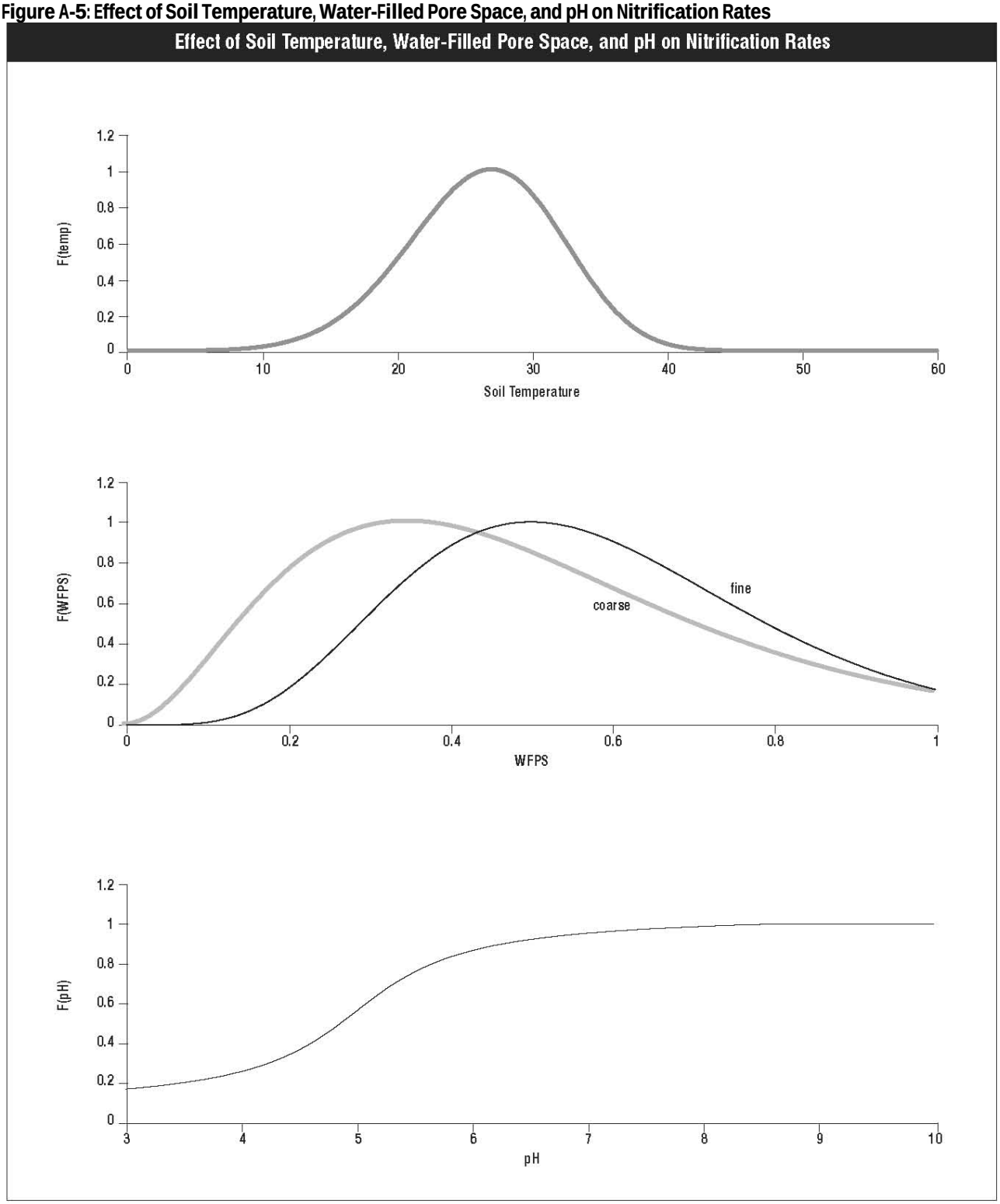
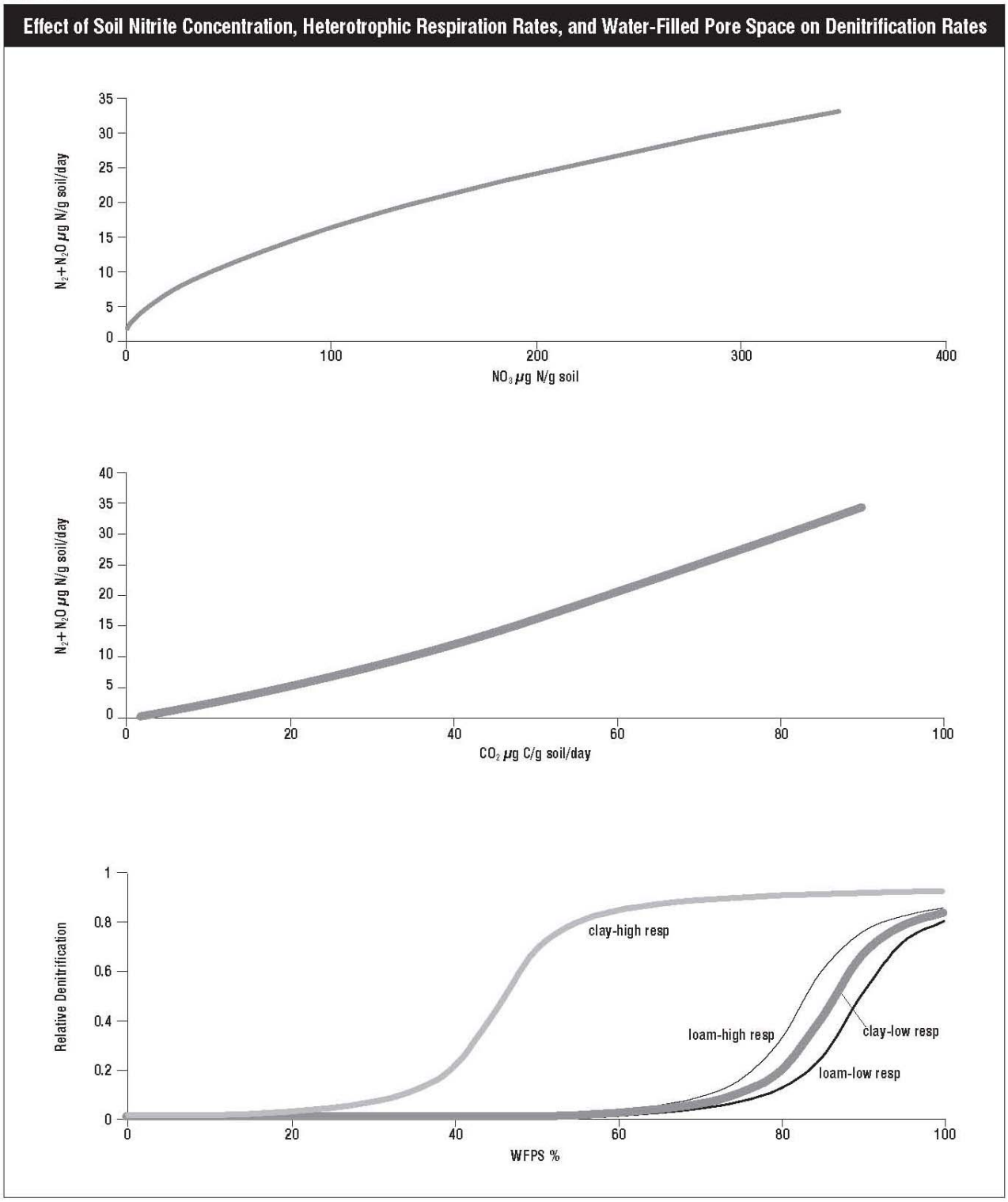


Figure A- 6: Effect of Soil Nitrite Concentration, Heterotrophic Respiration Rates, and Water-Filled Pore Space on Denitrification Rates



There are five steps in estimating direct N_2O emissions from mineral cropland and grassland soils and drained and cultivated organic cropland soils, in addition to 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 records, as well as expert knowledge. In the second, third, and fourth steps, direct 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 sub-annex describes the methods underlying each step.

Step 1: Derive Activity Data

The activity data requirements vary for major crops, non-major crops, grasslands, and organic cropland soils. 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 a 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.

Unlike the Tier 1 approach, N inputs from crop residues are not considered activity data in the DAYCENT analysis 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 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 N_2O 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.

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 during the Inventory time period (Ruddy et al. 2006). The trend and therefore the rates and uncertainties reflected in the 1995 survey data are considered representative for 1990 through 2006 (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 derived from additional publications (NASS 2004, 1999, 1992; ERS 1988; Grant and Krenz 1985; USDA 1966, 1957, 1954). 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 U.S.(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 is found in Table A-176.

Table A-176: Synthetic Fertilizer N Added to Major Crops (Gg N)

Fertilizer Type	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Fertilizer N	8,333	8,307	8,651	8,208	8,507	8,097	8,706	8,514	8,468	8,216	8,365	8,117	8,284	7,802	7,830	7,710	7,828

Simulations were conducted 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 later than 1970 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 Manure[47] *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. For DAYCENT simulations, the baseline scenario estimates have been used and 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 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 2a for further discussion of uncertainty methods).

Edmonds et al. (2003) only provide manure application rate data for 1997 and 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 any other given year. 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 for each livestock type was calculated by determining the population of animals that were on feedlots or otherwise housed in order to collect and manage the manure. Annual animal population data for all livestock types, except horses and goats, were obtained for all years from the U.S. Department of Agriculture-National Agricultural Statistics Service. Population data used for cattle, swine, and sheep were downloaded from the USDA NASS Population Estimates Database (USDA 2007a). Poultry population

[47] 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 operations. Unmanaged manure encompasses all manure deposited on soils by animals on PRP.

data were obtained from USDA NASS reports (USDA 1995a, 1995b, 1998a, 1999, 2004a, 2004b, 2006a, 2006b, 2007b, 2007c). Horse population data were obtained from the FAOSTAT database (FAO 2007). Goat population data for 1992, 1997, and 2002 were obtained from the Census of Agriculture (USDA 2005); these data were interpolated and extrapolated to derive estimates for the other years. Information regarding the poultry turnover (i.e., slaughter) rate was obtained from state Natural Resource Conservation Service personnel (Lange 2000). Additional population data for different farm size categories for dairy and swine were obtained from the 1992, 1997, and 2002 *Census of Agriculture* (USDA 2005). Information regarding the percentage of manure handled using various manure management systems is provided in the Manure Management Annex. Once the animal populations for each livestock type and management system were estimated, these populations were multiplied by a typical animal mass constant (USDA 1996, ASAE 1999; NRC 2000, ERG 2003, EPA 1992, Safley 2000) to derive total animal mass for each animal type in each management system. Total Kjeldahl N[48] excreted per year for each livestock type and management system was then calculated using daily rates of N excretion per unit of animal mass (USDA 1996, ASAE 1999). The annual amounts of Kjeldahl N were then summed over all livestock types and management systems to derive estimates of the annual managed manure N produced (Table A-177). Nitrogen available for application was estimated for managed systems based on the total amount of nitrogen produced in manure minus nitrogen losses and including the addition of nitrogen from bedding materials. Nitrogen losses include direct nitrous oxide emissions, volatilization of ammonia and NOx, and runoff and leaching; more information on these losses is available in the Manure Management Annex (3.10), Manure Management IPCC Source Category 4B. Animal-specific bedding factors were set equal to IPCC default factors (IPCC 2006). The estimated amount of manure available for application was adjusted for the small percent of poultry manure used for cattle feed between 1990 and 2002 (Carpenter 1992, Carpenter and Starkey 2007). The remaining manure N that was not applied to major crops and grassland was assumed to be applied to non-major crop types. Frequency and rates of manure application to cropland during the inventory period were estimated from data compiled by the USDA Natural Resources Conservation Service for 1997 (Edmonds et al. 2003), with adjustments based on managed manure N excretion in other years of the inventory, as discussed previously.

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 EPA 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, 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 addition, 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.

The remaining 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-177.

Table A-177: Fate of Livestock Manure Nitrogen (Gg N)

Activity	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Managed Manure N Applied to Major Crops and Grasslands[a]	1,150	1,194	1,189	1,166	1,169	1,113	1,154	1,172	1,227	1,208	1,235	1,233	1,258	1,116	1,139	1,029	1,153
Managed Manure N Applied to Non-Major Crops	758	760	753	810	812	878	818	836	802	821	827	849	830	944	937	1,062	973
Pasture, Range, & Paddock Manure N	3,873	3,888	3,971	4,011	4,110	4,075	4,152	4,023	3,933	3,802	3,811	3,783	3,788	3,827	3,829	3,903	3,920

[48] Total Kjeldahl N is a measure of organically bound N and ammonia N in both solid and liquid wastes.

Total[b]	**5,780**	**5,843**	**5,912**	**5,987**	**6,091**	**6,066**	**6,124**	**6,031**	**5,962**	**5,830**	**5,873**	**5,865**	**5,876**	**5,887**	**5,904**	**5,993**	**6,046**

[a] Includes N volatilized and leached/runoff during treatment, storage and transport before soil application.
[b] Totals may not sum exactly due to rounding.

Residue N Inputs: Residue N input is estimated as part of the DAYCENT simulation and is not an input to the model. The simulated total N inputs of above- and below-ground residue N and fixed N that was not harvested are provided in Table A-178.

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-178.

Table A-178: Crop Residue N and Other N Inputs to Major Crops as Simulated by DAYCENT (Gg N)

Activity	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Residue N[a]	4,693	4,345	4,896	5,000	4,625	4,873	4,850	4,903	4,662	5,153	4,797	4,584	4,400	4,930	4,512	4,822	4,707
Other N Inputs[b]	25,544	23,413	24,289	24,677	22,994	23,041	23,833	23,685	25,525	22,546	24,074	23,358	22,782	23,110	21,369	24,608	23,683

[a] Residue N inputs include unharvested fixed N from legumes as well as crop residue N.
[b] Other N inputs include mineralization from decomposition of soil organic matter as well as asymbiotic fixation of N from the atmosphere.

Crop Rotation and Land Management Information: Data for the 63 agricultural regions were obtained for specific timing and type of cultivation, timing of planting/harvest, and crop rotation schedules (Hurd 1930, 1929, Latta 1938, Iowa State College Staff Members 1946, Bogue 1963, Hurt 1994, USDA 2000b, 2000c, 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 data sets and interpolation/extrapolation was used to fill temporal gaps.

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) analysis, 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 km^2 resolution driven by weather station observations and an elevation model (Thornton et al. 2000, 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, even fewer are located in agricultural lands. Weather station data are for a point in space, and the DAYMET modeling process 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 km^2 resolution for 1980 through 2003. For each county, DAYMET weather data were selected from the 1 km^2 cell that occurred in agricultural lands according 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 from 2003 was assumed to represent 2004 through 2006, but the time series will be updated in the future when the latest 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 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 2006 (USDA-NASS 2007), 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) the amount of N in non-manure organic commercial fertilizers, and (3) 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 N fertilizer additions to non-major crop types. The total amount of fertilizer used on-farms has been estimated by the USGS on a county scale from fertilizer sales data (Ruddy et al. 2006). 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-179.

Table A-179: Synthetic Fertilizer N Added to Non-Major Crops (Gg N)

Fertilizer Type	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Fertilizer N	1,748	1,922	1,701	2,063	2,858	2,439	2,431	2,575	2,611	2,974	2,639	2,125	1,957	2,440	2,411	2,531	2,413

Manure and Other Commercial Organic Fertilizers:[49] Estimates of the manure N applied to non-major crops was estimated using the activity data described for major crops (Table A-2). Estimates of total national annual N additions from other organic fertilizers were derived from organic fertilizer statistics (TVA 1991, 1992a, 1993, 1994; AAPFCO 1995, 1996, 1997, 1998, 1999, 2000a, 2000b, 2002, 2003, 2004, 2005, 2006, 2007). 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 2006). 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 2006, 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-180.

Table A-180: Other Organic Commercial Fertilizer Consumption on Agricultural Lands (Gg N)

Fertilizer Type	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Other Commercial Organic Fertilizer N[a]	766	773	765	821	825	894	836	854	820	839	847	867	845	959	951	1,078	990

[a] Includes manure applied to non-major crops, dried blood, dried manure, tankage, compost, other. Excludes sewage sludge used as commercial fertilizer.

Retention of Crop Residue: Annual crop yield (metric tons per hectare) and area planted (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 1994a, 1998b, 2003, 2005i, 2006b). 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

[49] Other commercial organic fertilizers include manure applied to non-major crops, dried blood, dried manure, tankage, compost, other, but excludes sewage sludge used as commercial fertilizer.

the residue dry matter fractions shown in Table A-181. 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-182) 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 below-ground to above-ground biomass, and residue N fractions. The resulting annual biomass N inputs are presented in Table A-182.

Table A-181: 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-182: Nitrogen in Crop Residues Retained on Soils Producing Non-Major Crops (Gg N)

Crop	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Peanuts for Nuts	65	78	71	63	71	63	65	64	69	69	66	75	63	70	72	77	64
Dry Edible Beans	17	17	14	14	16	17	16	16	16	17	15	14	17	14	13	15	15
Dry Edible Peas	9	10	9	10	9	11	10	11	11	11	10	10	11	11	14	16	15
Austrian Winter Peas	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Lentils	9	9	9	9	9	9	9	9	9	9	10	10	9	9	10	11	10
Wrinkled Seed Peas	9	9	8	9	8	9	8	8	8	8	8	8	8	8	9	8	8
Barley	122	130	128	121	107	102	110	104	101	80	95	78	75	85	85	69	59
Oats	91	66	77	65	58	53	43	48	47	45	46	44	45	47	43	43	41
Rye	17	16	17	16	17	16	15	15	17	17	15	15	14	15	15	16	15
Millet	7	7	7	7	7	7	7	7	7	7	4	8	3	5	7	6	5
Rice	82	84	90	82	97	88	87	91	92	100	94	103	102	98	110	107	95
Total	**434**	**433**	**439**	**405**	**409**	**383**	**379**	**382**	**387**	**372**	**371**	**373**	**356**	**372**	**386**	**376**	**335**

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 2000b, as extracted by Eve 2001, and revised by Ogle 2002).[50] These areas were grouped by broad climatic region[51] 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 2006 (Table A-183).

[50] 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.

[51] These 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.

Table A-183: Drained and Cultivated Organic Soil Area (Thousand Hectares)

Year	Temperate Area	Sub-Tropical Area
1990	429	194
1991	429	194
1992	429	194
1993	439	196
1994	439	196
1995	439	196
1996	439	196
1997	439	196
1998	439	196
1999	439	196
2000	439	196
2001	439	196
2002	439	196
2003	439	196
2004	439	196
2005	439	196
2006	439	196

Step 1c: Activity Data for Direct Emissions from Grassland Management

N_2O emissions from grasslands were computed using DAYCENT and the Tier 1 methodology. 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. N_2O emissions from PRP manure N additions that were not included in the DAYCENT simulations (e.g., PRP manure N deposited on federal lands) 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, except county-level area data on privately-owned pasture and rangeland areas (i.e., not federal), which were compiled from the U.S. Department of Agriculture National Resources Inventory (USDA 2000b). A key source of N for grasslands is PRP manure N deposition. In the DAYCENT model, N additions to soils from grazing animal waste are simulated as a function of forage growth rates and nutrient contents, grazing intensity, soil texture, weather, and other factors that interact to control N flows among plants, animals, and soil. N fixation by legumes, and N residue inputs from senesced grass litter were included as sources of N to the soil, which are estimated as a function of vegetation type, weather, and soil properties. Similar to the methodology for major crops, "other N inputs" were simulated within the model framework in order to estimate soil N_2O 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-184.

Table A-184: Synthetic Fertilizer N, PRP Manure N, Organic Manure N Amendment, Forage Legume N, and Other N Inputs Simulated with the DAYCENT Model (Gg N)

Fertilizer Type	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Fertilizer N	8,333	8,307	8,651	8,208	8,507	8,097	8,706	8,514	8,468	8,216	8,365	8,117	8,284	7,802	7,830	7,710	7,828
PRP Manure N	2,920	2,918	3,295	3,293	2,751	3,250	2,365	3,262	2,870	3,159	2,651	2,815	2,141	2,701	2,483	2,905	2,835
Managed Manure	1,150	1,194	1,189	1,166	1,169	1,113	1,154	1,172	1,227	1,208	1,235	1,233	1,258	1,116	1,139	1,029	1,153
Residue N[a]	4,693	4,345	4,896	5,000	4,625	4,873	4,850	4,903	4,662	5,153	4,797	4,584	4,400	4,930	4,512	4,822	4,707
Other N Inputs[b]	24,544	23,413	24,289	24,677	22,994	23,041	23,833	23,685	25,525	22,546	24,074	23,358	22,782	23,110	21,369	24,608	23,683

[a] Residue N inputs include unharvested fixed N from legumes as well as crop residue N.
[b] Other N inputs include mineralization from decomposition of soil organic matter and litter, as well as asymbiotic fixation of N from the atmosphere.

Tier 1 Method: Additional Direct Soil N_2O 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: Manure N additions from grazing animals were modeled within DAYCENT, but the simulations only captured approximately 70 percent of total manure production in this category. The remainder of the PRP manure N was assumed to be excreted on federal grasslands, and soil N_2O emissions were estimated using Tier 1 methods. 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 following text.

Information regarding dairy farm grazing was obtained from communications with personnel from state Natural Resource Conservation Service offices, state universities, and other experts (Poe et al. 1999, Deal 2000, Johnson 2000, Miller 2000, Stettler 2000, Sweeten 2000, Wright 2000). Because grazing operations are typically related to the number of animals on a farm, farm-size distribution data reported in the *1992, 1997, and 2002 Census of Agriculture* (USDA 2005) were used in conjunction with the state data obtained from personal communications to determine the percentage of total dairy cattle that graze. An overall percent of dairy waste that is deposited in PRP was developed for geographic regions of the United States. These percentages were applied to the total annual dairy cow and heifer state population data for 1990 through 2006, which were obtained from NASS (USDA 2007).

To determine the population of beef cattle that are on PRP, the following assumptions were made: (1) beef cows, bulls, and calves were not housed on feedlots; (2) a portion of heifers and steers were on feedlots; and (3) all beef cattle that were not housed on feedlots were located on PRP (i.e., total population minus population on feedlots equals population on PRP) (Milton 2000). Information regarding the percentage of heifers and steers on feedlots was obtained from USDA personnel (Milton 2000) and used in conjunction with NASS population data (USDA 2007) to determine the population of steers and heifers on PRP.

Based on the assumption that smaller facilities are less likely to utilize manure management systems, farm-size distribution data reported in the *1992, 1997, and 2002 Census of Agriculture* (USDA 2005) were used to determine the percentage of all swine whose manure is not managed (i.e., the percentage on PRP). These percentages were applied to the average of the quarterly NASS population data for swine (USDA 2007) to determine the population of swine on PRP.

Total sheep and lamb population data were obtained from NASS (USDA 2007). To determine the number of sheep and lamb in managed systems, information on the number of sheep and lamb on feed were obtained from U.S. Department of Agriculture for 1990 through 1993 (USDA 1994c). However, population data for lamb and sheep on feed were not available after 1993, so the number of lamb and sheep on feed for 1994 through 2006 were estimated 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 were not necessarily managed on feedlots; they may have been unmanaged on pasture/crop residue supplemented by feed. To estimate the portion of on feed animals that are on PRP, data were obtained from U.S. Department of Agriculture for lambs only in 1993 (USDA 1994c). To calculate the number of sheep and lamb on feedlots for all years, it was assumed that the percentage of sheep and lamb on feedlots versus pasture/crop residue is the same as that for lambs in 1993 (Anderson 2000). It was assumed that all sheep and lamb manure not deposited on feedlots was deposited on PRP (Anderson 2000).

It was assumed that 92 percent of goat manure was deposited on PRP (Safley et al. 1992). Annual goat population data by state were available for only 1992, 1997, and 2002 (USDA 2005). The data for 1992 were used for 1990 through 1992 and the data for 2002 were used for 2002 through 2006. Data for 1993 through 1996 and 1998 through 2001 were linearly interpolated using the 1992, 1997, and 2002 data. In addition, it was assumed that one percent of poultry manure for broilers and turkeys was deposited on PRP (Safley et al. 1992). Poultry population data were obtained from NASS (USDA 1995a, 1995b, 1998a, 1999, 2004a, 2004b, 2006a, 2006b, 2007b, 2007c). The annual population data for boilers and turkeys were adjusted for turnover (i.e., slaughter) rate (Lange 2000). Lastly, it was assumed that 92 percent of horse manure was deposited on PRP (Safley et al. 1992). Horse population data were obtained from the FAOSTAT database (FAO 2007).

For each animal type, the population of animals within PRP systems was multiplied by a typical animal mass constant (USDA 1996, ASAE 1999; NRC 2000, ERG 2003, EPA 1992, Safley 2000) to derive total animal

mass for each animal type. Total Kjeldahl N excreted per year was then calculated for each animal type using daily rates of N excretion per unit of animal mass (USDA 1996, ASAE 1999). Annual N excretion was then summed over all animal types to yield total N in PRP manure (Table A-177).

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. 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 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 and 2006 (Bastian 2007), so the 1990 through 2004 data were linearly extrapolated for those two 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 N_2O fluxes from soils in *Settlements Remaining Settlements* (see section 7.5 of the Land Use, Land-Use Change, and Forestry chapter). Sewage sludge disposal data are provided in Table A-185.

Table A-185: Sewage Sludge Nitrogen by Disposal Practice (Gg N)

Disposal Practice	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Applied to Agricultural Soils	52	56	59	63	66	69	72	75	78	81	84	86	89	91	94	98	101
Other Land Application	25	26	27	27	28	28	29	29	29	30	30	30	30	30	30	31	32
Surface Disposal	20	20	19	18	17	16	15	14	13	12	10	9	8	6	5	4	3
Total	**98**	**101**	**105**	**109**	**111**	**113**	**116**	**118**	**121**	**122**	**124**	**125**	**127**	**128**	**130**	**133**	**136**

Note: Totals may not sum due to independent rounding.

Step 1d: Activity Data for Indirect N_2O Emissions from Managed Soils of all Land-Use Types and Managed Manure Systems

Volatilization leads to emissions of NH_3 and NO_x to the atmosphere from N that was applied or deposited as synthetic fertilizer, livestock manure, sewage sludge, and other organic amendments. In turn, this N is returned to soils through atmospheric deposition, thereby increasing mineral N availability and enhancing N_2O production. Additional N is lost from soils through leaching as water percolates through a soil profile and through runoff with overland water flow. These losses of N enter groundwater and waterways, from which a portion is emitted as N_2O. 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-176 through Table A-180, Table A-182, and Table A-185). The activity data for computing direct N_2O emissions from settlements and forest lands are described in the Land Use, Land-Use Change, and Forestry Chapter (Chapter 7).

Using the DAYCENT model, volatilization and leaching/surface run-off of N from soils was computed internally for major crop types and 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. 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 N_2O 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, and PRP manure 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 1996 IPCC 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). PDFs for the volatilized N were 0.03-0.3 kg NH_3-N+NOx-N/kg N for synthetic fertilizer and 0.05-0.5 kg NH_3-N+NOx-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 1996 IPCC default fraction subject to leaching/runoff losses of 0.3 kg N/kg N applied, with an uncertainty from 0.1–0.8 kg NO_3-N/kg N (IPCC 2006). PDFs were derived for each of the N inputs in the same manner as direct N_2O emissions, discussed in Steps 1a and 1c.

Volatilized N was estimated 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 N_2O Emissions from Cropland Soils

In this step, N_2O 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 N_2O Emissions from Cropland Mineral Soils

Two methods were used to estimate direct N_2O 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 N_2O emissions are sensitive to the amount of SOM. Lastly, simulations were performed for the modern agricultural period (1971 through 2006).

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. Principal crop types, as defined by NASS (USDA 2003), include all grain, hay and row crops as well as vegetables for processing, but not commercial vegetable crops or orchards. Overall, the DAYCENT simulations included approximately 86 percent of total cropped 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, N_2O 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. 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 N_2O 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. 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 N_2O emissions across regions from the past year's inventory, using a Neyman allocation (Cochran 1977). A Neyman allocation is based on the variance in N_2O 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 in the analysis. 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 8 agricultural experiments with 50 treatments, and the results were analyzed using a linear-mixed effect model in which measurements were statistically modeled as a function of simulated emissions. DAYCENT results 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, but no significant relationships were found at an alpha level of 0.05. 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 2006. To apply the uncertainty estimator, DAYCENT N_2O 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 and site by year random effects (Del Grosso et al., in prep.).

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 N_2O emissions. This means, for example, that N_2O 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 practices. 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 N_2O emissions assigned to each of the practices.[52] For example, if 70 percent of the mineral N made available in the soil was due to mineral fertilization, then 70 percent of the N_2O emissions were assigned to this practice. The remainder of soil N_2O 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 influence of "other N inputs" was necessary in order to meet the recommendation of reporting all emissions from managed lands (IPCC 2006).

[52] This method is a simplification of reality to allow partitioning of N_2O emissions, as it assumes that all N inputs have an identical chance of being converted to N_2O. This is unlikely to be the case, but DAYCENT does not track N_2O emissions by source of mineral N so this approximation is the only approach that can be used for approximating the portion of N_2O emissions by source of N input. Moreover, this approach is analogous to the IPCC Tier 1 method (IPCC 2006), which uses the same direct emissions factor for all N sources.

The final N_2O 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., in prep). In turn, regional values were summed to produce the national total. The uncertainty was based on the variance in simulated N_2O 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 N_2O emissions for the dominant condition, expressed as a 95 percent confidence interval.

Non-Major Crops: Tier 1 Method

To estimate direct N_2O emissions from N additions to non-major crops, the amount of applied synthetic and other organic fertilizer (i.e., dried blood, dried manure, tankage, compost, and other) N in each year was added to N inputs from crop residues, and the total N was multiplied by the IPCC default emission factor of 0.01 kg N_2O-N/kg N (IPCC 2006). The uncertainty was determined based on simple error propagation methods (IPCC 2006). The uncertainty in the default emission factor is 0.3–3.0 kg N_2O-N/kg N (IPCC 2006). Uncertainty in activity data is ± 20 percent for fertilizer additions (Mosier 2004).[53] 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 N_2O Emissions Due to Drainage and Cultivation of Organic Cropland Soils

To estimate annual N_2O emissions from drainage and cultivation of organic soils, the area of cultivated organic soils in temperate regions was multiplied by the IPCC default emission factor for temperate soils and the corresponding area in sub-tropical regions was multiplied by the average (12 kg N_2O-N/ha cultivated) of IPCC (2006) default emission factors for temperate (8 kg N_2O-N/ha cultivated) and tropical (16 kg N_2O-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 N_2O-N/ha (IPCC 2006).

Step 2c: Estimate Total Direct N_2O Emissions from Cropland Soils

In this step, total direct N_2O emissions from cropland soils are calculated by summing direct emissions due to anthropogenic activity on mineral soils with emissions resulting from the drainage and cultivation of organic cropland soils (Table A-186). Uncertainties were combined using the simple error propagation method (IPCC 2006).

Table A-186: Direct N_2O Emissions from Cropland Soils (Tg CO_2 Eq.)

Activity	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Mineral Soils	**128.1**	**135.9**	**127.5**	**136.2**	**139.1**	**130.3**	**146.1**	**140.7**	**146.1**	**135.6**	**139.1**	**144.7**	**134.3**	**127.4**	**133.2**	**137.1**	**136.1**
Major Crops	113.7	120.6	113.3	120.1	119.1	112.2	128.4	122.1	127.5	115.2	120.3	128.3	118.9	109.0	115.0	117.7	117.9
Synthetic Fertilizer	42.8	48.6	44.5	44.5	47.5	43.4	49.7	46.7	45.5	42.8	43.0	46.8	44.7	38.5	43.5	41.3	41.8
Managed Manure	5.7	6.8	5.9	6.1	6.3	5.8	6.4	6.3	6.4	6.1	6.1	6.8	6.6	5.3	6.0	5.1	5.8
Residue N[a]	6.9	6.7	8.0	8.2	7.3	7.8	8.9	8.6	7.3	8.8	8.4	7.9	7.2	8.6	7.3	7.7	8.5
Other N Inputs[b]	58.4	58.5	54.8	61.2	58.1	55.2	63.4	60.5	68.4	57.5	62.8	66.8	60.4	56.5	58.1	63.6	61.7
Non-Major Crops	**14.4**	**15.2**	**14.2**	**16.0**	**19.9**	**18.1**	**17.8**	**18.6**	**18.6**	**20.4**	**18.8**	**16.4**	**15.4**	**18.4**	**18.3**	**19.4**	**18.2**
Synthetic Fertilizer	8.5	9.4	8.3	10.0	13.9	11.9	11.8	12.5	12.7	14.5	12.9	10.3	9.5	11.9	11.7	12.3	11.8

[53] Note that due to lack of data, uncertainties in 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; every attempt will be made to include these sources of uncertainty in future Inventories.

Other Organic Commercial Fertilizer	3.7	3.8	3.7	4.0	4.0	4.4	4.1	4.2	4.0	4.1	4.1	4.2	4.1	4.7	4.6	5.3	4.8
Residue N[a]	2.1	2.1	2.1	2.0	2.0	1.9	1.8	1.9	1.9	1.8	1.8	1.8	1.7	1.8	1.9	1.8	1.6
Organic Soils	**2.8**	**2.8**	**2.8**	**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	**130.9**	**138.7**	**130.3**	**139.0**	**141.9**	**133.1**	**149.0**	**143.5**	**149.0**	**138.5**	**142.0**	**147.6**	**137.1**	**130.2**	**136.1**	**140.0**	**138.9**

+ Less than 0.05 Tg CO_2 Eq.
[a] Residue N inputs include unharvested fixed N from legumes as well as crop residue N.
[b] Other N inputs include mineralization from decomposition of soil organic matter as well as asymbiotic fixation.

Step 3: Estimate Direct N_2O Emissions from Grasslands

A combination of DAYCENT and the Tier 1 method was also used to estimate direct N_2O emissions from soils in grasslands (pastures and rangeland). 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 major crop types described above in Step 2a, including the analysis addressing uncertainty in the model inputs. The one exception is that the structural uncertainty associated with DAYCENT model predictions was not addressed because of limited measurement data from grasslands. Addressing this uncertainty is a planned improvement as more measurement data become available for grassland soil N_2O emissions.

A Tier 1 method was used to estimate emissions from N excreted by livestock that was not simulated by DAYCENT (approximately 25 percent of total PRP manure), which comprised PRP manure N deposited on federal grasslands. A Tier 1 method was also used to estimate emissions from sewage sludge application to grasslands. These sources of N were multiplied by the IPCC (2006) default emission factor (0.02 kg N_2O-N/kg N excreted) to estimate N_2O emissions. This emission estimate was summed with the DAYCENT simulated emissions to provide the national total for direct N_2O losses from grasslands (Table A-187). 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 0.007–0.06 kg N_2O-N/kg N (IPCC 2006).

Table A-187: Direct N_2O Emissions from Grasslands (Tg CO_2 Eq.)

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
DAYCENT	**77.8**	**81.6**	**75.9**	**78.8**	**71.2**	**68.8**	**78.9**	**68.7**	**69.4**	**61.9**	**62.3**	**64.9**	**64.1**	**60.6**	**58.9**	**67.7**	**64.7**
Synthetic Fertilizer	3.0	3.1	2.8	2.9	2.9	2.6	3.1	2.6	2.6	2.5	2.5	2.6	2.7	2.5	2.5	2.5	2.6
PRP Manure	10.5	11.0	11.1	11.6	9.4	10.4	9.1	10.5	9.4	9.6	8.3	9.1	7.2	8.2	7.8	9.2	9.0
Managed Manure	0.6	0.6	0.5	0.5	0.5	+	0.5	+	+	+	0.5	0.5	0.5	+	0.5	0.5	0.5
Residue N[a]	12.5	12.5	11.8	12.8	11.8	11.4	13.2	11.2	11.2	11.0	10.4	10.9	10.8	10.3	10.5	11.2	10.4
Other N Inputs[b]	51.3	54.4	49.6	51.0	46.5	44.0	52.9	44.0	45.7	38.3	40.7	41.8	42.8	39.2	37.6	44.2	42.2
Tier 1	**9.5**	**9.7**	**6.9**	**7.3**	**13.6**	**8.4**	**17.8**	**7.8**	**10.7**	**6.7**	**11.7**	**9.9**	**16.5**	**11.4**	**13.6**	**10.2**	**11.1**
PRP Manure	9.3	9.5	6.6	7.0	13.2	8.0	17.4	7.4	10.4	6.3	11.3	9.4	16.1	11.0	13.1	9.7	10.6
Sewage Sludge	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+
Total	**87.4**	**91.4**	**82.7**	**86.1**	**84.7**	**77.2**	**96.6**	**76.5**	**80.1**	**68.5**	**74.0**	**74.8**	**80.6**	**72.0**	**72.5**	**77.9**	**75.8**

+ Less than 0.05 Tg CO_2 Eq.
[a] Residue N inputs include unharvested fixed N from legumes as well as crop residue N.
[b] Other N inputs include mineralization from decomposition of soil organic matter and litter, as well as asymbiotic fixation

Step 4: Estimate Indirect N_2O Emissions for All Land-Use Types and Managed Manure Systems

In this step, N_2O emissions were calculated for the two indirect emission pathways (N_2O emissions due to volatilization, and N_2O emissions due to leaching and runoff of N), which were then summed to yield total indirect N_2O emissions from croplands, grasslands, forest lands, and settlements.

Step 4a: Indirect Emissions Due to Volatilization

Indirect emissions from volatilization were calculated according to the amount of mineral N that was transported in gaseous forms from the soil profile and later emitted as soil N_2O 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 N_2O-N/kg N (IPCC 2006) to compute total N_2O emissions from volatilization. The resulting estimates are provided in Table A-188. 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 N_2O-N/kg N (IPCC 2006).

Table A-188: Indirect N_2O Emissions (Tg CO_2 Eq.)

Activity	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Volatilization and Atm. Deposition	**16.6**	**16.3**	**16.5**	**16.4**	**16.7**	**16.4**	**16.5**	**16.6**	**16.8**	**16.3**	**16.2**	**15.7**	**15.6**	**16.0**	**15.5**	**16.9**	**16.1**
Croplands	5.8	5.6	5.8	5.9	6.3	6.1	6.2	6.4	6.6	6.5	6.7	6.1	6.0	6.4	6.1	6.6	6.5
Settlements	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+
Forest Land	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+
Grasslands	10.7	10.6	10.6	10.4	10.3	10.2	10.1	10.1	10.1	9.5	9.3	9.4	9.3	9.4	9.2	10.1	9.4
Surface Leaching & Run-off	**34.5**	**32.0**	**31.1**	**50.2**	**25.6**	**38.1**	**39.9**	**35.8**	**35.8**	**27.3**	**29.9**	**39.1**	**28.8**	**29.1**	**22.9**	**30.5**	**34.3**
Croplands	24.3	19.8	19.6	28.1	17.4	24.4	22.9	20.7	24.6	19.7	21.7	22.8	18.8	21.4	15.5	21.8	23.7
Settlements	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+
Forest Land	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+
Grasslands	9.9	12.0	11.3	21.7	7.9	13.4	16.7	14.7	10.9	7.2	7.8	15.8	9.6	7.2	6.9	8.2	10.1
Total	**51.1**	**48.3**	**47.7**	**66.6**	**42.3**	**54.6**	**56.5**	**52.4**	**52.6**	**43.5**	**46.1**	**54.8**	**44.4**	**45.1**	**38.4**	**47.4**	**50.4**

+ Less than 0.05 Tg CO_2 Eq.

Step 4b: Indirect Emissions Due to Leaching and Runoff

The amount mineral N originating in human activity 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 overland flow of runoff waters. 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 in aqueous forms was multiplied by the IPCC default emission factor of 0.0075 kg N_2O-N/kg N (IPCC 2006) to provide the emission estimate from this source. The resulting emission estimates are provided in Table A-189. The uncertainty was determined based on simple error propagation methods (IPCC 2006), including uncertainty in the default emission factor ranging from 0.0005–0.025 kg N_2O-N/kg N (IPCC 2006).

Step 5: Estimate Total N_2O 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-189. Uncertainties in the final estimate were combined using simple error propagation methods (IPCC 2006), and expressed as a 95 percent confidence interval.

Table A-189: Total N_2O Emissions from Agricultural Soil Management (Tg CO_2 Eq.)

Activity	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Total Direct	**218.3**	**230.0**	**213.0**	**225.1**	**226.7**	**210.3**	**245.6**	**220.0**	**229.1**	**207.0**	**216.0**	**222.3**	**217.7**	**202.2**	**208.6**	**217.9**	**214.7**
Direct Emissions from Mineral Cropland Soils	**128.1**	**135.9**	**127.5**	**136.2**	**139.1**	**130.3**	**146.1**	**140.7**	**146.1**	**135.6**	**139.1**	**144.7**	**134.3**	**127.4**	**133.2**	**137.1**	**136.1**
Synthetic Fertilizer	51.3	58.0	52.8	54.6	61.4	55.3	61.5	59.3	58.2	57.3	55.8	57.2	54.2	50.4	55.3	53.6	53.6
Organic Amendment[a]	9.4	10.5	9.6	10.1	10.3	10.1	10.4	10.4	10.4	10.2	10.2	11.1	10.7	10.0	10.7	10.4	10.7
Residue N[b]	9.0	8.8	10.2	10.2	9.2	9.6	10.8	10.5	9.2	10.6	10.2	9.7	8.9	10.4	9.2	9.6	10.1
Other N Inputs[c]	58.4	58.5	54.8	61.2	58.1	55.2	63.4	60.5	68.4	57.5	62.8	66.8	60.4	56.5	58.1	63.6	61.7
Direct Emissions from Drained Organic Cropland Soils	**2.8**	**2.8**	**2.8**	**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	**87.4**	**91.4**	**82.7**	**86.1**	**84.7**	**77.2**	**96.6**	**76.5**	**80.1**	**68.5**	**74.0**	**74.8**	**80.6**	**72.0**	**72.5**	**77.9**	**75.8**
Synthetic Mineral	3.0	3.1	2.8	2.9	2.9	2.6	3.1	2.6	2.6	2.5	2.5	2.6	2.7	2.5	2.5	2.5	2.6

Fertilizer																	
PRP Manure	19.8	20.5	17.7	18.6	22.7	18.4	26.5	17.9	19.7	15.9	19.6	18.5	23.3	19.2	20.9	18.9	19.6
Managed Manure	0.6	0.6	0.5	0.5	0.5	+	0.5	+	+	+	0.5	0.5	0.5	+	0.5	0.5	0.5
Sewage Sludge	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+
Residue[b]	12.5	12.5	11.8	12.8	11.8	11.4	13.2	11.2	11.2	11.0	10.4	10.9	10.8	10.3	10.5	11.2	10.4
Other N Inputs[c]	51.3	54.4	49.6	51.0	46.5	44.0	52.9	44.0	45.7	38.3	40.7	41.8	42.8	39.2	37.6	44.2	42.2
Total Indirect	**51.1**	**48.3**	**47.6**	**66.6**	**42.3**	**54.5**	**56.4**	**52.3**	**52.5**	**43.4**	**46.0**	**54.7**	**44.3**	**45.0**	**38.3**	**47.3**	**50.3**
Volatilization	16.6	16.3	16.5	16.4	16.7	16.4	16.5	16.6	16.8	16.2	16.2	15.7	15.6	16.0	15.5	16.9	16.1
Leaching/Runoff	34.5	32.0	31.1	50.1	25.6	38.1	39.9	35.7	35.7	27.2	29.8	39.0	28.7	29.0	22.8	30.4	34.2
Total Emissions	**269.4**	**278.3**	**260.7**	**291.7**	**268.9**	**264.8**	**302.0**	**272.3**	**281.6**	**250.4**	**262.1**	**277.0**	**262.0**	**247.3**	**246.9**	**265.2**	**265.0**

+ Less than 0.05 Tg CO_2 Eq.

[a] Organic amendment inputs include managed manure amendments and other commercial organic fertilizer (i.e., dried blood, dried manure, tankage, compost, and other).

[b] Residue N inputs include unharvested fixed N from legumes as well as crop residue N.

[c] Other N inputs include mineralization from decomposition of soil organic matter, as well as asymbiotic fixation.

Direct and indirect emissions of soil N_2O vary regionally in both croplands and grasslands as a function of N inputs, weather, and soil type. About half of the total N_2O emissions from major crops occur in Iowa, Illinois, Nebraska, Minnesota, Kansas and Texas, where N inputs associated with corn and soybean cropping are high or where large land areas are cropped (Table A-190). On a per area unit basis, direct N_2O is high in Arizona and some New England states (Figure A-5). Although only a small portion of the land in these regions is used for crop production, emissions are high in Arizona due to intensive irrigated cropping; in New England states emissions are high because subsurface soil layers are likely to remain frozen when surface soil layers thaw in spring. This creates saturated conditions near the surface that facilitate denitrification and N_2O emissions. Indirect emissions tend to be high on an area basis in the central and eastern United States relatively high rainfall facilitates N losses from leaching and runoff (Figure A-6).

Direct and indirect emissions from grasslands are typically lower than those from croplands (Table A-190, Figure A-11, and Figure A-12) because N inputs tend to be lower, particularly from synthetic fertilizer. The highest total emissions occurred in Texas, Nebraska, Missouri, and Oklahoma. On a per area unit basis, emissions are lower in the western United States because grasslands in the East are more intensively managed (legume seeding, fertilization) while western rangelands receive few, if any, N inputs.

Table A-190: Total 2006 N_2O Emissions (Direct and Indirect) from Agricultural Soil Management by State (Tg CO_2 Eq.)

State	Croplands[1]	Grasslands[2]	Settlements[3]	Forest Lands[4]	Total	Lower Bound	Upper Bound
AL	0.99	1.57	0.03	NE	2.59	2.17	3.82
AR	6.27	1.81	0.01	NE	8.09	6.24	11.98
AZ	0.95	0.67	0.02	NE	1.64	0.98	3.72
CA	4.06	2.65	0.18	NE	6.90	5.10	11.80
CO	1.28	2.24	0.02	NE	3.55	2.82	5.31
CT	0.13	0.09	0.02	NE	0.24	-0.58	1.08
DE	0.27	0.02	0.01	NE	0.30	0.21	0.77
FL	6.75	1.24	0.01	NE	8.00	7.17	9.71
GA	1.37	1.24	0.01	NE	2.63	2.14	4.00
HI5	0.03	NE	NE	NE	0.03	0.01	0.11
IA	20.20	3.54	0.07	NE	23.81	19.45	33.39
ID	1.70	2.70	0.02	NE	4.42	3.64	5.88
IL	14.95	1.41	0.11	NE	16.47	14.23	22.10
IN	8.02	1.05	0.07	NE	9.14	7.40	12.41
KS	8.00	4.20	0.06	NE	12.27	11.15	15.01
KY	2.22	2.80	0.03	NE	5.05	4.17	7.40
LA	2.27	1.06	0.04	NE	3.36	2.18	5.16
MA	0.17	0.11	0.04	NE	0.32	-0.98	1.70
MD	0.68	0.24	0.05	NE	0.97	0.40	1.66
ME	0.25	0.11	0.01	NE	0.36	-0.29	1.15
MI	2.80	1.34	0.08	NE	4.22	2.13	6.53
MN	11.23	4.19	0.03	NE	15.45	13.21	21.15
MO	7.85	5.28	0.07	NE	13.19	11.52	17.68
MS	2.67	1.11	0.03	NE	3.81	3.23	5.37
MT	1.56	3.82	0.01	NE	5.39	4.70	7.21

NC	1.40	1.03	0.07	NE	2.50	0.19	5.08
ND	4.21	1.58	0.05	NE	5.84	4.89	8.49
NE	11.03	5.29	0.06	NE	16.38	14.71	20.69
NH	0.13	0.05	0.01	NE	0.19	-2.09	2.50
NJ	0.29	0.98	0.07	NE	1.34	0.64	2.95
NM	0.39	2.83	0.01	NE	3.23	2.24	5.05
NV	0.17	0.90	0.01	NE	1.09	0.10	2.25
NY	0.55	1.57	0.01	NE	2.12	1.50	3.04
OH	7.06	1.60	0.03	NE	8.69	7.56	11.53
OK	2.58	5.25	0.03	NE	7.86	6.43	11.52
OR	0.78	1.99	0.01	NE	2.78	2.34	3.87
PA	1.09	1.54	0.06	NE	2.69	2.23	3.62
RI	0.12	0.01	0.01	NE	0.14	-0.52	0.94
SC	0.75	0.48	0.03	NE	1.26	0.27	2.45
SD	5.85	3.76	0.02	NE	9.63	8.42	12.77
TN	1.88	2.41	0.05	NE	4.34	3.48	6.52
TX	9.14	11.03	0.09	NE	20.26	17.59	28.19
UT	0.20	1.70	0.01	NE	1.91	1.34	2.82
VA	0.72	1.93	0.05	NE	2.70	2.08	4.24
VT	0.18	0.24	0.00	NE	0.42	0.17	0.91
WA	1.98	1.33	0.03	NE	3.34	2.65	5.12
WI	4.12	2.43	0.04	NE	6.60	5.38	9.05
WV	0.12	0.56	0.00	NE	0.68	0.52	1.24
WY	0.71	1.98	0.01	NE	2.70	2.24	4.03

[1] Emissions from crop residue N inputs for minor crops were not estimated (NE) at the state level.
[2] Emissions from sewage sludge applied to grasslands and were not estimated (NE) at the state level; The sum of state level grassland emissions is slightly (2 percent) higher than the national total due to uncertainties in the distribution of manure among states.
[3] Emissions from sewage sludge applied to settlements were not estimated (NE) at the state level.
[4] Forestland emissions were not estimated (NE) at the state level.
[5] N_2O emissions are not reported for Hawaii except from cropland organic soils.

Figure A-7: DAYCENT model flow diagram

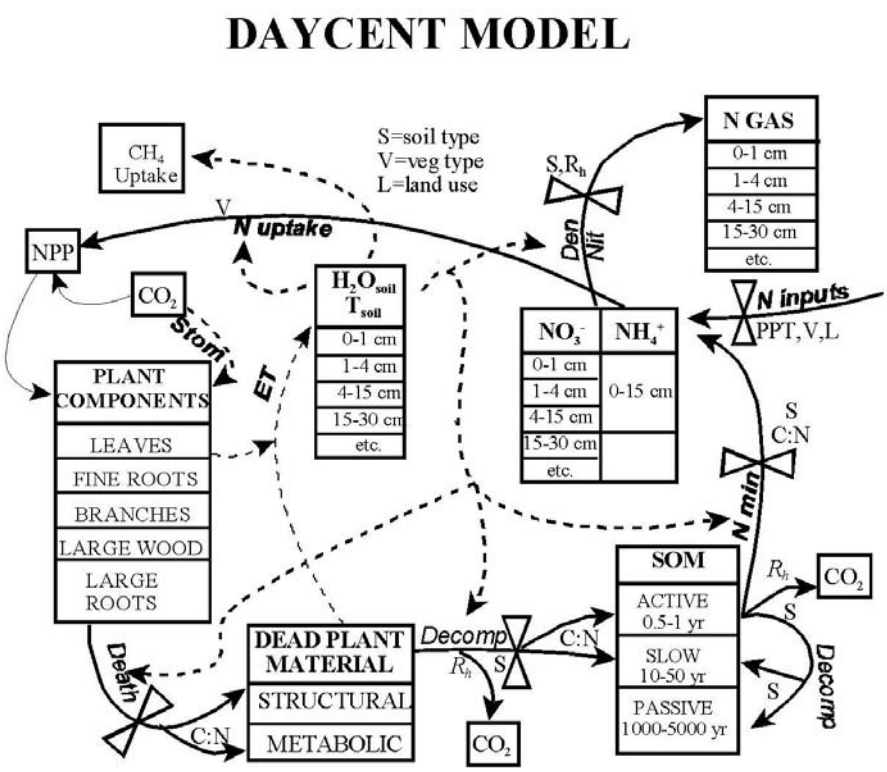


Figure A-8: Comparisons of Results from DAYCENT Model and IPCC Tier 1 Method with Measurements of Soil N_2O Emissions

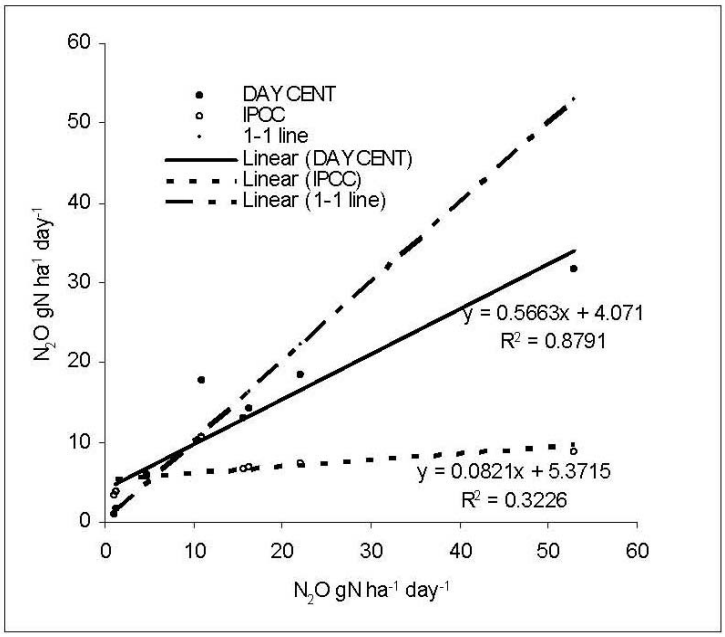


Figure A-9: Major Crops, Average Annual Direct N_2O Emissions Estimated Using the DAYCENT Model, 1990-2006 (Metric Tons CO_2 Eq./ha/yr)

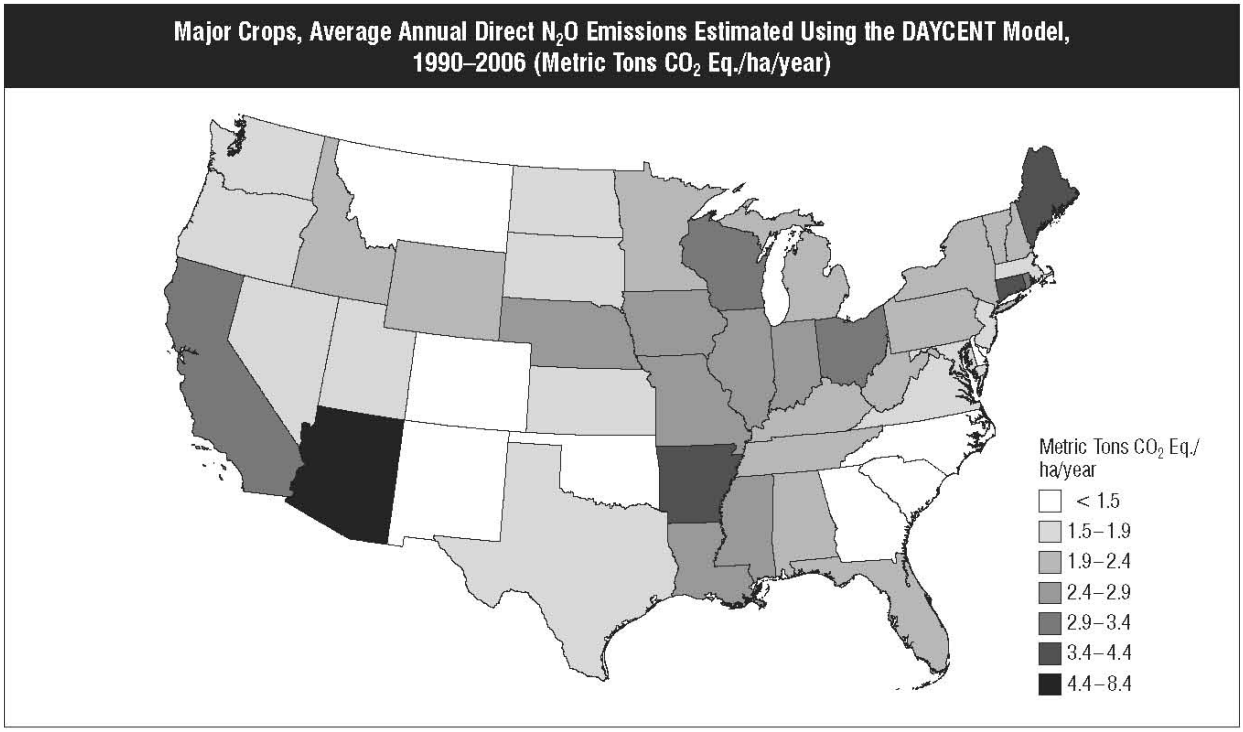


Figure A-10: Major Crops, Average Annual N Losses Leading to Indirect N_2O Emissions Estimated Using the DAYCENT Model, 1990-2006 (kg N/ha/yr)

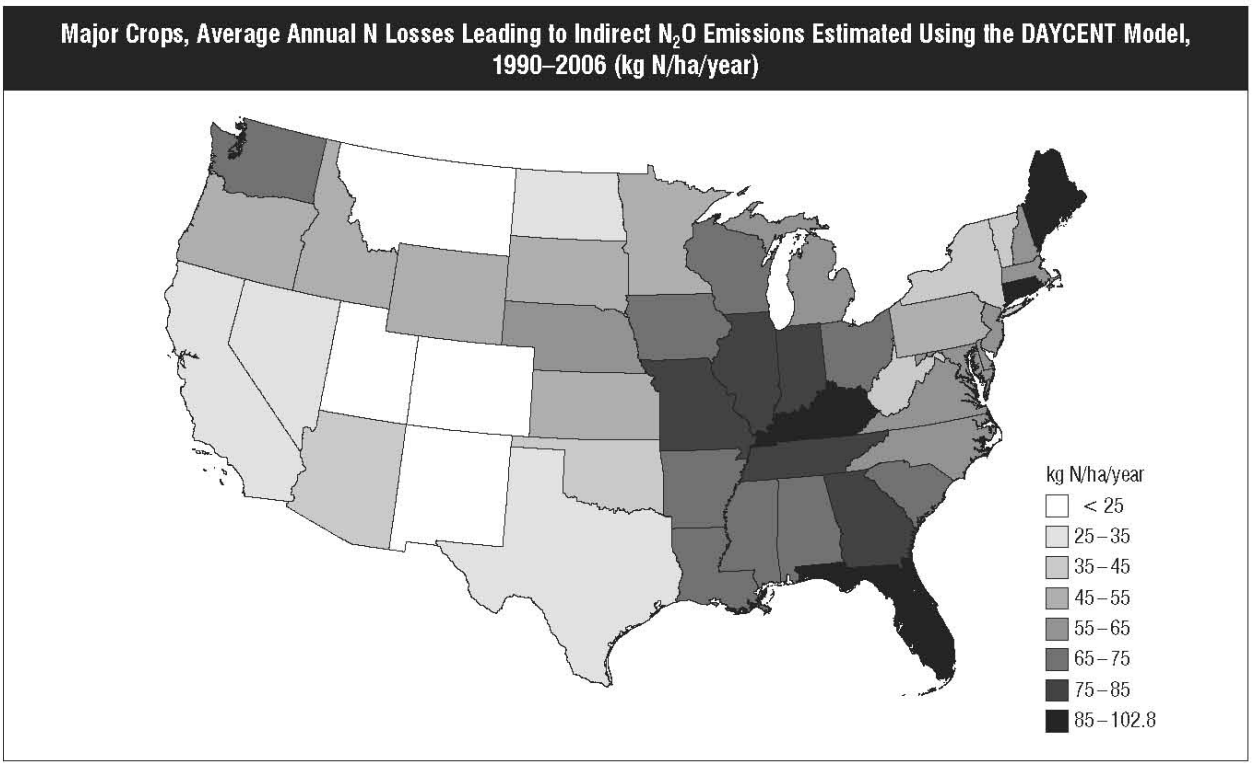


Figure A-11: Grasslands, Average Annual Direct N_2O Emissions Estimated Using the DAYCENT Model, 1990-2006 (Metric Tons CO_2 Eq./ha/yr)

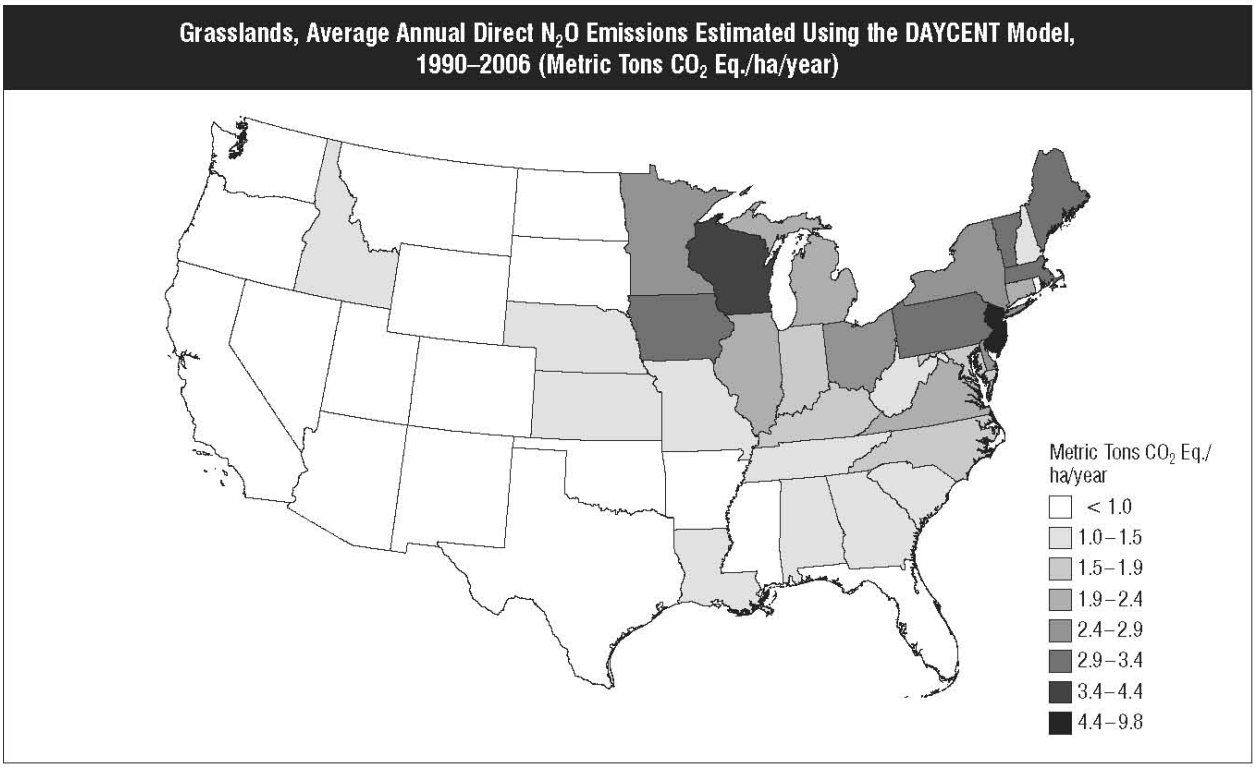
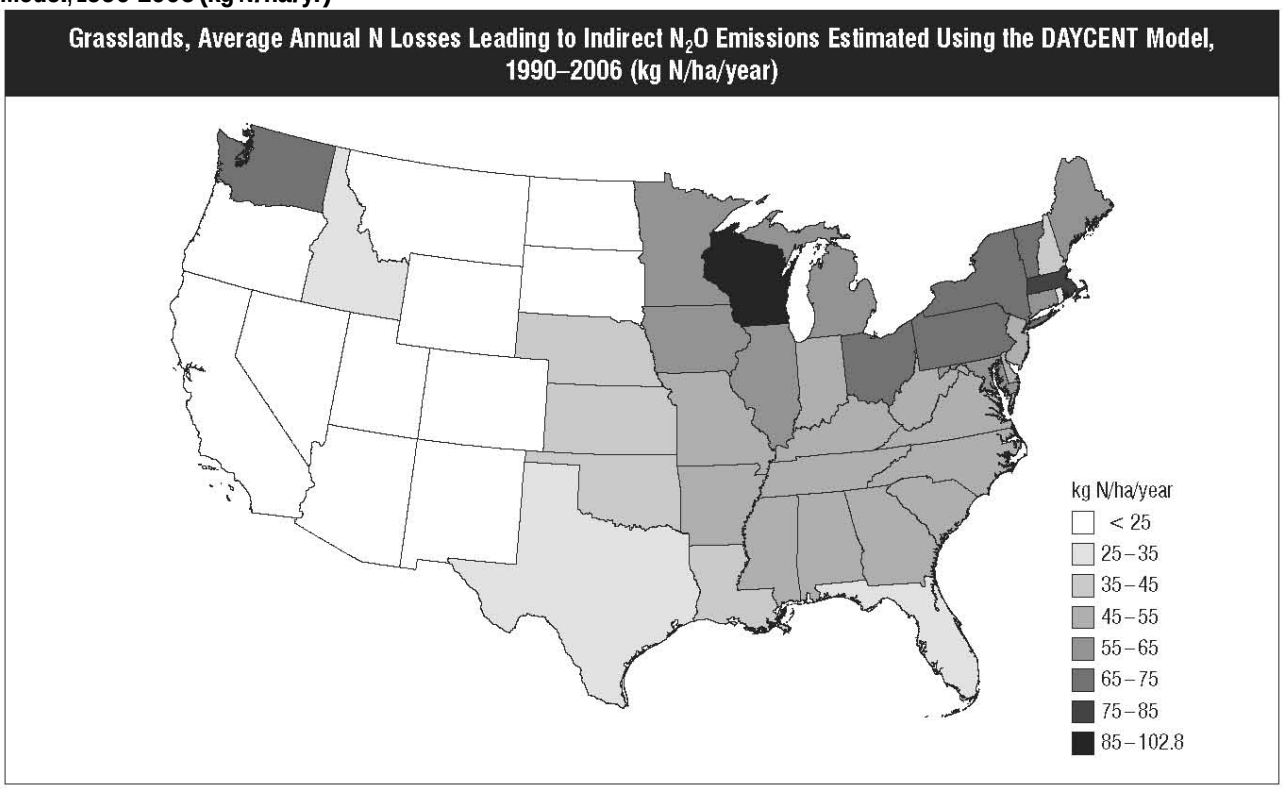


Figure A-12: Grasslands, Average Annual N Losses Leading to Indirect N_2O Emissions Estimated Using the DAYCENT Model, 1990-2006 (kg N/ha/yr)



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Del Grosso, S.J., W.J. Parton, A.R. Mosier, D.S. Ojima, A.E. Kulmala and S. Phongpan (2000) General model for N_2O and N_2 gas emissions from soils due to denitrification. *Global Biogeochem. Cycles*, 14:1045-1060.

Parton, W.J., E.A. Holland, S.J. Del Grosso, M.D. Hartman, R.E. Martin, A.R. Mosier, D.S. Ojima, and D.S. Schimel (2001) Generalized model for NO_x and N_2O emissions from soils. *Journal of Geophysical Research*. 106 (D15):17403-17420.

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 CO_2 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 the managed forests of Alaska and for most forest land in the 48 states of the conterminous 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 Arizona. 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 to determine forest areas, 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 (2006a). The inventory was designed for timber volume estimation rather than C stock estimation, so most C pools are not measured or sampled directly. Bechtold and Patterson (2005) provide the estimation procedures for standard forest inventory results. The data are freely available for download at USDA Forest Service (2006b) as the Forest Inventory and Analysis Database (FIADB) Version 2.1. The data identified as "snapshot" files and cited as FISDB 2.1, are the primary sources of inventory data used to estimate forest C stocks.

Forest surveys are currently being conducted in the U.S. territories and are planned for 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). Data are publicly posted for approximately 3.7 million hectares of forest land. This inventory covers most of the managed forestlands of Alaska. Our results show these forests emitted 12.3 Tg CO_2 per year over the period. Data are available for areas that are administratively designated as reserved, or areas where no harvesting is to occur; however, for these reserved areas, the first available inventory covered a much smaller land base compared to the second inventory, so that data was not used. The assumption applied here is that the reserved areas in this part of Alaska account for a net C change of zero.

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.[54] These practices are used to address many issues facing agricultural lands, such as economic diversification, habitat fragmentation, and water

[54] More information on agroforestry practices can be found online at <http://www.unl.edu/nac>.

quality. While providing these services and regardless of intent, these tree-based plantings will also reduce atmospheric CO_2. This occurs directly through CO_2 sequestration into woody biomass, and indirectly through enhancement of agricultural production, trapping wind-blown and surface runoff sediments, and/or reducing CO_2 emissions through fuel-use savings (Brandle et al. 1992). These practices are not worth reporting individually, but can potentially be quite large when taken into account within a whole-farm or within an aggregating larger entity (i.e., state-level) (Brandle et al. 1992, Schoeneberger 2006). The sequestration potential through agroforestry practices in the United States has been estimated to be approximately 90.3 Mt C/year by 2025 (Nair and Nair 2003).

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 Smith et al. (2007) and 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 2 to 4 surveys per state available electronically, beginning with a pre-1990 survey. 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 (the base year). This approach ensures that the period 1990 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).[55] 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 and/or reserved lands 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-191 provides a list of the specific surveys used here and Smith et al. (2007) provides further details.

Table A-191: Source of 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	Southern, 1982	1982
	FISDB 2.1, 1990	1990
	FISDB 2.1, 2000	1999
	FISDB 2.1, 2004	2003
Alaska, southcentral non-reserved	FISDB 2.1, 1998	2001
	FISDB 2.1, 2005	2005
Alaska, southeast non-reserved	FISDB 2.1, 1998	1997
	FISDB 2.1, 2005	2005
Arizona, NFS non-woodlands	1987 RPA	1985
	FISDB 2.1, 1999	1996
	FISDB 2.1, 2005	2003
Arizona, NFS woodlands	1987 RPA	1984
	FISDB 2.1, 1999	1996
	FISDB 2.1, 2005	2003
Arizona, non-NFS non-woodlands	FISDB 2.1, 1985	1986
	FISDB 2.1, 1999	1995
	FISDB 2.1, 2005	2003
Arizona, non-NFS woodlands	FISDB 2.1, 1999	1989

[55] 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. Productivity is at a minimum rate of 20 cubic feet of industrial wood per acre per year. The remaining portion of forest land is classified as either reserved forest land, which is forest land withdrawn from timber use by statute or regulation, or other forest land, which includes less productive forests on which timber is growing at a rate less than 20 cubic feet per acre per year. Forest land includes woodlands, which describes forest types consisting primarily of species that have their diameter measured at root collar, and for which there is no site index equations, nor stocking guides (Woudenberg 2006). These may include areas with a tree cover of between 5-9.9 percent; however, it is not known how much woodland is below 10 percent tree cover in some older inventories. In 2002, there were about 199 million hectares of timberland in the conterminous United States, which represented 79 percent of all forest lands over the same area (Smith et al. 2004b)..

	FISDB 2.1, 2003	2003
Arkansas	Eastwide, 1988	1988
	FISDB 2.1, 1995	1996
	FISDB 2.1, 2005	2003
California, NFS	1997 RPA	1991
	FISDB 2.1, 2005	2003
California, non-NFS	1987 RPA	1982
	Westwide, 1994	1994
	FISDB 2.1, 2005	2004
Colorado, NFS non-woodlands	1997 RPA	1981
	FISDB 2.1, 2005	2004
Colorado, NFS woodlands	1997 RPA	1975
	FISDB 2.1, 1984	1997
	FISDB 2.1, 2005	2004
Colorado, non-NFS non-woodlands	Westwide, 1983	1980
	FISDB 2.1, 2005	2004
Colorado, non-NFS woodlands	Westwide, 1983	1983
	FISDB 2.1, 2005	2004
Connecticut	FISDB 2.1, 1985	1985
	FISDB 2.1, 1998	1998
	FISDB 2.1, 2005	2005
Delaware	FISDB 2.1, 1986	1986
	FISDB 2.1, 1999	1999
	FISDB 2.1, 2004	2005
Florida	FISDB 2.1, 1987	1987
	FISDB 2.1, 1995	1995
	FISDB 2.1, 2005	2004
Georgia	FISDB 2.1, 1989	1989
	FISDB 2.1, 1997	1997
	FISDB 2.1, 2004	2001
Idaho, Caribou-Targhee NF	1987 RPA	1976
	Westwide, 1991	1992
	FISDB 2.1, 2005	2005
Idaho, Kootenai NF	1987 RPA	1988
	FISDB 2.1, 1991	1995
	FISDB 2.1, 2005	2006
Idaho, Payette NF	1987 RPA	1982
	FISDB 2.1, 2005	2005
Idaho, Salmon-Challis NF	1987 RPA	1978
	FISDB 2.1, 2005	2005
Idaho, Sawtooth NF	Westwide, 1991	1983
	FISDB 2.1, 1991	1996
	FISDB 2.1, 2005	2005
Idaho, non-NFS non-woodlands	1987 RPA	1982
	FISDB 2.1, 1991	1990
	FISDB 2.1, 2005	2005
Idaho, non-NFS woodlands	FISDB 2.1, 1991	1982
	FISDB 2.1, 2005	2005
Idaho, other NFS	Westwide, 1991	1988
	FISDB 2.1, 1991	2000
	FISDB 2.1, 2005	2005
Illinois	FISDB 2.1, 1985	1985
	FISDB 2.1, 1998	1998
	FISDB 2.1, 2005	2004
Indiana	FISDB 2.1, 1986	1986
	FISDB 2.1, 1998	1998
	FISDB 2.1, 2003	2001
	FISDB 2.1, 2005	2003
Iowa	FISDB 2.1, 1990	1990
	FISDB 2.1, 2003	2002
	FISDB 2.1, 2005	2004
Kansas	FISDB 2.1, 1981	1981

	FISDB 2.1, 1994	1994	
	FISDB 2.1, 2005	2003	
Kentucky	FISDB 2.1, 1988	1987	
	FISDB 2.1, 2004	2002	
Louisiana	Southern, 1984	1984	
	FISDB 2.1, 1991	1991	
	FISDB 2.1, 2005	2004	
Maine	Eastwide, 1982	1983	
	FISDB 2.1, 1995	1995	
	FISDB 2.1, 2003	2002	
Maryland	FISDB 2.1, 1986	1986	
	FISDB 2.1, 1999	2000	
	FISDB 2.1, 2004	2005	
Massachusetts	FISDB 2.1, 1985	1985	
	FISDB 2.1, 1998	1998	
	FISDB 2.1, 2005	2005	
Michigan	FISDB 2.1, 1980	1980	
	FISDB 2.1, 1993	1993	
	FISDB 2.1, 2004	2003	
	FISDB 2.1, 2005		2003
Minnesota	FISDB 2.1, 1990	1989	
	FISDB 2.1, 2003	2001	
	FISDB 2.1, 2005	2003	
Mississippi	Eastwide, 1987	1987	
	FISDB 2.1, 1994	1994	
Missouri	FISDB 2.1, 1989	1988	
	FISDB 2.1, 2003	2002	
	FISDB 2.1, 2005	2004	
Montana, NFS	1987 RPA	1988	
	FISDB 2.1, 1989	1996	
	FISDB 2.1, 2005	2005	
Montana, non-NFS non-reserved	FISDB 2.1, 1989	1989	
	FISDB 2.1, 2005	2005	
Montana, non-NFS reserved	1997 RPA	1990	
	FISDB 2.1, 2005	2005	
Nebraska	FISDB 2.1, 1983	1983	
	FISDB 2.1, 1994	1995	
	FISDB 2.1, 2005	2004	
Nevada, NFS non-woodlands	1987 RPA	1974	
	FISDB 2.1, 1989	1997	
	FISDB 2.1, 2005	2005	
Nevada, NFS woodlands	1987 RPA	1978	
	FISDB 2.1, 1989	1997	
	FISDB 2.1, 2005	2005	
Nevada, non-NFS non-woodlands	1997 RPA	1985	
	FISDB 2.1, 2005	2005	
Nevada, non-NFS woodlands	FISDB 2.1, 1989	1980	
	FISDB 2.1, 2005	2005	
New Hampshire	FISDB 2.1, 1983	1983	
	FISDB 2.1, 1997	1997	
	FISDB 2.1, 2003	2004	
New Jersey	FISDB 2.1, 1987	1987	
	FISDB 2.1, 1999	1999	
	FISDB 2.1, 2005	2006	
New Mexico, NFS non-woodlands	1987 RPA	1986	
	FISDB 2.1, 1999	1997	
New Mexico, NFS woodlands	1987 RPA	1986	
	FISDB 2.1, 1999	1997	
New Mexico, non-NFS non-woodlands	FISDB 2.1, 1987	1987	
	FISDB 2.1, 1999	1999	
New Mexico, non- NFS woodlands	FISDB 2.1, 1999	1989	
New York, non-reserved	Eastwide, 1980	1981	

	FISDB 2.1, 1993	1993
	FISDB 2.1, 2004	2003
New York, reserved	1987 RPA	1988
	FISDB 2.1, 2004	2003
North Carolina	FISDB 2.1, 1984	1984
	FISDB 2.1, 1990	1990
	FISDB 2.1, 2002	2001
	FISDB 2.1, 2005	2005
North Dakota	FISDB 2.1, 1980	1979
	FISDB 2.1, 1995	1995
	FISDB 2.1, 2005	2003
Ohio	1987 RPA	1988
	FISDB 2.1, 1991	1991
	FISDB 2.1, 2005	2004
Oklahoma, Central & West	FISDB 2.1, 1993	1989
Oklahoma, East	Southern, 1986	1986
	FISDB 2.1, 1993	1993
Oregon, NFS East	1987 RPA	1988
	Westwide, 1992	1995
	FISDB 2.1, 2005	2004
Oregon, non-NFS East	1987 RPA	1977
	FISDB 2.1, 1992	1990
	FISDB 2.1, 1999	1999
	FISDB 2.1, 2005	2003
Oregon, NFS West	1987 RPA	1987
	Westwide, 1992	1995
	FISDB 2.1, 2005	2004
Oregon, non-NFS West	Westwide, 1992	1988
	FISDB 2.1, 2005	2004
Pennsylvania	FISDB 2.1, 1989	1990
	FISDB 2.1, 2004	2003
Rhode Island	FISDB 2.1, 1985	1985
	FISDB 2.1, 1998	1999
	FISDB 2.1, 2005	2005
South Carolina	FISDB 2.1, 1986	1986
	FISDB 2.1, 1993	1993
	FISDB 2.1, 2001	2001
	FISDB 2.1, 2005	2004
South Dakota, NFS	1997 RPA	1986
	FISDB 2.1, 1995	1999
	FISDB 2.1, 2005	2004
South Dakota, non-NFS	1987 RPA	1986
	FISDB 2.1, 1995	1995
	FISDB 2.1, 2005	2004
Tennessee	FISDB 2.1, 1989	1989
	FISDB 2.1, 1999	1998
	FISDB 2.1, 2004	2003
Texas	Southern, 1986	1986
	FISDB 2.1, 1992	1992
	FISDB 2.1, 2003	2003
	FISDB 2.1, 2006	2004
Utah, non-woodlands	1987 RPA	1978
	FISDB 2.1, 1993	1993
	FISDB 2.1, 2005	2003
Utah, woodlands	1987 RPA	1979
	FISDB 2.1, 1993	1994
	FISDB 2.1, 2005	2003
Vermont	FISDB 2.1, 1983	1983
	FISDB 2.1, 1997	1997
	FISDB 2.1, 2005	2005
Virginia	FISDB 2.1, 1984	1985
	FISDB 2.1, 1992	1991

	FISDB 2.1, 2001	2000
	FISDB 2.1, 2005	2002
Washington, NFS East	1987 RPA	1988
	Westwide, 1991	1995
	FISDB 2.1, 2005	2004
Washington, non-NFS East	1987 RPA	1981
	FISDB 2.1, 1991	1992
	FISDB 2.1, 2005	2004
Washington, NFS West	1987 RPA	1988
	Westwide, 1991	1995
	FISDB 2.1, 2005	2004
Washington, non-NFS West	1987 RPA	1979
	FISDB 2.1, 1991	1991
	FISDB 2.1, 2005	2004
West Virginia	FISDB 2.1, 1989	1988
	FISDB 2.1, 2000	2001
	FISDB 2.1, 2005	2006
Wisconsin	FISDB 2.1, 1983	1982
	FISDB 2.1, 1996	1995
	FISDB 2.1, 2004	2002
	FISDB 2.1, 2005	2003
Wyoming, NFS	1997 RPA	1982
	2002 RPA	1997
	FISDB 2.1, 2000	2000
Wyoming, non-NFS non-reserved woodland	FISDB 2.1, 1984	1984
	FISDB 2.1, 2000	2002
Wyoming, non-NFS non-reserved woodlands	FISDB 2.1, 1984	1984
	FISDB 2.1, 2000	2002
Wyoming, non-NFS reserved	1997 RPA	1985
	FISDB 2.1, 2000	2000

[a] Substate areas (Smith et al. 2007) 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, National Field Guide, 2006a]), non-woodlands (used for clarity to emphasize that woodlands are not included), reserved (forest land withdrawn from timber utilization through statute, administrative regulation, or designation, Smith et al. (2004b)), 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). In Oklahoma, east refers to the eastern 18 counties. Texas and Alaska represent a portion of each state: eastern Texas and southcentral and southeast Alaska only

[b] FISDB 2.1 is the snapshot version of FIADB 2.1 as available on Internet May 31, 2007 (USDA Forest Service 2006c). Eastwide (Hansen et al. 1992) and Westwide (Woudenberg and Farrenkopf 1995) inventory data are formats that predate the FIADB data. Southern inventories are from older surveys compiled for the Southern region (CD of Southern data from Linda Heatherly, FIA Southern Region, July 7, 2004). 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 annual sampling (USDA Forest Service 2006a) was introduced by FIA about ten years ago. Most states have only recently been brought into this system, though. 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 to 10 years depending on region of the United States. Sampling is designed such that partial inventory cycles provide usable, unbiased samples of forest inventory, but with higher standard errors than the full cycle. Thus, many states have relatively recent partial inventories; that is, they are part-way through an annual inventory cycle. All annual surveys initiated since 1998 have followed the new national plot design for all forest land, including reserved and lower productivity lands.

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. Stocks and fluxes since the most recent survey are based on extrapolating estimates from the last two surveys. C stock and flux estimates for each pool are summed over all forest land in all states as identified in Table A-191 to form estimates for the United States. Summed fluxes and stocks are presented in Table A- 192 and Table A- 193, respectively. Table A- 193 also provides an estimate of forest area based on the interpolation procedure described above.

Table A-192.: Net Annual Changes in Carbon Stocks (Tg C yr^{-1}) in Forest and Harvested Wood Pools, 1990-2006

Carbon Pool	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Forest	**(133.4)**	**(143.5)**	**(142.8)**	**(134.2)**	**(150.0)**	**(147.4)**	**(147.7)**	**(152.8)**	**(144.8)**	**(132.7)**	**(119.1)**	**(144.3)**	**(163.1)**	**(173.2)**	**(173.2)**	**(173.2)**	**(173.2)**
Live, aboveground	(78.4)	(83.2)	(84.3)	(79.9)	(81.5)	(86.8)	(88.8)	(93.3)	(90.0)	(91.0)	(91.5)	(100.3)	(104.8)	(110.9)	(110.9)	(110.9)	(110.9)
Live, belowground	(14.8)	(15.8)	(16.1)	(15.3)	(15.8)	(17.0)	(17.5)	(18.5)	(17.9)	(18.2)	(18.3)	(20.1)	(21.0)	(22.1)	(22.1)	(22.1)	(22.1)
Dead Wood	(10.9)	(12.0)	(12.0)	(12.0)	(15.3)	(15.7)	(14.9)	(16.0)	(16.4)	(14.0)	(12.2)	(13.6)	(14.5)	(15.5)	(15.5)	(15.5)	(15.5)
Litter	(17.3)	(16.9)	(15.9)	(15.7)	(17.6)	(9.5)	(8.5)	(8.4)	(6.2)	(6.6)	(4.7)	(9.9)	(13.0)	(15.3)	(15.3)	(15.3)	(15.3)
Soil Organic Carbon	(12.0)	(15.6)	(14.5)	(11.3)	(19.8)	(18.4)	(18.0)	(16.6)	(14.3)	(2.9)	7.6	(0.4)	(9.8)	(9.4)	(9.4)	(9.4)	(9.4)
Harvested Wood	**(36.2)**	**(34.0)**	**(34.0)**	**(33.2)**	**(33.7)**	**(32.6)**	**(30.9)**	**(32.3)**	**(31.4)**	**(32.8)**	**(31.1)**	**(25.8)**	**(27.1)**	**(26.1)**	**(29.0)**	**(29.6)**	**(30.0)**
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)	(12.9)	(12.3)
SWDS	(18.5)	(19.0)	(17.7)	(18.2)	(17.7)	(17.5)	(16.8)	(17.5)	(18.0)	(18.6)	(18.2)	(17.1)	(17.5)	(16.5)	(16.6)	(16.7)	(17.7)
Total Net Flux	**(169.6)**	**(177.5)**	**(176.8)**	**(167.4)**	**(183.7)**	**(180.0)**	**(178.6)**	**(185.1)**	**(176.2)**	**(165.5)**	**(150.2)**	**(170.0)**	**(190.2)**	**(199.3)**	**(202.2)**	**(202.8)**	**(203.2)**

Note: Forest land basis for these estimates includes portions of Alaska, which represents an addition relative to previous similar tables.

Table A-193: Carbon Stocks (Tg C) in Forest and Harvested Wood Pools, 1990-2007

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Forest Area (1000 ha)	**245,799**	**246,415**	**247,050**	**247,674**	**248,301**	**249,036**	**249,687**	**250,318**	**250,984**	**251,655**	**252,251**	**252,798**	**253,443**	**254,155**	**254,889**	**255,624**	**256,358**	**257,093**
Carbon Pool																		
Forest	**40,106**	**40,239**	**40,383**	**40,525**	**40,660**	**40,810**	**40,957**	**41,105**	**41,258**	**41,402**	**41,535**	**41,654**	**41,798**	**41,962**	**42,135**	**42,308**	**42,481**	**42,654**
Live, aboveground	14,547	14,626	14,709	14,793	14,873	14,955	15,042	15,130	15,224	15,314	15,405	15,496	15,596	15,701	15,812	15,923	16,034	16,145
Live, belowground	2,896	2,911	2,927	2,943	2,958	2,974	2,991	3,009	3,027	3,045	3,063	3,081	3,102	3,123	3,145	3,167	3,189	3,211
Dead Wood	2,453	2,464	2,476	2,488	2,500	2,515	2,531	2,546	2,562	2,578	2,592	2,605	2,618	2,633	2,648	2,664	2,679	2,695
Litter	4,557	4,574	4,591	4,607	4,623	4,641	4,650	4,659	4,667	4,673	4,680	4,684	4,694	4,707	4,723	4,738	4,753	4,769
Soil Organic Carbon	15,652	15,664	15,679	15,694	15,705	15,725	15,744	15,761	15,778	15,792	15,795	15,788	15,788	15,798	15,807	15,817	15,826	15,835
Harvested Wood	**1,862**	**1,898**	**1,932**	**1,966**	**1,999**	**2,033**	**2,066**	**2,096**	**2,129**	**2,160**	**2,193**	**2,224**	**2,250**	**2,277**	**2,303**	**2,332**	**2,362**	**2,392**
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	1,461
SWDS	631	649	668	686	704	722	740	756	774	792	810	829	846	863	880	896	913	931
Total Carbon Stock	**41,968**	**42,137**	**42,315**	**42,492**	**42,659**	**42,843**	**43,023**	**43,201**	**43,386**	**43,562**	**43,728**	**43,878**	**44,048**	**44,238**	**44,438**	**44,640**	**44,843**	**43,376**

Note: Forest land basis for these estimates includes portions of Alaska, which represents an addition relative to previous similar tables.

Table A- 194 shows average C density values for forest ecosystem C pools according to region and forest types for the conterminous United States. These values were calculated by applying plot-level C estimation procedures as described above to the most recent inventory per state (Table A-191). 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- 194: 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 (see Table A-191), corresponding to an average year of 2003

Region (States) Forest Types	Above-ground Biomass	Below-ground Biomass	Dead Wood	Litter	Soil Organic Carbon	Forest Area
	Carbon Density (Mg/ha)					(1,000 ha)
Northeast						
(CT,DE,MA,MD,ME,NH,NJ,NY,OH,PA,RI,VT,WV)						
White/Red/Jack Pine	93.2	19.2	11.3	13.7	78.1	1,949
Spruce/Fir	51.4	10.9	11.8	30.6	98.0	2,974
Oak/Pine	75.5	14.9	9.1	27.2	66.9	1,362
Oak/Hickory	79.9	15.1	10.3	8.0	53.1	11,301
Elm/Ash/Cottonwood	52.4	9.9	8.1	23.6	111.7	1,126
Maple/Beech/Birch	75.3	14.4	12.4	26.4	69.6	15,833
Aspen/Birch	46.1	9.1	7.7	8.5	87.4	1,691
Minor Types and Nonstocked	50.1	10.1	6.9	14.3	82.8	1,253
All	72.9	14.1	11.0	19.3	69.7	37,489
Northern Lake States						
(MI,MN,WI)						
White/Red/Jack Pine	54.1	11.3	8.0	12.3	120.8	1,817
Spruce/Fir	40.6	8.6	8.2	32.6	261.8	3,062
Oak/Hickory	71.3	13.5	10.4	7.9	97.1	2,925
Elm/Ash/Cottonwood	50.4	9.6	8.6	25.6	179.9	1,665
Maple/Beech/Birch	70.8	13.6	10.9	26.6	134.3	5,232
Aspen/Birch	41.7	8.1	8.3	8.3	146.1	5,336
Minor Types and Nonstocked	37.4	7.4	6.2	11.0	125.9	910
All	54.5	10.7	9.2	18.2	152.8	20,946
Northern Prairie States						
(IA,IL,IN,KS,MO,ND,NE,SD)						
Ponderosa Pine	41.0	8.7	6.7	14.2	48.5	572
Oak/Pine	51.4	10.0	7.1	25.3	39.7	565
Oak/Hickory	69.6	13.1	9.4	7.6	48.9	8,266
Elm/Ash/Cottonwood	72.2	13.5	11.1	23.6	83.2	1,755
Maple/Beech/Birch	63.9	12.1	8.8	24.9	70.9	1,112
Minor Types and Nonstocked	36.5	7.3	5.8	12.5	57.2	897
All	65.2	12.4	9.1	12.6	55.5	13,166
South Central						
(AL,AR,KY,LA,MS,OK,TN,TX)						
Longleaf/Slash Pine	38.7	7.9	4.0	10.6	55.5	1,226
Loblolly/Shortleaf Pine	45.1	9.2	5.0	9.7	41.9	12,215
Oak/Pine	48.0	9.3	6.0	9.5	41.7	5,801
Oak/Hickory	61.3	11.5	7.1	6.3	38.6	20,517
Oak/Gum/Cypress	74.4	14.2	9.0	6.4	52.8	4,916
Elm/Ash/Cottonwood	56.4	10.6	7.7	5.9	49.9	2,424
Minor Types and Nonstocked	40.5	7.7	5.6	7.1	49.1	1,700
All	55.4	10.7	6.5	7.7	42.6	48,799
Southeast						
(FL,GA,NC,SC,VA)						
Longleaf/Slash Pine	34.2	7.0	3.7	9.7	110.0	4,073
Loblolly/Shortleaf Pine	47.5	9.8	5.9	9.5	72.9	9,030
Oak/Pine	50.8	9.9	5.6	9.2	61.4	4,077
Oak/Hickory	70.5	13.3	8.0	6.3	45.3	12,456
Oak/Gum/Cypress	74.3	14.3	9.2	6.4	158.0	3,992

Elm/Ash/Cottonwood	63.7	12.0	9.9	5.9	95.7	712
Minor Types and Nonstocked	46.6	9.0	6.3	6.3	100.0	1,226
All	57.7	11.2	6.8	7.8	77.1	35,567
Pacific Northwest, Westside						
(Western OR and WA)						
Douglas-fir	143.8	30.2	31.4	31.6	94.8	5,583
Fir/Spruce/Mt. Hemlock	149.0	31.5	38.3	37.9	62.1	1,286
Hemlock/Sitka Spruce	176.4	37.2	45.5	37.3	116.3	1,676
Alder/Maple	82.6	16.2	21.0	7.4	115.2	1,280
Minor Types and Nonstocked	69.5	13.8	12.0	13.4	84.8	1,302
All	133.6	27.9	30.8	28.3	95.4	11,127
Pacific Northwest, Eastside						
(Eastern OR and WA)						
Pinyon/Juniper	13.2	2.6	2.4	21.1	46.9	810
Douglas-fir	78.3	16.4	18.5	36.2	94.8	1,987
Ponderosa Pine	49.8	10.4	10.1	22.6	50.7	2,956
Fir/Spruce/Mt. Hemlock	93.2	19.7	26.4	37.9	62.1	1,627
Lodgepole Pine	41.4	8.7	9.8	21.1	52.0	1,039
Western Larch	66.6	13.9	18.0	36.0	45.1	286
Minor Types and Nonstocked	29.4	5.8	12.9	22.4	79.5	1,451
All	56.1	11.7	14.3	27.8	64.9	10,157
Pacific Southwest						
(CA)						
Pinyon/Juniper	26.0	5.1	2.0	21.1	26.3	924
Douglas-fir	165.0	34.3	34.3	35.4	40.1	433
Ponderosa Pine	54.9	11.4	10.6	35.0	41.3	396
Fir/Spruce/Mt. Hemlock	160.6	33.9	44.1	38.3	51.9	800
Lodgepole Pine	95.1	20.1	19.7	39.1	35.2	389
Redwood	200.0	41.7	42.1	60.4	53.8	261
California Mixed Conifer	116.6	24.4	28.7	37.6	49.8	3,763
Western Oak	67.3	12.8	7.6	29.2	27.6	3,792
Tanoak/Laurel	129.2	25.4	19.0	27.5	27.6	860
Minor Types and Nonstocked	34.5	6.7	8.8	23.6	37.7	1,834
All	89.4	18.2	18.1	31.9	38.1	13,451
Rocky Mountain, North						
(ID,MT)						
Douglas-fir	74.1	15.7	13.9	37.1	38.8	5,704
Ponderosa Pine	41.4	8.6	7.6	23.0	34.3	1,909
Fir/Spruce/Mt. Hemlock	68.3	14.5	21.4	37.4	44.1	4,445
Lodgepole Pine	52.5	11.2	9.9	23.2	37.2	2,710
Western Larch	61.1	12.9	14.2	36.1	34.2	467
Minor Types and Nonstocked	30.3	6.1	9.5	25.8	43.0	3,560
All	57.7	12.1	13.6	31.6	40.1	18,795
Rocky Mountain, South						
(AZ,CO,NM,NV,UT,WY)						
Pinyon/Juniper	23.0	4.7	0.9	21.1	19.7	18,818
Douglas-fir	74.1	15.7	16.7	38.0	30.9	1,798
Ponderosa Pine	48.2	10.2	8.2	23.6	24.1	3,498
Fir/Spruce/Mt. Hemlock	80.5	17.1	22.9	38.8	31.5	4,143
Lodgepole Pine	53.8	11.4	13.0	24.0	27.0	2,108
Aspen/Birch	58.8	11.4	12.2	28.5	58.8	2,490
Western Oak	20.3	3.9	2.3	27.1	38.0	2,876
Minor Types and Nonstocked	18.8	3.5	4.1	24.9	25.6	4,057
All	36.8	7.6	6.3	25.4	26.6	39,788
United States (lower 48 states)	**61.4**	**12.2**	**10.1**	**18.3**	**61.8**	**249,285**

The FIADB snapshot dataset includes some of the older periodic data from many states and, where necessary for some states, draws older survey data from other FIA-based datasets. The Resources Planning Act Assessment (RPA) database, which includes periodic summaries of state inventories, is one example. 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. 2004a). 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 and older tree-level inventories from the Southern FIA unit (Heatherly 2006). All FIADB snapshot data used for C stock estimates were obtained from USDA Forest Service (2006b). More complete information about these data is available on the Internet at the Forest Inventory and Analysis Datacenter (USDA Forest Service 2006b), and the results of these databases are found in Waddell et al. (1989), Smith et al. (2001), and Smith et al. (2004b).

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 is referred to as FORCARB2 (Birdsey and Heath 1995, Birdsey and Heath 2001, Heath et al. 2003, Smith et al. 2004a, Smith et al. 2007). 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- 195 and Table A- 196. 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 5.0 inches d.b.h. and larger are included in growing stock volume (Smith et al. 2004b). The full sets of coefficients are in Table A- 195 and Table A- 196. 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 m^3/ha.

Table A- 195: 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 Softwood	2.595	6.895	-0.074	0.886
	Loblolly/Shortleaf Pine	6.277	9.766	-0.415	0.943
	Spruce/Fir	6.424	16.903	-0.487	0.947
	White/Red/Jack Pine	3.908	12.117	-0.349	0.924
	Softwood minor types	6.277	17.234	-0.380	0.970
	Non-stocked	1.054	1.238	-0.174	0.866
Pacific Coast	Alder/Maple	8.425	4.444	0.056	0.828
	Other Western Hardwoods	8.425	10.483	0.041	0.864
	Tanoak/Laurel	8.425	10.203	-0.167	0.917
	Western Oak	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*ln(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 appendix D of the FISDB Users Guide (USDA Forest Service, 2006c).

Table A- 196: 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
	Harwood 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
	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
South	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*ln(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 appendix D of the FISDB Users Guide (USDA Forest Service, 2006c).

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-197. 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 constant ratios defined by coefficient A.

Table A-197: 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]
	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
NE	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
	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
NLS	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

[a]Prediction of ratio of understory C to live tree C is based on the equation: Ratio=exp(A-B*ln(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.
[b] Regions and types as defined in Smith et al. (2003)
[c]Maximum 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 FIA standing dead tree data because of yet unresolved problems with consistency among the state inventories. Instead, the estimates are based on a ratio of growing stock volume of live trees 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:

$$\text{Dry weight (Mg/ha)} = 1.0 \times (\text{growing stock volume})^{0.499}$$

It is multiplied by 0.5 to obtain Mg C/ha. All coefficients are provided in Table A- 198. 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. 2004a). 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-199. An example calculation for down dead wood in aspen-birch forests in the Northeast is:

C density (Mg C/ha) = (live tree C density, above- and below-ground) × (0.078) = 7.8% of live tree C

Conversion to C mass is not necessary because the live tree value is already in terms of C.

Table A- 198: 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

[a]Standing dead tree C is based on the equation: mass (Mg/ha) = A* (live-tree growing stock volume)^B. 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.
[b]Regions 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).
[c]Forest types are described in appendix D of the FISDB users guide (USDA Forest Service, 2006c). 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-199: 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	RMN	Douglas-fir	0.062
NLS	Aspen-Birch	0.081		Fir-Spruce	0.100
	Lowland Hardwood	0.061		Hardwoods	0.112
	Maple-Beech-Birch	0.076		Lodgepole Pine	0.058
	Oak-Hickory	0.077		Other Conifer	0.060
	Pine	0.072		Pinyon-Juniper	0.030
	Spruce-Fir	0.087		Ponderosa Pine	0.087
	Nonstocked	0.027		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		Ponderosa Pine	0.082
	Fir-Spruce	0.109		Nonstocked	0.020
	Hardwoods	0.042	SC	Bottomland Hardwood	0.063
	Other Conifer	0.100		Misc. Conifer	0.068

	Pinyon-Juniper	0.031
	Redwood	0.108
	Nonstocked	0.022
PWE	Douglas-fir	0.103
	Fir-Spruce	0.106
	Hardwoods	0.027
	Lodgepole Pine	0.093
	Pinyon-Juniper	0.032
	Ponderosa Pine	0.103
	Nonstocked	0.024
SE	Natural Pine	0.068
	Oak-Pine	0.072
	Planted Pine	0.077
	Upland Hardwood	0.067
	Nonstocked	0.013
	Bottomland Hardwood	0.064
	Misc. Conifer	0.081
	Natural Pine	0.081
	Oak-Pine	0.063
	Planted Pine	0.075
	Upland Hardwood	0.059
	Nonstocked	0.012

[a] Regions and types as defined in Smith et al. (2003).

Litter carbon

C of the litter layer is sampled on a subset of the FIA plots. However, the data are not yet available. 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 are 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- 194.

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 (in preparation) 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 focused on.

- **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**: 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. 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-201). 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 5 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-200. 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 product 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-200: 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
Net carbon additions per year (Tg C per year)																		
Total Harvested wood carbon	(36.2)	(34.0)	(34.0)	(33.2)	(33.7)	(32.6)	(30.9)	(32.3)	(31.4)	(32.8)	(31.1)	(25.8)	(27.1)	(26.1)	(29.0)	(29.6)	(30.0)	
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)	(12.9)	(12.3)	
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)	(11.8)	(10.8)	
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)	(1.1)	(1.5)	
Products in SWDS	(18.5)	(19.0)	(17.7)	(18.2)	(17.7)	(17.5)	(16.8)	(17.5)	(18.0)	(18.6)	(18.2)	(17.1)	(17.5)	(16.5)	(16.6)	(16.7)	(17.7)	
Solid wood products	(10.2)	(11.3)	(9.8)	(9.9)	(10.1)	(11.0)	(10.8)	(10.6)	(10.5)	(10.8)	(10.9)	(11.0)	(11.4)	(11.3)	(11.6)	(11.8)	(11.9)	
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)	(4.9)	(5.7)	
Total Carbon stocks (Tg C)																		
Total Harvested wood carbon	1,862	1,898	1,932	1,966	1,999	2,033	2,066	2,096	2,129	2,160	2,193	2,224	2,250	2,277	2,303	2,332	2,362	2,392
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	1,461
Products in SWDS	631	649	668	686	704	722	740	756	774	792	810	829	846	863	880	896	913	931

Note: Parentheses indicate net C sequestration (i.e., a net removal of C from the atmosphere).

Table A-201: 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	(130.5)	(139.3)	(132.6)
1991	(117.2)	(132.3)	(124.6)
1992	(120.9)	(132.6)	(124.7)
1993	(127.8)	(128.8)	(121.6)
1994	(130.9)	(130.9)	(123.4)
1995	(127.0)	(129.0)	(119.4)
1996	(123.4)	(123.5)	(113.2)
1997	(132.5)	(128.4)	(118.3)
1998	(140.9)	(123.8)	(115.1)
1999	(150.5)	(128.4)	(120.1)
2000	(144.3)	(121.4)	(113.9)
2001	(129.4)	(101.4)	(94.5)
2002	(136.7)	(104.3)	(99.2)
2003	(135.7)	(100.3)	(95.9)
2004	(164.0)	(110.2)	(106.3)
2005	(162.5)	(112.8)	(108.5)
2006	(147.9)	(114.8)	(110.0)

Note: Parentheses indicate net C sequestration (i.e., a net removal of C from the atmosphere).

Table A-202: 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 LULUCF 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	17,000	18,500	17,700	18,500	12,700	15,100	142,300	104,300	106,100	(132,600)
1991	13,100	18,800	14,900	19,000	11,600	15,700	144,400	108,300	110,400	(124,600)
1992	15,700	17,300	16,300	17,700	12,900	16,000	139,400	103,200	105,400	(124,700)
1993	17,000	17,900	15,000	18,200	14,500	14,800	134,600	99,400	101,400	(121,600)
1994	18,200	17,500	15,900	17,700	15,700	15,700	134,800	99,100	101,100	(123,400)
1995	17,300	17,300	15,100	17,500	16,700	17,300	137,000	101,800	104,500	(119,400)
1996	17,000	16,600	14,100	16,800	16,700	16,700	134,500	100,800	103,600	(113,200)
1997	18,800	17,400	14,700	17,500	18,000	16,900	135,400	100,400	103,200	(118,300)
1998	20,300	18,100	13,400	18,000	19,700	15,100	135,000	101,300	103,600	(115,100)
1999	22,000	19,000	14,100	18,600	21,300	15,200	134,900	99,900	102,200	(120,100)
2000	20,500	18,900	12,800	18,200	22,400	16,200	134,500	101,300	103,400	(113,900)
2001	17,300	18,000	8,700	17,100	23,000	15,300	128,600	101,000	102,800	(94,500)
2002	18,600	18,700	9,600	17,500	24,600	15,700	127,600	99,100	100,500	(99,200)
2003	19,200	17,800	9,700	16,500	26,000	16,300	124,900	97,600	98,800	(95,900)
2004	26,300	18,400	12,400	16,600	31,600	17,000	130,500	100,400	101,500	(106,300)
2005	25,800	18,600	12,900	16,700	31,800	18,200	131,800	101,000	102,200	(108,500)
2006	21,100	19,300	12,300	17,700	27,800	18,800	128,000	96,700	98,000	(110,000)

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 & forthcoming).

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 validation criteria, are shown in Table A-203. The first validation criteria 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 criteria 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.

Decay parameters for products in SWDS are shown in Table A-204. 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- 192 and Table A- 193.

Table A-203: 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

Table A-204: 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

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 (2000b), 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 uncertainty in the two most recent state or sub-state C stocks, which are summed to the national total. C stocks are based on plot-level estimates, and, therefore, uncertainty analysis starts 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 and the area expansion 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. Uncertainty surrounding plot area is assigned a symmetric triangular distribution and defined following the discussion of accuracy standards for the inventory data in USDA Forest Service (2006c). The cumulative sum of random samples from the 7 PDFs (6 C and 1 expansion) defined a PDF for each plot. These were summed to the state or sub-state total stocks.

The three most significant changes in forest ecosystem simulation methods as compared with the previous inventory probably had very little effect on the overall analysis. The first of these is the greater uncertainty (and uniform PDF) assigned to the average tree C densities assigned in some of the older data. The second change is in the triangular PDFs for understory, down dead wood, and litter, which moved the minimum value from 0 to 10 percent of the mean. Finally, true Monte Carlo simulation is used in contrast to the Latin hypercube sampling used for the previous inventory. This method is employed to facilitate the requirement of 10,000 iterations in the simulation. A part of the QA/QC process included verifying that the PDFs were adequately sampled.

Uncertainty about net C flux in HWP is based on Skog et al. (2004), with added revisions to the uncertainty analysis simulation made in conjunction with overall revisions in the HWP model (Skog in preparation). Latin hypercube sampling is the basis for the 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.

Emissions from fires

CO_2

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 CO_2 emissions from a disturbance such as fire and adding those emissions to the net CO_2 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 CO_2 emissions from disturbances such as fire. The IPCC (2003) methodology was employed to estimate emissions from forest fires. 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 at the state level for Alaska and the lower 48 states from FIA (USDA Forest Service 2006b). 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, and 2004 were obtained from the National Association of State Foresters (NASF 2007). 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, 2000, and 2001, and values for 2004 were assumed for years 2003, 2005, and 2006. For states where data were only available for *either* 2002 or 2004, the 2002 or 2004 value was assumed for years 1999-2006. 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, 2005, and 2006. Only 1990 and 1998 were available for New Mexico, so the 1990 value was assumed for years 1990-1997, while the 1998 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 fire for the lower 48 states across the 1990 to 2006 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 same was done for Alaska across the 1990 to 2006 time series.

The average C density in the lower 48 states for aboveground biomass C, dead wood C, and litter layer is 89.0 Mg/ha. A default value of 0.40 from IPCC (2003) was assumed for the amount of biomass burned by wildfire (combustion factor value). Thus, approximately 35.6 Mg/ha C is estimated to be emitted by wildfire. For Alaska, an average C density of 331 Mg/ha was estimated based on revised data from the U.S. Forest Service (Heath 2007); this translates into 132.4 Mg/ha emitted. Estimates for Mg C/ha were multiplied by estimates of forest area burned by year; the resulting estimates are displayed in Table A-205. C estimates were multiplied by 3.67 to yield CO_2 units. Total CO_2 emissions for the 48 states and Alaska in 2006 were estimated to be 267.9 Tg/yr.

Table A-205. Areas (hectares) from wildfire statistics and corresponding estimates of carbon and CO_2 (Tg/yr) emissions for the lower 48 states and Alaska[1]

	"Lower 48" states				Alaska			
Year	Reported area burned[2] (ha)	Forest area burned[3] (ha)	Carbon emitted (Tg/yr)	CO_2 emitted (Tg/yr)	Reported area burned [4] (ha)	Forest area burned[3,] (ha)	Carbon emitted (Tg/yr)	CO_2 emitted (Tg/yr)
1990	579,589	281,672	10.0	36.8	1,290,717	24,789	3.3	12.0
1991	486,807	237,174	8.4	31.0	708,465	13,597	1.8	6.6
1992	785,892	383,877	13.7	50.1	51,780	993	0.1	0.5
1993	438,865	214,909	7.7	28.1	288,588	5,530	0.7	2.7
1994	1,540,987	756,523	26.9	98.8	107,534	2,059	0.3	1.0
1995	727,051	391,380	13.9	51.1	17,792	340	0.0	0.2
1996	2,212,309	1,194,029	42.5	155.9	242,515	4,637	0.6	2.3
1997	335,914	181,758	6.5	23.7	820,258	15,672	2.1	7.6
1998	489,246	272,325	9.7	35.5	48,867	3,392	0.4	1.6
1999	1,869,918	1,047,438	37.3	136.7	406,883	28,220	3.7	13.7
2000	2,685,981	1,508,117	53.7	196.9	306,062	21,211	2.8	10.3
2001	1,356,830	763,481	27.2	99.7	88,268	6,113	0.8	3.0
2002	2,023,976	1,141,790	40.6	149.0	883,576	61,144	8.1	29.7
2003	1,358,986	707,805	25.2	92.4	243,912	6,108	0.8	3.0
2004	637,258	332,865	11.8	434	2,639,840	66,061	8.7	32.1
2005	1,629,067	853,377	30.4	111.4	1,887,407	47,197	6.2	22.9
2006	3,888,011	2,042,564	72.7	266.6	107,755	2,693	0.4	1.3

[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 (2008).

[3] Ratios calculated using forest land area estimates from FIA (USDA Forest Service 2006b) and wildland area under protection estimates from USDA Forest Service (1992) and the National Association of State Foresters (2007).
[4] Alaska Department of Natural Resources (2007).

Non-CO_2

The IPCC (2003) Tier 2 default methodology was used to calculate non-CO_2 emissions. Emissions estimates for CH_4 are calculated by multiplying the total estimated C emitted from forest burned by gas-specific emissions ratios and conversion factors. N_2O emissions are calculated in the same manner, but are also multiplied by an N-C ratio of 0.01 as recommended by IPCC (2003). The equations used are:

$$CH_4 \text{ Emissions} = (\text{C released}) \times (\text{emission ratio}) \times 16/12$$

$$N_2O \text{ Emissions} = (\text{C released}) \times (\text{N/C ratio}) \times (\text{emission ratio}) \times 44/28$$

The resulting estimates are presented in Table A-206.

Table A-206. Estimated carbon released and estimates of non-CO_2 emissions (Tg/yr) for U.S. forests[1]

Year	C emitted (Tg/yr)	CH_4 emitted (Tg/yr)	N_2O (Tg/yr)
1990	13.310	0.213	0.001
1991	10.244	0.164	0.001
1992	13.797	0.221	0.002
1993	8.383	0.134	0.001
1994	27.205	0.435	0.003
1995	13.978	0.224	0.002
1996	43.121	0.690	0.005
1997	8.546	0.137	0.001
1998	10.144	0.162	0.001
1999	41.025	0.656	0.005
2000	56.497	0.904	0.006
2001	27.989	0.448	0.003
2002	48.743	0.780	0.005
2003	26.007	0.416	0.003
2004	20.597	0.330	0.002
2005	36.629	0.586	0.004
2006	73.072	1.169	0.008

[1] Calculated based on C emission estimates in Table A-205 and default factors in IPCC (2003)

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 after 1997.

The soil C inventory uses a Tier 3 Approach 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 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 application 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.
- The model has input data requirements that were obtainable from existing national databases in the United States. The exceptions are CRP enrollment after 1997 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

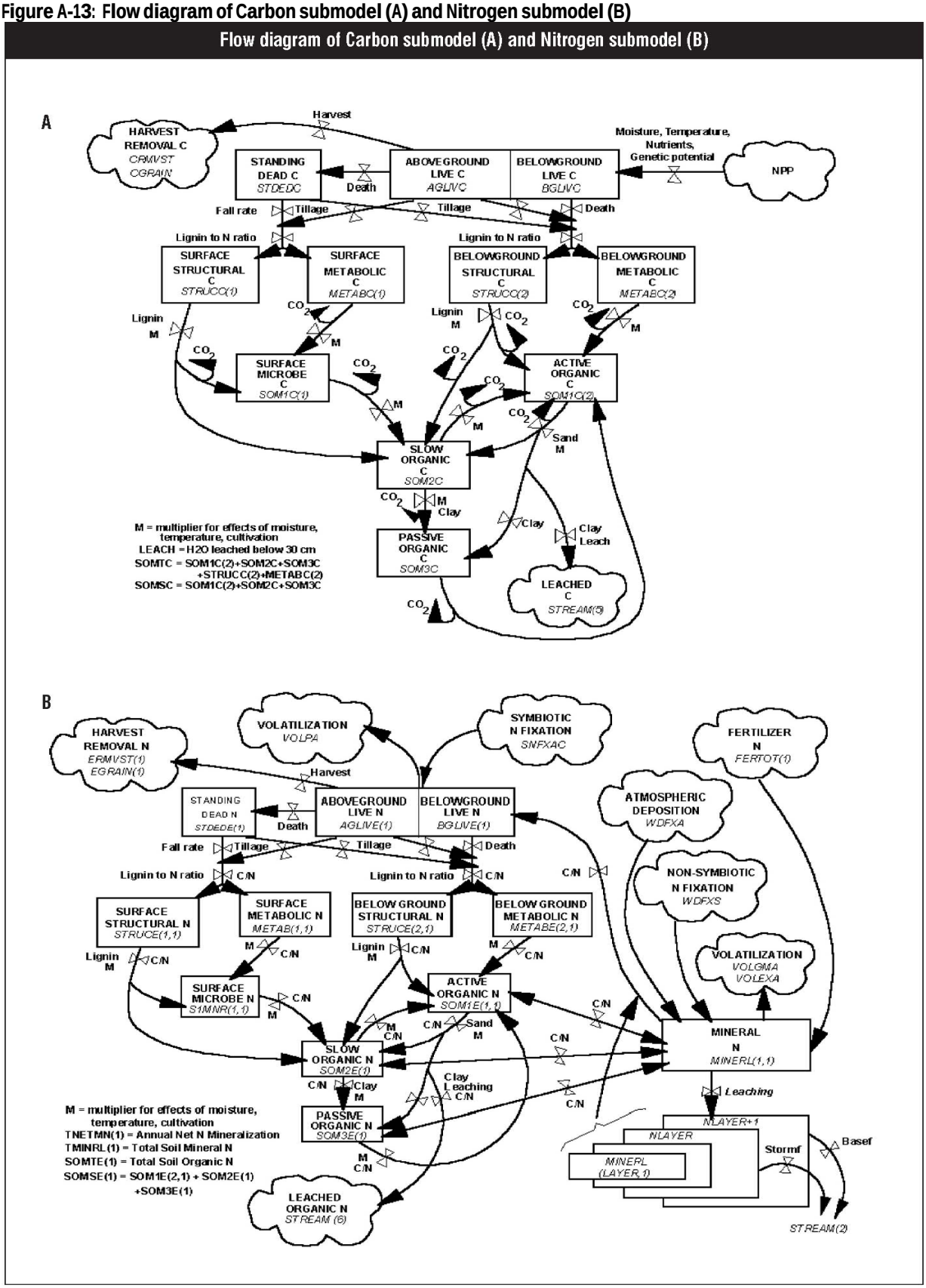
The Century model simulates C (and also N, P, and S) dynamics, soil temperature, and water dynamics for cropland, grassland, forest, and savanna (mixed forest-grassland) systems. For the U.S. inventory application, only C and N dynamics have been included for several reasons: to simplify the analysis 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 consists of 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 (termed metabolic and structural) and three soil organic matter (SOM) pools (termed 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, whereby 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)



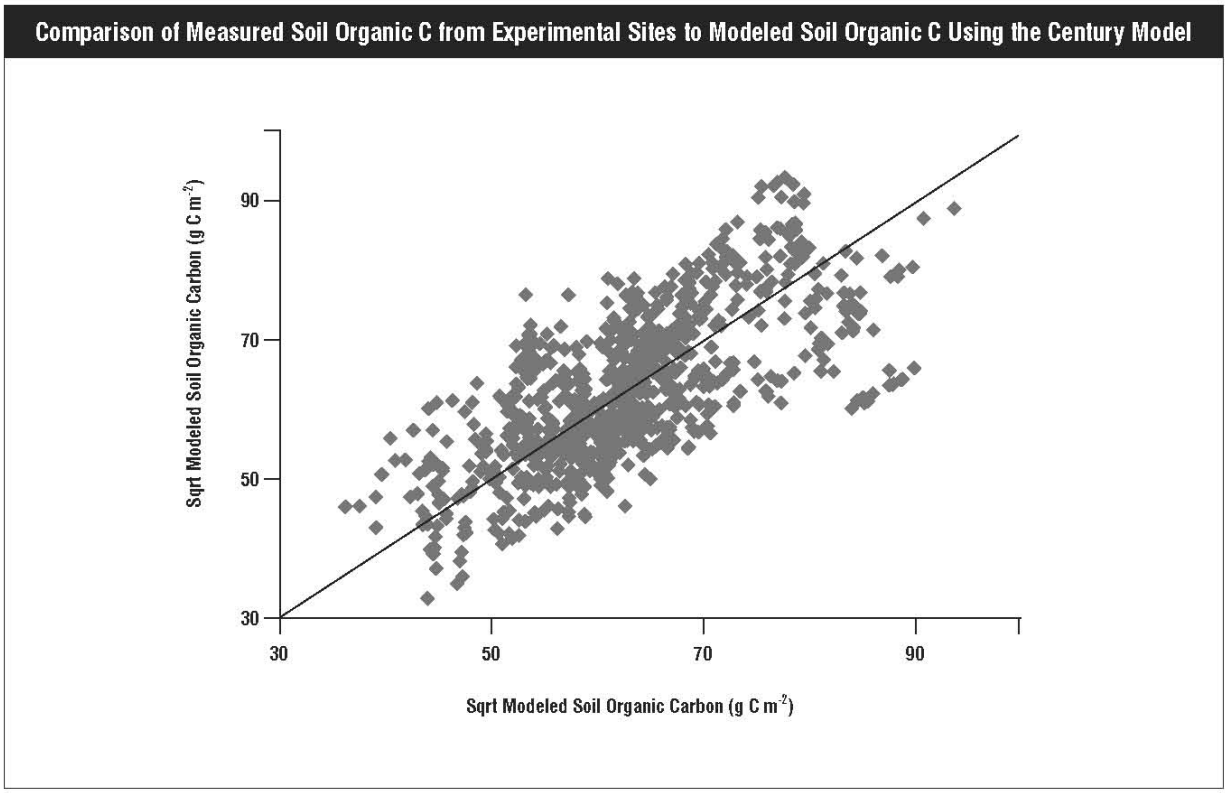
The plant growth submodel simulates C assimilation through photosynthesis, N uptake, dry matter production, partitioning of C within the crop or forage, senescence, and mortality. The primary function of the growth submodel is to estimate the amount, type, and timing of organic matter inputs to soil 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 scrubs). Only the herbaceous plant submodel is currently used in the agricultural inventory applications. Maximum monthly net primary production (NPP) rate (i.e., a crop and forage species/variety parameter 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 carbon 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 uncertainity associated with Century model results as described in Step 2b of this Annex. Additional discussion is provided in Ogle et al. (2007).

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 method has been developed to estimate C stock changes and CO_2 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 IPCC inventory 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. For this inventory, 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), and, thus, these measurements formed the basis to estimate reference C stocks. 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 CO_2 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, comprised of less common crop systems (e.g., horticultural, vegetable, tobacco, rice) and all agricultural land occurring on drained organic soils, were developed using the Tier 2 approach. Tier 2 methods were 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 1997. Most of the activity data sources were common to the Tier 2 and Tier 3 approaches, and, hence, they are described in an integrated fashion 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 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 land base was 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 of the inventory 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.[56] 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 (further elaboration provided in Step 1a). The areas modeled with Century and those estimated with the Tier 2 IPCC method were also subdivided. Parcels of land were allocated to the Tier 2 approach if: they occurred on organic soils; had a non-agricultural use such as forest and federal lands;[57] contained mineral soils that are 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 produced vegetables, perennial/horticultural crops, tobacco or rice, which was either grown continuously or in rotation with other crops. Finally, additional data were collected specific for each method 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, and classifying parcels into *Cropland Remaining Cropland*, *Land Converted to Cropland*, *Grassland Remaining Grassland*, and *Land Converted to Grassland* (USDA-NRCS 2000). 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). An extensive amount of soils, land-use, and land management data are collected during each survey, which occurs every five years (Nusser et al. 1998).[58] Primary sources for data include aerial photography and remote sensing materials as well as field visits and county office records.

NRI points were included in the land base if they were identified as cropland or grassland[59] in the 1992 or 1997 surveys (Table A-207). Overall, more than 400,000 NRI points were included in the inventory calculations. Each point represents a specific land parcel based upon the weighted expansion factors. To subdivide land parcels into *Cropland Remaining Cropland*, *Land Converted to Cropland*, *Grassland Remaining Grassland*, and *Land Converted to Grassland*, the time series was divided into four inventory time periods: 1980-1984, 1985-1989, 1990-

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[56] NRI points were classified according to land-use history records starting in 1982 when the NRI survey began. Therefore, the classification was based on less than 20 years of recorded land-use history for the time series from 1982 to 2001.

[57] 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).

[58] In the current inventory, NRI data only provide land-use and management statistics through 1997, but more recent data for 1998 through 2003 is currently being incorporated into the analysis.

[59] 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).

1994 and 1995-2000, using NRI data from 1982, 1987, 1992, and 1997, respectively.[60] At the end of each inventory time period, lands occurring on mineral and organic soils were classified into the four land use/land-use change categories based on whether the parcel was in the same use for at least the previous 20 years, or had been converted from another land use.[61] 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). The total agricultural land base was 386 million hectares.

Table A-207: Total Land Areas for the Agricultural Soil C Inventory, Subdivided by Land Use and Land Use Change Categories (Million Hectares)

	Land Areas (10^6 ha)					
	1990-94			1995-2000		
Category	**Century**	**IPCC**	**Total**	**Century**	**IPCC**	**Total**
Mineral	**339.03**	**46.01**	**385.04**	**339.03**	**46.01**	**385.04**
Cropland Remaining Cropland	127.61	29.20	156.81	124.29	28.00	152.29
Land Converted to Cropland	7.57	2.33	9.90	10.68	1.25	11.93
Grassland Remaining Grassland	197.72	8.00	205.72	194.95	6.24	201.19
Land Converted to Grassland	6.13	4.02	10.15	9.11	2.44	11.55
Non-Agricultural Uses[1]	0.00	2.46	2.46	0.00	8.08	8.08
Organic	**0.00**	**1.34**	**1.34**	**0.00**	**1.34**	**1.34**
Cropland Remaining Cropland	0.00	0.70	0.70	0.00	0.72	0.72
Land Converted to Cropland	0.00	0.07	0.07	0.00	0.03	0.03
Grassland Remaining Grassland	0.00	0.50	0.50	0.00	0.48	0.48
Land Converted to Grassland	0.00	0.04	0.04	0.00	0.07	0.07
Non-Agricultural Uses[1]	0.00	0.04	0.04	0.00	0.05	0.05
Total	**339.03**	**47.35**	**386.38**	**339.03**	**47.35**	**386.38**

[1] These non-agricultural uses were converted to or from cropland or grassland during the early or late 1990s (i.e., were cropland or grassland in either 1992 or 1997 according to the NRI).

Management System Classification—NRI points on mineral soils were classified into specific crop rotations, continuous pasture/rangeland, and other non-agricultural uses based on the survey data (Table A-2). For model calculations, land-use and management activities were grouped into inventory time periods (i.e., time "blocks") for 1980-1984, 1985-1989, 1990-1994 and 1995-2000, using NRI data from 1982, 1987, 1992, and 1997, respectively.

Crops were reported for the NRI inventory year and the three previous years for each NRI point location; hence, the full crop sequence is lacking one year in five. The most recent national-level data available for NRI were for 1997; crop rotations existing in 1997 were, thus, extended to 2006 in order to cover the last inventory time period. In addition, NRI differentiates between improved and unimproved grassland, where improvements include irrigation and interseeding of legumes.

Table A-208: Total Land Areas by Land-Use and Management System for the U.S. Agricultural Land Base on Mineral Soils (Million Hectares)

	Land Areas (10^6 ha)					
	1990-94			1995-2000		
Land-Use/Management System	**Century**	**IPCC**	**Total**	**Century**	**IPCC**	**Total**
Cropland Systems	**134.58**	**31.53**	**166.11**	**135.13**	**29.25**	**164.38**
Irrigated Crops	9.55	7.27	16.82	9.58	6.91	16.49
Continuous Row Crops	36.90	4.12	41.02	39.68	3.63	43.31
Continuous Small Grains	11.76	1.25	13.01	13.51	1.04	14.55
Continuous Row Crops and Small Grains	14.48	2.30	16.78	12.66	1.95	14.61
Row Crops in Rotation with Hay and/or Pasture	3.37	0.30	3.67	3.41	0.23	3.65
Small Grains in Rotation with Hay and/or Pasture	0.85	0.06	0.91	0.91	0.06	0.96
Row Crops and Small Grains in Rotation with Hay and/or Pasture	0.31	0.03	0.34	0.31	0.04	0.35
Vegetable Crops	0.00	2.90	2.90	0.00	3.16	3.16

[60] The first two inventory time periods occur before the 1990 baseline year of the reporting period and, therefore, are not included in this report.

[61] NRI points were classified according to land-use history records starting in 1982 when the NRI survey began. Therefore, the classification was based on less than 20 years of recorded land-use history for the time series from 1982 to 2001.

Low Residue Annual Crops (e.g., Tobacco or Cotton)	4.42	0.87	5.29	4.46	1.03	5.49
Small Grains with Fallow	17.60	2.01	19.61	14.34	1.31	15.65
Row Crops and Small Grains with Fallow	0.69	1.72	2.41	0.56	1.80	2.37
Row Crops with Fallow	2.09	0.52	2.60	1.66	0.34	2.01
Miscellaneous Crop Rotations	1.58	0.54	2.12	1.47	0.43	1.90
Continuous Rice	0.00	0.34	0.34	0.00	0.31	0.31
Rice in Rotation with other crops	0.00	1.78	1.78	0.00	1.91	1.91
Continuous Perennial or Horticultural Crops	0.00	2.57	2.57	0.00	2.50	2.50
Continuous Hay	5.56	0.59	6.15	6.70	0.50	7.21
Continuous Hay with Legumes or Irrigation	13.59	1.31	14.91	13.68	1.12	14.80
CRP	11.84	1.03	12.86	12.19	0.96	13.16
Aquaculture	0.00	0.01	0.01	0.00	0.01	0.01
Grassland Systems	**204.45**	**12.02**	**216.46**	**203.9**	**8.68**	**212.58**
Rangeland	158.66	5.98	164.64	158.94	5.16	164.10
Continuous Pasture	31.24	3.76	35.00	32.03	2.49	34.52
Continuous Pasture with Legumes or Irrigation (i.e., improved)	13.69	2.25	15.94	12.88	1.03	13.91
CRP	0.86	0.02	0.88	0.05	0.00	0.05
Non-Agricultural Systems	**0.00**	**2.46**	**2.46**	**0.00**	**8.08**	**8.08**
Forest	0.00	1.53	1.53	0.00	3.95	3.95
Federal	0.00	0.01	0.01	0.00	0.05	0.05
Water	0.00	0.11	0.11	0.00	0.25	0.25
Settlements	0.00	0.04	0.04	0.00	2.46	2.46
Miscellaneous	0.00	0.77	0.77	0.00	1.36	1.36
Total	**339.03**	**46.01**	**385.04**	**339.03**	**46.01**	**385.04**

As discussed above, Century was used to model NRI points on most mineral soils. The exceptions were for land that had one or more years of vegetable crops, tobacco, perennial/horticultural crops, and/or rice, in addition to soils that were classified as very or extremely gravelly, cobbly, or shaley (i.e., where greater than 35 percent of the soil volume is composed of gravel, cobbles or shale), regardless of the crops present. Change in soil organic C for these NRI point locations were estimated using the IPCC Tier 2 method. Century was also used to estimate stock changes in grassland, except for soils that were classified as very or extremely gravelly, cobbly or shaley (Table A-208). 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. The IPCC Tier 2 method was used to estimate stock changes for this portion of the land base, as well as land converted from non-agricultural uses to crop or grassland during the reporting period. Again, Century has not been fully tested for these types of transitions.

Organic soils are categorized into land-use systems based on drainage for purposes of estimating C losses (IPCC 2006). Undrained soils are treated as having no loss of organic C for purposes of the inventory. 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-209).

Table A-209: Total Land Areas for Drained Organic Soils By Land Management Category and Climate Region (Million Hectares)

	Land Areas (10^6 ha)					
	Cold Temperate		Warm Temperate		Tropical	
IPCC Land-Use Category for Organic Soils	**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[2]	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**

[1] Urban, 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

Management System Classification—Based on the classification of NRI data described in Step 1a, 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.

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. Due to the effects on soil C of the disturbance associated with periodic tillage, estimates of the area under continuous no-till were provided by experts at CTIC (Towery 2001).

Tillage practices were grouped into 3 categories: intensive, moderate, and no-tillage. Intensive 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 tillage 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. Moderate 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 intensive, reduced and no-till from the 1980s through 1990s. Generally, the fraction of intensive 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 intensive tillage to reduced and no-till, and reduced tillage to no-till. The remaining amount of cropland was assumed to have no tillage change (e.g., intensive tillage remained in intensive tillage). Transition matrices were constructed from CTIC data to represent tillage changes for two time periods, combining the first two and the second two inventory time periods as single management blocks (i.e., 1980-1989, 1990-2000). Areas in each of the three tillage classes—conventional till (CT), reduced till (RT), no till (NT)—in 1989 (the first year the CTIC data were available) were used for the first time period, and data from 1997 were used for the second time period. Percentage areas of cropland in each county were calculated for each possible transition (e.g., CT→CT, CT→RT, CT→NT, RT→CT, 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→CT 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 intensive tillage over the two decades, a 15 percent chance of a transition from intensive to reduced tillage and a 5 percent chance of a transition from intensive 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 intensive tillage over the entire time period if the value was greater than or equal to 0 and less than 80, a transition from intensive to reduced till if the random draw was equal to or greater than 80 and less than 95, or a transition from intensive 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 major producing states. Note that all wheat data were combined into one category and assumed to represent all small grains. 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 nitrogen 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.

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 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 two time blocks (1980-1989, 1990-2000) 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

Management System Classification—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 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.

Tillage Practices—PDFs were also 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, regional-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 Step1b, 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 amount 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 1997

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 1997.

Total sewage sludge generation data for 1988, 1996, 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 and 2006 (Bastian 2007), so the 1990 through 2004 data were linearly extrapolated for those two 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 1997 was based on the amount of land under active contracts from 1998 through 2006 relative to 1997 (Barbarika 2006).

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 1895-2006. 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 (50-2000 μm), silt (2-50 μm), and clay (< 2 μm) 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.[62] 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 function that varies from 0.3 under completely anaerobic conditions to 1.0 under fully aerobic conditions (default parameters in Century).[63]

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-210). Six of these climate zones occur in the conterminous United States and Hawaii (Eve et al. 2001).

Table A-210: 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

[62] Artificial drainage (e.g., ditch- or tile-drainage) is simulated as a management variable.

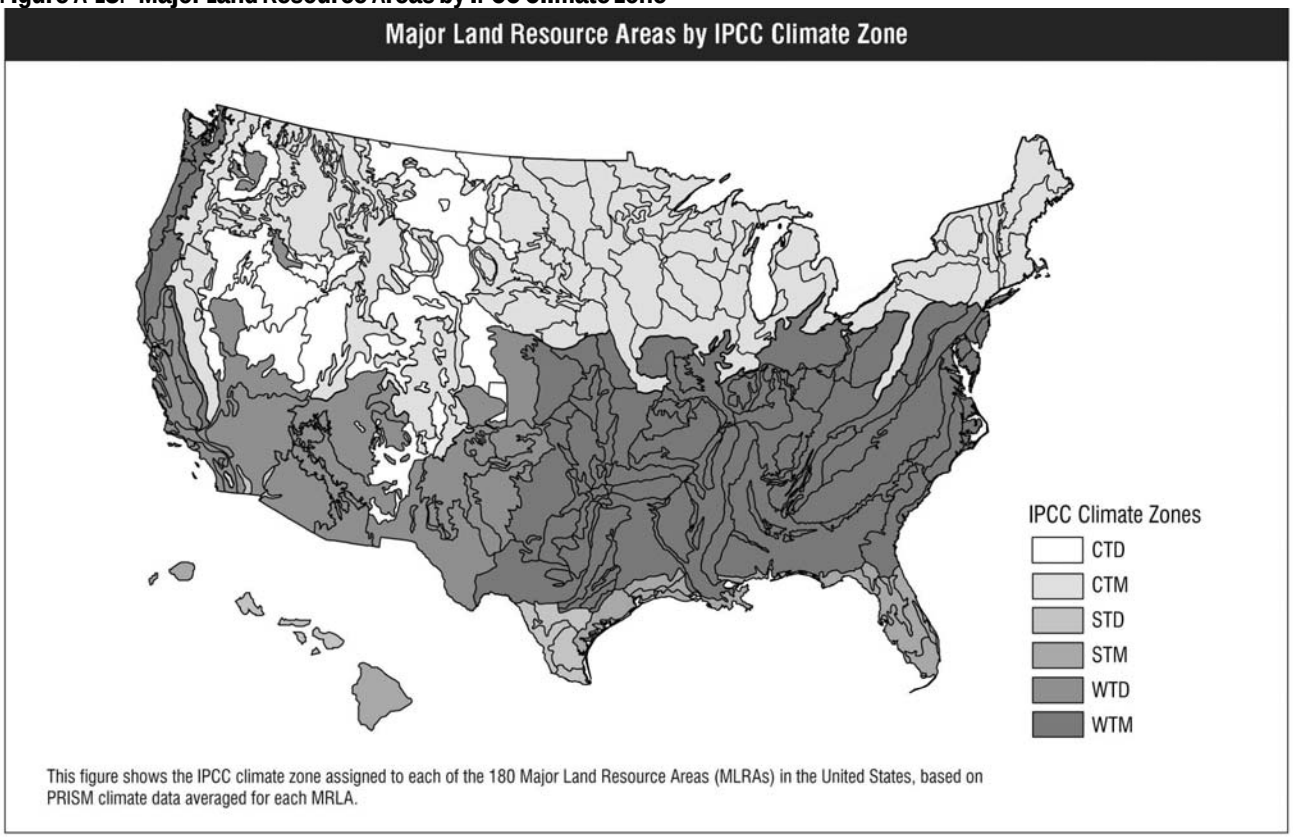
[63] Hydric soils are primarily subject to anaerobic conditions outside the plant growing season (i.e., in the absence of active plant water uptake). Soils that are water-logged during much of the year are typically classified as organic soils (e.g., peat), which are not simulated with the Century model.

Sub-Tropical, Moist (w/short dry season)*	> 20	1,000 – 2,000	< 5

* 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. Average annual precipitation and average annual temperature (4×4 km grid) were averaged (weighted by area) for each of the 180 MLRAs in the United States to assign an IPCC climate zone to each MLRA (Figure A-15). MLRAs represent geographic units with relatively similar soils, climate, water resources, and land uses (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 data from the National Soil Survey Characterization Database (NRCS 1997) (Table A-211). 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-211: U.S. Soil Groupings Based on the IPCC Categories and Dominant Taxonomic Soil, and Reference Carbon Stocks (Metric Tons C/ha)

		Reference Carbon Stock in Climate Regions					
IPCC Inventory Soil Categories	USDA Taxonomic Soil Orders	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)
Organic Soils*	Histosols	NA	NA	NA	NA	NA	NA

* 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 part of the inventory methods 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 first inventory time period (i.e., 1980-84). 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.

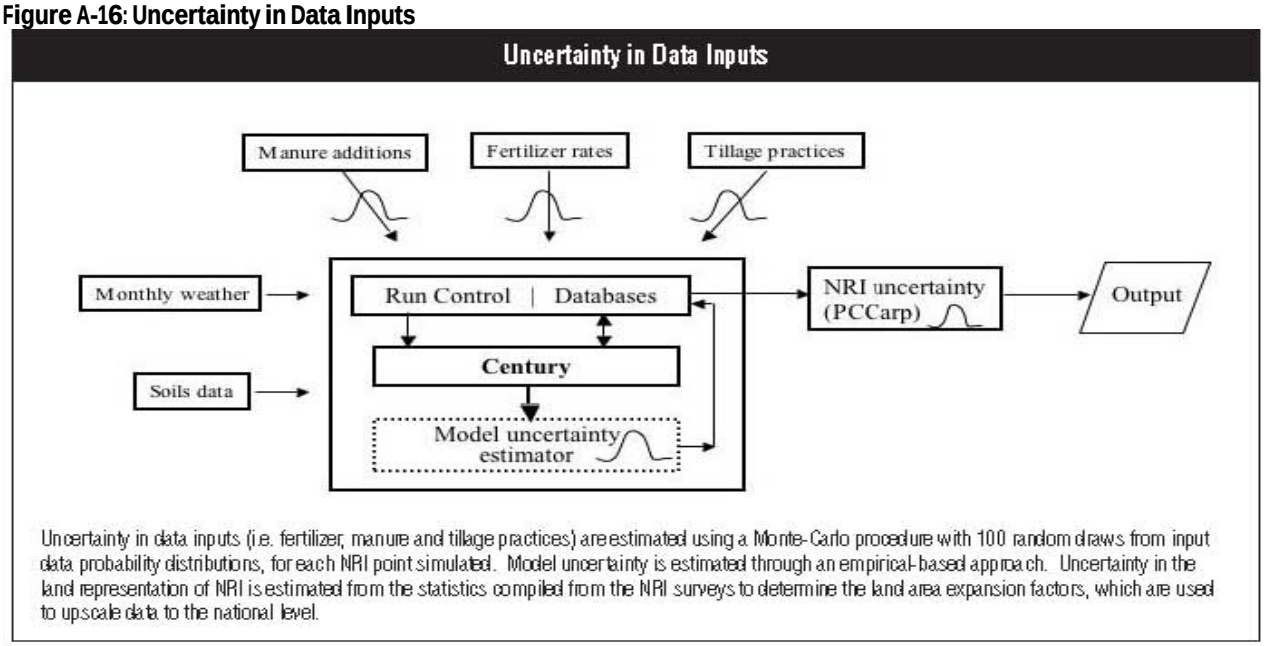
The first step involves running the model to a steady-state condition (e.g., equilibrium) under native vegetation, with long-term mean climate represented by 30-yr averages of the PRISM data (1960-1990), and the soil physical attributes for the NRI points. Native vegetation is represented at the MLRA level for pre-settlement time periods in the United States. The model was run for 7000 years to 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 through to 2000.[64] 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



Inventory points within a county that shared the same land-use/management histories and soil type were aggregated for simulation purposes (i.e., data inputs to the model were identical and, therefore, the model results were also identical). For the 370,738 NRI points representing non-federal cropland and grassland, there was a total of 170,279 clustered points that were simulated using Century (i.e., which represent the unique combinations of climate, soils, land use, and management in the modeled data set).

Evaluating uncertainty was an integral part of the analysis, and was comprised of 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). 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. 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 14 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

[64] The estimated soil C stock change in 2000 is currently assumed to represent the changes between 2001 and 2006. New estimates will be available by expert review based on more recent NRI land use activity data.

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, which explained significant variation in the relationship between modeled and measured stocks (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. 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. 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 cluster 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 of a particular cluster. 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 (Table A-207), soil organic C stocks ranged from losses of 13.9 Tg CO_2 Eq. to gains of 64.0 Tg CO_2 Eq. annually, depending on the land-use/land-use change category and inventory time period. Estimates and uncertainties are provided in Table A-212.

Table A-212: Annual Change in Soil Organic Carbon Stocks (95% Confidence Interval) for the Land Base Simulated with the Tier 3 Century Model-Based Approach (Tg CO_2 Eq.)

Soil Type	1990-1994	1995-2006
Mineral Soils		
Cropland Remaining Cropland	(55.84)	(64.02)
95% C.I.	(67.14) to (44.59)	(74.14) to (53.94)
Land Converted to Cropland	8.14	2.57
95% C.I.	7.55 to 8.76	2.02 to 3.08
Grassland Remaining Grassland	(4.80)	13.86
95% C.I.	(6.71) to (2.86)	12.43 to 15.25
Land Converted to Grassland	(10.19)	(12.22)
95% C.I.	(10.5) to (9.90)	(12.50) to (11.92)

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 CO_2 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 this 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-213). 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.[65] 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 re-estimate factor values for these systems, 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- 213: Stock Change Factors for the United States and the IPCC Default Values Associated with Management Impacts on Mineral Soils

		U.S. Factor			
	IPCC default	Warm Moist Climate	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

[65] 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.

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 aquic soils at 1.7. The U.S. analysis showed no significant differences between aquic and non-aquic 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-214). 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/cm^3) (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-214).

Table A-214: 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-215). PDFs were constructed as normal densities based on the mean C loss rates and associated variances.

Table A-215: Carbon Loss Rates for Organic Soils Under Agricultural Management in the United States, and IPCC Default Rates (Metric Ton C/ha-yr)

	Cropland		Grassland	
Region	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 CO_2 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.[66] 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 2006 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).

[66] The difference in C stocks is divided by 20 because the stock change factors represent change over a 20-year time period.

For organic soils, annual losses of CO_2 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 2006.

Mineral soils for the land base estimated with the Tier 2 approach sequestered about 1.7 to 3.0 Tg CO_2 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 CO_2 Eq. annually. Minerals soils in *Grassland Remaining Grassland* had small gains of about 0.2 to 0.3 Tg CO_2 Eq. annually and sequestered from 4.5 to 5.0 Tg CO_2 Eq. annually in *Land Converted to Grassland*. Organic soils lost about 27.4 to 27.7 Tg CO_2 Eq. annually in *Cropland Remaining Cropland* and 2.4 to 2.6 Tg CO_2 Eq. annually in *Land Converted to Cropland*, as well as an additional 3.7 to 3.9 Tg CO_2 Eq. annually in *Grassland Remaining Grassland* (Table A-216) and 0.5 to 0.9 Tg CO_2 Eq. annually in *Land Converted to Grassland*. Estimates and uncertainties are provided in Table A-216.

Table A-216: 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 CO_2 Eq. /yr)

Soil Type	1990-1992	1993-2006
Mineral Soils		
Cropland Remaining Cropland	(1.7)	(3.0)
95% C.I.	(2.6) to 5.8	(-6.9) to 0.8
Land Converted to Cropland	4.2	4.1
95% C.I.	2.5 to 5.98	2.3 to 5.8
Grassland Remaining Grassland	(0.3)	(0.2)
95% C.I.	(0.6) to (0.1)	(0.3) to 0.04
Land Converted to Grassland	(4.5)	(5.0)
95% C.I.	(6.5) to (2.74)	(6.96) to (2.84)
Organic Soils		
Cropland Remaining Cropland	27.4	27.7
95% C.I.	18.3 to 39.4	15.8 to 36.9
Land Converted to Cropland	2.4	2.6
95% C.I.	1.4 to 3.8	1.2 to 3.7
Grassland Remaining Grassland	3.9	3.7
95% C.I.	1.97 to 6.4	1.2 to 5.5
Land Converted to Grassland	0.5	0.9
95% C.I.	0.22 to 0.8	0.2 to 1.8

Step 4: Compute Additional Changes in Soil Organic C Stocks Due to Organic Amendments and CRP Enrollment after 1997

There are two additional land-use and management activities in U.S. agriculture 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 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-217), 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., $[50\times1.4\times1.11 - 50\times1.4]/20 = 0.38$). From 1990 through 2006, sewage sludge applications in agricultural lands increased SOC storage from 0.6 to 1.2 Tg CO_2 Eq./year (Table A-217). 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 1997 for mineral soils. Relative to the enrollment in 1997, the total area in the Conservation Reserve Program declined in 1998 through 2000, and then increased 2001 to 2006, leading to an additional enrollment of 1.4 million ha over the

five-year period (USDA-FSA 2007). 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- 213) 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., [50×1.2–50]/20 = 0.5). The change in enrollment generated emissions in 1998 through 2000, but with increased enrollment from 2001 to 2006, agricultural land sequestered an additional 0.7 to 2.5 Tg CO_2 Eq. annually between 2001 and 2006, respectively (Table A-218). 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 CO_2 Emissions and Removals from Agricultural Lands

The sum of total CO_2 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-218. Agricultural soils, both organic and mineral, were estimated to sequester 32 Tg CO_2 Eq. in 1990, and this rate had increased slightly by the end of the reporting period in 2006 to a net sequestration rate of 33 Tg CO_2 Eq.

The total stock change (see Figures 7-4, 7-5, 7-6, and 7-7 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 sequestration rates occurred in the southeastern and north-central United States, but states with highest net levels of C sequestration include Iowa, Missouri, Nebraska, North Dakota, and South Dakota (Table A-219). 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, 1993-2006

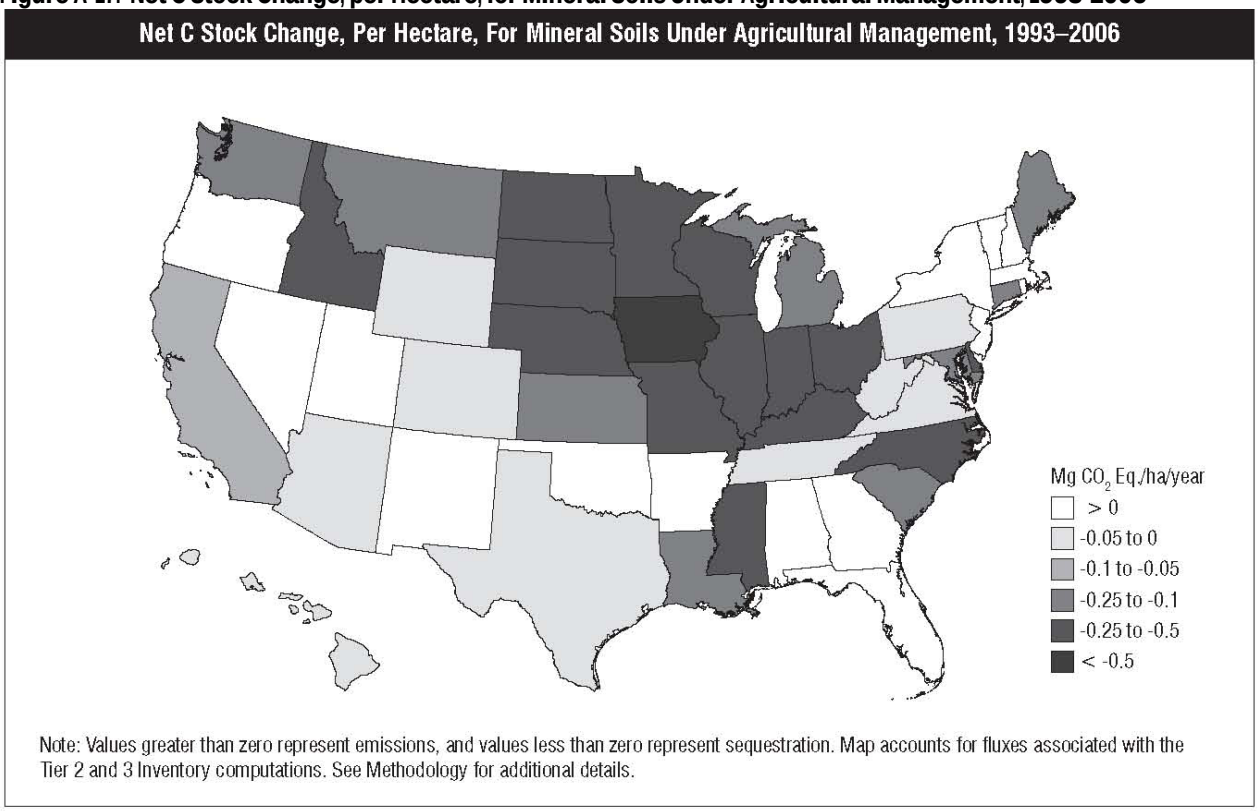


Figure A-18: Net C Stock Change, per Hectare, for Organic Soils Under Agricultural Management, 1993-2006

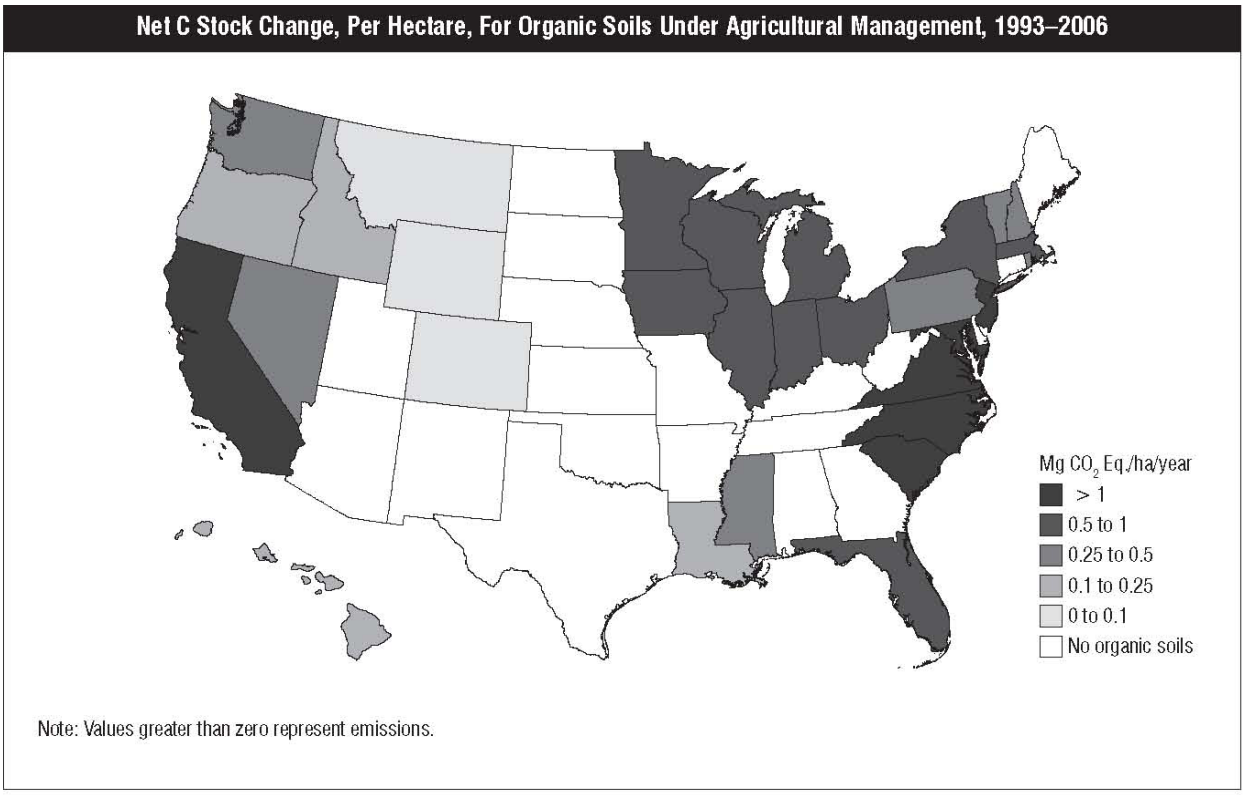


Table A-217: Assumptions and Calculations to Estimate the Contribution to Soil Organic Carbon Stocks from Application of Sewage Sludge to Mineral Soils

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
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	98,367	101,499
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
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	806,288	831,955
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
Contribution to Soil C ($TgCO_2$/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)**	**(1.16)**
95% C.I. Range	**(0.91) to (0.30)**	**(0.97) to (0.32)**	**(1.03) to (0.34)**	**(1.08) to (0.36)**	**(1.13) to (0.38)**	**(1.18) to (0.39)**	**(1.23) to (0.41)**	**(1.29) to (0.43)**	**(1.34) to (0.45)**	**(1.39) to (0.46)**	**(1.43) to (0.48)**	**(1.48) to (0.49)**	**(1.52) to (0.51)**	**(1.57) to (0.52)**	**(1.61) to (0.54)**	**(1.69) to (0.56)**	**(1.74) to (0.58)**

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 1993-2000.

[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-218: 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 CO_2 Eq.)

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Net emissions based on Tier 3 Century-based analysis (Step 2)																	
CRC	(55.84)	(55.84)	(55.84)	(55.84)	(55.84)	(64.02)	(64.02)	(64.02)	(64.02)	(64.02)	(64.02)	(64.02)	(64.02)	(64.02)	(64.02)	(64.02)	(64.02)
LCC	8.14	8.14	8.14	8.14	8.14	2.57	2.57	2.57	2.57	2.57	2.57	2.57	2.57	2.57	2.57	2.57	2.57
GRG	(4.80)	(4.80)	(4.80)	(4.80)	(4.80)	13.86	13.86	13.86	13.86	13.86	13.86	13.86	13.86	13.86	13.86	13.86	13.86
LCG	(10.19)	(10.19)	(10.19)	(10.19)	(10.19)	(12.22)	(12.22)	(12.22)	(12.22)	(12.22)	(12.22)	(12.22)	(12.22)	(12.22)	(12.22)	(12.22)	(12.22)
Net emissions based on the IPCC Tier 2 analysis (Step 3)																	
Mineral Soils																	
CRC	(1.65)	(1.65)	(1.65)	(3.02)	(3.02)	(3.02)	(3.02)	(3.02)	(3.02)	(3.02)	(3.02)	(3.02)	(3.02)	(3.02)	(3.02)	(3.02)	(3.02)
LCC	4.16	4.16	4.16	4.14	4.14	4.14	4.14	4.14	4.14	4.14	4.14	4.14	4.14	4.14	4.14	4.14	4.14
GRG	(0.31)	(0.31)	(0.31)	(0.15)	(0.15)	(0.15)	(0.15)	(0.15)	(0.15)	(0.15)	(0.15)	(0.15)	(0.15)	(0.15)	(0.15)	(0.15)	(0.15)
LCG	(4.54)	(4.54)	(4.54)	(4.99)	(4.99)	(4.99)	(4.99)	(4.99)	(4.99)	(4.99)	(4.99)	(4.99)	(4.99)	(4.99)	(4.99)	(4.99)	(4.99)
Organic Soils																	
CRC	27.43	27.43	27.43	27.67	27.67	27.67	27.67	27.67	27.67	27.67	27.67	27.67	27.67	27.67	27.67	27.67	27.67
LCC	2.42	2.42	2.42	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64
GRG	3.85	3.85	3.85	3.69	3.69	3.69	3.69	3.69	3.69	3.69	3.69	3.69	3.69	3.69	3.69	3.69	3.69
LCG	0.47	0.47	0.47	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.88
Additional changes in net emissions from mineral soils based on application of sewage sludge to agricultural land (Step 4)																	
GRG	(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)	(1.16)
Additional changes in net emissions from mineral soils based on additional enrollment of CRP land (Step 4)																	
CRC	-	-	-	-	-	-	-	-	1.91	2.13	0.94	(0.66)	(0.94)	(1.08)	(1.49)	(1.64)	(2.45)
Total Stock Changes by Land Use/Land-Use Change Category (Step 5)																	
CRC	(30.06)	(30.06)	(30.06)	(31.20)	(31.20)	(39.38)	(39.38)	(39.38)	(37.47)	(37.24)	(38.43)	(40.04)	(40.32)	(40.46)	(40.86)	(41.01)	(41.83)
LCC	14.72	14.72	14.72	14.92	14.92	9.35	9.35	9.35	9.35	9.35	9.35	9.35	9.35	9.35	9.35	9.35	9.35
GRG	(1.87)	(1.91)	(1.95)	(1.98)	(2.02)	16.61	16.58	16.54	16.50	16.47	16.45	16.42	16.39	16.36	16.33	16.28	16.24
LCG	(14.26)	(14.26)	(14.26)	(14.30)	(14.30)	(16.32)	(16.32)	(16.32)	(16.32)	(16.32)	(16.32)	(16.32)	(16.32)	(16.32)	(16.32)	(16.32)	(16.32)
Total	(31.5)	(31.5)	(31.6)	(32.6)	(32.6)	(29.7)	(29.8)	(29.8)	(27.9)	(27.7)	(29.0)	(30.6)	(30.9)	(31.1)	(31.5)	(31.7)	(32.6)

Table A-219: Soil C Stock Change for Mineral and Organic Soils during 2006 within individual states (Tg CO_2 Eq.))

State	Mineral Soil	Organic Soil	Total
AL	0.39	-	0.39
AR	0.06	-	0.06
AZ	(0.57)	-	(0.57)
CA	(0.83)	2.29	1.46
CO	(0.65)	0.00	(0.65)
CT	(0.03)	-	(0.03)
DE	(0.06)	-	(0.06)
FL	0.45	10.84	11.28
GA	0.01	-	0.01
HI	(0.02)	0.25	0.24
IA	(6.57)	0.75	(5.82)
ID	(1.79)	0.11	(1.68)
IL	(4.98)	0.54	(4.44)
IN	(3.11)	2.93	(0.18)
KS	(4.04)	-	(4.04)
KY	(1.40)	-	(1.40)
LA	(0.78)	0.07	(0.71)
MA	0.01	0.03	0.04
MD	(0.15)	0.03	(0.11)
ME	(0.03)	-	(0.03)
MI	(0.65)	2.72	2.07
MN	(3.78)	7.30	3.51
MO	(5.25)	-	(5.25)
MS	(1.22)	0.00	(1.22)
MT	(4.02)	0.11	(3.91)
NC	(0.81)	2.25	1.45
ND	(6.16)	-	(6.16)
NE	(5.73)	-	(5.73)
NH	0.01	0.01	0.02
NJ	0.01	0.01	0.02
NM	0.40	-	0.40
NV	0.15	0.00	0.15
NY	1.07	0.61	1.68
OH	(1.69)	0.42	(1.27)
OK	0.45	-	0.45
OR	0.04	0.12	0.16
PA	(0.14)	0.01	(0.13)
RI	0.00	0.00	0.01
SC	(0.22)	0.04	(0.19)
SD	(6.47)	-	(6.47)
TN	(0.14)	-	(0.14)
TX	(0.30)	-	(0.30)
UT	0.11	-	0.11
VA	(0.01)	0.02	0.01
VT	0.24	0.00	0.24
WA	(1.33)	0.26	(1.07)
WI	(2.17)	2.88	0.71
WV	(0.03)	-	(0.03)
WY	(0.29)	0.01	(0.28)

Note: Parentheses indicate net sequestration. Estimates do not include soil C stock change associated with CRP enrollment after 1997 or sewage sludge application to soils, which were only estimated at the national scale.

3.14. Methodology for Estimating CH_4 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 CH_4 and half CO_2.[67] The amount and rate of CH_4 generation depends upon the quantity and composition of the landfilled material, as well as the surrounding landfill environment.

Not all CH_4 generated within a landfill is emitted to the atmosphere. The CH_4 can be extracted and either flared or utilized for energy, thus oxidizing to CO_2 during combustion. Of the remaining CH_4, a portion oxidizes to CO_2 as it travels through the top layer of the landfill cover. In general, landfill-related CO_2 emissions are of biogenic origin and primarily result from the decomposition, either aerobic or anaerobic, of organic matter such as food or yard wastes.[68]

To estimate the amount of CH_4 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). However, this information is not available for all landfills in the United States. Consequently, to estimate CH_4 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 CH_4 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 CH_4 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 CH_4 generation potential for use in the first order decay model. In addition, the analysis and other studies provided estimates of the CH_4 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 CH_4 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, CH_4 emissions from industrial landfills were also estimated using the first order decay model. Total CH_4 emissions were estimated by adding the CH_4 from MSW and industrial landfills and subtracting the amounts recovered for energy or flared and the amount oxidized in the soil. The steps taken to estimate CH_4 emissions from U.S. landfills for the years 1990 through 2006 are discussed in greater detail below.

Figure A-19 presents the CH_4 emissions process—from waste generation to emissions—in graphical format.

Step 1: Estimate Annual Quantities of Solid Waste Placed in Landfills

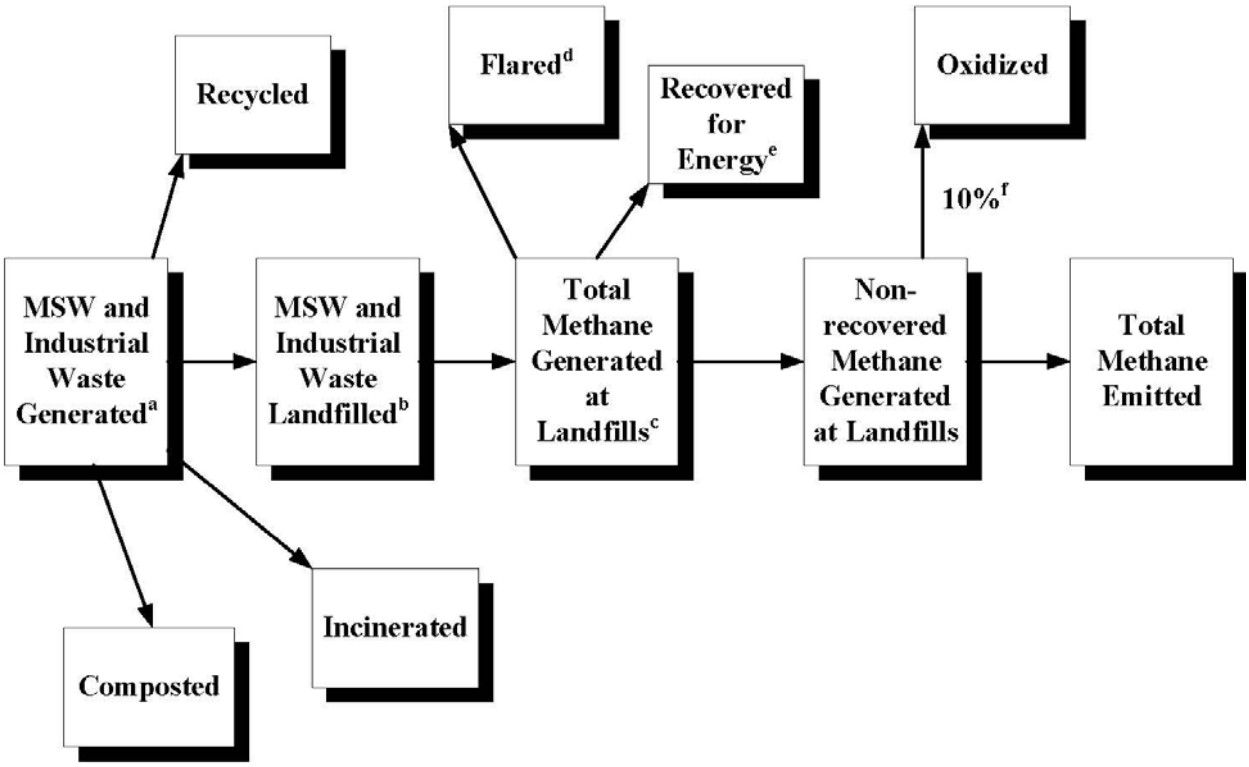
For 1989 to 2006, estimates of the annual quantity of waste placed in MSW landfills were developed from a survey of State agencies as reported in BioCycle's State of Garbage in America (BioCycle 2006), adjusted to include U.S. territories.[69]

[67] 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.

[68] See Box 3-3 in the Energy chapter for additional background on how biogenic emissions of landfill CO_2 are addressed in the U.S. Inventory.

[69] 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 2006) and the per capita rate for waste landfilled from BioCycle (2006).

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

Table A-220 shows estimates of waste quantities contributing to CH_4 emissions. The table shows BioCycle estimates of total waste landfilled each year from 1990 through 2000, 2002, and 2004, adjusted for U.S. territories. A linear interpolation was used for 2001 and 2003 because there were no BioCycle surveys for those years. Estimates were made for 2005 and 2006 based on the increase in population since BioCycle data were not yet available at the time this report was published. The estimates for 2005 and 2006 will be updated when the next BioCycle survey results become available.

Table A-220: Solid Waste in MSW Landfills Contributing to CH_4 Emissions (Tg unless otherwise noted)

Description	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Total Waste Generated[a]	271	259	269	283	298	302	302	314	346	353	377	416	455	462	470	474	478
Percent of Wastes Landfilled[a]	77%	76%	72%	71%	67%	63%	62%	61%	61%	60%	61%	63%	66%	65%	64%	64%	64%
Total Wastes Landfilled	209	197	194	201	200	190	187	192	211	212	230	263	298	300	301	304	307
Waste in Place (30 years)[b]	4,674	4,768	4,848	4,922	5,001	5,075	5,137	5,194	5,252	5,327	5,400	5,488	5,608	5,759	5,909	6,058	6,207
Wastes Contributing to Emissions[c]	6,815	7,012	7,206	7,407	7,606	7,796	7,984	8,175	8,386	8,598	8,828	9,092	9,390	9,690	9,991	10,295	10,601

[a] Source: *BioCycle* (2006), adjusted for missing U.S. territories using U.S. Census Bureau (2006) population data and per capita generation 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 and 2006 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 CH_4 generation.
[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.

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, and 190 million metric tons in the 1990s. 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 CH_4 Generation at Municipal Solid Waste Landfills

The CH_4 generation was estimated from the integrated form of the first order decay (FOD) model using the procedures and spreadsheets from IPCC (2006) for estimating CH_4 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 CH_4 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 CH_4 generation potential (L_0 in m^3 CH_4/Mg waste), which is discussed in more detail in subsequent paragraphs, and the following equation:

$$DOC = [L_0 \times 6.74 \times 10^{-4}] \div [F \times 16/12 \times DOC_f \times MCF]$$

Where,
DOC = degradable organic carbon (fraction, Gg C/Gg waste),
L_0 = CH_4 generation potential (m^3 CH_4/Mg waste),
6.74×10^{-4} = CH_4 density (m^3/Mg),
F = fraction of CH_4 by volume in generated landfill gas (equal to 0.5)
16/12 = molecular weight ratio CH_4/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 CH_4 generation estimates from MSW landfills is 0.203 based on the methane generation potential of 100 m^3 CH_4/Mg waste as described below.

Values for the CH_4 generation potential (L_o) were evaluated from landfill gas recovery data for 52 landfills, which resulted in a best fit value for L_o of 99 m^3/Mg of waste (RTI 2004) and from other studies. This value compares favorably with a range of 50 to 162 (midrange of 106) m^3/Mg presented by Peer, Thorneloe, and Epperson (1993); a range of 87 to 91 m^3/Mg from a detailed analysis of 18 landfills sponsored by the Solid Waste Association of North America (SWANA 1998); and a value of 100 m^3/Mg recommended in EPA's compilation of emission factors (EPA 1998) based on data from 21 landfills. Based on the results from these studies, a value of 100 m^3/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 m^3/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- 221.

Table A- 221. 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) 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 CH_4 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 vs. 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 vs. 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-222.

Table A-222. 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 1990 to 2006 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 Minz 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 CH_4 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, CH_4 generation at industrial landfills was estimated as seven percent of the total CH_4 generation from MSW landfills, based on a study conducted by EPA (1993). For the 1990 through 2005 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 CH_4 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 2007) and U.S. Department of Agriculture (2003) were the primary sources for years 1965 through 2006. 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 for the years 1990 through 2006 (ERG 2007). 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 CH_4 generation from industrial landfills: 1) quantity of waste that is disposed in industrial landfills (as a function of production), 2) CH_4 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 and k were taken from the default values in the 2006 IPCC revised guidelines. The DOC value is 0.20 (L_o of 99 m^3/Mg) for industrial pulp and

paper waste and 0.29 (L_o of 143 m^3/Mg) for industrial food waste. The value of k given for food waste with disposal in a wet temperate climate is 0.185 yr^{-1}, and the value given for paper waste is 0.06 $yr.^{-1}$

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 CH_4 generation from industrial landfills.

Step 4: Estimate CH_4 Emissions Avoided

The estimate of CH_4 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 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," 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 CH_4 Emissions Avoided Through Landfill Gas-to-Energy (LFGTE) Projects

The quantity of CH_4 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 2007). The EIA database included location information for landfills with LFGTE projects, estimates of CH_4 reductions, descriptions of the projects, and information on the methodology used to determine the CH_4 reductions. Generally the CH_4 reductions for each reporting year were based on the measured amount of landfill gas collected and the percent CH_4 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 CH_4 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 CH_4 Emissions Avoided Through Flaring

The quantity of CH_4 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 CH_4 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 CH_4 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 CH_4 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 CH_4 avoided through flaring from the flare vendor database was estimated by summing the estimates of CH_4 recovered by each flare for each year.

Step 4c: Reduce CH_4 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 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 in the flare vendor data; or 2) the lack of the flare in the flare vendor database. For those projects for which a flare was not identified due to inadequate information, CH_4 avoided would be overestimated, as both the CH_4 avoided from flaring and the LFGTE project would be counted. To avoid overestimating emissions avoided from flaring, the CH_4 avoided from LFGTE projects with no identified flares was determined and the flaring estimate from the flare vendor database was reduced by this quantity on a state-by-state basis. This step likely underestimates CH_4 avoided due to flaring. This approach was applied to be conservative in the estimates of CH_4 emissions avoided.

Step 5: Estimate CH_4 Oxidation

A portion of the CH_4 escaping from a landfill oxidizes to CO_2 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 CH_4 generated, minus the amount of gas recovered for flaring or LFGTE projects, ten 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. This oxidation factor was applied to the estimates of CH_4 generation minus recovery for both MSW and industrial landfills.

Step 6: Estimate Total CH_4 Emissions

Total CH_4 emissions were calculated by adding emissions from MSW and industrial landfills, and subtracting CH_4 recovered and oxidized, as shown in Table A-223.

Table A-223: CH_4 Emissions from Landfills (Gg)

Activity	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
MSW Generation	8,219	8,443	8,624	8,788	8,966	9,132	9,263	9,381	9,507	9,683	9,854	10,068	10,367	10,754	11,127	11,486	11,838
Industrial Generation	585	595	606	618	631	649	665	681	696	710	725	739	746	754	760	767	770
Potential Emissions	**8,804**	**9,038**	**9,230**	**9,406**	**9,597**	**9,781**	**9,928**	**10,062**	**10,204**	**10,393**	**10,579**	**11,284**	**11,569**	**11,944**	**12,304**	**12,653**	**12,991**
Emissions Avoided	(888)	(1,049)	(1,182)	(1,374)	(1,639)	(2,159)	(2,485)	(2,992)	(3,505)	(3,806)	(4,188)	(4,587)	(4,758)	(4,863)	(5,400)	(5,709)	(5,958)
Landfill Gas-to-Energy	(646)	(673)	(742)	(826)	(894)	(1,113)	(1,323)	(1,668)	(1,998)	(2,239)	(2,441)	(2,670)	(2,721)	(2,723)	(2,888)	(2,961)	(3,110)
Flare	(242)	(376)	(440)	(548)	(746)	(1,047)	(1,162)	(1,325)	(1,507)	(1,567)	(1,747)	(1,917)	(2,037)	(2,140)	(2,512)	(2,748)	(2,848)
Oxidation at MSW Landfills	(733)	(739)	(744)	(741)	(733)	(697)	(678)	(639)	(600)	(588)	(567)	(548)	(561)	(589)	(573)	(578)	(588)
Oxidation at Industrial Landfills	(59)	(59)	(61)	(62)	(63)	(65)	(67)	(68)	(70)	(71)	(72)	(74)	(75)	(75)	(76)	(77)	(77)
Net Emissions	**7,124**	**7,190**	**7,243**	**7,228**	**7,162**	**6,859**	**6,699**	**6,363**	**6,029**	**5,928**	**5,751**	**5,598**	**5,720**	**5,981**	**5,838**	**5,890**	**5,985**

Note: Totals may not sum exactly to the last significant figure due to rounding.
Note: MSW generation in Table A-223 represents emissions before oxidation. In other tables throughout the text, MSW generation estimates account for oxidation.
Note: Parentheses denote negative values.

ANNEX 4 IPCC Reference Approach for Estimating CO_2 Emissions from Fossil Fuel Combustion

It is possible to estimate carbon dioxide (CO_2) 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 CO_2 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 CO_2 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 CO_2 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 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 both coal and natural gas data. The third modification adjusts for the inclusion of ethanol in motor gasoline statistics. Ethanol is a biofuel, and it is assumed that no net CO_2 emissions occur due to its combustion. 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-1.

The C content of fuel varies with the fuel's heat content. Therefore, for an accurate estimation of CO_2 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-1 for 2006), they were converted to units of energy before CO_2 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-2. The resulting fuel type-specific energy data for 2006 are provided in Table A-3.

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:

Apparent Consumption = Production + Imports - Exports - 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:

Secondary Consumption = Imports - Exports - 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-2.

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 CO_2 emissions were estimated using fuel-specific C coefficients (see Table A-3).[1] The C in products from non-energy uses of fossil fuels (e.g., plastics or asphalt) was then estimated and subtracted (see Table A-5). 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 CO_2 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).[2] 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 CO_2 Emissions

Because the IPCC reporting guidelines recommend that countries report greenhouse gas emissions on a full molecular weight basis, the final step in estimating CO_2 emissions from fossil fuel consumption was converting from units of C to units of CO_2. Actual C emissions were multiplied by the molecular-to-atomic weight ratio of CO_2 to C (44/12) to obtain total CO_2 emitted from fossil fuel combustion in teragrams (Tg). The results are contained in Table A-4.

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 CO_2 from Fossil Fuel Combustion

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[1] 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 Table A-4 for more specific source information.

and Carbon Emitted from Non-Energy Uses of Fossil Fuels Annexes. These two sections together are henceforth referred to as the Sectoral 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-7 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 0.8 percent lower than the Sectoral Approach for 2006. The greatest differences lie in lower estimates for both coal and petroleum consumption for the Reference Approach (1.3 and 1.2 percent respectively).

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 CO_2 Emissions

Given these differences in energy consumption data, the next step for each methodology involved estimating emissions of CO_2. Table A-8 summarizes the differences between the two methods in estimated C emissions.

As mentioned above, for 2006, the Reference Approach resulted in a 0.8 percent lower estimate of energy consumption in the United States than the Sectoral Approach. The resulting emissions estimate for the Reference Approach was 0.5 percent higher. Estimates of petroleum and natural gas emissions from the Reference Approach are higher (1.3 percent and 0.6 percent respectively), and coal emission estimates are slightly lower (0.6 percent) 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 CO_2 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-1: 2006 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	1,514	a	a	a			
	Bituminous Coal	564,583	a	a	a			
	Sub-bituminous Coal	511,099	a	a	a	0		
	Lignite	84,248	a	a	a	3,872		
	Coke		4,068	1,616	71			
	Unspecified Coal		36,246	49,647	39,867	19,688		1,984
Gas Fuels (Million Cubic Feet)	Natural Gas	18,896,144	4,144,558	748,965	430,792	213,414		25,427
Liquid Fuels (Thousand Barrels)	Crude Oil	1,862,259	3,693,081	8,999	(7,367)			
	Nat Gas Liquids and LRGs	634,654	131,227	24,769	7,697			190
	Other Liquids	0	517,931	29,108	22,690			
	Motor Gasoline	183,027	173,448	51,765	(19,711)	88,023		38,979
	Aviation Gasoline		222	0	174			
	Kerosene		1,697	78,507	(1,719)			964
	Jet Fuel		67,716	14,873	(2,612)		180,615	12,249
	Distillate Fuel		133,126	78,507	7,629		21,825	23,145
	Residual Fuel		127,761	103,210	5,010	7,000	95,334	39,915
	Naphtha for petrochemical feedstocks		48,304	0	25			
	Petroleum Coke		14,437	133,569	(309)	13,707		
	Other Oil for petrochemical feedstocks		63,405	0	(16)	35,521		
	Special Naphthas		5,293	5,090	85			
	Lubricants		5,943	19,949	2,753			884
	Waxes		1,113	1,757	21			
	Asphalt/Road Oil		18,317	5,405	7,574			
	Still Gas		0	0	0			
	Misc. Products		61	2,432	(22)			18,094

[a] Included in Unspecified Coal

Data Sources: Solid and Gas Fuels: EIA (2007a); Liquid Fuels: EIA (1995-2007).

Table A-2: 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						
	Lignite	12.87				12.87		
	Coke		24.80	24.80	24.80			
	Unspecified		25.00	25.97	20.86	26.27		25.14
Natural Gas (BTU/Cubic Foot)		1,029	1,025	1,009	1,029	1,025		1,029
Liquid Fuels (Million Btu/Barrel)	Crude Oil	5.80	5.98	5.80	5.80		5.80	5.80
	Nat Gas Liquids and LRGs	3.71	3.71	3.71	3.71		3.71	3.71
	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		5.67	5.67
	Distillate Fuel		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 (2007b); Unspecified Solid Fuels: EIA (2007a); Coke, Natural Gas and Petroleum Products: EIA (2007a).

Table A-3: 2006 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	34.2							34.2
	Bituminous Coal	13,487.9							13,487.9
	Sub-bituminous Coal	8,760.2				12.4			8,747.9
	Lignite	1,083.9				49.8			1,034.1
	Coke		100.9	40.1	1.8				59.0
	Unspecified		906.1	1,289.4	831.7	517.2		49.9	(1,682.3)
Gas Fuels	Natural Gas	19,444.1	4,248.2	755.7	443.3	218.6		26.2	22,300.8
Liquid Fuels	Crude Oil	10,801.1	22,084.6	52.2	(42.7)				32,876.3
	Nat Gas Liquids and LRGs	2,355.8	487.1	91.9	28.6			0.7	2,723.1
	Other Liquids		3,016.9	169.6	132.2				2,715.2
	Motor Gasoline	955.0	905.1	270.1	(102.9)	459.3		203.4	1,436.9
	Aviation Gasoline		1.1		0.9				0.2
	Kerosene		9.6	445.1	(9.7)			5.5	(420.3)
	Jet Fuel		383.9	84.3	(14.8)		1,024.1	69.5	(640.2)
	Distillate Fuel		775.5	457.3	44.4		127.1	134.8	281.4
	Residual Oil		803.2	648.9	31.5	44.0	599.4	250.9	(269.6)
	Naphtha for petrochemical feedstocks		253.5		0.1				253.4
	Petroleum Coke		87.0	804.6	(1.9)	82.6			(798.4)
	Other Oil for petrochemical feedstocks		369.3		(0.1)	206.9			162.5
	Special Naphthas		27.8	26.7	0.4				0.6
	Lubricants		36.0	121.0	16.7			5.4	(96.3)
	Waxes		6.2	9.7	0.1				(3.7)
	Asphalt/Road Oil		121.6	35.9	50.3				35.4
	Still Gas								
	Misc. Products		0.4	14.1	(0.1)			104.9	91.3
Total		56,922.3	34,624.0	5,316.7	1,409.7	1,590.9	1,750.6	851.1	82,329.6

Note: Totals may not sum due to independent rounding.

Table A-4: 2006 Potential CO_2 Emissions

Fuel Category	Fuel Type	Apparent Consumption (QBtu)	Carbon Coefficients (Tg Carbon/QBtu)	Potential Emissions (Tg CO_2 Eq.)
Solid Fuels	Anthracite Coal	0.034	28.26	3.5
	Bituminous Coal	13.488	25.49	1,260.6
	Sub-bituminous Coal	8.748	26.48	849.4
	Lignite	1.034	26.30	99.7
	Coke	0.059	31.00	6.7
	Unspecified	(1.682)	25.34	(156.3)
Gas Fuels	Natural Gas	22.301	14.47	1,183.2
Liquid Fuels	Crude Oil	32.876	20.33	2,450.5
	Nat Gas Liquids and LRGs	2.723	16.99	169.6
	Other Liquids	2.715	20.33	202.4
	Motor Gasoline	1.437	19.33	101.8
	Aviation Gasoline	0.000	18.87	0.0
	Kerosene	(0.420)	19.72	(30.4)
	Jet Fuel	(0.640)	19.33	(45.4)
	Distillate Fuel	0.281	19.95	20.6
	Residual Oil	(0.270)	21.49	(21.2)
	Naphtha for petrochemical feedstocks	0.253	18.14	16.9
	Petroleum Coke	(0.798)	27.85	(81.5)
	Other Oil for petrochemical feedstocks	0.163	19.95	11.9
	Special Naphthas	0.001	19.86	0.0
	Lubricants	(0.096)	20.24	(7.1)
	Waxes	(0.004)	19.81	(0.3)
	Asphalt/Road Oil	0.035	20.62	2.7
	Still Gas	0.000	17.51	0.0
	Misc. Products	0.091	20.33	6.8
Total				6,044.1

Data Sources: C content coefficients by coal rank from USGS (1998) and SAIC (2004); Unspecified Solid Fuels, Natural Gas and Liquid Fuels: EIA (2007a).
Note: Totals may not sum due to independent rounding.

Table A-5: 2006 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 CO_2 Eq.)
Coal	85.9	31.00	2.7	0.10	0.98
Natural Gas	403.2	14.47	5.8	0.62	13.16
Asphalt & Road Oil	1,225.6	20.62	25.3	1.00	92.67
LPG	1,491.8	16.78	25.0	0.62	56.49
Lubricants	282.9	20.24	5.7	0.09	1.94
Pentanes Plus	105.1	18.24	1.9	0.62	4.32
Petrochemical Feedstocks	a	a	a	a	55.61
Petroleum Coke	178.7	27.85	5.0	0.50	9.12
Special Naphtha	68.7	19.86	1.4	0.62	3.08
Waxes/Misc.	a	a	a	a	1.49
Misc. U.S. Territories Petroleum	a	a	a	a	0.77
Total					239.6

[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-6: 2006 Reference Approach CO_2 Emissions from Fossil Fuel Consumption (Tg CO_2 Eq. unless otherwise noted)

Fuel Category	Potential Emissions	Carbon Sequestered	Net Emissions	Fraction Oxidized	Total Emissions
Coal	2,063.7	1.0	2,062.7	100.0%	2,062.7
Petroleum	2,797.2	225.5	2,571.7	100.0%	2,571.7
Natural Gas	1,183.2	13.2	1,170.0	100.0%	1,170.0
Total	6,044.1	239.6	5,804.5	-	5,804.5

Note: Totals may not sum due to independent rounding.

Table A-7: Fuel Consumption in the United States by Estimating Approach (TBtu)*

Approach	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Sectoral	69,806	69,406	71,038	72,808	74,236	75,217	77,781	78,813	79,156	80,407	82,734	81,260	82,444	82,844	84,075	84,275	82,972
Coal	18,055	17,984	18,163	18,932	19,005	19,187	20,112	20,533	20,768	20,824	21,823	21,181	21,272	21,724	22,029	22,302	21,974
Natural Gas	19,365	19,770	20,452	20,993	21,475	22,447	22,870	23,079	22,593	22,624	23,443	22,563	23,518	23,007	22,645	22,530	22,183
Petroleum	32,386	31,652	32,422	32,883	33,757	33,583	34,799	35,201	35,796	36,958	37,469	37,516	37,654	38,113	39,402	39,443	38,815
Reference (Apparent)	69,078	68,288	69,827	71,614	73,255	74,165	76,597	78,039	78,123	79,292	81,741	80,774	81,680	81,918	83,609	83,765	82,330
Coal	17,603	17,401	17,725	18,261	18,724	18,611	19,519	20,161	20,033	20,081	21,039	20,782	20,881	21,180	21,872	22,085	21,681
Natural Gas	19,747	19,765	20,425	20,981	21,460	22,412	22,816	22,951	22,531	22,635	23,599	22,622	23,361	22,759	22,783	22,686	22,301
Petroleum	31,728	31,122	31,677	32,372	33,071	33,142	34,262	34,927	35,559	36,576	37,103	37,370	37,439	37,980	38,954	38,994	38,348
Difference	-1.0%	-1.6%	-1.7%	-1.6%	-1.3%	-1.4%	-1.5%	-1.0%	-1.3%	-1.4%	-1.2%	-0.6%	-0.9%	-1.1%	-0.6%	-0.6%	-0.8%
Coal	-2.5%	-3.2%	-2.4%	-3.5%	-1.5%	-3.0%	-2.9%	-1.8%	-3.5%	-3.6%	-3.6%	-1.9%	-1.8%	-2.5%	-0.7%	-1.0%	-1.3%
Natural Gas	2.0%	0.0%	-0.1%	-0.1%	-0.1%	-0.2%	-0.2%	-0.6%	-0.3%	0.0%	0.7%	0.3%	-0.7%	-1.1%	0.6%	0.7%	0.5%
Petroleum	-2.0%	-1.7%	-2.3%	-1.6%	-2.0%	-1.3%	-1.5%	-0.8%	-0.7%	-1.0%	-1.0%	-0.4%	-0.6%	-0.3%	-1.1%	-1.1%	-1.2%

* Includes U.S. territories. Does not include international bunker fuels.

+ Does not exceed 0.05%.

Note: Totals may not sum due to independent rounding.

Table A-8: CO_2 Emissions from Fossil Fuel Combustion by Estimating Approach (Tg CO_2 Eq.)

Approach	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Sectoral	4,841	4,806	4,903	5,033	5,118	5,165	5,354	5,425	5,463	5,539	5,718	5,639	5,700	5,748	5,830	5,870	5,776
Coal	1,699	1,693	1,710	1,784	1,791	1,810	1,897	1,938	1,960	1,966	2,060	1,999	2,008	2,051	2,081	2,106	2,075
Natural Gas	1,018	1,039	1,077	1,104	1,128	1,180	1,202	1,212	1,186	1,187	1,229	1,184	1,235	1,208	1,187	1,182	1,163
Petroleum	2,124	2,073	2,116	2,145	2,199	2,175	2,254	2,275	2,317	2,386	2,429	2,456	2,457	2,490	2,562	2,582	2,538
Reference (Apparent)	4,811	4,756	4,858	4,991	5,098	5,143	5,324	5,436	5,445	5,510	5,698	5,663	5,719	5,758	5,885	5,905	5,804
Coal	1,658	1,641	1,672	1,725	1,770	1,761	1,846	1,908	1,900	1,908	1,997	1,974	1,984	2,011	2,077	2,097	2,063
Natural Gas	1,039	1,041	1,076	1,105	1,129	1,179	1,200	1,207	1,183	1,188	1,238	1,187	1,228	1,196	1,197	1,191	1,170
Petroleum	2,114	2,074	2,110	2,160	2,199	2,202	2,278	2,321	2,362	2,413	2,463	2,501	2,507	2,550	2,611	2,617	2,572
Difference	-0.6%	-1.0%	-0.9%	-0.8%	-0.4%	-0.4%	-0.6%	0.2%	-0.3%	-0.5%	-0.3%	0.4%	0.3%	0.2%	1.0%	0.6%	0.5%
Coal	-2.4%	-3.1%	-2.3%	-3.3%	-1.2%	-2.7%	-2.7%	-1.6%	-3.1%	-2.9%	-3.1%	-1.2%	-1.2%	-1.9%	-0.2%	-0.4%	-0.6%
Natural Gas	2.1%	0.1%	0.0%	0.1%	0.0%	0.0%	-0.1%	-0.4%	-0.2%	0.1%	0.8%	0.3%	-0.6%	-1.0%	0.8%	0.8%	0.6%
Petroleum	-0.5%	0.0%	-0.2%	0.7%	0.0%	1.2%	1.0%	2.0%	1.9%	1.1%	1.4%	1.8%	2.0%	2.4%	1.9%	1.4%	1.3%

+ Does not exceed 0.05%.

Note: Totals may not sum due to independent rounding. Includes U.S. territories. Does not include emissions from international bunker fuels

ANNEX 5 Assessment of the Sources and Sinks of Greenhouse Gas Emissions Excluded

Although this report is intended to be a comprehensive assessment of anthropogenic[72] sources and sinks of greenhouse gas emissions for the United States, certain sources have been identified yet excluded from 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 general, processes or activities that are not anthropogenic are considered natural (i.e., not directly influenced by human activity) in origin and, as an example, would include the following:

- Volcanic eruptions
- Carbon dioxide (CO_2) exchange (i.e., uptake or release) by oceans
- Natural forest fires[73]
- Methane (CH_4) emissions from wetlands not affected by human induced land-use changes

Some processes or activities may be anthropogenic in origin but do not result in net emissions of greenhouse gases, such as the respiration of CO_2 by people or domesticated animals.[74] Given a source category that is both anthropogenic and results in net greenhouse gas emissions, reasons for excluding a source related to an anthropogenic activity include one or more of the following:

- There is insufficient scientific understanding to develop a reliable method for estimating emissions at a national level.
- Although 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., CO_2 from Fossil Fuel Combustion).

It is also important to note that the United States believes the exclusion of the sources discussed below introduces only a minor bias in its overall estimate of U.S. greenhouse gas emissions.

CO_2 from Burning in Coal Deposits and Waste Piles

Coal is periodically burned in deposits and waste piles. It has been estimated that the burning of coal in deposits and waste piles would represent less than 1.3 percent of total U.S. coal consumption, averaged over ten-years. Because there is currently no known source of data on the quantity of coal burned in waste piles and there is uncertainty as to the fraction of coal oxidized during such burnings, these CO_2 emissions are not currently estimated. Further research would be required to develop accurate emission factors and activity data for these emissions to be

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[72] 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).

[73] In some cases forest fires that are started either intentionally or unintentionally are viewed as mimicking natural burning processes that have been suppressed by other human forest management activities. The United States does not consider forest fires within its national boundaries to be a net source of greenhouse emissions.

[74] Respiration of CO_2 by biological organisms is simply part of the broader global carbon cycle that also includes uptake of CO_2 by photosynthetic organisms.

estimated (see *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories: Reference Manual*, p. 1.112 – 1.113).

CO_2 from Enhanced Oil Recovery (EOR)

The 2006 IPCC Guidelines include, for the first time, methodological guidance to estimate emissions from the capture, transport, injection, and geological storage of CO_2. The methodology is based on the principle that the C capture and storage system should be handled in a complete and consistent manner across the entire Energy Sector. The approach accounts for CO_2 captured at natural and industrial sites as well as emissions from capture, transport, and use. For storage specifically, a Tier 3 methodology is outlined for estimating and reporting emissions based on site-specific evaluations. If site-specific monitoring and reporting data are not available, and the C capture and storage system cannot, therefore, be considered in a complete and consistent manner, the assumption is that the captured CO_2 is emitted. The assumption that, in the absence of site specific data, all CO_2 injected in storage sites is emitted is opposite from the current methodology implemented by the United States. The new methodology will not affect emission estimates for CO_2 consumption for non-EOR applications. The United States initiated data collection efforts to incorporate this new methodology for the current Inventory. However, time was not sufficient to fully implement this guidance and therefore estimates are not yet included in national totals. Preliminary estimates indicate that the amount of CO_2 emitted from EOR operations and CO_2 transport pipelines in 2005 was 35.16 Tg CO_2 (35,156 Gg CO_2). Site-specific monitoring and reporting data for CO_2 injection sites (i.e., EOR operations) were not readily available. Therefore, these estimates assume that all of the CO_2 used in EOR operations is emitted.

CO_2 from Natural Gas Processing

CO_2 is produced as a byproduct of natural gas production and processing. Natural gas produced from natural gas wells (referred to as non-associated natural gas) and natural gas produced from crude oil wells (referred to as associated-dissolved natural gas) may contain naturally occurring CO_2 that must be removed from the natural gas in order for it to meet pipeline specifications for CO_2 content. A fraction of the CO_2 remains in the natural gas delivered to end-users by pipeline, and is emitted when the natural gas is combusted. However, the majority of the CO_2 is separated from natural gas at natural gas processing plants. CO_2 removed at gas processing plants is generally vented to the atmosphere, but several gas processing plants in Wyoming and Texas and one gas processing plant in Michigan compress the CO_2 separated from natural gas and transport this CO_2 by pipeline for use in enhanced oil recovery. CO_2 used for enhanced oil recovery is injected into oil reservoirs to improve the recovery of oil remaining in the reservoir through a number of processes, including reduction of crude oil viscosity and oil density, acid effects on carbonate reservoirs, and miscible and immiscible displacement. Preliminary estimates indicate that in 2005 approximately 5.99 Tg CO_2 (5,992 Gg CO_2) produced from natural gas processing plants (acid gas removal plants) was captured and used in enhanced oil recovery operations. As discussed under CO_2 from Enhanced Oil Recovery (above) all of this CO_2 used in EOR operations is assumed to be emitted.

CO_2 from "Unaccounted for" Natural Gas

There is a discrepancy between the amount of natural gas sold by producers and that reported as purchased by consumers. This discrepancy, known as "unaccounted for" or unmetered natural gas, was assumed to be the sum of leakage, measurement errors, data collection problems, undetected non-reporting, undetected over reporting, and undetected under reporting. Historically, the amount of gas sold by producers has always exceeded that reportedly purchased by consumers; therefore, some portion of unaccounted for natural gas was assumed to be a source of CO_2 emissions. In other words, it was assumed that consumers were underreporting their usage of natural gas. In DOE/EIA's energy statistics for 1996, however, reported consumption of natural gas exceeded the amount sold by producers. Therefore, the historical explanation given for this discrepancy has lost credibility and unaccounted for natural gas is no longer used to calculate CO_2 emissions.

CO_2 from Shale Oil Production

Oil shale is shale saturated with kerogen.[75] It can be thought of as the geological predecessor to crude oil. CO2 is released as a by-product of the process of producing petroleum products from shale oil. As of now, it is not cost-effective to mine and process shale oil into usable petroleum products. The only identified large-scale oil shale processing facility in the United States was operated by Unocal during the years 1985 to 1990. There have been no known emissions from shale oil processing in the United States since 1990 when the Unocal facility closed.

CH_4 from the Production of Carbides other than Silicon Carbide

Methane (CH_4) may be emitted from the production of carbides because the petroleum coke used in the process contains volatile organic compounds, which form CH_4 during thermal decomposition. Methane emissions from the production of silicon carbide were estimated and accounted for, but emissions from the production of calcium carbide and other carbides were not. Further research is needed to estimate CH_4 emissions from the production of calcium carbide and other carbides other than silicon carbide. (See *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories: Reference Manual*, pp. 2.20 – 2.21)

CO_2 from Calcium Carbide and Silicon Carbide Production

CO_2 is formed by the oxidation of petroleum coke in the production of calcium carbide. These CO_2 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 to estimate emissions from this source. (See Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories: Reference Manual, pp. 2.20 – 2.21)

CO_2 from Graphite Consumption in Ferroalloy and Steel Production

Emissions from "graphite," "wood" or "biomass" in calculating CO_2 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.

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 CO_2 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.

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[75] Kerogen is fossilized insoluble organic material found in sedimentary rocks, usually shales, which can be converted to petroleum products by distillation.

N_2O 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 N_2O being produced as a by-product. Caprolactam production could be a significant source of N_2O—it has been identified as such in the Netherlands. 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. (See *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories: Reference Manual*, pp. 2.22 – 2.23)

N_2O from Cracking of Certain Oil Fractions

In order to improve the gasoline yield in crude oil refining, certain oil fractions are processed in a catcracker. Because crude oil contains some nitrogen, N_2O emissions may result from this cracking process. There is currently insufficient data to develop a methodology for estimating these emissions. (See *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories: Reference Manual*, p. 2.23)

CH_4 from Petroleum Coke Production

Coke production may result in CH_4 emissions. Detailed coke production statistics were not available for the purposes of estimating CH_4 emissions from this minor source. (See Petrochemical Production in the Industrial Processes chapter and the *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories: Reference Manual*, p. 2.23)

CO_2 from Metal Production

Coke is used as a reducing agent in the production of some metals from their ores, including magnesium, chromium, , nickel, silicon, and tin. CO_2 may be emitted during the metal's production from the oxidization of this coke and, in some cases, from the carbonate ores themselves (e.g., some magnesium ores contain carbonate). The CO_2 emissions from the carbonate ores are not presently accounted for, but their quantities are thought to be minor. (See *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories: Reference Manual*, p. 2.37 – 2.38)

N_2O from Acrylonitrile Production

Nitrous oxide may be emitted during acrylonitrile production. No methodology was available for estimating these emissions, and therefore further research is needed if these emissions are to be included. (See *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories: Reference Manual*, p. 2.22)

SF_6 from Aluminum Fluxing and Degassing

Occasionally, sulfur hexafluoride (SF_6) is used by the aluminum industry as a fluxing and degassing agent in experimental and specialized casting operations. In these cases it is normally mixed with argon, nitrogen, and/or chlorine and blown through molten aluminum; however, this practice is not used by primary aluminum production firms in the United States and is not believed to be extensively used by secondary casting firms. Where it does occur, the concentration of SF_6 in the mixture is small and a portion of the SF_6 is decomposed in the process (Waite and Bernard 1990, Corns 1990). It has been estimated that 230 Mg of SF_6 were used by the aluminum industry in the United States and Canada (Maiss and Brenninkmeijer 1998); however, this estimate is highly uncertain.

SF_6 from Production/Leakage/Breakage of Soundproofed Double-glazed Windows

Sulfur hexafluoride (SF_6) may be emitted from the production, breakage, or leakage of soundproof double-glazed windows. No methodology was available for estimating these emissions, and therefore further research is needed if these emissions are to be included.

SF_6 from Production/Leakage/Dismantling of Radar, Tracer and Night Vision Equipment

Sulfur hexafluoride (SF_6) 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.

SF_6 from Applications in Sports Shoes, Tires, and Tennis Balls

Sulfur hexafluoride (SF_6) may be emitted from application involving the production of sport shoes, tires, and tennis balls. These emissions are believed to be minor, and no data were available for estimating emissions.

SF_6 from Applications to Trace Leakage of Pressure Vessels and Used as a Tracer Gas in Open Air

Sulfur hexafluoride (SF_6) may be emitted from application involving tracer gasses to detect leakage from pressure vessels and as a tracer gas in the open air. Although emissions from this source are believed to be minor, emissions estimation data and methodologies were not available.

Miscellaneous SF_6 Uses

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. Data need to be gathered and methodologies developed if these emissions are to be estimated. A preliminary global assessment of aggregate emissions from these applications can be found in Maiss, M. Brenninkmeijer, and C.A.M. Brenninkmeijer (1998).

N_2O from Domestic House Animal Waste Deposited on Soils

A substantial amount of liquid and solid waste is produced by domestic animals that are kept as pets. A preliminary methodology was developed to estimate nitrous oxide (N_2O) emissions from the deposition of domestic house animal (i.e., dogs and cats) waste on lawns, fields and parks. Estimates calculated with this methodology suggest that, in 1990, approximately 330 Gg of nitrogen originating as domestic house animal waste were deposited on soils resulting in approximately 2.9 Tg CO_2 Eq. of N_2O emissions from soils. To estimate the amount of nitrogen deposited by domestic house animals, only those excretions that remained on land surfaces—as opposed to wastes that were collected by owners and are managed as municipal solid waste—were included.

Annual dog and cat population numbers were obtained from the Pet Food Institute.[76] Annual nitrogen excretion rates were estimated from protein intake. The recommended protein intake for an average size adult of each animal type[77] was multiplied by the average amount of nitrogen per unit of protein (0.16 kg N/kg protein, from the *Revised 1996 IPCC Guidelines*) to estimate nitrogen consumption. It was then assumed that 95 percent of this nitrogen was excreted, either in solid or liquid form (i.e., it was assumed that 5 percent was retained for fur and milk production). Of the total nitrogen excretion, 90 percent was assumed to occur through liquid waste, with the balance from solid waste.[78] Both cat and dog populations were divided into urban and rural fractions, using the metropolitan and non-metropolitan human population categories, respectively, of the U.S. Census Bureau.[79] Both liquid and solid wastes from the urban cat population, and solid waste from the urban dog population were assumed to be collected (i.e., not deposited on soils). Nitrous oxide emission estimates from domestic house animal excretion were calculated in the same manner as performed for estimating emissions from livestock excretion. Producing these estimates involved making a number of simplifying assumptions regarding average animal size and protein consumption, as well as the proportions of animal populations residing in urban and rural areas and the proportions

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[76] Pet Food Institute (1999) *Pet Incidence Trend Report*. Pet Food Institute, Washington DC.

[77] Bright, S. (1999) Personal communication between Marco Alcaraz of ICF Consulting and Susan Bright of the Dupont Animal Clinic, Washington, DC, August 1999.

[78] Swenson, M.J. and W.G. Reece, eds. (1993) *Duke's Physiology of Domestic Animals*. Cornell University Press. 11th Edition.

[79] U.S. Census Bureau (1999) <http://www.census.gov/population/estimates/metro-city/ma96-08.txt>

of wastes that are deposited on land. Further methodological development and data collection is required in order to reduce the uncertainty involved in the domestic house animal excretion estimates.

CO_2 from Non-Hazardous Industrial Waste Combustion

Waste combustion is incorporated in two sections of the energy chapter of the inventory: in the section on CO_2 emissions from waste combustion, 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 significant category of waste combustion 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 CO_2 emissions.

CH_4 from Land-Use Changes Including Wetlands Creation or Destruction

Wetlands are a known source of methane (CH_4) emissions. When wetlands are destroyed, CH_4 emissions may be reduced. Conversely, when wetlands are created (e.g., during the construction of hydroelectric plants), CH_4 emissions may increase. Grasslands and forestlands may also be weak sinks for CH_4 due to the presence of methanotrophic bacteria that use CH_4 as an energy source (i.e., they oxidize CH_4 to CO_2). Currently, an adequate scientific basis for estimating these emissions and sinks does not exist, and therefore further research and methodological development is required.

N_2O from Wastewater Treatment and Biological Processes

As a result of nitrification and denitrification processes, nitrous oxide (N_2O) may be produced and emitted from large-scale composting, small scale composting (e.g. households), post-composting of anaerobic digested wastes, and both domestic and industrial wastewater treatment plants. Nitrogen-containing compounds are found in composted wastes and wastewater due to the presence of both human excrement and other nitrogen-containing constituents (e.g., effluent from garbage disposals, bath and laundry water, and industrial wastes). The portion of emitted N_2O that originates from these sources is currently estimated under the Wastewater Treatment source category—based upon average dietary protein intake and assumptions on co-disposal of N that was not consumed. The portion of emitted N_2O that originates from other nitrogen-containing constituents is not currently estimated. Further research and methodological development is needed if these emissions are to be accurately estimated.

CH_4 from Large and Small Scale Composting

Methane (CH_4) may be released through large and small scale (e.g. household) composting. Detailed composting data is necessary in order to estimate emissions but were not available.

CH_4 from Treatment of Dredging Sludge, Remediation of Groundwater, Intermediate Storage of Slaughter Waste, Production of Process Water from Groundwater, and Post Composting of Anaerobic Digested Wastes

Methane (CH_4) may be released through the treatment of dredging sludge, remediation of groundwater, intermediate storage of slaughter waste, production of process water from groundwater, and post composting of anaerobic digested wastes. No methodology was available for estimating these emissions, and therefore further research is needed if these emissions are to be included.

References

Census (2002) *Industrial Gases: 2001*. U.S. Census Bureau, Department of Commerce, Washington, DC. MQ325C(01)-5.

EIA (2002) *Emissions of Greenhouse Gases in the United States 2001*. Energy Information Administration, Office of Integrated Analysis and Forecasting. DOE-EIA-0573(2001).

EPA (2000) Toxics Release Inventory, 1998. U.S. Environmental Protection Agency, Office of Environmental Information, Office of Information Analysis and Access, Washington, DC. Available online at <http://www.epa.gov/triexplorer/chemical.htm>.

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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 (CO_2) 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 Tg CO_2 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 roughly ±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-232).

> *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., CO_2, CH_4, N_2O, HFCs, PFCs, and SF_6) 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, other indirect greenhouse gases (e.g., NO_x, and NMVOCs), and tropospheric aerosols (e.g., SO_2 products and black carbon), however, 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-232: 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_2O)	120	310	280	170
HFC-23	264	11,700	9,100	9,800

[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-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
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-4310mee	17.1	1,300	3,000	400
CF_4	50,000	6,500	4,400	10,000
C_2F_6	10,000	9,200	6,200	14,000
C_4F_{10}	2,600	7,000	4,800	10,100
C_6F_{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 CO_2 is not included.

Table A-233 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.

Table A-233: 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_3Br	5	(2,600)	(500)
Halon-1211	1,300	(24,000)	(3,600)
Halon-1301	6,900	(76,000)	(9,300)

Source: IPCC (2001)

* 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 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*. The effects of these compounds on radiative forcing are not addressed in this report.

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 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. 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 CO_2 radiative forcing and an improved CO_2 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 CO_2 is about 8 percent lower than that in the TAR, the GWPs of the other gases relative to CO_2 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- 234 compares the lifetimes and GWPs for the SAR, TAR, and AR4.

Table A- 234: Comparison of GWPs and lifetimes used in the SAR and AR4

	Lifetime (years)			GWP (100 year)			Difference (relative to SAR)			
Gas	**SAR**	**TAR**	**AR4**	**SAR**	**TAR**	**AR4**	**TAR**	**TAR (%)**	**AR4**	**AR4 (%)**
Carbon dioxide (CO_2)	50-200	5-200[a]	5-200[a]	1	1	1	NC	NC	NC	NC
Methane (CH_4)[b]	12±3	8.4/12[c]	8.7/12[c]	21	23	25	2	10%	4	19%
Nitrous oxide (N_2O)	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	(1,900)	(7%)	(1,100)	(5%)
CF_4	50,000	50,000	50,000	6,500	5,700	7,390	(800)	(12%)	890	14%
C_2F_6	10,000	10,000	10,000	9,200	11,900	12,200	2,700	29%	3,000	33%
C_3F_8	2,600	2,600	2,600	7,000	8,600	8,830	1,600	23%	1,830	26%
C_4F_{10}	2,600	2,600	2,600	7,000	8,600	8,860	1,600	23%	1,860	27%
c-C_4F_8	3,200	3,200	3,200	8,700	10,000	10,300	1,300	15%	1,600	18%
C_5F_{12}	4,100	4,100	4,100	7,500	8,900	9,160	1,400	19%	1,660	22%
C_6F_{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

[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 CO_2 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.
Source: IPCC (2001)
NC (No Change)
NA (Not Applicable)

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-235 shows the overall trend in U.S. greenhouse gas emissions, by gas, from 1990 through 2006 using the three sets of GWPs. The table also presents the impact of TAR and AR4 GWPs on the total emissions for 1990 and for 2006.

Table A-235: Effects on U.S. Greenhouse Gas Emissions Using TAR, SAR, and AR4 GWPs (Tg CO_2 Eq.)

Gas	**Trend from 1990 to 2006**			**Revisions to Annual Estimates (relative to SAR)**			
				TAR	**AR4**	**TAR**	**AR4**
	SAR	**TAR**	**AR4**	**1990**		**2006**	
CO_2	914.6	914.6	914.6	NC	NC	NC	NC
CH_4	(50.8)	(55.6)	(60.5)	57.7	115.4	52.9	105.8
N_2O	(15.5)	(14.8)	(14.9)	(17.3)	(14.8)	(16.6)	(14.2)
HFCs, PFCs, and SF_6*	57.6	58.9	57.7	(2.5)	11.5	(1.2)	11.7
Total	**905.9**	**903.1**	**897.0**	**37.9**	**112.1**	**35.1**	**103.2**
Percent Change	**15%**	**15%**	**14%**	**0.6%**	**1.8%**	**0.5%**	**1.5%**

NC (No Change)
*Includes NF_3

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 2006 are 7,148.0 Tg CO_2 Eq., as compared to 7,054.2 Tg CO_2 Eq. when the GWPs from the SAR are used (a 1.3 percent difference). Table A-236 provides a detailed summary of U.S. greenhouse gas emissions and sinks for 1990 through 2006, using the GWPs from the AR4. The adjusted greenhouse gas emissions are shown for each gas in units of Tg CO_2 Eq. in Table A-237. The correlating percent change in emissions of each gas is shown in Table A-238. 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-237 summarizes the emissions and resulting change in emissions using GWPs from the SAR or the AR4 for 1990 and 2006.

Table A-236: Recent Trends in U.S. Greenhouse Gas Emissions and Sinks using the AR4 GWPs (Tg CO_2 Eq.)

Gas/Source	1990	1995	2000	2001	2002	2003	2004	2005	2006
CO_2	**5,068.5**	**5,394.2**	**5,939.7**	**5,846.2**	**5,908.6**	**5,952.7**	**6,038.2**	**6,074.3**	**5,983.1**
Fossil Fuel Combustion	4,724.1	5,032.4	5,577.1	5,507.4	5,564.8	5,617.0	5,681.4	5,731.0	5,637.9
Electricity Generation	1,809.6	1,939.3	2,282.3	2,244.3	2,253.7	2,283.1	2,314.9	2,380.2	2,328.2
Transportation	1,473.5	1,590.2	1,791.9	1,770.3	1,823.8	1,800.0	1,845.9	1,860.6	1,847.3
Industrial	849.9	880.6	863.2	855.0	857.3	859.5	862.6	851.9	866.8
Residential	344.4	359.9	374.3	365.4	362.3	385.6	372.0	361.6	329.1
Commercial	218.5	227.5	229.2	223.3	223.7	237.9	232.5	223.5	211.6
US Territories	28.3	35.0	36.2	49.0	44.0	51.0	53.5	53.2	54.9
Non-Energy Use of Fuels	117.2	133.2	141.4	131.9	135.9	131.8	148.9	139.1	138.0
Iron and Steel Production	86.2	74.7	66.6	59.2	55.9	54.7	52.8	46.6	49.1
Cement Manufacture	33.3	36.8	41.2	41.4	42.9	43.1	45.6	45.9	45.7
Natural Gas Systems	33.7	33.8	29.4	28.8	29.6	28.4	28.1	29.5	28.5
Municipal Solid Waste Combustion	10.9	15.7	17.5	18.0	18.5	19.1	20.1	20.7	20.9
Lime Manufacture	12.0	14.0	14.9	14.3	13.7	14.5	15.2	15.1	15.8
Ammonia Manufacture and Urea Consumption	16.9	17.8	16.4	13.3	14.2	12.5	13.2	12.8	12.4
Limestone and Dolomite Use	5.5	7.4	6.0	5.7	5.9	4.8	6.7	7.4	8.6
Cropland Remaining Cropland	7.1	7.0	7.5	7.8	8.5	8.3	7.6	7.9	8.0
Soda Ash Manufacture and Consumption	4.1	4.3	4.2	4.1	4.1	4.1	4.2	4.2	4.2
Aluminum Production	6.8	5.7	6.1	4.4	4.5	4.5	4.2	4.2	3.9
Petrochemical Production	2.2	2.8	3.0	2.8	2.9	2.8	2.9	2.8	2.6
Titanium Dioxide Production	1.2	1.5	1.8	1.7	1.8	1.8	2.1	1.8	1.9
Carbon Dioxide Consumption	1.4	1.4	1.4	0.8	1.0	1.3	1.2	1.3	1.6
Ferroalloy Production	2.2	2.0	1.9	1.5	1.3	1.3	1.4	1.4	1.5
Phosphoric Acid Production	1.5	1.5	1.4	1.3	1.3	1.4	1.4	1.4	1.2
Zinc Production	0.9	1.0	1.1	1.0	0.9	0.5	0.5	0.5	0.5
Petroleum Systems	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Lead Production	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Silicon Carbide Production and Consumption	0.4	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Land Use, Land-Use Change, and Forestry (Sink)a	*-737.7*	*-775.3*	*-673.6*	*-750.2*	*-826.8*	*-860.9*	*-873.7*	*-878.6*	*-883.7*
Wood Biomass and Ethanol Consumption[b]	*219.3*	*236.8*	*227.3*	*203.2*	*204.4*	*209.5*	*224.8*	*227.4*	*234.7*
International Bunker Fuels[b]	*113.7*	*100.6*	*101.1*	*97.6*	*89.1*	*103.6*	*119.0*	*122.6*	*127.1*
CH_4	**721.5**	**713.0**	**683.7**	**665.2**	**670.8**	**665.9**	**649.5**	**642.5**	**661.1**
Enteric Fermentation	151.1	157.6	148.3	147.1	147.4	148.3	145.7	148.2	150.3
Landfills	178.1	171.5	143.8	139.9	143.0	149.5	145.9	147.3	149.6
Natural Gas Systems	148.4	152.4	150.6	149.2	148.6	146.8	135.7	122.0	121.9
Coal Mining	100.1	79.8	71.9	71.8	67.7	67.7	71.1	67.9	69.6
Manure Management	36.9	41.9	46.2	47.9	49.1	48.5	47.7	49.7	49.3
Petroleum Systems	40.3	38.1	36.0	35.9	35.6	34.7	34.2	33.7	33.8
Forest Land Remaining Forest Land	5.3	5.6	22.6	11.2	19.5	10.4	8.2	14.7	29.2
Wastewater Treatment	27.4	29.0	29.3	28.8	28.7	28.5	28.5	28.3	28.4
Stationary Combustion	8.9	8.5	7.9	7.4	7.4	7.7	7.8	7.7	7.4

Rice Cultivation	8.5	9.1	8.9	9.1	8.1	8.2	9.0	8.2	7.0
Abandoned Underground Coal Mines	7.2	9.8	8.8	8.0	7.3	7.1	6.9	6.6	6.4
Mobile Combustion	5.6	5.1	4.0	3.9	3.5	3.3	3.1	3.0	2.8
Composting	0.4	0.9	1.5	1.5	1.5	1.7	1.9	1.9	1.9
Petrochemical Production	1.0	1.3	1.5	1.3	1.3	1.3	1.4	1.3	1.2
Iron and Steel Production	1.6	1.6	1.4	1.3	1.2	1.2	1.2	1.1	1.1
Field Burning of Agricultural Residues	0.8	0.8	0.9	0.9	0.8	1.0	1.0	1.0	1.0
Ferroalloy Production	+	+	+	+	+	+	+	+	+
Silicon Carbide Production and Consumption	+	+	+	+	+	+	+	+	+
International Bunker Fuels[b]	*0.2*	*0.2*	*0.1*	*0.1*	*0.1*	*0.1*	*0.2*	*0.2*	*0.2*
N_2O	**368.6**	**380.3**	**371.0**	**377.7**	**361.6**	**342.8**	**339.9**	**355.7**	**353.7**
Agricultural Soil Management	258.9	254.6	251.9	266.3	251.9	237.7	237.3	254.9	254.7
Mobile Combustion	41.8	51.4	50.5	48.0	44.2	40.7	38.1	34.9	31.8
Nitric Acid Production	16.3	18.2	17.9	14.5	15.7	14.8	14.6	15.2	15.0
Stationary Combustion	12.3	12.9	14.1	13.6	13.5	13.8	14.0	14.2	14.0
Manure Management	11.6	12.3	13.2	13.5	13.4	13.1	13.3	13.4	13.7
Wastewater Treatment	6.0	6.6	7.3	7.5	7.3	7.4	7.5	7.7	7.8
Adipic Acid Production	14.7	16.7	6.0	4.9	5.8	6.1	5.7	5.7	5.7
N_2O Product Usage	4.2	4.4	4.7	4.7	4.2	4.2	4.2	4.2	4.2
Composting	0.5	0.6	2.2	1.3	1.9	1.2	1.0	1.5	2.7
Settlements Remaining Settlements	0.3	0.8	1.3	1.3	1.4	1.5	1.7	1.7	1.7
Field Burning of Agricultural Residues	1.0	1.2	1.2	1.4	1.4	1.5	1.5	1.4	1.4
Forest Land Remaining Forest Land	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5
Municipal Solid Waste Combustion	0.5	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
International Bunker Fuels[b]	0.9	0.8	0.9	0.8	0.8	0.9	1.0	1.0	1.1
HFCs	**46.3**	**71.6**	**84.1**	**91.7**	**98.7**	**105.6**	**113.5**	**120.4**	**125.7**
Substitution of Ozone Depleting Substances	+	29.6	74.4	82.2	89.6	96.8	104.6	111.5	117.2
HCFC-22 Production	46.1	41.7	36.2	25.0	26.7	15.6	21.8	20.0	17.5
Semiconductor Manufacture	0.2	0.4	0.3	0.2	0.2	0.2	0.3	0.3	0.3
PFCs	**24.4**	**18.6**	**16.2**	**8.6**	**11.0**	**9.1**	**8.0**	**8.0**	**8.1**
Semiconductor Manufacture	2.9	4.9	6.3	4.6	4.9	4.7	4.7	4.5	5.2
Aluminum Production	21.6	13.8	9.9	4.0	6.1	4.4	3.3	3.4	2.9
SF_6	**31.2**	**26.7**	**18.3**	**17.8**	**17.2**	**17.3**	**17.1**	**17.4**	**16.5**
Electrical Transmission and Distribution	25.5	20.5	14.4	14.3	13.7	13.2	13.3	13.3	12.6
Magnesium Production and Processing	5.2	5.4	2.9	2.8	2.8	3.3	3.1	3.1	3.0
Semiconductor Manufacture	0.5	0.9	1.0	0.7	0.6	0.8	0.8	0.9	0.9
Total	**6,260.4**	**6,604.4**	**7,139.8**	**7,022.8**	**7,085.6**	**7,100.3**	**7,179.3**	**7,229.6**	**7,157.4**

+ Does not exceed 0.05 Tg CO_2 Eq.

[a] Sinks are only included in net emissions total, and are based partially on projected activity data. Parentheses indicate negative values (or sequestration).

[b] Emissions from International Bunker Fuels and Biomass Combustion are not included in totals.

Note: Totals may not sum due to independent rounding.

Table A-237: Change in U.S. Greenhouse Gas Emissions and Sinks Using TAR vs. AR4 GWPs (Tg CO_2 Eq.)

Gas	1990	1995	2000	2001	2002	2003	2004	2005	2006
CO_2	NC	NC	NC	NC	NC	NC	NC	NC	NC
CH_4	115.4	114.1	109.4	106.4	107.3	106.5	103.9	102.8	105.8
N_2O	(14.8)	(15.3)	(14.9)	(15.2)	(14.6)	(13.8)	(13.7)	(14.3)	(14.2)
HFCs	9.4	9.8	10.8	9.5	10.2	8.1	10.1	10.4	10.5
PFCs	3.7	3.0	2.8	1.7	2.3	2.0	1.8	1.8	2.0
SF_6	(1.5)	(1.3)	(0.9)	(0.9)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)
Total	**112.1**	**110.3**	**107.2**	**101.5**	**104.4**	**102.0**	**101.4**	**99.8**	**103.2**

NC (No change)

*Includes NF_3

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

Table A-238: Change in U.S. Greenhouse Gas Emissions Using TAR vs. AR4 GWPs (Percent)

Gas/Source	1990	1995	2000	2001	2002	2003	2004	2005	2006
CO_2	NC	NC	NC	NC	NC	NC	NC	NC	NC
CH_4	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%
N_2O	(3.9%)	(3.9%)	(3.9%)	(3.9%)	(3.9%)	(3.9%)	(3.9%)	(3.9%)	(3.9%)
SF_6	(4.6%)	(4.6%)	(4.6%)	(4.6%)	(4.6%)	(4.6%)	(4.6%)	(4.6%)	(4.6%)
HFCs	25.4%	11.0%	9.6%	8.3%	8.8%	7.2%	7.9%	7.8%	7.9%
Substitution of Ozone Depleting Substances	(100.0%)	3.6%	4.5%	5.4%	5.4%	5.3%	5.5%	5.8%	6.1%
HCFC-22 Production	26.5%	26.5%	26.5%	26.5%	26.5%	26.5%	26.5%	26.5%	26.5%
Semiconductor Manufacture	26.5%	26.5%	26.5%	26.5%	26.5%	26.5%	26.5%	26.5%	26.5%
PFCs	17.7%	19.4%	20.5%	23.6%	26.3%	28.0%	29.9%	28.4%	33.3%
Semiconductor Manufacture	28.4%	29.0%	29.1%	31.2%	41.8%	41.4%	41.5%	39.4%	45.0%
Aluminum Production	16.4%	16.4%	15.5%	15.9%	16.1%	16.1%	16.4%	16.3%	16.4%
Total	**1.8%**	**1.7%**	**1.5%**	**1.5%**	**1.5%**	**1.5%**	**1.4%**	**1.4%**	**1.5%**

NC (No change)
[a] PFC emissions from CF_4 and C_2F_6
[b] HFC-23 emitted
[c] Emissions from HFC-23, CF_4, C_2F_6, C_3F_8, SF_6, and the addition of NF_3
[d] SF_6 emitted
Note: Excludes Sinks. 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-237 and Table A-238. Table A-239 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 2006), due the predominance of CH_4 emissions in this sector. Emissions from all other sectors were comprised of mainly CO_2 or a mix of gases, which moderated the effect of the changes.

Table A-239: Comparison of Emissions by Sector using IPCC SAR and AR4 GWP Values (Tg CO_2 Eq.)

Sector	1990	1995	2000	2001	2002	2003	2004	2005	2006
Energy									
SAR GWP (Used in Inventory)	5,203.9	5,529.6	6,067.8	5,982.8	6,036.3	6,078.3	6,150.9	6,174.4	6,076.9
AR4 GWP, Updated	5,251.4	5,574.0	6,109.8	6,024.5	6,077.2	6,118.9	6,190.2	6,210.9	6,113.8
Difference (%)	0.9%	0.8%	0.7%	0.7%	0.7%	0.7%	0.6%	0.6%	0.6%
Industrial Processes									
SAR GWP (Used in Inventory)	299.9	315.7	326.5	297.9	308.6	301.2	315.9	315.5	320.9
AR4 GWP, Updated	310.6	326.3	338.7	307.7	319.8	310.1	326.6	326.4	332.2
Difference (%)	3.6%	3.4%	3.7%	3.3%	3.6%	2.9%	3.4%	3.4%	3.5%
Solvent and Other Product Use									
SAR GWP (Used in Inventory)	4.4	4.6	4.9	4.9	4.4	4.4	4.4	4.4	4.4
AR4 GWP, Updated	4.2	4.4	4.7	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%)	(3.9%)	(3.9%)
Agriculture									
SAR GWP (Used in Inventory)	447.5	453.8	447.9	463.7	449.0	434.3	432.1	453.6	454.1
AR4 GWP, Updated	468.2	476.5	469.9	485.2	471.2	457.1	454.5	475.9	476.5
Difference (%)	4.6%	5.0%	4.9%	4.6%	4.9%	5.3%	5.2%	4.9%	4.9%
Land Use, Land-Use Change, and Forestry									
SAR GWP (Used in Inventory)	(724.6)	(761.7)	(643.6)	(730.2)	(798.4)	(841.2)	(856.6)	(855.4)	(846.8)
AR4 GWP, Updated	(723.8)	(760.9)	(640.1)	(728.6)	(795.4)	(839.6)	(855.4)	(853.1)	(842.3)
Difference (%)	(0.1%)	(0.1%)	(0.5%)	(0.2%)	(0.4%)	(0.2%)	(0.1%)	(0.3%)	(0.5%)
Waste									
SAR GWP (Used in Inventory)	179.6	176.8	155.6	152.1	154.5	160.3	157.7	158.7	161.0
AR4 GWP, Updated	212.2	208.7	183.2	179.0	181.9	188.7	185.5	186.8	189.4
Difference (%)	18.2%	18.1%	17.7%	17.7%	17.7%	17.7%	17.7%	17.6%	17.6%
Net Emissions (Sources and Sinks)									
SAR GWP (Used in Inventory)	**5,410.6**	**5,718.7**	**6,359.0**	**6,171.1**	**6,154.4**	**6,137.3**	**6,204.3**	**6,251.3**	**6,170.5**
AR4 GWP	**5,522.8**	**5,829.0**	**6,466.2**	**6,272.6**	**6,258.9**	**6,239.4**	**6,305.7**	**6,351.0**	**6,273.8**
Difference (%)	**2.1%**	**1.9%**	**1.7%**	**1.6%**	**1.7%**	**1.7%**	**1.6%**	**1.6%**	**1.7%**

NC (No change)
Note: Totals may not sum due to independent rounding. Parentheses indicate negative values.

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 are used for maintaining the equipment. In addition, U.S. regulations require the recovery of ODSs in order to minimize "venting" to the atmosphere. 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), are being phased out at later dates because they have lower ozone depletion potentials. These compounds 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 increase over the next several years as equipment that use Class I 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- 240.

Table A- 240: Emissions of Ozone Depleting Substances (Gg)

Compound	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Class I																	
CFC-11	27.4	28.1	12.4	11.8	11.0	10.1	9.0	8.9	8.7	8.5	9.7	9.5	9.3	9.2	8.8	11.2	11.1

[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	106.6	108.8	110.3	107.9	86.2	65.0	58.9	54.1	46.6	39.4	33.2	27.0	22.0	17.4	13.3	9.7	7.4
CFC-113	59.4	60.5	56.3	51.9	34.9	11.5	+	+	+	+	+	+	+	+	+	+	+
CFC-114	5.0	3.5	2.0	0.5	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.2	0.2
CFC-115	5.5	5.8	5.9	5.7	5.6	5.3	5.1	4.9	4.6	4.4	4.1	3.6	3.2	2.7	2.0	1.3	0.6
Carbon Tetrachloride	4.3	4.4	3.6	2.7	1.9	0.9	+	+	+	+	+	+	+	+	+	+	+
Methyl Chloroform	222.5	227.0	209.1	190.4	147.7	72.1	8.7	+	+	+	+	+	+	+	+	+	+
Halon-1211	1.6	1.7	1.7	1.7	1.7	1.6	1.6	1.6	1.5	1.3	1.1	0.9	0.8	0.7	0.7	0.7	0.7
Halon-1301	1.6	1.7	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.5	1.5	1.5	1.5	1.5	1.4	1.3
Class II																	
HCFC-22	37.2	40.3	42.7	45.3	49.1	52.8	56.1	59.6	63.1	66.7	74.3	77.7	80.0	81.4	82.8	83.6	84.7
HCFC-123	+	+	0.1	0.1	0.2	0.3	0.3	0.4	0.5	0.5	0.6	0.6	0.7	0.7	0.8	0.8	0.8
HCFC-124	+	+	+	0.6	1.1	1.2	1.2	1.3	1.4	1.4	1.5	1.5	1.5	1.5	1.5	1.5	1.5
HCFC-141b	1.0	1.2	1.1	2.0	2.9	3.9	5.1	5.7	6.3	6.9	7.0	6.8	5.5	3.8	3.9	4.0	4.1
HCFC-142b	2.1	3.3	4.5	5.7	4.9	3.6	2.2	2.3	2.4	2.6	2.7	2.8	2.9	3.0	3.2	3.3	3.4
HCFC-225ca/cb	+	+	+	+	+	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	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.

6.3. Sulfur Dioxide Emissions

Sulfur dioxide (SO_2), 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 SO_2-derived aerosols on radiative forcing is believed to be negative (IPCC 1996). However, because SO_2 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-241.

The major source of SO_2 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 SO_2. The largest contributor to U.S. emissions of SO_2 is electricity generation, accounting for 61 percent of total SO_2 emissions in 2004 (see Table A-242); coal combustion accounted for approximately 92 percent of that total. The second largest source was industrial fuel combustion, which produced 7 percent of 2005 SO_2 emissions. Overall, SO_2 emissions in the United States decreased by 34 percent from 1990 to 2005. 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 SO_2 can cause significant increases in acute and chronic respiratory diseases. In addition, once SO_2 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 SO_2 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]

References

EPA (2005) *Air Emissions Trends—Continued Progress Through 2004.* U.S. Environmental Protection Agency, Washington DC. August 18, 2005 <http://www.epa.gov/airtrends/2005/econ-emissions.html>.

EPA (2003) E-mail correspondence containing preliminary ambient air pollutant data between EPA OAP and EPA OAQPS. December 22, 2003.

Table A-241: SO_2 Emissions (Gg)

Sector/Source	1990	1995	2000	2001	2002	2003	2004	2005	2006
Energy	**19,628**	**15,772**	**13,796**	**13,404**	**12,552**	**12,826**	**12,431**	**12,316**	**11,464**
Stationary Combustion	18,407	14,724	12,848	12,461	11,613	11,956	11,625	11,573	10,784
Mobile Combustion	793	672	632	624	683	621	564	508	451
Oil and Gas Activities	390	335	286	289	233	226	220	213	207
Waste Combustion	38	42	29	30	23	22	22	22	22
Industrial Processes	**1,307**	**1,117**	**1,031**	**1,047**	**850**	**804**	**800**	**797**	**793**
Chemical Manufacturing	269	259	307	310	235	234	234	233	233
Metals Processing	659	481	284	301	193	193	193	193	193
Storage and Transport	6	2	6	6	4	4	4	4	4
Other Industrial Processes	362	366	372	389	295	294	293	292	292
Miscellaneous*	11	9	63	40	122	78	76	73	71
Solvent Use	**+**	**1**	**1**	**1**	**+**	**+**	**+**	**+**	**+**
Degreasing	+	+	0	0	0	0	0	0	0

[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]

Graphic Arts	+	+	0	0	0	0	0	0	0
Dry Cleaning	NA	+	0	0	0	0	0	0	0
Surface Coating	+	1	0	0	0	0	0	0	0
Other Industrial	+	+	1	1	0	0	0	0	0
Non-industrial	NA	NA	NA	NA	NA	NA	NA	NA	NA
Agriculture	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**
Agricultural Burning	NA	NA	NA	NA	NA	NA	NA	NA	NA
Waste	**+**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**
Landfills	+	+	1	1	1	1	1	1	1
Wastewater Treatment	+	+	+	+	+	+	+	+	+
Miscellaneous Waste	+	+	+	+	+	+	+	+	+
Total	**20,935**	**16,891**	**14,829**	**14,452**	**13,403**	**13,631**	**13,232**	**13,114**	**12,258**

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-242: SO_2 Emissions from Electricity Generation (Gg)

Fuel Type	1990	1995	2000	2001	2002	2003	2004	2005	2006
Coal	13,808	10,526	9,621	9,056	8,707	9,049	8,760	8,729	8,020
Petroleum	580	375	429	478	459	477	462	460	423
Natural Gas	1	8	157	181	174	181	175	174	160
Misc. Internal Combustion	45	50	54	55	57	60	58	57	53
Other	NA	NA	78	74	71	74	71	71	65
Total	**14,433**	**10,959**	**10,339**	**9,843**	**9,468**	**9,840**	**9,526**	**9,492**	**8,721**

Source: Data taken from EPA (2005) and disaggregated based on EPA (2003).
Note: Totals may not sum due to independent rounding.

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_2O, CO, NO_x, NMVOC
Mobile Combustion (excluding CO_2)	CH_4, N_2O, CO, NO_x, NMVOC
Coal Mining	CH_4
Abandoned Underground Coal Mines	CH_4
Natural Gas Systems	CH_4
Petroleum Systems	CH_4
Municipal Solid Waste Combustion	CO_2, N_2O
Industrial Processes	
Titanium Dioxide Production	CO_2
Aluminum Production	CO_2, CF_4, C_2F_6
Iron and Steel Production	CO_2, CH_4
Ferroalloy Production	CO_2, CH_4
Ammonia Manufacture and Urea Application	CO_2
Cement Manufacture	CO_2
Lime Manufacture	CO_2
Limestone and Dolomite Use	CO_2
Soda Ash Manufacture 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_2O
Nitric Acid Production	N_2O
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_2O Product Usage	N_2O
Agriculture	
Enteric Fermentation	CH_4
Manure Management	CH_4, N_2O
Rice Cultivation	CH_4
Field Burning of Agricultural Residues	CH_4, N_2O
Agricultural Soil Management	N_2O, CO, NO_x
Land Use, Land-Use Change, and Forestry	
CO_2 Flux	CO_2 (sink)
Cropland Remianing Cropland	CO_2
Settlements Remaining Settlements	N_2O
Forestland Remaining Forestland	CH_4, N_2O
Waste	
Landfills	CH_4
Wastewater Treatment	CH_4, N_2O
Composting	CH_4, N_2O

[a] Includes HFC-23, HFC-32, HFC-125, HFC-134a, HFC-143a, HFC-236fa, CF_4, HFC-152a, HFC-227ea, HFC-245fa, HFC-4310mee, and PFC/PFPEs.

[b] Includes such gases as HFC-23, CF_4, C_2F_6, SF_6.

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- 243 provides a guide for determining the magnitude of metric units.

Table A- 243: 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 Conversions[89]

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-244 can be used as default factors, if local data are not available. See Appendix A of EIA's *Annual Energy Review 2006* (EIA 2007a) for more detailed information on the energy content of various fuels.

Table A-244: 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

[89] Reference: EIA (2007a)

Natural Gas (Btu/Cubic foot)	**1,027**
Liquid Fuels (Million Btu/Barrel)	
Crude oil	5.800
Natural gas liquids and LRGs	3.777
Other liquids	5.825
Motor gasoline	5.218
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 2006* (EIA 2007b). For coal ranks, *State Energy Data Report 1992* (EIA 1993). All values are given in higher heating values (gross calorific values).

References

EIA (2007a) *Emissions of Greenhouse Gases in the United States 2006, Draft Report.* Office of Integrated Analysis and Forecasting, Energy Information Administration, U.S. Department of Energy, Washington, DC. DOE-EIA-0573(2006).

EIA (2007b) Annual Energy Review 2006. Energy Information Administration, U.S. Department of Energy, Washington, DC. DOE/EIA-0384(2006). June 2007.

EIA (1998) *Emissions of Greenhouse Gases in the United States*, DOE/EIA-0573(97), Energy Information Administration, U.S. Department of Energy. Washington, DC. October.

EIA (1993) *State Energy Data Report 1992*, DOE/EIA-0214(93), Energy Information Administration, U.S. Department of Energy. Washington, DC. December.

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
APC	American Plastics Council
API	American Petroleum Institute
ASAE	American Society of Agricultural Engineers
ASTM	American Society for Testing and Materials
BEA	Bureau of Economic Analysis, U.S. Department of Commerce
BoC	Bureau of Census
BOD5	Biochemical oxygen demand over a 5-day period
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
CBI	Confidential Business Information
CFC	Chlorofluorocarbon
CFR	Code of Federal Regulations
CMA	Chemical Manufacturer's Association
CMOP	Coalbed Methane Outreach Program
CNG	Compressed Natural Gas
CRF	Common Reporting Format
CRM	Crop Residue Management
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
DIC	Dissolved inorganic carbon
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
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
FAA	Federal Aviation Administration
FAO	Food and Agricultural Organization
FCCC	Framework Convention on Climate Change
FEB	Fiber Economics Bureau
FHWA	Federal Highway Administration
FIA	Forest Inventory and Analysis
GAA	Governmental Advisory Associates
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
HTS	Harmonized Tariff Schedule
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
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
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
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
NIAR	Norwegian Institute for Air Research
NIR	National Inventory Report
NMVOC	Non-methane volatile organic compound
NOx	Nitrogen Oxides
NPRA	National Petroleum and Refiners Association
NRC	National Research Council
NRCS	Natural Resources Conservation Service
NRI	National Resources Inventory
NSCR	Non-selective catalytic reduction
NVFEL	National Vehicle Fuel Emissions Laboratory

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
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
PDF	Probability Density Function
PET	Polyethylene Terephthalate
PFC	Perfluorocarbon
PFPE	Perfluoropolyether
POTW	Publicly Owned Treatment Works
Ppbv	Parts per billion (10^9) by volume
PPC	Precipitated calcium carbonate
Ppmv	Parts per million(10^6) by volume
Pptv	Parts per trillion (10^{12}) by volume
PS	Polystyrene
PSU	Primary Sample Unit
PVC	Polyvinyl chloride
QA/QC	Quality Assurance and Quality Control
QBtu	Quadrillion Btu
RCRA	Resource Conservation and Recovery Act
SAE	Society of Automotive Engineers
SAN	Styrene Acrylonitrile
SAR	IPCC Second Assessment Report
SBSTA	Subsidiary Body for Scientific and Technical Advice
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
TAME	Tertiary Amyl Methyl Ether
TAR	IPCC Third Assessment Report
TBtu	Trillion Btu
TDN	Total Digestible Nutrients
Tg CO_2 Eq.	Teragrams carbon dioxide equivalent
TJ	Terajoule
TLEV	Traditional Low Emissions Vehicle
TRI	Toxic Release Inventory
TSDF	Hazardous waste treatment, storage, and disposal facility
TVA	Tennessee Valley Authority
U.S.	United States
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
ZEVs	Zero Emissions Vehicles

6.7. Chemical Formulas

Table A-245: Guide to Chemical Formulas

Symbol	Name
Al	Aluminum
Al_2O_3	Aluminum Oxide
Br	Bromine
C	Carbon
CH_4	Methane
C_2H_6	Ethane
C_3H_8	Propane
CF_4	Perfluoromethane
C_2F_6	Perfluoroethane, hexafluoroethane
c-C_3F_6	Perfluorocyclopropane
C_3F_8	Perfluoropropane
c-C_4F_8	Perfluorocyclobutane
C_4F_{10}	Perfluorobutane
C_5F_{12}	Perfluoropentane
C_6F_{14}	Perfluorohexane
CF_3I	Trifluoroiodomethane
$CFCl_3$	Trichlorofluoromethane (CFC-11)
CF_2Cl_2	Dichlorodifluoromethane (CFC-12)
CF_3Cl	Chlorotrifluoromethane (CFC-13)
$C_2F_3Cl_3$	Trichlorotrifluoroethane (CFC-113)*
CCl_3CF_3	CFC-113a*
$C_2F_4Cl_2$	Dichlorotetrafluoroethane (CFC-114)
C_2F_5Cl	Chloropentafluoroethane (CFC-115)
$CHCl_2F$	HCFC-21
CHF_2Cl	Chlorodifluoromethane (HCFC-22)
$C_2F_3HCl_2$	HCFC-123
C_2F_4HCl	HCFC-124
$C_2FH_3Cl_2$	HCFC-141b
$C_2H_3F_2Cl$	HCFC-142b
$CF_3CF_2CHCl_2$	HCFC-225ca
$CClF_2CF_2CHClF$	HCFC-225cb
CCl_4	Carbon tetrachloride
$CHClCCl_2$	Trichloroethylene
CCl_2CCl_2	Perchloroethylene, tetrachloroethene
CH_3Cl	Methylchloride
CH_3CCl_3	Methylchloroform
CH_2Cl_2	Methylenechloride
$CHCl_3$	Chloroform, trichloromethane
CHF_3	HFC-23
CH_2F_2	HFC-32
CH_3F	HFC-41
C_2HF_5	HFC-125
$C_2H_2F_4$	HFC-134
CH_2FCF_3	HFC-134a
$C_2H_3F_3$	HFC-143*
$C_2H_3F_3$	HFC-143a*
CH_2FCH_2F	HFC-152*
$C_2H_4F_2$	HFC-152a*
CH_3CH_2F	HFC-161
C_3HF_7	HFC-227ea
$CF_3CF_2CH_2F$	HFC-236cb
$CF_3CHFCHF_2$	HFC-236ea
$C_3H_2F_6$	HFC-236fa
$C_3H_3F_5$	HFC-245ca
$CHF_2CH_2CF_3$	HFC-245fa
$CF_3CH_2CF_2CH_3$	HFC-365mfc
$C_5H_2F_{10}$	HFC-43-10mee

CF_3OCHF_2	HFE-125
CF_2HOCF_2H	HFE-134
CH_3OCF_3	HFE-143a
$CF_3CHFOCF_3$	HFE-227ea
$CF_3CHClOCHF_2$	HCFE-235da2
$CF_3CHFOCHF_2$	HFE-236ea2
$CF_3CH_2OCF_3$	HFE-236fa
$CF_3CF_2OCH_3$	HFE-245cb2
$CHF_2CH_2OCF_3$	HFE-245fa1
$CF_3CH_2OCHF_2$	HFE-245fa2
$CHF_2CF_2OCH_3$	HFE-254cb2
$CF_3CH_2OCH_3$	HFE-263fb2
$CF_3CF_2OCF_2CHF_2$	HFE-329mcc2
$CF_3CF_2OCH_2CF_3$	HFE-338mcf2
$CF_3CF_2CF_2OCH_3$	HFE-347mcc3
$CF_3CF_2OCH_2CHF_2$	HFE-347mcf2
$CF_3CHFCF_2OCH_3$	HFE-356mec3
$CHF_2CF_2CF_2OCH_3$	HFE-356pcc3
$CHF_2CF_2OCH_2CHF_2$	HFE-356pcf2
$CHF_2CF_2CH_2OCHF_2$	HFE-356pcf3
$CF_3CF_2CH_2OCH_3$	HFE-365mcf3
$CHF_2CF_2OCH_2CH_3$	HFE-374pcf2
$C_4F_9OCH_3$	HFE-7100
$C_4F_9OC_2H_5$	HFE-7200
$CHF_2OCF_2OC_2F_4OCHF_2$	H-Galden 1040x
$CHF_2OCF_2OCHF_2$	HG-10
$CHF_2OCF_2CF_2OCHF_2$	HG-01
CH_3OCH_3	Dimethyl ether
CH_2Br_2	Dibromomethane
CH_2BrCl	Dibromochloromethane
$CHBr_3$	Tribromomethane
$CHBrF_2$	Bromodifluoromethane
CH_3Br	Methylbromide
CF_2BrCl	Bromodichloromethane (Halon 1211)
$CF_3Br(CBrF_3)$	Bromotrifluoromethane (Halon 1301)
CF_3I	FIC-13I1
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_2O_3	Ferric oxide
FeSi	Ferrosilicon
H, H_2	atomic Hydrogen, molecular Hydrogen
H_2O	Water
H_2O_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_2O	Nitrous oxide
NO	Nitric oxide
NO_2	Nitrogen dioxide
NO_3	Nitrate radical
Na	Sodium
Na_2CO_3	Sodium carbonate, soda ash
Na_3AlF_6	Synthetic cryolite

O, O_2	atomic Oxygen, molecular Oxygen
O_3	Ozone
S	atomic Sulfur
H_2SO_4	Sulfuric acid
SF_6	Sulfur hexafluoride
SF_5CF_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 estimates for some source categories, such as for CO_2 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 inventory 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 analyzed by comparing model results with those of other models developed to characterize the same emission (or removal) process. However, it would be very difficult—if not impossible—to quantify the model uncertainty associated with the inventory 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 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 two source categories, 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 QA/QC and uncertainty management plan in accordance with the IPCC *Good Practice Guidance*. Like the quality assurance/quality control 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 (EPA 2002). 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.

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 more powerful than Tier 1; both methods are described in the next section. The United States is currently in the process of implementing a multi-year strategy to develop quantitative estimates of uncertainty for all source categories using the Tier 2 approach. This year, 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 reflect additional detail and characterization of input parameters using statistical data collection, expert elicitation methods and more informed judgment. Emissions and sinks from International Bunker Fuels, Biomass Combustion, and Indirect Greenhouse Gas Emissions are not included in total emissions estimated for the U.S. Inventory; therefore, no quantitative uncertainty estimates have been developed for these source categories.

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 associated with each input variable is less than 30 percent, and (iii) the input variables (i.e., values to be combined) are not correlated.

The Tier 2 method is preferred (i) if the uncertainty associated with the input variables are 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 significantly 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 iterations specified) using an uncertainty model--which is an emission (or removal) estimation equation that simulates 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 a 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 Distribution 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 uniform, triangular, lognormal, or normal. The choice among these four PDFs depended largely on the observed or measured data and expert judgment.

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-246 summarizes results based on assessments of source category-level uncertainty. The table presents base year (1990 or 1995) and current year (2006) 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 2006 emissions estimated for that source category. Source category trend uncertainty is described subsequently in this Appendix.

Table A-246: Summary Results of Source Category Uncertainty Analyses

Source Category	Base Year Emissions*	2006 Emissions	2006 Uncertainty	
	Tg CO_2 Eq.	Tg CO_2 Eq.	Low	High
CO_2	**5,068.5**	**5,983.1**	**-2%**	**5%**
Fossil Fuel Combustion	4,724.1	5,637.9	-2%	5%
Non-Energy Use of Fuels	117.2	138.0	-20%	9%
Iron and Steel Production	86.2	49.1	-18%	15%
Cement Manufacture	33.3	45.7	-13%	14%
Natural Gas Systems	33.7	28.5	-23%	45%
Municipal Solid Waste Combustion	10.9	20.9	-20%	13%
Lime Manufacture	12.0	15.8	-8%	8%
Ammonia Manufacture and Urea Consumption	16.9	12.4	-10%	12%
Limestone and Dolomite Use	5.5	8.6	-7%	7%
Cropland Remaining Cropland	7.1	8.0	-60%	46%
Soda Ash Manufacture and Consumption	4.1	4.2	-7%	7%
Aluminum Production	6.8	3.9	-5%	5%
Petrochemical Production	2.2	2.6	-35%	39%
Titanium Dioxide Production	1.2	1.9	-12%	13%
Carbon Dioxide Consumption	1.4	1.6	-21%	26%
Ferroalloy Production	2.2	1.5	-12%	12%
Phosphoric Acid Production	1.5	1.2	-18%	19%
Silicon Carbide Production and Consumption	0.4	0.2	-10%	10%
Lead Production	0.3	0.3	-16%	16%
Zinc Production	0.9	0.5	-21%	25%
Petroleum Systems	0.4	0.3	-28%	144%
Land Use, Land-Use Change, and Forestry	*(737.7)*	*(883.7)*	*-19%*	*19%*
Wood Biomass and Ethanol Consumption[b]	*219.3*	*234.7*		
International Bunker Fuels[b]	*113.7*	*127.1*		
CH_4	**606.1**	**555.3**	**-8%**	**19%**
Enteric Fermentation	126.9	126.2	-11%	18%
Landfills	149.6	125.7	-41%	34%
Natural Gas Systems	124.7	102.4	-23%	45%
Coal Mining	84.1	58.5	-9%	30%
Manure Management	31.0	41.4	-18%	20%
Petroleum Systems	33.9	28.4	-28%	144%
Forest Land Remaining Forest Land	4.5	24.6	-69%	71%
Wastewater Treatment	23.0	23.9	-37%	48%
Stationary Combustion	7.4	6.2	-31%	116%
Rice Cultivation	7.1	5.9	-15%	16%
Abandoned Underground Coal Mines	6.0	5.4	-17%	19%
Mobile Combustion[c]	4.2	1.8	-16%	18%
Composting	0.3	1.6	-50%	50%
Petrochemical Production	0.9	1.0	-9%	9%
Iron and Steel Production	1.3	0.9	-8%	9%
Field Burning of Agricultural Residues	0.7	0.8	-65%	79%
Silicon Carbide Production and Consumption	+	+	-9%	10%
Ferroalloy Production	+	+	-12%	12%
International Bunker Fuels[b]	*0.2*	*0.2*		
N_2O	**383.4**	**367.9**	**-4%**	**22%**
Agricultural Soil Management	269.4	265.0	-10%	23%
Mobile Combustion[c]	40.4	29.5	-19%	19%
Nitric Acid Production	17.0	15.6	-40%	41%
Stationary Combustion	12.8	14.5	-24%	190%
Manure Management	12.1	14.3	-16%	24%
Wastewater Treatment	6.3	8.1	-78%	100%
Adipic Acid Production	15.3	5.9	-15%	16%

N_2O from Product Uses	4.4	4.4	-2%	2%
Forest Land Remaining Forest Land	0.5	2.8	-56%	73%
Composting	0.4	1.8	-50%	50%
Settlements Remaining Settlements	1.0	1.5	-49%	163%
Field Burning of Agricultural Residues	0.4	0.5	-64%	73%
Municipal Solid Waste Combustion	0.5	0.4	-66%	184%
International Bunker Fuels[b]	*1.0*	*1.1*		
HFCs, PFCs, and SF_6	**90.4**	**147.9**	**-1%**	**12%**
Substitution of Ozone Depleting Substances*	28.5	110.4	-9%	20%
HCFC-22 Production	36.4	13.8	-7%	10%
Electrical Transmission and Distribution	26.7	13.2	-16%	17%
Semiconductor Manufacture	2.9	4.8	-10%	8%
Magnesium Production and Processing	5.4	3.2	-14%	14%
Aluminum Production	18.5	2.5	-8%	8%
Total	**6,148.3**	**7,054.2**	**-1%**	**5%**
Net Emission (Sources and Sinks)	**5,410.6**	**6,170.5**	**-2%**	**7%**

otes:
otals 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 CO_2 Eq.
Sinks are only included in net emissions total.
Emissions from International Bunker Fuels and Biomass Combustion are not included in totals.
Uncertainty analysis for Mobile Combustion was not conducted for non-road sources. Therefore, the emission estimate prestend here only includes on-road ources and do not match the emission estimate presented in the Energy chapter of this Inventory.

Overall (Aggregate) Inventory Uncertainty Estimate

The overall uncertainty estimate for the U.S. greenhouse gas emissions inventory was developed using the PCC Tier 2 uncertainty estimation methodology. The uncertainty models of all the emission source categories could ot be directly integrated to develop the overall uncertainty estimates due to software constraints in integrating ultiple, large uncertainty models. Therefore, an alternative approach was adopted to develop the overall ncertainty estimates. The Monte Carlo simulation output data for each emission source category uncertainty nalysis were combined and the probability distribution was fitted to the combined simulation output data, where uch simulated output data were available. If such detailed output data were not available for particular emissions ources, individual probability distributions were assigned to those source category emission estimates based on the ost detailed data available from the quantitative uncertainty analysis performed.

For the Composting and for parts of Agricultural Soil Management source categories, Tier 1 uncertainty esults were used in the overall uncertainty analysis estimation. However, for all other emission sources (excluding nternational bunker fuels, CO_2 from biomass combustion), Tier 2 uncertainty results were used in the overall ncertainty estimation.

The results from the overall uncertainty model results indicate that the 2006 U.S. greenhouse gas emissions re estimated to be within the range of approximately 7,000 to 7,400 Tg CO_2 Eq., reflecting a relative 95 percent onfidence interval uncertainty range of -1 percent to 5 percent with respect to the total U.S. greenhouse gas mission estimate of approximately 7,100 Tg CO_2 Eq. The uncertainty interval associated with total CO_2 emissions, hich constitute about 85 percent of the total U.S. greenhouse gas emissions in 2006, ranges from -2 percent to 5 ercent of total CO_2 emissions estimated. The results indicate that the uncertainty associated with the inventory stimate of the total CH_4 emissions ranges from -8 percent to 19 percent, uncertainty associated with the total nventory N_2O emission estimate ranges from -4 percent to 22 percent, and uncertainty associated with high GWP as emissions ranges from -1 percent to 12 percent.

A summary of the overall quantitative uncertainty estimates are shown below, in Table A-247.

able A-247. Quantitative Uncertainty Assessment of Overall National Inventory Emissions (Tg CO_2 Eq. and Percent)

Gas	2006 Emission Estimate (Tg CO_2 Eq.)	Uncertainty Range Relative to Emission Estimate[a] (Tg CO_2 Eq.)		(%)		Mean[b] (Tg CO_2 Eq.)	Standard Deviation (Tg CO_2 Eq.)
		Lower Bound[c]	Upper Bound[c]	Lower Bound[c]	Upper Bound[c]		
CO_2	5,983.1	5,884.9	6,288.6	-2%	5%	6,082.2	105.5

CH_4	555.3	508.4	658.2	-8%	19%	576.6	38.9
N_2O	367.9	352.2	449.3	-4%	22%	398.4	25.0
PFC, HFC & SF_6[d]	147.9	145.7	166.3	-1%	12%	156.1	5.2
Total	**7,054.2**	**6,999.6**	**7,439.0**	**-1%**	**5%**	**7,213.3**	**115.2**
Net Emissions (Sources and Sinks)	**6,170.5**	**6,059.0**	**6,615.0**	**-2%**	**7%**	**6,332.3**	**143.3**

Notes:
[a] The emission estimates correspond to a 95 percent confidence interval.
[b] 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.
[c] The low and high estimates for total emissions were separately calculated through simulations and, hence, the low and high emission estimates for the sub-source categories do not sum to total emissions.
[d] The overall uncertainty estimate did not take into account the uncertainty in the GWP values for CH_4, N_2O and high GWP gases used in the inventory emission calculations for 2006.

Trend Uncertainty

In addition to estimates of uncertainty associated with the current year's emission estimates, this Annex also presents 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., 2006) inventory estimates. However, for purposes of understanding the concept of trend uncertainty, the emission trend is defined in this report 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 base year and 2006 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 correlation between base and current year estimates. Once calculated, the two sensitivities are combined using the error propagation equation to estimate 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 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 2006 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 2006, and are shown in Table A- 248.

Table A- 248. Quantitative Assessment of Trend Uncertainty (Tg CO_2 Eq. and Percent)

Gas/Source	Base Year*	2006	Emissions Trend	Trend Range[a]	
	(Tg CO_2 Eq.)		(%)	(%)	
				Lower Bound	Upper Bound
CO_2	**5,068.5**	**5,983.1**	**18%**	**12%**	**24%**
Fossil Fuel Combustion	4,724.1	5,637.9	19%	14%	25%
Non-Energy Use of Fuels	117.2	138.0	18%	-4%	48%
Iron and Steel Production	86.2	49.1	-43%	-59%	-34%
Cement Manufacture	33.3	45.7	37%	13%	66%
Natural Gas Systems	33.7	28.5	-15%	-48%	20%
Municipal Solid Waste Combustion	10.9	20.9	91%	45%	159%
Lime Manufacture	12.0	15.8	32%	25%	58%
Ammonia Manufacture and Urea Consumption	16.9	12.4	-27%	-44%	-26%
Limestone and Dolomite Use	5.5	8.6	56%	42%	70%
Cropland Remaining Cropland	7.1	8.0	13%	-63%	159%

Soda Ash Manufacture and Consumption	4.1	4.2	0%	-9%	11%
Aluminum Production	6.8	3.9	-43%	-46%	-39%
Petrochemical Production	2.2	2.6	16%	-34%	100%
Titanium Dioxide Production	1.2	1.9	57%	17%	78%
Carbon Dioxide Consumption	1.4	1.6	12%	-17%	48%
Ferroalloy Production	2.2	1.5	-30%	-41%	-16%
Phosphoric Acid Production	1.5	1.2	-24%	-42%	0%
Zinc Production	0.9	0.5	-44%	-62%	-27%
Lead Production	0.3	0.3	-5%	-25%	20%
Petroleum Systems	0.4	0.3	-22%	-63%	62%
Silicon Carbide Production and Consumption	0.4	0.2	-45%	-52%	-36%
Land Use, Land-Use Change, and Forestry (Sink)[b]	*(737.7)*	*(883.7)*	*20%*	*20%*	*20%*
Wood Biomass and Ethanol Consumption[c]	*219.3*	*234.7*			
International Bunker Fuels[c]	*113.7*	*127.1*			
CH_4	**606.1**	**555.3**	**-8%**	**-22%**	**11%**
Enteric Fermentation	126.9	126.2	-1%	-11%	34%
Landfills	149.6	125.7	-16%	-54%	49%
Natural Gas Systems	124.7	102.4	-18%	-44%	33%
Coal Mining	84.1	58.5	-30%	-46%	-11%
Manure Management	31.0	41.4	34%	2%	75%
Petroleum Systems	33.9	28.4	-16%	-65%	93%
Forest Land Remaining Forest Land	4.5	24.6	449%	53%	1710%
Wastewater Treatment	23.0	23.9	4%	-43%	89%
Stationary Combustion	7.4	6.2	-16%	-65%	101%
Rice Cultivation	7.1	5.9	-17%	-82%	291%
Abandoned Underground Coal Mines	6.0	5.4	-11%	-30%	15%
Mobile Combustion[d]	4.2	1.8	-58%	-61%	-54%
Composting	0.3	1.6	395%	122%	1003%
Petrochemical Production	0.9	1.0	17%	3%	31%
Iron and Steel Production	1.3	0.9	-28%	-36%	-19%
Field Burning of Agricultural Residues	0.7	0.8	19%	-65%	135%
Silicon Carbide Production and Consumption	+	+	-67%	-71%	-62%
Ferroalloy Production	+	+	-37%	-47%	-24%
International Bunker Fuels[c]	*0.2*	*0.2*			
N_2O	**383.4**	**367.9**	-4%	-10%	3%
Agricultural Soil Management	269.4	265.0	-2%	-2%	-2%
Mobile Combustion[d]	40.4	29.5	-27%	-45%	-4%
Nitric Acid Production	17.0	15.6	-8%	-49%	65%
Stationary Combustion	12.8	14.5	13%	-61%	232%
Manure Management	12.1	14.3	18%	-10%	56%
Wastewater Treatment	6.3	8.1	29%	-56%	281%
Adipic Acid Production	15.3	5.9	-61%	-69%	-52%
N_2O from Product Uses	4.4	4.4	0%	-2%	7%
Forest Land Remaining Forest Land	0.5	2.8	460%	460%	460%
Composting	0.4	1.8	395%	125%	1003%
Settlements Remaining Settlements	1.0	1.5	48%	48%	48%
Field Burning of Agricultural Residues	0.4	0.5	35%	-66%	415%
Municipal Solid Waste Combustion	0.5	0.4	-15%	-80%	401%
International Bunker Fuels[c]	*1.0*	*1.1*			
HFCs, PFCs, and SF_6	**90.4**	**147.9**	**64%**	**13%**	**35%**
Substitution of Ozone Depleting Substances*	28.5	110.4	262%	223%	308%
HCFC-22 Production	36.4	13.8	64%	44%	87%
Electrical Transmission and Distribution	26.7	13.2	-51%	-63%	-34%
Semiconductor Manufacture	2.9	4.8	-87%	-88%	-85%
Magnesium Production and Processing	5.4	3.2	-42%	-52%	-29%
Aluminum Production	18.5	2.5	-62%	-67%	-56%
Total	**6,148.3**	**7,054.2**	**15%**	**9%**	**19%**
Net Emission (Sources and Sinks)	**5,410.6**	**6,170.5**	**14%**	**8%**	**19%**

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 CO_2 Eq.

[a] Trend Range represents the 95% confidence interval for the change in emissions from Base Year to 2005.
[b] Sinks are only included in net emissions total.
[c] Emissions from International Bunker Fuels and Biomass Combustion are not included in totals.
[d] Uncertainty analysis for Mobile Combustion was not conducted for non-road sources. Therefore, the emission estimate prestend here only includes on-road sources and do not match the emission estimate presented in the Energy chapter of this Inventory.

7.3. Planned Improvements

Identifying the sources of uncertainties 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 uncertainties 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 sources, and preliminary uncertainty estimates based on their parameters' uncertainty have been developed for all the emission source categories, with the exception of international bunker fuels and wood biomass and ethanol combustion source categories, which are not included in the inventory totals.

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 CH_4 and N_2O 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 SF_6 from electrical transmission and distribution is limited due to a lack of activity data regarding national SF_6 consumption or average equipment leak rates.

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 adopting 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 2006 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 CO_2)

Mobile combustion emissions of CH_4 and N_2O 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, VMT, are collected and analyzed each year by government agencies. To determine the uncertainty associated with the activity data used in the calculations of CH_4 and N_2O 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 emission factors for highway 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 judgments were adopted in developing the emission factors. In those cases, the emission factors were developed based on comparisons of fuel consumption between similar vehicle and control technology categories.

The estimates of VMT for highway vehicles by vehicle type in the United States were provided by FHWA (1996 through 2007), and were generated though the cooperation of FHWA and state and 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 2007), 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 United States 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. The uncertainty in the individual estimates was assumed to be inversely related to the magnitude of estimated VMT (i.e., 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 FHWA and EPA data sources. For example, FHWA data are used for defining vehicle types and for developing the estimates of VMT by vehicle type, the estimates of VMT by fuel types are calculated using EPA's definition of vehicle categories (which differ from those of the FHWA).

A total of 171 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 activity-related input variables (e.g., VMT) except in the case of buses, in which a triangular distribution was used. 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 upper and lower bounds assigned to input variables 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 N_2O and CH_4 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-highway vehicles account for 24 percent of CH_4 emissions from mobile sources and 11 percent of N_2O emissions from mobile sources in 2006. A quantitative analysis of uncertainty in the inventory estimates of emissions from non-highway vehicles has not been performed. However, sources of uncertainty for non-highway vehicles are being investigated by examining the underlying uncertainty of emission factors and fuel consumption data, and in the future, EPA will consider conducting a quantitative analysis of uncertainty for these sources.

Estimates of fuel consumption for off-highway 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 2006a). 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 2007). 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 (2007b). 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 EIA (2007a) and FAA (2007). Estimates of jet fuel consumption are also adjusted downward to account for international bunker fuels, introducing a significant amount of uncertainty. Additionally, all jet fuel consumption in the transportation sector is assumed to be consumed by aircraft. Some fuel purchased by airlines is not used in aircraft but instead used to power auxiliary power units, ground equipment, and to test engines. Some jet fuel may also be used for other purposes such as blending with diesel fuel or heating oil.

In calculating CH_4 emissions from aircraft, an average emission factor is applied to total jet fuel consumption. This average emission factor takes into account the fact that CH_4 emissions occur only during the landing and take-off (LTO) cycles, with no CH_4 being emitted during the cruise cycle. However, a better approach would be to apply emission factors based on the number of LTO cycles.

Municipal Solid Waste Combustion

The upper and lower bounds of uncertainty in the CO_2 emissions estimate for Municipal Solid Waste Combustion are 13 percent and -20 percent respectively, and in the N_2O emission estimates are 184 percent and -66 percent respectively, relative to the respective 2006-Inventory estimates, at the 95% 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 N_2O emissions. For more information on emission estimates from MSW combustion, please refer to the Municipal Solid Waste Combustion 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 CO_2 and N_2O emissions is the estimate of the MSW combustion rate. The EPA (2000a, 2003, 2005a, 2006; 2007; Schneider 2007) estimates of materials generated, discarded, and combusted carry considerable uncertainty associated with the material flows methodology used to generate them. Similarly, the *BioCycle* (Glenn 1999, Goldstein and Matdes 2000, Goldstein and Matdes 2001, Kaufman et al. 2004a, Kaufman et al. 2004b, Simmons et al. 2006) estimate of total waste combustion—used for the N_2O emissions estimate—is 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 CO_2 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 is probably small since the major elastomers' carbon contents range from 77 to 91 percent; for plastics, it may be more significant, as their carbon contents range from 29 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 N_2O Emissions.* Because insufficient data exist to provide detailed estimates of N_2O emissions for individual combustion facilities, the estimates presented exhibit high uncertainty. The emission factor for N_2O from municipal solid waste combustion facilities used in the analysis is an average of default values used to estimate N_2O emissions from facilities worldwide (Johnke 1999, UK: Environment Agency 1999, Yasuda 1993). These factors span an order of magnitude, reflecting considerable variability in the processes from site to site. Due to a lack of information on the control of N_2O emissions from MSW combustion facilities in the United States, the estimate of zero percent for N_2O 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 12 percent and -10 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 CO_2/ton NH_3, with 1.2 ton CO_2/ton NH_3 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 CO_2/ton NH_3 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 CO_2 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 CO_2 emissions from fuel use and non-energy use are calculated separately.[90]

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 CO_2/ton NH_3, 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 CO_2 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 CO_2/ton NH_3, corresponding to CO_2 emissions estimates that are approximately 1.5 Tg CO_2 Eq. below the estimates calculated using the EFMA emission factor of 1.2 ton CO_2/ton NH_3. Natural gas feedstock consumption data are not available from EIA for other years, and data for 1991 and previous years may underestimate feedstock natural gas consumption, and therefore the EFMA emission factor was used to estimate CO_2 emissions from ammonia production, rather than EIA data.

Research indicates that there is only one U.S. plant that manufactures ammonia from petroleum coke. CO_2 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 CO_2 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 CO_2 for use in EOR. Such CO_2 is currently assumed to remain sequestered (see the section of this chapter on CO_2 Consumption); however, time series data for the amount of CO_2 recovered from this plant are not available and therefore all of the CO_2 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 CO_2 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 CO_2) of phosphate rock could vary ±1 percent, resulting in a variation in CO_2 emissions of ±20 percent.

Organic C is not included in the calculation of CO_2 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 CO_2 in the phosphoric acid production process, the CO_2 emission estimate would increase by on the order of 50 percent. If it is assumed that 100 percent of the reported domestic production of phosphate rock for Idaho and Utah was first

[90] It appears that the IPCC emission factor for ammonia production of 1.5 ton CO_2 per ton ammonia may include both CO_2 emissions from the natural gas feedstock to the process and some CO_2 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 CO_2 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 CO_2 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 CO_2 of 0.5 tons per ton. This corresponds to a total CO_2 emission factor for the ammonia production process, including both feedstock CO_2 and process heat CO_2, 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 CO_2 emission factor of 1.2 ton CO_2 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.

calcined, and it is assumed that 50 percent of the organic carbon content of the total production for Idaho and Utah was converted to CO_2 in the calcination process, the CO_2 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, CO_2 emissions would fall 10 percent.

Iron and Steel Production

The uncertainty upper and lower bounds of the CO_2 emission estimate for Iron and Steel Production were 15 percent and -18 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 CO_2 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 0.5 percent, respectively. The carbon content of pig iron can vary between 3 and 5 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 emissions estimate for Aluminum Production were 8 percent and -8 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. 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 2 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 the three smelters that participated in the 2003 EPA-funded measurement study, the uncertainties in the smelter-specific CF_4 and C_2F_6 slope coefficients were calculated to be 10 percent. For the two smelters with smelter-specific slope coefficients based on older studies, the uncertainty in the coefficients was assumed to be similar to that given by the IPCC guidance for technology-specific (Tier 2) slope coefficients. For the remaining 10 operating smelters, for which weighted average slope-factors were calculated based on technology-specific IPCC (2001) values, the uncertainty in the weighted average slope coefficients was based on information provided in IPCC (2001) for CWPB smelters, the technology type that makes up most of the production capacity of the 10 smelters. Consequently, the uncertainties assigned to the slope coefficients for CF_4 and C_2F_6 were 10 percent and 22 percent, respectively. (The uncertainty in CF_4 emissions is reported as 6 percent in IPCC (2001), but was increased to 10 percent in this analysis to better account for measurement uncertainty.) 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 14 percent and -14 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, SF_6 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 SF_6 usage estimate generated from the extrapolated emission factor and production information was estimated to be 30 percent. For those industry processes that are not represented in Partnership, such as permanent mold and wrought casting, SF_6 emissions were estimated using production and consumption statistics reported by USGS and estimated process-specific emission factors (see Table 4-63). 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 50 percent. Estimated

emissions for a secondary production facility participating in the Partnership were assigned an uncertainty of 75 percent due to an absence of reported data. In general, where precise quantitative information was not available on the uncertainty of a parameter, a conservative (upper-bound) value was used.

Electric Transmission and Distribution

The uncertainty upper and lower bounds of the emissions estimate for Electric Transmission and Distribution at the 95 percent confidence interval were 17 percent and -16 percent, respectively. Uncertainty associated with emissions of SF_6 from electric 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 SF_6 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 4.1 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 which 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 ±21 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 SF_6 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 SF_6 charged into equipment in 2006 is estimated to have an uncertainty of 49 percent, and is derived from the uncertainty in partner reported new nameplate capacity (estimated as 5 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 2006 emission estimate for SF_6 from electrical transmission and distribution. For each defined parameter (i.e., regression coefficient, transmission mileage, and partner-reported and partner-estimated SF_6 emissions data for electric power systems; and SF_6 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.

Agriculture Manure Management

The uncertainty information below pertains to the emission estimates presented in the Agriculture Manure Management section of the Agriculture chapter. Please refer to that section for information about various manure management systems and their affect on emissions from this source. The uncertainty upper and lower bounds of the CH_4 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 emission estimates are a lack of information on the usage of various manure management systems in each regional location and the exact CH_4 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 the 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 CH_4 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 CH_4 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 CH_4 producing potential of VS excreted by different animal groups (i.e., B_o). The B_o values used in the CH_4 calculations are published values for U.S. animal waste. However, there are several studies that provide a range of B_o values for certain animals, including dairy and swine. The B_o 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 CH_4 as manure from a milking cow. However, the data available for B_o 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 emissions estimate for Rice Cultivation were 117 percent and -65 percent, respectively, at the 95 percent confidence interval. Factors such as primary rice-cropped area, rationing, 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 2006. 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 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, CH_4 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 Agriculture 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., in prep). The analysis was conducted using probability distribution functions (PDFs) for weather, soil characteristics, and N inputs to simulate direct N_2O emissions for each crop- or grassland type in a county. A joint PDF was used to address the structural uncertainty for direct N_2O 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 using a method described by Ogle et al. (2007) to assess uncertainty in model structure associated with the algorithms and parameterization. The estimator was based on a linear mixed-effect modeling analysis comparing N_2O 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 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 2006. 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 N_2O measurement data become available for grassland sites. In general, DAYCENT tended to underestimate emissions if the rates were above 6 g N_2O/ha/day (Del Grosso et al., in prep). 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 N_2O emission factors were based on IPCC (2006), and PDFs for the activity data were based on the uncertainties associated underlying survey information and calculations.[91] 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 N_2O emission factors (IPCC 2006).

Field Burning of Agricultural Residues

The uncertainty upper and lower bounds of the CH_4 emissions estimate for Field Burning of Agricultural Residues were 79 percent and -65 percent, respectively, and of the N_2O emissions estimate were 73 percent and -64 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

[91] With the exception of organic fertilizers and crop yields, which were assumed to have a default ±50 percent uncertainty.

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. 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. Based on the range given for measurements of soybean dry matter fraction (Strehler and Stützle 1987), residue dry matter contents were assigned an uncertainty of 3.1 percent for all crop types. Burning and combustion efficiencies were assigned an uncertainty of 5 percent based on expert judgment.

The N_2O 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 CH_4 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

The uncertainty analysis descriptions in this section correspond to some source categories included in the Land Use, Land-Use Change and Forestry Chapter of the Inventory.

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 smaller, and precision at plot levels is larger. 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 exhibit 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 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.

Non-CO_2 Emissions from Forest Fires

The uncertainty information below pertains to the emission estimates presented in the Non-CO_2 Emissions from Forest Fires section of the LULUCF chapter. Please refer to that section for information about forest area estimates, average C density, and combustion factors, and emission estimates from this source. The uncertainty upper and lower bounds of the CH_4 emissions estimate from Forest Fires were 71 percent and -69 percent, respectively, and of the N_2O emissions estimate 75 percent and -69 percent, respectively, at the 95 percent confidence interval. To quantify the uncertainties for emissions from forest fires, a Monte Carlo (Tier 2) uncertainty analysis was performed using the information provided above. The uncertainty inputs are described in more detail in the section on non-CO_2 emissions from forest fires.

Uncertainty in forest area was estimated to be ±0.24 percent for the 95 percent confidence interval (Heath 2006a). This estimate was calculated based on FIA accuracy standards, which mandate that sampling error cannot exceed 3 percent error per 1 million acres of timberland (Heath 2006a). This same uncertainty was assumed for data on the area of forest land considered to be under protection from fire and the total area considered to be under protection from fire. Uncertainty in average C density was estimated to be ±0.4 percent for the lower 48 States and ±5 percent for Alaska (Heath 2006a, 2007). Uncertainties in emission ratios were based on IPCC (2003) guidance to apply a 70 percent uncertainty range. Since the combustion factor (0.4) was a default IPCC (2003) value, the uncertainty range provided by IPCC (0.36 to 0.45) was assumed.

Direct N_2O fluxes from Forest Soils

The uncertainty upper and lower bounds of the emissions estimate for Direct N_2O 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 N_2O fluxes from Forest Soils. For more information, please refer to that section of the LULUCF chapter. The uncertainty range of the IPCC default emission factor for synthetic fertilizer applied to soil, according to IPCC (2006), 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 35 percent and -38 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.

Uncertainties in 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.

Uncertainties in Organic Soil C 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.

Uncertainties in CO_2 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 CO_2 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 (HNO_3)—a process that releases CO_2—and what portion reacts with carbonic acid (H_2CO_3), resulting in the uptake of CO_2. The fractions can vary depending on soil pH and N fertilizer use. The second major source of uncertainty is the fraction of bicarbonate (HCO_3^-) 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 22 percent and -25 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*.

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. 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 15 percent and -18 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*. The uncertainty in the inventory estimate of a 0.2 Tg CO_2 Eq. removal was 89 percent below the mean and 127 percent above the mean.

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 14 percent and -13 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

N_2O Fluxes from Settlement Soil

The uncertainty information below pertains to the emission estimates presented in the N_2O Fluxes from Settlement Soil 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 N_2O 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, which were used to determine the amounts applied in 2005: (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**.**

(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 moisture content for branches. 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 half-life of grass was assumed to range from 1 to 15 years, the half-life of food scraps was assumed to range from 1 to 20 years, the half-life of leaves was assumed to

range from 2 to 30 years, and the half life of branches was assumed to range from 5 to 50 years. Finally, 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.

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