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 2004. 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 (1990-2004) Based on Tier 1 Approach

IPCC Source Categories	Gas	Level Without LULUCF	Trend Without LULUCF	Level With LULUCF	Trend With LULUCF	Qual[a]	2004 Emissions (Tg CO_2 Eq.)
Energy							
CO_2 Emissions from Stationary Combustion—Coal	CO_2	✓	✓	✓	✓		2,027.0
Mobile Combustion: Road & Other	CO_2	✓	✓	✓	✓		1,621.5
CO_2 Emissions from Stationary Combustion—Gas	CO_2	✓	✓	✓	✓		1,153.8
CO_2 Emissions from Stationary Combustion—Oil	CO_2	✓	✓	✓	✓		619.9
Mobile Combustion: Aviation	CO_2	✓	✓	✓	✓		179.6
Fugitive Emissions from Natural Gas Operations	CH_4	✓	✓	✓	✓		153.4
CO_2 Emissions from Non-Energy Use of Fuels	CO_2	✓	✓	✓	✓		118.8
International Bunker Fuels[b]	Several					✓	95.5
Fugitive Emissions from Coal Mining and Handling	CH_4	✓	✓	✓	✓		56.3
Mobile Combustion: Marine	CO_2	✓		✓			54.4
Mobile Combustion: Road & Other	N_2O	✓	✓	✓			40.6
Fugitive Emissions from Oil Operations	CH_4	✓	✓	✓	✓		25.7
Industrial Processes							

Emissions from Substitutes for Ozone Depleting Substances	Several	✓	✓	✓	✓	103.3
CO_2 Emissions from Iron and Steel Production	CO_2	✓	✓	✓	✓	51.3
CO_2 Emissions from Cement Production	CO_2	✓	✓	✓	✓	45.6
CO_2 Emissions from Ammonia Production and Urea Application	CO_2		✓			16.9
SF_6 Emissions from Electrical Equipment	SF_6		✓		✓	15.6
HFC-23 Emissions from HCFC-22 Manufacture	HFCs	✓	✓	✓	✓	13.8
N_2O Emissions from Adipic Acid Production	N_2O		✓		✓	5.7
PFC Emissions from Aluminum Production	PFCs		✓		✓	2.8
Agriculture						
Direct N_2O Emissions from Agricultural Soils	N_2O	✓		✓		170.9
CH_4 Emissions from Enteric Fermentation in Domestic Livestock	CH_4	✓	✓	✓	✓	112.6
Indirect N_2O Emissions from Nitrogen Used in Agriculture	N_2O	✓	✓	✓	✓	90.6
CH_4 Emissions from Manure Management	CH_4			✓		39.4
Waste						
CH_4 Emissions from Solid Waste Disposal Sites	CH_4	✓	✓	✓	✓	140.9
CH_4 Emissions from Wastewater Handling	CH_4		✓		✓	36.9
CO_2 Emissions from Waste Incineration	CO_2		✓		✓	19.4
Land Use, Land-Use Change, and Forestry						
CO_2 Emissions from Forest Land Remaining Forest Land	CO_2			✓	✓	(637.2)
CO_2 Emissions from Settlements Remaining Settlements	CO_2			✓		(97.3)
CO_2 Emissions from Cropland Remaining Cropland	CO_2			✓	✓	(28.9)
Subtotal Without LULUCF						6,918.2
Total Emissions Without LULUCF						7,067.6
Percent of Total Without LULUCF						97.9%
Subtotal With LULUCF						6,154.8
Total Emissions With LULUCF						6,294.3
Percent of Total With LULUCF						97.8%

[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 2004) 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 2004 level assessments for both with and withouth LULCF 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 2004.

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

IPCC Source Categories	Direct GHG	2004 Emissions (Tg CO_2 Eq.)	Key Category Flag?	ID Criteria	Comments
Energy					
CO_2 Emissions from Stationary Combustion—Coal	CO_2	2,027.0	✓	L,T	Level in 1990 and 2004
Mobile Combustion: Road & Other	CO_2	1,621.5	✓	L,T	Level in 1990 and 2004
CO_2 Emissions from Stationary Combustion—Gas	CO_2	1,153.8	✓	L,T	Level in 1990 and 2004
CO_2 Emissions from Stationary Combustion—Oil	CO_2	619.9	✓	L,T	Level in 1990 and 2004
Mobile Combustion: Aviation	CO_2	179.6	✓	L,T	Level in 1990 and 2004
CO_2 Emissions from Non-Energy Use of Fuels	CO_2	153.4	✓	L,T	Level in 1990 and 2004
Mobile Combustion: Marine	CO_2	54.4	✓	L	Level in 1990 and 2004
CO_2 Emissions from Natural Gas Flaring	CO_2	6.0			
CO_2 Emissions from Stationary Combustion—Geothermal Energy	CO_2	0.4			
Fugitive Emissions from Natural Gas Operations	CH_4	118.8	✓	L,T	Level in 1990 and 2004
Fugitive Emissions from Coal Mining and Handling	CH_4	56.3	✓	L,T	Level in 1990 and 2004
Fugitive Emissions from Oil Operations	CH_4	25.7	✓	L,T	Level in 1990
Non-CO_2 Emissions from Stationary Combustion	CH_4	6.4			
Fugitive Emissions from Abandoned Coal Mines	CH_4	5.6			
Mobile Combustion: Road & Other	CH_4	2.7			
Mobile Combustion: Aviation	CH_4	0.1			
Mobile Combustion: Marine	CH_4	0.1			
Mobile Combustion: Road & Other	N_2O	40.6	✓	L,T	Level in 1990 and 2004
Non-CO_2 Emissions from Stationary Combustion	N_2O	13.7			
Mobile Combustion: Aviation	N_2O	1.8			
Mobile Combustion: Marine	N_2O	0.4			
International Bunker Fuels[a]	Several	95.5	✓	Q	
Industrial Processes					
CO_2 Emissions from Iron and Steel Production	CO_2	51.3	✓	L,T	Level in 1990 and 2004
CO_2 Emissions from Cement Production	CO_2	45.6	✓	L,T	Level in 1990 and 2004
CO_2 Emissions from Ammonia Production and Urea Application	CO_2	16.9	✓	T	
CO_2 Emissions from Lime Production	CO_2	13.7			
CO_2 Emissions from Limestone and Dolomite Use	CO_2	6.7			
CO_2 Emissions from Aluminum Production	CO_2	4.3			
CO_2 Emissions from Soda Ash Manufacture and Consumption	CO_2	4.2			
CO_2 Emissions from Petrochemical Production	CO_2	2.9			
CO_2 Emissions from Titanium Dioxide Production	CO_2	2.3			
CO_2 Emissions from Phosphoric Acid Production	CO_2	1.4			
CO_2 Emissions from Ferroalloys	CO_2	1.3			
CO_2 Emissions from CO_2 Consumption	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 Consumption	CO_2	0.1			
CH_4 Emissions from Petrochemical Production	CH_4	1.6			
CH_4 Emissions from Iron and Steel Production	CH_4	1.0			
CH_4 Emissions from Silicon Carbide Production	CH_4	+			
N_2O Emissions from Nitric Acid Production	N_2O	16.6			
N_2O Emissions from Adipic Acid Production	N_2O	5.7	✓	T	
N_2O Emissions from N_2O Product Usage	N_2O	4.8			

Emissions from Substitutes for Ozone Depleting Substances	HiGWP	103.3	✓	L,T	Level in 2004
HFC-23 Emissions from HCFC-22 Manufacture	HiGWP	15.6	✓	L,T	Level in 1990
SF_6 Emissions from Electrical Equipment	HiGWP	13.8	✓	T	
PFC, HFC, and SF_6 Emissions from Semiconductor Manufacture	HiGWP	4.7			
PFC Emissions from Aluminum Production	HiGWP	2.8	✓	T	
SF_6 Emissions from Magnesium Production	HiGWP	2.7			
Agriculture					
CH_4 Emissions from Enteric Fermentation in Domestic Livestock	CH_4	112.6	✓	L,T	Level in 1990 and 2004
CH_4 Emissions from Manure Management	CH_4	39.4			
CH_4 Emissions from Rice Production	CH_4	7.6			
CH_4 Emissions from Agricultural Residue Burning	CH_4	0.9			
Direct N_2O Emissions from Agricultural Soils	N_2O	170.9	✓	L	Level in 1990 and 2004
Indirect N_2O Emissions from Nitrogen Used in Agriculture	N_2O	90.6	✓	L,T	Level in 1990 and 2004
N_2O Emissions from Manure Management	N_2O	17.7			
N_2O Emissions from Agricultural Residue Burning	N_2O	0.5			
Waste					
CO_2 Emissions from Waste Incineration	CO_2	19.4	✓	T	
CH_4 Emissions from Solid Waste Disposal Sites	CH_4	140.9	✓	L,T	Level in 1990 and 2004
CH_4 Emissions from Wastewater Handling	CH_4	36.9	✓	T	
N_2O Emissions from Wastewater Handling	N_2O	16.0			
N_2O Emissions from Waste Incineration	N_2O	0.5			

[a] Emissions from these sources not included in totals.
+ Does not exceed 0.05 Tg CO_2 Eq.
Note: LULUCF sourcesand 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	Direct GHG	2004 Emissions (Tg CO_2 Eq.)	Key Source Category Flag?	ID Criteria	Comments
Energy					
CO_2 Emissions from Stationary Combustion—Coal	CO_2	2,027.0	✓	L,T	Level in 1990 and 2004
Mobile Combustion: Road & Other	CO_2	1,621.5	✓	L,T	Level in 1990 and 2004
CO_2 Emissions from Stationary Combustion—Gas	CO_2	1,153.8	✓	L,T	Level in 1990 and 2004
CO_2 Emissions from Stationary Combustion—Oil	CO_2	619.9	✓	L,T	Level in 1990 and 2004
Mobile Combustion: Aviation	CO_2	179.6	✓	L,T	Level in 1990 and 2004
CO_2 Emissions from Non-Energy Use of Fuels	CO_2	153.4	✓	L,T	Level in 1990 and 2004
Mobile Combustion: Marine	CO_2	54.4	✓	L	Level in 1990 and 2004
CO_2 Emissions from Natural Gas Flaring	CO_2	6.0			
CO_2 Emissions from Stationary Combustion—Geothermal Energy	CO_2	0.4			
Fugitive Emissions from Natural Gas Operations	CH_4	118.8	✓	L,T	Level in 1990 and 2004
Fugitive Emissions from Coal Mining and Handling	CH_4	56.3	✓	L,T	Level in 1990 and 2004
Fugitive Emissions from Oil Operations	CH_4	25.7	✓	L,T	Level in 1990
Non-CO_2 Emissions from Stationary Combustion	CH_4	6.4			
Fugitive Emissions from Abandoned Coal Mines	CH_4	5.6			
Mobile Combustion: Road & Other	CH_4	2.7			
Mobile Combustion: Aviation	CH_4	0.1			
Mobile Combustion: Marine	CH_4	0.1			
Mobile Combustion: Road & Others	N_2O	40.6	✓	L	Level in 1990 and 2004

Non-CO_2 Emissions from Stationary Combustion	N_2O	13.7			
Mobile Combustion: Aviation	N_2O	1.8			
Mobile Combustion: Marine	N_2O	0.4			
International Bunker Fuels[a]	Several	95.5	✓	Q	
Industrial Processes					
CO_2 Emissions from Iron and Steel Production	CO_2	51.3	✓	L,T	Level in 1990 and 2004
CO_2 Emissions from Cement Production	CO_2	45.6	✓	L,T	Level in 1990 and 2004
CO_2 Emissions from Ammonia Production and Urea Application	CO_2	16.9			
CO_2 Emissions from Lime Production	CO_2	13.7			
CO_2 Emissions from Limestone and Dolomite Use	CO_2	6.7			
CO_2 Emissions from Aluminum Production	CO_2	4.3			
CO_2 Emissions from Soda Ash Manufacture and Consumption	CO_2	4.2			
CO_2 Emissions from Petrochemical Production	CO_2	2.9			
CO_2 Emissions from Titanium Dioxide Production	CO_2	2.3			
CO_2 Emissions from Phosphoric Acid Production	CO_2	1.4			
CO_2 Emissions from Ferroalloys	CO_2	1.3			
CO_2 Emissions from CO_2 Consumption	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 Consumption	CO_2	0.1			
CH_4 Emissions from Petrochemical Production	CH_4	1.6			
CH_4 Emissions from Iron and Steel Production	CH_4	1.0			
CH_4 Emissions from Silicon Carbide Production	CH_4	+			
N_2O Emissions from Nitric Acid Production	N_2O	16.6			
N_2O Emissions from Adipic Acid Production	N_2O	5.7	✓	T	
N_2O Emissions from N_2O Product Usage	N_2O	4.8			
Emissions from Substitutes for Ozone Depleting Substances	HiGWP	103.3	✓	L,T	Level in 2004
HFC-23 Emissions from HCFC-22 Manufacture	HiGWP	15.6	✓	L,T	Level in 1990
SF_6 Emissions from Electrical Equipment	HiGWP	13.8	✓	T	
PFC, HFC, and SF_6 Emissions from Semiconductor Manufacture	HiGWP	4.7			
PFC Emissions from Aluminum Production	HiGWP	2.8	✓	T	
SF_6 Emissions from Magnesium Production	HiGWP	2.7			
Agriculture					
CH_4 Emissions from Enteric Fermentation in Domestic Livestock	CH_4	112.6	✓	L,T	Level in 1990 and 2004
CH_4 Emissions from Manure Management	CH_4	39.4	✓	L	Level in 2004
CH_4 Emissions from Rice Production	CH_4	7.6			
CH_4 Emissions from Agricultural Residue Burning	CH_4	0.9			
Direct N_2O Emissions from Agricultural Soils	N_2O	170.9	✓	L	Level in 1990 and 2004
Indirect N_2O Emissions from Nitrogen Used in Agriculture	N_2O	90.6	✓	L,T	Level in 1990 and 2004
N_2O Emissions from Manure Management	N_2O	17.7			
N_2O Emissions from Agricultural Residue Burning	N_2O	0.5			
Waste					
CO_2 Emissions from Waste Incineration	CO_2	19.4	✓	T	
CH_4 Emissions from Solid Waste Disposal Sites	CH_4	140.9	✓	L,T	Level in 1990 and 2004
CH_4 Emissions from Wastewater Handling	CH_4	36.9	✓	T	
N_2O Emissions from Wastewater Handling	N_2O	16.0			
N_2O Emissions from Waste Incineration	N_2O	0.5			
Land Use, Land-Use Change, and Forestry					
CO_2 Emissions from Forest Land Remaining Forest Land	CO_2	(637.2)	✓	L,T	Level in 1990 and 2004
CO_2 Emissions from Settlements Remaining Settlements	CO_2	(97.3)	✓	L	Level in 1990 and 2004

CO_2 Emissions from Cropland Remaining Cropland	CO_2	(28.9)	✓	L,T	Level in 1990
CO_2 Emissions from Land Converted to Grassland	CO_2	(21.1)			
CO_2 Emissions from Grassland Remaining Grassland	CO_2	7.3			
CO_2 Emissions from Land Converted to Cropland	CO_2	(2.8)			
N_2O Emissions from Settlements Remaining Settlements	N_2O	6.4			
N_2O Emissions from Forest Land Remaining Forest Land	N_2O	0.4			

[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	1,683.8	1,683.8	0.28	0.28
Mobile Combustion: Road & Other	CO_2	1240.6	1240.6	0.20	0.48
CO_2 Emissions from Stationary Combustion—Gas	CO_2	971.0	971.0	0.16	0.64
CO_2 Emissions from Stationary Combustion—Oil	CO_2	580.0	580.0	0.10	0.73
Mobile Combustion: Aviation	CO_2	177.2	177.2	0.03	0.76
CH_4 Emissions from Solid Waste Disposal Sites	CH_4	172.3	172.3	0.03	0.79
Direct N_2O Emissions from Agricultural Soils	N_2O	150.4	150.4	0.02	0.82
Fugitive Emissions from Natural Gas Operations	CH_4	126.7	126.7	0.02	0.84
CH_4 Emissions from Enteric Fermentation in Domestic Livestock	CH_4	117.9	117.9	0.02	0.86
CO_2 Emissions from Non-Energy Use of Fuels	CO_2	117.2	117.2	0.02	0.87
Indirect N_2O Emissions from Nitrogen Used in Agriculture	N_2O	115.7	115.7	0.02	0.89
CO_2 Emissions from Iron and Steel Production	CO_2	85.0	85.0	0.01	0.91
Fugitive Emissions from Coal Mining and Handling	CH_4	81.9	81.9	0.01	0.92
Mobile Combustion: Marine	CO_2	43.6	43.6	0.01	0.93
Mobile Combustion: Road & Other	N_2O	41.4	41.4	0.01	0.93
HFC-23 Emissions from HCFC-22 Manufacture	HFCs	35.0	35.0	0.01	0.94
Fugitive Emissions from Oil Operations	CH_4	34.4	34.4	0.01	0.95
CO_2 Emissions from Cement Production	CO_2	33.3	33.3	0.01	0.95
CH_4 Emissions from Manure Management	CH_4	31.2	31.2	0.01	0.96
SF_6 Emissions from Electrical Equipment	SF_6	28.6	28.6	<0.01	0.96
CH_4 Emissions from Wastewater Handling	CH_4	24.8	24.8	<0.01	0.97
CO_2 Emissions from Ammonia Production and Urea Application	CO_2	19.3	19.3	<0.01	0.97
PFC Emissions from Aluminum Production	PFCs	18.4	18.4	<0.01	0.97
N_2O Emissions from Nitric Acid Production	N_2O	17.8	17.8	<0.01	0.97
N_2O Emissions from Manure Management	N_2O	16.3	16.3	<0.01	0.98
N_2O Emissions from Adipic Acid Production	N_2O	15.2	15.2	<0.01	0.98
N_2O Emissions from Wastewater Handling	N_2O	12.9	12.9	<0.01	0.98
Non-CO_2 Emissions from Stationary Combustion	N_2O	12.3	12.3	<0.01	0.98
CO_2 Emissions from Lime Production	CO_2	11.2	11.2	<0.01	0.99
CO_2 Emissions from Waste Incineration	CO_2	10.9	10.9	<0.01	0.99
Non-CO_2 Emissions from Stationary Combustion	CH_4	7.9	7.9	<0.01	0.99
CH_4 Emissions from Rice Production	CH_4	7.1	7.1	<0.01	0.99
CO_2 Emissions from Aluminum Production	CO_2	7.0	7.0	<0.01	0.99
Fugitive Emissions from Abandoned Coal Mines	CH_4	6.0	6.0	<0.01	0.99
CO_2 Emissions from Natural Gas Flaring	CO_2	5.8	5.8	<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	SF_6	5.4	5.4	<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	4.3	4.3	<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	SF_6	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 Ferroalloys	CO_2	2.0	2.0	<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
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	1.3	1.3	<0.01	1.00
CH_4 Emissions from Petrochemical Production	CH_4	1.2	1.2	<0.01	1.00
CO_2 Emissions from Zinc Production	CO_2	0.9	0.9	<0.01	1.00
CO_2 Emissions from CO_2 Consumption	CO_2	0.9	0.9	<0.01	1.00
CH_4 Emissions from Agricultural Residue Burning	CH_4	0.7	0.7	<0.01	1.00
N_2O Emissions from Waste Incineration	N_2O	0.5	0.5	<0.01	1.00
Emissions from Substitutes for Ozone Depleting Substances	Several	0.4	0.4	<0.01	1.00
CO_2 Emissions from Stationary Combustion—Geothermal Energy	CO_2	0.4	0.4	<0.01	1.00
N_2O Emissions from Agricultural Residue Burning	N_2O	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 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
CO_2 Emissions from Silicon Carbide Consumption	CO_2	0.1	0.1	<0.01	1.00
Mobile Combustion: Marine	CH_4	0.1	0.1	<0.01	1.00
CH_4 Emissions from Silicon Carbide Production	CH_4	0.0	0.0	<0.01	1.00
TOTAL		6,103.3	6,103.3	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	1,683.8	1,683.8	0.24	0.24
Mobile Combustion: Road & Other	CO_2	1,240.6	1,240.6	0.18	0.42
CO_2 Emissions from Stationary Combustion—Gas	CO_2	971.0	971.0	0.14	0.55
CO_2 Emissions from Forest Land Remaining Forest Land	CO_2	773.4	773.4	0.11	0.66
CO_2 Emissions from Stationary Combustion—Oil	CO_2	580.0	580.0	0.08	0.75
Mobile Combustion: Aviation	CO_2	177.2	177.2	0.03	0.77
CH_4 Emissions from Solid Waste Disposal Sites	CH_4	172.3	172.3	0.02	0.80
Direct N_2O Emissions from Agricultural Soils	N_2O	150.4	150.4	0.02	0.82
Fugitive Emissions from Natural Gas Operations	CH_4	126.7	126.7	0.02	0.84
CH_4 Emissions from Enteric Fermentation in Domestic Livestock	CH_4	117.9	117.9	0.02	0.85
CO_2 Emissions from Non-Energy Use of Fuels	CO_2	117.2	117.2	0.02	0.87
Indirect N_2O Emissions from Nitrogen Used in Agriculture	N_2O	115.7	115.7	0.02	0.89
CO_2 Emissions from Iron and Steel Production	CO_2	85.0	85.0	0.01	0.90
CO_2 Emissions from Settlements Remaining Settlements	CO_2	83.2	83.2	0.01	0.91
Fugitive Emissions from Coal Mining and Handling	CH_4	81.9	81.9	0.01	0.92
Mobile Combustion: Marine	CO_2	43.6	43.6	0.01	0.93
Mobile Combustion: Road & Other	N_2O	41.4	41.4	0.01	0.93
HFC-23 Emissions from HCFC-22 Manufacture	HFCs	35.0	35.0	<0.01	0.94
Fugitive Emissions from Oil Operations	CH_4	34.4	34.4	<0.01	0.94
CO_2 Emissions from Cement Production	CO_2	33.3	33.3	<0.01	0.95
CO_2 Emissions from Cropland Remaining Cropland	CO_2	33.1	33.1	<0.01	0.95
CH_4 Emissions from Manure Management	CH_4	31.2	31.2	<0.01	0.96
SF_6 Emissions from Electrical Equipment	SF_6	28.6	28.6	<0.01	0.96
CH_4 Emissions from Wastewater Handling	CH_4	24.8	24.8	<0.01	0.97
CO_2 Emissions from Ammonia Production and Urea Application	CO_2	19.3	19.3	<0.01	0.97
PFC Emissions from Aluminum Production	PFCs	18.4	18.4	<0.01	0.97
N_2O Emissions from Nitric Acid Production	N_2O	17.8	17.8	<0.01	0.97
CO_2 Emissions from Land Converted to Grassland	CO_2	17.6	17.6	<0.01	0.98
N_2O Emissions from Manure Management	N_2O	16.3	16.3	<0.01	0.98
N_2O Emissions from Adipic Acid Production	N_2O	15.2	15.2	<0.01	0.98
N_2O Emissions from Wastewater Handling	N_2O	12.9	12.9	<0.01	0.98
Non- CO_2 Emissions from Stationary Combustion	N_2O	12.3	12.3	<0.01	0.98
CO_2 Emissions from Lime Production	CO_2	11.2	11.2	<0.01	0.99
CO_2 Emissions from Waste Incineration	CO_2	10.9	10.9	<0.01	0.99
Non- CO_2 Emissions from Stationary Combustion	CH_4	7.9	7.9	<0.01	0.99
CH_4 Emissions from Rice Production	CH_4	7.1	7.1	<0.01	0.99
CO_2 Emissions from Aluminum Production	CO_2	7.0	7.0	<0.01	0.99
Fugitive Emissions from Abandoned Coal Mines	CH_4	6.0	6.0	<0.01	0.99
CO_2 Emissions from Natural Gas Flaring	CO_2	5.8	5.8	<0.01	0.99
N_2O Emissions from Settlements Remaining Settlements	N_2O	5.6	5.6	<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	SF_6	5.4	5.4	<0.01	0.99
CO_2 Emissions from Grassland Remaining Grassland	CO_2	4.5	4.5	<0.01	1.00
Mobile Combustion: Road & Other	CH_4	4.5	4.5	<0.01	1.00
N_2O Emissions from N_2O Product Usage	N_2O	4.3	4.3	<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	SF_6	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 Ferroalloys	CO_2	2.0	2.0	<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 Land Converted to Cropland	CO_2	1.5	1.5	<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	1.3	1.3	<0.01	1.00
CH_4 Emissions from Petrochemical Production	CH_4	1.2	1.2	<0.01	1.00
CO_2 Emissions from Zinc Production	CO_2	0.9	0.9	<0.01	1.00
CO_2 Emissions from CO_2 Consumption	CO_2	0.9	0.9	<0.01	1.00
CH_4 Emissions from Agricultural Residue Burning	CH_4	0.7	0.7	<0.01	1.00
N_2O Emissions from Waste Incineration	N_2O	0.5	0.5	<0.01	1.00
Emissions from Substitutes for Ozone Depleting Substances	Several	0.4	0.4	<0.01	1.00
CO_2 Emissions from Stationary Combustion—Geothermal Energy	CO_2	0.4	0.4	<0.01	1.00
N_2O Emissions from Agricultural Residue Burning	N_2O	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 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
CO_2 Emissions from Silicon Carbide Consumption	CO_2	0.1	0.1	<0.01	1.00
Mobile Combustion: Marine	CH_4	0.1	0.1	<0.01	1.00
N_2O Emissions from Forest Land Remaining Forest Land	N_2O	0.1	0.1	<0.01	1.00
CH_4 Emissions from Silicon Carbide Production	CH_4	0.0	0.0	<0.01	1.00
TOTAL		7,022.3	7,022.3	1.00	

Table A- 6: 2004 Key Source Category Tier 1 Analysis—Level Assessment, without LULUCF

IPCC Source Categories	Direct GHG	1990 Estimate (Tg CO_2 Eq.)	2004 Estimate (Tg CO_2 Eq.)	Level Assessment	Cumulative Total of Level Assessment
CO_2 Emissions from Stationary Combustion—Coal	CO_2	1,683.8	2,027.0	0.29	0.29
Mobile Combustion: Road & Other	CO_2	1,240.6	1,621.5	0.23	0.52
CO_2 Emissions from Stationary Combustion—Gas	CO_2	971.0	1153.8	0.16	0.68
CO_2 Emissions from Stationary Combustion—Oil	CO_2	580.0	619.9	0.09	0.77
Mobile Combustion: Aviation	CO_2	177.2	179.6	0.03	0.79
Direct N_2O Emissions from Agricultural Soils	N_2O	150.4	170.9	0.02	0.82
CO_2 Emissions from Non-Energy Use of Fuels	CO_2	117.2	153.4	0.02	0.84
CH_4 Emissions from Solid Waste Disposal Sites	CH_4	172.3	140.9	0.02	0.86
Fugitive Emissions from Natural Gas Operations	CH_4	126.7	118.8	0.02	0.88
CH_4 Emissions from Enteric Fermentation in Domestic Livestock	CH_4	117.9	112.6	0.02	0.89
Emissions from Substitutes for Ozone Depleting Substances	Several	0.4	103.3	0.01	0.91
Indirect N_2O Emissions from Nitrogen Used in Agriculture	N_2O	115.7	90.6	0.01	0.92
Fugitive Emissions from Coal Mining and Handling	CH_4	81.9	56.3	0.01	0.93
Mobile Combustion: Marine	CO_2	43.6	54.4	0.01	0.93
CO_2 Emissions from Iron and Steel Production	CO_2	85.0	51.3	0.01	0.94
CO_2 Emissions from Cement Production	CO_2	33.3	45.6	0.01	0.95
Mobile Combustion: Road & Other	N_2O	41.4	40.6	0.01	0.95
CH_4 Emissions from Manure Management	CH_4	31.2	39.4	0.01	0.96
CH_4 Emissions from Wastewater Handling	CH_4	24.8	36.9	0.01	0.96
Fugitive Emissions from Oil Operations	CH_4	34.4	25.7	<0.01	0.97
CO_2 Emissions from Waste Incineration	CO_2	10.9	19.4	<0.01	0.97
N_2O Emissions from Manure Management	N_2O	16.3	17.7	<0.01	0.97
CO_2 Emissions from Ammonia Production and Urea Application	CO_2	19.3	16.9	<0.01	0.98
N_2O Emissions from Nitric Acid Production	N_2O	17.8	16.6	<0.01	0.98
N_2O Emissions from Wastewater Handling	N_2O	12.9	16.0	<0.01	0.98
HFC-23 Emissions from HCFC-22 Manufacture	HFCs	35.0	15.6	<0.01	0.98

SF_6 Emissions from Electrical Equipment	SF_6	28.6	13.8	<0.01	0.98
CO_2 Emissions from Lime Production	CO_2	11.2	13.7	<0.01	0.99
Non-CO_2 Emissions from Stationary Combustion	N_2O	12.3	13.7	<0.01	0.99
CH_4 Emissions from Rice Production	CH_4	7.1	7.6	<0.01	0.99
CO_2 Emissions from Limestone and Dolomite Use	CO_2	5.5	6.7	<0.01	0.99
Non-CO_2 Emissions from Stationary Combustion	CH_4	7.9	6.4	<0.01	0.99
CO_2 Emissions from Natural Gas Flaring	CO_2	5.8	6.0	<0.01	0.99
N_2O Emissions from Adipic Acid Production	N_2O	15.2	5.7	<0.01	0.99
Fugitive Emissions from Abandoned Coal Mines	CH_4	6.0	5.6	<0.01	0.99
N_2O Emissions from N_2O Product Usage	N_2O	4.3	4.8	<0.01	0.99
PFC, HFC, and SF_6 Emissions from Semiconductor Manufacture	SF_6	2.9	4.7	<0.01	1.00
CO_2 Emissions from Aluminum Production	CO_2	7.0	4.3	<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 Petrochemical Production	CO_2	2.2	2.9	<0.01	1.00
PFC Emissions from Aluminum Production	PFCs	18.4	2.8	<0.01	1.00
Mobile Combustion: Road & Other	CH_4	4.5	2.7	<0.01	1.00
SF_6 Emissions from Magnesium Production	SF_6	5.4	2.7	<0.01	1.00
CO_2 Emissions from Titanium Dioxide Production	CO_2	1.3	2.3	<0.01	1.00
Mobile Combustion: Aviation	N_2O	1.7	1.8	<0.01	1.00
CH_4 Emissions from Petrochemical Production	CH_4	1.2	1.6	<0.01	1.00
CO_2 Emissions from Phosphoric Acid Production	CO_2	1.5	1.4	<0.01	1.00
CO_2 Emissions from Ferroalloys	CO_2	2.0	1.3	<0.01	1.00
CO_2 Emissions from CO_2 Consumption	CO_2	0.9	1.2	<0.01	1.00
CH_4 Emissions from Iron and Steel Production	CH_4	1.3	1.0	<0.01	1.00
CH_4 Emissions from Agricultural Residue Burning	CH_4	0.7	0.9	<0.01	1.00
N_2O Emissions from Waste Incineration	N_2O	0.5	0.5	<0.01	1.00
N_2O Emissions from Agricultural Residue Burning	N_2O	0.4	0.5	<0.01	1.00
CO_2 Emissions from Zinc Production	CO_2	0.9	0.5	<0.01	1.00
Mobile Combustion: Marine	N_2O	0.4	0.4	<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 Lead Production	CO_2	0.3	0.3	<0.01	1.00
Mobile Combustion: Aviation	CH_4	0.2	0.1	<0.01	1.00
CO_2 Emissions from Silicon Carbide Consumption	CO_2	0.1	0.1	<0.01	1.00
Mobile Combustion: Marine	CH_4	0.1	0.1	<0.01	1.00
CH_4 Emissions from Silicon Carbide Production	CH_4	0.0	0.0	<0.01	1.00
TOTAL		6,103.3	7,067.6	1.00	

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

Table A-7: 2004 Key Source Category Tier 1 Analysis—Level Assessment with LULUCF

IPCC Source Categories	Direct GHG	1990 Estimate (Tg CO_2 Eq.)	2004 Estimate (Tg CO_2 Eq.)	Level Assessment	Cumulative Total of Level Assessment
CO_2 Emissions from Stationary Combustion—Coal	CO_2	1,683.8	2,027.0	0.26	0.26
Mobile Combustion: Road & Other	CO_2	1,240.6	1,621.5	0.21	0.46
CO_2 Emissions from Stationary Combustion—Gas	CO_2	971.0	1,153.8	0.15	0.61
CO_2 Emissions from Forest Land Remaining Forest Land	CO_2	773.4	637.2	0.08	0.69
CO_2 Emissions from Stationary Combustion—Oil	CO_2	580.0	619.9	0.08	0.77
Mobile Combustion: Aviation	CO_2	177.2	179.6	0.02	0.79
Direct N_2O Emissions from Agricultural Soils	N_2O	150.4	170.9	0.02	0.81
CO_2 Emissions from Non-Energy Use of Fuels	CO_2	117.2	153.4	0.02	0.83
CH_4 Emissions from Solid Waste Disposal Sites	CH_4	172.3	140.9	0.02	0.85
Fugitive Emissions from Natural Gas Operations	CH_4	126.7	118.8	0.02	0.87
CH_4 Emissions from Enteric Fermentation in Domestic Livestock	CH_4	117.9	112.6	0.01	0.88
Emissions from Substitutes for Ozone Depleting Substances	Several	0.4	103.3	0.01	0.89
CO_2 Emissions from Settlements Remaining Settlements	CO_2	83.2	97.3	0.01	0.91

Indirect N_2O Emissions from Nitrogen Used in Agriculture	N_2O	115.7	90.6	0.01	0.92
Fugitive Emissions from Coal Mining and Handling	CH_4	81.9	56.3	0.01	0.93
Mobile Combustion: Marine	CO_2	43.6	54.4	0.01	0.93
CO_2 Emissions from Iron and Steel Production	CO_2	85.0	51.3	0.01	0.94
CO_2 Emissions from Cement Production	CO_2	33.3	45.6	0.01	0.94
Mobile Combustion: Road & Other	N_2O	41.4	40.6	0.01	0.95
CH_4 Emissions from Manure Management	CH_4	31.2	39.4	0.01	0.95
CH_4 Emissions from Wastewater Handling	CH_4	24.8	36.9	<0.01	0.96
CO_2 Emissions from Cropland Remaining Cropland	CO_2	33.1	28.9	<0.01	0.96
Fugitive Emissions from Oil Operations	CH_4	34.4	25.7	<0.01	0.97
CO_2 Emissions from Land Converted to Grassland	CO_2	17.6	21.1	<0.01	0.97
CO_2 Emissions from Waste Incineration	CO_2	10.9	19.4	<0.01	0.97
N_2O Emissions from Manure Management	N_2O	16.3	17.7	<0.01	0.97
CO_2 Emissions from Ammonia Production and Urea Application	CO_2	19.3	16.9	<0.01	0.98
N_2O Emissions from Nitric Acid Production	N_2O	17.8	16.6	<0.01	0.98
N_2O Emissions from Wastewater Handling	N_2O	12.9	16.0	<0.01	0.98
HFC-23 Emissions from HCFC-22 Manufacture	HFCs	35.0	15.6	<0.01	0.98
SF_6 Emissions from Electrical Equipment	SF_6	28.6	13.8	<0.01	0.98
CO_2 Emissions from Lime Production	CO_2	11.2	13.7	<0.01	0.99
Non-CO_2 Emissions from Stationary Combustion	N_2O	12.3	13.7	<0.01	0.99
CH_4 Emissions from Rice Production	CH_4	7.1	7.6	<0.01	0.99
CO_2 Emissions from Grassland Remaining Grassland	CO_2	4.5	7.3	<0.01	0.99
CO_2 Emissions from Limestone and Dolomite Use	CO_2	5.5	6.7	<0.01	0.99
N_2O Emissions from Settlements Remaining Settlements	N_2O	5.6	6.4	<0.01	0.99
Non-CO_2 Emissions from Stationary Combustion	CH_4	7.9	6.4	<0.01	0.99
CO_2 Emissions from Natural Gas Flaring	CO_2	5.8	6.0	<0.01	0.99
N_2O Emissions from Adipic Acid Production	N_2O	15.2	5.7	<0.01	0.99
Fugitive Emissions from Abandoned Coal Mines	CH_4	6.0	5.6	<0.01	0.99
N_2O Emissions from N_2O Product Usage	N_2O	4.3	4.8	<0.01	0.99
PFC, HFC, and SF_6 Emissions from Semiconductor Manufacture	SF_6	2.9	4.7	<0.01	1.00
CO_2 Emissions from Aluminum Production	CO_2	7.0	4.3	<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 Petrochemical Production	CO_2	2.2	2.9	<0.01	1.00
PFC Emissions from Aluminum Production	PFCs	18.4	2.8	<0.01	1.00
CO_2 Emissions from Land Converted to Cropland	CO_2	1.5	2.8	<0.01	1.00
Mobile Combustion: Road & Other	CH_4	4.5	2.7	<0.01	1.00
SF_6 Emissions from Magnesium Production	SF_6	5.4	2.7	<0.01	1.00
CO_2 Emissions from Titanium Dioxide Production	CO_2	1.3	2.3	<0.01	1.00
Mobile Combustion: Aviation	N_2O	1.7	1.8	<0.01	1.00
CH_4 Emissions from Petrochemical Production	CH_4	1.2	1.6	<0.01	1.00
CO_2 Emissions from Phosphoric Acid Production	CO_2	1.5	1.4	<0.01	1.00
CO_2 Emissions from Ferroalloys	CO_2	2.0	1.3	<0.01	1.00
CO_2 Emissions from CO_2 Consumption	CO_2	0.9	1.2	<0.01	1.00
CH_4 Emissions from Iron and Steel Production	CH_4	1.3	1.0	<0.01	1.00
CH_4 Emissions from Agricultural Residue Burning	CH_4	0.7	0.9	<0.01	1.00
N_2O Emissions from Waste Incineration	N_2O	0.5	0.5	<0.01	1.00
N_2O Emissions from Agricultural Residue Burning	N_2O	0.4	0.5	<0.01	1.00
CO_2 Emissions from Zinc Production	CO_2	0.9	0.5	<0.01	1.00
Mobile Combustion: Marine	N_2O	0.4	0.4	<0.01	1.00
N_2O Emissions from Forest Land Remaining Forest Land	N_2O	0.1	0.4	<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 Lead Production	CO_2	0.3	0.3	<0.01	1.00
Mobile Combustion: Aviation	CH_4	0.2	0.1	<0.01	1.00
CO_2 Emissions from Silicon Carbide Consumption	CO_2	0.1	0.1	<0.01	1.00
Mobile Combustion: Marine	CH_4	0.1	0.1	<0.01	1.00
CH_4 Emissions from Silicon Carbide Production	CH_4	0.0	0.0	<0.01	1.00

TOTAL	7,022.3	7,869.0	1.00	

Table A- 8: 1990-2004 Key Source Category Tier 1 Analysis—Trend Assessment, without LULUCF

IPCC Source Categories	Direct GHG	1990 Estimate (Tg CO_2 Eq.)	2004 Estimate (Tg CO_2 Eq.)	Trend Assessment	Percent Contribution to Trend (%)	Cumulative Contribution to Trend (%)
Mobile Combustion: Road & Other	CO_2	1,240.6	1,621.5	0.02	20.7	20.7
Emissions from Substitutes for Ozone Depleting Substances	Several	0.4	103.3	0.01	11.5	32.2
CO_2 Emissions from Stationary Combustion—Coal	CO_2	1,683.8	2,027.0	0.01	8.6	40.9
CH_4 Emissions from Solid Waste Disposal Sites	CH_4	172.3	140.9	0.01	6.6	47.5
CO_2 Emissions from Stationary Combustion—Oil	CO_2	580.0	619.9	0.01	5.8	53.2
CO_2 Emissions from Iron and Steel Production	CO_2	85.0	51.3	0.01	5.3	58.5
Indirect N_2O Emissions from Nitrogen Used in Agriculture	N_2O	115.7	90.6	0.01	4.9	63.4
Fugitive Emissions from Coal Mining and Handling	CH_4	81.9	56.3	<0.01	4.3	67.7
CO_2 Emissions from Stationary Combustion—Gas	CO_2	971.0	1,153.8	<0.01	3.3	71.0
Fugitive Emissions from Natural Gas Operations	CH_4	126.7	118.8	<0.01	3.1	74.1
Mobile Combustion: Aviation	CO_2	177.2	179.6	<0.01	2.9	77.0
HFC-23 Emissions from HCFC-22 Manufacture	HFCs	35.0	15.6	<0.01	2.8	79.8
CH_4 Emissions from Enteric Fermentation in Domestic Livestock	CH_4	117.9	112.6	<0.01	2.7	82.5
SF_6 Emissions from Electrical Equipment	SF_6	28.6	13.8	<0.01	2.2	84.6
PFC Emissions from Aluminum Production	PFCs	18.4	2.8	<0.01	2.1	86.7
CO_2 Emissions from Non-Energy Use of Fuels	CO_2	117.2	153.4	<0.01	2.0	88.7
Fugitive Emissions from Oil Operations	CH_4	34.4	25.7	<0.01	1.6	90.3
N_2O Emissions from Adipic Acid Production	N_2O	15.2	5.7	<0.01	1.3	91.6
CH_4 Emissions from Wastewater Handling	CH_4	24.8	36.9	<0.01	0.9	92.5
Mobile Combustion: Road & Other	N_2O	41.4	40.6	<0.01	0.8	93.3
CO_2 Emissions from Cement Production	CO_2	33.3	45.6	<0.01	0.8	94.1
CO_2 Emissions from Waste Incineration	CO_2	10.9	19.4	<0.01	0.8	94.9
CO_2 Emissions from Ammonia Production and Urea Application	CO_2	19.3	16.9	<0.01	0.6	95.5
N_2O Emissions from Nitric Acid Production	N_2O	17.8	16.6	<0.01	0.5	95.9
Mobile Combustion: Marine	CO_2	43.6	54.4	<0.01	0.4	96.4
CO_2 Emissions from Aluminum Production	CO_2	7.0	4.3	<0.01	0.4	96.8
SF_6 Emissions from Magnesium Production	SF_6	5.4	2.7	<0.01	0.4	97.2
CH_4 Emissions from Manure Management	CH_4	31.2	39.4	<0.01	0.4	97.6
Direct N_2O Emissions from Agricultural Soils	N_2O	150.4	170.9	<0.01	0.4	97.9
Non-CO_2 Emissions from Stationary Combustion	CH_4	7.9	6.4	<0.01	0.3	98.2
Mobile Combustion: Road & Other	CH_4	4.5	2.7	<0.01	0.3	98.5
PFC, HFC, and SF_6 Emissions from Semiconductor Manufacture	SF_6	2.9	4.7	<0.01	0.1	98.7
Fugitive Emissions from Abandoned Coal Mines	CH_4	6.0	5.6	<0.01	0.1	98.8
N_2O Emissions from Manure Management	N_2O	16.3	17.7	<0.01	0.1	98.9
N_2O Emissions from Wastewater Handling	N_2O	12.9	16.0	<0.01	0.1	99.1
CO_2 Emissions from Ferroalloys	CO_2	2.0	1.3	<0.01	0.1	99.2
CO_2 Emissions from Titanium Dioxide Production	CO_2	1.3	2.3	<0.01	0.1	99.3
CO_2 Emissions from Natural Gas Flaring	CO_2	5.8	6.0	<0.01	0.1	99.3
CH_4 Emissions from Rice Production	CH_4	7.1	7.6	<0.01	0.1	99.4
CO_2 Emissions from Lime Production	CO_2	11.2	13.7	<0.01	0.1	99.5
CO_2 Emissions from Soda Ash Manufacture and Consumption	CO_2	4.1	4.2	<0.01	0.1	99.6
CO_2 Emissions from Zinc Production	CO_2	0.9	0.5	<0.01	0.1	99.6
Non-CO_2 Emissions from Stationary Combustion	N_2O	12.3	13.7	<0.01	0.1	99.7
CH_4 Emissions from Iron and Steel Production	CH_4	1.3	1.0	<0.01	0.1	99.7
CO_2 Emissions from Phosphoric Acid Production	CO_2	1.5	1.4	<0.01	<0.01	99.8

CO_2 Emissions from Petrochemical Production	CO_2	2.2	2.9	<0.01	<0.01	99.8
CO_2 Emissions from Limestone and Dolomite Use	CO_2	5.5	6.7	<0.01	<0.01	99.8
CH_4 Emissions from Petrochemical Production	CH_4	1.2	1.6	<0.01	<0.01	99.9
Mobile Combustion: Aviation	N_2O	1.7	1.8	<0.01	<0.01	99.9
N_2O Emissions from N_2O Product Usage	N_2O	4.3	4.8	<0.01	<0.01	99.9
CO_2 Emissions from CO_2 Consumption	CO_2	0.9	1.2	<0.01	<0.01	99.9
CO_2 Emissions from Stationary Combustion—Geothermal Energy	CO_2	0.4	0.4	<0.01	<0.01	100.0
N_2O Emissions from Agricultural Residue Burning	N_2O	0.4	0.5	<0.01	<0.01	100.0
CH_4 Emissions from Agricultural Residue Burning	CH_4	0.7	0.9	<0.01	<0.01	100.0
CO_2 Emissions from Lead Production	CO_2	0.3	0.3	<0.01	<0.01	100.0
Mobile Combustion: Aviation	CH_4	0.2	0.1	<0.01	<0.01	100.0
Mobile Combustion: Marine	N_2O	0.4	0.4	<0.01	<0.01	100.0
N_2O Emissions from Waste Incineration	N_2O	0.5	0.5	<0.01	<0.01	100.0
CH_4 Emissions from Silicon Carbide Production	CH_4	0.0	0.0	<0.01	<0.01	100.0
CO_2 Emissions from Silicon Carbide Consumption	CO_2	0.1	0.1	<0.01	<0.01	100.0
Mobile Combustion: Marine	CH_4	0.1	0.1	<0.01	<0.01	100.0
TOTAL		6,103.3	7,067.6	0.11		

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

Table A- 9: 1990-2004 Key Source Category Tier 1 Analysis—Trend Assessment, with LULUCF

IPCC Source Categories	Direct GHG	1990 Estimate (Tg CO_2 Eq.)	2004 Estimate (Tg CO_2 Eq.)	Trend Assessment	Percent Contribution to Trend (%)	Cumulative Contribution to Trend (%)
Mobile Combustion: Road & Other	CO_2	1,240.6	1,621.5	0.03	18.8	18.8
CO_2 Emissions from Forest Land Remaining Forest Land	CO_2	773.4	637.2	0.03	18.7	37.5
CO_2 Emissions from Stationary Combustion—Coal	CO_2	1,683.8	2,027.0	0.02	11.4	48.9
Emissions from Substitutes for Ozone Depleting Substances	Several	0.4	103.3	0.01	8.3	57.2
CO_2 Emissions from Stationary Combustion—Gas	CO_2	971.0	1,153.8	0.01	5.3	62.6
CH_4 Emissions from Solid Waste Disposal Sites	CH_4	172.3	140.9	0.01	4.2	66.8
CO_2 Emissions from Iron and Steel Production	CO_2	85.0	51.3	<0.01	3.6	70.4
Indirect N_2O Emissions from Nitrogen Used in Agriculture	N_2O	115.7	90.6	<0.01	3.2	73.6
Fugitive Emissions from Coal Mining and Handling	CH_4	81.9	56.3	<0.01	2.9	76.4
CO_2 Emissions from Stationary Combustion—Oil	CO_2	580.0	619.9	<0.01	2.4	78.9
HFC-23 Emissions from HCFC-22 Manufacture	HFCs	35.0	15.6	<0.01	1.9	80.8
Fugitive Emissions from Natural Gas Operations	CH_4	126.7	118.8	<0.01	1.9	82.7
CO_2 Emissions from Non-Energy Use of Fuels	CO_2	117.2	153.4	<0.01	1.8	84.5
CH_4 Emissions from Enteric Fermentation in Domestic Livestock	CH_4	117.9	112.6	<0.01	1.6	86.1
Mobile Combustion: Aviation	CO_2	177.2	179.6	<0.01	1.5	87.6
SF_6 Emissions from Electrical Equipment	SF_6	28.6	13.8	<0.01	1.5	89.1
PFC Emissions from Aluminum Production	PFCs	18.4	2.8	<0.01	1.4	90.5
Fugitive Emissions from Oil Operations	CH_4	34.4	25.7	<0.01	1.1	91.6
N_2O Emissions from Adipic Acid Production	N_2O	15.2	5.7	<0.01	0.9	92.5
CH_4 Emissions from Wastewater Handling	CH_4	24.8	36.9	<0.01	0.7	93.3
CO_2 Emissions from Cement Production	CO_2	33.3	45.6	<0.01	0.7	93.9
CO_2 Emissions from Cropland Remaining Cropland	CO_2	33.1	28.9	<0.01	0.7	94.6
CO_2 Emissions from Waste Incineration	CO_2	10.9	19.4	<0.01	0.6	95.2
Mobile Combustion: Road & Other	N_2O	41.4	40.6	<0.01	0.5	95.6
Mobile Combustion: Marine	CO_2	43.6	54.4	<0.01	0.5	96.1
CO_2 Emissions from Ammonia Production and Urea Application	CO_2	19.3	16.9	<0.01	0.4	96.5
CH_4 Emissions from Manure Management	CH_4	31.2	39.4	<0.01	0.4	96.8
CO_2 Emissions from Settlements Remaining	CO_2	83.2	97.3	<0.01	0.3	97.2

Settlements						
CO_2 Emissions from Aluminum Production	CO_2	7.0	4.3	<0.01	0.3	97.5
N_2O Emissions from Nitric Acid Production	N_2O	17.8	16.6	<0.01	0.3	97.7
SF_6 Emissions from Magnesium Production	SF_6	5.4	2.7	<0.01	0.3	98.0
Direct N_2O Emissions from Agricultural Soils	N_2O	150.4	170.9	<0.01	0.2	98.2
Non-CO_2 Emissions from Stationary Combustion	CH_4	7.9	6.4	<0.01	0.2	98.4
Mobile Combustion: Road & Other	CH_4	4.5	2.7	<0.01	0.2	98.6
CO_2 Emissions from Grassland Remaining Grassland	CO_2	4.5	7.3	<0.01	0.2	98.8
N_2O Emissions from Wastewater Handling	N_2O	12.9	16.0	<0.01	0.1	98.9
PFC, HFC, and SF_6 Emissions from Semiconductor Manufacture	SF_6	2.9	4.7	<0.01	0.1	99.0
CO_2 Emissions from Land Converted to Grassland	CO_2	17.6	21.1	<0.01	0.1	99.1
CO_2 Emissions from Land Converted to Cropland	CO_2	1.5	2.8	<0.01	0.1	99.2
CO_2 Emissions from Lime Production	CO_2	11.2	13.7	<0.01	0.1	99.3
Fugitive Emissions from Abandoned Coal Mines	CH_4	6.0	5.6	<0.01	0.1	99.4
CO_2 Emissions from Ferroalloys	CO_2	2.0	1.3	<0.01	0.1	99.5
CO_2 Emissions from Titanium Dioxide Production	CO_2	1.3	2.3	<0.01	0.1	99.5
CO_2 Emissions from Zinc Production	CO_2	0.9	0.5	<0.01	<0.01	99.6
N_2O Emissions from Manure Management	N_2O	16.3	17.7	<0.01	<0.01	99.6
CO_2 Emissions from Limestone and Dolomite Use	CO_2	5.5	6.7	<0.01	<0.01	99.7
CO_2 Emissions from Natural Gas Flaring	CO_2	5.8	6.0	<0.01	<0.01	99.7
CO_2 Emissions from Soda Ash Manufacture and Consumption	CO_2	4.1	4.2	<0.01	<0.01	99.7
CH_4 Emissions from Iron and Steel Production	CH_4	1.3	1.0	<0.01	<0.01	99.8
CH_4 Emissions from Rice Production	CH_4	7.1	7.6	<0.01	<0.01	99.8
CO_2 Emissions from Petrochemical Production	CO_2	2.2	2.9	<0.01	<0.01	99.8
N_2O Emissions from Forest Land Remaining Forest Land	N_2O	0.1	0.4	<0.01	<0.01	99.9
CO_2 Emissions from Phosphoric Acid Production	CO_2	1.5	1.4	<0.01	<0.01	99.9
CH_4 Emissions from Petrochemical Production	CH_4	1.2	1.6	<0.01	<0.01	99.9
CO_2 Emissions from CO_2 Consumption	CO_2	0.9	1.2	<0.01	<0.01	99.9
Mobile Combustion: Aviation	N_2O	1.7	1.8	<0.01	<0.01	99.9
N_2O Emissions from Settlements Remaining Settlements	N_2O	5.6	6.4	<0.01	<0.01	100.0
CH_4 Emissions from Agricultural Residue Burning	CH_4	0.7	0.9	<0.01	<0.01	100.0
N_2O Emissions from Agricultural Residue Burning	N_2O	0.4	0.5	<0.01	<0.01	100.0
CO_2 Emissions from Stationary Combustion—Geothermal Energy	CO_2	0.4	0.4	<0.01	<0.01	100.0
Non-CO_2 Emissions from Stationary Combustion	N_2O	12.3	13.7	<0.01	<0.01	100.0
CO_2 Emissions from Lead Production	CO_2	0.3	0.3	<0.01	<0.01	100.0
N_2O Emissions from N_2O Product Usage	N_2O	4.3	4.8	<0.01	<0.01	100.0
Mobile Combustion: Marine	N_2O	0.4	0.4	<0.01	<0.01	100.0
Mobile Combustion: Aviation	CH_4	0.2	0.1	<0.01	<0.01	100.0
CO_2 Emissions from Silicon Carbide Consumption	CO_2	0.1	0.1	<0.01	<0.01	100.0
CH_4 Emissions from Silicon Carbide Production	CH_4	0.0	0.0	<0.01	<0.01	100.0
N_2O Emissions from Waste Incineration	N_2O	0.5	0.5	<0.01	<0.01	100.0
Mobile Combustion: Marine	CH_4	0.1	0.1	<0.01	<0.01	100.0
Total		7,022.3	7,869.0	0.14		

References

Flugsrud, K., W. Irving, and K. Rypdal (1999) Methodological Choice in Inventory Preparation. Suggestions for Good Practice Guidance. Statistics Norway Department of Economic Statistics. 1999/19.

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-10 through Table A-24, 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 "Energy Conversions" in Annex 6.5). 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 2004 total adjusted energy consumption across all sectors, including territories, and energy types was 77,845.5 trillion British thermal units (TBtu), as indicated in the last entry of Column 8 in Table A-10. 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* (2005a).

There are also three basic differences between the consumption data presented in Table A-10 through Table A-24 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-10 through Table A-24. It is reported separately from domestic sectoral consumption, because it is collected separately by EIA with no sectoral disaggregation.

Third, there were a number of modifications made in this report that may cause consumption information herein to differ from figures given in the cited literature. These are 1) the reallocation of select amounts of coking coal, petroleum coke, natural gas, residual fuel oil, and other oil (>401 F) for processes accounted for in the Industrial Processes chapter, 2) corrections for synthetic natural gas production, 3) 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 carbon anodes and cathodes), 3) titanium dioxide production (in the chloride process), and 4) ammonia production.
- 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 (>401 F) are both used in the production of carbon 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 carbon dioxide. The synthetic natural gas enters the natural gas distribution system. Since October 2000 a portion of the carbon dioxide produced by the coal gasification plant has been exported to Canada by pipeline. The remainder of the carbon dioxide 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 carbon contained in the fuel. For example, asphalt made from petroleum can sequester up to 100 percent of the carbon contained in the petroleum feedstock for extended periods of time. Other non-energy fossil fuel products, such as lubricants or plastics also store carbon, but can lose or emit some of this carbon when they are used and/or burned as waste.[3] As the emission pathways of carbon 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-25, 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-26). Emissions from international bunker fuels have been estimated separately and not included in national totals.[4]

Step 6: Determine the Carbon Content of All Fuels

The carbon content of combusted fossil fuels was estimated by multiplying adjusted energy consumption (Columns 2 through 8 of Table A-10 through Table A-24) by fuel-specific carbon content coefficients (see Table A-27 and Table A-28) that reflect the amount of carbon per unit of energy in each fuel. The resulting carbon contents are sometimes referred to as potential emissions, or the maximum amount of carbon that could potentially be released to the atmosphere if all carbon in the fuels were oxidized. The carbon content coefficients used in the U.S. inventory were derived by EIA from detailed fuel information and are similar to the carbon 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: Account for Carbon that Does Not Oxidize During Combustion

Because combustion processes are not 100 percent efficient, some of the carbon contained in fuels is not emitted in a gaseous form to the atmosphere. Rather, it remains behind as soot, particulate matter and ash. The estimated fraction of carbon not oxidized in U.S. energy conversion processes due to inefficiencies during combustion ranges from 0.5 percent for natural gas to 1 percent for petroleum and coal. Except for coal these assumptions are consistent with the default values recommended by the IPCC (IPCC/UNEP/OECD/IEA 1997). In the United States, unoxidized carbon from coal combustion was estimated to be no more than one percent (Bechtel 1993). Table A-27 presents fractions oxidized by fuel type, which are multiplied by the net carbon content of the combusted energy to give final emissions estimates.

Of the fraction of carbon that is oxidized (e.g., 99 to 99.5 percent), the vast majority is emitted in its fully oxidized form as carbon dioxide (CO_2). A much smaller portion of this "oxidized" carbon is also emitted as carbon

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[3] See Waste Combustion section of the Energy chapter and Annex 3.6 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.

monoxide (CO), methane (CH_4), and non-methane volatile organic compounds (NMVOCs). When in the atmosphere, though, these partially oxidized or unoxidized carbon compounds are generally oxidized to CO_2 through atmospheric processes (e.g., reaction with hydroxyl (OH)).[5]

Step 8: Summarize Emission Estimates

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 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-29). This pro-rated approach to allocating emissions from electricity generation may overestimate or underestimate emissions for particular sectors due to differences in the average carbon content of fuel mixes burned to generate electricity.

[5] See the Indirect CO_2 from CH_4 Oxidation box in the Energy chapter for a discussion of accounting of carbon from hydrocarbon and CO emissions.

Table A-10: 2004 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Adjusted Consumption (TBtu)[a]							Emissions[b] (Tg CO_2 Eq.) from Energy Use						
Fuel Type	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total
Total Coal	11.0	87.0	1,258.3	NE	20,081.9	39.8	21,478.0	1.0	8.2	117.1	NE	1,877.6	3.6	2,007.5
Residential Coal	11.0						11.0	1.0						1.0
Commercial Coal		87.0					87.0		8.2					8.2
Industrial Other Coal			1,258.3				1,258.3			117.1				117.1
Transportation Coal				NE										NE
Electric Power Coal					20,081.9		20,081.9					1,877.6		1,877.6
U.S. Territory Coal (bit)						39.8	39.8						3.6	3.6
Natural Gas	5,030.0	3,082.0	8,114.8	708.0	5,604.1	24.73	22,563.7	265.5	162.7	428.4	37.4	295.9	1.3	1,191.2
Total Petroleum	1,570.6	803.9	4,239.3	25,304.5	1,200.9	635.7	33,754.9	108.5	57.9	305.1	1,791.2	97.4	46.5	2,406.6
Asphalt & Road Oil														
Aviation Gasoline				31.2			31.2				2.1			2.1
Distillate Fuel Oil	944.0	502.4	1,174.0	5,816.6	111.1	106.5	8,654.6	68.4	36.4	85.0	421.2	8.0	7.7	626.7
Jet Fuel				2,528.7	12.7	71.9	2,613.3				177.4	0.9	5.0	183.4
Kerosene	89.2	23.7	20.6			9.7	143.2	6.4	1.7	1.5			0.7	10.3
LPG	537.4	94.8	601.8	13.3		13.4	1,260.7	33.7	5.9	37.8	0.8		0.8	79.1
Lubricants														
Motor Gasoline		46.6	319.3	16,568.7		215.0	17,149.6		3.3	22.4	1,162.6		15.1	1,203.4
Residual Fuel		136.1	213.5	345.8	885.5	219.2	1,800.2		10.6	16.7	27.0	69.1	17.1	140.4
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)			(155.5)				(155.5)			(11.3)				(11.3)
Pentanes Plus			52.1				52.1			3.4				3.4
Petroleum Coke		0.3	595.9		191.6		787.8		0.0	60.2		19.4		79.6
Still Gas			1,482.6				1,482.6			94.2				94.2
Special Naphtha														
Unfinished Oils			(75.6)				(75.6)			(5.6)				(5.6)
Waxes														
Geothermal					49.0		49.0					0.4		0.4
TOTAL (All Fuels)	6,611.6	3,972.9	13,612.4	26,012.5	26,935.9	700.2	77,845.5	375.0	228.9	850.6	1,828.6	2,271.2	51.4	5,605.7

[a] Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-25), and international bunker fuel consumption (see Table A-26).
[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: 2003 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Adjusted Consumption (TBtu)[a]							Emissions[b] (Tg CO_2 Eq.) from Energy Use						
Fuel Type	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total
Total Coal	10.0	84.0	1,265.4	NE	20,066.1	39.6	21,465.1	0.9	7.9	117.7	NE	1,876.1	3.6	2,006.3
Residential Coal	10.0						10.0	0.9						0.9
Commercial Coal		84.0					84.0		7.9					7.9
Industrial Other Coal			1,265.4				1,265.4			117.7				117.7
Transportation Coal				NE										NE
Electric Power Coal					20,066.1		20,066.1					1,876.1		1,876.1
U.S. Territory Coal (bit)						39.6	39.6						3.6	3.6
Natural Gas	5,246.0	3,323.0	7,882.3	706.0	5,259.2	26.94	22,443.5	276.9	175.4	416.1	37.3	277.6	1.4	1,184.8
Total Petroleum	1,502.9	750.7	4,112.5	24,643.4	1,208.9	597.1	32,815.6	103.7	54.0	295.6	1,744.2	97.1	43.7	2,338.2
Asphalt & Road Oil														
Aviation Gasoline				30.2			30.2				2.1			2.1
Distillate Fuel Oil	904.6	481.4	1,124.5	5,583.6	160.3	100.3	8,354.7	65.5	34.9	81.4	404.4	11.6	7.3	605.0
Jet Fuel				2,418.3	11.2	68.5	2,498.0				169.7	0.8	4.8	175.3
Kerosene	75.5	20.1	17.4			9.1	122.2	5.4	1.4	1.2			0.7	8.7
LPG	522.9	92.3	574.2	13.0		12.5	1,214.8	32.8	5.8	36.0	0.8		0.8	76.3
Lubricants														
Motor Gasoline		45.5	312.0	16,266.4		201.2	16,825.1		3.2	21.9	1,141.4		14.1	1,180.6
Residual Fuel		111.1	163.9	331.9	875.4	205.4	1,687.6		8.7	12.8	25.9	68.3	16.0	131.6
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)			(143.8)				(143.8)			(10.4)				(10.4)
Pentanes Plus			51.7				51.7			3.4				3.4
Petroleum Coke		0.3	578.3		162.1		740.7		0.0	58.5		16.4		74.9
Still Gas			1,477.3				1,477.3			93.9				93.9
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)	6,758.9	4,157.7	13,260.2	25,349.4	26,583.4	663.6	76,773.4	381.6	237.3	829.4	1,781.5	2,251.2	48.7	5,529.7

[a] Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-25), and international bunker fuel consumption (see Table A-26).
[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: 2002 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Adjusted Consumption (TBtu)[a]							Emissions[b] (Tg CO_2 Eq.) from Energy Use						
Fuel Type	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total
Total Coal	11.0	91.0	1,250.9	NE	19,659.7	12.6	21,025.2	1.0	8.6	116.4	NE	1,838.1	1.2	1,965.3
Residential Coal	11.0						11.0	1.0						1.0
Commercial Coal		91.0					91.0		8.6					8.6
Industrial Other Coal			1,250.9				1,250.9			116.4				116.4
Transportation Coal				NE										NE
Electric Power Coal					19,659.7		19,659.7					1,838.1		1,838.1
U.S. Territory Coal (bit)						12.6	12.6						1.2	1.2
Natural Gas	5,031.0	3,235.0	8,167.4	702.0	5,789.4	22.85	22,947.6	265.6	170.8	431.1	37.1	305.6	1.2	1,211.4
Total Petroleum	1,462.5	680.9	3,980.9	24,412.4	960.1	556.8	32,053.7	100.6	48.7	286.1	1,729.0	77.9	40.7	2,283.1
Asphalt & Road Oil														
Aviation Gasoline				33.7			33.7				2.3			2.3
Distillate Fuel Oil	859.8	444.1	1,192.7	5,322.2	126.8	92.8	8,038.3	62.3	32.2	86.4	385.4	9.2	6.7	582.1
Jet Fuel				2,459.8	7.2	61.8	2,528.8				172.6	0.5	4.3	177.5
Kerosene	59.9	16.0	13.8			8.2	97.9	4.3	1.1	1.0			0.6	7.0
LPG	542.7	95.8	579.6	13.5		11.2	1,242.7	34.1	6.0	36.4	0.8		0.7	78.0
Lubricants														
Motor Gasoline		45.1	309.0	16,196.3		189.4	16,739.8		3.2	21.7	1,137.6		13.3	1,175.8
Residual Fuel		79.8	133.5	386.9	663.4	193.6	1,457.2		6.2	10.4	30.2	51.7	15.1	113.7
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)			(144.2)				(144.2)			(10.4)				(10.4)
Pentanes Plus			52.4				52.4			3.5				3.5
Petroleum Coke		0.2	569.0		162.7		732.0		0.0	57.5		16.4		74.0
Still Gas			1,403.3				1,403.3			89.2				89.2
Special Naphtha														
Unfinished Oils			(135.7)				(135.7)			(10.0)				(10.0)
Waxes														
Geothermal					49.4		49.4					0.4		0.4
TOTAL (All Fuels)	6,504.5	4,006.9	13,399.2	25,114.4	26,458.6	592.3	76,075.9	367.3	228.1	833.7	1,766.1	2,222.0	43.1	5,460.2

[a] Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-25), and international bunker fuel consumption (see Table A-26).
[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: 2001 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Adjusted Consumption (TBtu)[a]							Emissions[b] (Tg CO_2 Eq.) from Energy Use						
Fuel Type	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total
Total Coal	11.2	91.0	1,355.2	NE	19,574.4	10.2	21,042.0	1.1	8.6	126.1	NE	1,830.1	0.9	1,966.8
Residential Coal	11.2						11.2	1.1						1.1
Commercial Coal		91.0					91.0		8.6					8.6
Industrial Other Coal			1,355.2				1,355.2			126.1				126.1
Transportation Coal				NE										NE
Electric Power Coal					19,574.4		19,574.4					1,830.1		1,830.1
U.S. Territory Coal (bit)						10.2	10.2						0.9	0.9
Natural Gas	4,906.5	3,123.7	8,047.6	642.0	5,484.3	22.92	22,227.0	259.0	164.9	424.9	33.9	289.5	1.2	1,173.4
Total Petroleum	1,538.6	754.8	4,155.3	23,940.0	1,284.1	632.2	32,304.9	106.2	54.1	299.7	1,694.1	101.5	46.4	2,301.9
Asphalt & Road Oil														
Aviation Gasoline				34.9			34.9				2.4			2.4
Distillate Fuel Oil	908.3	508.4	1,288.2	5,219.3	170.5	109.4	8,204.1	65.8	36.8	93.3	378.0	12.3	7.9	594.1
Jet Fuel				2,580.4		98.9	2,679.2				181.1		6.9	188.0
Kerosene	95.1	31.4	23.2			0.9	150.6	6.8	2.2	1.7			0.1	10.8
LPG	535.2	94.5	500.6	12.9		7.0	1,150.2	33.6	5.9	31.4	0.8		0.4	72.2
Lubricants														
Motor Gasoline		37.4	295.0	15,823.4		187.6	16,343.5		2.6	20.7	1,110.9		13.2	1,147.4
Residual Fuel		82.9	184.7	269.0	1,016.0	228.4	1,781.1		6.5	14.4	21.0	79.3	17.8	138.9
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)			(131.3)				(131.3)			(9.5)				(9.5)
Pentanes Plus			61.6				61.6			4.1				4.1
Petroleum Coke		0.2	571.8		97.6		669.6		0.0	57.8		9.9		67.7
Still Gas			1,430.7				1,430.7			90.9				90.9
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)	6,456.4	3,969.4	13,558.0	24,582.0	26,389.6	665.3	75,620.8	366.3	227.6	850.6	1,728.0	2,221.5	48.5	5,442.4

[a] Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-25), and international bunker fuel consumption (see Table A-26).
[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: 2000 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Adjusted Consumption (TBtu)[a]							Emissions[b] (Tg CO_2 Eq.) from Energy Use						
Fuel Type	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total
Total Coal	10.6	85.8	1,366.8	NE	20,110.4	10.2	21,583.8	1.0	8.1	127.2	NE	1,880.2	0.9	2,017.4
Residential Coal	10.6						10.6	1.0						1.0
Commercial Coal		85.8					85.8		8.1					8.1
Industrial Other Coal			1,366.8				1,366.8			127.2				127.2
Transportation Coal				NE										NE
Electric Power Coal					20,110.4		20,110.4					1,880.2		1,880.2
U.S. Territory Coal (bit)						10.2	10.2						0.9	0.9
Natural Gas	5,099.8	3,254.4	8,745.5	672.0	5,114.7	12.67	22,889.1	269.2	171.8	461.7	35.5	270.0	0.7	1,208.9
Total Petroleum	1,563.1	749.7	3,692.7	23,976.8	1,150.3	471.7	31,604.3	107.7	53.7	264.5	1,697.2	90.9	34.2	2,248.3
Asphalt & Road Oil														
Aviation Gasoline				36.3			36.3				2.5			2.5
Distillate Fuel Oil	904.8	491.0	1,188.7	5,078.7	174.5	71.3	7,908.9	65.5	35.6	86.1	367.8	12.6	5.2	572.7
Jet Fuel				2,718.1		74.1	2,792.1				190.7		5.2	195.9
Kerosene	94.6	29.7	15.6			2.4	142.2	6.8	2.1	1.1			0.2	10.2
LPG	563.7	99.5	605.3	11.2		8.0	1,287.7	35.4	6.2	38.0	0.7		0.5	80.8
Lubricants														
Motor Gasoline		44.5	150.2	15,753.5		185.1	16,133.3		3.1	10.5	1,106.0		13.0	1,132.6
Residual Fuel		84.9	169.6	379.1	882.2	130.9	1,646.8		6.6	13.2	29.6	68.8	10.2	128.5
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)			(145.6)				(145.6)			(10.5)				(10.5)
Pentanes Plus			106.5				106.5			7.0				7.0
Petroleum Coke		0.2	564.0		93.6		657.8		0.0	57.0		9.5		66.5
Still Gas			1,435.6				1,435.6			91.2				91.2
Special Naphtha														
Unfinished Oils			(401.2)				(401.2)			(29.5)				(29.5)
Waxes														
Geothermal					48.1		48.1					0.4		0.4
TOTAL (All Fuels)	6,673.5	4,089.9	13,805.0	24,648.8	26,423.5	494.6	76,135.3	377.9	233.6	853.4	1,732.7	2,241.5	35.8	5,475.0

[a] Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-25), and international bunker fuel consumption (see Table A-26).
[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: 1999 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Adjusted Consumption (TBtu)[a]							Emissions[b] (Tg CO_2 Eq.) from Energy Use						
Fuel Type	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total
Total Coal	13.9	101.6	1,362.2	NE	19,333.6	10.2	20,821.5	1.3	9.6	126.7	NE	1,807.6	0.9	1,946.2
Residential Coal	13.9						13.9	1.3						1.3
Commercial Coal		101.6					101.6		9.6					9.6
Industrial Other Coal			1,362.2				1,362.2			126.7				126.7
Transportation Coal				NE										NE
Electric Power Coal					19,333.6		19,333.6					1,807.6		1,807.6
U.S. Territory Coal (bit)						10.2	10.2						0.9	0.9
Natural Gas	4,856.9	3,132.0	8,598.1	674.0	4,736.3	-	21,997.3	256.4	165.3	453.9	35.6	250.0		1,161.3
Total Petroleum	1,472.7	661.4	3,598.1	23,415.5	1,215.8	461.0	30,824.5	101.5	47.3	259.4	1,655.2	96.5	33.6	2,193.6
Asphalt & Road Oil														
Aviation Gasoline				39.2			39.2				2.7			2.7
Distillate Fuel Oil	827.8	438.4	1,175.5	4,887.4	139.5	79.4	7,548.0	59.9	31.8	85.1	353.9	10.1	5.8	546.6
Jet Fuel				2,623.8		59.5	2,683.4				184.1		4.2	188.3
Kerosene	111.2	26.9	12.8			3.7	154.7	8.0	1.9	0.9			0.3	11.1
LPG	533.7	94.2	435.0	13.5		8.3	1,084.7	33.6	5.9	27.4	0.8		0.5	68.3
Lubricants														
Motor Gasoline		28.4	151.7	15,675.9		164.0	16,020.0		2.0	10.6	1,099.9		11.5	1,124.1
Residual Fuel		73.3	150.9	175.7	970.4	146.0	1,516.3		5.7	11.8	13.7	75.7	11.4	118.3
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)			(127.8)				(127.8)			(9.3)				(9.3)
Pentanes Plus			103.5				103.5			6.9				6.9
Petroleum Coke		0.1	556.9		106.0		663.0		0.0	56.3		10.7		67.0
Still Gas			1,421.1				1,421.1			90.3				90.3
Special Naphtha														
Unfinished Oils			(287.9)				(287.9)			(21.1)				(21.1)
Waxes														
Geothermal					50.6		50.6					0.4		0.4
TOTAL (All Fuels)	6,343.4	3,895.1	13,558.4	24,089.5	25,336.3	471.2	73,693.8	359.2	222.3	840.0	1,690.8	2,154.5	34.5	5,301.4

[a] Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-25), and international bunker fuel consumption (see Table A-26).
[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: 1998 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Adjusted Consumption (TBtu)[a]							Emissions[b] (Tg CO_2 Eq.) from Energy Use						
Fuel Type	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total
Total Coal	12.4	100.6	1,409.4	NE	19,264.2	10.5	20,797.1	1.2	9.5	131.1	NE	1,801.1	1.0	1,943.9
Residential Coal	12.4						12.4	1.2						1.2
Commercial Coal		100.6					100.6		9.5					9.5
Industrial Other Coal			1,409.4				1,409.4			131.1				131.1
Transportation Coal				NE										NE
Electric Power Coal					19,264.2		19,264.2					1,801.1		1,801.1
U.S. Territory Coal (bit)						10.5	10.5						1.0	1.0
Natural Gas	4,671.1	3,098.2	8,980.5	665.0	4,507.1	-	21,921.9	246.6	163.6	474.1	35.1	237.9		1,157.3
Total Petroleum	1,313.8	660.8	3,511.2	22,623.1	1,310.4	445.4	29,864.7	90.9	47.5	254.0	1,598.3	104.1	32.5	2,127.4
Asphalt & Road Oil														
Aviation Gasoline				35.5			35.5				2.4			2.4
Distillate Fuel Oil	771.9	428.8	1,199.8	4,652.7	135.5	71.9	7,260.6	55.9	31.1	86.9	336.9	9.8	5.2	525.8
Jet Fuel				2,549.4		59.9	2,609.2				178.9		4.2	183.1
Kerosene	108.3	31.2	22.1			6.3	167.8	7.8	2.2	1.6			0.4	12.0
LPG	433.6	76.5	303.9	16.6		5.9	836.5	27.3	4.8	19.1	1.0		0.4	52.6
Lubricants														
Motor Gasoline		39.0	199.4	15,289.9		160.3	15,688.7		2.7	14.0	1,072.9		11.3	1,100.8
Residual Fuel		85.2	173.3	78.9	1,059.5	141.1	1,538.1		6.6	13.5	6.2	82.7	11.0	120.0
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)			(154.9)				(154.9)			(11.2)				(11.2)
Pentanes Plus			89.7				89.7			5.9				5.9
Petroleum Coke		0.1	550.6		115.3		666.1		0.0	55.7		11.7		67.3
Still Gas			1,437.3				1,437.3			91.4				91.4
Special Naphtha														
Unfinished Oils			(313.9)				(313.9)			(23.1)				(23.1)
Waxes														
Geothermal					50.4		50.4					0.4		0.4
TOTAL (All Fuels)	5,997.4	3,859.6	13,901.0	23,288.1	25,132.1	456.0	72,634.2	338.7	220.5	859.3	1,633.4	2,143.5	33.5	5,228.9

[a] Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-25), and international bunker fuel consumption (see Table A-26).
[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: 1997 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Adjusted Consumption (TBtu)[a]							Emissions[b] (Tg CO_2 Eq.) from Energy Use						
Fuel Type	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total
Total Coal	15.9	128.7	1,462.7	NE	18,945.2	10.4	20,563.0	1.5	12.2	136.1	NE	1,771.3	1.0	1,922.0
Residential Coal	15.9						15.9	1.5						1.5
Commercial Coal		128.7					128.7		12.2					12.2
Industrial Other Coal			1,462.7				1,462.7			136.1				136.1
Transportation Coal				NE										NE
Electric Power Coal					18,945.2		18,945.2					1,771.3		1,771.3
U.S. Territory Coal (bit)						10.4	10.4						1.0	1.0
Natural Gas	5,125.0	3,306.4	9,203.5	779.0	3,987.6	-	22,401.4	270.6	174.5	485.9	41.1	210.5		1,182.6
Total Petroleum	1,428.1	703.9	3,873.0	22,089.5	929.9	445.3	29,469.7	98.9	50.7	278.5	1,562.2	74.2	32.4	2,096.8
Asphalt & Road Oil														
Aviation Gasoline				39.7			39.7				2.7			2.7
Distillate Fuel Oil	874.4	443.8	1,192.6	4,546.8	110.5	81.6	7,249.7	63.3	32.1	86.4	329.3	8.0	5.9	525.0
Jet Fuel				2,511.6		62.1	2,573.7				176.2		4.4	180.6
Kerosene	92.9	24.6	18.8			4.0	140.3	6.6	1.8	1.3			0.3	10.0
LPG	460.7	81.3	463.7	13.4		6.5	1,025.7	28.9	5.1	29.1	0.8		0.4	64.3
Lubricants														
Motor Gasoline		42.7	211.8	14,841.6		160.0	15,256.2		3.0	14.9	1,042.5		11.2	1,071.6
Residual Fuel		111.2	235.6	136.5	723.1	131.1	1,337.5		8.7	18.4	10.6	56.4	10.2	104.3
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)			(152.4)				(152.4)			(11.0)				(11.0)
Pentanes Plus			30.0				30.0			2.0				2.0
Petroleum Coke		0.1	516.9		96.4		613.4		0.0	52.3		9.7		62.0
Still Gas			1,445.1				1,445.1			91.8				91.8
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)	6,569.0	4,139.0	14,539.2	22,868.5	23,913.0	455.7	72,484.4	370.9	237.4	900.5	1,603.3	2,056.3	33.4	5,201.8

[a] Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-25), and international bunker fuel consumption (see Table A-26).
[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: 1996 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Adjusted Consumption (TBtu)[a]							Emissions[b] (Tg CO_2 Eq.) from Energy Use						
Fuel Type	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total
Total Coal	16.4	120.1	1,498.9	NE	18,467.6	10.3	20,113.3	1.5	11.3	139.3	NE	1,725.8	0.9	1,878.9
Residential Coal	16.4						16.4	1.5						1.5
Commercial Coal		120.1					120.1		11.3					11.3
Industrial Other Coal			1,498.9				1,498.9			139.3				139.3
Transportation Coal				NE										NE
Electric Power Coal					18,467.6		18,467.6					1,725.8		1,725.8
U.S. Territory Coal (bit)						10.3	10.3						0.9	0.9
Natural Gas	5,390.6	3,251.0	9,198.1	736.0	3,729.0	-	22,304.6	284.6	171.6	485.6	38.9	196.9		1,177.5
Total Petroleum	1,488.0	751.3	3,865.3	21,966.1	819.5	434.3	29,324.6	103.1	54.3	278.6	1,555.0	65.1	31.5	2,087.6
Asphalt & Road Oil														
Aviation Gasoline				37.4			37.4				2.6			2.6
Distillate Fuel Oil	926.0	482.9	1,177.6	4,355.2	109.3	76.5	7,127.5	67.1	35.0	85.3	315.4	7.9	5.5	516.2
Jet Fuel				2,530.6		78.5	2,609.0				177.6		5.5	183.1
Kerosene	88.8	21.0	18.3			3.0	131.1	6.4	1.5	1.3			0.2	9.4
LPG	473.2	83.5	436.9	14.7		7.3	1,015.7	29.7	5.2	27.4	0.9		0.5	63.7
Lubricants														
Motor Gasoline		26.5	199.9	14,713.3		151.1	15,090.8		1.9	14.0	1,034.0		10.6	1,060.5
Residual Fuel		137.2	281.7	314.9	635.0	118.0	1,486.7		10.7	22.0	24.6	49.5	9.2	116.0
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)			(151.4)				(151.4)			(11.0)				(11.0)
Pentanes Plus			38.5				38.5			2.6				2.6
Petroleum Coke		0.1	518.8		75.2		594.2		0.0	52.4		7.6		60.1
Still Gas			1,437.1				1,437.1			91.3				91.3
Special Naphtha														
Unfinished Oils			(112.8)				(112.8)			(8.3)				(8.3)
Waxes														
Geothermal					48.9		48.9					0.4		0.4
TOTAL (All Fuels)	6,895.0	4,122.3	14,562.3	22,702.1	23,065.0	444.7	71,791.3	389.2	237.2	903.5	1,593.9	1,988.1	32.5	5,144.4

[a] Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-25), and international bunker fuel consumption (see Table A-26).
[b] Consumption and/or emissions of select fuels are shown as negative due to differences in EIA energy balancing accounting. These are designated with parentheses.
NE (Not Estimated)

Table A-19: 1995 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Adjusted Consumption (TBtu)[a]							Emissions[b] (Tg CO_2 Eq.) from Energy Use						
Fuel Type	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total
Total Coal	17.4	116.3	1,521.7	NE	17,466.3	10.2	19,131.9	1.6	11.0	141.6	NE	1,632.2	0.9	1,787.4
Residential Coal	17.4						17.4	1.6						1.6
Commercial Coal		116.3					116.3		11.0					11.0
Industrial Other Coal			1,521.7				1,521.7			141.6				141.6
Transportation Coal				NE										NE
Electric Power Coal					17,466.3		17,466.3					1,632.2		1,632.2
U.S. Territory Coal (bit)						10.2	10.2						0.9	0.9
Natural Gas	4,983.6	3,116.6	8,900.4	723.0	4,325.5	-	22,049.0	263.1	164.5	469.9	38.2	228.3		1,164.0
Total Petroleum	1,383.3	732.0	3,524.4	21,357.1	757.4	461.8	28,216.0	96.2	53.1	253.9	1,513.3	60.3	33.7	2,010.4
Asphalt & Road Oil														
Aviation Gasoline				39.6			39.6				2.7			2.7
Distillate Fuel Oil	904.8	478.9	1,123.0	4,069.2	108.1	89.5	6,773.4	65.5	34.7	81.3	294.7	7.8	6.5	490.5
Jet Fuel				2,409.2	2.8	75.7	2,487.8				169.1	0.2	5.3	174.6
Kerosene	74.3	22.1	15.4			3.6	115.4	5.3	1.6	1.1			0.3	8.3
LPG	404.2	71.3	432.5	16.7		5.6	930.5	25.4	4.5	27.1	1.1		0.4	58.4
Lubricants														
Motor Gasoline		18.1	200.1	14,435.1		146.7	14,800.0		1.3	14.1	1,015.5		10.3	1,041.2
Residual Fuel		141.5	284.7	387.3	566.0	140.7	1,520.1		11.0	22.2	30.2	44.2	11.0	118.6
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)			(144.7)				(144.7)			(10.5)				(10.5)
Pentanes Plus			34.5				34.5			2.3				2.3
Petroleum Coke		0.1	502.5		80.5		583.2		0.0	50.8		8.1		59.0
Still Gas			1,377.3				1,377.3			87.5				87.5
Special Naphtha														
Unfinished Oils			(320.9)				(320.9)			(23.6)				(23.6)
Waxes														
Geothermal					45.6		45.6					0.3		0.3
TOTAL (All Fuels)	6,384.3	3,964.9	13,946.4	22,080.1	22,594.8	472.0	69,442.6	360.9	228.6	865.3	1,551.4	1,921.2	34.6	4,962.2

[a] Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-25), and international bunker fuel consumption (see Table A-26).
[b] Consumption and/or emissions of select fuels are shown as negative due to differences in EIA energy balancing accounting. These are designated with parentheses.
NE (Not Estimated)

Table A-20: 1994 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Adjusted Consumption (TBtu)[a]							Emissions[b] (Tg CO_2 Eq.) from Energy Use						
Fuel Type	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total
Total Coal	20.7	117.1	1,575.0	NE	17,260.9	10.0	18,983.7	1.9	11.0	146.6	NE	1,611.5	0.9	1,771.9
Residential Coal	20.7						20.7	1.9						1.9
Commercial Coal		117.1					117.1		11.0					11.0
Industrial Other Coal			1,575.0				1,575.0			146.6				146.6
Transportation Coal				NE										NE
Electric Power Coal					17,260.9		17,260.9					1,611.5		1,611.5
U.S. Territory Coal (bit)						10.0	10.0						0.9	0.9
Natural Gas	4,980.9	2,978.1	8,424.0	708.0	4,000.1	-	21,091.2	263.0	157.2	444.7	37.4	211.2		1,113.4
Total Petroleum	1,420.2	787.5	3,742.0	20,941.9	1,063.2	506.3	28,461.0	99.0	57.3	269.4	1,487.1	83.8	37.1	2,033.7
Asphalt & Road Oil														
Aviation Gasoline				38.1			38.1				2.6			2.6
Distillate Fuel Oil	959.8	500.9	1,103.7	3,910.8	120.1	118.8	6,714.1	69.5	36.3	79.9	283.2	8.7	8.6	486.2
Jet Fuel				2,470.6	4.4	65.8	2,540.7				173.5	0.3	4.6	178.4
Kerosene	64.9	19.5	16.9			3.0	104.3	4.6	1.4	1.2			0.2	7.5
LPG	395.4	69.8	450.8	32.2		7.3	955.5	24.8	4.4	28.3	2.0		0.5	60.0
Lubricants														
Motor Gasoline		25.2	192.4	14,132.1		147.4	14,497.1		1.8	13.6	997.8		10.4	1,023.5
Residual Fuel		171.9	368.4	358.1	869.0	164.1	1,931.5		13.4	28.7	27.9	67.8	12.8	150.7
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)			(135.8)				(135.8)			(9.8)				(9.8)
Pentanes Plus			80.8				80.8			5.4				5.4
Petroleum Coke		0.1	501.8		69.7		571.7		0.0	50.7		7.0		57.8
Still Gas			1,417.5				1,417.5			90.1				90.1
Special Naphtha														
Unfinished Oils			(279.2)				(279.2)			(20.5)				(20.5)
Waxes														
Geothermal					53.0		53.0					0.4		0.4
TOTAL (All Fuels)	6,421.8	3,882.7	13,741.0	21,650.0	22,377.2	516.3	68,588.9	363.9	225.5	860.7	1,524.5	1,906.9	38.0	4,919.4

[a] Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-25), and international bunker fuel consumption (see Table A-26).
[b] Consumption and/or emissions of select fuels are shown as negative due to differences in EIA energy balancing accounting. These are designated with parentheses.
NE (Not Estimated)

Table A-21: 1993 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Adjusted Consumption (TBtu)[a]							Emissions[b] (Tg CO_2 Eq.) from Energy Use						
Fuel Type	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total
Total Coal	25.6	116.5	1,573.9	NE	17,187.6	9.6	18,913.2	2.4	11.0	146.3	NE	1,603.9	0.9	1,764.4
Residential Coal	25.6						25.6	2.4						2.4
Commercial Coal		116.5					116.5		11.0					11.0
Industrial Other Coal			1,573.9				1,573.9			146.3				146.3
Transportation Coal				NE										NE
Electric Power Coal					17,187.6		17,187.6					1,603.9		1,603.9
U.S. Territory Coal (bit)						9.6	9.6						0.9	0.9
Natural Gas	5,098.0	2,944.4	8,445.6	644.0	3,559.8	-	20,691.8	269.1	155.4	445.9	34.0	187.9		1,092.3
Total Petroleum	1,448.0	779.9	3,619.5	20,535.0	1,125.1	459.9	27,967.4	101.0	56.7	261.3	1,457.3	89.1	33.8	1,999.1
Asphalt & Road Oil														
Aviation Gasoline				38.4			38.4				2.6			2.6
Distillate Fuel Oil	973.8	493.0	1,109.9	3,649.2	86.5	104.9	6,417.3	70.5	35.7	80.4	264.3	6.3	7.6	464.7
Jet Fuel				2,352.9	1.4	62.1	2,416.3				165.5	0.1	4.4	169.9
Kerosene	75.6	14.0	13.1			3.8	106.5	5.4	1.0	0.9			0.3	7.6
LPG	398.6	70.3	443.3	19.0		4.9	936.2	25.0	4.4	27.8	1.2		0.3	58.8
Lubricants														
Motor Gasoline		29.6	179.5	14,108.0		128.3	14,445.3		2.1	12.7	995.0		9.0	1,018.8
Residual Fuel		172.7	391.5	367.5	958.6	155.9	2,046.3		13.5	30.5	28.7	74.8	12.2	159.6
Other Petroleum														
AvGas Blend Components			0.1				0.1			0.0				0.0
Crude Oil			21.2				21.2			1.6				1.6
MoGas Blend Components														
Misc. Products														
Naphtha (<401 deg. F)														
Other Oil (>401 deg. F)			(114.3)				(114.3)			(8.3)				(8.3)
Pentanes Plus			56.4				56.4			3.7				3.7
Petroleum Coke		0.2	513.1		78.6		591.9		0.0	51.9		8.0		59.8
Still Gas			1,401.8				1,401.8			89.1				89.1
Special Naphtha														
Unfinished Oils			(396.0)				(396.0)			(29.1)				(29.1)
Waxes														
Geothermal					57.3		57.3					0.4		0.4
TOTAL (All Fuels)	6,571.5	3,840.8	13,639.1	21,179.0	21,929.8	469.5	67,629.7	372.5	223.1	853.4	1,491.3	1,881.3	34.6	4,856.3

[a] Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-25), and international bunker fuel consumption (see Table A-26).
[b] Consumption and/or emissions of select fuels are shown as negative due to differences in EIA energy balancing accounting. These are designated with parentheses.
NE (Not Estimated)

Table A-22: 1992 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Adjusted Consumption (TBtu)[a]							Emissions[b] (Tg CO_2 Eq.) from Energy Use						
Fuel Type	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total
Total Coal	25.6	116.8	1,536.4	NE	16,465.6	8.8	18,153.2	2.4	11.1	142.9	NE	1,535.8	0.8	1,692.9
Residential Coal	25.6						25.6	2.4						2.4
Commercial Coal		116.8					116.8		11.1					11.1
Industrial Other Coal			1,536.4				1,536.4			142.9				142.9
Transportation Coal				NE										NE
Electric Power Coal					16,465.6		16,465.6					1,535.8		1,535.8
U.S. Territory Coal (bit)						8.8	8.8						0.8	0.8
Natural Gas	4,819.7	2,882.8	8,319.8	608.0	3,534.1	-	20,164.3	254.4	152.2	439.2	32.1	186.6		1,064.5
Total Petroleum	1,427.2	854.0	3,933.2	20,013.9	991.4	444.9	27,664.6	99.6	62.1	280.5	1,420.2	78.0	32.6	1,973.0
Asphalt & Road Oil														
Aviation Gasoline				41.1			41.1				2.8			2.8
Distillate Fuel Oil	979.7	506.7	1,100.1	3,538.0	73.5	91.8	6,289.7	70.9	36.7	79.7	256.2	5.3	6.6	455.5
Jet Fuel				2,334.9	0.7	61.3	2,396.9				164.3	0.1	4.3	168.7
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	24.0	4.2	29.5	1.2		0.7	59.6
Lubricants														
Motor Gasoline		79.6	194.2	13,681.4		122.1	14,077.4		5.6	13.7	964.5		8.6	992.4
Residual Fuel		189.1	328.4	400.1	872.2	154.6	1,944.3		14.8	25.6	31.2	68.0	12.1	151.7
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			5.3				5.3
Misc. Products														
Naphtha (<401 deg. F)														
Other Oil (>401 deg. F)			(85.8)				(85.8)			(6.2)				(6.2)
Pentanes Plus			261.0				261.0			17.3				17.3
Petroleum Coke		0.1	472.3		45.0		517.4		0.0	47.8		4.5		52.3
Still Gas			1,435.7				1,435.7			91.3				91.3
Special Naphtha														
Unfinished Oils			(354.8)				(354.8)			(26.0)				(26.0)
Waxes														
Geothermal					55.1		55.1					0.4		0.4
TOTAL (All Fuels)	6,272.4	3,853.6	13,789.4	20,621.9	21,046.2	453.7	66,037.1	356.5	225.4	862.6	1,452.3	1,800.7	33.4	4,730.9

[a] Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-25), and international bunker fuel consumption (see Table A-26).
[b] Consumption and/or emissions of select fuels are shown as negative due to differences in EIA energy balancing accounting. These are designated with parentheses.
NE (Not Estimated)

Table A-23: 1991 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Adjusted Consumption (TBtu)[a]							Emissions[b] (Tg CO_2 Eq.) from Energy Use						
Fuel Type	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total
Total Coal	25.3	115.4	1,577.2	NE	16,249.7	7.7	17,975.4	2.4	10.9	146.5	NE	1,515.6	0.7	1,676.2
Residential Coal	25.3						25.3	2.4						2.4
Commercial Coal		115.4					115.4		10.9					10.9
Industrial Other Coal			1,577.2				1,577.2			146.5				146.5
Transportation Coal				NE										NE
Electric Power Coal					16,249.7		16,249.7					1,515.6		1,515.6
U.S. Territory Coal (bit)						7.7	7.7						0.7	0.7
Natural Gas	4,683.7	2,806.6	7,942.3	620.0	3,398.8	-	19,451.4	247.3	148.2	419.3	32.7	179.4		1,026.5
Total Petroleum	1,392.2	905.2	3,562.1	19,589.9	1,198.6	425.4	27,073.5	97.0	66.0	254.0	1,388.4	93.7	31.0	1,930.1
Asphalt & Road Oil														
Aviation Gasoline				41.7			41.7				2.9			2.9
Distillate Fuel Oil	930.4	517.4	1,070.8	3,451.3	83.6	71.4	6,124.9	67.4	37.5	77.5	249.9	6.1	5.2	443.6
Jet Fuel				2,364.4	0.3	78.2	2,443.0				166.5	0.0	5.5	172.0
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	24.5	4.3	23.3	1.3		0.9	54.2
Lubricants														
Motor Gasoline		85.1	193.3	13,488.2		124.7	13,891.2		6.0	13.6	950.4		8.8	978.8
Residual Fuel		221.9	270.9	224.4	1,085.3	134.6	1,937.1		17.3	21.1	17.5	84.7	10.5	151.1
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)			(18.4)				(18.4)			(1.3)				(1.3)
Pentanes Plus			249.2				249.2			16.5				16.5
Petroleum Coke			446.2		29.3		475.5			45.1		3.0		48.1
Still Gas			1,404.5				1,404.5			89.3				89.3
Special Naphtha														
Unfinished Oils			(450.2)				(450.2)			(33.0)				(33.0)
Waxes														
Geothermal					54.5		54.5					0.4		0.4
TOTAL (All Fuels)	6,101.2	3,827.2	13,081.6	20,209.9	20,901.6	433.2	64,554.7	346.7	225.0	819.8	1,421.1	1,789.2	31.7	4,633.6

[a] Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-25), and international bunker fuel consumption (see Table A-26).
[b] Consumption and/or emissions of select fuels are shown as negative due to differences in EIA energy balancing accounting. These are designated with parentheses.
NE (Not Estimated)

Table A-24: 1990 Energy Consumption Data and CO_2 Emissions from Fossil Fuel Combustion by Fuel Type

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Adjusted Consumption (TBtu)[a]							Emissions[b] (Tg CO_2 Eq.) from Energy Use						
Fuel Type	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total	Res.	Comm.	Ind.	Trans.	Elec.	Terr.	Total
Total Coal	31.0	123.8	1,628.1	NE	16,294.6	7.0	18,084.5	2.9	11.6	151.2	NE	1,519.1	0.6	1,685.5
Residential Coal	31.0						31.0	2.9						2.9
Commercial Coal		123.8					123.8		11.6					11.6
Industrial Other Coal			1,628.1				1,628.1			151.2				151.2
Transportation Coal				NE										NE
Electric Power Coal					16,294.6		16,294.6					1,519.1		1,519.1
U.S. Territory Coal (bit)						7.0	7.0						0.6	0.6
Natural Gas	4,519.1	2,697.8	7,826.4	680.0	3,335.0	-	19,058.3	238.6	142.4	413.2	35.9	176.1		1,006.1
Total Petroleum	1,407.0	953.1	3,875.7	19,900.3	1,292.2	374.8	27,803.3	98.3	69.5	276.9	1,410.9	100.9	27.4	1,983.9
Asphalt & Road Oil														
Aviation Gasoline				45.0			45.0				3.1			3.1
Distillate Fuel Oil	978.1	535.8	1,143.4	3,503.1	96.5	74.0	6,331.1	70.8	38.8	82.8	253.7	7.0	5.4	458.5
Jet Fuel				2,473.0		61.0	2,534.0				174.2		4.3	178.5
Kerosene	63.9	11.8	12.3			2.6	90.6	4.6	0.8	0.9			0.2	6.5
LPG	365.0	64.4	406.4	21.6		14.4	871.9	22.9	4.0	25.5	1.4		0.9	54.8
Lubricants														
Motor Gasoline		111.2	185.2	13,557.2		101.0	13,954.6		7.8	13.0	955.2		7.1	983.2
Residual Fuel		229.8	364.1	300.3	1,167.0	121.8	2,183.2		17.9	28.4	23.4	91.0	9.5	170.3
Other Petroleum														
AvGas Blend Components			0.2				0.2			0.0				0.0
Crude Oil			50.9				50.9			3.7				3.7
MoGas Blend Components			53.7				53.7			3.8				3.8
Misc. Products														
Naphtha (<401 deg. F)														
Other Oil (>401 deg. F)			(33.1)				(33.1)			(2.4)				(2.4)
Pentanes Plus			167.8				167.8			11.1				11.1
Petroleum Coke			441.8		28.7		470.6			44.7		2.9		47.6
Still Gas			1,451.9				1,451.9			92.3				92.3
Special Naphtha														
Unfinished Oils			(369.0)				(369.0)			(27.0)				(27.0)
Waxes														
Geothermal					52.7		52.7					0.4		0.4
TOTAL (All Fuels)	5,957.0	3,774.8	13,330.2	20,580.3	20,974.6	381.9	64,998.8	339.8	223.5	841.3	1,446.8	1,796.5	28.0	4,675.9

[a] Expressed as gross calorific values (i.e., higher heating values). Adjustments include biofuels, conversion of fossil fuels, non-energy use (see Table A-25), and international bunker fuel consumption (see Table A-26).
[b] Consumption and/or emissions of select fuels are shown as negative due to differences in EIA energy balancing accounting. These are designated with parentheses.
NE (Not Estimated)

Table A-25: Unadjusted Non-Energy Fuel Consumption (TBtu)

Sector/Fuel Type	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
Industry	4,537.5	4,559.5	4,676.3	4,843.9	5,161.3	5,221.7	5,292.9	5,513.5	5,744.4	6,013.4	5,633.6	5,289.1	5,429.8	5,384.0	5,933.3
Industrial Coking Coal	0.0	0.0	0.0	0.0	9.3	43.8	26.0	0.0	8.4	45.7	62.7	25.5	46.4	72.0	214.3
Industrial Other Coal	8.2	8.5	9.5	10.0	10.9	11.3	11.4	11.2	10.4	11.1	12.4	11.3	12.0	11.9	11.9
Natural Gas to Chemical Plants, Other Uses	302.5	301.1	259.4	292.0	354.0	357.2	359.9	385.5	426.6	437.7	440.6	415.7	422.8	423.4	423.4
Asphalt & Road Oil	1,170.2	1,076.5	1,102.2	1,149.0	1,172.9	1,178.2	1,175.9	1,223.6	1,262.6	1,324.4	1,275.7	1,256.9	1,240.0	1,219.5	1,303.9
LPG	1,201.4	1,377.9	1,390.7	1,351.0	1,545.7	1,586.9	1,652.0	1,670.4	1,744.4	1,820.7	1,665.4	1,553.4	1,620.3	1,545.1	1,576.4
Lubricants	186.3	166.7	170.0	173.1	180.9	177.8	172.5	182.3	190.8	192.8	189.9	174.0	171.9	159.0	161.0
Pentanes Plus	82.6	44.8	61.5	275.9	257.9	303.4	316.5	298.9	204.3	261.4	236.7	201.6	171.4	169.1	170.4
Naphtha (<401 deg. F)	347.8	298.9	377.1	350.6	398.3	373.0	479.3	536.4	584.0	502.1	613.5	493.7	582.6	613.0	749.4
Other Oil (>401 deg. F)	753.9	827.3	814.5	844.1	838.6	801.0	729.6	861.3	818.7	811.1	722.2	662.4	632.1	699.4	779.5
Still Gas	21.3	22.0	11.3	28.4	21.9	40.1	0.0	2.1	0.0	16.1	12.6	35.8	57.8	59.0	63.5
Petroleum Coke	178.0	153.0	231.1	123.5	136.4	132.6	148.2	117.7	213.8	283.9	140.7	207.6	192.1	163.5	272.7
Special Naphtha	107.1	88.0	104.6	104.6	81.1	70.8	74.5	72.3	107.3	145.4	97.4	78.5	102.4	80.5	51.0
Other (Wax/Misc.)															
Distillate Fuel Oil	7.0	7.1	7.0	6.9	6.8	8.0	9.2	10.4	11.7	11.7	11.7	11.7	11.7	11.7	11.7
Waxes	33.3	35.1	37.3	40.0	40.6	40.6	48.7	43.7	42.4	37.4	33.1	36.3	32.2	31.0	30.8
Miscellaneous Products	137.8	152.6	100.1	94.7	105.9	97.1	89.0	97.8	119.0	111.9	119.2	124.9	134.2	126.0	113.4
Transportation	176.0	157.5	160.5	163.5	170.8	167.9	163.0	172.1	180.2	182.1	179.4	164.3	162.4	150.1	152.1
Lubricants	176.0	157.5	160.5	163.5	170.8	167.9	163.0	172.1	180.2	182.1	179.4	164.3	162.4	150.1	152.1
U.S. Territories	86.7	114.4	62.6	74.3	54.9	92.8	121.0	133.5	137.9	143.8	165.5	80.3	138.7	146.6	156.3
Lubricants	0.7	0.6	1.5	3.3	1.9	2.0	0.8	2.5	1.3	1.4	16.4	0.0	1.5	1.6	1.7
Other Petroleum (Misc. Prod.)	86.0	113.8	61.2	71.0	53.0	90.8	120.2	131.0	136.7	142.4	149.1	80.3	137.2	145.0	154.6
Total	4,800.2	4,831.4	4,899.4	5,081.6	5,387.0	5,482.4	5,576.9	5,819.1	6,062.5	6,339.2	5,978.4	5,533.8	5,730.9	5,680.8	6,241.8

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-26: International Bunker Fuel Consumption (TBtu)

Fuel Type	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
Marine Residual Fuel Oil	715.7	801.5	669.8	533.9	524.5	523.2	536.4	575.2	594.8	489.7	444.1	426.0	289.9	239.0	353.7
Marine Distillate Fuel Oil & Other	158.0	149.3	145.9	146.6	121.2	125.7	114.1	125.5	158.8	113.6	85.9	72.4	70.2	82.7	96.6
Aviation Jet Fuel	656.5	660.6	666.4	675.1	683.9	723.0	743.7	796.6	807.4	837.9	862.3	845.6	880.5	847.2	853.8
Total	1,530.2	1,611.4	1,482.2	1,355.7	1,329.6	1,372.0	1,394.2	1,497.3	1,561.0	1,441.2	1,392.2	1,344.0	1,240.7	1,168.9	1,304.1

Table A-27: Key Assumptions for Estimating Carbon Dioxide Emissions

Fuel Type	Carbon Content Coefficient (Tg Carbon/QBtu)	Fraction Oxidized
Coal		
Residential Coal	[a]	0.99
Commercial Coal	[a]	0.99
Industrial Coking Coal	31.00	0.99
Industrial Other Coal	[a]	0.99
Electric Power Coal	[a]	0.99
U.S. Territory Coal (bit)	25.14	0.99
Natural Gas	14.47	0.995
Petroleum		
Asphalt & Road Oil	20.62	0.99
Aviation Gasoline	18.87	0.99
Distillate Fuel Oil	19.95	0.99
Jet Fuel	[a]	0.99
Kerosene	19.72	0.99
LPG (energy use)	[a]	0.995
LPG (non-energy use)	[a]	-
Lubricants	20.24	0.99
Motor Gasoline	[a]	0.99
Residual Fuel Oil	21.49	0.99
Other Petroleum		
AvGas Blend Components	18.87	0.99
Crude Oil	[a]	0.99
MoGas Blend Components	[a]	0.99
Misc. Products	[a]	0.99
Misc. Products (Territories)	20.00	0.99
Naphtha (<401 deg. F)	18.14	0.99
Other Oil (>401 deg. F)	19.95	0.99
Pentanes Plus	18.24	0.99
Petrochemical Feedstocks	19.37	0.99
Petroleum Coke	27.85	0.99
Still Gas	17.51	0.99
Special Naphtha	19.86	0.99
Unfinished Oils	[a]	0.99
Waxes	19.81	0.99
Geothermal	2.05	1.00

Sources: Carbon coefficients from EIA (2004b). Combustion efficiency for coal from Bechtel (1993) and for petroleum and natural gas from IPCC (IPCC/UNEP/OECD/IEA 1997).

[a] These coefficients vary annually due to fluctuations in fuel quality (see Table A-28).

Table A-28: Annually Variable Carbon Content Coefficients by Year (Tg Carbon/QBtu)

Fuel Type	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
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
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
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
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
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
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
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
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
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
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
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
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

Source: EIA (2004b)

Table A-29: 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
Residential	924	955	936	995	1,008	1,043	1,083	1,076	1,130	1,145	1,192	1,203	1,267	1,273	1,293
Commercial	838	855	850	885	913	953	980	1,027	1,078	1,104	1,159	1,197	1,218	1,200	1,229
Industrial	1,070	1,071	1,107	1,116	1,154	1,163	1,186	1,194	1,212	1,230	1,235	1,127	1,138	1,176	1,187
Transportation	5	5	5	5	5	5	5	5	5	5	5	5	6	7	8
Total	2,837	2,886	2,897	3,001	3,081	3,164	3,254	3,302	3,425	3,484	3,592	3,532	3,629	3,656	3,717

Note: Does not include the U.S. territories.
Source: EIA (2004a)

2.2. Methodology for Estimating the Carbon Content of Fossil Fuels

This subannex presents the background and methodology for estimating the carbon content of fossil fuels combusted in the United States. The carbon content of a particular fossil fuel represents the maximum potential emissions to the atmosphere if all carbon in the fuel is oxidized during combustion. The carbon 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 carbon content of coal, and presents a time-series analysis of changes in U.S. carbon content coefficients. A summary of carbon content coefficients used in this report appears in Table A-30.

Though the methods for estimating carbon contents for coal, natural gas, and petroleum products differ in their details, they each follow the same basic approach. First, because carbon coefficients are presented in terms of mass per unit energy (i.e., teragrams carbon per quadrillion Btu or Tg/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, carbon contents are derived from fuel sample data, using descriptive statistics to estimate the carbon 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 carbon content of coal is described first because approximately one-third of all U.S. carbon emissions from fossil fuel combustion are associated with coal consumption. The methods and sources for estimating the carbon 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 carbon contents of petroleum products. U.S. energy consumption statistics account for more than 20 different petroleum products.

Table A-30: 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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
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

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

[b]Carbon 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 carbon dioxide 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. carbon dioxide emissions from fossil fuel combustion are associated with coal consumption. Although the IPCC guidelines provide carbon contents for coal according to rank, it was necessary to develop carbon content coefficients by consuming sector to match the format in which coal consumption is reported by EIA. Because the carbon 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 carbon content for coal combusted in each consuming sector also varies over time. A time series of carbon contents by coal rank and consuming sector appears in Table A-31.[1]

Methodology

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

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

Carbon 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 carbon content of the coal samples are calculated. Dividing the carbon content (reported in pounds carbon dioxide) by the heat content (reported in million Btu or MMBtu) yields an average carbon content coefficient. This coefficient is then converted into units of Tg/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 carbon contents are calculated by multiplying the share of coal purchased from each state by rank by the carbon content estimated in Step 1. The resulting partial carbon contents are then totaled across all states and ranks to generate a national sectoral carbon content.

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

Where,

C_{sector} = The carbon 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 carbon 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-31: Carbon Content Coefficients for Coal by Consuming Sector and Coal Rank (Tg/QBtu) (1990-2004)

Consuming Sector	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
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
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
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
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
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 [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 [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 [p]
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 [p]

[p] Preliminary

Sources: Carbon content coefficients by consuming sector from EIA (2005a). Carbon content coefficients by coal rank from USGS (1998) and SAIC (2005).

Step 4. Develop national-level carbon contents by rank for comparison to IPCC defaults

Although not used to calculate emissions, national-level carbon contents by rank are more easily compared to carbon contents of other countries than are sectoral carbon contents. This step requires weighting the state-level carbon 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 carbon content by rank is multiplied by the share of national production of that rank that each state represents. The resulting partial carbon contents are then summed across all states to generate an overall carbon 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 carbon 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 carbon 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

Carbon 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. Carbon content coefficients for bituminous coal vary from a low of 200.5 pounds carbon dioxide per MMBtu in Kansas to a high of 232.0 pounds carbon dioxide 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 carbon content for bituminous coals of ±0.7 percent, based on more than 2,000 samples (see Table A-32).

Similarly, the carbon content coefficients for sub-bituminous coal range from 201.3 pounds carbon dioxide per MMBtu in Utah to 217.5 pounds carbon dioxide 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 carbon content coefficient for Wyoming, based on 435 samples, dominates.

The interquartile range of carbon 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-32: Variability in Carbon Content Coefficients by Rank Across States (Kilograms Carbon Dioxide 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 (2005).

Natural Gas

Natural gas is predominantly composed of methane, which is 75 percent carbon 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 carbon 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 carbon atoms than methane (which has only one), their presence increases the overall carbon 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 carbon dioxide, 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 carbon dioxide, it will typically have a higher overall carbon content than gas that has been processed and moved to end-use customers via transmission and distribution pipelines.

Methodology

The methodology for estimating the carbon contents of natural gas can be described in five steps.

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.

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 carbon dioxide.

However, there is a range of gas compositions that are consistent with pipeline specifications. The minimum carbon 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 carbon emissions factors, because the "low" Btu gas has a higher content of inert gases (including carbon dioxide 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 carbon dioxide). All natural gas flared for these reasons is probably "rich" associated gas, with relatively high energy content, high NGL content, and a high carbon 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 carbon content and heat content may be used to develop a carbon content coefficient for natural gas consumed in the United States. In 1994, EIA examined the composition (and therefore carbon 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-33.

Table A-33: 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)

Carbon contents were then calculated for a series of sub samples stratified by heat content. Carbon contents were developed for eight separate sub-samples based on heat content and are shown in Table A-34.

Table A-34: Carbon Content of Pipeline-Quality Natural Gas by Energy Content (Tg/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 carbon content was calculated using the average carbon 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/QBtu. This was identical to the average carbon content of all samples with more than 1,000 Btu per cubic foot and the average carbon 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 carbon content coefficient attributable to large portions of carbon dioxide (not seen in the median sample), they were excluded so as not to bias the carbon content coefficient upwards by including them in the final sample used to select a carbon content.

Step 5. Apply carbon content coefficients developed in Step 3 to flare gas

Selecting a carbon 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 carbon content for samples with more than 1,100 Btu per cubic foot, 14.92 Tg/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 (2005a) and EIA (2003), respectively.

Uncertainty

The assignment of carbon 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 carbon 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 carbon 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 carbon 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 carbon content for a single Btu value. In fact, the variation in carbon 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 carbon content coefficient beyond the ±5.0 percent offered with the knowledge that it is of pipeline-quality.

The plot of carbon 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 carbon content of a cubic foot of gas was 14.51 Tg/QBtu (see Table A-34). 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/QBtu that represents fuels more typically consumed is used.[2]

Petroleum

There are four critical determinants of the carbon 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 carbon content coefficient of the fuel;
D_{fuel} = The density of the fuel;
S_{fuel} = The share of the fuel that is carbon; 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 carbon content, however, is much smaller (±5 to 7 percent): ethane is 80 percent carbon by weight, while petroleum coke is 90 to 92 percent carbon. The tightly bound range of carbon contents can be explained by basic petroleum chemistry.

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[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.

[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.

Petroleum Chemistry

Crude oil and petroleum products are typically mixtures of several hundred distinct compounds, predominantly hydrocarbons. All hydrocarbons contain hydrogen and carbon 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 carbon atoms in each molecule. Petroleum products consisting of relatively simple molecules and few carbon atoms have low boiling temperatures, while larger molecules with more carbon atoms have higher boiling temperatures.

Products that boil off at higher temperatures are usually more dense, which implies greater carbon content as well. Petroleum products with higher carbon contents, in general, have lower energy content per unit mass and higher energy content per unit volume than products with lower carbon contents. Empirical research led to the establishment of a set of quantitative relationships between density, energy content per unit weight and volume, and carbon and hydrogen content. Figure A-2 compares carbon content coefficients calculated on the basis of the derived formula with actual carbon content coefficients for a range of crude oils, fuel oils, petroleum products, and pure hydrocarbons. The actual fuel samples were drawn from the sources described below in the discussions of individual petroleum products.

Figure A-2: Estimated and Actual Relationships Between Petroleum Carbon Content Coefficients and Hydrocarbon Density

Source: Carbon content factors for paraffins are calculated based on the properties of hydrocarbons in Guthrie (1960). 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 DOC (1929), and relationship between energy content and fuel composition in Ringen et al. (1979).

The derived empirical relationship between carbon 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 carbon 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 carbon 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 carbon 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 carbon content of the paraffins increases with their carbon number: ethane is 80 percent carbon by weight, octane 84 percent. As the size of paraffin molecules increases, the carbon content approaches the limiting value of 85.7 percent asymptotically (see Figure A- 3).

Cycloparaffins. Cycloparaffins are similar to paraffins, except that the carbon 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 carbon 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 carbon 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 carbon 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 carbon by mass, while xylene is 90.6 percent carbon by mass. Unlike the other hydrocarbon families, the carbon content of aromatics declines asymptotically toward 85.7 percent with increasing carbon 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 carbon by mass) and anthracene ($C_{14}H_4$ and 97.7 percent carbon). They are relatively rare but do appear in heavier petroleum products.

Figure A- 3 illustrates the share of carbon by weight for each class of hydrocarbon. Hydrocarbon molecules containing 2 to 4 carbon atoms are all natural gas liquids; hydrocarbons with 5 to 10 carbon atoms are predominantly found in naphtha and gasoline; and hydrocarbon compounds with 12 to 20 carbons 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 carbon by mass is not an unreasonable first approximation. Since denser products have higher carbon numbers, this guess would be most likely to be correct for crude oils and fuel oils. The carbon 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 carbon contents, heat contents, and density for each product are provided below in Table A-35. A description of the methods and data sources for estimating the key parameters for each individual petroleum product appears below.

Table A-35: Carbon Content Coefficients and Underlying Data for Petroleum Products

Fuel	2004 Carbon Content (Tg/QBtu)	Gross Heat of Combustion (MMBtu/Barrel)	Density (API Gravity)	Percent Carbon

Motor Gasoline	19.33	5.253	59.6	86.60
LPG(total)	16.99	a	a	a
LPG (energy use)	17.20	a	a	a
LPG (non-energy use)	16.81	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 carbon content, see Table A-38.
[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 (2005a), and SAIC (2005).

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. carbon dioxide 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 carbon and energy contents per barrel. Table A-36 reflects changes in the density of gasoline over time and across grades of gasoline through 2004.

Table A-36: Motor Gasoline Density, 1990 – 2004 (Degrees API)

Fuel Grade	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
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
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
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
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
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
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

Source: National Institute of Petroleum and Energy Research (1990 through 2005).

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

[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.

lead, the portion of aromatic hydrocarbons used in gasoline increased. As discussed above, aromatic hydrocarbons have a lower ratio of hydrogen to carbon 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 carbon 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-37.

Table A-37: Characteristics of Major Reformulated Fuel Additives

Additive	Density (Degrees API)	Carbon Share (Percent)	Carbon Content (Tg/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

Carbon content coefficients for each grade and type are derived from three parameters: gasoline density, share of the gasoline mixture that is carbon; and the energy content of a gallon of gasoline. Carbon content coefficients for reformulated fuels were calculated by applying the carbon content coefficient for the fuel additives listed in Table A-37 to the increased share of reformulated gasoline represented by these additives (standard gasoline contains small amounts of MTBE and TAME) and weighting the gasoline carbon content accordingly.

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

The carbon 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 carbon content coefficient.

Data Sources

Data for the density of motor gasoline were obtained from the National Institute for Petroleum and Energy Research (1990 through 2005). Data on the characteristics of reformulated gasoline were taken from API (1988). Carbon contents of motor gasoline were obtained from the following: DeLuchi (1993), Applied Systems Corporation (1979), 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 (2005a).

Uncertainty

There are two primary contributors to the uncertainty of carbon 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 carbon 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 carbon content per unit of volume, rather than per unit of energy. Adopting this approach, however, makes it difficult to compare U.S. carbon 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 carbon 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 carbon 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 carbon 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 carbon 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 carbon content coefficient

Data Sources

Data on the carbon 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 (2005a). Data on the carbon 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 carbon 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 carbon 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 carbon 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 carbon content of No. 2 fuel oil is assumed to typify the carbon content of distillate fuel generally. The carbon share in No. 2 fuel oil was estimated based on the average of 11 ultimate analyses. This carbon 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 carbon 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 (2005a).

Uncertainty

The primary source of uncertainty for the estimated carbon 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 carbon 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 carbon compared to the 86.34 percent contained in samples of No.2 fuel oil. A carbon content coefficient based on No.1 fuel oil would equal 19.72 Tg/QBtu rather than the 19.95 Tg/QBtu for No. 2 fuel oil. There is also small uncertainty in the share of carbon 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 carbon content coefficient for this report. An average share of carbon in residual fuel of 85.67 percent by mass was used based on ultimate analyses of a dozen samples.

Data Sources

Data on carbon 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 (1992, 1993). A standard heat content was adopted from EIA (2005a).

Uncertainty

The largest source of uncertainty for estimating the carbon 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 carbon. Overall, the uncertainty associated with the carbon 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 carbon shares are easily derived by taking into account the atomic weight of carbon (12) and the atomic weight of hydrogen (1). Thus, for example, the carbon share of propane, C_3H_8, is 81.8 percent. The densities and heat content of the compounds are also well known allowing carbon content coefficients to be calculated directly. Table A-38 summarizes the physical characteristic of LPG.

Table A-38: 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/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 carbon 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 carbon 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 carbon 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-39.

Data Sources

Data on carbon share, density, and heat content of LPG was obtained from Guthrie (1960). LPG consumption was based on data obtained from API (1990-2005) and EIA (2005b). Non-fuel use of LPG was obtained from API (1990 through 2005).

Uncertainty

Because LPG consists of pure paraffinic compounds whose density, heat content and carbon share are physical constants, there is limited uncertainty associated with the carbon 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-39: Consumption and Carbon Content Coefficients of Liquefied Petroleum Gases, 1990-2004

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
Energy Consumption (QBtu)															
Fuel Use	0.90	0.85	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
Ethane	0.03	0.02	0.03	0.02	0.02	0.02	0.03	0.05	0.00	0.00	0.08	0.05	0.05	0.05	0.05
Propane	0.79	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
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
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
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
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
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
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
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

Sources: Fuel use of LPG based on data from EIA (2005b) and API (1990 through 2005). Non-fuel use of LPG from API (1990 through 2005). Carbon contents from EIA (2005a).

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 carbon 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 carbon in the fuel, it was assumed that aviation gasoline is 87.5 percent iso-octane, 9.0 percent toluene, and 3.5 percent xylene. The maximum allowable sulfur content in aviation gasoline is 0.05 percent, and the maximum allowable lead content is 0.1 percent. These amounts were judged negligible and excluded for the purposes of this analysis. This yielded a carbon share of 85 percent and a carbon content coefficient of 18.87 Tg/QBtu.

Data Sources

Data sources include ASTM (1985). A standard heat content for aviation gas was adopted from EIA (2005a).

Uncertainty

The uncertainty associated with the carbon 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 carbon 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-40 below shows the composition of those samples.

Table A-40: 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/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 carbon 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 carbon content coefficient for this product is highly uncertain, with an accuracy of ±33 percent. The carbon 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 carbon 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 carbon contents than other hydrocarbons.

Methodology

Ultimate analyses of twelve samples of asphalts showed an average carbon 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 carbon content coefficient of 20.62 Tg/QBtu.

Data Sources

A standard heat content for asphalt was adopted from EIA (2005a). The density of asphalt was determined by the ASTM (1985).

Uncertainty

The share of carbon 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 carbon share and total heat content in asphalts do vary systematically, the overall carbon 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 carbon content of 85.8 percent. A standard heat content of 6.065 MMBtu per barrel was adopted from EIA. These factors produce a carbon content coefficient of 20.24 Tg/QBtu.

Data Sources

A standard heat content was adopted from the EIA (2005a). The density of asphalt was determined by ASTM (1985).

Uncertainty

Uncertainty in the estimated carbon 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 carbon content coefficients range from just under 20.0 Tg/QBtu to about 21.5 Tg/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 carbon 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 carbon 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 carbon content coefficient of 18.14 Tg/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 carbon content coefficient of 19.95 Tg/Btu 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 carbon content coefficients for petroleum feedstocks equals 19.37 Tg/Btu.

Data Sources

Data on the carbon content and density of naphtha was taken from Unzelman (1992). A standard heat content for petrochemical feedstock was adopted from EIA (2005a).

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 carbon 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 carbon 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 carbon content coefficient of 19.72 Tg/Btu.

Data Sources

A standard heat content was adopted from EIA (2005a).

Uncertainty

Uncertainty in the estimated carbon 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 carbon content coefficient is likely to be some 2 percent lower. If kerosene is more aptly compared to No. 2 fuel oil, then the true carbon 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 carbon 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 carbon 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 carbon content coefficient of 27.85 Tg/QBtu.

Data Sources

Carbon 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 (2005a).

Uncertainty

The uncertainty associated with the estimated carbon content coefficient of petroleum coke can be traced to two factors: the use of only two samples to establish carbon contents and a standard heat content which may be too low. Together, these uncertainties are likely to bias the carbon 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 carbon percentage, requiring the development of multiple coefficients.

Methodology

The method for estimating the carbon content coefficient of special naphtha includes three steps.

Step 1. Estimate the carbon content coefficient for hexane

Hexane is a pure paraffin containing 6 carbon atoms and 14 hydrogen atoms. Thus, it is 83.7 percent carbon. Its density is 76.6 degrees API or 5.649 pounds per gallon and its derived carbon content coefficient is 17.17 Tg/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 carbon content factors contained in Table A-41, below.

Table A-41: Characteristics of Non-hexane Special Naphthas

Special Naphtha	Aromatic Content (Percent)	Density (Degrees API)	Carbon Content (Percent)	Carbon Content (Tg/Btu)

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 carbon 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/QBtu.

Data Sources

A standard heat content for special naphtha was adopted from EIA (2005a). Density and aromatic contents were adopted from Boldt and Hall (1977).

Uncertainty

The principal uncertainty associated with the estimated carbon 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 carbon content of hexane and on the upper end by the carbon 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 carbon atoms and the type of hydrocarbon compounds. Microcrystalline waxes have longer carbon chains and more variation in their chemical bonds than paraffin waxes.

Methodology

The method for estimating the carbon 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 carbon atoms. The resulting carbon 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 carbon atoms, yielding a carbon 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 carbon content was calculated for petroleum waxes, assuming that wax consumption is 80 percent paraffin wax and 20 percent microcrystalline wax. The weighted average carbon 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 carbon content coefficient for petroleum waxes of 19.81 Tg/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 (2005a).

Uncertainty

Although there is considerable qualitative uncertainty associated with the allocation of petroleum waxes and microcrystalline waxes, the quantitative variation in the carbon contents for all waxes is limited to ± 1 percent because of the nearly uniform relationship between carbon 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 carbon accounting purposes, it was assumed that all these products have the same carbon 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 carbon content based on this information, ultimate analyses of 182 crude oil samples were collected. Within the sample set, carbon content ranged from 82 to 88 percent carbon, but almost all samples fell between 84 percent and 86 percent carbon. The density and sulfur content of the crude oil data were regressed on the carbon content, producing the following equation:

$$\text{Percent Carbon} = 76.99 + (10.19 \times \text{Specific Gravity}) + (-0.76 \times \text{Sulfur Content})$$

Absent the term representing sulfur content, the equation had an R-squared of only 0.35.[1] When carbon 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 carbon 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 carbon content of 85.81 percent. Applying the density and carbon content to the EIA standard energy content for crude oil of 5.800 MMBtu per barrel produced an emissions coefficient of 20.23 Tg/QBtu.

Data Sources

Carbon 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 (2005a).

Uncertainty

The uncertainty of the estimated carbon 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 carbon content coefficient by ±3 percent. Since unfinished oils and miscellaneous products are impossible to define, the uncertainty of applying a crude oil carbon 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 carbon content coefficients for coal were updated and revised in 2005. 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 carbon content estimates. The results from that sample set appear below in Table A-42. The EIA Coal Analysis File was originally developed by the U.S. Bureau of Mines and contained over 60,000 coal samples obtained through

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

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.

Petroleum Products

Jet Fuel

Between 1994 and 1995, the carbon content coefficient for kerosene-based jet fuel was revised downward from 19.71 Tg/QBtu to 19.33 Tg/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 carbon 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 carbon content coefficient.

Liquefied Petroleum Gases (LPG)

The carbon 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 carbon per unit of energy, its removal from the consumption mix lowered the carbon content coefficient for LPG from 17.26 Tg/QBtu to 17.02 Tg/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 carbon content coefficient for fuel use is about 2 percent higher than the coefficient for non-fuel use.

Motor Gasoline

The carbon 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 carbon content coefficients for motor gasoline. This change resulted in a downward step function in carbon content coefficients for gasoline of approximately 0.3 percent beginning in 1995.

Table A-42: Carbon Content Coefficients for Coal by Consuming Sector and Coal Rank , 1990-2004 [Tg/QBtu)

Consuming Sector	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
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
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
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
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
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 [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 [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 [p]
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 [p]

[p] (Preliminary)

Sources: Carbon content coefficients by consuming sector from EIA (2005a). Carbon content coefficients by coal rank from USGS (1998) and SAIC (2005).

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

Carbon 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 carbon content) by a fuel-specific storage factor, as listed in Table A-43. 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 for the remaining non-energy fuel uses are either based on values recommended for use by IPCC (1997), or when these were not available, assumptions based on the potential fate of carbon in the respective NEU products.

Table A-43: Fuel Types and Percent of Carbon Stored for Non-Energy Uses

Sector/Fuel Type	Storage Factor (%)
Industry	-
Industrial Coking Coal[a]	0.75
Industrial Other Coal [b]	0.62
Natural Gas to Chemical Plants [b]	0.62
Asphalt & Road Oil	1.00
LPG [b]	0.62
Lubricants	0.09
Pentanes Plus [b]	0.62
Naphtha (<401 deg. F) [b]	0.62
Other Oil (>401 deg. F) [b]	0.62
Still Gas [b]	0.62
Petroleum Coke[c]	0.50
Special Naphtha [b]	0.62
Distillate Fuel Oil	0.50
Waxes	0.58
Miscellaneous Products	0.00
Transportation	
Lubricants	0.09
U.S. Territories	
Lubricants	0.09
Other Petroleum (Misc. Prod.)	0.10

- 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 2004. 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., carbon 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.

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 215.1 Tg CO_2 Eq., or 53 percent, of the 403.6 Tg CO_2 Eq. of non-energy fuel consumption in 2004. For 2004 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 carbon stored in the final products to total carbon 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, 2005) 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 carbon derived from fossil fuels (i.e., fossil carbon), so estimates of net flows not already considered in EIA's dataset were developed for the entire time series from 1990 to 2004.

The approach to estimate imports and exports involves three steps:

Step 1. Identify commodities derived from petrochemical feedstocks, and calculate net import/export for each.

Step 2. Estimate the carbon content for each commodity.

Step 3. Sum the net carbon imports/exports across all commodities.

Step 1 relies heavily on information provided by the National Petrochemical and Refiners Association (NPRA) and U.S. Bureau of the Census (BoC) trade statistics published by the U.S. International Trade Commission (USITC). NPRA provided a spreadsheet of the ten-digit BoC Harmonized Tariff Schedule (HTS) Commodity Codes used to compile import-export data for periodic reports issued to NPRA's membership on trade issues. Additional feedstock commodities were identified by HTS code in the BoC data system and included in the net import/export analysis.

One of the difficulties in analyzing trade data is that a large portion of the outputs from the refining industry are fuels and fuel components, and it was difficult to segregate these from the outputs used for non-energy uses. The NPRA-supplied codes identify fuels and fuel components, thus providing a sound basis for isolating net

[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.

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 carbon 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 carbon, 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 carbon 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 2004. 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 carbon 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 carbon imports/exports across all commodities. The results of this step are shown in Table A-44. As shown in the table, the United States has been a net exporter of chemical intermediates and products throughout the 1990 to 2004 period.

Table A-44: Net Exports of Petrochemical Feedstocks, 1990 – 2004 (Tg CO_2 Eq.)

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
Net Exports	-12.0	-13.6	-12.9	-15.3	-12.9	-14.2	-11.7	-13.8	-9.0	-8.9	-8.7	-2.2	-7.5	-15.0	-20.4

After adjusting for imports and exports, the carbon budget is adjusted for the quantity of carbon that is used in the industrial processes sector of the GHG Inventory. Fossil fuels used for non-energy purposes in industrial processes—and for which carbon 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 in the Inventory, the total carbon 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-44) to yield net domestic fuel consumption for non-energy. The balance was apportioned to either stored carbon or emissive carbon, based on a storage factor.

The overall storage factor for the feedstocks was determined by developing a mass balance on the carbon in feedstocks, and characterizing products, uses, and environmental releases as resulting in either storage or emissions. The total carbon in the system was estimated by multiplying net domestic consumption for non-energy by the carbon 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). Carbon content values for the fuel feedstocks are discussed in Annexes 2.1 and 2.2.

Next, carbon pools and releases in a variety of industrial releases, energy recovery processes, and products were characterized. The carbon fate categories are plastics, energy recovery, synthetic rubber, synthetic fibers, organic solvents, carbon black, detergents and personal cleansers, industrial non-methane volatile organic compound

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

(NMVOC) emissions, hazardous waste incineration, industrial toxic chemical (i.e., TRI) releases, pesticides, food additives, antifreeze and deicers (glycols), and silicones.[14]

The carbon in each product or waste produced was categorized as either stored or emitted. The aggregate storage factor is the carbon-weighted average of storage across fuel types. As discussed later in the section on uncertainty, the sum of stored carbon and emitted carbon (i.e., the outputs of the system) exceeded total carbon 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 carbon storage divided by total carbon outputs (rather than carbon storage divided by carbon inputs).

Note that the system boundaries for the storage factor do not encompass the entire life-cycle of fossil-based carbon 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 carbon in each product and waste shown in Table A-45. Summing the carbon stored and dividing it by total carbon outputs yields the overall storage factor, as shown in the following equation for 2004:

$$\text{Overall Storage Factor} = \text{Carbon Stored} / (\text{Carbon Stored} + \text{Carbon Emitted}) =$$
$$156.5 \text{ Tg } CO_2 \text{ Eq.} / (156.5 + 94.0) \text{ Tg } CO_2 \text{ Eq.} = 62\ \%$$

Table A-45: Carbon Stored and Emitted by Products from Feedstocks in 2004 (Tg CO_2 Eq.)

Product/Waste Type	Carbon Stored (Tg CO_2 Eq.)	Carbon Emitted (Tg CO_2 Eq.)
Industrial Releases	0.4	5.2
TRI Releases	0.4	1.0
Industrial VOCs	-	2.0
Non-combustion CO	-	0.9
Hazardous Waste Incin.	-	1.4
Energy Recovery	-	71.2
Products	156.0	17.6
Plastics	133.2	-
Synthetic Rubber	11.5	-
Abraded tire rubber	-	0.7
Synthetic Fiber	10.6	-
Pesticides	0.3	0.2
Soaps, shampoos, detergents	-	5.6
Food additives	-	0.9
Antifreeze and deicers	-	1.3
Silicones	0.5	-
Solvent VOCs	-	8.8
Total	156.5	94.0

- Not applicable
Note: Totals may not sum due to independent rounding.

The three categories of carbon accounted for in the table are industrial releases, energy recovery, and products. Each is discussed below.

[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 2004 time series, outputs exceeded inputs by 0.2 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.

Industrial Releases

Industrial releases include toxic chemicals reported through the Toxics Release Inventory, industrial emissions of volatile organic compounds (VOCs), carbon monoxide emissions (other than those related to fuel combustion), and emissions from hazardous waste incineration.

TRI Releases

Fossil-derived carbon is found in many toxic substances released by industrial facilities. The Toxics Release Inventory (TRI), maintained by EPA, tracks these releases by chemical and environmental release medium (i.e., land, air, or water) on a biennial basis (EPA 2000b). By examining the carbon 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 carbon stored and emitted in the form of toxic releases can be estimated.

The TRI specifies releases by chemical, so carbon 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 carbon released in each disposal location is provided in Table A-46.

Each on-site classification was assigned a storage factor. A one hundred percent storage factor was applied to disposition of carbon 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 carbon-weighted average storage factor for the on-site carbon 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 carbon content value, based upon the top 35 chemicals' carbon 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 2004 time series were not readily available. Since this category is small (less than 1 MMTC emitted and stored), the 1998 value was applied for the entire time series.

Table A-46: 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
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 National Air Quality and Emissions Trends Report data (EPA 2005). The 1990-2004 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-45 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 chemical and allied products, metals processing,

[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).

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 carbon content of the NMVOCs for each category of emissions. The assumptions for calculating the carbon fraction of industrial and solvent utilization emissions were made separately and differ significantly. For industrial NMVOC emissions, a carbon content of 85 percent was assumed. This value was chosen to reflect the carbon 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 (carbon contents ranging from 80 to 85 percent based upon carbon number), alkenes (carbon contents approximately 85.7 percent), and some aromatics (carbon contents approximately 90 percent, depending upon substitution).

An EPA solvent evaporation emissions dataset (Tooly 2001) was used to estimate the carbon 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 carbon of each compound identified in the dataset was calculated based on the molecular formula of the individual compound (e.g., the carbon content of methylene chloride is 14 percent; the carbon 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 carbon content of the category was estimated based on the carbon content of the representative compound. The overall carbon 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-47 for 1990 through 2004. Solvent evaporation emissions in 2004 were 8.8 Tg CO_2 Eq., and industrial NMVOC emissions in 2004 were 2.0 Tg CO_2 Eq. In 2004, NMVOC and solvent activity data were revised across the entire time series to reflect updated information from the 2004 National Air Quality and Emissions Trends Report.

Table A-47: Industrial and Solvent NMVOC Emissions

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
Industrial NMVOCs[a]															
NMVOCs ('000 Short Tons)	1,157	1,224	1,254	1,267	1,254	1,235	896	904	915	755	775	753	689	690	691
Carbon Content (%)	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%
Carbon Emitted (Tg CO_2 Eq.)	3.3	3.5	3.5	3.6	3.5	3.5	2.5	2.6	2.6	2.1	2.2	2.1	1.9	2.0	2.0
Solvent Evaporation[b]															
Solvents ('000 Short Tons)	5,750	5,782	5,901	6,016	6,162	6,183	5,477	5,622	5,149	5,037	4,832	5,012	4,692	4,698	4,704
Carbon Content (%)	56%	56%	56%	56%	56%	56%	56%	56%	56%	56%	56%	56%	56%	56%	56%
Carbon Emitted (Tg CO_2 Eq.)	10.8	10.8	11.0	11.3	11.5	11.6	10.3	10.5	9.6	9.4	9.0	9.4	8.8	8.8	8.8

[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 2004 National Air Quality and Emissions Trends Report (EPA 2005). 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 carbon emissions from the primary aluminum, titanium dioxide, iron and steel, and ferroalloys production processes. The total carbon (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-48 lists the CO emissions that remain after taking into account the exclusions listed above.

Table A-48: 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	633	0.9
2003	633	0.9
2004	633	0.9

[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 U.S. is burned in BIFs; these processes are included in the energy recovery calculations described below.

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). 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

[17] [42 U.S.C. §6924, SDWA §3004]

waste quantities to carbon 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 carbon content factors (discussed in Annex 2.2) yields tons of carbon emitted. Implied carbon content is calculated by dividing the tons of carbon 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, and 2001 (EPA 2000a, 2004). Values for years after 2001 were held constant at the 2001 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-49). Regulations require incinerators to achieve at least 99.99 percent destruction of organics; this formed the basis for assuming the fraction of carbon oxidized. Emissions from hazardous waste incineration in 2001 were 1.4 Tg CO_2 Eq. Table A-50 lists the CO_2 emissions from hazardous waste incineration.

Table A-49: 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-50: 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
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	1.4	1.4

Energy Recovery

The amount of feedstocks combusted for energy recovery was estimated from data included in EIA's Manufacturers Energy Consumption Survey (MECS) for 1991, 1994, 1998, and 2002 (EIA 1994, 1997, 2001b, 2004). Some fraction of the fossil carbon 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-51). The conversion factors listed in Annex 2.1 were used to convert the Btu values for each fuel feedstock to Tg CO_2. Petrochemical feedstocks combusted for energy recovery corresponded to 42.2 Tg CO_2 Eq. in 1991, 35.4 Tg CO_2 Eq. in 1994, 58.1 Tg CO_2 Eq. in 1998, and 71.2 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-52).

Table A-51: 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 Carbon Content (Tg/QBtu)		18.14	20.62	17.51	0	19.37
Fraction Oxidized		0.99	0.99	0.99	0	0.99
Total Carbon (Tg)		8.71	0.43	24.20		10.27
Total Carbon (Tg) (ex. still gas from refining)		8.71	0.43	0.00		10.27

[a] Carbon content: Waste Gas is assumed to be same as naphtha <401 deg. F
[b] Carbon 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 carbon content estimate
[d] Net steam fuel consumption is reported elsewhere in the Inventory and is excluded from the total carbon content estimate
[e] Carbon content: "Other" is assumed to be the same as petrochemical feedstocks

Table A-52: 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
C Emissions	42.2	42.2	40.0	37.7	35.4	41.1	46.8	52.4	58.1	61.4	64.6	67.9	71.2	71.2	71.2

Products

More carbon is found in products than in industrial releases or energy recovery. The principal types of products are plastics; synthetic rubber; synthetic fiber; carbon 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, 2004, 2005; SPI 2000; Eldredge-Roebuck 2000). These data were organized by resin type (see Table A-53) 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 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 carbon content was then assigned for each resin. These contents were based on molecular formulas and are listed in Table A-54 and Table A-55. 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 carbon 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 carbon 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-53: 2004 Plastic Resin Production (Tg dry weight) and Carbon Stored (Tg CO_2 Eq.)

Resin Type	2004 Production[a] (Tg dry weight)	Carbon Stored (Tg CO_2 Eq.)
Epoxy	0.29	0.8
Urea	0.71	0.9
Melamine	0.71	0.8
Phenolic	1.98	5.6
Low-Density Polyethylene (LDPE)	3.54	11.1
Linear Low-Density Polyethylene (LLDPE)	5.31	16.7
High Density Polyethylene (HDPE)	7.50	23.6
Polypropylene (PP)	7.93	24.9
Acrylonitrile-butadiene-styrene (ABS)	0.56	1.8
Styrene-acrylonitrile (SAN)	0.06	0.2
Other Styrenics	0.72	2.4
Polystyrene (PS)	2.88	9.8
Nylon	0.55	1.3
Polyvinyl chloride (PVC) [b]	6.83	9.6
Thermoplastic Polyester	3.41	7.8
Engineering Resins	1.16	2.9
All Other (including Polyester (unsaturated))	5.22	13.1
Total	49.35	133.2

[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
Note: Totals may not sum due to independent rounding.

Table A-54: Assigned Carbon Contents of Plastic Resins (% by weight)

Resin Type	Carbon Content	Source of Carbon 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-55)
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-55: Major Nylon Resins and their Carbon Contents (% by weight)

Resin	Carbon 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 *U.S. Scrap Tire Markets 2003* (RMA 2004), while the tire composition information is from the "Scrap Tires, Facts and Figures" section of the organization's website (STMC 2003). No data were available for 2004, so tire consumption for 2004 was assumed to equal 2003 consumption. 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, 1997, 1998, 1999, 2000, 2001, 2002, 2003, and 2005). 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 carbon 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 carbon contents (based on molecular formula) by elastomer type consumed in 1998, 2000, and 2001 (see Table A-56). 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-56: 2002 Rubber Consumption (Gg) and Carbon Content (%)

Elastomer Type	2002 Consumption (Gg)*	Carbon 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* (2001, 2003, and 2005). These data are organized by year and fiber type. For each fiber, a carbon content was assigned based on molecular formula (see Table A-57). For polyester, the carbon content for poly(ethylene terephthalate) (PET) was used as a representative compound. For nylon, the average carbon 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' carbon accounting because much of their carbon 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 carbon 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-57: 2004* Fiber Production (Tg), Carbon Content (%), and Carbon Stored (Tg CO_2 Eq.)

Fiber Type	Production (Tg)	Carbon Content	Carbon Stored (Tg CO_2 Eq.)
Polyester	1.5	63%	3.33
Nylon	1.1	64%	2.67
Olefin	1.4	86%	4.31
Acrylic	0.1	68%	0.27
Total	4.1	-	10.59

- Not applicable
Note: Totals may not sum due to independent rounding

Pesticides

Pesticide consumption data were obtained from the *1994/1995, 1996/1997, and 1998/1999 Pesticides Industry Sales and Usage Market Estimates* (EPA 1998b, 1999b, 2002c) reports. The most recent data available were for 1999, so it was assumed that the 2000 through 2003 consumption was equal to that of 1999. 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 carbon 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 carbon in the compound was assumed to be stored. All other pesticides were assumed to release their carbon to the atmosphere. Over one-third of 1999 total pesticide active ingredient consumption was not specified by chemical type in the *Sales and Usage* report (EPA 2002c). This unspecified portion of the active ingredient consumption was treated as a single chemical and assigned a carbon content and a storage factor based on the weighted average of the known chemicals' values.

Table A-58: Active Ingredient Consumption in Pesticides (Million lbs.) and Carbon Emitted and Stored (Tg CO_2 Eq.)

Pesticide Use*	Active Ingredient (Million lbs.)	Carbon Emitted (Tg CO_2 Eq.)	Carbon Stored (Tg CO_2 Eq.)
Agricultural Uses [a]	475.0	0.1	0.2
Non-Agricultural Uses [b]	80.5	+	+
Home & Garden	33.5	+	+
Industry/Gov't/Commercial	47.0	+	+
Other	356.5	0.1	0.1
Total	912.0	0.2	0.3

+ Less than 0.05 Tg CO_2 Eq.
*1999 estimates (EPA 2002c).
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 carbon. All of the carbon in cleansers was assumed to be fossil-derived, and, as cleansers eventually biodegrade, all of the carbon was assumed to be emitted. The first step in estimating carbon 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 and 2004 was assumed to equal the 2002 value.

Chemical formulae were used to determine carbon contents (as percentages) of the ingredients in the cleansers. Each product's overall carbon content was then derived from the composition and contents of its ingredients. From these values the mean carbon 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 carbon content (21.9 percent) by this value yielded an estimate of 4.9 Tg CO_2 Eq. in cleansers for 1997. For 1992 and 2002 the estimates are 3.9 Tg CO_2 Eq. and 5.6 Tg CO_2 Eq. Estimates for other years are based on these values as described above, and are shown in Table A-59.

Table A-59: Carbon 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
C Emissions	3.9	3.9	3.9	4.1	4.3	4.5	4.7	4.9	4.9	4.7	4.8	5.2	5.6	5.6	5.6

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, 2003 (American Chemistry Council 2004). 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-60.

Table A-60: Carbon 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
C Emissions	1.1	1.1	1.1	1.2	1.2	1.2	1.3	1.3	1.3	1.3	1.3	1.1	1.2	1.2	1.3

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, 2003 (American Chemistry Council 2004). 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

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

was estimated from Chemical Profiles data published on The Innovation Group website <http://www.the-innovation-group.com/ChemProfiles>. 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-62.

Table A-61: Carbon 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
Emissions	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.8	0.9	0.8	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 carbon 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, 2003 (American Chemistry Council, 2004). 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 <http://www.the-innovation-group.com/ChemProfiles>. 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-62.

Table A-62: Carbon Stored in Silicone Products (Tg CO_2 Eq.)

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
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

Uncertainty

A Tier 2 Monte Carlo analysis was performed using @RISK software to determine the level of uncertainty surrounding the estimates of the feedstocks carbon storage factor and the quantity of carbon emitted from feedstocks in 2004. The Tier 2 analysis was performed to allow the specification of probability density functions for key variables, within a computational structure that mirrors the calculation of the Inventory estimate. Statistical analyses or expert judgments of uncertainty were not available directly from the information sources for the activity variables; thus, uncertainty estimates were determined using assumptions based on source category knowledge. Uncertainty estimates for production data (the majority of the variables) were assumed to exhibit a normal distribution with a relative error of ±20 percent in the underlying EIA estimates, plus an additional ±15 percent to account for uncertainty in the assignment of imports and 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 carbon coefficient.

The Monte Carlo analysis produced a storage factor distribution that approximates a normal curve around a mean of 62.2 percent, with a standard deviation of 1 percent and 95 percent confidence limits of 60 percent and 64 percent. This compares to the calculated estimate, used in the Inventory, of 65 percent. The analysis produced a carbon emission distribution approximating a normal curve with a mean of 80.0 Tg CO_2 Eq., standard deviation of 2.2 Tg CO_2 Eq., and 95 percent confidence limits of 64.8 and 95.9 Tg CO_2 Eq. This compares with a calculated estimate of 80.5 Tg CO_2 Eq. The uncertainty emission distribution does not currently capture additional emissions from industrial other coal, which constitutes less than 0.5 Tg CO_2 to the overall estimate of feedstocks emissions; improvements to include other industrial coal in the uncertainty analysis will be made in future Inventories.

The apparently tight confidence limits for the storage factor and carbon 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 carbon 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 carbon 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 carbon estimate. Generally, the estimate for a product is subject to one or both of the following uncertainties:

- The value used for estimating the carbon content has been assumed or assigned based upon a representative compound.
- The split between carbon 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 carbon enters the non-energy mass balance. Some of the pathways that lead to emissions as CO_2 may take actually place on a time-scale of several years or decades. By attributing the emissions to the year in which the carbon 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 carbon 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 2005). 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 carbon.

Oxidation factors have been applied to non-energy uses of petrochemical feedstocks in the same manner as for energy uses. However, 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 carbon. 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 carbon 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 carbon 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 industry are in the estimates of total NMVOC emissions and in the application of factors for the carbon content of these emissions. 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 carbon 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 carbon content for industrial emissions has more

uncertainty, however, as it is calculated from the average carbon 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 carbon 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. Carbon 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 carbon 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 carbon 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 carbon 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 carbon stored in synthetic rubber only accounts for the carbon 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 carbon stored. There are also uncertainties as to the assignment of carbon 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 carbon content values is much narrower. Lastly, assuming that all of the carbon contained in rubber is stored ignores the possibility of volatilization or degradation during product lifetimes. However, the proportion of the total carbon that is released to the atmosphere during use is probably negligible.

A small degree of uncertainty arises from the assignment of carbon 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 carbon 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 carbon content values applied to the unaccounted for portion of active ingredient. Carbon 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, and 1999; the majority of the time series data were interpolated or held constant at the latest (1999) 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 carbon 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 carbon are emitted during production, asphalt has an overall carbon 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 carbon in asphalt roofing; it was assumed that it has the same fate as carbon in asphalt paving applications.

Methodology and Data Sources

A carbon storage factor was calculated for each type of asphalt paving. The fraction of carbon emitted by each asphalt type was multiplied by consumption data for asphalt paving (EPA 2000c, EIIP 1998) to come up with a weighted average carbon storage factor for asphalt as a whole.

The fraction of carbon emitted by HMA was determined by first calculating the organic emissions (volatile organic compounds [VOCs], carbon monoxide, polycyclic aromatic hydrocarbons [PAHs], hazardous air pollutants [HAPs], and phenol) from HMA paving, using emission factors reported in EPA (2000e) and total HMA production.[19] The next step was to estimate the carbon content of the organic emissions. This calculation was based on the carbon content of carbon monoxide (CO) and phenol, and an assumption of 85 percent carbon content for PAHs and HAPs. The carbon 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 carbon in asphalt cement. For the latter factor, all paving types were characterized as having a mass fraction of 85 percent carbon 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 carbon 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 carbon 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 carbon 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).

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

Data on asphalt and road oil consumption and carbon 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 carbon 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 carbon storage factor and the quantity of carbon stored in asphalt in 2004. 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 carbon 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 99.4 percent, with a standard deviation of 0.2 percent and boundaries between 99.0 and 99.7 percent. This compares to the storage factor value used in the Inventory of 100 percent. The analysis produced an emission 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 carbon 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 carbon 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 carbon storage factor is minimal (on the order of 0.1 percent). Similarly, changes in the assumed carbon 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 carbon 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 (2005), the carbon content from U.S. production of lubricants in 2004 was approximately 6.4 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 carbon storage factor was estimated to be 9 percent; thus, emissions in 2004 were about 5.7 Tg C, or 20.9 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 carbon for each practice. An overall lubricant carbon 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.[20] The effect of these regulations and policies has been to restrict landfilling and dumping, and to encourage collection of used oil. Given the relatively inexpensive price of crude oil, the economics have not favored re-refining—instead, most of the used oil that has been collected has been combusted.

Table A-63 provides an estimated allocation of the fates of lubricant oils (Rinehart 2000), along with an estimate of the proportion of carbon 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 carbon 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 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), i.e., it was assumed that about 97 percent of the carbon 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 carbon in oil lubricants goes into long-term storage.

Table A-63: Commercial and Environmental Fate of Oil Lubricants (Percent)

Fate of Oil	Portion of Total Oil	Carbon 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-64 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 carbon in landfilled and dumped grease, respectively, would be stored. The overall storage factor is 82 percent for grease.

Table A-64: Commercial and Environmental Fate of Grease Lubricants (Percent)

[20] 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.

Fate of Grease	Total Grease	Carbon 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 carbon storage factor and the quantity of carbon emitted from lubricants in 2004. 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 carbon 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 10.2 percent, with a standard deviation of 3.7 percent and 95 percent confidence limits of 4.5 and 16.5 percent. This compares to the calculated estimate, used in the Inventory, of 9.2 percent. The analysis produced an emission distribution approximating a normal curve with a mean of 20.8 Tg CO_2, standard deviation of 0.5, and 95 percent confidence limits of 18.0 and 23.8 Tg CO_2. This compares with a calculated estimate of 21.1 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 carbon 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 carbon storage factor and carbon 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. Previous *Inventories* have assumed that all carbon contained in this source is stored (i.e., an assumed storage factor of 100 percent). An analysis of wax end uses in the US, and the fate of carbon in these uses, suggests that about 42 percent of carbon 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. There are many other 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)

A carbon storage factor for each wax end use was estimated and then summed across all end uses to provide an overall carbon storage factor for wax. Because no specific data on carbon contents of wax used in each end use were available, all wax products are assumed to have the same carbon content. Table A-65 categorizes wax end uses identified by the NPRA, and lists each end use's estimated carbon storage factor.

Table A-65: Wax End-Uses by Fate, Percent of Total Mass, Percent Stored, and Percent of Total Mass Stored

Use	Percent of Total Mass	Percent Stored	Percent of Total Mass Stored
Candles	20%	10%	2%
Firelogs	7%	1%	+
Hotmelts	3%	50%	2%
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%	10%
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.

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 carbon 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 carbon contained in product. Similarly, carbon 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 carbon 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 carbon 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 carbon contained in these wax products will be stored. It is assumed that approximately 21 percent of the carbon 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 carbon 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 carbon storage factor for waxes, wax contained in tires and rubber products is assigned a carbon 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 carbon storage factor and the quantity of carbon emitted from wax in 2004. 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 carbon content coefficients.

The Monte Carlo analysis produced a storage factor distribution that approximates a normal curve around a mean of 57.8 percent, with a standard deviation of 6.6 percent and 95 percent confidence limits of 46 percent and 68 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 1.0 Tg CO_2, standard deviation of 0.19 Tg CO_2, and 95 percent confidence limits of 0.76 and 1.39 Tg CO_2. This compares with a calculated estimate of 0.95 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 carbon 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 (2004) U.S. production of miscellaneous petroleum products in 2004 was 154.6 TBtu. One hundred percent of the carbon 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 the IPCC *Guidelines for National Greenhouse Gas Inventories*, 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 carbon in the respective NEUs. For all these fuel types, the overall methodology simply involves multiplying carbon content by a storage factor, yielding an estimate of the mass of carbon 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' carbon storage factors and the total quantity of carbon emitted from these other fuels in 2004. 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 carbon content coefficients were assumed to have a uniform distribution; the greatest uncertainty range, 10 percent, was applied to coking coal and miscellaneous products. Carbon 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 42.0 percent, with a standard deviation of 12.2 percent and 95 percent confidence limits of 24 percent and 64 percent. This compares to the calculated, weighted average (across the various fuels) storage factor of 28 percent. The analysis produced an emission distribution approximating a normal curve with a mean of 31.0 Tg CO_2 and a standard deviation of 6.9 Tg CO_2, and 95 percent confidence limits of 19.2 Tg CO_2 and 42.1 Tg CO_2. This compares with the Inventory estimate of 39.3 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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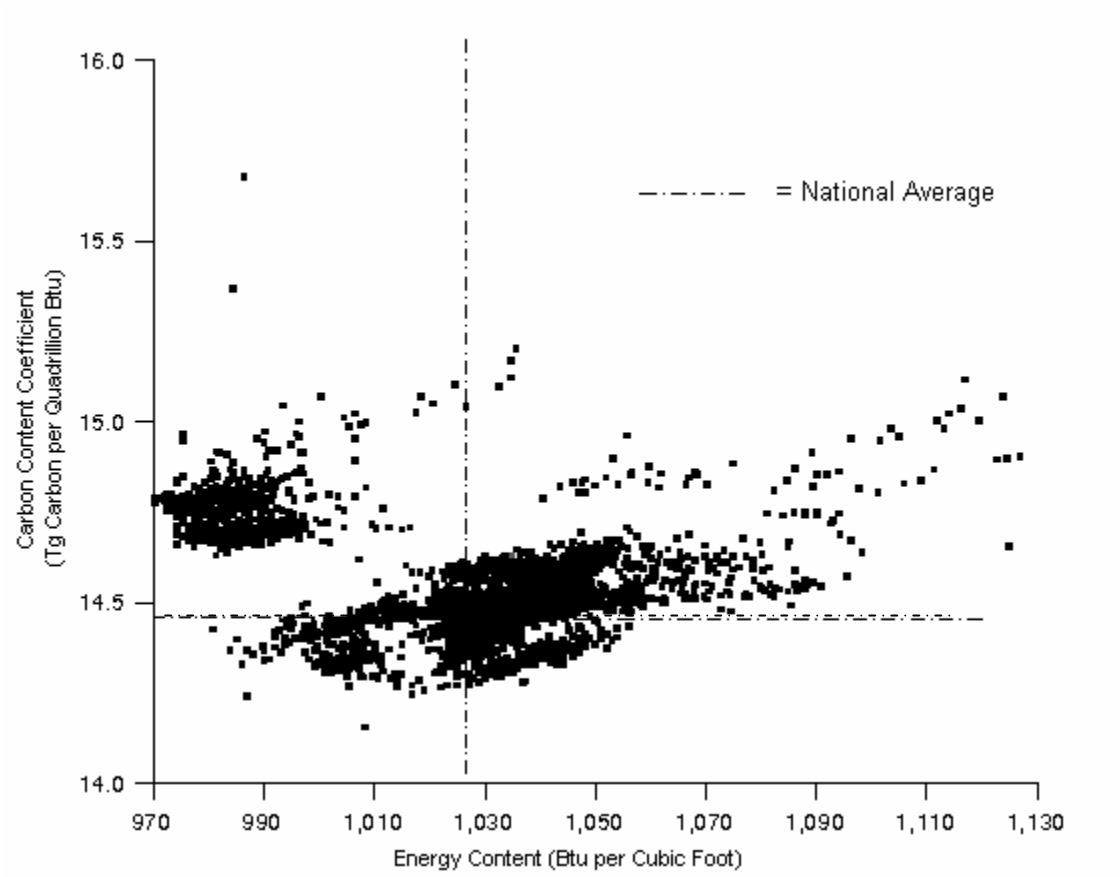
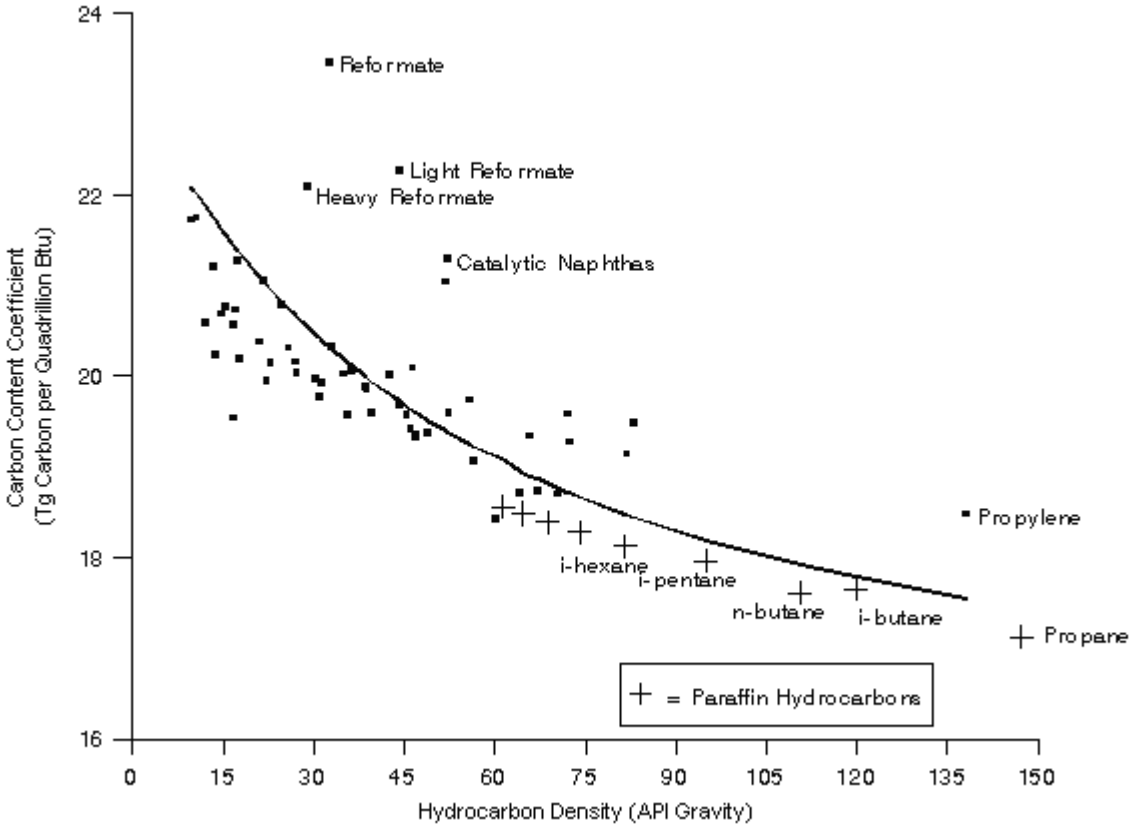
Figure A-1: Carbon Content for Samples of Pipeline-Quality Natural Gas Included in the Gas Technology Institute Database



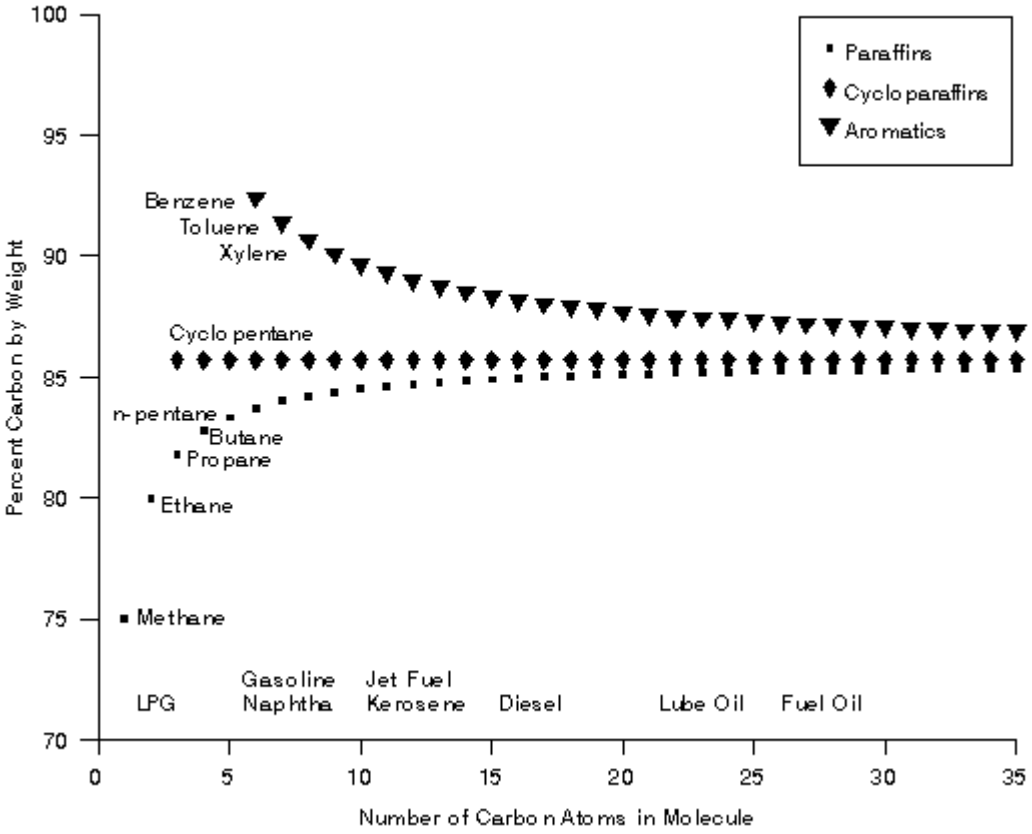
Source: EIA (1994) Energy Information Administration, Emissions of Greenhouse Gases in the United States 1987-1992, U.S. Department of Energy, Washington, DC, November, 1994, DOE/EIA 0573, Appendix A.

Figure A-2: Estimated and Actual Relationships Between Petroleum Carbon Content Coefficients and Hydrocarbon Density



Source: Carbon content factors for paraffins are calculated based on the properties of hydrocarbons in V. Guthrie (ed.), *Petroleum Products Handbook* (New York: McGraw Hill, 1960) p. 33. Carbon content factors from other petroleum products are drawn from sources described below. Relationship between density and emission factors based on the relationship between density and energy content in U.S. Department of Commerce, National Bureau of Standards, *Thermal Properties of Petroleum Products*, Miscellaneous Publication, No. 97 (Washington, D.C., 1929), pp.16-21, and relationship between energy content and fuel composition in S. Ringen, J. Lanum, and F.P. Miknis, "Calculating Heating Values from the Elemental Composition of Fossil Fuels,' *Fuel,* Vol. 58 (January 1979), p.69.

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



Source: J.M. Hunt, *Petroleum Geochemistry and Geology* (San Francisco, CA, W.H. Freeman and Company, 1979), pp. 31-37.

Descriptions of Figures: Annex 2

Figure A-1 shows the relationship between the calculated carbon 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 carbon 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 carbon emission coefficient to be predicted with an accuracy of ±5.0 percent.

Figure A-2 compares carbon content coefficients calculated on the basis of the derived formula with actual carbon content coefficients for a range of crude oils, fuel oils, petroleum products, and pure hydrocarbons. The estimated relationship is shown as a line depicting decreasing carbon content with increasing hydrocarbon density. The actual relationship is appears as dozens of points scattered along this line.

Figure A-3 illustrates the share of carbon by weight for each class of hydrocarbon. Hydrocarbon molecules containing 2 to 4 carbon atoms are all natural gas liquids; hydrocarbons with 5 to 10 carbon atoms are predominantly found in naphtha and gasoline; and hydrocarbon compounds with 12 to 20 carbons 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.

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-66 through Table A-70.

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, September 2005* and Unpublished Supplemental Tables on Petroleum Product detail (EIA 2005). 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 (2005).[21] Fuel consumption for the industrial sector was adjusted to subtract out construction and agricultural use, which is reported under mobile sources.[22] 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-66 provides annual energy consumption data for the years 1990 through 2004.

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 *Revised 1996 IPCC Guidelines* (IPCC/UNEP/OECD/IEA 1997). 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-67 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 2005) and disaggregated based on EPA (2003), which, in its final iteration, will be published on the National Emission Inventory (NEI) Air Pollutant Emission Trends web site.

For indirect greenhouse gases, the major source categories included coal, fuel oil, natural gas, wood, other fuels (i.e., bagasse, liquefied petroleum gases, coke, coke oven gas, and others), and stationary internal combustion,

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[21] 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.

[22] 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.

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-68 through Table A-70 present indirect greenhouse gas emission estimates for 1990 through 2004.

The basic calculation procedure for most source categories presented in EPA (2003) and EPA (2005) 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-66: 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
Coal	18,075	18,000	18,191	18,952	19,037	19,188	20,125	20,578	20,809	20,833	21,771	21,222	21,161	21,595	21,698
Residential	31	25	26	26	21	17	16	16	12	14	11	11	11	10	11
Commercial	124	115	117	117	117	116	120	129	101	102	86	91	91	84	87
Industrial	1,637	1,586	1,546	1,585	1,586	1,533	1,510	1,474	1,420	1,373	1,379	1,366	1,263	1,277	1,270
Electric Power	16,276	16,266	16,494	17,216	17,303	17,511	18,468	18,950	19,265	19,334	20,285	19,743	19,783	20,185	20,290
U.S. Territories	7	8	9	10	10	10	10	10	11	10	10	10	13	40	40
Petroleum	6,981	6,583	6,664	5,977	6,334	5,643	6,230	6,094	5,949	6,041	6,225	6,962	6,049	6,722	6,818
Residential	1,382	1,387	1,382	1,358	1,325	1,293	1,436	1,343	1,243	1,377	1,453	1,472	1,362	1,463	1,496
Commercial	940	902	831	735	738	684	724	661	621	611	690	718	629	730	764
Industrial	3,020	2,691	3,052	2,368	2,768	2,524	2,890	2,811	2,445	2,481	2,554	2,953	2,711	2,897	2,926
Electric Power	1,263	1,178	955	1,056	996	680	744	834	1,195	1,110	1,057	1,186	790	1,036	997
U.S. Territories	375	425	445	460	506	462	434	445	445	461	472	632	557	597	636
Natural Gas	18,393	18,844	19,571	20,059	20,394	21,346	21,742	21,802	21,468	21,530	22,442	21,585	22,246	21,737	21,856
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	5,031	5,246	5,030
Commercial	2,698	2,807	2,883	2,944	2,978	3,117	3,251	3,306	3,098	3,132	3,254	3,124	3,235	3,323	3,082
Industrial	7,826	7,942	8,320	8,446	8,424	8,900	9,198	9,203	8,980	8,598	8,746	8,048	8,167	7,882	8,115
Electric Power	3,350	3,412	3,548	3,571	4,011	4,346	3,902	4,167	4,718	4,943	5,329	5,484	5,789	5,259	5,604
U.S. Territories	0	0	0	0	0	0	0	0	0	0	13	23	23	27	25
Wood	2,191	2,190	2,290	2,227	2,315	2,420	2,467	2,350	2,175	2,224	2,257	1,980	1,899	1,929	1,989
Residential	581	613	645	548	537	596	595	433	387	414	433	370	313	359	332
Commercial	39.145	41.052	44.005	45.858	46.103	46.105	50	49	48	52	53	40	39	40	41
Industrial	1,442	1,410	1,461	1,483	1,580	1,652	1,684	1,731	1,603	1,620	1,636	1,443	1,396	1,363	1,448
Electric Power	129	126	140	150	152	125	138	137	137	138	134	126	150	167	168
U.S. Territories	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-67: CH_4 and N_2O Emission Factors by Fuel Type and Sector (g/GJ)[23]

Fuel/End-Use Sector	CH_4	N_2O
Coal		
Residential	300	1.4
Commercial	10	1.4
Industrial	10	1.4
Electric Power	1	1.4
U.S. Territories	1	1.4
Petroleum		
Residential	10	0.6
Commercial	10	0.6
Industrial	2	0.6
Electric Power	3	0.6
U.S. Territories	5	0.6
Natural Gas		
Residential	5	0.1
Commercial	5	0.1
Industrial	5	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)

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

Table A-68: 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
Electric Power	6,045	5,914	5,901	6,034	5,956	5,792	5,595	5,697	5,653	5,190	4,836	4,461	4,263	3,873	3,393
Coal	5,119	5,043	5,062	5,211	5,113	5,061	5,081	5,120	4,932	4,437	4,130	3,802	3,626	3,295	2,886
Fuel Oil	200	192	154	163	148	87	107	132	202	179	147	149	142	129	113
Natural gas	513	526	526	500	536	510	259	289	346	400	383	332	317	288	252
Wood	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	32	28
Internal Combustion	213	152	159	160	159	134	142	150	149	141	140	140	143	130	114
Industrial	2,754	2,703	2,786	2,859	2,855	2,852	2,859	2,813	2,768	2,458	2,470	2,499	2,602	2,606	2,610
Coal	530	517	521	534	546	541	490	487	475	475	484	518	539	540	541
Fuel Oil	240	215	222	222	219	224	203	196	190	190	166	153	160	160	160
Natural gas	1,072	1,134	1,180	1,207	1,210	1,202	1,092	1,079	1,066	880	902	914	952	953	955
Wood	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	120	121	121
Internal Combustion	792	720	748	783	767	774	965	948	933	813	809	798	830	832	833
Commercial	336	333	348	360	365	365	360	369	347	255	256	261	243	243	243
Coal	36	33	35	37	36	35	30	32	34	23	21	21	19	19	19
Fuel Oil	88	80	84	84	86	94	86	88	73	54	52	52	49	49	49
Natural gas	181	191	204	211	215	210	224	229	220	156	161	165	154	154	154
Wood	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
Residential	749	829	879	827	817	813	726	699	651	441	439	446	415	416	416
Coal[b]	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
Natural Gas[b]	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	20	20	20
Other Fuels[a]	708	784	831	787	777	769	699	671	624	416	417	424	395	395	396
Total	9,884	9,779	9,914	10,080	9,993	9,822	9,540	9,578	9,419	8,344	8,002	7,667	7,522	7,138	6,662

NA (Not Applicable)

[a] "Other Fuels" include LPG, waste oil, coke oven gas, coke, and non-residential wood (EPA 2003, 2005).

[b] Residential coal, fuel oil, and natural gas emissions are included in the "Other Fuels" category (EPA 2003, 2005).

Note: Totals may not sum due to independent rounding.

Table A-69: CO Emissions from Stationary Combustion (Gg)

Sector/Fuel Type	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
Electric Power	329	317	318	329	335	338	369	385	409	450	439	439	451	451	451
Coal	213	212	214	224	224	227	228	233	220	187	221	220	226	226	226
Fuel Oil	18	17	14	15	13	9	11	13	17	36	27	28	28	28	28
Natural gas	46	46	47	45	48	49	72	76	88	151	96	92	95	95	95
Wood	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	33	33	33
Internal Combustion	52	41	43	46	50	52	52	54	54	52	63	67	69	69	69
Industrial	798	835	867	946	944	958	1,079	1,055	1,044	1,100	1,106	1,137	1,303	1,303	1,303
Coal	95	92	92	92	91	88	100	99	96	114	118	125	143	143	143
Fuel Oil	67	54	58	60	60	64	49	47	46	54	48	45	52	52	52
Natural gas	205	257	272	292	306	313	308	308	305	350	355	366	419	419	419
Wood	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other Fuels[a]	253	242	239	259	260	270	317	302	303	286	300	321	368	368	368
Internal Combustion	177	189	205	243	228	222	306	299	294	296	285	279	320	320	320
Commercial	205	196	204	207	212	211	122	126	122	151	151	154	124	124	124
Coal	13	13	13	14	13	14	13	13	14	16	14	13	11	11	11
Fuel Oil	16	16	16	16	16	17	17	18	15	17	17	17	14	14	14
Natural gas	40	40	46	48	49	49	58	59	57	81	83	84	68	68	68
Wood	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	31	31	31
Residential	3,668	3,965	4,195	3,586	3,515	3,876	2,364	2,361	2,352	3,323	2,644	2,648	2,142	2,142	2,142
Coal[b]	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
Natural Gas[b]	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Wood	3,430	3,711	3,930	3,337	3,272	3,628	2,133	2,133	2,133	3,094	2,416	2,424	1,961	1,961	1,961
Other Fuels[a]	238	255	265	249	243	248	231	229	220	229	228	224	181	181	181
Total	4,999	5,313	5,583	5,068	5,007	5,383	3,935	3,927	3,927	5,024	4,340	4,377	4,020	4,020	4,020

NA (Not Applicable)

[a] "Other Fuels" include LPG, waste oil, coke oven gas, coke, and non-residential wood (EPA 2003, 2005).

[b] Residential coal, fuel oil, and natural gas emissions are included in the "Other Fuels" category (EPA 2003, 2005).

Note: Totals may not sum due to independent rounding.

Table A-70: NMVOC Emissions from Stationary Combustion (Gg)

Sector/Fuel Type	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
Electric Power	43	40	40	41	41	40	44	47	51	49	56	55	47	46	45
Coal	25	25	25	26	26	26	25	26	26	25	27	26	22	22	21
Fuel Oil	5	5	4	4	4	2	3	4	5	4	4	4	4	4	4
Natural gas	2	2	2	2	2	2	7	7	9	9	12	12	10	10	10
Wood	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
Internal Combustion	11	9	9	9	9	9	9	10	10	10	11	10	9	9	9
Industrial	165	177	169	169	178	187	163	160	159	156	157	159	155	155	155
Coal	7	5	7	5	7	5	6	6	6	9	9	10	10	10	10
Fuel Oil	11	10	11	11	11	11	8	7	7	10	9	9	8	8	8
Natural gas	52	54	47	46	57	66	54	54	54	52	53	54	52	52	53
Wood	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	29	29	29
Internal Combustion	49	61	60	60	58	59	63	62	61	60	58	57	55	55	55
Commercial	18	18	20	22	21	21	22	22	21	25	28	29	25	25	25
Coal	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	3	3	3
Natural gas	7	8	9	10	10	10	13	13	12	11	14	14	12	12	12
Wood	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	9	9	9
Residential	686	739	782	670	657	726	788	787	786	815	837	836	696	697	697
Coal[b]	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
Natural Gas[b]	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Wood	651	704	746	633	621	689	756	756	756	794	809	809	673	674	675
Other Fuels[a]	35	35	36	36	36	37	33	32	30	21	27	27	23	23	23
Total	912	975	1,011	901	898	973	1,018	1,016	1,016	1,045	1,077	1,080	923	922	922

NA (Not Applicable)

[a] "Other Fuels" include LPG, waste oil, coke oven gas, coke, and non-residential wood (EPA 2003, 2005).

[b] Residential coal, fuel oil, and natural gas emissions are included in the "Other Fuels" category (EPA 2003, 2005).

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

Estimates of CH_4 and N_2O Emissions

Greenhouse gas emissions from mobile combustion other than CO_2 are reported by transport mode (e.g., road, rail, aviation, and waterborne), vehicle type, and fuel type. Emission estimates for 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 such information as fuel consumption and vehicle miles traveled (VMT). These estimates are 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, heavy-duty trucks,[24] buses, and motorcycles) were obtained from the Federal Highway Administration's (FHWA) *Highway Statistics* (FHWA 1996 through 2005). 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 2005) 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 2004). 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) were 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.[25] The resulting national VMT estimates for gasoline and diesel highway vehicles are presented in Table A-71 and Table A-72, 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 in Table A-83 through Table A-89. This distribution was derived by weighting the appropriate age distribution of the U.S. vehicle fleet according to vehicle registrations (Table A-75 through Table A-81) by the average annual age-specific vehicle mileage accumulation of U.S. vehicles (Table A-82). 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 2005d).[26] Age-specific vehicle mileage accumulation was obtained from EPA's MOBILE6 model (EPA 2000).

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[24] The category "heavy-duty trucks" includes vehicles that are sometimes classified as medium-duty trucks (those with a GVWR between 8,500 and 14,000 lbs.). The only exception is Table A-74, which provides VMT data for medium-duty alternative fuel vehicles.

[25] 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.

[26] Age distributions were held constant for the period 1990-1998, and reflect a 25-year vehicle age span. EPA (2005d) provides a variable age distribution and 31-year vehicle age span beginning in year 1999.

Step 2: Allocate VMT Data to Control Technology Type

VMT by vehicle type for each model year were distributed across various control technologies as shown in Table A-91 through Table A-94. 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, 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 1 and its predecessor EPA Tier 0 both apply to vehicles equipped with three-way catalysts. The introduction of "early three-way catalysts," and "advanced three-way catalysts," as described in the *Revised 1996 IPCC Guidelines*, roughly correspond to the introduction of EPA Tier 0 and EPA Tier 1 regulations (EPA 1998).[27]

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 2005b). Vehicle classes and emission standard tiers to which each engine family was certified were taken from annual certification test results and data (EPA 2005a). This information was used to determine the fraction of sales of each class of vehicle that met EPA Tier 0, EPA Tier 1, 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.

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.[28] The data obtained include vehicle fuel use and total number of vehicles in use from 1992 through 2004. 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,

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

[28] 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.

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, 2000). These ratios were used to estimate fuel economy in miles per gasoline gallon equivalent for each alternative fuel and vehicle type. Energy use per fuel type was then divided among the various weight categories and vehicle technologies that use that fuel. Total VMT per vehicle type for each calendar year was then determined by dividing the energy usage by the fuel economy. Note that for AFVs capable of running on both/either traditional and alternative fuels, the VMT given reflects only those miles driven that were powered by the alternative fuel, as explained in Browning (2003). VMT estimates for AFVs by vehicle category (passenger car, light-duty truck, heavy-duty vehicles) are shown in Table A-73, while more detailed estimates of VMT by control technology are shown in Table A-74.

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

Limited data exist on N_2O and CH_4 emission factors for alternative fuel vehicles, and most of these data are for older technologies, or do not cover all of the various technologies and weight classes. Light-duty alternative fuel vehicle emission factors are estimated in Argonne National Laboratory's GREET 1.5—Transportation Fuel Cycle Model (Wang 1999). In addition, Lipman and Delucchi estimate emission factors for some light and heavy-duty alternative fuel vehicles (Lipman and Delucchi 2002). The approach taken here was to calculate CH_4 emissions from actual test data and determine N_2O emissions from NO_x emissions from the same tests. Since most alternative fuel vehicles likely use the same or similar catalysts as their conventional counterpart, the amount of N_2O emissions will depend upon the amount of NO_x emissions that the engine produces. For a given emission control system, the higher the NO_x emissions from the engine, the higher the tailpipe N_2O emissions that are formed in the catalyst. Since most alternative fuel vehicles use catalysts similar to EPA Tier 1 gasoline cars, as an approximation, the NO_x to N_2O ratio of EPA Tier 1 cars was used to determine the N_2O emissions from alternative fueled vehicles. Based upon gasoline data for EPA Tier 1 cars, the tailpipe NO_x to N_2O ratio is 5.75. [29]

Methane emission factors for light-duty vehicles were taken from the Auto/Oil Air Quality Improvement Research Program dataset (CRC 1997). This dataset provided CH_4 emission factors for all light-duty vehicle technologies except for LPG (propane). Light-duty propane emission factors were determined from reports on LPG-vehicle emissions from the California Air Resources Board (Brasil and McMahon, 1999) and the University of California Riverside (Norbeck et al. 1998).

Medium/heavy-duty emission factors for alternative fuel vehicles were determined from test data using the West Virginia University mobile dynamometer (NREL 2002). Emission factors were determined based on the ratio of total hydrocarbon emissions to CH_4 emissions found for light-duty vehicles using the same fuel. Nitrous oxide emissions for heavy-duty engines were calculated from NO_x emission results using a NO_x to N_2O ratio of 50, which is more typical for heavy-duty engines with oxidation catalysts. These emission factors are shown in Table A-96.

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 are 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-90. Consumption data for ships and boats (i.e., vessel bunkering) were obtained from EIA (1991 through 2005) for distillate fuel, and EIA (2005a) for residual fuel; marine transport fuel consumption data for U.S. territories (EIA 2002b, EIA 2003 through 2004) were added to domestic consumption,

[29] Lipman and Delucchi (2002) found NO_x to N_2O ratios for light-duty alternative fuel vehicles with three-way catalyst systems to vary from 3 to 5.5 for older technology.

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 2004c). Annual diesel consumption for Class I railroad locomotives was obtained from AAR (2005), while consumption by Class II and III railroad locomotives was provided by Benson (2004). Diesel consumption by commuter and intercity rail was obtained from DOE (1993 through 2004). Data on the consumption of jet fuel and aviation gasoline in aircraft were obtained from EIA (2005a), 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. Data on fuel consumption by all other off-road modes[31] were obtained from EPA's NONROAD model (EPA 2004c). Finally, gasoline consumption for trucks used off-road was taken from FHWA (1996 through 2005).

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-97). Table A-98 and Table A-99 provide complete emissions of CH_4 and N_2O emissions, respectively, for 1990 through 2004.

Estimates of NO_x, CO, and NMVOC Emissions

The emission estimates of NO_x, CO, and NMVOCs for mobile combustion were obtained from preliminary data (EPA 2005c), which, in its 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-100 through Table A-102 provide complete emissions estimates for 1990 through 2004.

Table A-71: Vehicle Miles Traveled for Gasoline Highway Vehicles (10^9 Miles)

Year	Passenger Cars	Light-Duty Trucks	Heavy-Duty Vehicles	Motorcycles
1990	1,391.3	554.1	25.7	9.6
1991	1,341.8	627.1	25.2	9.2
1992	1,355.0	682.8	25.0	9.6
1993	1,356.7	720.2	24.7	9.9
1994	1,387.6	738.5	25.1	10.2
1995	1,420.8	762.2	24.9	9.8
1996	1,454.9	787.8	24.3	9.9
1997	1,488.8	820.8	23.9	10.1
1998	1,536.9	836.7	23.9	10.3
1999	1,559.3	867.3	24.1	10.6
2000	1,591.9	886.5	23.9	10.5
2001	1,619.7	904.8	23.7	9.6
2002	1,649.6	925.6	23.6	9.6
2003	1,663.1	942.9	24.0	9.6
2004	1,695.8	971.8	24.9	10.0

Source: Derived from FHWA (1996 through 2005).

Table A-72: Vehicle Miles Traveled for Diesel Highway Vehicles (10^9 Miles)

Year	Passenger Cars	Light-Duty Trucks	Heavy-Duty Vehicles
1990	16.9	19.7	125.4
1991	16.3	21.6	129.2
1992	16.5	23.4	133.3
1993	17.9	24.7	140.2
1994	18.3	25.3	150.4

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

[31] "Off-road" modes 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.

1995	17.3	26.9	158.7
1996	14.7	27.8	164.2
1997	13.5	29.0	173.2
1998	12.4	30.5	178.3
1999	9.4	32.6	184.9
2000	8.0	35.3	187.7
2001	8.1	37.0	190.7
2002	8.3	39.0	196.0
2003	8.4	39.7	198.9
2004	8.5	40.9	206.3

Source: Derived from FHWA (1996 through 2005).

Table A-73: Vehicle Miles Traveled for Alternative Fuel Highway Vehicles (10^9 Miles)

Year	Passenger Cars	Light-Duty Trucks	Heavy-Duty Vehicles
1990	0.1	0.8	0.9
1991	0.1	0.8	0.9
1992	0.1	0.7	0.8
1993	0.1	0.9	1.1
1994	0.2	0.9	1.0
1995	0.2	0.9	1.0
1996	0.2	0.9	1.1
1997	0.3	1.0	1.2
1998	0.3	1.1	1.3
1999	0.4	1.2	1.3
2000	0.4	1.3	1.5
2001	0.5	1.4	1.8
2002	0.6	1.5	1.8
2003	0.6	1.5	1.8
2004	0.6	1.6	1.9

Source: Derived from Browning (2003).

Table A-74: Detailed Vehicle Miles Traveled for Alternative Fuel Highway Vehicles (10^6 Miles)

Vehicle Type	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
Passenger Cars	67.4	79.8	104.2	141.7	171.4	189.8	218.2	265.5	292.3	352.7	408.7	525.7	562.1	583.0	608.5
Methanol-Flex Fuel ICE	0.0	9.0	21.8	33.9	50.5	44.2	39.3	35.8	28.3	25.3	14.2	10.8	8.2	0.0	0.0
Ethanol-Flex Fuel ICE	0.0	0.0	0.1	0.2	0.3	0.8	2.9	5.5	7.6	16.9	32.4	40.5	47.2	58.6	68.6
CNG ICE	7.5	9.5	11.5	16.1	19.5	25.9	34.4	46.0	54.9	67.7	76.4	100.5	106.5	112.1	115.6
CNG Bi-fuel	15.9	18.8	24.5	35.9	43.9	61.4	79.4	109.5	127.5	157.9	175.9	232.9	244.9	249.4	254.3
LPG ICE	5.0	4.7	4.4	5.8	5.5	5.2	5.5	5.5	5.8	6.1	6.4	6.7	7.0	7.3	8.0
LPG Bi-fuel	38.9	37.7	36.4	42.4	42.0	39.7	42.1	42.6	44.2	46.1	47.0	48.0	50.4	52.9	55.8
NEVs	0.0	0.0	5.0	6.7	8.9	11.4	13.3	18.4	21.7	29.4	50.9	77.9	88.1	89.6	86.8
Electric	0.0	0.0	0.4	0.6	0.9	1.2	1.4	2.0	2.4	3.3	5.5	8.4	9.8	13.2	19.4
Light-Duty Trucks[a]	845.9	768.6	699.8	890.6	872.4	851.8	906.3	999.9	1,059.5	1,156.5	1,271.3	1,384.8	1,471.1	1,521.9	1,571.6
Ethanol-Flex Fuel ICE	0.0	0.1	0.3	0.6	1.0	2.5	9.3	17.8	24.4	54.3	104.2	130.3	152.0	188.6	222.2
CNG ICE	7.0	9.9	13.0	17.7	22.8	30.5	38.4	58.6	67.2	81.3	100.4	124.1	136.9	141.0	143.2
CNG Bi-fuel	15.8	18.6	21.7	28.1	35.5	45.1	56.3	106.2	125.0	151.0	174.6	215.3	237.8	216.8	223.2
LPG ICE	18.8	18.3	17.9	19.6	19.1	18.1	18.8	19.4	19.8	20.3	20.7	21.1	22.0	22.9	24.2
LPG Bi-fuel	804.3	721.7	646.2	823.5	792.6	753.5	781.0	794.5	819.0	843.9	861.6	879.6	905.4	931.5	934.8
Electric	0.0	0.0	0.8	1.1	1.5	2.1	2.5	3.5	4.2	5.7	9.7	14.4	17.0	21.0	24.0
Medium-Duty Trucks	192.9	176.5	159.7	198.4	187.3	179.2	190.2	195.7	200.1	204.6	221.3	251.9	259.6	266.9	275.4
CNG Bi-fuel	1.5	1.8	2.1	2.6	3.4	4.3	5.5	6.7	7.8	9.2	10.5	11.9	12.7	13.0	13.3
LPG ICE	16.4	16.2	15.6	17.2	16.6	15.6	16.8	17.3	17.8	18.1	19.6	22.4	23.0	23.5	24.3
LPG Bi-fuel	174.9	158.5	141.9	178.7	167.4	159.3	167.9	171.7	174.5	177.3	191.2	217.6	223.9	230.4	237.8
Heavy-Duty Trucks	632.7	619.7	600.9	780.7	743.5	726.3	765.7	842.0	863.1	903.7	997.2	1,175.8	1,206.9	1,233.7	1,265.4
Neat Methanol ICE	0.0	4.6	9.6	12.7	13.2	7.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Neat Ethanol ICE	0.0	0.0	0.0	0.0	0.0	2.9	10.4	6.6	0.1	0.3	0.1	0.0	0.0	0.0	0.0
CNG ICE	14.2	18.2	22.9	29.6	31.6	51.2	68.6	88.4	96.5	123.8	139.2	176.4	174.8	180.0	186.3
LPG ICE	522.0	498.5	474.1	640.0	606.1	575.2	590.7	642.1	655.5	663.6	726.1	838.5	860.8	876.9	895.3
LPG Bi-fuel	96.5	98.3	93.6	94.8	88.4	83.9	89.3	96.5	98.8	100.3	114.1	136.2	142.7	144.3	147.4
LNG	0.0	0.0	0.7	3.6	4.3	5.6	6.7	8.3	12.1	15.7	17.7	24.8	28.5	32.5	36.5
Buses	90.5	86.4	83.6	111.7	112.1	122.7	145.9	184.7	201.6	232.5	269.9	327.7	332.4	338.0	344.6
Neat Methanol ICE	3.7	3.7	3.8	4.3	4.3	3.8	1.3	1.4	1.8	1.8	1.8	1.6	0.0	0.0	0.0
Neat Ethanol ICE	0.1	0.2	0.3	0.3	0.5	1.7	3.3	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0
CNG ICE	17.1	19.3	21.5	27.2	29.7	44.3	62.4	97.0	107.5	134.9	160.3	195.2	195.1	197.0	198.9
LPG ICE	69.7	63.3	56.7	76.4	73.1	67.9	72.9	78.9	81.4	81.9	92.2	108.9	110.0	111.1	112.2
LNG	0.0	0.0	1.3	3.5	4.4	5.0	5.9	7.3	10.6	13.7	15.4	21.7	27.0	29.4	33.0
Electric	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.2	0.3	0.4	0.4	0.5
Total VMT	1,829.4	1,731.1	1,648.1	2,123.2	2,086.7	2,069.9	2,226.3	2,487.8	2,616.6	2,850.0	3,168.5	3,665.9	3,832.1	3,943.4	4,065.6

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-75: Age Distribution by Vehicle/Fuel Type for Highway Vehicles,[a] 1990 to 1998

Vehicle Age	LDGV	LDGT	HDGV	LDDV	LDDT	HDDV	MC[c]
0	5.3%	5.8%	4.9%	5.3%	5.9%	4.2%	14.4%
1	7.1%	7.6%	8.9%	7.1%	7.4%	7.8%	16.8%
2	7.1%	7.5%	8.1%	7.1%	6.9%	7.2%	13.5%
3	7.1%	7.3%	7.4%	7.1%	6.4%	6.7%	10.9%
4	7.0%	7.1%	6.8%	7.0%	6.0%	6.2%	8.8%
5	7.0%	6.8%	6.2%	7.0%	5.6%	5.8%	7.0%
6	6.9%	6.5%	5.6%	6.9%	5.2%	5.3%	5.6%
7	6.8%	6.1%	5.1%	6.8%	4.8%	5.0%	4.5%
8	6.6%	5.7%	4.7%	6.6%	4.5%	4.6%	3.6%
9	6.3%	5.2%	4.3%	6.3%	4.2%	4.3%	2.9%
10	5.9%	4.7%	3.9%	5.9%	3.9%	4.0%	2.3%
11	5.4%	4.2%	3.6%	5.4%	3.6%	3.7%	9.7%
12	4.6%	3.6%	3.3%	4.6%	3.4%	3.4%	0.0%
13	3.6%	3.1%	3.0%	3.6%	3.2%	3.2%	0.0%
14	2.9%	2.6%	2.7%	2.9%	2.9%	2.9%	0.0%
15	2.3%	2.2%	2.5%	2.3%	2.7%	2.7%	0.0%
16	1.8%	1.8%	2.3%	1.8%	2.5%	2.5%	0.0%
17	1.4%	1.4%	2.1%	1.4%	2.4%	2.4%	0.0%
18	1.1%	1.2%	1.9%	1.1%	2.2%	2.2%	0.0%
19	0.9%	1.1%	1.7%	0.9%	2.1%	2.0%	0.0%
20	0.7%	1.1%	1.6%	0.7%	1.9%	1.9%	0.0%
21	0.6%	1.0%	1.5%	0.6%	1.8%	1.8%	0.0%
22	0.4%	1.0%	1.3%	0.4%	1.7%	1.6%	0.0%
23	0.4%	0.9%	1.2%	0.4%	1.6%	1.5%	0.0%
24	1.0%	4.6%	5.4%	1.0%	7.3%	7.2%	0.0%
Total	100%	100%	100%	100%	100%	100%	100%

Source: EPA (2000).

[a] The following abbreviations correspond to vehicle types: LDGV (light-duty gasoline vehicles), LDGT (light-duty gasoline trucks), HDGV (heavy-duty gasoline vehicles),LDDV (light-duty diesel vehicles), LDDT (light-duty diesel trucks), HDDV (heavy-duty diesel vehicles), and MC (motorcycles).

[b] Because of a lack of data, all motorcycles 11 of age or older are considered to have the same emissions and travel characteristics, and therefore are presented in aggregate.

Table A-76: Age Distribution by Vehicle/Fuel Type for Highway Vehicles,[a] 1999

Vehicle Age	LDGV	LDGT	HDGV	LDDV	LDDT	HDDV	MC
0	8.1%	7.7%	8.1%	8.1%	7.7%	8.1%	9.5%
1	6.1%	7.0%	6.5%	6.1%	7.0%	6.5%	9.3%
2	6.2%	6.5%	5.8%	6.2%	6.5%	5.8%	7.5%
3	5.9%	7.6%	5.6%	5.9%	7.6%	5.6%	6.8%
4	6.9%	8.0%	6.7%	6.9%	8.0%	6.7%	6.1%
5	6.1%	7.6%	6.0%	6.1%	7.6%	6.0%	5.7%
6	6.1%	6.6%	4.8%	6.1%	6.6%	4.8%	5.2%
7	5.6%	5.1%	3.6%	5.6%	5.1%	3.6%	4.3%
8	5.8%	5.0%	3.7%	5.8%	5.0%	3.7%	3.7%
9	5.8%	4.7%	4.7%	5.8%	4.7%	4.7%	3.5%
10	6.1%	5.2%	5.5%	6.1%	5.2%	5.5%	3.4%
11	5.9%	5.1%	5.2%	5.9%	5.1%	5.2%	3.9%
12	5.3%	5.2%	4.5%	5.3%	5.2%	4.5%	4.6%
13	4.8%	5.0%	4.9%	4.8%	5.0%	4.9%	4.2%
14	3.9%	3.2%	4.1%	3.9%	3.2%	4.1%	3.8%
15	3.1%	2.5%	2.9%	3.1%	2.5%	2.9%	3.4%
16	1.9%	1.6%	3.0%	1.9%	1.6%	3.0%	3.1%
17	1.2%	0.9%	1.8%	1.2%	0.9%	1.8%	2.7%
18	1.0%	0.8%	1.7%	1.0%	0.8%	1.7%	2.3%
19	0.9%	0.6%	1.7%	0.9%	0.6%	1.7%	2.0%
20	1.0%	0.7%	1.4%	1.0%	0.7%	1.4%	1.6%
21	0.8%	1.0%	1.7%	0.8%	1.0%	1.7%	1.3%
22	0.6%	0.5%	1.0%	0.6%	0.5%	1.0%	0.9%
23	0.4%	0.5%	0.9%	0.4%	0.5%	0.9%	0.6%

24	0.2%	0.1%	0.8%	0.2%	0.1%	0.8%	0.3%
25	0.3%	0.1%	0.7%	0.3%	0.1%	0.7%	0.0%
26	0.0%	0.3%	0.8%	0.0%	0.3%	0.8%	0.0%
27	0.0%	0.3%	1.5%	0.0%	0.3%	1.5%	0.0%
28	0.0%	0.1%	0.4%	0.0%	0.1%	0.4%	0.0%
29	0.0%	0.2%	0.2%	0.0%	0.2%	0.2%	0.0%
30	0.0%	0.1%	0.1%	0.0%	0.1%	0.1%	0.0%
Total	100%	100%	100%	100%	100%	100%	100%

Source: EPA (2005d).

[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-77: Age Distribution by Vehicle/Fuel Type for Highway Vehicles,[a] 2000

Vehicle Age	LDGV	LDGT	HDGV	LDDV	LDDT	HDDV	MC
0	7.9%	7.7%	7.1%	7.9%	7.7%	7.1%	11.8%
1	7.8%	7.4%	7.8%	7.8%	7.4%	7.8%	8.9%
2	5.8%	6.7%	6.3%	5.8%	6.7%	6.3%	8.7%
3	6.0%	6.3%	5.6%	6.0%	6.3%	5.6%	7.0%
4	5.6%	7.3%	5.4%	5.6%	7.3%	5.4%	6.2%
5	6.6%	7.6%	6.3%	6.6%	7.6%	6.3%	5.6%
6	5.8%	7.1%	5.7%	5.8%	7.1%	5.7%	5.2%
7	5.8%	6.1%	4.5%	5.8%	6.1%	4.5%	4.7%
8	5.2%	4.7%	3.4%	5.2%	4.7%	3.4%	3.8%
9	5.3%	4.6%	3.5%	5.3%	4.6%	3.5%	3.3%
10	5.3%	4.3%	4.4%	5.3%	4.3%	4.4%	3.1%
11	5.5%	4.7%	5.0%	5.5%	4.7%	5.0%	2.9%
12	5.3%	4.6%	4.8%	5.3%	4.6%	4.8%	3.3%
13	4.8%	4.6%	4.1%	4.8%	4.6%	4.1%	3.9%
14	4.2%	4.5%	4.5%	4.2%	4.5%	4.5%	3.5%
15	3.5%	2.8%	3.7%	3.5%	2.8%	3.7%	3.2%
16	2.7%	2.2%	2.6%	2.7%	2.2%	2.6%	2.9%
17	1.6%	1.4%	2.7%	1.6%	1.4%	2.7%	2.5%
18	1.1%	0.7%	1.6%	1.1%	0.7%	1.6%	2.2%
19	0.9%	0.7%	1.5%	0.9%	0.7%	1.5%	1.9%
20	0.7%	0.5%	1.5%	0.7%	0.5%	1.5%	1.6%
21	0.9%	0.6%	1.3%	0.9%	0.6%	1.3%	1.3%
22	0.7%	0.9%	1.5%	0.7%	0.9%	1.5%	1.0%
23	0.5%	0.4%	0.9%	0.5%	0.4%	0.9%	0.7%
24	0.3%	0.4%	0.8%	0.3%	0.4%	0.8%	0.5%
25	0.2%	0.1%	0.7%	0.2%	0.1%	0.7%	0.2%
26	0.2%	0.1%	0.6%	0.2%	0.1%	0.6%	0.0%
27	0.0%	0.2%	0.7%	0.0%	0.2%	0.7%	0.0%
28	0.0%	0.2%	1.3%	0.0%	0.2%	1.3%	0.0%
29	0.0%	0.1%	0.3%	0.0%	0.1%	0.3%	0.0%
30	0.0%	0.2%	0.2%	0.0%	0.2%	0.2%	0.0%
Total	100%	100%	100%	100%	100%	100%	100%

Source: EPA (2005d).

[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-78: Age Distribution by Vehicle/Fuel Type for Highway Vehicles,[a] 2001

Vehicle Age	LDGV	LDGT	HDGV	LDDV	LDDT	HDDV	MC[b]
0	7.2%	7.7%	5.5%	7.2%	7.7%	5.5%	13.1%
1	7.6%	7.4%	7.0%	7.6%	7.4%	7.0%	10.8%
2	7.5%	7.1%	7.6%	7.5%	7.1%	7.6%	8.2%
3	5.6%	6.5%	6.1%	5.6%	6.5%	6.1%	8.0%
4	5.7%	6.0%	5.5%	5.7%	6.0%	5.5%	6.3%
5	5.4%	7.0%	5.2%	5.4%	7.0%	5.2%	5.6%
6	6.3%	7.2%	6.1%	6.3%	7.2%	6.1%	5.0%
7	5.5%	6.6%	5.4%	5.5%	6.6%	5.4%	4.6%
8	5.4%	5.7%	4.3%	5.4%	5.7%	4.3%	4.1%

9	4.8%	4.3%	3.2%	4.8%	4.3%	3.2%	3.3%
10	4.9%	4.2%	3.3%	4.9%	4.2%	3.3%	2.8%
11	4.8%	3.9%	4.1%	4.8%	3.9%	4.1%	2.6%
12	5.0%	4.3%	4.7%	5.0%	4.3%	4.7%	2.5%
13	4.8%	4.1%	4.4%	4.8%	4.1%	4.4%	2.8%
14	4.3%	4.2%	3.8%	4.3%	4.2%	3.8%	3.2%
15	3.8%	4.0%	4.2%	3.8%	4.0%	4.2%	2.9%
16	3.1%	2.5%	3.4%	3.1%	2.5%	3.4%	2.6%
17	2.3%	1.9%	2.4%	2.3%	1.9%	2.4%	2.3%
18	1.4%	1.2%	2.4%	1.4%	1.2%	2.4%	2.0%
19	0.9%	0.6%	1.4%	0.9%	0.6%	1.4%	1.7%
20	0.8%	0.6%	1.3%	0.8%	0.6%	1.3%	1.5%
21	0.6%	0.5%	1.3%	0.6%	0.5%	1.3%	1.2%
22	0.7%	0.5%	1.1%	0.7%	0.5%	1.1%	1.0%
23	0.6%	0.7%	1.3%	0.6%	0.7%	1.3%	0.8%
24	0.4%	0.3%	0.8%	0.4%	0.3%	0.8%	0.6%
25	0.3%	0.4%	0.7%	0.3%	0.4%	0.7%	0.4%
26	0.2%	0.1%	0.6%	0.2%	0.1%	0.6%	0.2%
27	0.2%	0.1%	0.6%	0.2%	0.1%	0.6%	0.0%
28	0.0%	0.2%	0.6%	0.0%	0.2%	0.6%	0.0%
29	0.0%	0.2%	1.1%	0.0%	0.2%	1.1%	0.0%
30	0.0%	0.1%	0.3%	0.0%	0.1%	0.3%	0.0%
Total	100%	100%	100%	100%	100%	100%	100%

Source: EPA (2005d).

[a] The following abbreviations correspond to vehicle types: LDGV (light-duty gasoline vehicles), LDGT (light-duty gasoline trucks), HDGV (heavy-duty gasoline vehicles),LDDV (light-duty diesel vehicles), LDDT (light-duty diesel trucks), HDDV (heavy-duty diesel vehicles), and MC (motorcycles).

[b] 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 in aggregate.

Table A-79: Age Distribution by Vehicle/Fuel Type for Highway Vehicles,[a] 2002

Vehicle Age	LDGV	LDGT	HDGV	LDDV	LDDT	HDDV	MC
0	6.7%	7.4%	4.8%	6.7%	7.4%	4.8%	11.8%
1	7.0%	7.4%	5.5%	7.0%	7.4%	5.5%	12.2%
2	7.3%	7.2%	6.9%	7.3%	7.2%	6.9%	10.1%
3	7.2%	6.9%	7.5%	7.2%	6.9%	7.5%	7.5%
4	5.4%	6.2%	6.1%	5.4%	6.2%	6.1%	7.3%
5	5.5%	5.7%	5.3%	5.5%	5.7%	5.3%	5.7%
6	5.2%	6.6%	5.0%	5.2%	6.6%	5.0%	5.0%
7	6.1%	6.7%	5.9%	6.1%	6.7%	5.9%	4.4%
8	5.2%	6.2%	5.2%	5.2%	6.2%	5.2%	4.0%
9	5.0%	5.2%	4.1%	5.0%	5.2%	4.1%	3.6%
10	4.5%	4.0%	3.1%	4.5%	4.0%	3.1%	2.9%
11	4.5%	3.9%	3.1%	4.5%	3.9%	3.1%	2.4%
12	4.4%	3.6%	3.9%	4.4%	3.6%	3.9%	2.3%
13	4.6%	3.8%	4.5%	4.6%	3.8%	4.5%	2.1%
14	4.3%	3.7%	4.2%	4.3%	3.7%	4.2%	2.3%
15	3.8%	3.7%	3.6%	3.8%	3.7%	3.6%	2.7%
16	3.4%	3.5%	3.9%	3.4%	3.5%	3.9%	2.4%
17	2.7%	2.2%	3.2%	2.7%	2.2%	3.2%	2.2%
18	2.1%	1.7%	2.2%	2.1%	1.7%	2.2%	1.9%
19	1.2%	1.0%	2.2%	1.2%	1.0%	2.2%	1.6%
20	0.8%	0.5%	1.3%	0.8%	0.5%	1.3%	1.4%
21	0.7%	0.5%	1.2%	0.7%	0.5%	1.2%	1.2%
22	0.5%	0.4%	1.2%	0.5%	0.4%	1.2%	1.0%
23	0.6%	0.4%	1.0%	0.6%	0.4%	1.0%	0.8%
24	0.5%	0.6%	1.2%	0.5%	0.6%	1.2%	0.6%
25	0.3%	0.3%	0.7%	0.3%	0.3%	0.7%	0.4%
26	0.2%	0.3%	0.6%	0.2%	0.3%	0.6%	0.3%
27	0.1%	0.1%	0.6%	0.1%	0.1%	0.6%	0.1%
28	0.1%	0.0%	0.5%	0.1%	0.0%	0.5%	0.0%
29	0.0%	0.2%	0.5%	0.0%	0.2%	0.5%	0.0%
30	0.0%	0.2%	1.1%	0.0%	0.2%	1.1%	0.0%

Total	100%	100%	100%	100%	100%	100%	100%

Source: EPA (2005d).
[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-80: Age Distribution by Vehicle/Fuel Type for Highway Vehicles,[a] 2003

Vehicle Age	LDGV	LDGT	HDGV	LDDV	LDDT	HDDV	MC
0	6.4%	7.0%	4.6%	6.4%	7.0%	4.6%	11.0%
1	6.5%	7.2%	4.8%	6.5%	7.2%	4.8%	11.1%
2	6.8%	7.2%	5.4%	6.8%	7.2%	5.4%	11.4%
3	7.1%	7.0%	6.9%	7.1%	7.0%	6.9%	9.3%
4	7.0%	6.7%	7.5%	7.0%	6.7%	7.5%	6.9%
5	5.2%	6.0%	6.0%	5.2%	6.0%	6.0%	6.6%
6	5.4%	5.5%	5.2%	5.4%	5.5%	5.2%	5.2%
7	5.0%	6.2%	4.9%	5.0%	6.2%	4.9%	4.5%
8	5.7%	6.3%	5.7%	5.7%	6.3%	5.7%	3.9%
9	4.8%	5.7%	5.0%	4.8%	5.7%	5.0%	3.5%
10	4.7%	4.8%	4.0%	4.7%	4.8%	4.0%	3.1%
11	4.1%	3.7%	2.9%	4.1%	3.7%	2.9%	2.5%
12	4.1%	3.6%	3.0%	4.1%	3.6%	3.0%	2.1%
13	4.1%	3.2%	3.7%	4.1%	3.2%	3.7%	1.9%
14	4.2%	3.5%	4.2%	4.2%	3.5%	4.2%	1.8%
15	3.9%	3.3%	3.9%	3.9%	3.3%	3.9%	2.0%
16	3.4%	3.3%	3.4%	3.4%	3.3%	3.4%	2.3%
17	3.0%	3.1%	3.6%	3.0%	3.1%	3.6%	2.0%
18	2.4%	1.9%	2.9%	2.4%	1.9%	2.9%	1.8%
19	1.8%	1.4%	2.0%	1.8%	1.4%	2.0%	1.5%
20	1.1%	0.9%	2.1%	1.1%	0.9%	2.1%	1.3%
21	0.7%	0.5%	1.2%	0.7%	0.5%	1.2%	1.1%
22	0.6%	0.4%	1.1%	0.6%	0.4%	1.1%	0.9%
23	0.4%	0.3%	1.1%	0.4%	0.3%	1.1%	0.8%
24	0.5%	0.3%	0.9%	0.5%	0.3%	0.9%	0.6%
25	0.4%	0.5%	1.1%	0.4%	0.5%	1.1%	0.5%
26	0.3%	0.2%	0.6%	0.3%	0.2%	0.6%	0.3%
27	0.2%	0.2%	0.6%	0.2%	0.2%	0.6%	0.2%
28	0.1%	0.1%	0.5%	0.1%	0.1%	0.5%	0.1%
29	0.1%	0.0%	0.4%	0.1%	0.0%	0.4%	0.0%
30	0.0%	0.2%	0.8%	0.0%	0.2%	0.8%	0.0%
Total	100%	100%	100%	100%	100%	100%	100%

Source: EPA (2005d).
[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: Age Distribution by Vehicle/Fuel Type for Highway Vehicles,[a] 2004

Vehicle Age	LDGV	LDGT	HDGV	LDDV	LDDT	HDDV	MC
0	6.2%	7.2%	4.8%	6.2%	7.2%	4.8%	10.4%
1	6.2%	6.8%	4.6%	6.2%	6.8%	4.6%	10.3%
2	6.4%	7.0%	4.7%	6.4%	7.0%	4.7%	10.4%
3	6.6%	7.0%	5.4%	6.6%	7.0%	5.4%	10.6%
4	7.0%	6.7%	6.8%	7.0%	6.7%	6.8%	8.6%
5	6.8%	6.4%	7.4%	6.8%	6.4%	7.4%	6.3%
6	5.1%	5.7%	5.8%	5.1%	5.7%	5.8%	6.0%
7	5.2%	5.1%	5.1%	5.2%	5.1%	5.1%	4.7%
8	4.7%	5.8%	4.7%	4.7%	5.8%	4.7%	4.0%
9	5.3%	5.8%	5.5%	5.3%	5.8%	5.5%	3.5%
10	4.5%	5.3%	4.8%	4.5%	5.3%	4.8%	3.1%
11	4.3%	4.5%	3.8%	4.3%	4.5%	3.8%	2.7%
12	3.8%	3.4%	2.8%	3.8%	3.4%	2.8%	2.2%
13	3.8%	3.2%	2.8%	3.8%	3.2%	2.8%	1.8%
14	3.7%	2.9%	3.5%	3.7%	2.9%	3.5%	1.6%
15	3.8%	3.1%	4.0%	3.8%	3.1%	4.0%	1.5%

16	3.5%	2.9%	3.7%	3.5%	2.9%	3.7%	1.6%
17	3.0%	2.8%	3.2%	3.0%	2.8%	3.2%	1.9%
18	2.6%	2.7%	3.3%	2.6%	2.7%	3.3%	1.6%
19	2.1%	1.6%	2.7%	2.1%	1.6%	2.7%	1.4%
20	1.6%	1.2%	1.9%	1.6%	1.2%	1.9%	1.2%
21	0.9%	0.8%	1.9%	0.9%	0.8%	1.9%	1.0%
22	0.6%	0.4%	1.1%	0.6%	0.4%	1.1%	0.9%
23	0.5%	0.3%	1.0%	0.5%	0.3%	1.0%	0.7%
24	0.4%	0.3%	1.0%	0.4%	0.3%	1.0%	0.6%
25	0.4%	0.3%	0.8%	0.4%	0.3%	0.8%	0.5%
26	0.3%	0.4%	0.9%	0.3%	0.4%	0.9%	0.3%
27	0.2%	0.2%	0.6%	0.2%	0.2%	0.6%	0.2%
28	0.1%	0.2%	0.5%	0.1%	0.2%	0.5%	0.1%
29	0.1%	0.0%	0.4%	0.1%	0.0%	0.4%	0.1%
30	0.1%	0.1%	0.6%	0.1%	0.1%	0.6%	0.0%
Total	100%	100%	100%	100%	100%	100%	100%

Source: EPA (2005d).

[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-82: 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

Source: EPA (2000).

[a] 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 in aggregate.

Table A-83: VMT Distribution by Vehicle Age and Vehicle/Fuel Type, 1990-1998

Vehicle Age	LDGV	LDGT	HDGV	LDDV	LDDT	HDDV	MC
0	7.51%	9.41%	7.89%	7.51%	11.50%	8.27%	19.39%
1	9.52%	11.56%	13.48%	9.52%	13.07%	14.00%	21.15%

2	9.05%	10.62%	11.11%	9.05%	11.15%	11.86%	15.82%
3	8.59%	9.70%	9.85%	8.59%	9.51%	10.05%	11.82%
4	8.14%	8.80%	8.43%	8.14%	8.11%	8.52%	8.77%
5	7.68%	7.92%	7.21%	7.68%	6.92%	7.22%	6.37%
6	7.22%	7.04%	6.16%	7.22%	5.90%	6.13%	4.60%
7	6.72%	6.19%	5.27%	6.72%	5.04%	5.20%	3.31%
8	6.20%	5.36%	4.51%	6.20%	4.30%	4.41%	2.33%
9	5.64%	4.57%	3.86%	5.64%	3.67%	3.74%	1.62%
10	5.03%	3.82%	3.31%	5.03%	3.13%	3.18%	1.09%
11	4.38%	3.14%	2.83%	4.38%	2.67%	2.70%	3.73%
12	3.54%	2.52%	2.42%	3.54%	2.28%	2.29%	0.00%
13	2.67%	1.99%	2.07%	2.67%	1.95%	1.94%	0.00%
14	2.01%	1.54%	1.76%	2.01%	1.66%	1.65%	0.00%
15	1.52%	1.16%	1.52%	1.52%	1.42%	1.40%	0.00%
16	1.14%	0.87%	1.30%	1.14%	1.21%	1.19%	0.00%
17	0.86%	0.64%	1.12%	0.86%	1.04%	1.01%	0.00%
18	0.65%	0.50%	0.96%	0.65%	0.89%	0.86%	0.00%
19	0.49%	0.43%	0.82%	0.49%	0.76%	0.73%	0.00%
20	0.37%	0.37%	0.70%	0.37%	0.65%	0.62%	0.00%
21	0.28%	0.32%	0.60%	0.28%	0.55%	0.53%	0.00%
22	0.21%	0.27%	0.52%	0.21%	0.47%	0.45%	0.00%
23	0.16%	0.23%	0.44%	0.16%	0.40%	0.38%	0.00%
24	0.43%	1.04%	1.85%	0.43%	1.75%	1.65%	0.00%
25	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
26	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
27	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
28	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
29	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
30	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Total	100%	100%	100%	100%	100%	100%	100%

Note: Estimated by weighting data in Table A-75 by data in Table A-82.

Table A-84: VMT Distribution by Vehicle Age and Vehicle/Fuel Type, 1999

Vehicle Age	LDGV	LDGT	HDGV	LDDV	LDDT	HDDV	MC
0	11.64%	12.03%	13.39%	11.64%	13.39%	15.49%	16.17%
1	8.27%	10.23%	10.08%	8.27%	11.08%	11.37%	14.92%
2	8.07%	8.94%	8.11%	8.07%	9.45%	9.26%	11.21%
3	7.21%	9.79%	7.55%	7.21%	10.10%	8.11%	9.36%
4	8.06%	9.67%	8.47%	8.06%	9.76%	8.87%	7.74%
5	6.76%	8.52%	7.14%	6.76%	8.43%	7.30%	6.57%
6	6.47%	6.92%	5.36%	6.47%	6.71%	5.34%	5.41%
7	5.66%	5.01%	3.79%	5.66%	4.77%	3.69%	4.03%
8	5.49%	4.60%	3.64%	5.49%	4.31%	3.46%	3.04%
9	5.25%	3.98%	4.30%	5.25%	3.68%	3.99%	2.52%
10	5.26%	4.07%	4.70%	5.26%	3.72%	4.25%	2.01%
11	4.80%	3.69%	4.15%	4.80%	3.34%	3.66%	1.89%
12	4.14%	3.49%	3.42%	4.14%	3.13%	2.95%	2.25%
13	3.53%	3.12%	3.47%	3.53%	2.79%	2.91%	2.06%
14	2.75%	1.82%	2.66%	2.75%	1.62%	2.21%	1.87%
15	2.05%	1.33%	1.80%	2.05%	1.18%	1.44%	1.68%
16	1.19%	0.78%	1.73%	1.19%	0.69%	1.35%	1.50%
17	0.75%	0.37%	0.96%	0.75%	0.33%	0.73%	1.32%
18	0.60%	0.31%	0.85%	0.60%	0.28%	0.63%	1.14%
19	0.47%	0.23%	0.81%	0.47%	0.21%	0.59%	0.97%
20	0.53%	0.22%	0.64%	0.53%	0.20%	0.46%	0.80%
21	0.39%	0.31%	0.70%	0.39%	0.29%	0.48%	0.63%
22	0.28%	0.13%	0.39%	0.28%	0.13%	0.26%	0.46%
23	0.17%	0.13%	0.34%	0.17%	0.13%	0.22%	0.30%
24	0.10%	0.03%	0.28%	0.10%	0.03%	0.18%	0.14%
25	0.12%	0.02%	0.26%	0.12%	0.02%	0.17%	0.00%
26	0.00%	0.07%	0.26%	0.00%	0.07%	0.17%	0.00%

27	0.00%	0.06%	0.51%	0.00%	0.06%	0.33%	0.00%
28	0.00%	0.03%	0.12%	0.00%	0.03%	0.08%	0.00%
29	0.00%	0.05%	0.06%	0.00%	0.04%	0.04%	0.00%
30	0.00%	0.01%	0.05%	0.00%	0.01%	0.03%	0.00%
Total	100%	100%	100%	100%	100%	100%	100%

Note: Estimated by weighting data in Table A-76 by data in Table A-82.

Table A-85: VMT Distribution by Vehicle Age and Vehicle/Fuel Type, 2000

Vehicle Age	LDGV	LDGT	HDGV	LDDV	LDDT	HDDV	MC
0	11.33%	12.10%	11.79%	11.33%	13.46%	13.63%	19.41%
1	10.59%	10.94%	12.08%	10.59%	11.86%	13.62%	13.64%
2	7.52%	9.28%	8.76%	7.52%	9.82%	10.00%	12.53%
3	7.34%	8.11%	7.59%	7.34%	8.37%	8.15%	9.26%
4	6.55%	8.87%	6.81%	6.55%	8.95%	7.13%	7.61%
5	7.33%	8.66%	7.56%	7.33%	8.57%	7.73%	6.18%
6	6.15%	7.54%	6.32%	6.15%	7.32%	6.30%	5.19%
7	5.82%	6.05%	4.74%	5.82%	5.77%	4.61%	4.19%
8	4.99%	4.33%	3.32%	4.99%	4.06%	3.15%	3.04%
9	4.80%	3.97%	3.19%	4.80%	3.67%	2.95%	2.23%
10	4.58%	3.40%	3.77%	4.58%	3.10%	3.40%	1.78%
11	4.55%	3.46%	4.07%	4.55%	3.14%	3.59%	1.37%
12	4.15%	3.10%	3.60%	4.15%	2.79%	3.10%	1.57%
13	3.54%	2.90%	2.93%	3.54%	2.59%	2.46%	1.85%
14	2.99%	2.58%	2.94%	2.99%	2.30%	2.44%	1.67%
15	2.33%	1.49%	2.31%	2.33%	1.32%	1.85%	1.52%
16	1.71%	1.07%	1.53%	1.71%	0.96%	1.19%	1.35%
17	0.98%	0.62%	1.47%	0.98%	0.55%	1.12%	1.19%
18	0.62%	0.30%	0.80%	0.62%	0.27%	0.60%	1.03%
19	0.49%	0.24%	0.71%	0.49%	0.22%	0.52%	0.89%
20	0.38%	0.18%	0.67%	0.38%	0.17%	0.47%	0.75%
21	0.43%	0.17%	0.53%	0.43%	0.15%	0.37%	0.61%
22	0.31%	0.23%	0.58%	0.31%	0.22%	0.39%	0.48%
23	0.22%	0.10%	0.32%	0.22%	0.10%	0.21%	0.35%
24	0.13%	0.10%	0.28%	0.13%	0.09%	0.18%	0.22%
25	0.08%	0.02%	0.25%	0.08%	0.02%	0.16%	0.10%
26	0.10%	0.02%	0.23%	0.10%	0.02%	0.14%	0.00%
27	0.00%	0.05%	0.23%	0.00%	0.05%	0.15%	0.00%
28	0.00%	0.05%	0.44%	0.00%	0.05%	0.29%	0.00%
29	0.00%	0.02%	0.11%	0.00%	0.02%	0.07%	0.00%
30	0.00%	0.04%	0.07%	0.00%	0.04%	0.04%	0.00%
Total	100%	100%	100%	100%	100%	100%	100%

Note: Estimated by weighting data in Table A-77 by data in Table A-82.

Table A-86: VMT Distribution by Vehicle Age and Vehicle/Fuel Type, 2001

Vehicle Age	LDGV	LDGT	HDGV	LDDV	LDDT	HDDV	MC
0	10.43%	12.14%	9.27%	10.43%	13.51%	10.75%	20.77%
1	10.41%	11.00%	10.95%	10.41%	11.93%	12.39%	16.07%
2	9.73%	9.94%	10.82%	9.73%	10.51%	12.39%	11.24%
3	6.91%	8.42%	8.44%	6.91%	8.70%	9.09%	10.16%
4	6.74%	7.34%	7.05%	6.74%	7.42%	7.41%	7.39%
5	6.02%	7.94%	6.26%	6.02%	7.85%	6.42%	5.96%
6	6.74%	7.67%	6.88%	6.74%	7.44%	6.89%	4.79%
7	5.59%	6.60%	5.75%	5.59%	6.29%	5.61%	3.94%
8	5.19%	5.23%	4.27%	5.19%	4.91%	4.07%	3.10%
9	4.41%	3.74%	2.99%	4.41%	3.46%	2.78%	2.19%
10	4.23%	3.38%	2.87%	4.23%	3.09%	2.61%	1.54%
11	4.00%	2.89%	3.36%	4.00%	2.61%	2.97%	1.19%
12	3.97%	2.91%	3.63%	3.97%	2.61%	3.14%	1.12%
13	3.58%	2.57%	3.17%	3.58%	2.30%	2.68%	1.26%
14	3.02%	2.40%	2.56%	3.02%	2.13%	2.13%	1.47%

15	2.55%	2.11%	2.63%	2.55%	1.88%	2.11%	1.33%
16	1.97%	1.20%	2.02%	1.97%	1.07%	1.58%	1.19%
17	1.43%	0.85%	1.34%	1.43%	0.76%	1.02%	1.05%
18	0.82%	0.49%	1.27%	0.82%	0.44%	0.95%	0.91%
19	0.52%	0.23%	0.70%	0.52%	0.21%	0.51%	0.79%
20	0.40%	0.19%	0.61%	0.40%	0.17%	0.43%	0.67%
21	0.31%	0.14%	0.57%	0.31%	0.13%	0.40%	0.56%
22	0.34%	0.12%	0.46%	0.34%	0.12%	0.31%	0.45%
23	0.25%	0.18%	0.49%	0.25%	0.17%	0.32%	0.35%
24	0.18%	0.07%	0.27%	0.18%	0.07%	0.17%	0.25%
25	0.11%	0.08%	0.25%	0.11%	0.08%	0.16%	0.16%
26	0.07%	0.02%	0.22%	0.07%	0.02%	0.14%	0.07%
27	0.08%	0.01%	0.20%	0.08%	0.01%	0.13%	0.00%
28	0.00%	0.04%	0.20%	0.00%	0.04%	0.13%	0.00%
29	0.00%	0.04%	0.39%	0.00%	0.04%	0.25%	0.00%
30	0.00%	0.03%	0.11%	0.00%	0.03%	0.07%	0.00%
Total	100%	100%	100%	100%	100%	100%	100%

Note: Estimated by weighting data in Table A-78 by data in Table A-82.

Table A-87: VMT Distribution by Vehicle Age and Vehicle/Fuel Type, 2002

Vehicle Age	LDGV	LDGT	HDGV	LDDV	LDDT	HDDV	MC
0	9.77%	11.81%	8.15%	9.77%	13.15%	9.51%	18.38%
1	9.66%	11.09%	8.71%	9.66%	12.02%	9.91%	17.68%
2	9.64%	10.03%	9.92%	9.64%	10.61%	11.43%	13.61%
3	9.01%	9.05%	10.54%	9.01%	9.35%	11.43%	9.37%
4	6.40%	7.66%	7.93%	6.40%	7.74%	8.39%	8.33%
5	6.25%	6.61%	6.56%	6.25%	6.54%	6.77%	5.95%
6	5.58%	7.06%	5.77%	5.58%	6.85%	5.81%	4.75%
7	6.18%	6.74%	6.34%	6.18%	6.43%	6.23%	3.74%
8	5.02%	5.73%	5.24%	5.02%	5.38%	5.02%	3.00%
9	4.62%	4.54%	3.89%	4.62%	4.20%	3.64%	2.29%
10	3.92%	3.20%	2.73%	3.92%	2.92%	2.49%	1.56%
11	3.72%	2.89%	2.59%	3.72%	2.62%	2.31%	1.07%
12	3.52%	2.44%	3.03%	3.52%	2.19%	2.63%	1.00%
13	3.46%	2.43%	3.24%	3.46%	2.17%	2.75%	0.93%
14	3.08%	2.14%	2.80%	3.08%	1.90%	2.35%	1.03%
15	2.60%	1.97%	2.31%	2.60%	1.75%	1.87%	1.20%
16	2.18%	1.71%	2.32%	2.18%	1.52%	1.83%	1.08%
17	1.66%	0.96%	1.78%	1.66%	0.86%	1.37%	0.95%
18	1.21%	0.68%	1.17%	1.21%	0.61%	0.88%	0.83%
19	0.68%	0.39%	1.11%	0.68%	0.35%	0.81%	0.71%
20	0.43%	0.18%	0.60%	0.43%	0.16%	0.43%	0.61%
21	0.33%	0.14%	0.53%	0.33%	0.13%	0.37%	0.52%
22	0.25%	0.10%	0.50%	0.25%	0.10%	0.34%	0.43%
23	0.28%	0.09%	0.39%	0.28%	0.09%	0.26%	0.34%
24	0.20%	0.13%	0.42%	0.20%	0.13%	0.27%	0.26%
25	0.15%	0.06%	0.25%	0.15%	0.06%	0.16%	0.19%
26	0.09%	0.06%	0.22%	0.09%	0.06%	0.15%	0.12%
27	0.06%	0.01%	0.20%	0.06%	0.01%	0.13%	0.05%
28	0.06%	0.01%	0.18%	0.06%	0.01%	0.12%	0.00%
29	0.00%	0.03%	0.18%	0.00%	0.03%	0.12%	0.00%
30	0.00%	0.04%	0.38%	0.00%	0.04%	0.25%	0.00%
Total	100%	100%	100%	100%	100%	100%	100%

Note: Estimated by weighting data in Table A-79 by data in Table A-82.

Table A-88: VMT Distribution by Vehicle Age and Vehicle/Fuel Type, 2003

Vehicle Age	LDGV	LDGT	HDGV	LDDV	LDDT	HDDV	MC
0	9.38%	11.17%	7.92%	9.38%	12.45%	9.30%	16.86%
1	9.10%	10.87%	7.69%	9.10%	11.80%	8.81%	15.93%
2	8.99%	10.19%	7.92%	8.99%	10.79%	9.18%	15.25%

3	8.98%	9.21%	9.71%	8.98%	9.53%	10.58%	11.56%
4	8.39%	8.30%	9.95%	8.39%	8.39%	10.58%	7.83%
5	5.96%	6.95%	7.41%	5.96%	6.88%	7.69%	6.83%
6	5.81%	5.92%	6.07%	5.81%	5.75%	6.14%	4.83%
7	5.14%	6.25%	5.34%	5.14%	5.97%	5.27%	3.78%
8	5.58%	5.90%	5.81%	5.58%	5.54%	5.60%	2.90%
9	4.49%	5.01%	4.80%	4.49%	4.64%	4.52%	2.26%
10	4.13%	3.91%	3.56%	4.13%	3.58%	3.27%	1.67%
11	3.46%	2.75%	2.47%	3.46%	2.50%	2.21%	1.10%
12	3.29%	2.46%	2.35%	3.29%	2.21%	2.05%	0.91%
13	3.08%	2.05%	2.72%	3.08%	1.83%	2.32%	0.84%
14	2.99%	2.03%	2.88%	2.99%	1.81%	2.42%	0.77%
15	2.67%	1.77%	2.54%	2.67%	1.57%	2.07%	0.86%
16	2.23%	1.61%	2.05%	2.23%	1.43%	1.63%	0.99%
17	1.84%	1.38%	2.06%	1.84%	1.23%	1.59%	0.88%
18	1.40%	0.77%	1.57%	1.40%	0.69%	1.18%	0.77%
19	1.01%	0.54%	1.03%	1.01%	0.49%	0.76%	0.66%
20	0.57%	0.30%	0.96%	0.57%	0.28%	0.69%	0.57%
21	0.35%	0.14%	0.52%	0.35%	0.13%	0.37%	0.48%
22	0.27%	0.11%	0.46%	0.27%	0.10%	0.31%	0.40%
23	0.20%	0.08%	0.43%	0.20%	0.08%	0.29%	0.33%
24	0.22%	0.07%	0.34%	0.22%	0.07%	0.22%	0.26%
25	0.17%	0.11%	0.39%	0.17%	0.11%	0.25%	0.20%
26	0.12%	0.05%	0.22%	0.12%	0.05%	0.15%	0.14%
27	0.08%	0.05%	0.20%	0.08%	0.05%	0.13%	0.09%
28	0.04%	0.01%	0.18%	0.04%	0.01%	0.12%	0.04%
29	0.05%	0.01%	0.16%	0.05%	0.01%	0.11%	0.00%
30	0.00%	0.04%	0.28%	0.00%	0.04%	0.18%	0.00%
Total	100%	100%	100%	100%	100%	100%	100%

Note: Estimated by weighting data in Table A-80 by data in Table A-82.

Table A-89: VMT Distribution by Vehicle Age and Vehicle/Fuel Type, 2004

Vehicle Age	LDGV	LDGT	HDGV	LDDV	LDDT	HDDV	MC
0	9.21%	11.62%	8.35%	9.21%	12.95%	9.84%	15.99%
1	8.75%	10.23%	7.44%	8.75%	11.11%	8.56%	14.79%
2	8.49%	9.94%	6.97%	8.49%	10.53%	8.11%	13.90%
3	8.39%	9.31%	7.73%	8.39%	9.63%	8.46%	13.10%
4	8.37%	8.41%	9.13%	8.37%	8.50%	9.75%	9.76%
5	7.83%	7.49%	9.26%	7.83%	7.42%	9.65%	6.49%
6	5.56%	6.20%	6.83%	5.56%	6.02%	6.95%	5.62%
7	5.37%	5.22%	5.59%	5.37%	4.98%	5.55%	3.89%
8	4.65%	5.45%	4.87%	4.65%	5.12%	4.71%	2.97%
9	5.00%	5.13%	5.30%	5.00%	4.75%	5.00%	2.21%
10	4.02%	4.30%	4.38%	4.02%	3.94%	4.04%	1.66%
11	3.66%	3.36%	3.22%	3.66%	3.04%	2.90%	1.18%
12	3.07%	2.33%	2.23%	3.07%	2.10%	1.96%	0.94%
13	2.89%	2.05%	2.10%	2.89%	1.84%	1.80%	0.77%
14	2.67%	1.71%	2.40%	2.67%	1.52%	2.03%	0.71%
15	2.60%	1.67%	2.60%	2.60%	1.49%	2.12%	0.65%
16	2.29%	1.44%	2.25%	2.29%	1.28%	1.79%	0.72%
17	1.89%	1.29%	1.82%	1.89%	1.15%	1.41%	0.82%
18	1.56%	1.10%	1.80%	1.56%	0.99%	1.37%	0.71%
19	1.18%	0.61%	1.37%	1.18%	0.55%	1.01%	0.62%
20	0.84%	0.42%	0.89%	0.84%	0.39%	0.64%	0.53%
21	0.47%	0.23%	0.84%	0.47%	0.22%	0.59%	0.45%
22	0.29%	0.11%	0.45%	0.29%	0.10%	0.31%	0.38%
23	0.22%	0.08%	0.39%	0.22%	0.08%	0.26%	0.31%
24	0.16%	0.06%	0.37%	0.16%	0.06%	0.24%	0.26%
25	0.19%	0.06%	0.31%	0.19%	0.06%	0.20%	0.20%
26	0.14%	0.09%	0.35%	0.14%	0.09%	0.23%	0.15%
27	0.10%	0.04%	0.20%	0.10%	0.04%	0.13%	0.11%

28	0.06%	0.04%	0.18%	0.06%	0.04%	0.12%	0.07%
29	0.04%	0.01%	0.16%	0.04%	0.01%	0.11%	0.03%
30	0.04%	0.02%	0.23%	0.04%	0.02%	0.15%	0.00%
Total	100%	100%	100%	100%	100%	100%	100%

Note: Estimated by weighting data in Table A-81 by data in Table A-82.

Table A-90: Fuel Consumption for Non-Highway Vehicles by Fuel Type (million gallons)

Vehicle Type	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
Aircraft															
Gasoline[a]	374.2	347.1	341.6	319.4	317.3	329.3	310.8	330.3	295.3	325.9	301.9	290.7	280.6	251.4	259.9
Jet Fuel	18,318.4	17,513.8	17,295.5	17,428.4	18,300.1	17,845.4	18,744.4	18,603.9	18,883.9	19,435.5	20,133.5	19,113.5	18,220.4	17,912.8	18,731.1
Ships and Boats															
Diesel	1,175.2	1,212.2	1,214.7	1,098.0	1,266.1	1,184.8	1,472.5	1,317.5	1,079.3	1,352.6	1,525.5	1,680.4	1,653.8	1,370.6	1,726.4
Gasoline	1,090.9	1,113.6	1,136.3	1,307.2	1,209.1	1,259.3	1,309.5	1,312.7	1,315.9	1,317.3	1,315.6	1,316.4	1,311.9	1,307.2	1,300.0
Residual	2,060.7	1,553.7	2,727.4	2,511.2	2,451.1	2,646.1	2,168.5	976.2	584.3	1,238.1	2,597.7	1,862.5	2,649.9	2,282.5	2,375.3
Construction Equipment															
Diesel	3,508.2	3,644.4	3,780.7	5,284.3	4,053.2	4,189.5	4,325.7	4,462.0	4,598.3	4,732.4	4,866.5	5,005.7	5,145.0	5,284.3	5,423.6
Gasoline	74.3	74.3	74.3	64.2	74.3	74.3	72.1	69.3	68.5	68.2	68.0	66.2	65.1	64.2	63.1
Agricultural Equipment															
Diesel	2,291.5	2,380.5	2,469.5	3,427.4	2,647.5	2,736.6	2,825.6	2,914.6	3,003.6	3,092.6	3,181.6	3,263.5	3,345.5	3,427.4	3,509.3
Gasoline	31.3	31.9	32.6	37.2	33.9	34.5	34.9	35.0	35.2	35.6	36.1	36.5	36.8	37.2	37.2
Locomotives															
Diesel	3,460.6	3,253.8	3,350.6	3,445.3	3,716.2	3,863.5	3,933.8	3,946.6	3,974.5	4,121.6	4,105.9	4,119.0	4,160.0	4,257.2	4,490.2
Other[b]															
Diesel	670.9	692.5	714.1	963.2	757.3	779.0	800.6	822.2	843.8	858.6	886.7	912.2	937.7	963.2	2,267.7
Gasoline	2,723.7	2,756.6	2,784.9	2,950.3	2,710.2	2,772.5	2,849.7	2,775.4	2,829.8	2,748.4	2,825.6	3,576.2	3,677.8	3,812.2	4,620.0

Sources: AAR (2005), BEA (1991 through 2005), Benson (2002), DESC (2005), DOC (1991 through 2005), DOE (1993 through 2004), DOT (1991 through 2005), EIA (1991 through 2004), EIA (2005a), EIA (2005b), EIA (2002b), EIA (2003 through 2004), EPA (2004c), and FHWA (1996 through 2005).

[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-91: Control Technology Assignments for Gasoline Passenger Cars (Percent of VMT)

Model Years	Non-catalyst	Oxidation	EPA Tier 0	EPA Tier 1	LEV
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%	100%
2004	-	-	-	<1%	100%

Sources: EPA (1998), EPA (2005a), and EPA (2005b).
Note: Detailed descriptions of emissions control technologies are provided in the following section of this annex.
- Not applicable.

Table A-92: 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]
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%	100%
2004	-	-	-	<1%	100%

Sources: EPA (1998), EPA (2005a), and EPA (2005b).
[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-93: 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]

≤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%	35%
2004	-	-	-	-	5%	95%

Sources: EPA (1998), EPA (2005a), and EPA (2005b).

[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 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-94: 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	1996-2004
Heavy-Duty Diesel Vehicles	
Uncontrolled	1960-1982
Moderate control	1983-1995
Advanced control	1996-2004
Motorcycles	
Uncontrolled	1960-1995
Non-catalyst controls	1996-2004

Source: EPA (1998) and Browning (2005)

Note: Detailed descriptions of emissions control technologies are provided in the following section of this annex.

Table A-95: 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		
Low Emission Vehicles	0.0222	0.0169
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		
Low Emission Vehicles	0.0146	0.0216
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		
Low Emission Vehicles	0.0290	0.0434
EPA Tier 1[a]	0.1750	0.0655
EPA Tier 0[a]	0.2135	0.2630
Oxidation Catalyst	0.1317	0.2356
Non-Catalyst Control	0.0473	0.4181
Uncontrolled	0.0497	0.4604

Diesel Passenger Cars		
Advanced	0.0010	0.0005
Moderate	0.0010	0.0005
Uncontrolled	0.0012	0.0006
Diesel Light-Duty Trucks		
Advanced	0.0015	0.0010
Moderate	0.0014	0.0009
Uncontrolled	0.0017	0.0011
Diesel Heavy-Duty Vehicles		
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 (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-96: Emission Factors for CH_4 and N_2O for Alternative Fuel Vehicles

Vehicle Type/Control Technology	N_2O (g/mi)	CH_4 (g/mi)
Light-duty Vehicles		
Methanol	0.063	0.014
CNG	0.113	0.914
LPG	0.008	0.038
Ethanol	0.076	0.043
Heavy-duty Vehicles		
Methanol	0.217	0.646
CNG	0.297	9.629
LNG	0.440	6.857
LPG	0.150	0.108
Ethanol	0.307	1.975
Buses		
Methanol	0.217	0.646
CNG	0.162	12.416
Ethanol	0.364	2.079

Source: Developed from Browning (2003), Wang (1999), Lipman and Delucchi (2002), CRC (1997), Brasil and McMahon (1999), and Norbeck, et al (1998).

Table A-97: 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
Locomotives		
Diesel	0.08	0.250
Agricultural Equipment		
Gas	0.08	0.450
Diesel	0.08	0.450
Construction		
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-98: CH_4 Emissions from Mobile Combustion (Tg CO_2 Eq.)

Fuel Type/Vehicle Type	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
Gasoline Highway	4.2	4.1	4.1	4.0	3.9	3.8	3.6	3.4	3.3	3.0	2.9	2.7	2.5	2.3	2.2
Passenger Cars	2.6	2.4	2.3	2.3	2.2	2.1	2.0	1.9	1.8	1.7	1.6	1.5	1.4	1.3	1.3
Light-Duty Trucks	1.4	1.5	1.5	1.5	1.5	1.4	1.4	1.3	1.3	1.2	1.1	1.0	1.0	0.9	0.9
Heavy-Duty Vehicles	0.2	0.2	0.2	0.2	0.2	0.2	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	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+
Heavy-Duty Vehicles	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+
Alternative Fuel Highway	+	+	+	+	+	+	+	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Non-Highway	0.5	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.6
Ships and Boats	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
Locomotives	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
Agricultural Equipment	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.1	0.2	0.2	0.1	0.1	0.1	0.1
Construction Equipment	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
Aircraft	+	+	+	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Other[a]	+	+	+	+	+	+	+	+	+	+	+	+	0.1	0.1	0.1
Total	4.7	4.6	4.6	4.6	4.4	4.3	4.2	4.0	3.8	3.6	3.5	3.3	3.2	3.0	2.9

+ 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-99: N_2O Emissions from Mobile Combustion (Tg CO_2 Eq.)

Fuel Type/Vehicle Type	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
Gasoline Highway	40.1	42.3	45.1	47.2	48.7	49.8	50.4	51.2	51.2	50.3	49.1	46.0	43.5	40.8	38.6
Passenger Cars	25.4	25.0	25.7	26.1	26.7	26.9	26.8	26.7	26.6	25.9	25.1	23.9	22.9	21.8	21.0
Light-Duty Trucks	14.1	16.6	18.7	20.4	21.3	22.1	22.8	23.7	23.6	23.5	23.1	21.2	19.7	18.1	16.7
Heavy-Duty Vehicles	0.6	0.6	0.6	0.7	0.7	0.7	0.8	0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Motorcycles	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+
Diesel Highway	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Passenger Cars	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+
Light-Duty Trucks	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+
Heavy-Duty Vehicles	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	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	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Non-Highway	3.1	3.0	3.1	3.4	3.3	3.3	3.4	3.3	3.3	3.4	3.6	3.6	3.6	3.5	3.7
Ships and Boats	0.4	0.3	0.4	0.4	0.4	0.4	0.4	0.3	0.2	0.3	0.4	0.4	0.5	0.4	0.4
Locomotives	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	0.4
Agricultural Equipment	1.7	1.6	1.6	1.6	1.7	1.7	1.8	1.7	1.8	1.8	1.9	1.8	1.7	1.7	1.8
Construction Equipment	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4
Aircraft	0.3	0.3	0.3	0.4	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5
Other[a]	0.2	0.2	0.2	0.3	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4
Total	43.5	45.5	48.5	50.8	52.3	53.4	54.2	54.8	54.8	54.1	53.1	50.0	47.5	44.8	42.8

+ 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-100: NO_x Emissions from Mobile Combustion, 1990-2004 (Gg)

Fuel Type/Vehicle Type	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
Gasoline Highway	5,746	5,508	5,271	5,034	4,797	4,559	4,322	4,268	4,090	3,924	3,812	3,715	3,519	3,359	3,206
Passenger Cars	3,847	3,628	3,409	3,190	2,971	2,752	2,533	2,447	2,316	2,158	2,084	2,027	1,920	1,833	1,749
Light-Duty Trucks	1,364	1,356	1,349	1,341	1,333	1,325	1,318	1,334	1,294	1,268	1,303	1,285	1,217	1,162	1,109
Heavy-Duty Vehicles	515	505	496	487	478	469	459	475	467	485	411	390	369	353	336
Motorcycles	20	19	17	16	15	14	13	13	13	13	13	14	13	12	12
Diesel Highway	2,956	3,064	3,171	3,278	3,386	3,493	3,600	3,708	3,729	3,671	3,803	3,338	3,162	3,018	2,881
Passenger Cars	39	35	31	27	23	19	15	13	11	10	7	6	6	5	5
Light-Duty Trucks	20	19	17	16	14	12	11	10	9	8	6	5	5	5	5
Heavy-Duty Vehicles	2,897	3,010	3,123	3,236	3,349	3,462	3,575	3,685	3,709	3,653	3,791	3,326	3,151	3,008	2,871
Alternative Fuel Highway[a]	IE	IE	IE	IE	IE	IE	IE	IE	IE	IE	IE	IE	IE	IE	IE
Non-Highway	3,432	3,492	3,552	3,612	3,672	3,732	3,791	3,792	3,772	3,705	3,780	3,770	3,707	3,539	3,377
Ships and Boats	953	962	971	980	990	999	1,008	963	919	818	966	971	954	911	870
Locomotives	857	873	888	904	920	935	951	962	973	910	908	907	891	851	812
Agricultural Equipment	63	64	65	65	66	67	67	75	83	84	80	73	72	69	66
Construction Equipment	437	445	453	461	470	478	486	487	487	497	484	480	472	451	430
Aircraft[b]	641	652	663	675	686	697	708	708	706	765	697	690	678	647	618
Other[c]	480	496	511	526	541	556	572	597	604	632	645	650	639	610	582
Total	12,134	12,064	11,994	11,924	11,854	11,784	11,714	11,768	11,592	11,300	11,395	10,823	10,389	9,916	9,465

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-101: CO Emissions from Mobile Combustion, 1990-2004 (Gg)

Fuel Type/Vehicle Type	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
Gasoline Highway	98,328	93,597	88,866	84,135	79,403	74,672	69,941	67,509	65,246	61,210	60,657	56,716	55,541	55,541	55,541
Passenger Cars	60,757	57,019	53,281	49,542	45,804	42,065	38,327	36,825	35,686	32,921	32,867	31,600	30,945	30,945	30,945
Light-Duty Trucks	29,237	28,799	28,361	27,923	27,486	27,048	26,610	25,748	24,754	23,343	24,532	22,574	22,107	22,107	22,107
Heavy-Duty Vehicles	8,093	7,555	7,017	6,480	5,942	5,404	4,867	4,787	4,642	4,782	3,104	2,411	2,361	2,361	2,361
Motorcycles	240	223	206	189	172	155	138	150	163	164	154	131	129	129	129
Diesel Highway	1,696	1,642	1,587	1,533	1,479	1,424	1,370	1,301	1,202	1,122	1,088	869	851	851	851
Passenger Cars	35	31	28	25	21	18	15	13	10	10	7	6	6	6	6
Light-Duty Trucks	22	21	20	18	17	16	14	13	12	9	6	5	5	5	5
Heavy-Duty Vehicles	1,639	1,589	1,539	1,490	1,440	1,391	1,341	1,276	1,179	1,103	1,075	858	840	840	840
Alternative Fuel Highway[a]	IE	IE	IE	IE	IE	IE	IE	IE	IE	IE	IE	IE	IE	IE	IE
Non-Highway	19,459	19,899	20,339	20,778	21,218	21,658	22,098	21,474	21,493	21,152	21,935	22,387	22,181	22,181	22,181
Ships and Boats	1,679	1,724	1,770	1,815	1,861	1,906	1,951	1,948	1,943	2,121	1,946	1,952	1,934	1,934	1,934
Locomotives	85	86	88	90	91	93	94	89	83	98	90	90	89	89	89
Agricultural Equipment	217	218	220	221	222	224	225	250	274	285	245	233	231	231	231
Construction Equipment	582	591	600	610	619	628	638	636	633	630	626	621	615	615	615
Aircraft[b]	1,090	1,098	1,107	1,115	1,123	1,132	1,140	1,098	1,081	1,074	1,047	1,041	1,032	1,032	1,032
Other[c]	15,807	16,181	16,554	16,928	17,302	17,676	18,049	17,453	17,478	16,943	17,981	18,449	18,280	18,280	18,280
Total	119,482	115,137	110,791	106,446	102,100	97,755	93,409	90,284	87,940	83,484	83,680	79,972	78,574	78,574	78,574

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-102: NMVOCs Emissions from Mobile Combustion, 1990-2004 (Gg)

Fuel Type/Vehicle Type	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
Gasoline Highway	8,110	7,652	7,194	6,735	6,277	5,819	5,360	5,167	5,067	4,924	4,615	4,285	3,931	3,723	3,525
Passenger Cars	5,120	4,774	4,429	4,084	3,739	3,394	3,049	2,928	2,895	2,810	2,610	2,393	2,195	2,079	1,969
Light-Duty Trucks	2,374	2,303	2,232	2,161	2,090	2,019	1,947	1,882	1,812	1,734	1,750	1,664	1,527	1,446	1,369
Heavy-Duty Vehicles	575	536	498	459	420	382	343	336	335	351	232	206	189	179	170
Motorcycles	42	38	35	31	28	24	21	22	25	28	23	22	20	19	18
Diesel Highway	406	386	365	345	324	304	283	263	249	230	216	207	190	180	171
Passenger Cars	16	15	13	12	10	8	7	6	5	5	3	3	3	3	3
Light-Duty Trucks	14	13	12	11	10	9	9	8	7	6	4	4	3	3	3
Heavy-Duty Vehicles	377	358	340	322	304	286	268	249	237	219	209	201	184	174	165
Alternative Fuel Highway[a]	IE	IE	IE	IE	IE	IE	IE	IE	IE	IE	IE	IE	IE	IE	IE
Non-Highway	2,416	2,457	2,498	2,540	2,581	2,622	2,663	2,498	2,427	2,432	2,398	2,379	2,438	2,309	2,186
Ships and Boats	608	634	660	687	713	739	765	766	763	769	744	730	748	708	671
Locomotives	33	34	35	35	36	36	37	35	33	38	35	35	36	34	32
Agricultural Equipment	28	28	28	28	28	28	28	32	35	38	24	19	20	19	18
Construction Equipment	85	85	85	86	86	86	86	83	81	81	76	72	74	70	67
Aircraft[b]	149	150	150	151	152	152	153	142	137	141	130	125	128	121	115
Other[c]	1,513	1,527	1,540	1,553	1,567	1,580	1,593	1,441	1,378	1,366	1,390	1,397	1,432	1,356	1,284
Total	10,933	10,495	10,058	9,620	9,182	8,744	8,306	7,928	7,742	7,586	7,230	6,872	6,560	6,212	5,882

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-91 through Table A-94 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 light-duty cars and 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.

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 2004.

Supplemental Information on GHG Emissions from Transportation and Other Mobile Sources

This section of this subannex 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 organized by greenhouse gas, with separate tables for 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 emissions sources.

This section of this subannex 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 equipment, recreational vehicles), and to provide more detailed breakdowns of emissions by source. This section also summarizes the methodology used to apportion CO_2 emissions to transportation modes.

Methodology for Apportioning CO_2 Emissions to Transportation Modes

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 information on the methodology for apportioning CO_2 emissions to individual transportation modes and vehicle types. As noted in Annex 2.1, CO_2 emissions estimates for the transportation sector as a whole were developed for all fuel types except diesel (i.e., motor gasoline, jet fuel, aviation gasoline, residual fuel oil, natural gas, LPG, and electricity) based on transportation fuel consumption estimates from the Energy Information Administration (EIA 2004). For transportation diesel fuel consumption, a "bottom-up" analysis of transportation fuel consumption using VMT resulted in higher apparent consumption than the EIA national statistics for diesel fuel consumption allocated to the transportation sector. Therefore, "bottom-up" estimates were used directly in the calculation of transportation CO_2 emissions from diesel fuel consumption. Since the total diesel consumption estimate from EIA is considered to be accurate at the national level, the diesel consumption totals for the residential, commercial, and industrial sectors were adjusted downward proportionately. For all non-diesel fuels, CO_2 emissions by fuel type were apportioned to individual transportation modes (e.g.,

automobiles, light-duty trucks, etc.) on the basis of "bottom up" fuel consumption estimates from various data sources.

The EIA transportation fuel consumption estimates generally match the "bottom up" fuel consumption estimates, with the exceptions of diesel and jet fuel. As noted above, CO_2 from transportation diesel fuel consumption was calculated directly from the "bottom up" figures. For jet fuel, the EIA fuel consumption estimates exceed the fuel consumption estimates drawn from the following "bottom up" sources: DOT (1991 through 2004) for commercial aircraft, FAA (2004) for general aviation aircraft, and DESC (2004) for military aircraft. Data from these sources were used directly to calculate CO_2 from these sources, and the remainder of jet fuel consumption reported by EIA was assigned to "other aircraft."

The methodology for developing "bottom up" fuel consumption estimates for other sources is as follows. For highway vehicles, annual estimates of fuel consumption by vehicle category were taken from FHWA's *Highway Statistics'* annual editions, Table VM-1 (FHWA 1996 through 2004). For each vehicle category, the percent gasoline, diesel, and other (e.g., CNG, LPG) fuel consumption was estimated using data from the Appendix to DOE's *Transportation Energy Data Book* (DOE 2004). 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 2003). Gasoline fuel consumption from recreational boats was taken from EPA's NONROAD Model (EPA 2004c). Natural gas and LPG fuel consumption by vehicle type and mode were taken from DOE (1993 through 2004).

Estimates of diesel fuel consumption from locomotives were taken from the Association of American Railroads (AAR 2004) for Class I railroads, the Upper Great Plains Transportation Institute (Benson 2002 through 2004) for Class II and III railroads, and DOE's *Transportation Energy Data Book* (DOE 1993 through 2004) for passenger rail. Diesel and residual fuel consumption from ships and boats were taken from EIA's *Fuel Oil and Kerosene Sales* (1991 through 2004).

Apportionment of CO_2 to Other 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 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 data, are included in the agricultural, industrial, and commercial sectors. In order to provide comparable information on transportation and mobile sources, Table A-103 provides estimates of CO_2 from these other mobile sources. These estimates were developed using the same data sources utilized in developing the N_2O and CH_4 estimates and using the methodology for estimating CO_2 described in Annex 2.1.

Table A-103: CO_2 Emissions from Non-Transportation Mobile Sources (Tg CO_2 Eq.)

	1990		1998	1999	2000	2001	2002	2003	2004
Agricultural Equipment	30.2		38.1	37.2	37.7	39.8	40.9	41.9	44.8
Construction Equipment	38.7		48.8	49.7	51.1	55.3	56.9	58.6	60.3
Other	30.9		33.4	32.8	33.7	40.6	41.7	43.1	44.7
Total	99.8		120.3	119.7	122.6	135.6	139.5	143.6	149.9

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

Table A-104 presents estimates of greenhouse gas emissions from all transportation and other mobile sources in CO_2 equivalent. In total, transportation and mobile sources emitted 2,111.1 Tg CO_2 Eq. in 2004, an increase of 30 percent over the 1990 emissions level. These estimates were generated using the estimates of CO_2 emissions from transportation sources reported in Table 3-6, CH_4 emissions reported in Table 3-22, and N_2O emissions reported in Table 3-23 of Chapter 3; information on HFCs from mobile air conditioners and refrigerated transportation from Chapter 4; and estimates of CO_2 emitted from non-transportation mobile sources reported in Table A-103 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., heavy-duty trucks or buses) to match the level of detail for CO_2 emissions. Nitrous oxide 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 1995 through 2004). Similarly, N_2O and CH_4 estimates were developed for 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 2004). 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 1,959.8 Tg CO_2 Eq. in 2004.

On-road vehicles were responsible for about 81 percent of transportation GHG emissions in 2004. Although passenger cars make up the largest component of on-road vehicle greenhouse gas emissions, light-duty and heavy-duty trucks have been the primary sources of growth in on-road vehicle emissions. Between 1990 and 2004, greenhouse gas emissions from passenger cars increased only 2 percent, while emissions from light-duty trucks increased 64 percent, largely due to the increased use of sport-utility vehicles and other light-duty trucks. Meanwhile, greenhouse gas emissions from heavy-duty trucks increased 62 percent, reflecting the increased amount of freight movement in the economy and an increasing share transported by trucks.

In contrast to other transportation sources, aircraft saw only a very modest (one percent) increase in GHG emissions between 1990 and 2004, despite a substantial rise in passenger miles traveled. The small increase reflected a decline in emissions from military aircraft and a relatively small (10 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 and 2002, due largely to a decrease in air travel following the September 11, 2001 terrorist attacks.

Non-transportation mobile sources, such as construction equipment, agricultural equipment, and industrial/commercial equipment, emitted approximately 151.3 Tg CO_2 Eq. in 2004. Together, these sources emitted more greenhouse gases than boats and ships (domestic travel in the U.S.), rail, and pipelines combined. Emissions from non-transportation mobile sources increased rapidly, growing approximately 50 percent between 1990 and 2004.

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

Table A-105 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 2003). Emissions of CO_2 from transportation and mobile sources increased by 444.3 Tg CO_2 Eq. between 1990 and 2004. In contrast, the combined emissions of CH_4 and N_2O decreased by 2.4 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 45.0 Tg CO_2 Eq. in 2003 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-106 and Table A-107 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 and commercial aviation), recreational boats, and mobile air conditioners, and are illustrated in Table A-106. Freight modes include heavy-duty trucks, freight rail, refrigerated transport, waterborne freight vessels, and pipelines, and are illustrated in Table A-107. Note that although aircraft do carry some freight, separating out the emissions associated with freight versus passenger aircraft travel is difficult, and so general and commercial aviation as counted as passenger transportation for purposes of this analysis. The remaining transportation and mobile emissions were from sources not considered to be either freight or passenger modes (e.g., construction and agricultural equipment, lubricants).

The estimates in these tables are drawn from the estimates in Table A-104. In addition, estimates of fuel consumption from DOE (1993 through 2004) were used to allocate rail emissions between passenger and freight categories.

In 2004, passenger transportation modes emitted 1,515.2 Tg CO_2 Eq., while freight transportation modes emitted 503.9 Tg CO_2 Eq. The rate of growth of greenhouse gas emissions from freight sources, however, was more than twice as fast, due largely to the rapid increase in emissions associated with heavy-duty trucks.

Table A-104: Total U.S. Greenhouse Gas Emissions from Transportation and Mobile Sources (Tg CO_2 Eq.)

Mode/Vehicle Type/ Fuel Type	1990	1998	1999	2000	2001	2002	2003	2004	% of Total	% Change 1990-2004
Transportation Total	1,523.4	1,756.6	1,822.6	1,870.3	1,856.2	1,901.4	1,903.1	1,959.8	100%	29%
On-Road Vehicles	1,214.5	1,431.8	1,475.2	1,494.7	1,496.4	1,535.2	1,543.8	1,581.1	81%	30%
Passenger Cars	647.0	650.0	658.8	660.1	661.9	675.9	654.4	658.7	34%	2%
Gasoline	639.3	644.5	654.5	656.5	658.3	672.2	650.3	654.5	33%	2%
Diesel	7.7	5.5	4.3	3.6	3.6	3.7	4.1	4.2	<1%	-45%
AFVs	+	+	+	+	+	+	+	+	<1%	<1%
Light-Duty Trucks	331.2	462.2	479.7	482.6	484.4	495.5	528.6	543.6	28%	64%
Gasoline	319.4	444.9	460.9	462.7	463.7	473.7	501.6	515.4	26%	61%
Diesel	11.2	16.8	18.4	19.6	20.4	21.4	26.6	27.8	1%	148%
AFVs	0.5	0.4	0.3	0.3	0.3	0.3	0.3	0.3	<1%	-42%
Heavy-Duty Trucks	226.1	307.7	323.7	339.2	338.2	352.3	348.6	366.7	19%	62%
Gasoline	38.7	35.1	35.3	36.3	35.3	35.8	31.0	32.1	2%	-17%
Diesel	186.6	272.0	287.8	302.3	302.4	315.9	317.0	333.9	17%	79%
AFVs	0.9	0.7	0.6	0.5	0.6	0.6	0.6	0.6	<1%	-25%
Buses	8.4	10.1	11.2	11.0	10.1	9.8	10.5	10.5	1%	24%
Gasoline	0.6	0.5	0.5	0.5	0.5	0.4	0.4	0.4	<1%	-29%
Diesel	7.9	9.3	10.3	10.0	9.1	8.6	9.4	9.4	<1%	19%
AFVs	+	0.3	0.4	0.5	0.5	0.7	0.7	0.7	<1%	7691%
Motorcycles	1.7	1.8	1.9	1.9	1.7	1.7	1.6	1.7	<1%	-2%
Gasoline	1.7	1.8	1.9	1.9	1.7	1.7	1.6	1.7	<1%	-2%
Aircraft	179.1	183.2	188.8	195.3	185.4	176.8	173.6	181.5	9%	1%
General Aviation Aircraft	9.5	10.3	12.0	11.8	11.6	11.8	11.5	11.9	1%	25%
Jet Fuel	6.4	7.8	9.3	9.3	9.1	9.4	9.4	9.7	<1%	53%
Aviation Gasoline	3.1	2.5	2.7	2.5	2.4	2.4	2.1	2.2	<1%	-31%
Commercial Aircraft (Jet Fuel)	118.4	127.6	137.9	142.1	134.2	123.0	124.0	130.4	7%	10%
Military Aircraft (Jet Fuel)	35.1	21.7	20.8	21.2	23.1	20.6	20.8	21.4	1%	-39%
Other Aircraft[a] (Jet Fuel)	16.1	23.6	18.1	20.1	16.6	21.4	17.3	17.8	1%	11%
Boats and Ships	44.0	27.6	37.8	55.7	48.6	57.5	50.2	54.9	3%	25%
Gasoline	9.6	11.4	11.4	11.4	11.4	11.3	11.2	11.2	1%	17%
Distillate Fuel	10.7	10.0	12.6	14.4	16.0	15.7	12.9	16.5	1%	53%
Residual Fuel	23.6	6.2	13.8	29.8	21.2	30.5	26.1	27.2	1%	15%
Rail	38.1	43.4	45.0	45.0	45.3	45.6	47.5	50.3	3%	32%
Distillate Fuel	35.1	40.3	41.8	41.6	41.8	42.2	43.2	45.5	2%	30%
Electricity	3.0	3.1	3.2	3.4	3.5	3.4	4.3	4.7	<1%	57%
Pipelines[b] (Natural Gas)	35.9	34.9	35.3	35.0	33.4	36.4	36.7	36.8	2%	2%
Mobile Air Conditioning	+	16.5	19.7	22.8	25.3	27.4	28.9	31.9	2%	NA
Refrigerated Transport	+	7.0	8.5	9.8	10.8	11.5	12.3	13.1	1%	NA
Lubricants	11.9	12.1	12.3	12.1	11.1	10.9	10.1	10.2	1%	-14%
Non-Trans Mobile Total	100.7	121.5	120.8	123.7	136.9	140.8	145.0	151.3	100%	50%
Agricultural Equipment	30.5	38.5	37.6	38.1	40.2	41.3	42.3	45.3	30%	49%
Gasoline	7.2	8.0	6.2	5.8	7.1	7.3	7.5	9.7	6%	34%
Diesel	23.3	30.5	31.4	32.3	33.1	34.0	34.8	35.6	24%	53%
Construction Equipment	39.0	49.3	50.1	51.6	55.8	57.4	59.1	60.9	40%	56%
Gasoline	3.5	2.7	2.2	2.3	5.1	5.3	5.6	5.9	4%	70%
Diesel	35.6	46.6	48.0	49.3	50.7	52.1	53.6	55.0	36%	55%
Other Mobile Sources[c]	31.2	33.7	33.1	34.1	40.9	42.1	43.5	45.1	30%	45%
Gasoline	24.4	25.1	24.4	25.1	31.7	32.6	33.8	35.1	23%	44%
Diesel	6.8	8.5	8.7	9.0	9.2	9.5	9.7	10.0	7%	47%
Total Transportation & Mobile Total	1,624.2	1,878.0	1,943.4	1,994.1	1,993.1	2,042.2	2,048.1	2,111.1		30%

[a] The difference between total U.S. jet fuel consumption (as reported by EIA) and civilian air carrier consumption for both domestic and international flights (as reported by DOT and BEA) plus military jet fuel consumption is reported as "other" under the jet fuel category in Table 3-7, and includes such fuel uses as blending with heating oils and fuel used for chartered aircraft flights.

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

[c] "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-105: Transportation and Mobile Source Emissions by Gas (Tg CO_2 Eq.)

Gas	1990	1998	1999	2000	2001	2002	2003	2004	% of Total	% Change 1990-2004
CO_2	1,576.0	1,795.9	1,857.5	1,904.9	1,903.7	1,952.6	1,959.1	2,020.3	95.7%	28%
N_2O	43.5	54.8	54.1	53.1	50.0	47.5	44.8	42.8	2.0%	-1%
CH_4	4.7	3.8	3.6	3.5	3.3	3.2	3.0	2.9	0.1%	-38%
HFC	+	23.5	28.2	32.6	36.1	38.9	41.2	45.0	2.1%	NA
Total	1,624.1	1,878.0	1,943.4	1,994.1	1,993.1	2,042.2	2,048.1	2,111.1	100.0%	30%

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 2004 (Tg CO_2 Eq.)

Table A-106: Greenhouse Gas Emissions from Passenger Transportation (Tg CO_2 Eq.)

Vehicle Type	1990	1998	1999	2000	2001	2002	2003	2004	% Change 1990-2004
On-Road Vehicles	986.6	1,122.2	1,149.7	1,153.6	1,156.4	1,181.2	1,193.6	1,212.7	23%
Passenger Cars	647.0	650.0	658.8	660.1	661.9	675.9	654.4	658.7	2%
Light-duty Trucks	331.2	462.2	479.7	482.6	484.4	495.5	528.6	543.6	64%
Buses	8.4	10.1	11.2	11.0	10.1	9.8	10.5	10.5	24%
Aircraft	137.4	148.2	161.9	165.8	157.3	146.5	147.0	154.2	12%
General Aviation	127.9	137.9	149.9	153.9	145.7	134.8	135.5	142.3	11%
Commercial Aviation	9.5	10.3	12.0	11.8	11.6	11.8	11.5	11.9	25%
Recreational Boats	118.4	127.6	137.9	142.1	134.2	123.0	124.0	130.4	10%
Passenger Rail	9.6	11.4	11.4	11.4	11.4	11.3	11.2	11.2	17%
Mobile Air Conditioners	4.3	4.6	4.7	5.1	5.2	5.3	6.3	6.7	55%
Total	1,256.3	1,414.1	1,465.5	1,478.0	1,464.5	1,467.4	1,482.1	1,515.2	21%

Note: Data from DOE (1993 through 2004) were used to disaggregate emissions from rail and buses.

Table A-107: Greenhouse Gas Emissions from Domestic Freight Transportation (Tg CO_2 Eq.)

By Mode	1990	1998	1999	2000	2001	2002	2003	2004	% Change 1990-2004
Trucking	226.1	307.7	323.7	339.2	338.2	352.3	348.6	366.7	62%
Rail	33.8	38.8	40.2	40.0	40.1	40.3	41.3	43.6	29%
Waterborne	34.4	16.2	26.5	44.3	37.2	46.2	39.0	43.7	27%
Refrigerated Transport	+	7.0	8.5	9.8	10.8	11.5	12.3	13.1	NA
Pipelines	35.9	34.9	35.3	35.0	33.4	36.4	36.7	36.8	2%
Total	330.2	404.6	434.2	468.2	459.7	486.8	477.8	503.9	53%

+ 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 2004) were used to allocate the passenger/freight split of rail emissions.

3.3. Methodology for Estimating CH_4 Emissions from Coal Mining

The methodology for estimating methane 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 methane 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 Methane Liberated and Methane Emitted from Underground Mines

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

Step 1.1: Estimate Methane Liberated from Ventilation Systems

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

For the years 1990 through 1996 and 1998 through 2004, 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- 108. 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 methane emissions was obtained. These mines were assumed to account for 100 percent of methane 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- 108). The proportion was then applied to the years 1990 through 2004 to account for the less than 10 percent of ventilation emissions coming from mines without MSHA data.

For 1990 through 1999, average daily methane emissions were multiplied by 365 to determine the annual emissions for each mine. For 2000 through 2004, MSHA provided quarterly emissions. The average daily methane 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 methane emissions were multiplied by 92 days. Total ventilation emissions for a particular year were estimated by summing emissions from individual mines.

Table A- 108: Mine-Specific Data Used to Estimate Ventilation Emissions

[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.

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)*

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

Step 1.2: Estimate Methane Liberated from Degasification Systems

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

Step 1.3: Estimate Methane Recovered from Degasification Systems and Used (Emissions Avoided)

In 2004, twelve active coal mines had methane recovery and use projects, eleven sold the recovered methane to a pipeline and one used the methane on site to heat mine ventilation air. One coal mine also used some recovered methane in a thermal dryer in addition to selling gas to a pipeline. In order to calculate emissions avoided from pipeline sales, information was needed regarding the amount of gas recovered and the number of years in advance of mining that wells were drilled. Several state agencies provided gas sales data, which were used to estimate emissions avoided for these projects. Additionally, coal mine operators provided information on gas sales and/or the number of years in advance of mining. Emissions avoided were attributed to the year in which the coal seam was mined. For example, if a coal mine recovered and sold methane 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 up to 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 Methane Emitted from Surface Mines and Post-Mining Activities

Mine-specific data were not available for estimating methane 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 methane emissions.

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

The first step in estimating methane 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- 109, which presents coal basin definitions by basin and by state.

The Energy Information Administration's (EIA) Coal Industry Annual reports 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- 109. 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- 110 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* methane 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* methane content in the basin. For this analysis, the surface mining emission factor was determined to be twice the *in situ* methane content in the basin. Furthermore, the post-mining emission factors used were estimated to be 25 to 40 percent of the average *in situ* methane content in the basin. For this analysis, the post-mining emission factor was determined to be 32.5 percent of the *in situ* methane content in the basin. Table A- 111 presents the average *in situ* content for each basin, along with the resulting emission factor estimates.

Step 2.3: Estimate Methane Emitted

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

Total annual methane emissions are equal to the sum of underground mine emissions plus surface mine emissions plus post-mining emissions. Table A- 112 and Table A- 113 present estimates of methane liberated, used, and emitted for 1990 through 2004. Table A- 114 provides emissions by state.

Table A- 109: 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-110: Annual Coal Production (Thousand Short Tons)

Basin	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
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
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
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
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
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
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
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
West Interior	105	26	59	100	147	25	137	212	247	200	241	416	464	394	410
Northwest	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	757,823
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	42,444
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
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
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
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
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
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
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
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	1,125,354
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	149,359
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
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
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
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
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
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
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

Source for 1990-2004 data: EIA (1990-04), Coal Industry Annual. U.S. Department of Energy, Washington, DC, Table 3.
Note: Totals may not sum due to independent rounding.

Table A-111: Coal Surface and Post-Mining Methane 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 (Unita 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	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)	33.1	127.9	66.2	10.8	41.6
Northwest (AK)	5.6	160.0	11.2	1.8	52.0
Northwest (WA)	5.6	47.3	11.2	1.8	18.9

Source: 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.

Table A- 112: Underground Coal Mining Methane Emissions (Billion Cubic Feet)

Activity	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
Ventilation Output	112	NA	NA	95	96	97	90	96	94	92	87	84	79	76	82
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%
Adjusted Ventilation Output	114	NA	NA	97	98	106	99	96	96	94	89	86	80	77	84
Degasification System Liberated	54	NA	NA	45	46	44	50	42	49	41	45	48	52	56	47
Total Underground Liberated	168	164	162	142	144	150	149	138	146	135	134	135	132	133	131
Recovered & Used	(14)	(14)	(16)	(23)	(27)	(30)	(36)	(28)	(35)	(32)	(36)	(40)	(43)	(37)	(35)
Total	154	150	146	119	117	120	113	110	110	103	98	95	89	96	97

* Refer to Table A- 108.
Note: Totals may not sum due to independent rounding.

Table A- 113: Total Coal Mining Methane Emissions (Billion Cubic Feet)

Activity	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
Underground Mining	154	149	144	119	117	120	113	110	110	103	98	95	89	96	97
Surface Mining	26	24	24	23	23	22	23	23	23	22	22	23	22	21	23
Post-Mining (Underground)	19	18	18	16	17	17	18	18	18	17	17	17	16	16	16
Post-Mining (Surface)	4	4	4	4	4	4	4	4	4	4	4	4	4	3	4
Total	203	196	191	162	162	163	157	156	156	146	140	138	130	136	140

Note: Totals may not sum due to independent rounding.

Table A- 114: Total Coal Mining Methane Emissions by State (Million Cubic Feet)

State	1990		1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
Alabama	32,300		29,565	31,921	29,134	25,731	26,740	25,787	23,657	21,952	19,415	20,301	23,235
Alaska	22		20	22	19	19	17	20	21	20	15	14	20
Arizona	192		222	203	177	199	192	200	223	228	217	205	216
Arkansas	7		8	5	4	3	4	4	2	2	2	1	1
California	1		0	0	0	0	0	0	0	0	0	0	0
Colorado	10,325		9,192	8,663	5,960	9,189	9,181	9,390	10,784	11,117	12,082	13,216	12,554
Illinois	10,502		10,585	11,084	10,850	8,534	7,847	7,810	8,521	7,270	5,972	4,744	5,784
Indiana	2,795		2,495	1,866	2,192	2,742	2,878	2,650	2,231	3,373	3,496	3,821	3,527
Iowa	30		4	0	0	0	0	0	0	0	0	0	0
Kansas	57		23	23	19	29	27	33	16	14	16	12	6
Kentucky	10,956		11,259	9,748	8,978	10,451	10,005	9,561	9,056	9,363	8,464	8,028	7,916
Louisiana	245		267	286	248	273	247	227	284	286	293	310	293
Maryland	519		237	237	259	267	251	225	331	340	401	391	411
Mississippi	-		0	0	0	0	0	1	57	43	165	264	256
Missouri	211		67	44	57	32	30	31	35	29	20	43	46
Montana	490		542	514	492	534	558	535	449	510	487	481	519
New Mexico	451		679	466	408	459	489	497	464	630	1,280	1,864	2,047
North Dakota	380		420	392	389	385	389	405	407	397	401	401	390
Ohio	5,065		4,583	4,029	4,064	4,349	4,350	3,914	3,515	3,619	2,831	2,649	5,154
Oklahoma	285		359	323	286	385	395	469	453	620	660	620	847
Pennsylvania	22,735		24,024	26,995	26,382	30,026	29,491	23,626	22,253	22,253	19,667	24,649	19,980
Tennessee	296		101	112	143	148	116	119	99	142	142	124	136
Texas	4,291		4,028	4,054	4,245	4,104	4,047	4,084	3,732	3,466	3,482	3,657	3,530
Utah	3,587		2,616	2,410	2,805	3,566	3,859	3,633	2,811	2,081	2,709	3,408	5,240
Virginia	46,137		26,742	19,820	19,675	16,851	13,978	13,321	11,981	11,506	11,227	11,906	11,372
Washington	65		64	63	59	59	60	53	56	60	76	81	74
West Virginia	49,039		30,588	36,657	36,307	33,572	36,962	35,416	31,311	33,745	31,981	30,070	31,166
Wyoming	2,385		3,065	3,419	3,604	3,652	4,080	4,376	4,408	4,801	4,859	4,899	5,162
Total	203,368		161,753	163,356	156,755	155,559	155,925	146,389	139,727	137,867	130,360	136,159	139,881

+ 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. Emission estimates are not given for 1991 and 1992 because underground mine data was not available for those years.

3.4. Methodology for Estimating CH_4 Emissions from Natural Gas Systems

The following steps were used to estimate CH_4 emissions from natural gas systems.

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

The first step in estimating methane emissions from natural gas systems was to develop a detailed base year estimate of emissions. The study by EPA/GRI (1996) divides the industry into four stages to construct a detailed emission inventory for the year 1992. These stages include: field production, processing, transmission and storage (i.e., both underground and liquefied gas storage), and distribution. This study produced emission factors and activity data for over 100 different emission sources within the natural gas system. Emissions for 1992 were estimated by multiplying activity levels by emission factors for each system component and then summing by stage. Since publication, the EPA has updated activity data for some of the components in the system. Table A- 115 displays the 1992 GRI/EPA activity levels and 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 emissions from all stages.

Step 2: Collect Aggregate Statistics on Main Driver Variables

As detailed data on each of the over 100 sources were not available for the period 1990 through 2004, activity levels were estimated using aggregate statistics on key drivers, including: number of producing wells (EIA 2005a-b, New Mexico 2005a-b, Texas 2005a), number of gas plants (AGA 1991-1998; OGJ 2005), number of shallow and deep offshore platforms (MMS 2005a-e), miles of transmission pipeline (OPS 2005a), miles of distribution pipeline (OPS 2005b), miles of distribution services (OPS 2005b), energy consumption (EIA 2005d). 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- 116 provides the activity levels of some of the key drivers in the natural gas analysis.

Step 3: Estimate 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 reductions reported to the Natural Gas STAR program.

Industry partners report 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- 117. Table A- 118 illustrates emission estimates from the natural gas distribution stage. Table A- 119 presents total natural gas production and associated CH_4 emissions.

Table A- 115: 1992 Data and Emissions (Gg) 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	110.53 Mscf/mile-yr	174,794.23
Mains—Protected steel	68,308 equiv leaks	20.30 Mscf/leak-yr	26,706.93	444,768 miles	3.13 Mscf/mile-yr	26,790.38
Mains—Plastic	49,226 equiv leaks	99.80 Mscf/leak-yr	94,619.66	254,595 miles	9.91 Mscf/mile-yr	48,593.70
Services—Unprotected steel	458,476 equiv leaks	20.20 Mscf/leak-yr	178,371.00	5,446,393 services	1.71 Mscf/service	178,928.41
Services Protected steel	390,628 equiv leaks	9.20 Mscf/leak-yr	69,216.16	20,352,983 services	0.18 Mscf/service	69,432.46
Services—Plastic	68,903 equiv leaks	2.39 Mscf/leak-yr	3,171.70	17,681,238 services	0.01 Mscf/service	3,181.61
Services—Copper	7,720 equiv leaks	7.68 Mscf/leak-yr	1,141.92	233,246 services	0.25 Mscf/service	1,145.49
Meter/Regulator (City Gates)						
M&R >300	3,460 stations	179.80 scfh/station	104,960.57	3,580 stations	179.80 scfh/station	108,615.98
M&R 100-300	13,335 stations	95.60 scfh/station	215,085.58	13,799 stations	95.60 scfh/station	222,576.26
M&R <100	7,127 stations	4.31 scfh/station	5,182.56	7,375 stations	4.31 scfh/station	5,363.05
Reg >300	3,995 stations	161.90 scfh/station	109,124.94	4,134 stations	161.90 scfh/station	112,925.38
R-Vault >300	2,346 stations	1.30 scfh/station	514.55	2,428 stations	1.30 scfh/station	532.48
Reg 100-300	12,273 stations	40.50 scfh/station	83,862.18	12,700 stations	40.50 scfh/station	86,782.81
R-Vault 100-300	5,514 stations	0.18 scfh/station	167.46	5,706 stations	0.18 scfh/station	173.29
Reg 40-100	36,328 stations	1.04 scfh/station	6,374.34	37,593 stations	1.04 scfh/station	6,596.34
R-Vault 40-100	32,215 stations	0.09 scfh/station	470.15	33,337 stations	0.09 scfh/station	486.52
Reg <40	15,377 stations	0.13 scfh/station	345.05	15,913 stations	0.13 scfh/station	357.07
Customer Meters						
Residential	40,049,306 outdoor meters	138.50 scfy/meter	106,831.92	40,049,306 outdoor meters	143.70 scfy/meter	110,842.94
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	836,760 mile main	0.05 Mscf/mile	805.80
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- 116: Key Activity Factor Drivers

Variable	Units	1990	1998	1999	2000	2001	2002	2003	2004
Transmission Pipelines Length	miles	291,990	302,714	296,114	298,957	290,975	302,493	297,973	298,267
Wells									
NE—Associated Gas Wells*	# wells	68,261	60,318	59,330	58,671	54,727	52,928	51,172	51,172
NE—Non-associated Gas Wells*	# wells	124,241	126,550	127,279	143,922	149,436	154,590	156,320	155,257
MC—Associated Gas Wells*	# wells	64,379	68,293	68,476	67,880	67,278	65,786	65,660	65,660
MC—Non-associated Gas Wells*	# wells	53,940	65,355	53,243	51,217	63,595	67,861	70,377	72,809
RM—Associated Gas Wells*	# wells	13,749	14,108	12,941	12,328	12,148	12,446	12,188	12,188
RM—Non-associated Gas Wells*	# wells	24,339	44,655	43,375	64,539	70,450	72,438	71,239	70,770
SW—Associated Gas Wells*	# wells	69,339	57,539	58,704	54,830	57,188	60,623	60,315	60,315
SW—Non-associated Gas Wells*	# wells	24,217	30,344	29,407	32,346	33,936	35,025	36,648	37,219
WC—Associated Gas Wells*	# wells	20,672	19,791	19,332	20,494	20,808	22,503	22,121	22,121
WC—Non-associated Gas Wells*	# wells	1,292	1,010	1,270	1,338	1,434	1,415	1,459	1,388
GC—Associated Gas Wells*	# wells	36,279	35,768	34,109	32,497	32,549	29,880	28,727	28,727
GC—Non-associated Gas Wells*	# wells	41,753	49,015	47,846	48,316	51,182	53,198	54,245	54,544
Platforms									
Gulf of Mexico and Pacific OCS Off-shore Platforms	# platforms	3,939	4,059	4,022	4,027	4,075	4,057	4,009	3,944
GoM and Pacific OCS Deep Water Platforms	# platforms	17	29	36	38	40	44	46	50
Gas Plants	# gas plants	761	558	581	585	570	590	574	572
Distribution Services	# of services	47,883,083	54,035,004	54,317,439	56,761,042	57,461,795	58,876,416	58,090,561	59,798,601
Steel—Unprotected	# of services	7,633,526	5,463,253	5,751,250	5,675,520	5,449,653	5,186,134	4,741,921	4,790,927
Steel—Protected	# of services	19,781,581	18,478,344	18,310,719	17,855,560	17,911,402	17,778,463	17,200,364	18,208,689
Plastic	# of services	18,879,865	28,629,388	28,796,952	31,795,871	32,706,753	34,547,274	34,781,899	35,460,483
Copper	# of services	1,588,111	1,464,019	1,458,518	1,434,091	1,393,987	1,364,545	1,366,377	1,338,502
Distribution Mains	miles	944,157	1,019,816	1,004,907	1,048,485	1,099,137	1,133,625	1,095,198	1,135,705
Cast Iron	miles	58,292	47,587	45,865	44,750	44,283	42,025	40,588	40,581
Steel—Unprotected	miles	108,941	86,639	84,534	82,800	81,291	78,119	71,477	75,817
Steel—Protected	miles	465,538	484,963	459,298	471,510	475,329	480,982	481,596	497,031
Plastic	miles	311,386	400,627	415,210	449,425	498,234	532,499	501,537	522,276

* 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- 117: Methane reductions derived from the Natural Gas STAR program (Gg)

Process	1992		1998	1999	2000	2001	2002	2003	2004
Production	0		216	256	314	373	406	506	653
Processing	0		7	10	12	16	21	24	39
Transmission and Storage	0		231	274	321	418	416	411	536
Distribution	0		26	24	21	27	156	105	81

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- 118: CH_4 Emission Estimates from the Natural Gas Distribution Stage (Gg)

Activity	1990		1998	1999	2000	2001	2002	2003	2004
Pipeline Leaks									
Mains—Cast Iron	280.00		228.58	220.31	214.95	212.71	201.86	194.96	194.92
Mains—Unprotected steel	191.15		152.02	148.33	145.28	142.64	137.07	125.42	133.03
Mains—Protected steel	26.59		27.70	26.23	26.93	27.15	27.47	27.50	28.39
Mains—Plastic	56.61		72.84	75.49	81.71	90.58	96.81	91.18	94.95
Services—Unprotected steel	191.33		136.94	144.16	142.26	136.60	129.99	118.86	120.08
Services Protected steel	69.57		64.99	64.40	62.80	62.99	62.53	60.49	64.04
Services—Plastic	2.90		4.40	4.43	4.89	5.03	5.31	5.35	5.45
Services—Copper	1.16		1.07	1.07	1.05	1.02	1.00	1.00	0.98
Meter/Regulator (City Gates)									
M&R >300	101.70		104.68	109.45	115.70	110.49	113.22	117.60	112.97
M&R 100-300	208.40		214.51	224.28	237.10	226.42	232.02	240.99	231.50
M&R <100	5.02		5.17	5.40	5.71	5.46	5.59	5.81	5.58
Reg >300	105.73		108.83	113.79	120.29	114.87	117.72	122.27	117.45
R-Vault >300	0.50		0.51	0.54	0.57	0.54	0.56	0.58	0.55
Reg 100-300	81.26		83.64	87.45	92.44	88.28	90.46	93.96	90.26
R-Vault 100-300	0.16		0.17	0.17	0.18	0.18	0.18	0.19	0.18
Reg 40-100	6.18		6.36	6.65	7.03	6.71	6.88	7.14	6.86
R-Vault 40-100	0.46		0.47	0.49	0.52	0.49	0.51	0.53	0.51
Reg <40	0.33		0.34	0.36	0.38	0.36	0.37	0.39	0.37
Customer Meters									
Residential	103.78		106.82	111.69	118.07	112.76	115.54	120.01	115.28
Commercial/Industry	3.97		4.66	4.58	4.66	4.27	4.38	4.26	4.28
Routine Maintenance									
Pressure Relief Valve Releases	0.86		0.93	0.91	0.95	1.00	1.03	1.00	1.03
Pipeline Blowdown	2.39		2.46	2.57	2.72	2.59	2.66	2.76	2.65
Upsets									
Mishaps (Dig-ins)	37.20		38.30	40.04	42.33	40.42	41.42	43.02	41.33

Table A- 119: U.S. Total Natural Gas Production (Trillion Ft^3/yr) and Associated CH_4 Emissions (Gg)

Activity	1990		1998	1999	2000	2001	2002	2003	2004
Production	17.8		19.0	18.8	19.2	19.6	18.9	19.0	18.8
CH_4 Emissions from Production	1,621		1,819	1,679	1,865	2,014	2,073	2,007	1,873

3.5. Methodology for Estimating CH_4 Emissions from Petroleum Systems

The methodology for estimating CH_4 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* (Radian 1996e). Sixty-four activities that emit CH_4 from petroleum systems were examined from these reports. Most of the activities analyzed involve crude oil production field operations, which accounted for about 97 percent of total oil industry emissions. Crude transportation and refining accounted for the remaining emissions of one and just over two percent, respectively. The following steps were taken to estimate CH_4 emissions from petroleum systems.

Step 1: Determine Emission Factors for all Activities

The 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 sixty-four 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 Radian (1996b). The oil tank venting emission factor is taken from the API E&P Tank Calc average for API gravity less than 44 deg. Offshore emissions from shallow water and deep water oil platforms are taken from analysis of the GOADS report (MMS 2005c). The emission factors determined for 1995 were assumed to be representative of emissions from each source type over the period 1990 through 2004. Therefore, the same emission factors are used for each year throughout this period.

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 is 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) are used to extrapolate the activity levels from the base year to each year between 1990 and 2004. 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 were not yet available. In this case, all the crude oil that is transported is assumed to go to refineries. Therefore, the activity data for the refining sector was used also for the transportation sector. For a small number of sources, 2004 data were not yet available. In these cases, the 2003 activity factors were used. In the few cases where no data was located, oil industry data based on expert judgment was used.

Step 3: Estimate Methane Emissions for Each Activity for Each Year

Annual emissions from each of the 64 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 emissions. Table A- 120, Table A- 121, and Table A- 122 provide 2004 activity factors, emission factors, and emission estimates. Table A- 123 provides a summary of emissions estimates for the years 1990 through 2004.

Table A- 120: 2004 CH_4 Emissions from Petroleum Production Field Operations

Activity/Equipment	Emission Factor Units	Activity Factor Units	Emissions (Bcf/yr)
Vented Emissions			55.483

Activity/Equipment	Emission Factor	Units	Activity Factor	Units	Emissions (Bcf/yr)
Oil Tanks	5.28	scf of CH_4/bbl crude	1,410	MMbbl/yr (non stripper wells)	7.443
Pneumatic Devices, High Bleed	330	scfd CH_4/device	138,547	No. of high-bleed devices	16.708
Pneumatic Devices, Low Bleed	52	scfd CH_4/device	257,302	No. of low-bleed devices	4.884
Chemical Injection Pumps	248	scfd CH_4/pump	27,845	No. of pumps	2.521
Vessel Blowdowns	78	scfy CH_4/vessel	180,849	No. of vessels	0.014
Compressor Blowdowns	3,775	scf/yr of CH_4/compressor	2,452	No. of compressors	0.009
Compressor Starts	8,443	scf/yr. of CH_4/compressor	2,452	No. of compressors	0.021
Stripper wells	2,345	scf/yr of CH_4/stripper well	314,770	No. of stripper wells vented	0.738
Well Completion Venting	733	scf/completion	7,090	Oil well completions	0.005
Well Workovers	96	scf CH_4/workover	39,000	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	1,090	No. of oil platforms	21.806
Offshore Platforms, Deepwater oil, fugitive, vented and combusted	260,274	scfd CH_4/platform	14	No. of oil platforms	1.330
Fugitive Emissions					2.508
Oil Wellheads (heavy crude)	0.13	scfd/well	14,469	No. of hvy. crude wells	0.001
Oil Wellheads (light crude)	16.6	scfd/well	190,761	No. of lt. crude wells	1.158
Separators (heavy crude)	0.15	scfd CH_4/separator	10,642	No. of hvy. crude seps.	0.001
Separators (light crude)	14	scfd CH_4/separator	96,857	No. of lt. crude seps.	0.490
Heater/Treaters (light crude)	19	scfd CH_4/heater	73,349	No. of heater treaters	0.514
Headers (heavy crude)	0.08	scfd CH_4/header	13,564	No. of hvy. crude hdrs.	0.000
Headers (light crude)	11	scfd CH_4/header	42,051	No. of lt. crude hdrs.	0.167
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	2,452	No. of compressors	0.090
Large Compressors	16,360	scfd CH_4/compressor	0	No. of large comprs.	0.000
Sales Areas	41	scf CH_4/loading	1,651,361	Loadings/year	0.067
Pipelines	0	scfd of CH_4/mile of pipeline	14,187	Miles of gathering line	0.000
Well Drilling	0	scfd of CH_4/oil well drilled	8,036	No. of oil wells drilled	0.000
Battery Pumps	0.24	scfd of CH_4/pump	156,000	No. of battery pumps	0.014
Combustion Emissions					3.732
Gas Engines	0.24	scf CH_4/HP-hr	15,449	MMHP-hr	3.708
Heaters	0.52	scf CH_4/bbl	1982.0	MBbl/yr	0.001
Well Drilling	2,453	scf CH_4/well drilled	8,036	Oil wells drilled	0.020
Flares	20	scf CH_4/Mcf flared	163,748	Mcf flared/yr	0.003
Process Upset Emissions					0.073
Pressure Relief Valves	35	scf/yr/PR valve	165,552	No. of PR valves	0.006
Well Blowouts Onshore	2.5	MMscf/blowout	26.8	No. of blowouts/yr	0.067
Total					61.80

Table A-121: 2004 CH_4 Emissions from Petroleum Transportation

Activity/Equipment	Emission Factor	Units	Activity Factor	Units	Emissions (Bcf/yr)
Vented Emissions					0.223
Tanks	0.021	scf CH_4/yr/bbl of crude delivered to refineries	5,664	MMbbl crude feed/yr	0.117
Truck Loading	0.520	scf CH_4/yr/bbl of crude transported by truck	48.8	MMbbl trans. by truck	0.025
Marine Loading	2.544	scf CH_4/1000 gal. crude marine loadings	24,850,146	1,000 gal./yr loaded	0.063
Rail Loading	0.520	scf CH_4/yr/bbl of crude transported by rail	6.2	MMbbl. Crude by rail/yr	0.003
Pump Station Maintenance	36.80	scf CH_4/station/yr	501	No. of pump stations	0.000
Pipeline Pigging	39	scfd of CH_4/pig station	1,003	No. of pig stations	0.014
Fugitive Emissions					0.050
Pump Stations	25	scfCH_4/mile/yr.	50,149	No. of miles of crude p/l	0.001
Pipelines	0	scf CH_4/bbl crude transported by pipeline	6,941	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

Activity/Equipment	Emission Factor	Units	Activity Factor	Units	Emissions (Bcf/yr)
Heaters	0.521	scf CH_4/bbl.burned	NE	No. of bbl. Burned	NE
Total					0.273

NE: Note estimated for lack of activity factor data

Table A-122: 2004 CH_4 Emissions from Petroleum Refining

Activity/Equipment	Emission Factor	Units	Activity Factor	Units	Emissions (Bcf/yr)
Vented Emissions					1.265
Tanks	20.6	scfCH_4/Mbbl	1,991	Mbbl/cd heavy crude feed	0.015
System Blowdowns	137	scfCH_4/Mbbl	15,517	Mbbl/cd refinery feed	0.775
Asphalt Blowing	2,555	scfCH_4/Mbbl	509	Mbbl/cd production	0.475
Fugitive Emissions					0.088
Fuel Gas System	439	McfCH_4/refinery/yr	144	Refineries	0.063
Floating Roof Tanks	587	scf CH_4/floating roof tank/yr.	767	No. of floating roof tanks	0.000
Wastewater Treating	1.88	scfCH_4/Mbbl	15,517	Mbbl/cd refinery feed	0.011
Cooling Towers	2.36	scfCH_4/Mbbl	15,517	Mbbl/cd refinery feed	0.013
Combustion Emissions					0.097
Atmospheric Distillation	3.61	scfCH_4/Mbbl	15,783	Mbbl/cd refinery feed	0.021
Vacuum Distillation	3.61	scfCH_4/Mbbl	7,084	Mbbl/cd feed	0.009
Thermal Operations	6.02	scfCH_4/Mbbl	2,205	Mbbl/cd feed	0.005
Catalytic Cracking	5.17	scfCH_4/Mbbl	5,350	Mbbl/cd feed	0.010
Catalytic Reforming	7.22	scfCH_4/Mbbl	3,280	Mbbl/cd feed	0.009
Catalytic Hydrocracking	7.22	scfCH_4/Mbbl	1,339	Mbbl/cd feed	0.004
Hydrorefining	2.17	scfCH_4/Mbbl	2,109	Mbbl/cd feed	0.002
Hydrotreating	6.50	scfCH_4/Mbbl	9,673	Mbbl/cd feed	0.023
Alkylation/Polymerization	12.6	scfCH_4/Mbbl	1,189	Mbbl/cd feed	0.005
Aromatics/Isomeration	1.80	scfCH_4/Mbbl	1,001	Mbbl/cd feed	0.001
Lube Oil Processing	0.00	scfCH_4/Mbbl	166	Mbbl/cd feed	0.000
Engines	0.006	scfCH_4/hp-hr	1,467	MMhp-hr/yr	0.008
Flares	0.189	scfCH_4/Mbbl	15,517	Mbbl/cd refinery feed	0.001
Total					1.450

Table A-123: Summary of CH_4 Emissions from Petroleum Systems (Gg)

Activity	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
Production Field Operations	1,609	1,607	1,552	1,501	1,477	1,450	1,433	1,409	1,381	1,326	1,292	1,271	1,242	1,203	1,188
Pneumatic device venting	545	556	537	527	524	516	516	515	504	488	478	475	473	466	464
Tank venting	179	179	173	167	161	161	161	164	162	153	154	154	151	150	143
Combustion & process upsets	88	90	86	84	83	82	82	82	80	76	76	75	75	73	73
Misc. venting & fugitives	771	756	731	699	686	666	649	623	610	584	562	545	520	492	486
Wellhead fugitives	26	26	24	24	24	25	25	25	25	24	22	22	23	22	22
Crude Oil Transportation	7	6	6	6	6	6	6	6	6	6	5	5	5	5	5
Refining	25	24	24	25	25	25	26	27	27	27	28	27	27	27	28
Total	1,640	1,637	1,582	1,532	1,508	1,481	1,465	1,441	1,414	1,358	1,325	1,303	1,274	1,236	1,222

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 carbon 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 *Characterization of Municipal Solid Waste in the United States* reports (EPA 1997, 1998, 1999, 2000c, 2002, 2003, 2005), the flows of plastics in the U.S. waste stream are reported for seven resin categories. For 2003, the most recent year for which these data are reported, the quantity generated, recovered, and discarded for each resin is shown in Table A- 124. The data set for 1990 through 2004 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 2004 are held constant at the 2003 level.

Table A- 124: 2003 Plastics in the Municipal Solid Waste Stream by Resin (Gg)

Waste Pathway	PET	HDPE	PVC	LDPE/ LLDPE	PP	PS	Other	Total
Generation	2,870	5,140	1,470	6,210	3,610	2,270	5,080	26,650
Recovery	410	470	0	150	10	0	350	1,390
Discard	2,460	4,670	1,470	6,060	3,600	2,270	4,730	25,260
Landfill	1,964	3,728	1,173	4,838	2,874	1, 812	3,776	20,164
Combustion	496	942	297	1,222	726	458	954	5,096
Recovery*	14%	9%	0%	2%	0%	0%	7%	5%
Discard*	86%	91%	100%	98%	100%	100%	93%	95%
Landfill*	68%	73%	80%	78%	80%	80%	74%	76%
Combustion*	17%	18%	20%	20%	20%	20%	19%	19%

*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, carbon content, and fraction oxidized (see Table A- 125, which shows calculations for 2003). The carbon 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- 125: 2003 Plastics Combusted (Gg), Carbon Content (%), Fraction Oxidized (%) and Carbon Combusted (Gg)

Factor	PET	HDPE	PVC	LDPE/ LLDPE	PP	PS	Other	Total
Quantity Combusted	496	942	297	1,222	726	458	954	5,096
Carbon Content of Resin	63%	86%	38%	86%	86%	92%	66% [a]	-
Fraction Oxidized	98%	98%	98%	98%	98%	98%	98%	-
Carbon in Resin Combusted	304	791	112	1027	610	414	616	3,874
Emissions (Tg CO_2 Eq.)	1.0	2.6	0.4	3.4	2.0	1.4	2.1	12.9

[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 carbon content of the tires. *U.S. Scrap Tire Markets 2003* (RMA 2004) reports that 129.7 million of the 233.3 million scrap tires generated in 2003 (approximately 56 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 carbon black in scrap tires was determined:

- Synthetic rubber in tires was estimated to be 90 percent carbon by weight, based on the weighted average carbon contents of the major elastomers used in new tire consumption.[34] Table A- 126 shows consumption and carbon content of elastomers used for tires and other products in 2002, the most recent year for which data are available.

- Carbon black is 100 percent carbon (Miller 1999).

Multiplying the mass of scrap tires combusted by the total carbon content of the synthetic rubber and carbon black portions of scrap tires and by a 98 percent oxidation factor yielded CO_2 emissions, as shown in Table A- 127. 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- 126 (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- 126: 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 carbon content of non-tire rubber products in municipal solid waste.
- Not applicable
Note: Totals may not sum due to independent rounding.

Table A- 127: Scrap Tire Constituents and CO_2 Emissions from Scrap Tire Combustion in 2003

Material	Weight of Material (Tg)	Fraction Oxidized	Carbon Content	Emissions (Tg CO_2 Eq.)
Synthetic Rubber	0.3	98%	90%	1.0
Carbon Black	0.4	98%	100%	1.3
Total	0.6	-	-	2.3

- Not applicable

[34] 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 carbon content. The amount of rubber in the MSW stream was estimated from data provided in the *Characterization of Municipal Solid Waste in the United States* reports (EPA 1996, 1997, 1998, 1999, 2000c, 2002, 2003, 2005). 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-128.[35] A carbon content of 85 percent was assigned to synthetic rubber for all product types (based on the weighted average carbon content of rubber consumed for non-tire uses), and a 98 percent fraction oxidized was assumed. For 2004, waste generation values were not available, so values were held constant at the 2003 level.

Table A-128: Rubber and Leather in Municipal Solid Waste in 2003

Product Type	Combustion (Gg)	Synthetic Rubber (%)	Carbon Content (%)	Fraction Oxidized (%)	Emissions (Tg CO_2 Eq.)
Durables (not Tires)	517.9	100%	85%	98%	1.6
Non-Durables	67.7	-			0.2
Clothing and Footwear	26.5	25%	85%	98%	0.1
Other Non-Durables	41.2	75%	85%	98%	0.1
Containers and Packaging	5.5	100%	85%	98%	+
Total	591.1	-	-	-	1.8

+ Less than 0.05 Tg CO_2 Eq.
- Not applicable

CO_2 from Combustion of Synthetic Fibers

Carbon dioxide emissions from synthetic fibers were estimated as the product of the amount of synthetic fiber discarded annually and the average carbon content of synthetic fiber. Fiber in the MSW stream was estimated from data provided in the *Characterization of Municipal Solid Waste in the United States* (EPA 2000c, 2002, 2003, 2005) reports for textiles. The amount of synthetic fiber in MSW was estimated by subtracting (a) the amount recovered from (b) the waste generated (see Table A-129). 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 carbon content of 70 percent was assigned to synthetic fiber using the production-weighted average of the carbon contents of the four major fiber types (polyester, nylon, olefin, and acrylic) produced in 2004 (see Table A-130). The equation relating CO_2 emissions to the amount of textiles combusted is shown below. Since 2004 values were not provided in the *Characterization* reports, generation and recovery rates for those years were held constant at the 2003 values.

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

Table A-129: Textiles in MSW (Gg)

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

Year	Generation	Recovery	Discards	Combustion
1990	2,884	328	2,557	473
1991	3,008	347	2,661	504
1992	3,286	387	2,899	561
1993	3,386	397	2,988	586
1994	3,604	432	3,172	631
1995	3,674	447	3,227	725
1996	3,832	472	3,361	801
1997	4,090	526	3,564	817
1998	4,269	556	3,713	788
1999	4,498	611	3,887	797
2000	4,681	640	4,041	824
2001	4,870	715	4,155	861
2002	5,093	740	4,354	882
2003	5,257	755	4,503	908
2004*	5,257	755	4,503	908

* Set equal to 2003 data.

Table A-130: Synthetic Fiber Production in 2004

Fiber	Production (Tg)	Carbon Content
Polyester	1.5	63%
Nylon	1.1	64%
Olefin	1.4	86%
Acrylic	0.1	68%
Total	4.1	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). 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* (Kaufman et al 2004). 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 2004, so the value was assumed to remain constant at the 2003 level.

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

Bunker fuel emissions estimates for the Department of Defense (DoD) are developed using data generated by the Defense Energy Support Center 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 2004, 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[36] and NATO[37] 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-131 displays DoD's consumption of fuels that remain at the completion of Step 1, summarized by fuel type. Table A-131 reflects the adjustments for jet fuel used in land-based equipment, as described above.

Step 3: Omit Land-Based Fuels

Navy and Air Force land-based fuels (i.e., fuel not used by ships or aircraft) were also omitted for the purpose of calculating international bunker fuels. The remaining fuels, listed below, were considered potential DoD international bunker fuels.

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

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

[37] 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-132 and Table A-133 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. Carbon dioxide 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 3-56 and Table 3-57 in the Energy Chapter were based on the international bunker fuel totals provided in Table A-132 and Table A-133, below. Carbon dioxide emissions from aviation bunkers and distillate marine bunkers presented in Table A-136, and are based on emissions from fuels tallied in Table A-132 and Table A-133.

Table A-131: 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
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
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
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*
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*
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*
Aviation Gasoline	+	+	+	+	+	+	+	+	+	+	+	+	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
Middle Distillate (MGO)	+	+	+	+	+	+	38.5	47.5	51.1	49.2	48.3	33.0	41.2	88.1	71.2
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
Intermediate Fuel Oil (IFO)[b]	+	+	+	+	+	+	5.9	9.0	14.7	6.7	8.1	16.3	19.5	60.2	49.9
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
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
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
Jet Fuel[d]	+	+	+	+	+	+	+	11.7	23.4	35.0	46.7	58.4	125.9	133.9	105.1
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

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-132: 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
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
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
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
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
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
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
JP4	420.8	417.5	341.4	229.6	113.1	21.5	1.1	0.1	0.0	0.0	0.0	0.0	0.0	+	+
Navy	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	0.0	0.0	0.0	0.0	+	+	+
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
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
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
JA1	+	+	+	+	+	+	+	+	0.0	0.0	0.0	0.1	0.6	0.2	0.5
Navy	+	+	+	+	+	+	+	+	0.0	0.0	0.0	0.0	+	0.0	0.0
Air Force	+	+	+	+	+	+	+	+	+	+	0.0	0.1	0.6	0.2	0.5
JAB	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+
Navy	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+
Air Force	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+
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
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
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

+ Does not exceed 0.005 million gallons.
Note: Totals may not sum due to independent rounding.

Table A-133: 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
Navy—MGO	+	+	+	+	+	+	30.3	35.6	31.9	39.7	23.8	22.5	27.1	63.7	56.2
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
Navy—IFO	+	+	+	+	+	+	4.6	7.1	11.6	5.3	6.4	12.9	15.4	47.5	39.4
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

+ Does not exceed 0.005 million gallons.
Note: Totals may not sum due to independent rounding.

Table A-134: Aviation and Marine Carbon Contents (Tg Carbon/QBtu) and Fraction Oxidized

Mode (Fuel)	Carbon Content Coefficient	Fraction Oxidized
Aviation (Jet Fuel)	variable	0.99
Marine (Distillate)	19.95	0.99
Marine (Residual)	21.49	0.99

Source: EIA (2005) and IPCC (1997)

Table A-135: 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
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

Source: EIA (2005)

Table A-136: 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
Aviation	8.2	8.1	6.6	6.4	5.8	5.6	5.2	4.8	4.8	4.7	4.6	5.0	4.6	4.6	4.8
Marine	5.2	4.8	4.9	4.5	3.7	3.4	3.7	4.9	5.2	5.1	3.3	3.2	3.5	4.6	5.3
Total	13.4	12.9	11.6	10.9	9.5	8.9	8.9	9.6	10.0	9.8	7.9	8.2	8.1	9.2	10.1

Note: Totals may not sum due to independent rounding.

3.8. Methodology for Estimating HFC and PFC Emissions from Substitution of Ozone Depleting Substances

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 over 40 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 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 forms of the emission estimating 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:

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

Where,

Es	= Emissions from Equipment Serviced. Emissions in year j from normal leakage and servicing (including recharging) of equipment.
l_a	= Annual Leak Rate. Average annual leak rate during normal equipment operation (expressed as a percentage of total chemical charge).
l_s	= Service Leak Rate. Average leakage during equipment servicing (expressed as a percentage of total chemical charge).
Qc	= Quantity of Chemical in New Equipment. Total amount of a specific chemical used to charge new equipment in a given year by weight.
i	= Counter, runs from 1 to lifetime (k).
j	= Year of emission.
k	= Lifetime. The average lifetime of the equipment.

Step 2: Calculate disposal emissions

The disposal emission equations assume that a certain percentage of the chemical charge will be emitted to the atmosphere when that vintage is discarded. Disposal emissions are thus a function of the quantity of chemical contained in the retiring equipment fleet and the proportion of chemical released at disposal:

$$Ed_j = Qc_{j-k+1} \times [1 - (rm \times rc)]$$

Where,

Ed = Emissions from Equipment Disposed. Emissions in year j from the disposal of equipment.
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- 137, 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, presented in Table A- 137.

Table A- 137. Refrigeration and Air-Conditioning Market Transition Assumptions

Initial Market Segment	Primary Substitute	Start Date	Date of Full Penetration in New Equipment	Maximum Market Penetration	Secondary Substitute	Start Date	Date of Full Penetration in New Equipment	Maximum Market Penetration	Growth Rate
Mobile Air Conditioners									
CFC-12	HFC-134a	1992	1994	100%	None				2.6%
Chillers									
CFC-11	HCFC-123	1993	1994	45%	HFC-134a	2015	2019	75%	0.5%
					HFC-245fa	2015	2019	25%	
	HCFC-22	1991	1994	16%	HFC-134a	2000	2009	70%	
					R-407C	2000	2009	30%	
	HFC-134a	1992	1994	39%	None				
CFC-12	HFC-134a	1992	1994	53%	None				0.5%
	HCFC-22	1991	1994	16%	HFC-134a	2000	2009	70%	
					R-407C	2000	2009	30%	
	HCFC-123	1993	1994	31%	HFC-134a	2015	2019	75%	
					HFC-245fa	2015	2019	25%	
R-500	HFC-134a	1992	1994	53%	None				0.5%
	HCFC-22	1991	1994	16%	HFC-134a	2000	2009	70%	
					R-407C	2000	2009	30%	
	HCFC-123	1993	1994	31%	HFC-134a	2015	2019	75%	
					HFC-245fa	2015	2019	25%	
HCFC-22*	HCFC-22	1992	1993	100%	HFC-134a	2000	2009	70%	0.5%
					R-407C	2000	2009	30%	
CFC-114	HFC-236fa	1997	1998	100%	HFC-134a	1998	2009	100%	0.2%
Cold Storage									
CFC-12	HCFC-22	1990	1993	65%	R-404A	1996	2009	75%	2.5%
					R-507	1996	2009	25%	
	HFC-134a	1994	1996	35%	HFC-134a	2005	2005	100%	

Initial Market Segment	Primary Substitute	Start Date	Date of Full Penetration in New Equipment	Maximum Market Penetration	Secondary Substitute	Start Date	Date of Full Penetration in New Equipment	Maximum Market Penetration	Growth Rate
HCFC-22	HCFC-22	1992	1993	100%	R-404A	1996	2009	75%	2.5%
					R-507	1996	2009	25%	
R-502	HCFC-22	1990	1993	40%	R-404A	1996	2009	38%	2.5%
					R-507	1996	2009	12%	
					Non-ODP/GWP	1996	2009	50%	
	R-404A	1993	1996	45%	R-404A	2010	2010	100%	
	R-507	1994	1996	15%	R-507	2010	2010	100%	
Commercial Unitary Air Conditioners									
HCFC-22	R-407C	2000	2006	5%	None				2.5%
	R-407C	2006	2009	25%	None				
	R-410A	2000	2006	5%	None				
	R-410A	2006	2009	45%	None				
	HFC-134a	2000	2009	20%	None				
HCFC-22	R-407C	2000	2006	5%	None				2.5%
	R-407C	2006	2009	25%	None				
	R-410A	2000	2006	5%	None				
	R-410A	2006	2009	45%	None				
	HFC-134a	2000	2009	20%	None				
Dehumidifiers									
HCFC-22	HFC-134a	1997	1997	89%	None				0.5%
	R-410A	2007	2009	11%	None				
Ice Makers									
CFC-12	HFC-134a	1993	1995	100%	None				
Industrial Process Refrigeration									
CFC-11	HCFC-123	1992	1994	70%	None				
	HFC-134a	1992	1994	15%	None				
	HCFC-22	1991	1994	15%	HFC-134a	1995	2009	100%	
CFC-12	HCFC-22	1991	1994	10%	HFC-134a	1995	2009	15%	2.5%
					R-404A	1995	2009	50%	
					R-410A	1999	2009	20%	
					R-507	1995	2009	15%	
	HCFC-123	1992	1994	35%	HFC-134a	2015	2019	100%	
	HFC-134a	1992	1994	50%	None				
	R-401A	1995	1996	5%	HFC-134a	1997	2000	100%	
HCFC-22	HCFC-22	1992	1993	100%	HFC-134a	1995	2009	15%	2.5%
					R-404A	1995	2009	50%	
					R-410A	1999	2009	20%	
					R-507	1995	2009	15%	
Refrigerated Appliances									
CFC-12	HFC-134a	1994	1995	100%	None				0.5%
Residential Unitary Air Conditioners									
HCFC-22	R-407C	2006	2009	25%	None				1.9%
	R-410A	2000	2006	10%					
	R-410A	2006	2009	65%					
Retail Food									
CFC-12	HCFC-22	1990	1993	70%	R-404A	1996	2009	75%	1.7%
					R-507	1996	2009	25%	
	HFC-134a	1994	1996	30%	None				
HCFC-22	HCFC-22	1992	1993	100%	R-404A	1996	2009	60%	1.7%
					R-507	1996	2009	15%	
					HFC-134a	1999	2009	25%	
R-502	HCFC-22	1990	1993	40%	R-404A	2000	2009	75%	1.7%
					R-507	2000	2009	25%	
	R-404A	1993	1996	40%	R-404A	2005	2005	100%	
	R-507	1994	1996	10%	R-507	2005	2005	100%	
	HFC-134a	1996	1996	10%	None				
Transport Refrigeration									

Initial Market Segment	Primary Substitute	Start Date	Date of Full Penetration in New Equipment	Maximum Market Penetration	Secondary Substitute	Start Date	Date of Full Penetration in New Equipment	Maximum Market Penetration	Growth Rate
CFC-12	HFC-134a	1993	1995	98%	None				2.5%
	HCFC-22	1993	1995	2%	HFC-134a	1995	1999	100%	
R-502	HFC-134a	1993	1995	55%	None				2.5%
	R-404A	1993	1995	45%	R-404A	2005	2005	100%	
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%	2.5%
					R-407C	2006	2009	25%	
					R-410A	2000	2006	5%	
					R-410A	2006	2009	45%	
					HFC-134a	2000	2009	20%	
HCFC-22	HCFC-22	1992	1993	100%	R-407C	2000	2006	5%	2.5%
					R-407C	2006	2009	25%	
					R-410A	2000	2006	5%	
					R-410A	2006	2009	45%	
					HFC-134a	2000	2009	20%	
Window Units									
HCFC-22	R-407C	2003	2006	3%	None				5.0%
	R-410A	2003	2006	7%	None				
	R-407C	2006	2009	35%	None				
	R-410A	2006	2009	55%	None				

* HCFC-22 Chillers has a tertiary substitution; R-407C is substituted with R-407C (60%) and R-410A (40%). Substitution begins in 2009, with 100 percent penetration in new equipment by 2019.

Table A- 138 presents the average equipment lifetimes for each end use assumed by the Vintaging Model.

Table A- 138. Refrigeration and Air-conditioning Lifetime Assumptions

End Use	Lifetime (Years)
Mobile Air Conditioners	12
Chillers	20 – 27
Retail Food	15 – 20
Cold Storage	20 – 25
Industrial Process Refrigeration	25
Transport Refrigeration	12
Dehumidifiers	15
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
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, including metered dose inhalers 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.

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- 139.

Table A- 139. Aerosol Product Transition Assumptions

Initial Market Segment	Primary Substitute	Start Date	Date of Full Penetration in New Products	Maximum Market Penetration	Secondary Substitute	Start Date	Date of Full Penetration in New Products	Maximum Market Penetration	Growth Rate
				MDI Aerosols					
CFC-11	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	56%	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	56%	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	56%	None				
	HFC-227ea	2009	2015	6%	None				
				Consumer Aerosols					
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- 140.

Table A- 140. Solvent Market Transition Assumptions

Initial Market Segment	Primary Substitute	Start Date	Date of Full Pene-tration in New Uses	Maximum Market Penetration	Secondary Substitute	Start Date	Date of Full Pene-tration in New Uses	Maximum Market Penetration	Growth Rate
Electronics Cleaning									
CFC-113	Non-ODP/GWP	1992	1996	40.3%	None				
	Non-ODP/GWP	1992	1996	5.7%	None				2.0%
	HCFC-225ca/cb	1994	1995	0.2%	None				
	Non-ODP/GWP	1994	1995	52.5%	None				
	HFE-7100	1994	1995	0.7%	None				
	HFC-4310mee	1995	1996	0.7%	None				
MCF	Non-ODP/GWP	1996	1997	28.5%	None				2.0%
	Non-ODP/GWP			6.5%	None				
	Non-ODP/GWP			8.5%	None				
	Non-ODP/GWP			0.2%	Non-ODP/GWP	2000	2003	90%	
	PFC/PFPE	1996	1997	56.3%	Non-ODP/GWP	2005	2009	10%	
					None				
Metals Cleaning									
MCF	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 Cleaning									
MCF	Non-ODP/GWP	1995	1996	14.5%	None				2.0%
	Non-ODP/GWP	1995	1996	9.6%					
	Non-ODP/GWP	1995	1996	29.4%					
	Non-ODP/GWP	1995	1996	11.7%					
	HFC-4310mee	1995	1996	0.6%	None				
	PFC/PFPE	1995	1996	0.1%	Non-ODP/GWP	2000	2003	90%	
					Non-ODP/GWP	2005	2009	10%	
	Non-ODP/GWP	1995	1996	34.1%					
CFC-113	Non-ODP/GWP	1995	1996	90.2%	None				2.0%
	HCFC-225ca/cb	1995	1996	1.0%	None				
	HFE-7100	1995	1996	3.3%	None				
	Non-ODP/GWP	1995	1996	5.5%	None				
Adhesives, Coatings, Inks									
MCF	Non-ODP/GWP	1994	1995	100%	None				2.0%

MCF= Methyl Chloroform, also known as TCA or 1,1,1-Trichloroethane
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 2 percent of all chemical in use in each year, while in flooding systems 1.5 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 10-year lifetime and flooding applications have a 20-year lifetime.

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

Where,

E = Emissions. Total emissions of a specific chemical in year j for streaming fire extinguishing equipment, by weight.
r = Percent Released. The percentage of the total chemical in operation that is released to the atmosphere.
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-141.

Table A-141. Fire Extinguishing Market Transition Assumptions

Initial Market Segment	Primary Substitute	Start Date	Date of Full Penetration in New Equipment	Maximum Market Penetration	Secondary Substitute	Start Date	Date of Full Penetration in New Equipment	Maximum Market Pene-tration	Growth Rate
Streaming Agents									
Halon 1211	HFC-236fa	1997	1999	4%	Non-ODP/GWP	2010	2010	50%	3.0%
	Blends	1995	1999	6%	Non-ODP/GWP	2010	2010	50%	
	Non-ODP/GWP	1993	1994	75%	None				
	Non-ODP/GWP	2005	2005	15%	None				
Flooding Agents									
Halon 1301	HFC-23	1988	1993	0.4%	None				2.2%
	HFC-227ea	1988	1993	14.7%	None				
	Blends	1988	1993	9.2%	None				
	Non-ODP/GWP	1988	1993	67.7%	None				
	HFC-23	2013	2013	+	None				
	HFC-227ea	2013	2013	1.0%	None				
	Blends	2013	2013	0.6%	None				
	Non-ODP/GWP	2013	2013	4.4%	None				

+ Does not exceed 0.05%.

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 closed-cell foams are calculated using the following equation.

$$E_j = \sum (ef_i \times Qc_{j-i+1}) \quad \text{for } i=1 \rightarrow k$$

Where,

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

ef = Emission Factor. Percent of foam's original charge emitted in each year (for i=1→k). This emission factor is generally variable, including a rate for manufacturing emissions (occurs in the first year of foam life), annual emissions (every year throughout the foam lifetime), and disposal emissions (occurs during the final year of foam life).

Qc = Quantity of Chemical. Total amount of a specific chemical used in closed-cell foams in year j-I+1.

i = Counter, runs from 1 to lifetime (k).

j = Year of emission.

k = Lifetime. The average lifetime of the equipment.

Assumptions

The Vintaging Model contains 13 foam types, whose transition assumptions away from ODS and growth rates are presented in Table A- 142. The emission profiles of the foam types estimating in the Vintaging Model are shown in Table A- 143.

Table A- 142. Foam Blowing Market Transition Assumptions

Initial Market Segment	Primary Substitute	Start Date	Date of Full Penetration in New Equipment	Maximum Market Penetration	Secondary Substitute	Start Date	Date of Full Penetration in New Equipment	Maximum Market Penetration	Growth Rate
Commercial Refrigeration Foam									
CFC-11	HCFC-141b	1989	1996	40%	HFC-245fa	2002	2003	80%	6.0%
					Non-ODP/GWP	2002	2003	20%	
	HCFC-142b	1989	1996	8%	Non-ODP/GWP	2009	2010	80%	
					HFC-245fa	2009	2010	20%	
	HCFC-22	1989	1996	52%	Non-ODP/GWP	2009	2010	80%	
					HFC-245fa	2009	2010	20%	
Flexible Polyurethane Foam									
CFC-11	Non-ODP/GWP	1992	1992	100%	None				2.0%
One Component Foam									
CFC-12	Blend	1989	1996	70%	Non-ODP/GWP	2009	2010	80%	4.0%
					HFC-134a	2009	2010	10%	
					HFC-152a	2009	2010	10%	
	HCFC-22	1989	1996	30%	Non-ODP/GWP	2009	2010	80%	
					HFC-134a	2009	2010	10%	
					HFC-152a	2009	2010	10%	
Phenolic Foam									
CFC-11	HCFC-141b	1989	1990	100%	Non-ODP/GWP	1992	1992	100%	2.0%
Polyisocyanurate Boardstock Foam									
CFC-11	HCFC-141b	1993	1996	100%	Non-ODP/GWP	2000	2003	95%	6.0%
					Blend	2000	2003	5%	
Polyolefin Foam									
CFC-114	HFC-152a	1989	1993	10%	Non-ODP/GWP	2005	2010	100%	2.0%
	HCFC-142b	1989	1993	90%	Non-ODP/GWP	1994	1996	100%	
Polystyrene Boardstock Foam									
CFC-12	Blend	1989	1994	10%	HFC-134a	2009	2010	70%	2.5%
					HFC-152a	2009	2010	10%	

Initial Market Segment	Primary Substitute	Start Date	Date of Full Penetration in New Equipment	Maximum Market Penetration	Secondary Substitute	Start Date	Date of Full Penetration in New Equipment	Maximum Market Penetration	Growth Rate
					CO_2	2009	2010	10%	
					Non-ODP/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-ODP/GWP	2009	2010	10%	
Polystyrene Sheet/Insulation Board Foam									
CFC-12	CO_2	1989	1994	1%	None				2.0%
	Non-ODP/GWP	1989	1994	99%	CO_2	1995	1999	9%	
					HFC-152a	1995	1999	10%	
Polyurethane Appliance Foam									
CFC-11	HCFC-141b	1993	1996	89%	HFC-134a	1996	2003	10%	3.0%
					HFC-245fa	2002	2003	85%	
					Non-ODP/GWP	2002	2003	5%	
	Blend	1993	1996	1%	HFC-245fa	2009	2010	50%	
					HFC-134a	2009	2010	50%	
	HCFC-22	1993	1996	10%	HFC-134a	2009	2010	100%	
Polyurethane 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%	
Polyurethane Panel Foam*									
CFC-11	HCFC-141b	1989	1996	82%	Blend	2001	2003	20%	6.0%
					Blend	2002	2004	20%	
					Non-ODP/GWP	2001	2004	40%	
					HFC-134a	2002	2004	20%	
	HCFC-22	1989	1996	18%	Blend	2009	2010	40%	
					Non-ODP/GWP	2009	2010	20%	
					CO_2	2009	2010	20%	
					HFC-134a	2009	2010	20%	
Polyurethane Slabstock and Other Foam**									
CFC-11	HCFC-141b	1989	1996	100%	CO_2	1999	2003	45%	2.0%
					Non-ODP/GWP	2001	2003	45%	
					HCFC-22	2003	2003	10%	
Polyurethane Spray Foam									
CFC-11	HCFC-141b	1989	1996	100%	HFC-245fa	2004	2005	30%	6.0%
					Blend	2004	2005	60%	
					Non-ODP/GWP	2003	2005	10%	

* Polyurethane Panel Foam has a tertiary substitution; the first blend is assumed to contain HCFCs, and is thus substituted with a 50/50 mixture of another blend and a non-ODP/GWP substitute in 2009, with 100% penetration in new equipment by 2010.

** 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.

Table A-143. 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	100	0	1	0	100
Polyisocyanurate Boardstock	6	1	50	44	100
Rigid PU Integral Skin	95	2.5	2	0	100
Rigid PU Appliance	4	0.25	20	27.3	35
Rigid PU Commercial Refrigeration	6	0.25	15	90.25	100
Rigid PU Spray	15	1.5	56	1	100
One Component	100	0	1	0	100
Rigid PU Slabstock and Other	37.5	0.75	15	51.25	100
Phenolic	23	0.875	32	49	100

Polyolefin	95	2.5	2	0	100
XPS Sheet/Insulation Board*	40	2	25	0	90
XPS Boardstock	25	0.75	50	37.5	100
PU Sandwich Panels	5.5	0.5	50	69.5	100

PU (Polyurethane)
XPS (Extruded Polystyrene)

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 carbon dioxide 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. A model based on recommendations provided in IPCC/UNEP/OECD/IEA (1997) and IPCC (2000) was developed that uses information on population, energy requirements, digestible energy, and methane conversion rates to estimate methane emissions. The emission methodology consists of the following three steps: (1) characterize the cattle population to account for animal population categories with different emissions profiles; (2) characterize cattle diets to generate information needed to estimate emissions factors; and (3) estimate emissions using these data and the IPCC Tier 2 equations.

Step 1: Characterize U.S. Cattle Population

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 methane 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 use also impacts methane emissions (e.g., beef versus dairy). Consequently, cattle life stages were modeled for several categories of dairy and beef cattle. These categories are listed in Table A- 144.

Table A- 144: Cattle Population Categories Used for Estimating Methane Emissions

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

The key variables tracked for each of these cattle population categories (except bulls[38]) are as follows:

- *Calving rates:* 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 (2005a, 2004a, 2003a, 2002a, 2001a, 2000a, 1999a, 1995a). Average percentages of births by month for beef from USDA (USDA/APHIS/VS 1998, 1994, 1993) were used for 1990 through 2004. For dairy animals, birth rates were assumed constant throughout the year. Whether calves were born to dairy or beef cows was estimated using the dairy cow calving rate (USDA/APHIS/VS 2002) and the total dairy cow population to determine the percent of births attributable to dairy cows, with the remainder assumed to be attributable to beef cows.

- *Average weights and weight gains:* 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. Other reported target weights were available for 12,

[38] Only published population statistics and national average emission factors were used to estimate methane emissions from the bull population.

15, 24, and 36 month-old animals. Live slaughter weights were derived from dressed slaughter weight data for each year (USDA 2005c, 2004c, 2003c, 2002c, 2001c, 2000c, 1999a, 1995a). Live slaughter weight was estimated as dressed weight divided by 0.63.

- *Feedlot placements:* Feedlot placement statistics were available that specify placement of animals from the stocker population into feedlots on a monthly basis by weight class. The model used 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 time on a step-up diet to become acclimated to the new feed type. Animals are then switched to a finishing diet for a period of time before they are slaughtered. 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 end weight (as determined by weights at slaughter). Weight gain during start-up diets is estimated to be 2.8 to 3 pounds per day. Weight gain during finishing diets is estimated to be 3 to 3.3 pounds per day (Johnson 1999). All animals are estimated to spend 25 days in the step-up diet phase (Johnson 1999). Length of time finishing was calculated based on start weight, weight gain per day, and target slaughter weight.

- *Pregnancy and lactation:* 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 methane 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, 4.5, 3.0, and 2.8 lbs milk/animal/day. Monthly estimates for dairy cattle were taken from USDA monthly milk production statistics.

- *Death rates:* This factor is applied to all heifer and steer cohorts to account for death loss within the model on a monthly basis. The death rates are estimated by determining the death rate that results in model estimates of the end-of-year population for cows that match the published end-of-year population census statistics.

- *Number of animals per category each month:* The population of animals per category is calculated based on 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 (including feedlot placements). These monthly age groups are tracked in the enteric fermentation model to estimate emissions by animal type on a regional basis.

- *Animal characteristic data:* Dairy lactation estimates for 1990 through 2004 are shown in Table A- 145. Table A- 146 provides the target weights used to track average weights of cattle by animal type. Table A- 147 provides a summary of the reported feedlot placement statistics for 2004. Data on feedlot placements were available for 1996 through 2004. Data for 1990 to 1995 were based on the average of monthly placements from the 1996 to 1998 reported figures.

Cattle population data were taken from U.S. Department of Agriculture (USDA) National Agricultural Statistics Service (NASS) reports. A summary of the annual average populations upon which all livestock-related emissions are based is provided in Table A-156 of the Manure Management Annex. The USDA publishes monthly, annual, and multi-year livestock population and production estimates. Multi-year reports include revisions to earlier published data. Cattle and calf populations, feedlot placement statistics (e.g., number of animals placed in feedlots by weight class), slaughter numbers, and lactation data were obtained from USDA (2005a, 2004a, 2004c, 2003a, 2003c, 2002a, 2002c, 2001a, 2002c, 2000a, 2000c, 1999a, 1995a). Beef calf birth percentages were obtained from the National Animal Health Monitoring System (NAHMS) (USDA/APHIS/VS 1998, 1994, 1993).

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 methane conversion rate (Y_m, the fraction of gross energy converted to methane) 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 (1996a). 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).

Digestible energy and Y_m vary by diet and animal type. The IPCC recommends Y_m values of 3.5 to 4.5 percent for feedlot cattle and 5.5 to 6.5 percent for all other cattle. 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[39] 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.

Digestible energy 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). 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 digestible energy values for grazing beef cattle, the diet descriptions were used to estimate weighted digestible energy 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 percent 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 percent 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- 148, 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.[40] For beef cows, the DE value was adjusted downward by two percent to reflect the reduced diet of the mature beef cow. The percent of each diet that is assumed to be supplemental and the DE values for each region are shown in Table A- 149 . 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 2003 were taken from Johnson (1999). Values for 1990 through 1995 were linearly extrapolated from the 1996 value based on Johnson (1999). In response to peer reviewer comments (Johnson 2000), values for dairy replacement heifers are based on EPA (1993).

Table A- 150 shows the regional DE, the Y_m, and percent of total U.S. cattle population in each region based on 2004 data.

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[39] 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.

[40] 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 65.2 percent was used for five percent of the diet, for a total weighted DE of 64.9 percent.

Step 3: Estimate CH_4 Emissions from Cattle

Emissions were estimated in three steps: a) determine gross energy (GE) intake using the IPCC (2000) equations, b) determine an emissions factor using the GE values and other factors, and c) sum the daily emissions for each animal type. The necessary data values include:

- Body Weight (kg)
- Weight Gain (kg/day)
- Net Energy for Activity (C_a, MJ/day)[41]
- Standard Reference Weight[42] (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 methane)

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 (2000).

$$GE = [((NE_m + NE_{mobilized} + NE_a + NE_l + NE_p) / \{NE_{ma}/DE\}) + (NE_g / \{NE_{ga}/DE\})] / (DE / 100)$$

Where,

GE	= Gross energy (MJ/day)
NE_m	= Net energy required by the animal for maintenance (MJ/day)
$NE_{mobilized}$	= Net energy due to weight loss (mobilized) (MJ/day)
NE_a	= Net energy for animal activity (MJ/day)
NE_l	= Net energy for lactation (MJ/day)
NE_p	= Net energy required for pregnancy (MJ/day)
$\{NE_{ma}/DE\}$	= Ratio of net energy available in a diet for maintenance to digestible energy consumed
NE_g	= Net energy needed for growth (MJ/day)
$\{NE_{ga}/DE\}$	= 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:

$$DayEmit = [GE \times Y_m] / [55.65 \text{ MJ/kg } CH_4]$$

Where,

DayEmit	= Emission factor (kg CH_4/head/day)
GE	= Gross energy intake (MJ/head/day)
Y_m	= Methane conversion rate which is the fraction of gross energy in feed converted to methane (percent)

41 Zero for feedlot conditions, 0.17 for high quality confined pasture conditions, 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.

42 Standard Reference Weight is used in the model to account for breed potential.

The daily emission factors were estimated for each animal type, weight, and region.

Step 3c: Estimate Total Emissions

Emissions were summed for each month and for each population category using the daily emission factor for a representative animal and the number of animals in the category. The following equation was used:

$$\text{Emissions} = \text{DayEmit} \times \text{Days/Month} \times \text{SubPop}$$

Where,

DayEmit	= The emission factor for the subcategory (kg CH_4/head/day)
Days/Month	= The number of days in the month
SubPop	= The number of animals in the subcategory during the month

This process was repeated for each month, and the totals for each subcategory were summed to achieve an emission estimate for the entire year. The estimates for each of the 10 subcategories of cattle are listed in Table A-151. The emissions for each subcategory were then summed to estimate total emissions from beef cattle and dairy cattle for the entire year.

Emission Estimates from Other Livestock

All livestock population data, except for horses, were taken from U.S. Department of Agriculture (USDA) National Agricultural Statistics Service (NASS) reports. Table A-156 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. Multi-year reports include revisions to earlier published data. Recent reports were obtained from the USDA Economics and Statistics System, while historical data were downloaded from the USDA-NASS. The Food and Agriculture Organization (FAO) publishes horse population data. These data were accessed from the FAOSTAT database (FAO 2005). Methane emissions from sheep, goats, swine, and horses were estimated by multiplying published national population estimates by the national emission factor for each year. Table A- 152 shows the emission factors used for these other livestock.

A complete time series of enteric fermentation emissions from all livestock types is shown in Table A- 153 (Tg CO_2 Eq.) and Table A- 154 (Gg).

Table A-145: Dairy Lactation by Region (lbs· year/cow)*

Year	California	West	Northern Great Plains	Southcentral	Northeast	Midwest	Southeast
1990	18,443	17,293	13,431	13,399	14,557	14,214	12,852
1991	18,522	17,615	13,525	13,216	14,985	14,446	13,053
1992	18,709	18,083	13,998	13,656	15,688	14,999	13,451
1993	18,839	18,253	14,090	14,027	15,602	15,086	13,739
1994	20,190	18,802	14,686	14,395	15,732	15,276	14,111
1995	19,559	18,708	14,807	14,294	16,254	15,680	14,318
1996	19,148	19,076	15,040	14,402	16,271	15,651	14,232
1997	19,815	19,537	15,396	14,330	16,519	16,116	14,517
1998	19,437	19,814	15,919	14,722	16,864	16,676	14,404
1999	20,767	20,477	16,325	14,990	17,246	16,966	14,840
2000	21,116	20,781	17,205	15,363	17,482	17,426	15,176
2001	20,890	20,775	17,242	14,952	17,603	17,217	15,304
2002	21,263	21,073	18,079	15,746	18,001	17,576	15,451
2003	20,979	21,132	18,550	16,507	17,727	18,048	15,113
2004	21,125	21,140	18,746	17,567	17,720	18,176	15,696

Source: USDA (2005d, 2004d, 2003d, 2002d, 2001d, 2000d, 1999a, 1995a).
* Beef lactation data were developed using the methodology described in the text.

Table A-146: 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).

Table A- 147: Feedlot Placements in the United States for 2004 (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	367	319	347	315	495	460	445	506	628	912	590	465	5,849
600 – 700 lbs	466	351	347	304	493	359	324	416	475	764	557	558	5,414
700 – 800 lbs	579	548	646	566	772	453	499	565	552	529	326	489	6,524
> 800 lbs	342	394	470	415	610	375	451	615	720	496	270	322	5,480
Total	1,754	1,612	1,810	1,600	2,370	1,647	1,719	2,102	2,375	2,701	1,743	1,834	23,267

Source: USDA (2005f, 2004f, 2003f, 2002f, 2001f, 2000f, 1999a, 1995a).
Note: Totals may not sum due to independent rounding.

Table A- 148: 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	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			65%	65%	62%	65%	74%	59%	69%

Source of representative regional diets: Donovan (1999).

Table A- 149 : Percent of Each Diet that is Supplemental, and the Resulting DE Values for Each Region

Region	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).

Table A-150: Regional Digestible Energy (DE), Methane Conversion Rates (Y_m), and Population Percents for Cattle in 2004

Animal Type	Data	California	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%
	Pop.[c]	2%	9%	30%	25%	2%	14%	18%
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%
	Pop.	18%	13%	5%	4%	18%	36%	6%
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%
	Pop.	4%	8%	40%	25%	2%	18%	4%
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%
	Pop.	2%	7%	48%	23%	1%	15%	4%
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%
	Pop.	4%	8%	48%	23%	1%	16%	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%
	Pop.	4%	8%	48%	23%	1%	16%	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%
	Pop.	2%	8%	27%	27%	2%	14%	19%
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%
	Pop.	19%	15%	4%	5%	17%	32%	7%
Steer Step-Up	DE	74%	74%	74%	74%	74%	74%	74%
	Y_m	4.8%	4.8%	4.8%	4.8%	4.8%	4.8%	4.8%
Heifer Step-Up	DE	74%	74%	74%	74%	74%	74%	74%
	Y_m	4.8%	4.8%	4.8%	4.8%	4.8%	4.8%	4.8%

[a] Digestible Energy in units of percent GE (MJ/Day).
[b] Methane Conversion Rate is the fraction of GE in feed converted to methane.
[c] Percent of each subcategory population present in each region.

Table A-151: CH_4 Emissions from Cattle (Gg)

Cattle Type	1990		1998	1999	2000	2001	2002	2003	2004
Dairy	1,375		1,251	1,265	1,283	1,280	1,288	1,299	1,285
Cows	1,142		1,026	1,037	1,058	1,053	1,060	1,070	1,058
Replacements 7-11 months	49		48	48	48	48	49	48	49
Replacements 12-23 months	184		177	180	177	179	179	181	178
Beef	3,961		4,047	4,045	3,973	3,928	3,924	3,934	3,830
Cows	2,428		2,531	2,520	2,507	2,492	2,472	2,461	2,453
Replacements 7-11 months	52		54	53	53	54	54	53	54
Replacements 12-23 months	190		206	198	198	200	200	201	198
Steer Stockers	431		418	400	362	352	355	361	325
Heifer Stockers	232		236	229	207	203	205	210	188
Feedlot Cattle	412		378	420	426	408	421	429	399
Bulls	218		223	224	220	219	217	217	213
Total	5,337		5,297	5,310	5,256	5,208	5,212	5,233	5,115

Note: Totals may not sum due to independent rounding.

Table A-152: 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 (2000).

Table A-153: CH_4 Emissions from Enteric Fermentation (Tg CO_2 Eq.)

Livestock Type	1990		1998	1999	2000	2001	2002	2003	2004
Beef Cattle	83.2		85.0	84.9	83.4	82.5	82.4	82.6	80.4
Dairy Cattle	28.9		26.3	26.6	27.0	26.9	27.1	27.3	27.0
Horses	1.9		2.0	2.0	2.0	2.0	2.0	2.0	2.0
Sheep	1.9		1.3	1.2	1.2	1.2	1.1	1.1	1.0
Swine	1.7		2.0	1.9	1.9	1.9	1.9	1.9	1.9
Goats	0.3		0.2	0.2	0.3	0.3	0.3	0.3	0.3
Total	117.9		116.7	116.8	115.6	114.6	114.7	115.1	112.6

Table A-154: CH_4 Emissions from Enteric Fermentation (Gg)

Livestock Type	1990		1998	1999	2000	2001	2002	2003	2004
Beef Cattle	3,961		4,047	4,045	3,973	3,928	3,923	3,934	3,830
Dairy Cattle	1,375		1,251	1,265	1,283	1,280	1,288	1,299	1,285
Horses	91		94	93	94	95	95	95	95
Sheep	91		63	58	56	55	53	51	49
Swine	81		93	90	88	88	90	90	91
Goats	13		12	12	12	12	13	13	13
Total	5,612		5,559	5,563	5,507	5,459	5,463	5,481	5,362

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

This sub-annex presents a discussion of the methodology used to calculate CH_4 and N_2O emissions from manure management systems. More detailed discussions of selected topics may be found in supplemental memoranda in the supporting docket to this inventory.

The following steps were used to estimate CH_4 and 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 sub-annex 3.11).

Step 1: Livestock Population Characterization Data

Annual animal population data for 1990 through 2004 for all livestock types, except horses and goats, were obtained from the USDA National Agricultural Statistics Service (USDA 1994a-b, 1995a-b, 1998a-b, 1999a-c, 2000a, 2004a-e, 2005a-f). The actual population data used in the emissions calculations for cattle and swine were downloaded from the USDA National Agricultural Statistics Service Population Estimates Data Base <http://www.usda.gov/nass/>. Horse population data were obtained from the FAOSTAT database (FAO 2005). Goat population data for 1992, 1997, and 2002 were obtained from the Census of Agriculture (USDA 2005g).

A summary of the livestock population characterization data used to calculate methane and nitrous oxide emissions is presented in Table A-156.

Dairy Cattle: The total annual dairy cow and heifer state population data for 1990 through 2004 are provided in various USDA National Agricultural Statistics Service reports (1995a, 1999a, 2004a, 2005a-b). The actual total annual dairy cow and heifer state population data used in the emissions calculations were downloaded from the U.S. Department of Agriculture National Agricultural Statistics Service Published Estimates Database <http://www.nass.usda.gov/QuickStats/>, U.S. and State, Cattle and Calves. The specific data used to estimate dairy cattle populations are "Cows That Calved—Milk" and "Heifers 500+ Lbs—Milk Replacement"

Beef Cattle: The total annual beef cattle population data for each state for 1990 through 2004 are provided in various USDA National Agricultural Statistics Service reports (1995a, 1999a, 2004a, 2005a-b). The actual data used in the emissions calculations were downloaded from the U.S. Department of Agriculture National Agricultural Statistics Service Published Estimates Database <http://www.nass.usda.gov/QuickStats/>, U.S. and State, Cattle and Calves. The specific data used to estimate beef cattle populations are: "Cows That Calved—Beef," "Heifers 500+ Lbs—Beef Replacement," "Heifers 500+ Lbs—Other," "Calves Less Than 500 Lbs," "Bulls 500+ Lbs," and "Steers 500+ Lbs." Additional information regarding the percent of beef steers and heifers in feedlots was obtained from contacts with the national USDA office (Milton 2000).

For all beef cattle groups (cows, heifers, steers, bulls, and calves), the USDA data provide cattle inventories from January and July 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. USDA provides January inventory data for each state; however, July inventory data is only presented as a total for the United States. 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 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.

Swine: The total annual swine population data for each state for 1990 through 2004 are provided in various USDA National Agricultural Statistics Service reports (USDA 1994a, 1998a, 2004b, 2005c). The USDA data 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. The actual data used in the emissions calculations were downloaded from the U.S. Department of Agriculture National Agricultural Statistics Service Published Estimates Database <http://www.nass.usda.gov/QuickStats/>, U.S. and State, Hogs and Pigs.

Sheep: The total annual sheep population data for each state for 1990 through 2004 were obtained from USDA National Agricultural Statistics Service (USDA 1994b, 1999c, 2004e, 2005f). Population data for lamb and sheep on feed are not available after 1993. The number of lamb and sheep on feed for 1994 through 2004 were calculated using the average of the percent of lamb and sheep on feed from 1990 through 1993. In addition, all of the sheep and lamb "on feed" are not necessarily on "feedlots;" they may be on pasture/crop residue supplemented by feed. Data for those animals on feed that are in feedlots versus pasture/crop residue were provided only for lamb in 1993. To calculate the populations of sheep and lamb in feedlots for all years, it was assumed that the percentage of sheep and lamb on feed that are in feedlots versus pasture/crop residue is the same as that for lambs in 1993 (Anderson 2000).

Goats: Annual goat population data by state were available for only 1992, 1997, and 2002 (USDA 2005g). The data for 1992 were used for 1990 through 1992 and the data for 2002 were used for 2002 through 2004. 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: Annual poultry population data by state for the various animal categories (hens 1 year and older, total pullets, other chickens, broilers, and turkeys) were obtained from USDA National Agricultural Statistics Service (USDA 1995b, 1998b, 1999b, 2000a, 2004c-d, 2005d-e). The annual population data for boilers and turkeys were adjusted for turnover (i.e., slaughter) rate (Lange 2000). All poultry population data were adjusted to account for states that report non-disclosed populations to USDA National Agricultural Statistics Service. The combined populations of the states reporting non-disclosed populations are reported as "other" states. State populations were estimated for the non-disclosed states by equally distributing the population attributed to "other" states to the non-disclosed states.

Horses: The Food and Agriculture Organization (FAO) publishes annual total U.S. horse population, which were accessed from the FAOSTAT database at < http://faostat.fao.org> (FAO 2005). 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.

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 excretion rate (VS)
- Maximum methane producing capacity (B_o) for U.S. animal waste
- Nitrogen excretion rate (N_{ex})
- Typical animal mass (TAM)

Table A- 157 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 National Engineering Handbook, 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 VS and N_{ex} data for breeding swine are 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). The dairy cow population is 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. N_{ex} rates were collected from the sources indicated in Table A- 157 and are based on measurement data from excreted manure.

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. VS content of manure equals the fraction of the diet consumed by cattle that is not digested and thus excreted as fecal material which, when combined with urinary excretions, constitutes manure. The enteric fermentation model requires the estimation of gross energy intake and its fractional digestibility (digestible energy) in the process of estimating enteric methane emissions (see Annex 3.9 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 2 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 volatile solids is as follows:

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

Where,

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

This equation is used to calculate volatile solids rates for each region, cattle type, and year, with state-specific volatile solids excretion rates assigned based on which region of the country the state is located in (Lieberman and Pape 2005).

Table A- 158 presents the state-specific volatile solids production rates used for 2004.

Step 3: Waste Management System Usage Data

Estimates were made of the distribution of waste by management system and animal type using the following sources of information:

- State contacts to estimate the breakout of dairy cows on pasture, range, or paddock, and the percent of waste managed by daily spread systems (Deal 2000, Johnson 2000, Miller 2000, Stettler 2000, Sweeten 2000, Wright 2000)
- Data collected for EPA's Office of Water, including site visits, to medium and large beef feedlot, dairy, swine, and poultry operations (EPA 2002b)
- Contacts with the national USDA office to estimate the percent of beef steers and heifers in feedlots (Milton 2000)
- Survey data collected by USDA and re-aggregated by farm size and geographic location (USDA 1998d, 2000b), used for small operations
- Survey data collected by the United Egg Producers (UEP 1999) and USDA (2000c) and previous EPA estimates (EPA 1992) of waste distribution for layers
- Survey data collected by Cornell University on dairy manure management operations in New York (Poe 1999)
- Previous EPA estimates of waste distribution for sheep, goat, and horse operations (EPA 1992)

Table A- 159 through Table A- 164 summarize 2004 manure distribution data among waste management systems at beef feedlots, dairies, dairy heifer facilities, and swine, layer, broiler, and turkey operations. 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: The beef feedlot and dairy heifer waste management system 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, beef 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 0.003 to 0.010 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/paddock systems, which are utilized for the majority of the population of beef cattle in the country.

Dairy Cows: The waste management system 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 and 1997 Census of Agriculture (USDA 2005g). It was assumed that the data provided for 1992 were the same as that for 1990 and 1991, and data provided for 1997 were the same as that for 1998 through 2004. Data for 1993 through 1996 were extrapolated using the 1992 and 1997 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 (also includes slurry tank, slurry earth-basin, and aerated lagoon), anaerobic lagoon, and solid storage (also 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 National Agricultural Statistics Service (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 1999). Census of Agriculture population data for 1992 and 1997 (USDA 2005g) 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 2004, which were obtained from the National Agricultural Statistics Service (USDA 1994a-b, 1995a-b, 1998a-b, 1999a-c, 2000a, 2004a-e, 2005a-f).

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. Therefore, the total percent of systems reported by USDA for a region and farm size is greater than 100 percent. Typically, this means that some of the manure at a dairy is handled in one system (e.g., a lagoon), and some of the manure is handled in another system (e.g., drylot). However, it is unlikely that the same manure is moved from one system to another. Therefore, 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).

Dairy Heifers: Similar to beef cattle, dairy heifers are housed on drylots when not pasture based. Based on data from EPA's Office of Water (EPA 2002b), it was assumed that 100 percent of the manure excreted by dairy heifers is deposited on drylots and generates emissions. 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 2000a) and was used to estimate the percentage of manure managed in runoff ponds in addition to drylots; this percentage ranges from 0.003 to 0.010 percent. The percentage of manure generating emissions from dairy heifers is therefore greater than 100 percent.

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. Manure management system data were obtained from USDA (USDA 1998d). It was assumed those operations with less than 200 head use pasture, range, or paddock systems. The percent of waste by system was estimated using the USDA data broken out by geographic region and farm size. Farm-size distribution data reported in the 1992 and 1997 Census of Agriculture (USDA 2005g) were used to determine the percentage of all swine utilizing the various manure management systems. The reported

manure management systems were deep pit, liquid/slurry (also includes above- and below-ground slurry), anaerobic lagoon, and solid storage (also 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 is greater than 100 percent. Typically, this means that some of the manure at a swine operation is handled in one system (e.g., liquid system), and some 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.

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 1997 were the same as that for 1998 through 2004. Data for 1993 through 1996 were extrapolated using the 1992 and 1997 data.

Sheep: It was assumed that all sheep waste not deposited in feedlots was deposited on pasture, range, or paddock lands (Anderson 2000).

Goats/Horses: Waste management system data for 1990 to 2004 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 were 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 2004 was equal to that estimated for 1999.

Poultry—Broilers/Turkeys: The percentage of turkeys and broilers on pasture was obtained from *Global Methane Emissions from Livestock and Poultry Manure* (EPA1992). It was assumed that one percent of poultry waste are 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 nitrous oxide emission factors (EFs) used in the emission calculations were determined using the methodologies shown below:

Methane Conversion Factors (MCFs)

IPCC default MCFs were used for all dry systems modeling, while a country-specific methodology was used to develop MCFs for all lagoon and liquid systems. IPCC *Good Practice Guidance* (IPCC 2000) published default CH_4 conversion factors for dry systems according to climate classification (cool, temperate, or warm). The IPCC default MCFs for the temperate climate classification (listed in Table A-155) were used for all animal waste managed in dry systems.

Table A-155. IPCC Default MCFs for the Temperate Climate Classification

Type	MCF (%)
Pasture/Range/Paddock	1.5%
Daily Spread	0.5%
Solid Storage	1.5%
Dry Lot	1.5%
Poultry Manure with Bedding	1.5%
Poultry Manure without Bedding	1.5%

IPCC *Good Practice Guidance* (IPCC 2000) published default CH_4 conversion factors of 0 to 100 percent for anaerobic lagoon systems, which reflects the wide range in performance that may be achieved with these systems, depending on temperature and retention time. Therefore, a climate-based approach 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.

The following approach was used to develop the MCFs for liquid systems, and is based on the van't Hoff-Arrhenius equation used to forecast performance of biological reactions. One practical way of estimating MCFs for liquid manure handling systems is based on the mean ambient temperature and the van't Hoff-Arrhenius equation with a base temperature of 30°C, as 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 = 303.16K
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 volatile solids that are biologically available for conversion to methane based on the temperature of the system. The temperature is assumed equal to the ambient temperature. For colder climates, a minimum temperature of 5°C was established for uncovered anaerobic lagoons and 7.5°C for other liquid manure handling systems. 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 2004). 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 2005g). 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 2004 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:

- Monthly temperatures are calculated by using county-level temperature and population data. 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 anaerobic lagoons and 7.5°C is used for liquid/slurry and deep pit systems.
- Monthly production of volatile solids that are 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 volatile solids are removed from the management system prior to conversion to methane, such as solids being removed from the system for application to cropland. This factor, equal to 0.8, has been estimated using currently available methane measurement data from anaerobic lagoon systems in the United States (ERG 2001).
- The amount of volatile solids available for conversion to methane is assumed to be equal to the amount of volatile solids produced during the month (from Step 3). For anaerobic lagoons, the amount of volatile solids available also includes volatile solids that may remain in the system from previous months.
- The amount of volatile solids consumed during the month is equal to the amount available for conversion multiplied by the "f" factor.

- For anaerobic lagoons, the amount of volatile solids 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 methane generated during the month is equal to the monthly volatile solids consumed multiplied by the maximum methane potential of the waste (B_o).

The annual MCF is then calculated as:

$$\text{MCF (annual)} = CH_4 \text{ generated (annual)} / (\text{VS produced (annual)} \times Bo)$$

Where,

$MCF_{(annual)}$	= Methane conversion factor
VS produced $_{(annual)}$	= Volatile solids excreted annually
B_o	= Maximum methane producing potential of the waste

In order to account for the carry-over of volatile solids from the year prior to the inventory year for which estimates are calculated, it is assumed in the MCF calculation for lagoons that a portion of the volatile solids from October, November, and December of the year prior to the inventory year are available in the lagoon system starting January of the inventory year.

Following this procedure, the resulting MCF accounts for temperature variation throughout the year, residual volatile solids in a system (carry-over), and management and design practices that may reduce the volatile solids available for conversion to CH_4. The MCFs presented in Table A- 165 by state and waste management system represent the average MCF for 2004 by state for all animal groups located in that state. However, in the actual calculation of methane emissions, specific MCFs for each animal type in the state are used that represent the locations of the particular animal group in each state.

Nitrous Oxide Emission Factors

Nitrous oxide emission factors for all manure management systems were set equal to the default IPCC factors (IPCC 2000) of 0.02 kg N_2O-N/kg N excreted for dry manure systems, 0.001 kg N_2O-N/kg N excreted for wet manure systems, and 0.005 kg N_2O-N/kg N excreted for poultry systems without bedding.

Step 5: Weighted Emission Factors

For beef cattle, dairy cattle, swine, and poultry, the emission factors for both CH_4 and N_2O were weighted to incorporate the distribution of waste by management system for each state. The following equation was used to determine the weighted MCF for a particular animal type in a particular state:

$$MCF_{animal,\ state} = \sum_{system} (MCF_{system,\ state} \times \%Manure_{animal,\ system,\ state})$$

Where,

$MCF_{animal,\ state}$	= Weighted MCF for that animal group and state
$MCF_{system,\ state}$	= MCF for that system and state (see Step 4)
% $Manure_{animal,\ system,\ state}$	= Percent of manure managed in the system for that animal group in that state (expressed as a decimal)

The weighted nitrous oxide emission factor for a particular animal type in a particular state was determined as follows:

$$EF_{animal,\ state} = \sum_{system} (EF_{system} \times \%\ Manure_{animal,\ system,\ state})$$

Where,

$Methane_{animal\ group}$	= Methane emissions for that animal group (kg CH_4/yr)
Population	= Annual average state animal population for that animal group (head)
VS	= Total volatile solids produced annually per animal (kg/yr/head)
B_o	= Maximum methane producing capacity per kilogram of VS (m^3 CH_4/kg VS)
$MCF_{animal,\ state}$	= Weighted MCF for the animal group and state (see Step 5)
0.662	= Conversion factor of m^3 CH_4 to kilograms CH_4 (kg CH_4 /m^3 CH_4)

Nitrous oxide emissions were calculated for each animal group as follows:

$$\text{Nitrous Oxide}_{\text{animal group}} = \sum_{state} (Population \times N_{ex} \times EF_{animal,\ state} \times 44/28)$$

Where,

$Nitrous\ Oxide_{animal\ group}$	= Nitrous oxide emissions for that animal group (kg/yr)
Population	= Annual average state animal population for that animal group (head)
N_{ex}	= Total Kjeldahl nitrogen excreted annually per animal (kg/yr/head)
$EF_{animal,\ state}$	= Weighted nitrous oxide emission factor for the animal group and state, kg N_2O-N/kg N excreted (see Step 5)
44/28	= Conversion factor of N_2O-N to N_2O

Emission estimates are summarized in Table A- 167 and Table A- 168.

Table A-156: Livestock Population (1,000 Head)

Animal Type	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
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
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
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
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	60,621
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	20,120
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
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
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
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
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	86,449
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
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
NOF Bulls2	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
NOF Calves2	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	22,055
NOF Heifers2	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
NOF Steers2	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
NOF Cows2	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	33,181
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
Sheep NOF	10,178	10,062	9,612	9,008	8,823	8,082	7,594	7,171	6,990	6,444	6,232	6,111	5,871	5,584	5,415
Sheep on Feed	1,180	1,112	1,185	1,193	1,013	907	871	852	836	803	804	797	752	737	690
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
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	2,031,163	2,056,531	2,091,952	2,077,811	2,122,636
Hens >1 yr.	119,551	117,178	121,103	131,688	135,094	133,841	138,048	140,966	151,298	152,024	153,439	153,817	153,884	169,263	171,599
Pullets1	227,083	239,559	243,267	240,712	243,286	246,599	247,446	261,515	266,375	275,718	275,313	282,156	281,614	272,062	274,303
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	8,263
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
Turkeys	117,685	115,504	114,426	110,635	107,469	106,960	108,112	105,088	97,365	90,064	88,195	87,019	86,087	83,892	79,262
Horses	5,069	5,100	5,121	5,130	5,110	5,130	5,150	5,170	5,237	5,170	5,240	5,300	5,300	5,300	5,300

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- 157: 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- 158	Lieberman and Pape, 2005
Dairy Heifers	476	Safley 2000	0.31	USDA 1996a	0.17	Bryant et. al. 1976	Table A- 158	Lieberman and Pape, 2005
Feedlot Steers	420	USDA 1996a	0.30	USDA 1996a	0.33	Hashimoto 1981	Table A- 158	Lieberman and Pape, 2005
Feedlot Heifers	420	USDA 1996a	0.30	USDA 1996a	0.33	Hashimoto 1981	Table A- 158	Lieberman and Pape, 2005
NOF Bulls	750	Safley 2000	0.31	USDA 1996a	0.17	Hashimoto 1981	6.04	USDA 1996a
NOF Calves	118	ERG 2003	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- 158	Lieberman and Pape, 2005
NOF Steers	318	Safley 2000	0.31	USDA 1996a	0.17	Hashimoto 1981	Table A- 158	Lieberman and Pape, 2005
NOF Cows	533	NRC 2000	0.33	USDA 1996a	0.17	Hashimoto 1981	Table A- 158	Lieberman and Pape, 2005
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	EPA 1992
NOF Sheep	80	EPA 1992	0.42	ASAE 1999	0.19	EPA 1992	9.20	EPA 1992
Goats	64	ASAE 1999	0.45	ASAE 1999	0.17	EPA 1992	9.50	EPA 1992
Horses	450	ASAE 1999	0.30	ASAE 1999	0.33	EPA 1992	10.0	EPA 1992
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

NA = Not Applicable. In these cases, methane emissions were projected based on animal population growth from base year.

Table A-158: Estimated Volatile Solids Production Rate by State for 2004

State	Dairy Cow kg/day/1000 kg	Dairy Heifer kg/day/1000 kg	NOF Cows kg/day/1000 kg	NOF Heifers kg/day/1000 kg	NOF Steers kg/day/1000 kg	Feedlot Heifers kg/day/1000 kg	Feedlot Steers kg/day/1000 kg
Alabama	8.47	6.81	6.74	7.24	7.86	3.99	3.87
Alaska	10.87	6.81	8.71	9.52	10.40	3.95	3.82
Arizona	10.87	6.81	8.71	9.57	10.40	3.95	3.82
Arkansas	8.55	7.56	6.72	7.23	7.84	3.93	3.81
California	9.35	6.81	6.57	7.12	7.65	3.96	3.83
Colorado	8.64	6.81	6.19	6.75	7.17	3.94	3.81
Connecticut	8.41	6.13	6.62	7.14	7.72	4.00	3.87
Delaware	8.41	6.13	6.62	7.26	7.72	4.00	3.87
Florida	8.47	6.81	6.74	7.21	7.86	3.99	3.87
Georgia	8.47	6.81	6.74	7.24	7.86	3.99	3.87
Hawaii	10.87	6.81	8.71	9.56	10.40	3.95	3.82
Idaho	10.87	6.81	8.71	9.68	10.40	3.95	3.82
Illinois	8.51	6.81	6.63	7.22	7.72	4.00	3.88
Indiana	8.51	6.81	6.63	7.20	7.72	4.00	3.88
Iowa	8.51	6.81	6.63	7.25	7.72	4.00	3.88
Kansas	8.64	6.81	6.19	6.75	7.17	3.94	3.81
Kentucky	8.47	6.81	6.74	7.28	7.86	3.99	3.87
Louisiana	8.55	7.56	6.72	7.19	7.84	3.93	3.81
Maine	8.41	6.13	6.62	7.11	7.72	4.00	3.87
Maryland	8.41	6.13	6.62	7.17	7.72	4.00	3.87
Massachusetts	8.41	6.13	6.62	7.11	7.72	4.00	3.87
Michigan	8.51	6.81	6.63	7.20	7.72	4.00	3.88
Minnesota	8.51	6.81	6.63	7.21	7.72	4.00	3.88
Mississippi	8.47	6.81	6.74	7.23	7.86	3.99	3.87
Missouri	8.51	6.81	6.63	7.17	7.72	4.00	3.88
Montana	8.64	6.81	6.19	6.61	7.17	3.94	3.81
Nebraska	8.64	6.81	6.19	6.75	7.17	3.94	3.81
Nevada	10.87	6.81	8.71	9.60	10.40	3.95	3.82
New Hampshire	8.41	6.13	6.62	7.11	7.72	4.00	3.87
New Jersey	8.41	6.13	6.62	7.15	7.72	4.00	3.87
New Mexico	10.87	6.81	8.71	9.64	10.40	3.95	3.82
New York	8.41	6.13	6.62	7.19	7.72	4.00	3.87
North Carolina	8.47	6.81	6.74	7.23	7.86	3.99	3.87
North Dakota	8.64	6.81	6.19	6.69	7.17	3.94	3.81
Ohio	8.51	6.81	6.63	7.18	7.72	4.00	3.88
Oklahoma	8.55	7.56	6.72	7.30	7.84	3.93	3.81
Oregon	10.87	6.81	8.71	9.62	10.40	3.95	3.82
Pennsylvania	8.41	6.13	6.62	7.18	7.72	4.00	3.87
Rhode Island	8.41	6.13	6.62	7.11	7.72	4.00	3.87
South Carolina	8.47	6.81	6.74	7.25	7.86	3.99	3.87
South Dakota	8.64	6.81	6.19	6.70	7.17	3.94	3.81
Tennessee	8.47	6.81	6.74	7.24	7.86	3.99	3.87
Texas	8.55	7.56	6.72	7.32	7.84	3.93	3.81
Utah	10.87	6.81	8.71	9.62	10.40	3.95	3.82
Vermont	8.41	6.13	6.62	7.15	7.72	4.00	3.87
Virginia	8.47	6.81	6.74	7.27	7.86	3.99	3.87
Washington	10.87	6.81	8.71	9.69	10.40	3.95	3.82
West Virginia	8.41	6.13	6.62	7.13	7.72	4.00	3.87
Wisconsin	8.51	6.81	6.63	7.17	7.72	4.00	3.88
Wyoming	8.64	6.81	6.19	6.66	7.17	3.94	3.81

Table A-159: 2004 Manure Distribution Among Waste Management Systems at Beef Feedlots (Percent)

State	Pasture	Daily Spread	Solid Storage	Dry Lot[a]	Liquid/ Slurry[a]	Anaerobic Lagoon	Deep Pit	Poultry with Bedding	Poultry without Bedding
Alabama	0	0	0	100	1.3	0	0	0	0
Alaska	0	0	0	100	1.3	0	0	0	0
Arizona	0	0	0	100	0.4	0	0	0	0
Arkansas	0	0	0	100	1.3	0	0	0	0
California	0	0	0	100	1.3	0	0	0	0
Colorado	0	0	0	100	0.4	0	0	0	0
Connecticut	0	0	0	100	1.0	0	0	0	0
Delaware	0	0	0	100	1.0	0	0	0	0
Florida	0	0	0	100	1.3	0	0	0	0
Georgia	0	0	0	100	1.3	0	0	0	0
Hawaii	0	0	0	100	1.3	0	0	0	0
Idaho	0	0	0	100	0.4	0	0	0	0
Illinois	0	0	0	100	0.6	0	0	0	0
Indiana	0	0	0	100	0.6	0	0	0	0
Iowa	0	0	0	100	0.6	0	0	0	0
Kansas	0	0	0	100	0.6	0	0	0	0
Kentucky	0	0	0	100	1.0	0	0	0	0
Louisiana	0	0	0	100	1.3	0	0	0	0
Maine	0	0	0	100	1.0	0	0	0	0
Maryland	0	0	0	100	1.0	0	0	0	0
Massachusetts	0	0	0	100	1.0	0	0	0	0
Michigan	0	0	0	100	0.6	0	0	0	0
Minnesota	0	0	0	100	0.6	0	0	0	0
Mississippi	0	0	0	100	1.3	0	0	0	0
Missouri	0	0	0	100	0.6	0	0	0	0
Montana	0	0	0	100	0.4	0	0	0	0
Nebraska	0	0	0	100	0.6	0	0	0	0
Nevada	0	0	0	100	0.4	0	0	0	0
New Hampshire	0	0	0	100	1.0	0	0	0	0
New Jersey	0	0	0	100	1.0	0	0	0	0
New Mexico	0	0	0	100	0.4	0	0	0	0
New York	0	0	0	100	1.0	0	0	0	0
North Carolina	0	0	0	100	1.0	0	0	0	0
North Dakota	0	0	0	100	0.6	0	0	0	0
Ohio	0	0	0	100	0.6	0	0	0	0
Oklahoma	0	0	0	100	0.4	0	0	0	0
Oregon	0	0	0	100	1.3	0	0	0	0
Pennsylvania	0	0	0	100	1.0	0	0	0	0
Rhode Island	0	0	0	100	1.0	0	0	0	0
South Carolina	0	0	0	100	1.3	0	0	0	0
South Dakota	0	0	0	100	0.6	0	0	0	0
Tennessee	0	0	0	100	1.0	0	0	0	0
Texas	0	0	0	100	0.4	0	0	0	0
Utah	0	0	0	100	0.4	0	0	0	0
Vermont	0	0	0	100	1.0	0	0	0	0
Virginia	0	0	0	100	1.0	0	0	0	0
Washington	0	0	0	100	1.3	0	0	0	0
West Virginia	0	0	0	100	1.0	0	0	0	0
Wisconsin	0	0	0	100	0.6	0	0	0	0
Wyoming	0	0	0	100	0.4	0	0	0	0

[a] 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.

Table A-160: 2004 Manure Distribution Among Waste Management Systems at Dairies (Percent)

State	Pasture	Daily Spread	Solid Storage	Dry Lot	Liquid/ Slurry	Anaerobic Lagoon	Deep Pit	Poultry with Bedding	Poultry without Bedding
Alabama	63	14	8	0	7	8	0	0	0
Alaska	10	17	23	0	20	25	6	0	0
Arizona	0	10	9	0	20	61	0	0	0
Arkansas	63	14	12	0	5	6	1	0	0
California	1	11	9	0	21	57	0	0	0
Colorado	1	2	13	0	27	56	2	0	0
Connecticut	6	44	23	0	17	7	3	0	0
Delaware	8	45	25	0	14	5	3	0	0
Florida	12	23	7	0	15	43	0	0	0
Georgia	53	16	9	0	9	13	0	0	0
Hawaii	12	0	13	0	21	53	2	0	0
Idaho	1	2	15	0	25	56	2	0	0
Illinois	7	12	51	0	19	6	5	0	0
Indiana	11	18	45	0	16	5	4	0	0
Iowa	10	17	47	0	16	6	4	0	0
Kansas	8	14	51	0	17	5	5	0	0
Kentucky	63	14	16	0	5	1	1	0	0
Louisiana	58	15	11	0	6	9	1	0	0
Maine	9	47	26	0	12	4	3	0	0
Maryland	8	46	25	0	13	5	3	0	0
Massachusetts	8	46	26	0	13	5	3	0	0
Michigan	6	10	42	0	26	12	5	0	0
Minnesota	11	19	45	0	16	5	4	0	0
Mississippi	63	14	10	0	6	7	0	0	0
Missouri	10	16	49	0	16	5	5	0	0
Montana	3	4	32	0	23	30	9	0	0
Nebraska	9	16	48	0	17	5	5	0	0
Nevada	2	3	11	0	20	63	0	0	0
New Hampshire	7	45	26	0	13	5	3	0	0
New Jersey	8	46	26	0	13	4	3	0	0
New Mexico	0	10	10	0	19	61	0	0	0
New York	8	46	23	0	14	7	2	0	0
North Carolina	63	14	10	0	8	3	2	0	0
North Dakota	12	20	48	0	12	3	4	0	0
Ohio	10	17	46	0	17	5	5	0	0
Oklahoma	0	5	34	0	23	29	9	0	0
Oregon	31	0	13	0	20	33	3	0	0
Pennsylvania	10	48	27	0	10	3	2	0	0
Rhode Island	12	51	28	0	6	2	2	0	0
South Carolina	63	14	7	0	7	9	0	0	0
South Dakota	10	17	47	0	16	5	4	0	0
Tennessee	63	14	13	0	7	2	2	0	0
Texas	0	7	16	0	26	49	3	0	0
Utah	2	3	22	0	28	41	5	0	0
Vermont	8	46	24	0	14	6	3	0	0
Virginia	63	14	12	0	7	2	2	0	0
Washington	23	0	11	0	22	43	2	0	0
West Virginia	9	47	27	0	11	4	3	0	0
Wisconsin	10	17	46	0	17	6	4	0	0
Wyoming	8	14	23	0	22	28	6	0	0

Table A-161: 2004 Manure Distribution Among Waste Management Systems at Dairy Heifer Facilities (Percent)

State	Pasture	Daily Spread	Solid Storage	Dry Lot[1]	Liquid/ Slurry[1]	Anaerobic Lagoon	Deep Pit	Poultry with Bedding	Poultry without Bedding
Alabama	0	0	0	100	1.0	0	0	0	0
Alaska	0	0	0	100	1.0	0	0	0	0
Arizona	0	0	0	100	0.3	0	0	0	0
Arkansas	0	0	0	100	1.0	0	0	0	0
California	0	0	0	100	1.0	0	0	0	0
Colorado	0	0	0	100	0.3	0	0	0	0
Connecticut	0	0	0	100	0.8	0	0	0	0
Delaware	0	0	0	100	0.8	0	0	0	0
Florida	0	0	0	100	1.0	0	0	0	0
Georgia	0	0	0	100	1.0	0	0	0	0
Hawaii	0	0	0	100	1.0	0	0	0	0
Idaho	0	0	0	100	0.3	0	0	0	0
Illinois	0	0	0	100	0.5	0	0	0	0
Indiana	0	0	0	100	0.5	0	0	0	0
Iowa	0	0	0	100	0.5	0	0	0	0
Kansas	0	0	0	100	0.5	0	0	0	0
Kentucky	0	0	0	100	0.8	0	0	0	0
Louisiana	0	0	0	100	1.0	0	0	0	0
Maine	0	0	0	100	0.8	0	0	0	0
Maryland	0	0	0	100	0.8	0	0	0	0
Massachusetts	0	0	0	100	0.8	0	0	0	0
Michigan	0	0	0	100	0.5	0	0	0	0
Minnesota	0	0	0	100	0.5	0	0	0	0
Mississippi	0	0	0	100	1.0	0	0	0	0
Missouri	0	0	0	100	0.5	0	0	0	0
Montana	0	0	0	100	0.3	0	0	0	0
Nebraska	0	0	0	100	0.5	0	0	0	0
Nevada	0	0	0	100	0.3	0	0	0	0
New Hampshire	0	0	0	100	0.8	0	0	0	0
New Jersey	0	0	0	100	0.8	0	0	0	0
New Mexico	0	0	0	100	0.3	0	0	0	0
New York	0	0	0	100	0.8	0	0	0	0
North Carolina	0	0	0	100	0.8	0	0	0	0
North Dakota	0	0	0	100	0.5	0	0	0	0
Ohio	0	0	0	100	0.5	0	0	0	0
Oklahoma	0	0	0	100	0.3	0	0	0	0
Oregon	0	0	0	100	1.0	0	0	0	0
Pennsylvania	0	0	0	100	0.8	0	0	0	0
Rhode Island	0	0	0	100	0.8	0	0	0	0
South Carolina	0	0	0	100	1.0	0	0	0	0
South Dakota	0	0	0	100	0.5	0	0	0	0
Tennessee	0	0	0	100	0.8	0	0	0	0
Texas	0	0	0	100	0.3	0	0	0	0
Utah	0	0	0	100	0.3	0	0	0	0
Vermont	0	0	0	100	0.8	0	0	0	0
Virginia	0	0	0	100	0.8	0	0	0	0
Washington	0	0	0	100	1.0	0	0	0	0
West Virginia	0	0	0	100	0.8	0	0	0	0
Wisconsin	0	0	0	100	0.5	0	0	0	0
Wyoming	0	0	0	100	0.3	0	0	0	0

[1] 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-162: 2004 Manure Distribution Among Waste Management Systems at Swine Operations (Percent)

State	Pasture	Daily Spread	Solid Storage	Dry Lot	Liquid/ Slurry	Anaerobic Lagoon	Deep Pit	Poultry with Bedding	Poultry without Bedding
Alabama	10	0	4	0	12	41	33	0	0
Alaska	100	0	0	0	0	0	0	0	0
Arizona	6	0	4	0	12	45	34	0	0
Arkansas	2	0	4	0	10	50	34	0	0
California	10	0	3	0	8	49	30	0	0
Colorado	2	0	5	0	26	17	49	0	0
Connecticut	60	0	2	0	11	8	19	0	0
Delaware	11	0	5	0	24	16	44	0	0
Florida	62	0	2	0	11	8	18	0	0
Georgia	9	0	4	0	13	40	34	0	0
Hawaii	36	0	3	0	18	14	30	0	0
Idaho	34	0	3	0	18	13	32	0	0
Illinois	4	0	4	0	27	16	48	0	0
Indiana	4	0	4	0	27	16	48	0	0
Iowa	3	0	4	0	16	40	38	0	0
Kansas	6	0	4	0	27	14	49	0	0
Kentucky	7	0	4	0	15	39	36	0	0
Louisiana	61	0	2	0	11	8	18	0	0
Maine	100	0	0	0	0	0	0	0	0
Maryland	19	0	4	0	22	16	39	0	0
Massachusetts	42	0	3	0	16	12	27	0	0
Michigan	7	0	5	0	25	17	46	0	0
Minnesota	3	0	5	0	26	18	48	0	0
Mississippi	4	0	4	0	8	52	32	0	0
Missouri	5	0	4	0	27	14	49	0	0
Montana	8	0	5	0	24	17	46	0	0
Nebraska	5	0	4	0	27	16	47	0	0
Nevada	100	0	0	0	0	0	0	0	0
New Hampshire	63	0	2	0	10	8	17	0	0
New Jersey	49	0	2	0	14	11	24	0	0
New Mexico	100	0	0	0	0	0	0	0	0
New York	32	0	4	0	18	13	34	0	0
North Carolina	0	0	4	0	7	58	32	0	0
North Dakota	14	0	4	0	23	16	42	0	0
Ohio	10	0	4	0	25	16	45	0	0
Oklahoma	2	0	4	0	7	56	31	0	0
Oregon	66	0	1	0	9	7	16	0	0
Pennsylvania	6	0	5	0	25	18	46	0	0
Rhode Island	45	0	2	0	15	12	26	0	0
South Carolina	9	0	4	0	11	44	33	0	0
South Dakota	8	0	5	0	25	17	45	0	0
Tennessee	13	0	4	0	15	33	35	0	0
Texas	12	0	3	0	8	46	30	0	0
Utah	3	0	5	0	26	17	49	0	0
Vermont	100	0	0	0	0	0	0	0	0
Virginia	5	0	4	0	9	51	32	0	0
Washington	30	0	3	0	19	14	34	0	0
West Virginia	42	0	3	0	16	12	27	0	0
Wisconsin	14	0	4	0	23	17	41	0	0
Wyoming	5	0	5	0	25	16	48	0	0

Table A-163: 2004 Manure Distribution Among Waste Management Systems at Layer Operations (Percent)

State	Pasture	Daily Spread	Solid Storage	Dry Lot	Liquid/ Slurry	Anaerobic Lagoon	Deep Pit	Poultry with Bedding	Poultry without Bedding
Alabama	0	0	0	0	0	42	0	0	58
Alaska	0	0	0	0	0	25	0	0	75
Arizona	0	0	0	0	0	60	0	0	40
Arkansas	0	0	0	0	0	0	0	0	100
California	0	0	0	0	0	12	0	0	88
Colorado	0	0	0	0	0	60	0	0	40
Connecticut	0	0	0	0	0	5	0	0	95
Delaware	0	0	0	0	0	5	0	0	95
Florida	0	0	0	0	0	42	0	0	58
Georgia	0	0	0	0	0	42	0	0	58
Hawaii	0	0	0	0	0	25	0	0	75
Idaho	0	0	0	0	0	60	0	0	40
Illinois	0	0	0	0	0	2	0	0	98
Indiana	0	0	0	0	0	0	0	0	100
Iowa	0	0	0	0	0	0	0	0	100
Kansas	0	0	0	0	0	2	0	0	98
Kentucky	0	0	0	0	0	5	0	0	95
Louisiana	0	0	0	0	0	60	0	0	40
Maine	0	0	0	0	0	5	0	0	95
Maryland	0	0	0	0	0	5	0	0	95
Massachusetts	0	0	0	0	0	5	0	0	95
Michigan	0	0	0	0	0	2	0	0	98
Minnesota	0	0	0	0	0	0	0	0	100
Mississippi	0	0	0	0	0	60	0	0	40
Missouri	0	0	0	0	0	0	0	0	100
Montana	0	0	0	0	0	60	0	0	40
Nebraska	0	0	0	0	0	2	0	0	98
Nevada	0	0	0	0	0	0	0	0	100
New Hampshire	0	0	0	0	0	5	0	0	95
New Jersey	0	0	0	0	0	5	0	0	95
New Mexico	0	0	0	0	0	60	0	0	40
New York	0	0	0	0	0	5	0	0	95
North Carolina	0	0	0	0	0	42	0	0	58
North Dakota	0	0	0	0	0	2	0	0	98
Ohio	0	0	0	0	0	0	0	0	100
Oklahoma	0	0	0	0	0	60	0	0	40
Oregon	0	0	0	0	0	25	0	0	75
Pennsylvania	0	0	0	0	0	0	0	0	100
Rhode Island	0	0	0	0	0	5	0	0	95
South Carolina	0	0	0	0	0	60	0	0	40
South Dakota	0	0	0	0	0	2	0	0	98
Tennessee	0	0	0	0	0	5	0	0	95
Texas	0	0	0	0	0	12	0	0	88
Utah	0	0	0	0	0	60	0	0	40
Vermont	0	0	0	0	0	5	0	0	95
Virginia	0	0	0	0	0	5	0	0	95
Washington	0	0	0	0	0	12	0	0	88
West Virginia	0	0	0	0	0	5	0	0	95
Wisconsin	0	0	0	0	0	2	0	0	98
Wyoming	0	0	0	0	0	60	0	0	40

Table A- 164: 2004 Manure Distribution Among Waste Management Systems at Broiler and Turkey Operations (Percent)

State	Pasture	Daily Spread	Solid Storage	Dry Lot	Liquid/ Slurry	Anaerobic Lagoon	Deep Pit	Poultry with Bedding	Poultry without Bedding
Alabama	1	0	0	0	0	0	0	99	0
Alaska	1	0	0	0	0	0	0	99	0
Arizona	1	0	0	0	0	0	0	99	0
Arkansas	1	0	0	0	0	0	0	99	0
California	1	0	0	0	0	0	0	99	0
Colorado	1	0	0	0	0	0	0	99	0
Connecticut	1	0	0	0	0	0	0	99	0
Delaware	1	0	0	0	0	0	0	99	0
Florida	1	0	0	0	0	0	0	99	0
Georgia	1	0	0	0	0	0	0	99	0
Hawaii	1	0	0	0	0	0	0	99	0
Idaho	1	0	0	0	0	0	0	99	0
Illinois	1	0	0	0	0	0	0	99	0
Indiana	1	0	0	0	0	0	0	99	0
Iowa	1	0	0	0	0	0	0	99	0
Kansas	1	0	0	0	0	0	0	99	0
Kentucky	1	0	0	0	0	0	0	99	0
Louisiana	1	0	0	0	0	0	0	99	0
Maine	1	0	0	0	0	0	0	99	0
Maryland	1	0	0	0	0	0	0	99	0
Massachusetts	1	0	0	0	0	0	0	99	0
Michigan	1	0	0	0	0	0	0	99	0
Minnesota	1	0	0	0	0	0	0	99	0
Mississippi	1	0	0	0	0	0	0	99	0
Missouri	1	0	0	0	0	0	0	99	0
Montana	1	0	0	0	0	0	0	99	0
Nebraska	1	0	0	0	0	0	0	99	0
Nevada	1	0	0	0	0	0	0	99	0
New Hampshire	1	0	0	0	0	0	0	99	0
New Jersey	1	0	0	0	0	0	0	99	0
New Mexico	1	0	0	0	0	0	0	99	0
New York	1	0	0	0	0	0	0	99	0
North Carolina	1	0	0	0	0	0	0	99	0
North Dakota	1	0	0	0	0	0	0	99	0
Ohio	1	0	0	0	0	0	0	99	0
Oklahoma	1	0	0	0	0	0	0	99	0
Oregon	1	0	0	0	0	0	0	99	0
Pennsylvania	1	0	0	0	0	0	0	99	0
Rhode Island	1	0	0	0	0	0	0	99	0
South Carolina	1	0	0	0	0	0	0	99	0
South Dakota	1	0	0	0	0	0	0	99	0
Tennessee	1	0	0	0	0	0	0	99	0
Texas	1	0	0	0	0	0	0	99	0
Utah	1	0	0	0	0	0	0	99	0
Vermont	1	0	0	0	0	0	0	99	0
Virginia	1	0	0	0	0	0	0	99	0
Washington	1	0	0	0	0	0	0	99	0
West Virginia	1	0	0	0	0	0	0	99	0
Wisconsin	1	0	0	0	0	0	0	99	0
Wyoming	1	0	0	0	0	0	0	99	0

Table A-165: Methane Conversion Factors By State for Liquid Systems[43] for 2004 (percent)

State	Liquid/Slurry and Deep Pit	Anaerobic Lagoon
Alabama	38.5	75.8
Alaska	13.8	48.3
Arizona	53.2	79.3
Arkansas	36.1	75.9
California	37.7	76.2
Colorado	22.2	66.7
Connecticut	23.9	69.4
Delaware	29.7	73.9
Florida	52.2	77.8
Georgia	38.3	75.6
Hawaii	59.7	77.1
Idaho	23.2	68.3
Illinois	26.9	71.5
Indiana	26.0	70.6
Iowa	24.7	69.7
Kansas	31.9	74.5
Kentucky	30.4	73.2
Louisiana	46.1	77.2
Maine	19.5	63.3
Maryland	27.6	72.1
Massachusetts	23.2	68.7
Michigan	22.0	66.7
Minnesota	22.8	67.9
Mississippi	40.1	76.1
Missouri	30.4	73.8
Montana	21.1	65.9
Nebraska	26.7	71.5
Nevada	25.7	70.5
New Hampshire	21.0	65.5
New Jersey	26.4	71.9
New Mexico	32.6	74.4
New York	21.7	66.6
North Carolina	33.7	74.6
North Dakota	21.7	66.9
Ohio	24.8	69.5
Oklahoma	36.5	76.1
Oregon	22.8	67.0
Pennsylvania	25.2	70.4
Rhode Island	24.6	70.4
South Carolina	37.8	75.8
South Dakota	24.2	69.6
Tennessee	32.6	74.2
Texas	41.6	77.0
Utah	26.2	71.1
Vermont	20.2	64.5
Virginia	27.9	72.0
Washington	23.4	67.9
West Virginia	25.3	69.8
Wisconsin	22.4	67.7
Wyoming	21.3	66.0

[43] As defined by IPCC (IPCC 2000). MCFs represent weighted average of multiple animal types.

Table A-166: Weighted Methane Conversion Factors for 2004[a] (Percent)

State	Beef Feedlot-Heifer	Beef Feedlot-Steers	Dairy Cow	Dairy Heifer	Swine—Market	Swine—Breeding	Layer	Broiler	Turkey
Alabama	2.0	2.0	10.1	1.9	48.3	48.3	32.5	1.5	1.5
Alaska	1.7	1.6	16.5	1.7	1.5	1.5	13.2	1.5	1.5
Arizona	1.7	1.7	61.2	1.7	53.1	53.1	47.8	1.5	1.5
Arkansas	2.0	2.0	7.4	1.9	53.5	54.0	1.5	1.5	1.5
California	2.0	2.0	51.8	1.9	50.8	50.5	10.6	1.5	1.5
Colorado	1.6	1.6	43.2	1.6	27.6	27.6	40.0	1.5	1.5
Connecticut	1.7	1.7	10.6	1.7	13.8	13.7	4.9	1.5	1.5
Delaware	1.8	1.8	9.6	1.7	32.4	32.4	5.1	1.5	1.5
Florida	2.2	2.2	42.0	2.0	21.6	21.7	33.3	1.5	1.5
Georgia	2.0	2.0	14.4	1.9	49.0	48.6	32.0	1.5	1.5
Hawaii	2.3	2.3	54.6	2.1	39.6	39.6	20.4	1.5	1.5
Idaho	1.6	1.6	45.7	1.6	21.1	20.9	40.9	1.5	1.5
Illinois	1.7	1.6	11.8	1.6	31.5	31.5	2.9	1.5	1.5
Indiana	1.7	1.6	9.8	1.6	30.5	30.5	1.5	1.5	1.5
Iowa	1.7	1.6	9.9	1.6	40.6	40.8	1.5	1.5	1.5
Kansas	1.7	1.7	12.0	1.7	34.5	34.5	3.0	1.5	1.5
Kentucky	1.8	1.8	4.1	1.7	43.9	43.8	5.1	1.5	1.5
Louisiana	2.1	2.1	11.1	2.0	20.5	20.4	46.8	1.5	1.5
Maine	1.7	1.7	6.3	1.7	1.5	1.5	4.6	1.5	1.5
Maryland	1.8	1.7	9.0	1.7	29.1	29.1	5.1	1.5	1.5
Massachusetts	1.7	1.7	7.6	1.7	18.8	18.8	4.8	1.5	1.5
Michigan	1.6	1.6	15.4	1.6	27.4	27.4	2.8	1.5	1.5
Minnesota	1.6	1.6	9.1	1.6	29.3	29.2	1.5	1.5	1.5
Mississippi	2.0	2.0	9.3	1.9	55.3	55.4	46.1	1.5	1.5
Missouri	1.7	1.7	10.7	1.7	33.7	33.7	1.5	1.5	1.5
Montana	1.6	1.6	26.3	1.6	25.5	25.5	39.9	1.5	1.5
Nebraska	1.7	1.6	10.5	1.6	31.2	31.2	2.9	1.5	1.5
Nevada	1.6	1.6	51.3	1.6	1.5	1.5	1.5	1.5	1.5
New Hampshire	1.7	1.7	7.4	1.7	11.9	11.8	4.7	1.5	1.5
New Jersey	1.8	1.7	8.2	1.7	18.2	18.4	5.0	1.5	1.5
New Mexico	1.6	1.6	52.5	1.6	1.5	1.5	45.8	1.5	1.5
New York	1.7	1.7	9.0	1.7	20.0	20.0	4.7	1.5	1.5
North Carolina	1.8	1.8	6.6	1.8	57.7	57.6	31.8	1.5	1.5
North Dakota	1.6	1.6	6.8	1.6	25.4	25.4	2.8	1.5	1.5
Ohio	1.7	1.6	9.9	1.6	28.6	28.6	1.5	1.5	1.5
Oklahoma	1.6	1.6	35.0	1.6	55.9	56.4	46.0	1.5	1.5
Oregon	1.8	1.8	27.1	1.7	11.4	11.4	17.3	1.5	1.5
Pennsylvania	1.8	1.7	5.9	1.7	30.6	30.5	1.5	1.5	1.5
Rhode Island	1.8	1.7	3.9	1.7	18.7	18.7	4.9	1.5	1.5
South Carolina	2.0	2.0	10.4	1.9	50.6	50.4	45.9	1.5	1.5
South Dakota	1.7	1.6	9.3	1.6	29.2	29.2	2.8	1.5	1.5
Tennessee	1.8	1.8	5.5	1.8	41.6	41.5	5.1	1.5	1.5
Texas	1.7	1.6	50.4	1.6	52.2	52.2	10.5	1.5	1.5
Utah	1.6	1.6	38.2	1.6	30.5	31.3	43.6	1.5	1.5
Vermont	1.7	1.7	8.3	1.7	1.5	1.5	4.6	1.5	1.5
Virginia	1.8	1.8	5.3	1.7	48.7	48.8	5.0	1.5	1.5
Washington	1.8	1.8	33.7	1.8	21.8	21.5	9.1	1.5	1.5
West Virginia	1.8	1.7	6.8	1.7	20.1	20.0	4.9	1.5	1.5
Wisconsin	1.6	1.6	9.9	1.6	26.5	26.5	2.8	1.5	1.5
Wyoming	1.6	1.6	23.7	1.6	26.9	26.9	39.6	1.5	1.5

[a] MCFs are weighted by the distribution of waste management systems for each animal type.

Table A-167: CH_4 Emissions from Livestock Manure Management (Gg)

Animal Type	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
Dairy Cattle	544	584	573	565	610	638	610	638	660	672	691	713	720	746	749
Dairy Cows	535	575	564	556	601	629	602	630	652	663	683	704	711	737	741
Dairy Heifer	9	9	9	9	9	9	9	9	8	9	9	9	9	9	8
Swine	622	674	637	678	739	761	727	780	874	837	812	826	843	811	820
Market Swine	483	524	500	533	584	607	581	625	715	683	664	677	695	670	680
Market <60 lbs.	102	110	103	108	118	121	116	125	139	131	128	131	133	129	130
Market 60-119 lbs.	101	111	104	110	119	123	117	127	143	136	132	134	138	133	135
Market 120-179 lbs.	136	147	140	151	164	170	164	175	200	191	185	187	193	187	189
Market >180 lbs.	144	156	152	164	181	193	184	198	233	225	219	225	231	222	226
Breeding Swine	139	151	138	145	155	154	147	155	160	155	148	150	149	142	141
Beef Cattle	153	155	153	155	156	157	155	152	149	148	149	148	147	146	145
Feedlot Steers	23	24	21	21	19	18	16	16	16	16	18	19	18	17	18
Feedlot Heifers	12	13	11	11	10	10	9	10	10	10	11	11	11	10	10
NOF Bulls	6	6	6	6	6	7	7	6	6	6	6	6	6	6	6
NOF Calves	11	11	11	11	11	12	12	11	11	11	11	11	11	10	10
NOF Heifers	16	17	18	18	19	20	20	19	18	18	17	17	17	17	17
NOF Steers	11	11	12	11	12	12	13	12	12	12	11	10	11	11	11
NOF Cows	73	73	74	76	78	79	79	77	76	75	75	74	74	74	73
Sheep	9	9	8	8	8	7	7	6	6	6	5	5	5	5	5
Goats	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Poultry	128	129	125	129	129	127	125	127	129	125	125	129	127	127	127
Hens >1 yr.	33	31	33	34	34	33	32	31	33	31	31	31	30	31	31
Total Pullets	63	65	59	60	60	58	56	58	59	57	57	60	59	58	58
Chickens	4	4	4	4	4	4	3	3	4	3	3	3	4	4	3
Broilers	19	20	21	21	22	23	24	25	25	26	27	27	28	27	28
Turkeys	10	10	10	10	9	9	9	9	8	8	8	7	7	7	7
Horses	27	27	28	28	28	28	28	28	28	28	28	29	29	29	29

Table A-168: N_2O Emissions from Livestock Manure Management (Gg)

Animal Type	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
Dairy Cattle	13.9	13.6	13.5	13.4	13.3	13.2	13.0	12.9	12.7	12.7	12.7	12.6	12.6	12.5	12.3
Dairy Cows	9.4	9.3	9.0	8.9	8.7	8.7	8.6	8.4	8.2	8.2	8.2	8.0	7.9	7.9	7.7
Dairy Heifer	4.4	4.4	4.4	4.5	4.6	4.6	4.5	4.5	4.5	4.6	4.6	4.6	4.6	4.6	4.6
Swine	1.2	1.2	1.3	1.3	1.3	1.3	1.3	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Market Swine	0.9	0.9	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
Market <60 lbs.	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Market 60-119 lbs.	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Market 120-179 lbs.	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
Market >180 lbs.	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Breeding Swine	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
Beef Cattle	15.8	17.3	16.2	17.3	17.0	17.1	16.5	17.4	17.8	17.9	19.1	19.8	19.2	18.1	18.5
Feedlot Steers	10.6	11.5	11.0	11.5	11.3	11.2	10.7	11.1	11.3	11.3	12.1	12.5	12.2	11.5	11.8
Feedlot Heifers	5.2	5.8	5.2	5.7	5.7	5.9	5.8	6.4	6.4	6.6	7.1	7.3	7.0	6.6	6.7
Sheep	0.4	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.2	0.2	0.2
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
Poultry	20.5	20.9	21.3	21.7	22.1	22.6	23.2	23.3	23.2	23.2	23.4	23.5	23.9	23.6	23.9
Hens >1 yr.	0.7	0.7	0.7	0.7	0.7	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.7	0.7
Pullets	1.0	1.0	1.0	0.9	0.9	0.9	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
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
Broilers	12.0	12.5	13.1	13.7	14.3	15.0	15.5	15.9	16.2	16.7	16.9	17.2	17.6	17.4	17.9
Turkeys	6.7	6.6	6.5	6.3	6.1	6.1	6.2	6.0	5.6	5.1	5.0	5.0	4.9	4.8	4.5
Horses	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7

+ Emission estimate is less than 0.1 Gg.

3.11. Methodology for Estimating N_2O Emissions from Agricultural Soil Management

Nitrous oxide (N_2O) emissions from agricultural soils attributed to anthropogenic activity result from management decisions that add or release mineral nitrogen (N) in the soil profile, and thereby increase emissions above the background levels of natural N_2O emissions. Nitrous oxide emissions for U.S. agricultural soils were calculated for four categories: (1) direct emissions from cropped mineral soils, (2) direct emissions from drainage and cultivation of organic cropland soils (i.e., histosols), (3) direct emissions from grasslands, and (4) indirect emissions from all managed land-use types.[44]

A combination of 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 applied to estimate N_2O emissions resulting from mineral soil croplands producing major crop types, while the IPCC Tier 1 methodology was applied to non-major crop types on mineral soils. The IPCC Tier 1 method was used to estimate N_2O emissions due to drainage and cultivation of organic cropland soils. Direct N_2O emissions from grasslands were obtained by using a combination of DAYCENT and IPCC Tier 1 methods. A combination of DAYCENT and IPCC Tier 1 methods was also used to estimate indirect emissions. The amount of N volatilized and leached or transported off-site in surface runoff waters was computed by DAYCENT for the direct emission analyses using DAYCENT, while IPCC default factors were used to estimate N transport for the analyses using the IPCC Tier 1 methodology. The indirect N_2O emissions resulting from off-site transport of N were then computed using the IPCC Tier 1 method.

DAYCENT (Del Grosso et al. 2001, Parton et al. 1998) was used to simulate fluxes of N_2O between mineral agricultural soils and the atmosphere for croplands producing corn, soybean, wheat, alfalfa hay, other hay, cotton, and sorghum, and for grasslands. DAYCENT simulated 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 qualities that influence the N cycle; and management practices at a daily time step. For example, plant growth is controlled by nutrient availability and 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 soil organic matter (SOM) decomposition rates and external nutrient additions, 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 the 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, nitrification and denitrification processes, and methane (CH_4) oxidation. 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). The simulations reported here were performed for each individual county in the conterminous United States and summed to yield national totals.

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 N inputs from crop residue. Consequently, emission estimates could not be partitioned into the IPCC recommended categories (i.e., synthetic fertilizer, organic fertilizer, sewage sludge, biological N-fixation, PRP manure, and crop residues). Nitrogen losses from major crops due to volatilization, leaching, and surface runoff in overland water flow are calculated within DAYCENT based on the soil and daily weather conditions. Also, other parameters needed to address the impact of anthropogenic activity are simulated dynamically, such as N inputs due to crop residue applications and management–induced decomposition of soil organic matter, which also increase mineral N availability for nitrification and denitrification and subsequent N_2O emissions.

There are five steps in estimating direct N_2O emissions from mineral cropland soils, drained and cultivated organic cropland soils, and grassland, in addition to indirect N_2O emissions from volatilization, leaching, and runoff. 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 from croplands,

[44] The indirect N_2O emissions reported here include those from non-agricultural lands as well as agricultural lands, i.e., from forests and settlements as well as croplands and grasslands.

direct N_2O emissions from grasslands, and indirect N_2O emissions from all managed lands are estimated using DAYCENT and/or the IPCC Tier 1 method. In the fifth step, total emissions are computed by summing each component. The remainder of this annex describes the methods underlying each step.

Step 1: Derive Activity Data

The activity data requirements vary for major crops, non-major crops, grasslands, 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 differently according to the methodology described here.

Major Crop Types: Tier 3 DAYCENT Simulations

The activity data requirements for estimating N_2O emissions from major crop types (corn, soybean, wheat, alfalfa hay, other hay, sorghum, and cotton) include the following: a) crop specific mineral N fertilizer rates and timing, b) manure amendment N rates and timing, c) land management information, d) the amount of N in other commercial organic fertilizers amendments to soils, e) daily weather data for every county, f) county-level soil texture data, and g) 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 IPCC approach, N inputs from biological fixation and crop residues are not considered activity data in the DAYCENT analysis because N availability from these sources are internally generated by the model. That is, while the model accounts for the contribution of N from fixation and crop residues to the soil profile and subsequent N_2O emissions, these sources of mineral soil N are not activity data in the sense that they are not model inputs.

Synthetic Nitrogen Fertilizer Application: Fertilizer application rates and timing of applications within each of the 63 agricultural regions were determined from regional, state, or sub-state estimates for different crops (Alexander and Smith 1990, Anonymous 1924, Battaglin and Goolsby 1994, Engle and Makela 1947; ERS 1994, 2002, 2003, Fraps and Asbury 1931, Ibach and Adams 1967, Ibach et al.1964, NFA 1946, NRIAI 2003, Ross and Mehring 1938, Skinner 1931, Smalley et al. 1939, Taylor 1994, USDA 1966, 1957, 1954, 1946). Prior to 1990, estimates for crop specific regional fertilizer rates 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, and therefore mean values from the southeastern United States were used to simulate fertilization to corn fields in this state).

To constrain annual fertilizer rates for different crops between 1990 through 2004, the best estimates for crop specific fertilizer rates during this time period were combined with yearly national fertilizer consumption data (Table A-1), under the assumption that fertilizer rates would not exceed the amount that was produced. Furthermore, the cropland area changes from year-to-year and consequently the rates were adjusted to allow for all N fertilizer sold in a particular year to be applied across the entire land base. The best estimates of fertilization rates for different crops during 1990 through 2004 were assumed to represent the proportions observed in 1997. The reference year 1997 was chosen because that was the only year in which both crop specific fertilizer and manure amendment rates were available. Fertilizer application rates for years other than 1997 were adjusted first by the specific amount of N fertilizer sold in the year of interest based on the ratio of the amount of fertilizer produced in that year relative to the amount produced in 1997. Multiplying this ratio by the 1997 application rates would lead to higher applications if the amount of fertilizer sold in the year of interest exceeded the sales in 1997, and conversely the application rates would decline if fertilizer sales were smaller than 1997. The second adjustment was to account for changes in the land area base over which fertilizers were applied by taking the ratio of the 1997 land area receiving N fertilizer applications to the amount of land area receiving fertilizer application in the year of interest. These lands areas were based on county-level NASS reports (USDA 2005h). Multiplying this ratio by the 1997 application rate led to higher rate of application if the land area receiving fertilizer applications was smaller than the

area in 1997, while the application rates were reduced if the land area receiving fertilizer applications was greater than the area in 1997. Therefore, absolute applications of fertilizers varied from year to year.

Annual commercial fertilizer consumption data for the United States were taken from publications of synthetic fertilizer statistics (TVA 1991, 1992a, 1993, 1994; AAPFCO 1995, 1996, 1997, 1998, 1999, 2000a, 2000b, 2002, 2003). Synthetic consumption data were converted into calendar year totals from the recorded "fertilizer year" totals (i.e., July to June). 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). Estimates were not available for the July to December period in 2002, and so a "least squares line" statistical extrapolation method was used to derive an approximate value from the previous twelve years of data. Annual consumption of commercial fertilizers in units of N is presented on a calendar year basis in Table A-169. Synthetic fertilizer rates were reduced by 50 percent for cropped land that received organic N amendments.

Table A-169: Commercial Fertilizer Consumption for all Agricultural Lands (Gg N)

Fertilizer Type	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
Synthetic mineral N	9,085	9,239	9,302	9,628	10,023	9,686	9,999	10,002	10,011	10,030	9,759	9,465	9,715	10,022	10,453
Other Commercial Organic Fertililzer N*	5	9	6	5	8	11	13	15	13	11	10	8	8	9	11
Total	9,090	9,248	9,308	9,633	10,031	9,697	10,012	10,017	10,024	10,041	9,769	9,473	9,723	10,031	10,464

* Includes dried blood, dried manure, tankage, compost, other. Excludes manure and sewage sludge used as commercial fertilizer.

Managed Livestock Manure[45] *N Amendment Rates and Timing:* Manure N amendments within the 63 agricultural regions were assumed to occur on major crop types and grasslands simulated by DAYCENT. N_2O emissions from these amendments were simulated by DAYCENT, assuming that the manure was applied during spring at the same time as mineral N fertilizer. Managed manure applied to soils was based on data from Edmonds et al. (2003) for the year 1997. These data were at the county level and included crop specific manure application rates. For other reporting years, N application rates were adjusted to account for annual variation in managed manure production after adjusting for manure used as feed. Crop specific application rates of manure N for other years were obtained by multiplying the 1997 crop-specific rates by the ratio of managed manure N produced in that year to the managed manure N produced in 1997; the amount of land receiving manure (approximately 5 percent of total cropped land) was assumed to be constant during 1990 through 2004. Prior to 1990, manure application rates and timing were based on various sources (Brooks 1901, Anonymous 1924, Fraps and Asbury 1931, Ross and Mehring 1938, Saltzer and Schollenberger 1938, Alexander and Smith 1990). As with mineral N fertilization, data for manure were incomplete so regional averages were used to fill spatial gaps in data and interpolation/extrapolation was used to fill temporal gaps.

To estimate the amount of managed livestock manure nitrogen produced, it was assumed that all of the managed livestock manure is stored, transported or applied to soils except the portion of poultry manure that is used as a feed supplement for ruminants. 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 USDA National Agricultural Statistics Service (USDA 1994b-c, 1995a-b, 1998a, 1998c, 1999a-c, 2000a, 2004a-e, 2005a-f). Horse population data were obtained from the FAOSTAT database (FAO 2005). Goat population data for 1992, 1997, and 2002 were obtained from the Census of Agriculture (USDA 2005g); these data were interpolated and extrapolated to derive estimates for the other years. Information regarding 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 and 1997 *Census of Agriculture* (USDA 2005g).

[45] 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 pasture, range, and paddock.

Information regarding the percentage of manure handled using various manure management systems for dairy cattle, beef cattle, and sheep was obtained from communications with personnel from state Natural Resource Conservation Service offices, state universities, National Agricultural Statistics Service, and other experts (Poe et al. 1999, Anderson 2000, Deal 2000, Johnson 2000, Miller 2000, Milton 2000, Stettler 2000, Sweeten 2000, Wright 2000). Information regarding the percentage of manure handled using various manure management systems for swine, poultry, goats, and horses was obtained from Safley et al. (1992). A more detailed discussion of manure management system usage is provided in Annex 3.10.

Once the animal populations for each livestock type and management system were estimated, these populations were multiplied by an average animal mass constant (USDA 1996, 1998d; ASAE 1999; Safley 2000) to derive total animal mass for each animal type in each management system. Total Kjeldahl nitrogen[46] excreted per year for each livestock type and management system was then calculated using daily rates of nitrogen excretion per unit of animal mass (USDA 1996, ASAE 1999). The total poultry manure nitrogen in managed systems was reduced by the amount used as a feed supplement (i.e., 4.2 percent of the managed poultry manure; Carpenter 1992). The annual amounts of Kjeldahl nitrogen were then summed over all livestock types and management systems to derive estimates of the annual managed manure nitrogen applied to soils (Table A-170).

Even after accounting for the managed manure N used as feed, the amount of managed manure N available for application to soils was still more than the amount of managed manure N that was actually applied, according to data provided by Edmonds et al. (2003). The remaining manure N that was not applied to soils was assumed to be volatilized during storage, treatment, and transport, and thus contribute to indirect emissions. The fate of manure N is summarized in Table A-170.

Table A-170: Fate of Livestock Manure Nitrogen (Gg N)

Activity	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
Managed Manure N Applied to Croplands	965	990	987	1,007	1,014	1,022	1,015	1,037	1,050	1,049	1,063	1,072	1,073	1,058	1,065
Managed Manure N Volatilized	1,488	1,539	1,537	1,582	1,606	1,628	1,624	1,672	1,697	1,697	1,723	1,743	1,747	1,721	1,738
Managed Manure N Used in Cattle Feed	32	33	33	34	35	36	37	37	37	38	38	38	39	38	39
Pasture, Range, & Paddock Manure N	3,879	3,895	3,977	4,017	4,116	4,167	4,159	4,030	3,947	3,900	3,837	3,805	3,794	3,787	3,747
Total	6,364	6,457	6,535	6,640	6,770	6,853	6,835	6,776	6,731	6,683	6,661	6,657	6,652	6,604	6,588

Other Commercial Organic Fertilizers:[47] Estimates of total national annual N additions from land application of other organic fertilizers were derived from organic fertilizer statistics (TVA 1991, 1992a, 1993, 1994; AAPFCO 1995, 1996, 1997, 1998, 1999, 2000a, 2000b, 2002, 2003). The organic fertilizer data, which are recorded in mass units of fertilizer, had to be converted to mass units of N by multiplying 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 2004). Annual consumption of these organic fertilizers in units of N is presented in Table A-169.

Agricultural region specific application rates for other commercial organic fertilizers were assumed to be equivalent to manure application rates in 1997 (i.e., amounts of N added per unit area; see manure N section above). Currently no data sets are available with crop specific application rates of other commercial organic fertilizers, and therefore the manure N applications rates were used to approximate these values. Amounts of carbon (C) added for other commercial organic fertilizers were calculated according to the ratio of C to N in the base material. It was necessary to calculate the amount of C in organic matter additions because C and N inputs influence N cycling and therefore N_2O emissions. Crop-specific areas receiving other commercial organic fertilizers in 1997 were estimated by dividing the total amount of applied organic fertilizer N by the crop specific rates for manure N addition. Cropland area receiving other commercial organic fertilizer amendments (less than 1 percent of total cropped land)

[46] Total Kjeldahl nitrogen is a measure of organically bound nitrogen and ammonia nitrogen in both the solid and liquid wastes.

[47] Other commercial organic fertilizers include dried blood, dried manure, tankage, compost, other, but excludes manure and sewage sludge which are used as commercial fertilizers.

was assumed to be constant through time. Crop-specific rates for years other than 1997 were obtained by multiplying the 1997 rates by the ratio of other commercial organic fertilizer produced in that year to the total amounts produced in 1997. The year 1997 was chosen as the reference year because that was the only year for which crop specific manure N amendment rates were available (Kellogg et al. 2000).

Crop Areas by County: County level total crop area data were downloaded from the USDA NASS web site for the years 1990 through 2004 (USDA 2005h), and these data formed the basis to scale emissions from individual crop types across the entire county.

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 2000d, USDA 2000b, CTIC 1998, Piper et al. 1924, Hardies and Hume 1927, Holmes 1902, 1929, Spillman 1902, 1905, 1907, 1908, Chilcott 1910, Smith 1911, Kezer ca 1917, Hargreaves 1993, ERS 2002, Warren 1911, Larson et al. 1922, Russell et al. 1922, Elliot and Tapp 1928, Elliot 1933, Ellsworth 1929, Garey 1929, Holmes 1929, Hodges et al. 1930, Bonnen and Elliot 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 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 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 occur in agricultural lands. Weather station data are for a point in space, and the DAYMET modeling process uses this information and 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 was closest to the area-weighted geographical center of cropland, and then provided as an input to drive DAYCENT simulations.

Soil Properties by County: Soil texture data required by DAYCENT were obtained from STATSGO (Soil Survey Staff, Natural Resources Conservation Service, 2005) and were based on observations. Observed data for soil hydraulic properties needed for model inputs were not available so they were calculated from STATSGO (Soil Survey Staff, Natural Resources Conservation Service, 2005) texture class and Saxton et al.'s (1986) hydraulic properties calculator. The dominant soil within the STATSGO map unit that contains the geographic center of the largest cluster of agricultural land in each county was used to represent soil texture and depth in the simulations.

Non-Major Crop Types: Tier 1 IPCC Method

The activity data required for calculating emissions from non-major crop types include: a) the amount of mineral N in synthetic fertilizers that are applied annually, b) the amount of N in the aboveground biomass of non-major N-fixing crops, and c) the annual amount of N in non-major crop residues retained on soils. No organic amendments (i.e., manure N, other organic commercial fertilizers) were considered here because they were assumed to be applied to the major crop types simulated by DAYCENT.

Application of synthetic commercial fertilizers: A process of elimination was used to estimate synthetic fertilizer N applied to non-major crop types. Estimates for synthetic N fertilizer applied to settlements and forest lands were added to the amount of synthetic N fertilizer applied to major crops. This sum was subtracted from total synthetic N fertilizer consumed in the United States and the difference was assumed to be applied to non-major crops. Further discussion is provided in the methodological section for major crops on the sources of fertilizer statistics.

Production of N-fixing crops: Annual production 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, 2000c, 2001, 2002, 2003). The production statistics for beans and pulses were obtained in tons of product, which

was converted to tons of aboveground biomass N. This was done by multiplying the production statistics by one plus the aboveground residue to crop product mass ratios, dry matter fractions, and N contents. The residue to crop product ratios and dry matter contents for beans and pulses not simulated by DAYCENT were estimated from the average of soybean and peanut values. The residue to crop product mass ratios for soybeans and peanuts, and the dry matter content for soybeans, were obtained from Strehler and Stützle (1987). The dry matter content for peanuts was obtained through personal communications with Ketzis (1999). The IPCC default N content of 3 percent (IPCC/UNEP/OECD/IEA 1997) was used for all beans and pulses.[48]

The final estimates of annual aboveground biomass production, in units of N, are presented in Table A-171. The residue to crop product mass ratios and dry matter fractions used in these calculations are presented in Table A-172.

Table A-171: Aboveground Biomass Nitrogen in Non-Major Nitrogen-Fixing Crops (Gg N)

Crop Type	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
Peanuts	84	115	100	79	99	81	86	83	93	90	76	100	78	97	100
Dry Edible Beans	98	102	68	66	87	93	84	89	92	100	80	59	92	68	54
Dry Edible Peas	7	11	8	10	7	14	8	17	18	14	10	11	14	16	34
Austrian Winter Peas	+	+	+	+	+	+	+	+	+	+	+	+	1	1	1
Lentils	3	5	5	6	6	7	4	7	6	7	9	9	8	7	13
Wrinkled Seed Peas	3	3	2	3	2	3	2	2	2	2	2	2	2	2	3
Total	195	237	183	164	202	198	184	199	211	213	178	182	194	191	204

+ Less than 0.5 Gg N.
Note: Totals may not sum due to independent rounding.

Table A-172: Key Assumptions for Production of N-fixing Crops and Retention of Crop Residue

Crop	Residue/Crop Ratio	Residue Dry Matter Fraction	Residue Nitrogen Fraction
Peanuts	1.00	0.86	0.0106
Dry Edible Beans	1.55	0.87	0.0168
Dry Edible Peas	1.55	0.87	0.0168
Austrian Winter Peas	1.55	0.87	0.0168
Lentils	1.55	0.87	0.0168
Wrinkled Seed Peas	1.55	0.87	0.0168
Barley	1.20	0.93	0.0077
Oats	1.30	0.92	0.0070
Rye	1.60	0.90	0.0048
Millet	1.40	0.89	0.0070
Rice	1.40	0.91	0.0072

Note: For the derivation of activity data for N-fixing crop production, the IPCC default N content of aboveground biomass (3 percent) was used.

Retention of Crop Residue: For non-major crops, it was assumed that 90 percent of residues from oats, rye, millet, peanuts, and other beans and pulses are left on the field after harvest (e.g., rolled into the soil, chopped and disked into the soil, or otherwise left behind) (Karkosh 2000).[49] It was also assumed that 100 percent of unburned rice residue is left on the field.[50]

The derivation of crop residue N activity data was very similar to the derivation of N-fixing crop activity data. Crop production statistics were multiplied by aboveground residue to crop product mass ratios, residue dry matter fractions, residue N contents, and the fraction of residues left on soils. Annual production statistics for all crops except rice in Florida and Oklahoma were taken from U.S. Department of Agriculture reports (USDA 1994a,

[48] This N content may be an overestimate for the residue portion of the aboveground biomass of the beans and pulses. Also, the dry matter fractions used for beans and pulses were taken from literature on crop residues, and so may be underestimates for the product portion of the aboveground biomass.

[49] Although the mode of residue application would likely affect the magnitude of N_2O emissions, an emission estimation methodology that accounts for this has not been developed.

[50] Some of the rice residue may be used for other purposes, such as for biofuel or livestock bedding material. Research to obtain more detailed information regarding final disposition of rice residue, as well as the residue of other crops, will be undertaken for future inventories.

1998b, 2001, 2002, 2003); production statistics for rice in Florida and Oklahoma were estimated by applying average primary and ratoon rice crop yields for Florida (Schueneman and Deren 2002) to annual Florida acreages and for Arkansas to Oklahoma rice areas (Schueneman 1999, 2001, Deren 2002, Kirstein 2003, Cantens 2004, Lee 2003, 2004). Residue to crop product ratios for all crops were provided directly or derived from Strehler and Stützle (1987). Dry matter content of rice residue was obtained from Turn et al. (1997); values for soybean and millet residue were obtained from Strehler and Stützle (1987); and values for peanut, oat, and rye were provided by Ketzis (1999). Dry matter content of residues for other beans and pulses were estimated by averaging soybean and peanut values. The residue N content of rice were from Turn et al. (1997); soybean residue N contents were from Barnard and Kristoferson (1985); peanut, oat, and rye residue from Ketzis (1999); and the N content of millet residue was from Strehler and Stützle (1987). Nitrogen contents of all other beans and pulses were estimated by averaging the values for soybeans and peanuts. Estimates of the amounts of rice residue burned annually were based on expert knowledge of agricultural extension agents in each of the rice-growing states (see Section 6.5 of the main document, Field Burning of Agricultural Residues, for more detail). The residue to crop product mass ratios, residue dry matter fractions, and residue N contents used in the calculations for non-major crops are presented in Table A-172. The final estimates of residue retained on soil, in units of N, are presented in Table A-173.

Table A-173: Nitrogen in Crop Residues Retained on Soils Producing Non-Major Crops (Gg N)

Product Type	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
Peanuts for Nuts	13	18	16	13	16	13	14	13	15	14	12	16	12	15	16
Dry Edible Beans	30	31	21	20	27	28	26	27	28	31	25	18	28	21	16
Dry Edible Peas	2	3	2	3	2	4	2	5	5	4	3	3	4	5	11
Austrian Winter Peas	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+
Lentils	1	2	1	2	2	2	1	2	2	2	3	3	2	2	4
Wrinkled Seed Peas	1	1	+	1	1	1	1	1	1	1	1	1	1	1	1
Barley	71	78	77	67	63	61	66	61	59	46	54	42	38	47	47
Oats	39	27	32	23	25	18	17	18	18	16	16	13	13	16	13
Rye	2	2	2	2	2	2	1	1	2	2	1	1	1	1	1
Millet	3	3	3	3	3	3	3	3	3	3	1	3	1	2	3
Rice	51	52	60	52	65	59	57	65	66	74	67	77	71	67	84
Total	213	218	215	185	205	190	188	197	200	192	183	177	172	178	195

+ Less than 0.5 Gg N.
Note: Totals may not sum due to independent rounding.

Step 1b: Activity Data for Direct Emissions from Drainage and Cultivation of Organic Cropland Soils: IPCC Tier 1 Method

Estimates of the areas of drained and cultivated organic cropland soils in 1982, 1992, and 1997 were obtained from the USDA's *1997 National Resources Inventory* (USDA 2000b, as extracted by Eve 2001, and revised by Ogle 2002).[51] These areas were grouped by broad climatic region[52] 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. These final areas were then linearly interpolated and extrapolated to obtain estimates not reported in the NRI between 1990 through 2004 (Table A-174).

Table A-174: Cultivated Organic Soil Area (Thousand Hectares)

Year	Temperate Area	Sub-Tropical Area
1990	432	192
1991	431	193
1992	429	194
1993	431	194
1994	433	195
1995	435	195
1996	437	196
1997	439	196

[51] 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.

[52] 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.

1998	441	197
1999	443	197
2000	445	197
2001	447	198
2002	449	198
2003	451	199
2004	453	199

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

N_2O emissions from grasslands were computed using DAYCENT and the Tier 1 IPCC methodology. DAYCENT simulations addressed the influence of legume seeding, managed manure N amendments (i.e., not PRP manure), sewage sludge amendments, and synthetic fertilizer applications, in addition to the manure N that was excreted by livestock and deposited directly onto soils (i.e., pasture, range, and paddock [PRP] manure). PRP manure N additions that were not included in the DAYCENT simulations were addressed using the Tier 1 IPCC method. Similarly, N fixed by forage legumes not accounted for by DAYCENT simulations were addressed using the Tier 1 IPCC method.

Tier 3 DAYCENT Simulations

Activity data for the DAYCENT simulations of grasslands (i.e., climate and soils) 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) from the National Resources Inventory (USDA 2000b).

Sewage sludge is generated from the treatment of raw sewage in public or private wastewater treatment works, and either is used for beneficial purposes (e.g., as a soil amendment in agriculture or landscaping) or is disposed of (e.g., spread in landfills). Estimates of the amounts of sewage sludge N applied to agricultural lands were derived from national data on sewage sludge generation, disposition, and nitrogen content. Total sewage sludge generation data for 1988, 1996, and 1998, and a projection for 2000, in dry mass units, were obtained from EPA reports (EPA 1993, 1999), and linearly interpolated to estimate values for the intervening years. Sewage sludge generation data are not available for 2001 through 2004 (Bastian 2002, 2003, 2005), so the 2000 projection was linearly extrapolated using the growth in national wastewater flow between 1996 and 2000 (EPA 1997, 2003). The total sludge generation estimates were then converted to units of nitrogen by applying an average N content of 3.3 percent (Metcalf and Eddy 1991), and disaggregated into use and disposal practices using historical data and projections in EPA (1993) and EPA (1999). The use and disposal practices were agricultural land application, other land application, surface disposal, 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). Both of these data sets are presented in Table A-175.

Table A-175: 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
Applied to Agricultural Soils	51	58	65	72	78	85	87	89	90	93	97	101	104	108	112
Other Land Application	27	30	34	37	41	44	45	46	47	49	51	52	54	56	58
Surface Disposal	16	15	14	12	10	9	9	9	9	8	8	8	8	8	8
Total	94	103	112	121	130	138	141	144	146	150	155	161	167	173	179

Agricultural region specific application rates were assumed to be equivalent to manure application rates in 1997 (i.e., amounts of N added per unit area; see manure N section in section on major croplands). Manure N application rates were used to approximate sewage sludge application rates. Amounts of carbon (C) added were calculated according to the ratio of C to N in the base material. It was necessary to calculate the amount of C in organic matter additions because C and N inputs influence N cycling and therefore N_2O emissions. Grassland areas receiving sewage sludge in 1997 were estimated by dividing the total amount of sewage sludge N by the assimilative capacity according to Kellogg et al. (2000). Amended grassland area (less than 1 percent of total cropped land) was assumed to be constant through time. Application rates for years other than 1997 were obtained by multiplying the 1997 rates by the ratio of sewage sludge produced in that year to the total amounts produced in 1997. The year 1997

was chosen as the reference year because that was the only year for which manure N amendment rates were available (Edmonds et al. 2003).

Tier 1 IPCC Method: Additional Direct Soil N_2O Emissions

The IPCC Tier 1 method was used to estimate emissions from PRP manure and forage legumes that were not simulated with DAYCENT.

PRP Manure: Manure N additions from grazing animals were modeled within DAYCENT, but the simulations only captured approximately 75 percent of total manure production in this category. It is reasonable that DAYCENT did not account for all PRP manure because the NRI data does not include all grassland areas, such as federal grasslands. Soil N_2O emissions from remaining manure N after subtracting the amount simulated with DAYCENT was 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 as follows:

Dairy Cattle: 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 and 1997 Census of Agriculture* (USDA 2005g) 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 pasture, range, and paddock 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 2004, which were obtained from the USDA National Agricultural Statistics Service (USDA 1995a, 1999a, 2004a, 2005a-b).

Beef Cattle: To determine the population of beef cattle that are on pasture, range, and paddock, 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 pasture, range, and paddock (i.e., total population minus population on feedlots equals population of pasture, range, and paddock) (Milton 2000). Information regarding the percentage of heifers and steers on feedlots was obtained from USDA personnel (Milton 2000) and used in conjunction with the USDA National Agricultural Statistics Service population data (USDA 2005a-b, 2004a, 1999a, 1995a) to determine the population of steers and heifers on pasture, range, and paddock.

Swine: Based on the assumption that smaller facilities are less likely to utilize manure management systems, farm-size distribution data reported in the *1992 and 1997 Census of Agriculture* (USDA 2005g) were used to determine the percentage of all swine whose manure is not managed (i.e., the percentage on pasture, range, and paddock). These percentages were applied to the average of the quarterly USDA National Agricultural Statistics Service population data for swine (USDA 1994b, 1998c, 2004b, 2005c) to determine the population of swine on pasture, range, and paddock.

Sheep: Total **s**heep and lamb population data were obtained from the USDA National Agricultural Statistics Service (USDA 1994c, 1999c, 2004e, 2005f). To determine the number of sheep and lamb in managed systems, information on the number of sheep and lamb on feed were obtained from USDA 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 2004 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" 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 pasture, range, and paddock data were obtained from USDA 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 pasture, range, and paddock (Anderson 2000).

Goats: It was assumed that 92 percent of goat manure was deposited on pasture, range, and paddock (Safley et al. 1992). Annual goat population data by state were available for only 1992 and 1997 (USDA 1999c-d). The data for 1992 were used for 1990 through 1992 and the data for 1997 were used for 1997 through 2004. Data for 1993 through 1996 were linearly interpolated using the 1992 and 1997 data.

Poultry: It was assumed that one percent of poultry manure was deposited on pasture, range, and paddock (Safley et al. 1992). Poultry population data were obtained from USDA National Agricultural Statistics Service (USDA 1995b, 1998a, 1999b, 2000a, 2004c-d, 2005d-e). The annual population data for boilers and turkeys were adjusted for turnover (i.e., slaughter) rate (Lange 2000).

Horses: It was assumed that 92 percent of horse manure was deposited on pasture, range, and paddock (Safley et al. 1992). Horse population data were obtained from the FAOSTAT database (FAO 2005).

For each animal type, the population of animals within pasture, range, and paddock systems was multiplied by an average animal mass constant (USDA 1996, 1998d; ASAE 1999; Safley 2000) to derive total animal mass for each animal type. Total Kjeldahl nitrogen excreted per year was then calculated for each animal type using daily rates of nitrogen excretion per unit of animal mass (USDA 1996, ASAE 1999). Annual nitrogen excretion was then summed over all animal types to yield total nitrogen in pasture, range, and paddock manure (Table A-170).

Forage Legumes: N inputs from forage legumes were not fully addressed in the Tier 3 method. Consequently, the amount of N input from N-fixation in pastures simulated by DAYCENT (residue N inputs are a DAYCENT output) was subtracted from total N inputs from forage legumes. Total N input from forage legumes was based on legume forage production data (USDA 1994a, 1998b), and the difference was assumed to represent N inputs from forage legumes not simulated by DAYCENT.

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

The amount of N subject to indirect emissions was estimated in the DAYCENT simulations for major crop types on mineral cropland soils and grasslands. The IPCC Tier 1 method was used to estimate the amount of N subject to indirect emissions for settlements and forest land, and minor crop types and grasslands not included in the DAYCENT simulations. 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) of the main Inventory document. Volatilization of N from manure during storage, treatment, and transport was also considered (Table A-170).

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 fertilizers. 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 and in 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 commercial fertilizer, livestock manure, and sewage sludge N are the same as those used in the calculation of direct emissions from agricultural mineral soils, and may be found in Table A-169, Table A-170, and Table A-175.

Losses of N from soil profiles were computed differently for the DAYCENT simulations than the IPCC Tier 1 methodology. Using the DAYCENT model, volatilization as well as leaching and surface run-off of N from soils was computed internally in the model 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 (plowing, irrigation, harvest, etc.), 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 IPCC methodology. Similarly, the N available for producing indirect emissions resulting from grassland management as well as deposited PRP manure was also calculated 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.

The IPCC Tier 1 method was used to estimate N losses from mineral soils due to volatilization and leaching/runoff for non-major crop types, PRP manure not accounted for by DAYCENT, forest lands, and settlements. To estimate volatilized losses, synthetic fertilizer and manure N inputs were multiplied by the fraction subject to gaseous losses using the respective IPCC default values (0.1 kg N/kg N added as mineral fertilizers, and 0.2 kg N/ kg N added as manure; IPCC/UNEP/OECD/IEA 1997). Leaching/runoff losses of N were estimated by summing the N additions from synthetic fertilizers and manure, and then multiplying by the IPCC default fraction subject to leaching/runoff losses (0.3 kg N/ kg N applied; IPCC/UNEP/OECD/IEA 1997). Furthermore, N from managed manure not applied to crops (or pastures), which was assumed to volatilize and later be added to soils through atmospheric deposition, was also included in the estimates of volatilized N losses.

Volatilized N from major crop types, grasslands, minor crop types, settlements, forest lands, and volatilized during manure storage and handling was summed to obtain the total annual losses for this pathway. 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 direct N_2O emissions due to the N additions and cultivation of major crop types, N additions to non-major crop types, and direct N_2O emissions due to 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 IPCC 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

Three sets of simulations were performed for each county in the United States using the DAYCENT model: one for the native vegetation (year 1 to plow out), one to represent historical agricultural practices (plow out to 1970) and one for modern agriculture (1971 through 2003). 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. 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.

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. All crops were simulated with and without organic matter amendments. The simulations with organic matter amendments included separate ones for manure and other commercial organic fertilizer additions. 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, in regions where wheat/corn/fallow cropping is used, 3 rotations were simulated: 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. We accounted for improvements of cultivars (cultivated varieties) because it is unrealistic to assume that modern corn is identical, in terms of yield potential, N demand, etc., as corn grown in 1900. Realistic simulations of historical land management and vegetation type are important because they influence present day soil carbon and N levels, which influence present day N cycling and associated N_2O emissions. These simulations included approximately 90 percent of principal cropland area and approximately 86 percent of total cropped area. Total cropped area includes principal crops plus perennial crops, such as fruit and nut trees, as well as commercial vegetables.

Native vegetation was also simulated through the modern period in order to provide an estimate of natural "background emissions" that are not associated with anthropogenic activity. The difference between N_2O emissions from the major cropland types and its associated potential native vegetation was assumed to represent the anthropogenic influence on soil N_2O emissions.

For each crop in a county, 4 separate sets of simulations were performed during the modern cropping period: 1) land area that received only synthetic fertilizer N additions, 2) land area that received manure N additions, 3) land area that received sewage sludge N additions, and 4) land area that received other organic fertilizer N additions. For each crop in each county, the emissions for non-organic matter amended cropping were multiplied by the non-organic matter amended annual area for that crop. DAYCENT simulated direct soil N_2O emissions, NO_3 that is leached through the soil profile and lost in overland water runoff, and volatilized NO_x and NH_3 for each county in the United States. The simulated direct and indirect N_2O emissions from the native condition were subtracted from the resulting cropland estimates to obtain the approximate influence of anthropogenic activity. Emissions attributed to organic matter amendments were multiplied by the applicable area amended with manure or other organic fertilizer for that crop. Emissions for the respective non-organic matter amended and organic matter amended areas were then summed to obtain county and state level totals. State-level totals were summed to get national totals for direct soil N_2O emissions, as well as indirect N_2O emissions from N volatilization and leaching/runoff.

Non-Major Crops: Tier 1 IPCC Method

To estimate direct N_2O emissions from N additions to non-major crops, the amount of applied synthetic fertilizer N in each year was first reduced by the IPCC default volatilization fraction (10 percent) to account for the portion that volatilizes to NH_3 and NO_x (IPCC/UNEP/OECD/IEA 1997). The un-volatilized amount of synthetic fertilizer N was then added to N inputs from legumes and crop residues, and the total N was multiplied by the IPCC default emission factor of 0.0125 kg N_2O-N/kg N (IPCC/UNEP/OECD/IEA 1997).

Total Direct Emissions from Cropping on Mineral Soils

Direct N_2O emissions from major and non-major cropped soils were summed to obtain total direct emissions for mineral cropland soils.

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 cropland soils, the area of cultivated organic soils in temperate regions was multiplied by the IPCC default emission factor for temperate soils (8 kg N_2O-N/ha cultivated; IPCC 2000), and the corresponding area in the sub-tropical regions was multiplied by the average of the temperate and tropical IPCC default emission factors (12 kg N_2O-N/ha cultivated; IPCC 2000).

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-176).

Table A-176: 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
Mineral Soils	105	115	104	112	115	110	122	119	127	115	122	129	119	115	131
Organic Soils	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Total	108	118	106	115	118	113	125	122	130	118	125	132	122	118	134

Note: Totals may not sum due to independent rounding.

Step 3: Estimate Direct N_2O Emissions from Grasslands

A combination of DAYCENT and the IPCC Tier 1 method was 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 that for major crop types described above in Step 2a, except that sewage sludge amendments were also included in these simulations.

The N excreted by livestock not accounted for by DAYCENT simulations of pasture and rangeland (~25 percent of total PRP manure) was multiplied by the IPCC default emission factor (0.02 kg N_2O-N/kg N excreted). Similarly, the N fixed from forage legumes not accounted for by DAYCENT simulations of pasture and rangeland (~48 percent of total forage legume fixed N) was multiplied by the IPCC default emission factor (0.0125 kg N_2O-N/kg N fixed). DAYCENT simulated emissions were added to the emissions estimated using the IPCC Tier 1 method to provide the national total for direct N_2O losses from grasslands (see Table A-177).

Table A-177: 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
Grasslands	42	43	34	33	44	35	56	34	37	30	41	34	48	38	37

Step 4: Estimate Indirect N_2O Emissions for All Land Use and Management Activity

In this step, N_2O emissions were calculated for each of two indirect emission pathways (N_2O emissions due to volatilization, and indirect 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 from managed manure during storage, treatment, and transport, and redeposited on land or water bodies after originating from anthropogenic activity. 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/UNEP/OECD/IEA 1997) to compute total N_2O emissions from volatilization. The resulting estimates are provided in Table A-178.

Table A-178: Indirect N_2O Emissions (Tg CO_2 Eq.)

Activity	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
Volatilization and Atm. Deposition	16	16	16	17	17	17	17	17	18	17	18	18	18	18	17
Croplands, Grasslands, Settlements, and Forestland	11	11	11	11	12	12	12	12	12	12	13	12	12	12	12
Grasslands	5	5	5	5	6	5	6	5	6	5	5	5	5	5	5
Surface Leaching & Run-off	100	101	95	148	82	143	116	104	117	116	95	99	90	86	73
Croplands, Grasslands, Settlements, and Forestland	81	70	71	103	66	116	79	75	86	67	73	75	63	71	53
Grasslands	19	31	25	45	16	27	36	29	30	49	21	25	27	15	20
Total	116	117	112	165	100	160	133	121	134	134	113	117	108	104	91

Note: Totals may not sum due to independent rounding.

Step 4b: Indirect Emissions Due to Leaching and Runoff

Indirect emissions from leaching of mineral N from soils and losses in overland flow of runoff waters were calculated according to the amount of mineral N that was transported from soil profiles in aqueous forms after originating from anthropogenic activity 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 0.025 kg N_2O-N/kg N (IPCC/UNEP/OECD/IEA 1997) to provide the emission estimate from this source. The resulting emission estimates are provided in Table A-178.

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-179.

Table A-179: 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
Total Direct	150	161	141	148	162	148	181	156	167	148	165	166	170	155	171
Direct emissions from mineral cropland soils	105	115	104	112	115	110	122	119	127	115	122	129	119	115	131
Direct emissions from drained organic cropland soils	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Direct emissions from grasslands	42	43	34	33	44	35	56	34	37	30	41	34	48	38	37
Total Indirect	116	117	112	165	100	160	133	121	134	134	113	117	108	104	91
Volatilization	16	16	16	17	17	17	17	17	18	17	18	18	18	18	17
Leaching/Runoff	100	101	95	148	82	143	116	104	117	116	95	99	90	86	73
Total Emissions	266	278	252	313	262	308	314	277	301	281	278	283	278	259	261

Note: Totals may not sum due to independent rounding.

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; more detailed descriptions of selected topics may be found in the cited references.

Carbon Stocks and Net Changes in Forest Ecosystem Carbon Stocks

C stocks were estimated at the inventory plot level for each C pool within each state in the conterminous United States based on availability of inventory data. Forest survey data in the United States were obtained from USDA Forest Service, Forest Inventory and Analysis (FIA) Resources Planning Act Assessment (RPA) databases or the individual state surveys in the FIA Database (FIADB), version 2.1. More complete information about these data is available at an FIA Internet site (FIA Database Retrieval System). All FIADB surveys used for C stock estimates were obtained from this site on September 30, 2005.

The first step in developing C estimates was to identify separate inventory surveys for each state and associate each with an average year for field collection of data. Most inventory databases provide the year, month, and day in which the data were collected for each plot. If only the year is specified, the date for collection of data is assigned the midpoint in the year. If data for an individual survey were collected over a number of years, an average value is calculated. A few surveys had missing or incorrect values for year of field data; in some cases it was possible to obtain this information from the regional FIA units, otherwise the year was inferred from other data. Some overlap exists between the RPA and FIADB inventories because the RPA summaries were compiled from the FIADB. Such overlaps are identified and adjusted to avoid duplication. Older surveys for some states, particularly in the West, have National Forest System lands surveyed at different times than other forest land in the state. For this reason, C stocks for National Forests were separately estimated from other forests to account for differences in average year. The inventories used for each state as well as average year identified for each are provided in Table A-180.

For each inventory summary in each state, each C pool was estimated using coefficients from the FORCARB2 model (Birdsey and Heath 1995, Birdsey and Heath 2001, Heath et al. 2003, Smith et al. 2004a). Coefficients of the model are applied to the survey data at the scale of FIA inventory plots; the results are estimates of C density (Mg per hectare) for a number of separate C pools. C stocks and fluxes for Forests Remaining Forests are reported in pools following IPCC *Good Practice Guidance for Land Use, Land-Use Change, and Forestry* (2003). FORCARB2 estimates C density for live trees, standing dead trees, understory vegetation, down dead wood, forest floor, and soil organic matter. All non-soil pools except forest floor can be separated into aboveground and belowground components. FORCARB2's 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. Definitions of forest floor and soil organic matter in FORCARB2 correspond to litter and forest soils, respectively, in IPCC *Good Practice Guidance for Land Use, Land-Use Change, and Forestry* (2003).

The tree C pools in FORCARB2 include aboveground and belowground (coarse root) C mass of live trees. Separate estimates are made for whole-tree and aboveground-only biomass. Thus, the belowground portion is determined as the difference between the two estimates. Tree C estimates are based on Jenkins et al. (2003) and are functions of tree species and diameter as well as forest type and region. Some survey data do not provide measurements of individual trees; tree C in these plots are estimated from plot-level growing stock volume of live trees and equations based on Smith et al. (2003). C mass of wood is 50 percent of dry weight (IPCC/UNEP/OECD/IEA 1997). The minimum-sized tree included in these FIA data is one-inch diameter (2.54 cm) at diameter breast height (1.3 meter); this represents the minimum size included in the tree C pools.

A second, but minor, component of biomass is understory vegetation. Understory vegetation is defined in FORCARB2 as all biomass of undergrowth plants in a forest, including woody shrubs and trees less than one-inch diameter, measured at breast height. 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 *LULUCF Good Practice Guidance* (2003) 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. C density estimates are based on Birdsey (1996) and were applied at the inventory plot level (Smith et al. 2004a).

Dead wood includes the FORCARB2 pools of down dead wood and standing dead trees. 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 by FORCARB2 simulations and applied at the plot level (Smith et al. 2004a). The standing dead tree C pools in FORCARB2 include aboveground and belowground (coarse root) mass. Estimates are based on Smith et al. (2003) and are functions of plot level growing stock volume of live trees, C density of live trees, forest type, and region.

Estimates of litter and soil organic carbon (SOC) are not based on C density of trees. Litter C is the pool of organic C (litter, 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. 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.

An historical focus of the FIA program was to provide information on timber resources of the US. For this reason, some forest lands, which were less productive or reserved (i.e., land where harvesting was prohibited by law), were less intensively surveyed. This generally meant that forest type and area were identified but data were not collected on individual tree measurements. However, all annualized surveys initiated since 1998 have followed a new national plot design for all forest land (Alerich et al. 2005, FIA Database Retrieval System). 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, which are necessary inputs to FORCARB2. The data gaps in the surveys taken before 1998 were filled by assigning regional average C densities calculated from the more complete later inventories. The overall effect of this is to generate estimates for C stock with no net change in C density on those lands with gaps in past surveys.

Average C density values for forest ecosystem C pools according to region and forest types within regions are provided in Table A-181. Note that C densities reflect the most recent survey for each state as available in the FIADB, not potential maximum C storage. Thus, 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 is likely to reduce the regional average for C density.

The overall approach for determining forest C stocks and stock change was to estimate forest C stocks based on data from two forest surveys conducted several years apart (Table A-180). C stocks were calculated separately for each state based on inventories available since 1990 and for the most recent inventory prior to 1990. For each pool in each state in each year, C stocks were estimated by linear interpolation between survey years. Similarly, fluxes were 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 (net flux) estimates for each state was one less than the number of available inventories. Stocks and fluxes since the most recent survey were based on extrapolating estimates from the last two surveys. C stock and flux estimates for each pool were summed over all states to form estimates for the conterminous United States. Summed fluxes and stocks are in Table A-182 and Table A- 183, respectively.

Carbon in Harvested Wood Products

Estimates of C stock changes in wood products and wood discarded in landfills were based on the methods described by Skog and Nicholson (1998) which were based in turn on earlier efforts using similar approaches (Heath et al. 1996, Row and Phelps 1996). C stocks in wood products in use and wood products stored in landfills were estimated from 1910 onward based on several sets of historical data from the USDA Forest Service. These data include estimates of wood product demand, trade, and consumption (USDA 1964, Ulrich 1989, Howard 2001). Annual historical estimates and model projections of the production of wood products were used to divide consumed roundwood into wood product, wood mill residue, and pulp mill residue. To estimate the amount of time products

remain in use before disposal, wood and paper products were divided into 21 categories, each with an estimated product half-life (Skog and Nicholson 1998). After disposal, the amount of waste burned was estimated. For products entering dumps or landfills, the proportion of C emitted as CO_2 or CH_4 was estimated using the maximum proportion of wood and paper converted to CO_2 or CH_4 in landfills for 5 product types. By following the fate of C from the wood harvested in each year from 1910 onward, the change in C stocks in wood products and landfills and the amount of C emitted to the atmosphere with and without energy recovery were estimated for each year through 2003. To account for imports and exports, the production approach was used, meaning that C in exported wood was counted as if it remained in the United States, and C in imported wood was not counted. From 1990 through 2002, the amount of C in exported wood averaged 6 Tg C per year, with little variation from year to year. Imports, which were not included in the harvested wood C stock estimates, increased from 7.2 Tg C per year in 1990 to 13 Tg C per year in 2002. For more details, see Skog and Nicholson (1998). Summaries of net fluxes and stocks for harvested wood in products and landfills are in Table A-182 and Table A- 183.

Uncertainty Analysis

The uncertainty analysis for total net flux of forest C (see Table 7-8 in LULUCF chapter) was consistent with the IPCC-recommended Tier 2 methodology (IPCC 2003). The estimates were simulated with Monte Carlo sampling of probability densities representing plot-level C for the forest ecosystem estimates following general methods described in Heath and Smith (2000b) and Smith and Heath (2000). Estimates of uncertainty for C in harvested wood were based on Skog et al. (2004). Monte Carlo sampling of all probability densities involved random sampling of equal-probable intervals. The 95 percent confidence interval about the simulated flux (Table A-180) is based on the bounds of the central 95 percent of the simulated probability density for flux.

Uncertainty about C density (Mg/ha) was defined for each of six FORCARB2 C pools for each inventory plot. Live and standing dead trees were assigned normal or truncated normal probability densities, which were defined according to Jenkins et al. (2003) and the species and number of trees measured on each plot. Down dead wood and forest floor were assigned skewed distributions, which assume that a small proportion of plots will have relatively high carbon densities. Understory and soil organic C were assigned uniform distributions to reflect the fact that the model currently has little information to assign plot-specific values. Monte Carlo sampling of live tree, down dead wood, and understory probabilities were highly correlated to reflect the same process in FORCARB2. Uncertainty about plot area was assigned a normal distribution and follows the accuracy standards defined for the surveys (Alerich et al. 2005). The uncertainty analysis of Skog et al. (2004) was developed for a slightly different estimate of C in harvested wood as compared with the method followed here (Skog and Nicholson 1998). Therefore, the probability densities for annual flux for wood products and landfilled wood were defined as uniform densities bounded by the summaries in Table 3 of Skog et al. (2004). Two effects of estimating uncertainty at the plot level and aggregating to state totals for determining net stock change (flux) are: 1) relative uncertainty tends to decrease, and 2) skewed probability densities for individual plots tend to approach normality as independent samples among plots are summed.

Table A-180: Source of forest inventory and average year of field used to estimate statewide carbon stocks

State[a]	Source of Inventory Data[b]	Average Year Assigned to Inventory[c]
Alabama	1987 RPA	1982
	FIADB, cycle 1	1990
	FIADB, cycle 7	1999
	FIADB, cycle 4	2002
Arizona, NFS	1987 RPA	1985
	FIADB, cycle 2	1996
	FIADB, cycle 3	2003
Arizona, all other	FIADB, cycle 1	1986
	FIADB, cycle 2	1992
	FIADB, cycle 3	2003
Arkansas	1987 RPA	1978
	FIADB, cycle 1	1996
	FIADB, cycle 3	2002
California, NFS	1987 RPA	1981
	1997 RPA	1993
	FIADB, cycle 5	2003

California, all other	1987 RPA	1983
	FIADB, cycle 3	1993
	FIADB, cycle 5	2003
Colorado, NFS	2002 RPA	1986
	FIADB, cycle 2	2004
Colorado, all other	2002 RPA	1979
	FIADB, cycle 2	2004
Connecticut	FIADB, cycle 3	1985
	FIADB, cycle 4	1998
	FIADB, cycle 5	2004
Delaware	FIADB, cycle 3	1986
	FIADB, cycle 4	1999
Florida	FIADB, cycle 1	1987
	FIADB, cycle 2	1995
Georgia	FIADB, cycle 1	1989
	FIADB, cycle 7	1997
	FIADB, cycle 4	2001
Idaho, NFS	1987 RPA	1982
	FIADB, cycle 1	1998
	FIADB, cycle 2	2005
Idaho, all other	1987 RPA	1981
	FIADB, cycle 1	1990
	FIADB, cycle 2	2005
Illinois	FIADB, cycle 3	1985
	FIADB, cycle 4	1998
	FIADB, cycle 5	2003
Indiana	FIADB, cycle 3	1986
	FIADB, cycle 4	1998
	FIADB, cycle 5	2001
Iowa	FIADB, cycle 3	1990
	FIADB, cycle 4	2002
Kansas	FIADB, cycle 3	1981
	FIADB, cycle 4	1994
	FIADB, cycle 5	2003
Kentucky	FIADB, cycle 1	1987
	FIADB, cycle 4	2002
Louisiana	1987 RPA	1984
	FIADB, cycle 1	1991
	FIADB, cycle 3	2003
Maine	1987 RPA	1983
	FIADB, cycle 4	1995
	FIADB, cycle 5	2002
Maryland	FIADB, cycle 4	1986
	FIADB, cycle 5	2000
Massachusetts	FIADB, cycle 3	1985
	FIADB, cycle 4	1998
	FIADB, cycle 5	2004
Michigan	FIADB, cycle 4	1980
	FIADB, cycle 5	1993
	FIADB, cycle 6	2002
Minnesota	FIADB, cycle 4	1977
	FIADB, cycle 5	1989
	FIADB, cycle 12	2001
Mississippi	1987 RPA	1977
	FIADB, cycle 1	1994
Missouri	FIADB, cycle 4	1988
	FIADB, cycle 5	2002
Montana, NFS	1987 RPA	1987
	FIADB, cycle 1	1996
	FIADB, cycle 2	2004
Montana, all other	FIADB, cycle 1	1989
	FIADB, cycle 2	2004

Nebraska	FIADB, cycle 2	1983
	FIADB, cycle 3	1995
	FIADB, cycle 4	2003
Nevada, NFS	1987 RPA	1984
	FIADB, cycle 1	1997
	FIADB, cycle 2	2005
Nevada, all other	FIADB, cycle 1	1981
	FIADB, cycle 2	2005
New Hampshire	FIADB, cycle 4	1983
	FIADB, cycle 5	1997
	FIADB, cycle 6	2004
New Jersey	FIADB, cycle 3	1987
	FIADB, cycle 4	1999
New Mexico, NFS	1987 RPA	1985
	FIADB, cycle 2	1997
New Mexico, all other	FIADB, cycle 1	1987
	FIADB, cycle 2	1991
New York	1987 RPA	1987
	2002 RPA	1993
	FIADB, cycle 5	2003
North Carolina	FIADB, cycle 1	1984
	FIADB, cycle 2	1990
	FIADB, cycle 3	2001
North Dakota	FIADB, cycle 2	1979
	FIADB, cycle 3	1995
	FIADB, cycle 4	2003
Ohio	1987 RPA	1987
	FIADB, cycle 4	1991
	FIADB, cycle 5	2003
Oklahoma	1987 RPA	1986
	FIADB, cycle 1	1992
Oregon, eastern NFS	1987 RPA	1987
	2002 RPA	1995
	FIADB, cycle 5	2003
Oregon, eastern all other	1987 RPA	1976
	FIADB, cycle 3	1991
	FIADB, cycle 4	1999
	FIADB, cycle 5	2003
Oregon, western NFS	1987 RPA	1986
	2002 RPA	1996
	FIADB, cycle 5	2003
Oregon, western all other	1997 RPA	1989
	2002 RPA	1997
	FIADB, cycle 5	2003
Pennsylvania	FIADB, cycle 4	1990
	FIADB, cycle 5	2002
Rhode Island	FIADB, cycle 3	1985
	FIADB, cycle 4	1999
	FIADB, cycle 5	2004
South Carolina	FIADB, cycle 1	1986
	FIADB, cycle 2	1993
	FIADB, cycle 3	2001
South Dakota, NFS	1997 RPA	1986
	FIADB, cycle 4	1999
	FIADB, cycle 5	2003
South Dakota, all other	1987 RPA	1987
	FIADB, cycle 4	1995
	FIADB, cycle 5	2003
Tennessee	FIADB, cycle 5	1989
	FIADB, cycle 6	1998
	FIADB, cycle 4	2002
Texas	1987 RPA	1986

	FIADB, cycle 1	1992
	FIADB, cycle 3	2003
Utah	1987 RPA	1977
	FIADB, cycle 1	1993
	FIADB, cycle 2	2003
Vermont	FIADB, cycle 4	1983
	FIADB, cycle 5	1997
	FIADB, cycle 6	2004
Virginia	FIADB, cycle 1	1985
	FIADB, cycle 2	1991
	FIADB, cycle 3	2000
Washington, eastern NFS	1987 RPA	1987
	2002 RPA	1995
	FIADB, cycle 5	2004
Washington, eastern all other	1987 RPA	1981
	FIADB, cycle 3	1992
	FIADB, cycle 5	2004
Washington, western NFS	1987 RPA	1987
	2002 RPA	1995
	FIADB, cycle 5	2004
Washington, western all other	1987 RPA	1979
	FIADB, cycle 3	1990
	FIADB, cycle 5	2004
West Virginia	FIADB, cycle 4	1988
	FIADB, cycle 5	2001
Wisconsin	FIADB, cycle 4	1982
	FIADB, cycle 5	1995
	FIADB, cycle 6	2002
Wyoming, NFS	1997 RPA	1982
	2002 RPA	1992
	FIADB, cycle 2	2000
Wyoming, all other	2002 RPA	1984
	FIADB, cycle 2	2001

[a] Inventories for 11 western states were separated into National Forest System (NFS) and all other forest land (all other). Oregon and Washington were also divided into eastern and western forests (east or west of the crest of the Cascade Mountains).
[b] FIADB is version 2.1 as available on the Internet September 30, 2005.
[c] Based on forest land survey plots and rounded to the nearest integer year.

Table A-181: Average carbon density (Mg/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 the FIADB (see Table A-180)

Region (States) Forest Types	Above-ground Biomass	Below-ground Biomass	Dead Wood	Litter	Soil Organic Carbon	Forest Area
	Carbon Density (Mg/ha)					1000 ha
Northeast (CT,DE,MA,MD,ME,NH,NJ,NY,OH,PA,RI,VT,WV)						
White/Red/Jack Pine	91.9	19.0	11.3	13.6	78.1	1,966
Spruce/Fir	51.4	10.9	11.8	30.6	98.0	2,972
Oak/Pine	73.6	14.5	8.9	27.1	66.9	1,403
Oak/Hickory	77.6	14.7	10.1	7.9	53.1	11,802
Elm/Ash/Cottonwood	51.2	9.7	8.1	23.9	111.7	1,266
Maple/Beech/Birch	75.1	14.4	12.4	26.4	69.6	15,239
Aspen/Birch	46.2	9.1	7.7	8.5	87.4	1,659
Minor Types and Nonstocked	42.9	8.6	6.2	13.8	81.8	1,218
Northern Lake States (MI,MN,WI)						
White/Red/Jack Pine	52.7	11.0	7.9	12.2	120.8	1,794
Spruce/Fir	41.1	8.7	8.3	32.5	261.8	3,081
Oak/Hickory	70.2	13.3	10.3	7.8	97.1	2,920
Elm/Ash/Cottonwood	50.1	9.6	8.6	25.5	179.9	1,652
Maple/Beech/Birch	71.4	13.7	10.9	26.4	134.3	5,110
Aspen/Birch	42.1	8.2	8.4	8.3	146.1	5,346

Minor Types and Nonstocked	37.4	7.4	6.2	11.1	127.2	886
Northern Prairie States						
(IA,IL,IN,KS,MO,ND,NE,SD)						
Ponderosa Pine	42.0	8.9	6.9	14.3	48.5	563
Oak/Pine	51.8	10.1	7.1	25.3	39.7	573
Oak/Hickory	68.4	12.9	9.2	7.5	49.1	8,154
Elm/Ash/Cottonwood	72.1	13.5	11.1	23.6	83.0	1,760
Maple/Beech/Birch	62.5	11.8	8.7	24.8	71.0	1,017
Minor Types and Nonstocked	36.1	7.2	5.8	12.5	58.8	884
South Central						
(AL,AR,KY,LA,MS,OK,TN,TX)						
Longleaf/Slash Pine	37.3	7.6	3.9	10.7	55.5	1,321
Loblolly/Shortleaf Pine	42.2	8.6	4.7	9.6	41.9	12,701
Oak/Pine	51.6	10.0	6.4	9.7	41.7	6,928
Oak/Hickory	63.5	11.9	7.3	6.4	38.6	18,841
Oak/Gum/Cypress	71.3	13.6	8.7	6.3	52.8	5,303
Elm/Ash/Cottonwood	57.7	10.9	7.8	5.8	49.9	2,455
Minor Types and Nonstocked	52.1	10.0	7.1	8.1	46.4	1,155
Southeast						
(FL,GA,NC,SC,VA)						
Longleaf/Slash Pine	30.5	6.2	3.3	9.5	110.0	4,185
Loblolly/Shortleaf Pine	44.8	9.2	5.5	9.2	72.9	8,691
Oak/Pine	49.4	9.6	5.5	9.1	61.4	4,928
Oak/Hickory	71.5	13.5	8.2	6.4	45.3	11,006
Oak/Gum/Cypress	71.4	13.8	9.0	6.3	158.0	4,643
Elm/Ash/Cottonwood	70.3	13.3	11.0	6.2	95.7	666
Minor Types and Nonstocked	40.5	7.8	5.7	6.3	87.2	1,129
Pacific Northwest, Westside						
(Western OR and WA)						
Douglas-fir	143.4	30.1	31.3	31.4	94.8	5,594
Fir/Spruce/Mt. Hemlock	144.1	30.4	37.5	37.9	62.1	1,215
Hemlock/Sitka Spruce	175.6	37.0	45.0	38.4	116.3	1,659
Alder/Maple	82.5	16.2	21.0	7.4	115.2	1,359
Minor Types and Nonstocked	69.4	13.8	12.0	13.7	83.0	1,276
Pacific Northwest, Eastside						
(Eastern OR and WA)						
Pinyon/Juniper	13.3	2.6	2.4	21.1	46.9	832
Douglas-fir	79.4	16.6	18.6	36.5	94.8	2,004
Ponderosa Pine	50.0	10.4	10.1	22.8	50.7	2,925
Fir/Spruce/Mt. Hemlock	95.5	20.2	27.0	37.9	62.1	1,573
Lodgepole Pine	41.2	8.7	9.7	21.0	52.0	1,034
Western Larch	70.7	14.8	18.9	36.1	45.1	288
Minor Types and Nonstocked	29.0	5.7	13.1	22.3	79.7	1,486
Pacific Southwest						
(CA)						
Pinyon/Juniper	25.6	5.0	1.9	21.1	26.3	789
Douglas-fir	156.8	32.4	32.8	34.8	40.1	442
Ponderosa Pine	51.9	10.8	10.1	35.1	41.3	376
Fir/Spruce/Mt. Hemlock	163.6	34.6	45.0	38.3	51.9	777
Lodgepole Pine	94.8	20.0	19.8	39.2	35.2	396
Redwood	200.4	41.8	42.0	60.8	53.8	274
California Mixed Conifer	116.7	24.5	28.8	37.6	49.8	3,825
Western Oak	67.1	12.8	7.4	29.0	27.6	3,677
Tanoak/Laurel	125.7	24.6	18.5	27.1	27.6	790
Minor Types and Nonstocked	37.2	7.2	9.0	23.9	38.0	1,935
Rocky Mountains, North						
(ID,MT)						
Douglas-fir	73.8	15.6	13.8	37.2	38.8	5,917
Ponderosa Pine	43.5	9.1	7.9	23.1	34.3	1,772
Fir/Spruce/Mt. Hemlock	68.1	14.4	21.2	37.3	44.1	4,574
Lodgepole Pine	55.2	11.8	10.4	23.3	37.2	2,622
Western Larch	63.2	13.3	14.9	35.9	34.2	411

Minor Types and Nonstocked	27.4	5.5	9.6	24.7	42.5	4,010
Rocky Mountains, South (AZ,CO,NM,NV,UT,WY)						
Pinyon/Juniper	22.1	4.5	0.8	21.1	19.7	19,809
Douglas-fir	72.6	15.4	16.4	38.0	30.9	1,719
Ponderosa Pine	48.5	10.2	8.2	23.6	24.1	3,453
Fir/Spruce/Mt. Hemlock	81.3	17.3	23.0	38.8	31.5	4,180
Lodgepole Pine	53.8	11.4	13.0	24.1	27.0	2,157
Aspen/Birch	56.2	10.8	11.6	28.5	58.8	2,589
Western Oak	19.8	3.8	2.2	27.1	38.0	2,874
Minor Types and Nonstocked	16.6	3.1	4.1	23.7	25.3	5,164

Table A-182: Net Annual Changes in Carbon Stocks (Tg C yr^{-1}) in Forest and Harvested Wood Pools, 1990-2004

Carbon Pool	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
Forest	(154)	(157)	(145)	(112)	(109)	(78)	(74)	(82)	(113)	(115)	(115)	(115)	(115)	(115)	(115)
Live, aboveground	(92)	(92)	(87)	(71)	(70)	(63)	(62)	(67)	(78)	(84)	(85)	(85)	(85)	(85)	(85)
Live, belowground	(18)	(18)	(17)	(13)	(13)	(12)	(11)	(13)	(15)	(16)	(16)	(16)	(16)	(16)	(16)
Dead Wood	(12)	(13)	(11)	(9)	(10)	(8)	(8)	(8)	(11)	(10)	(9)	(9)	(9)	(9)	(9)
Litter	(23)	(20)	(17)	(11)	(7)	1	2	3	(3)	(7)	(7)	(7)	(7)	(7)	(7)
Soil Organic Carbon	(9)	(14)	(12)	(8)	(9)	4	5	3	(4)	1	3	3	3	3	3
Harvested Wood	(57)	(54)	(55)	(56)	(57)	(55)	(57)	(58)	(56)	(59)	(57)	(58)	(58)	(59)	(59)
Wood Products	(13)	(11)	(13)	(15)	(17)	(15)	(15)	(16)	(14)	(17)	(16)	(16)	(16)	(16)	(17)
Landfilled Wood	(44)	(43)	(43)	(41)	(41)	(41)	(41)	(42)	(42)	(42)	(41)	(42)	(42)	(42)	(43)
Total Net Flux	(211)	(211)	(200)	(167)	(166)	(133)	(131)	(140)	(169)	(174)	(172)	(173)	(173)	(173)	(174)

Table A- 183: Carbon Stocks (Tg C) in Forest and Harvested Wood Pools, 1990-2005

Carbon Pool	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Forest	39,508	39,661	39,818	39,963	40,074	40,183	40,261	40,335	40,417	40,529	40,645	40,760	40,874	40,989	41,103	41,218
Live, aboveground	14,334	14,426	14,518	14,605	14,676	14,746	14,809	14,871	14,938	15,016	15,100	15,184	15,269	15,354	15,438	15,523
Live, belowground	2,853	2,871	2,888	2,905	2,918	2,931	2,943	2,954	2,967	2,982	2,998	3,014	3,031	3,047	3,064	3,080
Dead Wood	2,409	2,421	2,434	2,445	2,454	2,464	2,472	2,479	2,488	2,499	2,509	2,518	2,527	2,536	2,545	2,554
Litter	4,492	4,515	4,535	4,553	4,563	4,570	4,570	4,568	4,565	4,569	4,575	4,583	4,590	4,597	4,604	4,612
Soil Organic Carbon	15,420	15,429	15,443	15,455	15,463	15,472	15,467	15,463	15,460	15,464	15,463	15,460	15,458	15,455	15,452	15,449
Harvested Wood	1,915	1,973	2,027	2,082	2,137	2,195	2,250	2,307	2,365	2,421	2,480	2,537	2,595	2,654	2,713	2,772
Wood Products	1,134	1,147	1,158	1,171	1,186	1,202	1,217	1,232	1,248	1,262	1,279	1,295	1,311	1,327	1,344	1,360
Landfilled Wood	781	825	868	911	952	992	1,033	1,074	1,117	1,159	1,200	1,242	1,284	1,327	1,369	1,411
Total Carbon Stock	41,423	41,634	41,845	42,044	42,212	42,378	42,511	42,642	42,782	42,951	43,125	43,297	43,470	43,643	43,816	43,990

3.13. Methodology for Estimating Net Changes in Carbon Stocks in Mineral and Organic Soils

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 1 methods for estimating the additional changes in mineral soil C stocks due to manure amendments, sewage sludge additions to soils, and enrollment changes in the Conservation Reserve Program after 1997.

Previous agricultural soil C inventories have been based solely on the IPCC Tier 1 and 2 approaches (EPA 2005). The major difference from previous inventory reports is the use of a simulation model for estimating soil C stock changes. This Tier 3 model-based approach has several advantages over the IPCC Tier 2 approach:

- 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 2 method; 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 2 method.

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. For this latter case, 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.

Century Model Description

The Century model simulates carbon (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 attainable 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-5) 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 and three soil organic matter (SOM) pools (termed active, slow, and passive). 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 shows the greatest relative 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-5 . 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 subroutines are designed to simulate herbaceous plants (i.e., agricultural crops and grasses) and woody vegetation (i.e., trees and scrubs). Only the herbaceous plant model, which is used in the agricultural inventory applications, is described here (although the basic concepts are similar in the woody vegetation model). 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 agricultural systems) for specifying crop type and 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.

IPCC Tier 2 Method Description

The IPCC method is a C accounting approach that is used to estimate C stock changes and CO_2 fluxes between soils and the atmosphere based on land-use and management activity (IPCC/UNEP/OECD/IEA 1997, 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.

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/UNEP/OECD/IEA 1997). The IPCC approach uses an emission factor to estimate annual losses of CO_2 from organic soils, rather than an explicit stock change approach.

Methodological Steps for Derivation of Soil Organic C Stock Change Estimates

This inventory of soil C stock changes in U.S. agricultural land combines Tier 1, 2 and 3 approaches. A simulation-based Tier 3 approach was used to estimate of soil C changes for most agricultural land (ca. 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 made using the Tier 2 approach. Tier 1 methods are used to estimate additional changes in mineral soil C stocks due to manure amendments, 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 1, 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*. The areas modeled with Century and those estimated with the Tier 2 IPCC method were subdivided with parcels of land allocated to the Tier 2 approach if they occurred on organic soils, had a non-agricultural use such as forest and federal lands, or produced vegetables, perennial/horticultural crops, tobacco or rice, grown continuously or in rotation with other crops. Finally, additional data were collected specific to each method, describing other key management activities and environmental conditions (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). 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[53] in the 1992 or 1997 surveys (Table A-184). 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: 1979-1982; 1983-1987; 1988-

[53] Non-federal lands only.

1992; and 1993-1997.[54] These time periods coincided with the collection of land use and management activity data in the NRI. At the end of each inventory time period, lands were classified into the four land use/land-use change categories based on whether the parcel was in the same use during the previous inventory time periods or had been converted from another land use. The total agricultural land base was 386 million hectares, and the Tier 3 Century model-based approach was used to estimate emissions and removals for about 90 percent of the total area.

Table A-184: Total Land Areas for the Agricultural Soil C Inventory, Subdivided into *Cropland Remaining Cropland*, *Land Converted to Cropland*, *Grassland Remaining Grassland*, and *Land Converted to Grassland* (Million Hectares)

	Land Areas (10^6 ha)					
	1990-92			1993-97		
Category	Century	IPCC	Total	Century	IPCC	Total
Mineral	339.03	46.01	385.04	339.03	46.01	385.04
Cropland Remaining Cropland	116.03	28.97	145.00	112.37	26.74	139.11
Land Converted to Cropland	6.45	0.00	6.45	10.36	0.00	10.36
Grassland Remaining Grassland	198.37	0.00	198.37	195.59	0.00	195.59
Land Converted to Grassland	18.18	14.57	32.75	20.71	11.18	31.90
Non-Agricultural Uses[1]	0.00	2.47	2.47	0.00	8.08	8.08
Organic	0.00	1.34	1.34	0.00	1.34	1.34
Cropland Remaining Cropland	0.00	0.75	0.75	0.00	0.75	0.75
Grassland Remaining Grassland	0.00	0.55	0.55	0.00	0.55	0.55
Non-Agricultural Uses[1]	0.00	0.04	0.04	0.00	0.05	0.05
Total	339.03	47.36	386.39	339.03	47.36	386.39

[1] These non-agricultural uses were converted to or from cropland or grassland during the 1990s.

Management System Classification—NRI points were classified into specific crop rotations, continuous pasture/rangeland, and other non-agricultural uses based on the survey data. Cropping rotations were classified for each of the inventory time periods (i.e., 1979-1982, 1983-1987, 1988-1992, 1992-1997, and >1997) based on data collected in 1982, 1987, 1992, and 1997. 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; thus crop rotations existing in 1997 were extended to 2004 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.

As discussed above, Century was used to model NRI points on mineral soils for most crops, except those parcels that had one or more years of vegetable crops, tobacco, perennial/horticultural crops, and/or rice. Century was also used to estimate stock changes in grassland over the entire time series from 1979 to 1997 (Table A-185). Century has not been fully tested for non-major crops, horticultural or perennial crops, rice and agricultural use of organic soils. 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.

Table A-185: Total Land Areas by Land-Use and Management System for the Entire U.S. Agricultural Land Base (Million Hectares)

	Land Areas (10^6 ha)					
	1990-92			1993-97		
Land-Use/Management System	Century	IPCC	Total	Century	IPCC	Total
Cropland Systems	135.44	32.32	167.77	135.18	30.02	165.20
Irrigated Crops	9.55	7.53	17.07	9.58	7.17	16.75
Continuous Row Crops	36.90	4.32	41.22	39.68	3.84	43.52
Continuous Small Grains	11.76	1.27	13.03	13.51	1.06	14.57
Continuous Row Crops and Small Grains	14.48	2.34	16.81	12.66	2.00	14.66
Row Crops in Rotation with Hay and/or Pasture	3.37	0.31	3.68	3.41	0.25	3.67
Small Grains in Rotation with Hay and/or Pasture	0.85	0.07	0.92	0.91	0.06	0.97
Row Crops and Small Grains in Rotation with	0.31	0.03	0.34	0.31	0.04	0.35

[54] Note: the first two inventory time periods occur before the 1990 baseline year of the reporting period and therefore are not included in this report.

Hay and/or Pasture						
Vegetable Crops	0.00	2.93	2.93	0.00	3.20	3.20
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	2.02	19.62	14.34	1.32	15.66
Row Crops and Small Grains with Fallow	0.69	1.72	2.41	0.56	1.80	2.36
Row Crops with Fallow	2.09	0.54	2.63	1.66	0.35	2.02
Miscellaneous Crop Rotations	1.58	0.56	2.14	1.47	0.45	1.92
Continuous Rice	0.00	0.35	0.35	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	2.60	2.60	0.00	2.52	2.52
Continuous Hay	5.56	0.62	6.19	6.70	0.54	7.24
Continuous Hay with Legumes or Irrigation	13.59	1.38	14.97	13.68	1.17	14.85
CRP	12.70	1.08	13.78	12.25	0.99	13.23
Aquaculture	0.00	0.01	0.01	0.00	0.01	0.01
Grassland Systems	203.59	12.53	216.11	203.85	9.22	213.07
Rangeland	158.66	6.14	164.80	158.94	5.30	164.23
Continuous Pasture	31.24	3.99	35.22	32.03	2.74	34.77
Continuous Pasture with Legumes or Irrigation (i.e., improved)	13.69	2.40	16.08	12.88	1.17	14.06
Non-Agricultural Systems	0.00	2.50	2.50	0.00	8.12	8.12
Forest	0.00	1.54	1.54	0.00	3.97	3.97
Federal	0.00	0.01	0.01	0.00	0.05	0.05
Water	0.00	0.12	0.12	0.00	0.25	0.25
Settlements	0.00	0.04	0.04	0.00	2.46	2.46
Miscellaneous	0.00	0.79	0.79	0.00	1.39	1.39
Total	339.03	47.35	386.38	339.03	47.35	386.38

Organic soils are categorized into land-use systems based on drainage for purposes of estimating carbon losses (IPCC/UNEP/OECD/IEA 1997). 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 carbon, and those used for managed pasture, which are assumed to have less drainage and smaller losses of carbon. Overall, organic soils drained for cropland have remained relatively stable since 1982, but the area of organic soils managed as forest or pasture has increased slightly (see Table A-186).

Table A-186: Total Land Areas for Drained Organic Soils By Land Management Category and Climate Region (Million Hectares)

IPCC Land-Use Category for Organic Soils	Land Areas (10^6 ha)					
	Cold Temperate		Warm Temperate		Tropical	
	1992	1997	1992	1997	1992	1997
Undrained	0.07	0.06	0.0020	0.0017	0.12	0.09
Managed Pasture and Forest (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
Totals	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.

Tillage practices—Tillage practices were estimated for each cropping system based on data compiled by the Conservation Technology Information Center (CTIC). 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).

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 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, etc.). 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). 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 was 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 1966, 1957, 1954).

The ERS survey parameter "TOT N" (total amount of nitrogen 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 was 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 were used to construct PDFs with normal densities, in order to address uncertainties in application rates (see Step 2b for discussion of uncertainty methods).

Manure application—County-level manure addition estimates have been derived from manure nitrogen 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 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 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 and for two scenarios—before implementation of Comprehensive Nutrient Management Plans (baseline) and after implementation. For Century 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 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 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 2b for further discussion of uncertainty methods).

To estimate the carbon inputs associated with the manure N application rates derived from Edmonds et al. (2003), C:N ratios for various manure types were adapted from the Agricultural Waste Management Field Handbook (USDA 1996) and the On-Farm Composting Handbook (NRAES 1992), and derived from recoverability factors from Edmonds et al (2003). These C:N ratios were applied to EPA county-level estimates of manure nitrogen excreted by animal type and management system to produce a weighted county average C:N ratio of applied manure. This average C:N ratio was used to determine the associated C input for all crop amendments derived from Edmonds et al. (2003).

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 an IPCC soil type using soil taxonomy and texture information in the soils database that accompanies the NRI data (USDA-NRCS 2000). In addition, points were assigned to an IPCC climate zone based on location within Major Land Resource Areas (MLRAs).

In order to estimate uncertainties, PDFs for the NRI land-use data were multivariate normal, using the total area estimates for each land use/management category and the covariance matrix computed from the NRI data. 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 and to ensure 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 provided 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 were re-classified as high input, and a portion of the high input systems were 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/UNEP/OECD/IEA 1997, IPCC 2003). 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 probability density functions for the uncertainty analysis.

Step 1d—Obtain Management Activity Data to Compute Additional Changes in Soil Organic C Stocks in Mineral Soils Due to CRP Enrollment after 1997 and Organic Amendment

Three additional influences on soil organic C stocks in mineral soils were estimated using a Tier 1 method, including: sewage sludge additions to agricultural soils; influence of variation in manure N production on the amount of land amended with manure relative to 1997; and changes in enrollment for the Conservation Reserve Program after 1997.

The derivation of the amount of sewage sludge nitrogen (N) produced each year, including the amount that was available for application on agricultural lands, has been described in the Agricultural Soil Management Annex of this report (see Annex 3.11). Sewage sludge N was assumed to be applied at the assimilative capacity for crops (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 impact of sewage sludge on soil C, stocks was estimated using a generalized amount of C gain or loss using the default IPCC factors, as discussed in Step 4.

Manure production is a critical piece of information for estimating the effect of organic amendments in the United States. The Tier 2 and Tier 3 approaches were implemented using the application rates and grassland/cropland areas receiving manure for 1997 from Edmonds et al. (2003). This study did not provide data on land area and application rates for manure amendments in other years. However, manure production and, thus, amendments will vary from year to year. In order to approximate differences in amendments in other years of the inventory relative to 1997, estimates of the amounts of manure N produced each year were derived from data on livestock populations, manure management usage, livestock weights, and livestock N excretion rates. A detailed description of the derivation of the manure N production data is contained in Annex 3.10. 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. Thus PRP manure production estimates were not included in the manure production totals for the soil C analysis. In addition, poultry manure production was reduced by 4.8% because this percentage is used for feed and not applied to soils.

The change in enrollment for the Conservation Reserve Program after 1997 was based on the amount of land under active contracts from 1998 through 2004 relative to 1997 (Barbarika 2005).

Step 1e: Obtain Climate and Soils Data

Tier 3 Century Model—Monthly weather data (temperature and precipitation) were used to drive the Century model simulations for the period 1895-2004 from the PRISM database (Parameter-elevation Regressions on Independent Slopes Model) (Daly et al. 1994). 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 ca. 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 descriptions corresponding to each NRI point (used to specify land-use and management time series-see below) were used for model input. Soils are classified according to "soil-series," which is the most detailed taxonomic level used in soil mapping in the United States. Surface soil texture and hydric condition were obtained from the soil attribute table in the NRI database and assigned to one of twelve texture classes and either hydric or non-hydric status. 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. 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.[55] 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).[56]

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/UNEP/OECD/IEA 1997) (Table A-187). Six of these climate zones occur in the conterminous United States and Hawaii (Eve et al. 2001).

Table A-187: Characteristics of the IPCC Climate Zones that Occur in the United States

Climate Zone	Annual Average Temperature (˚C)	Average Annual Precipitation (mm)	Length of Dry Season (months)
Cold Temperate, Dry	< 10	< Potential Evapotranspiration	NA
Cold Temperate, Moist	< 10	≥ Potential Evapotranspiration	NA
Warm Temperate, Dry	10 – 20	< 600	NA
Warm Temperate, Moist	10 – 20	≥ Potential Evapotranspiration	NA
Sub-Tropical, Dry*	> 20	< 1,000	Usually long
Sub-Tropical, Moist (w/short dry season)*	> 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 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-6). MLRAs represent geographic units with relatively similar soils, climate, water resources, and land uses (NRCS 1981).

Figure A-6. Major Land Resource Areas by IPCC Climate Zone

[55] Artificial drainage (e.g. ditch- or tile-drainage) is simulated as a management variable

[56] 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 Century.

Soils were classified into one of seven classes based upon texture, morphology, and ability to store organic matter (IPCC/UNEP/OECD/IEA 1997). 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-188). 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-188: 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

* Carbon 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 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, initial conditions and C stocks were simulated prior to 1979 when the NRI (USDA-NRCS 2000) began recording land-use and management histories in agricultural land. 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, including the reporting period starting in 1990.

Step 2a: Simulate Initial Conditions (Pre-NRI Conditions)

Century model initialization involves two steps, so that initial C stocks can be estimated along with the distribution of organic C among the pools (e.g., Structural, Metabolic, Active, Slow, Passive) represented in the model. Each pool has a different turnover rate (thus 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. At present there is no national set of soil carbon 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 carbon 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. Long-term mean climate represented by 30-yr averages of the PRISM data (1960-1990) are used as data inputs to the model, along with 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, which is the first year of the NRI survey.

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 2004a). For each point within a given MLRA, a representative land-use and management scenario, from the time of initial conversion to agricultural use to 1979, was run for the purpose of model initialization. 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

The model is simulated through the time of land-use conversion to 1979, when the NRI observations begin and continuing through to 2000. 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-7.

Figure A-7. Uncertainty in Data Inputs

Inventory points within the same county (i.e., same weather) 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 probability density functions (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. 2006a). The Century model was initialized for 45 long-term field experiments with over 800 treatments in which soil C was measured under a variety of management conditions (e.g., variation in crop rotation, tillage, fertilization rates, manure amendments). These studies were obtained from an extensive search of published studies. All studies located in North America that met minimum criteria of having sufficient site level information and experimental designs were used, including C stock estimates, texture data, experimental designs with control plots, and land-use and management records for the experimental time period and pre-experiment condition. The inputs to the model were essentially known in the simulations for the long-term experiments, and, therefore, the analysis was designed to evaluate uncertainties associated with the model structure (i.e., model algorithms and parameterization).

The relationship between modeled soil C stocks and field measurements were 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 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.

To apply the uncertainty estimator, parameter values for the statistical equation (i.e., fixed effects) were selected from their joint probability distribution in a Monte Carlo Analysis. 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 the 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-184), soil organic C stocks increased at a rate between 77.3 and 90.8 Tg CO_2 Eq. annually. Estimates and uncertainties are provided in Table A-189.

Table A-189: 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	1995-2004
Mineral Soils		
Cropland Remaining Cropland	(71.24)	(62.52)
95% C.I.	(69.7) to (73.0)	(60.9) to (64.2)
Land Converted to Cropland	1.47	(2.82)
95% C.I.	0.7 to 2.2	(2.2) to (3.3)
Grassland Remaining Grassland	(8.25)	3.96
95% C.I.	(6.2) to (10.3)	2.2 to 5.5
Land Converted to Grassland	(12.80)	(15.99)
95% C.I.	(12.5) to (13.2)	(15.8) to (16.1)

Note: Does not include the change in storage resulting from the annual application of sewage sludge, or the additional Conservation Reserve Program enrollment, or the change in manure management after 1997.

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 probability density functions, 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 probability density functions in an iterative process to estimate SOC change 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. 2006b). 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. The data were synthesized in linear mixed-effects models, 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 times 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- 190). 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.[57] 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 *Good Practice Guidance for Land Use, Land-Use Change, and Forestry* (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- 190: Stock Change Factors for the United States and the IPCC Default Values Associated with 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
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

[57] 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.

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/UNEP/OECD/IEA 1997) 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-191). 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 probability density function with a normal density (Table A-191).

Table A-191: 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-192). Probability density functions were constructed as normal densities based on the mean C loss rates and associated variances.

Table A-192: Carbon Loss Rates from 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.[58] 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 2004 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).

[58] 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 2004.

Mineral soils for the land base estimated with the Tier 2 approach lost about from 1.2 to 2.5 Tg CO_2 Eq. in *Cropland Remaining Cropland*, and sequestered from 4.8 to 5.1 Tg CO_2 Eq. in *Land Converted to Grassland*. Organic soils lost about 30 Tg CO_2 Eq. annually in cropland and an additional 4.5 Tg CO_2 Eq. in grassland (Table A-193). Uncertainties in the mineral soils ranged from losses of 8.4 Tg CO_2 Eq. on cropland soils to gains of 7.3 Tg CO_2 Eq. on grassland soils from 1993 through 2004. Estimates and uncertainties are provided in Table A-193.

Table A-193: 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.)

Soil Type	1990-1992	1993-2004
Mineral Soils[1]		
Cropland Remaining Cropland	2.52	1.22
95% C.I.	(2.93) to 8.43	(4.03) to 6.6
Land Converted to Grassland	(4.84)	(5.13)
95% C.I.	(6.97) to (2.93)	(7.33) to (2.93)
Organic Soils[2]		
Cropland Remaining Cropland	29.86	30.30
95% C.I.	19.8 to 42.9	20.17 to 43.27
Grassland Remaining Grassland	4.33	4.58
95% C.I.	2.2 to 7.33	2.2 to 7.7

[1]The entire land base for *Grassland Remaining Grassland* was estimated using the Tier 3 approach, and thus no stock changes are reported here. In addition, cropland have not been subdivided into land use/land use change categories for the Tier 2 method, and therefore all stock changes are reported in the *Cropland Remaining Cropland* Category (Note: subdividing land-use change categories is a planned improvement for the soil C inventory).
[2] The land base for organic soils was not subdivided into land-use change categories and therefore C emissions are reported in the *Cropland Remaining Cropland* and *Grassland Remaining Grassland* categories (Note: subdividing land-use change categories is a planned improvement for the soil C inventory)
Note: Does not include the change in storage resulting from the annual application of sewage sludge, or the additional Conservation Reserve Program enrollment, or the change in manure management after 1997. The ranges are a 95 percent confidence interval from 50,000 simulations (Ogle et al. 2003).

Step 4: Compute Additional Changes in Soil Organic C Stocks Due to CRP Enrollment after 1997 and Organic Amendments

There are three 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 (from the Soil Management Section of the Agriculture chapter of this Inventory), 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 was applied to grassland because of the high heavy metal content and other pollutants found in human waste, which limits it 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 IPCC calculations that represent the effect of converting nominal, medium-input grassland to high input improved grassland (assuming a reference C stock of 50 metric tonnes C/ha-yr, which represents a mid-range value for the dominant agricultural soils in the United States, and the country-specific factor of 1.11 for high input improved grassland). From 1990 through 2004, sewage sludge applications in agricultural lands increased SOC storage from 0.6 to 1.3 Tg CO_2 Eq. (Table A-194). 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 to estimate the impact of changing manure N production on amendments relative to 1997. This adjustment was needed because manure application was computed based on 1997 amendment estimates across the entire times series for the Tier 3 Century simulations and Tier 2 IPCC calculations. 1997 was the only year in which data on amendments had been compiled (Edmonds et al. 2003). Manure N production was slightly lower in the early 1990s and then declined again in each year following 1997, reaching a net reduction of 132 thousand metric tons N by 2004.

To account for this variation and its impact on soil C stocks, the increase or decrease in manure N production was computed relative to manure N production in 1997. The resulting difference in manure N production was divided by the assimilative capacity of crops (Kellogg et al. 2000) to estimate the change in land

area amended with manure N relative to 1997. The impact of manure additions on soil organic carbon was calculated as 0.18 metric tons C/ha-yr for cropland. This rate is based on IPCC calculations that represent the effect of converting medium input cropping systems to high input systems (assuming a reference carbon stock of 50 metric tonnes C/ha-yr, which represents a mid-range value for the dominant agricultural soils in the United States, and the country-specific factor of 1.07 for high input cropland). Cropland was selected because the vast majority of collected manure is applied to cropland soils. Soil C storage was slightly lower from 1990 to 1996 due to less manure N production relative to 1997, but storage increased over the latter part of the time series as manure N production exceeded the estimated production values in 1997 (Table A-195). Similar to sewage sludge applications, a nominal ±50 percent uncertainty was attached to these estimates due to limited information about amendment rates and areas receiving manure in years other than 1997.

The third 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 in 2001 and 2003, leading to an additional enrollment of 514,377 ha over the five-year period (Barbarika 2005). 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 estimate was based on an IPCC calculation for how much SOC increases by setting aside a medium input cropping system in the Conservation Reserve Program (assuming a reference C stock of 50 metric tonnes C/yr, which represents a mid-range value for the dominant agricultural soils in the United States, and the average country-specific factor of 1.2 for setting-aside cropland from production). The change in enrollment generated emissions in 1998 through 2000, but with increased enrollment from 2001 to 2004, agricultural land sequestered an additional 0.7 to 1.5 Tg CO_2 Eq. annually between 2001 and 2004, respectively, relative to the baseline inventory (Table A-196). 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-196. Agricultural soils, both organic and mineral, were estimated to sequester from 43 to 54 Tg CO_2 Eq. annually between 1990 and 2004, based on the change in SOC storage.

Table A-194: 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
Sewage Sludge N Applied to Agricultural Land (Mg N)[a]	51,222	57,794	64,688	71,906	78,442	85,129	87,245	88,547	89,849	93,430	97,076	100,704	104,458	108,342	112,362
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
Area covered by Available Sewage SludgeN (ha)[c]	426,848	481,618	539,064	589,391	642,964	697,777	715,122	725,795	736,469	765,821	795,706	825,442	856,213	888,053	920,998
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
Contribution to Soil C ($TgCO_2$/yr)[e,f]	(0.59)	(0.67)	(0.75)	(0.82)	(0.90)	(0.97)	(1.00)	(1.01)	(1.03)	(1.07)	(1.11)	(1.15)	(1.19)	(1.24)	(1.28)
95% C.I.	(0.89) to (0.30)	(1.01) to (0.34)	(1.13) to (0.38)	(1.30) to (0.41)	(1.35) to (0.45)	(1.46) to (0.49)	(1.50) to (0.50)	(1.52) to (0.51)	(1.55) to (0.52)	(1.61) to (0.54)	(1.66) to (0.56)	(1.73) to (0.58)	(1.79) to (0.60)	(1.86) to (0.62)	(1.92) to (0.64)

Values in parentheses indicate net carbon storage.

[a] N applied to soils based upon EPA (this volume).

[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 (0.33 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] Note: 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-195: Additional Change in Soil Organic C in Mineral Soils Due to Variation in Managed Manure N Production and Amendments Relative to 1997

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
Manure N Production (Mg N)[a]	2,715,956	2,787,671	2,777,895	2,835,175	2,854,530	2,876,591	2,858,250	2,919,938	2,955,612	2,953,518	2,993,669	3,017,091	3,021,643	2,979,441	2,998,412
Net change in manure N production relative to 1997 (Mg N)[b]	-203,982	-132,267	-142,044	-84,764	-65,408	-43,348	-61,688	n/a	35,674	33,580	73,731	97,153	101,705	59,503	78,474
Assimilative Capacity (Mg N/ha)[c]	0.120	0.120	0.120	0.122	0.122	0.122	0.122	n/a	0.122	0.122	0.122	0.122	0.122	0.122	0.122
Net change in land area amended with manure N relative to 1997 (thousand ha)	-1,699,853	-1,102,224	-1,183,697	-694,784	-536,134	-355,309	-505,641	n/a	292,409	275,243	604,350	796,332	833,645	487,731	643,229
Average Annual C storage (Mg/ha/yr)[d]	0.18	0.18	0.18	0.18	0.18	0.18	0.18	n/a	0.18	0.18	0.18	0.18	0.18	0.18	0.18
Change in soil C ($(TgCO_2/yr)$	1.09	0.70	0.76	0.44	0.34	0.23	0.33	n/a	(0.19)	(0.18)	(0.40)	(0.52)	(0.54)	(0.32)	(0.42)
95% C.I.	0.55 to 1.64	0.35 to 1.05	0.38 to 1.14	0.22 to 0.66	0.17 to 0.51	0.12 to 0.35	0.17 to 0.50	n/a	(0.29) to (0.10)	(0.27) to (0.09)	(0.60) to (0.20)	(0.78) to (0.26)	(0.81) to (0.27)	(0.48) to (0.16)	(0.63) to (0.21)

[a] Managed manure N production after subtracting 4.8% of the poultry manure, which is used for feed. Pasture/Range/Paddock manure N is not included in these estimates because PRP manure is not collected and applied to soils.

[b] Computed using the equation [Manure N Production in Year X - Manure N Production in 1997)]

[c] Assimilative Capacity is the national average amount of manure-derived N that can be applied on cropland without buildup of nutrients in the soil, estimated at 0.122 Mg ha^{-1} (Kellogg et al. 2000). The additional manure N is divided by this value to obtain the amended area (or in this case the reduction in area amended).

[d] Annual rate of C storage based on the national average increase in carbon storage for cropland that is attributed to organic matter amendments (0.10 Mg/ha/yr in cropland)

Table A-196: 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
Net emissions based on Tier 3 Century-based analysis (Step 2)															
CRC	(71.24)	(71.24)	(71.24)	(71.24)	(71.24)	(62.52)	(62.52)	(62.52)	(62.52)	(62.52)	(62.52)	(62.52)	(62.52)	(62.52)	(62.52)
LCC	1.47	1.47	1.47	1.47	1.47	(2.82)	(2.82)	(2.82)	(2.82)	(2.82)	(2.82)	(2.82)	(2.82)	(2.82)	(2.82)
GRG	(8.25)	(8.25)	(8.25)	(8.25)	(8.25)	3.96	3.96	3.96	3.96	3.96	3.96	3.96	3.96	3.96	3.96
LCG	(12.8)	(12.8)	(12.8)	(12.8)	(12.8)	(15.99)	(15.99)	(15.99)	(15.99)	(15.99)	(15.99)	(15.99)	(15.99)	(15.99)	(15.99)
Net emissions based on the IPCC uncertainty analysis (Step 3)															
Mineral Soils															
CRC	2.52	2.52	2.52	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22
LCG	(4.84)	(4.84)	(4.84)	(5.13)	(5.13)	(5.13)	(5.13)	(5.13)	(5.13)	(5.13)	(5.13)	(5.13)	(5.13)	(5.13)	(5.13)
Organic Soils															
CRC	29.86	29.86	29.86	30.30	30.30	30.30	30.30	30.30	30.30	30.30	30.30	30.30	30.30	30.30	30.30
GRG	4.33	4.33	4.33	4.58	4.58	4.58	4.58	4.58	4.58	4.58	4.58	4.58	4.58	4.58	4.58
Additional changes in net emissions from mineral soils based on application of sewage sludge to agricultural and other land (Step 4)															
GRG	(0.59)	(0.67)	(0.75)	(0.82)	(0.90)	(0.97)	(1.00)	(1.01)	(1.03)	(1.07)	(1.11)	(1.15)	(1.19)	(1.24)	(1.28)
Additional changes in net emissions from mineral soils based on annual manure N production relative to 1997 manure N production (Step 4)															
CRC	1.09	0.70	0.76	0.44	0.34	0.23	0.33	n/a	(0.19)	(0.18)	(0.40)	(0.52)	(0.54)	(0.32)	(0.42)
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
Total Stock Changes by Land Use/Land-Use Change Category (Step 5)															
CRC	(37.77)	(38.16)	(38.10)	(39.28)	(39.38)	(30.77)	(30.66)	(30.99)	(29.28)	(29.04)	(30.45)	(32.18)	(32.48)	(32.39)	(32.90)
LCC	1.47	1.47	1.47	1.47	1.47	(2.82)	(2.82)	(2.82)	(2.82)	(2.82)	(2.82)	(2.82)	(2.82)	(2.82)	(2.82)
GRG	(4.52)	(4.59)	(4.67)	(4.49)	(4.56)	7.57	7.55	7.53	7.52	7.48	7.43	7.39	7.35	7.31	7.26
LCG	(17.64)	(17.64)	(17.64)	(17.93)	(17.93)	(21.12)	(21.12)	(21.12)	(21.12)	(21.12)	(21.12)	(21.12)	(21.12)	(21.12)	(21.12)
Total	(58.5)	(58.9)	(58.9)	(60.2)	(60.4)	(47.1)	(47.1)	(47.4)	(45.7)	(45.5)	(47.0)	(48.7)	(49.1)	(49.0)	(50.0)

Regionally, 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 the per hectare rate varies among MLRAs (Figure A-8, Figure A-9, Figure A-10, Figure A-11). On a per hectare basis, the highest sequestration rates occurred in the southeastern and north-central United States, along with small inclusions in southern Great Plains, southern Corn Belt Region, and Pacific Northwest. For organic soils, emission rates were highest in the regions that contain the majority of the drained organic soils, including the southeastern Coastal Region, central and northern portions of the Pacific Coast, and Great Lakes Region. On a per hectare basis, the emission rate patterns were very similar to the total emissions from MLRAs, 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-8: Net C Stock Change, per Hectare, for Mineral Soils Under Agricultural Management, 1990-1992

Figure A-9: Net C Stock Change, per Hectare, for Mineral Soils Under Agricultural Management, 1993-2004

Figure A-10: Net C Stock Change, per Hectare, for Organic Soils Under Agricultural Management, 1990-1992

Figure A-11: Net C Stock Change, per Hectare, for Organic Soils Under Agricultural Management, 1993-2004

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 municipal solid waste (MSW). By volume, MSW landfill gas is about half methane and half carbon dioxide.[59] The amount and rate of methane 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. Methane can be extracted and either flared or utilized for energy, thus oxidizing to CO_2 during combustion. Of the remaining methane, a portion oxidizes to carbon dioxide (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.[60]

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 methane generation rates for U.S. landfills with gas recovery systems.

From various studies and surveys of the generation and disposal of municipal solid waste, estimates of the amount of waste placed in 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 were used to develop an estimate of the CH_4 generation potential for use in the first order decay model. In addition, the analysis 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 organic content in industrial landfills, CH_4 emissions from industrial landfills were estimated to be seven percent of the total CH_4 generated from MSW at landfills (EPA 1993). Total methane emissions were estimated by adding the methane 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 emissions from U.S. landfills for the years 1990 through 2004 are discussed in greater detail below.

Figure A-12 presents the CH_4 emissions process—from waste generation to emissions—in graphical format.

Figure A-12: Methane Emissions Resulting from Landfilling Municipal and Industrial Waste

*Seven percent represents the relative methane generation at MSW landfills versus industrial landfills and is based on a comparative analysis of MSW and industrial waste (see "step 3" above). Consequently, the value for methane generated at industrial landfills is not subtracted from the value for methane generation at MSW landfills.
[a] BioCycle 2004.
[b] 1960 through 1988 based on EPA 1988 and EPA 1993; 1989 through 2004 based on BioCycle 2004.
[c] Jensen and Pipatti 2002 (first order decay model).
[d] EIA 2005 and flare vendor database.
[e] EIA 2005 and EPA (LMOP) 2005.
[f] Mancinelli and McKay 1985; Czepiel et al 1996.

[59] 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.

[60] 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.

Step 1: Estimate Annual Quantities of Solid Waste Placed in Landfills

For 1989 to 2004, 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 2004), adjusted to include U.S. territories.[61] Table A-197 shows estimates of MSW contributing to CH_4 emissions. The table shows BioCycle estimates of total waste landfilled each year from 1990 through 2000 and for 2002, adjusted for U.S. territories. A linear interpolation was used for 2001 because there was no BioCycle survey for that year. An estimate was made for 2003 and 2004 (assuming the same rate as for 2002) since BioCycle data were not yet available at the time this report was published. The estimates for 2003 and 2004 will be updated when the BioCycle survey results become available in 2006.

Table A-197: Municipal Solid Waste (MSW) 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
Total MSW Generated[a]	271	259	269	283	298	302	302	314	346	353	377	416	455	455	455
Percent of MSW Landfilled[a]	77%	76%	72%	71%	67%	63%	62%	61%	61%	60%	61%	61%	61%	61%	61%
Total MSW Landfilled	209	197	194	201	200	190	187	192	211	212	230	254	279	279	279
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	5,599	5,730	5,859
MSW 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	9,083	9,361	9,640	9,919

[a] Source: *BioCycle* (2004), adjusted for missing U.S. territories using U.S. Census Bureau (2005) population data and per capita generation rate from *BioCycle*. The data, originally reported in short tons, are converted to metric tons. Data shown for 2001 are based on an interpolation because there was no survey in 2001; data shown for 2003 and 2004 are estimates as BioCycle data were not available at the time this report was published.
[b] This estimate represents the waste that has been in place for 30 years or less, which contributes about 90 percent of the methane 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, EPA estimated that 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 Methane Generation at Municipal Solid Waste Landfills

The annual quantity of waste placed in landfills was used in the first order decay (FOD) model to estimate methane generation rates. The FOD model from the IPCC Guidance (Jensen and Pipatti 2002) for generating regional or national estimates of methane from landfills is shown in the two following equations:

$$Q_{T,x} = k \times R_x \times L_o \times e^{-k(T-x)}$$

Where,

$Q_{T,x}$ = Amount of methane (m^3) generated in year T by the waste R_x,
T = Current year,
x = Year of waste input,
k = Methane generation rate constant (yr^{-1}),
R_x = Amount of waste landfilled in year x (Mg), and
L_o = Methane generation potential (m^3/Mg of waste).

To estimate all methane generation in the year T from waste landfilled in previous years, the equation is solved for all values of R_x and the results summed:

$$Q_T = \sum Q_{T,x} \quad \text{(for x equal to initial year to year T)}$$

Where,

[61] 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 2004) and the per capita rate for waste landfilled from BioCycle (2004).

Q_T = Methane generated (m^3) in year T from waste landfilled in previous years (including year T).

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). 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); a value of 100 m^3/Mg recommended in EPA's compilation of emission factors (EPA 1998) based on data from 21 landfills; and a range of 50 to 150 (midrange 100) m^3/Mg based on landfill studies conducted by SCS Engineers. 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- 198.

Table A- 198. 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 methane 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-199.

Table A-199. Percent of US 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.

The methodology apportions R_x for each year according to the population vs. precipitation distributions for each decade. The appropriate k value is assigned to each portion of R_x for the three ranges of rainfall. The FOD model is then used for the three values of k and R_x to estimate methane generation in year T for each year x that waste is landfilled, and then the methane generation is summed to estimate the generation rate for each year in the time series (1990 to 2004).

Step 3: Estimate Methane Generation at Industrial Landfills

Industrial landfills receive waste from factories, processing plants, and other manufacturing activities. Because no data were available on CH_4 generation at industrial landfills, emissions from industrial landfills were assumed to equal seven percent of the total methane emitted from MSW landfills (EPA 1993). This estimate was based on the relative quantities of organic content in industrial waste compared to municipal waste at the time of the EPA study, as shown in the equations below (EPA 1993):

8.6 MMT organic waste in industrial landfills	÷	65% organic content of MSW	=	13.2 MMT of equivalent total MSW

13.2 MMT ÷ 190 MMT total MSW in MSW landfills = 7%

Estimates of CH_4 generation from industrial landfills are shown in Table A-200.

Table A-200: Methane Emissions from Landfills (Gg)

Activity	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
MSW Generation	9,391	9,543	9,679	9,831	9,973	10,080	10,175	10,279	10,435	10,588	10,785	11,045	11,364	11,669	11,960
Industrial Generation	657	668	678	688	698	706	712	720	730	741	755	773	795	817	837
Potential Emissions	10,048	10,211	10,357	10,520	10,671	10,786	10,887	10,999	11,166	11,329	11,540	11,818	12,160	12,486	12,798
Emissions Avoided	(931)	(1,089)	(1,224)	(1,399)	(1,667)	(2,149)	(2,490)	(2,979)	(3,528)	(3,836)	(4,186)	(4,613)	(4,761)	(4,950)	(5,343)
Landfill Gas-to-Energy	(667)	(686)	(743)	(817)	(864)	(1,078)	(1,304)	(1,610)	(1,982)	(2,239)	(2,419)	(2,676)	(2,679)	(2,751)	(2,841)
Flare	(263)	(403)	(481)	(582)	(802)	(1,071)	(1,186)	(1,369)	(1,545)	(1,597)	(1,767)	(1,938)	(2,082)	(2,199)	(2,502)
Oxidation at MSW Landfills	(846)	(845)	(846)	(843)	(831)	(793)	(768)	(730)	(691)	(675)	(660)	(643)	(660)	(672)	(662)
Oxidation at Industrial Landfills	(66)	(67)	(68)	(69)	(70)	(71)	(71)	(72)	(73)	(74)	(75)	(77)	(80)	(82)	(84)
Net Emissions	8,206	8,209	8,219	8,209	8,104	7,773	7,557	7,218	6,874	6,743	6,619	6,484	6,659	6,782	6,709

Note: Totals may not sum due to independent rounding.
Note: MSW generation in Table A-200 represents emissions before oxidation. In other tables throughout the text, MSW generation estimates account for oxidation.
Note: Parentheses denote negative values.

Step 4: Estimate Methane 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.

Step 4a: Estimate Methane 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 2005) and (2) a database compiled by EPA's Landfill Methane Outreach Program (LMOP) (EPA 2005). 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 methane 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. The combined database included 359 landfills with operational LFGTE projects.

Step 4b: Estimate Methane 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 Methane 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 EPA had comprehensive data on flares, 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, EPA was unable to identify a flare 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, EPA would be overestimating methane avoided as both the methane avoided from flaring and the LFGTE project would be counted. To avoid overestimating emissions avoided from flaring, EPA determined the CH_4 avoided from LFGTE projects for which no flare was identified and reduced the flaring estimate from the flare vendor database by this quantity on a state-by-state basis. This step likely underestimates CH_4 avoided due to flaring. EPA took this approach 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). This oxidation factor was applied to the methane generation estimates for both MSW and industrial landfills.

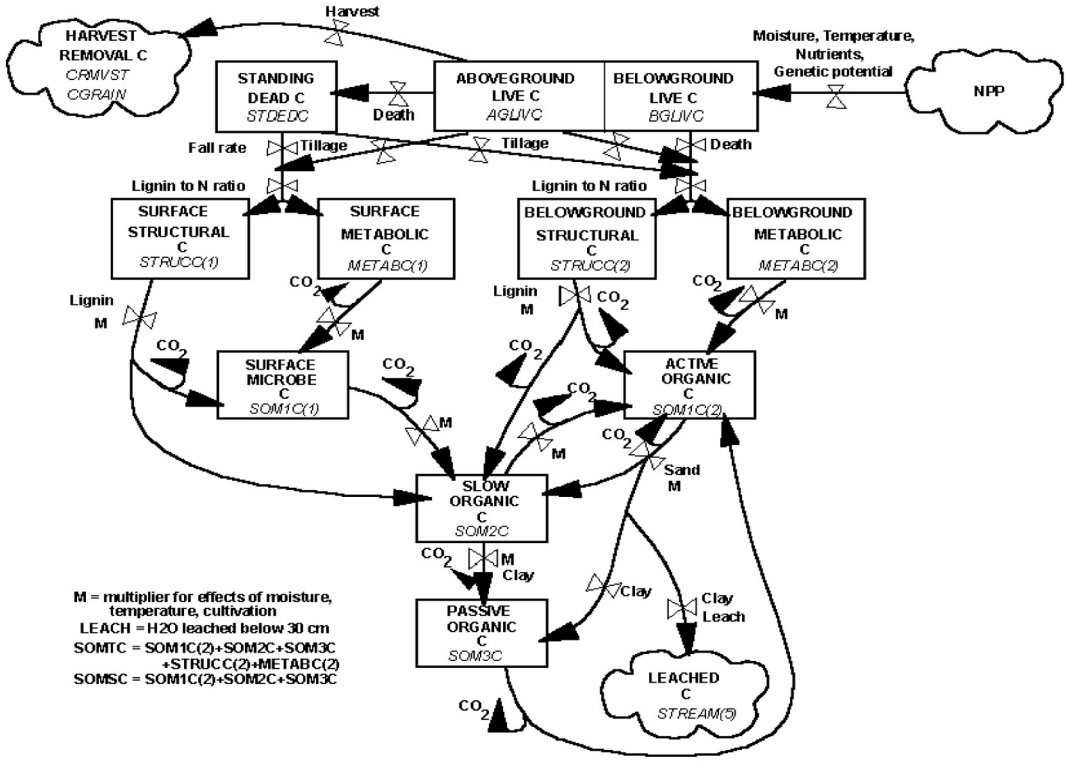
Step 6: Estimate Total Methane Emissions

Total CH_4 emissions were calculated by adding emissions from MSW and industrial waste, and subtracting CH_4 recovered and oxidized, as shown in Table A-200.

Figure A-4

Flow diagram of Carbon submodel (A) and Nitrogen submodel (B)

A



B

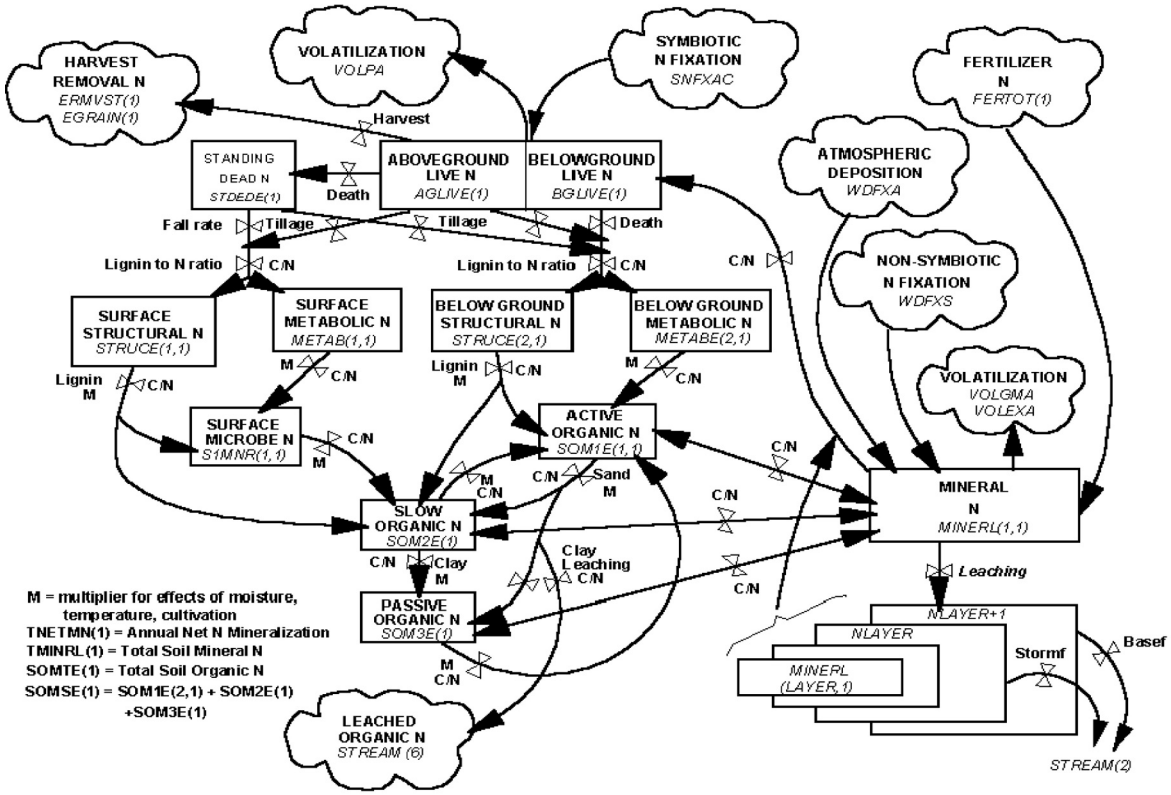
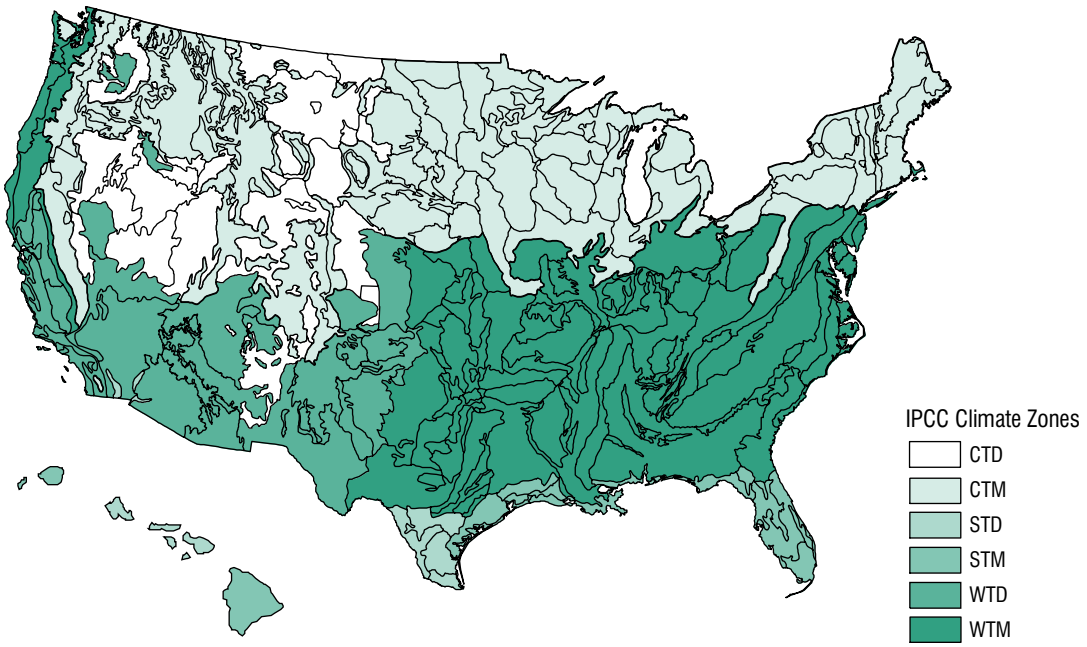


Figure A-5

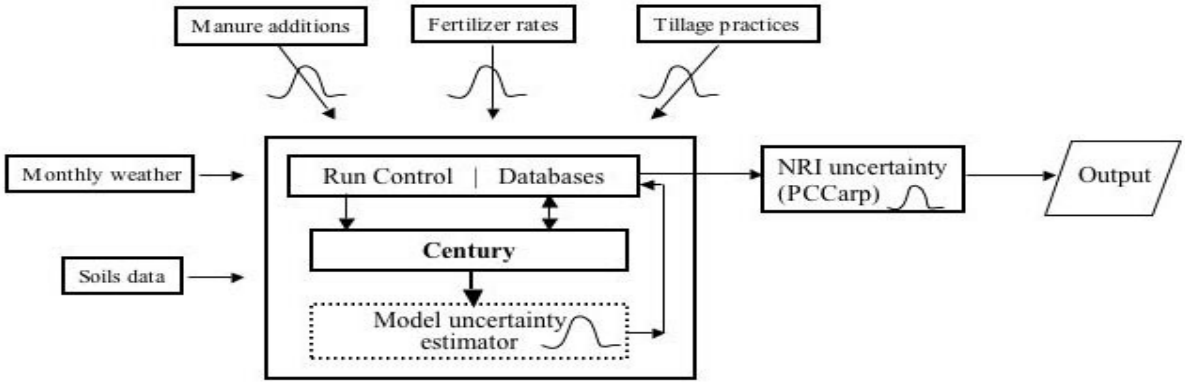
Major Land Resource Areas by IPCC Climate Zone



This figure shows the IPCC climate zone assigned to each of the 180 Major Land Resource Areas (MLRAs) in the United States, based on PRISM climate data averaged for each MRLA.

Figure A-6

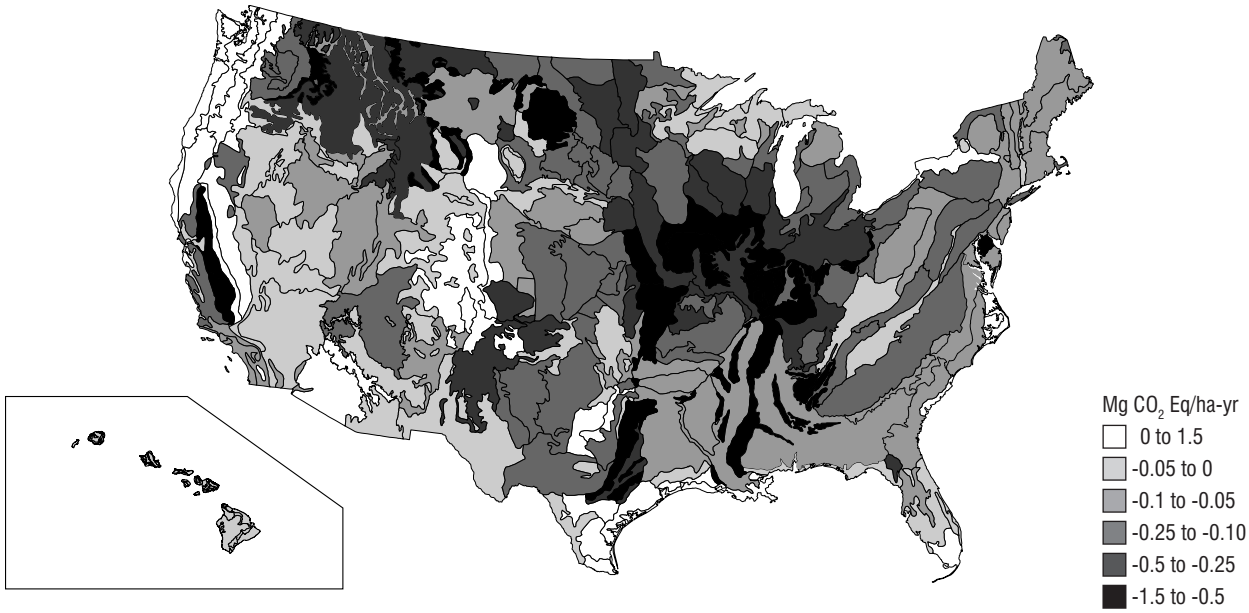
Uncertainty in Data Inputs



Uncertainty in data inputs (i.e. fertilizer, manure, and tillage practices) are estimated using a Monte-Carlo procedure with 100 random draws from input data probability distributions, for each NRI point simulated. Model uncertainty is estimated through an empirically-based approach. Uncertainty in the land representation of NRI is estimated from the statistics compiled from the NRI surveys to determine the land area expansion factors, which are used to upscale data to the national level.

Figure A-7

Net C Stock Change, per Hectare, for Mineral Soils Under Agricultural Management, 1990-1992

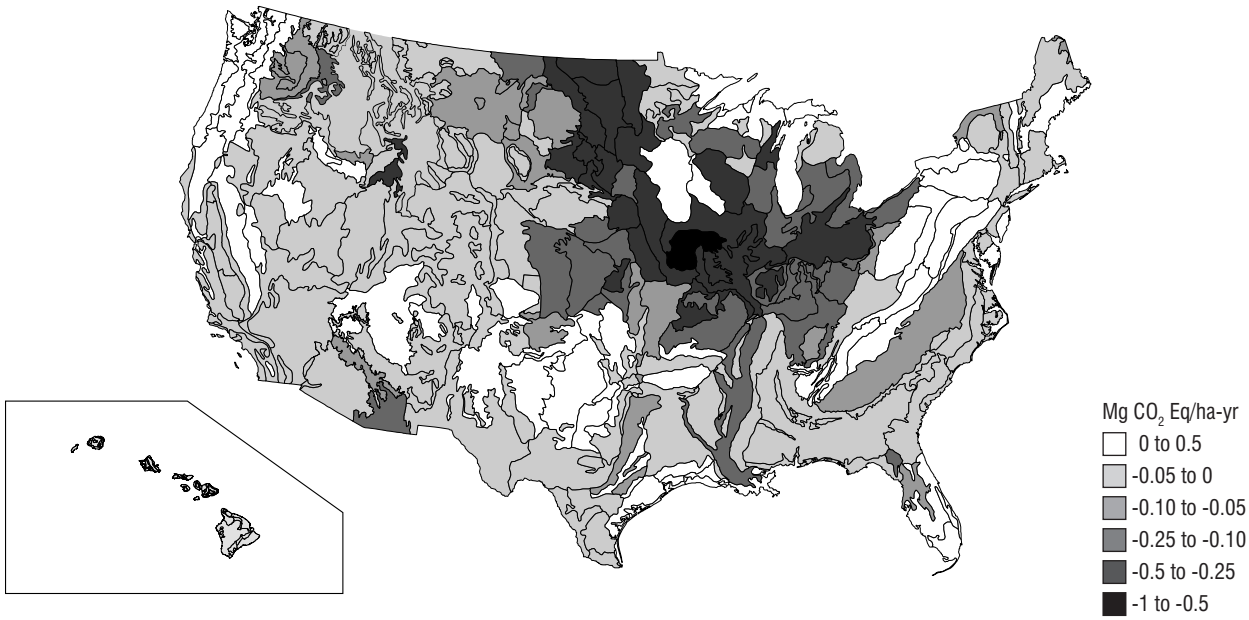


Note: Values greater than zero represent emissions, and values less than zero represent sequestration. Map accounts for fluxes associated with the Tier 2 and 3 inventory computations, but not the Tier 1 estimates. See text for additional details.

This map shows the spat
each polygon represents the average annual flux per hectare for the total area of managed mineral soils in that polygon.

Figure A-8

Net C Stock Change, per Hectare, for Mineral Soils Under Agricultural Management, 1993-2004

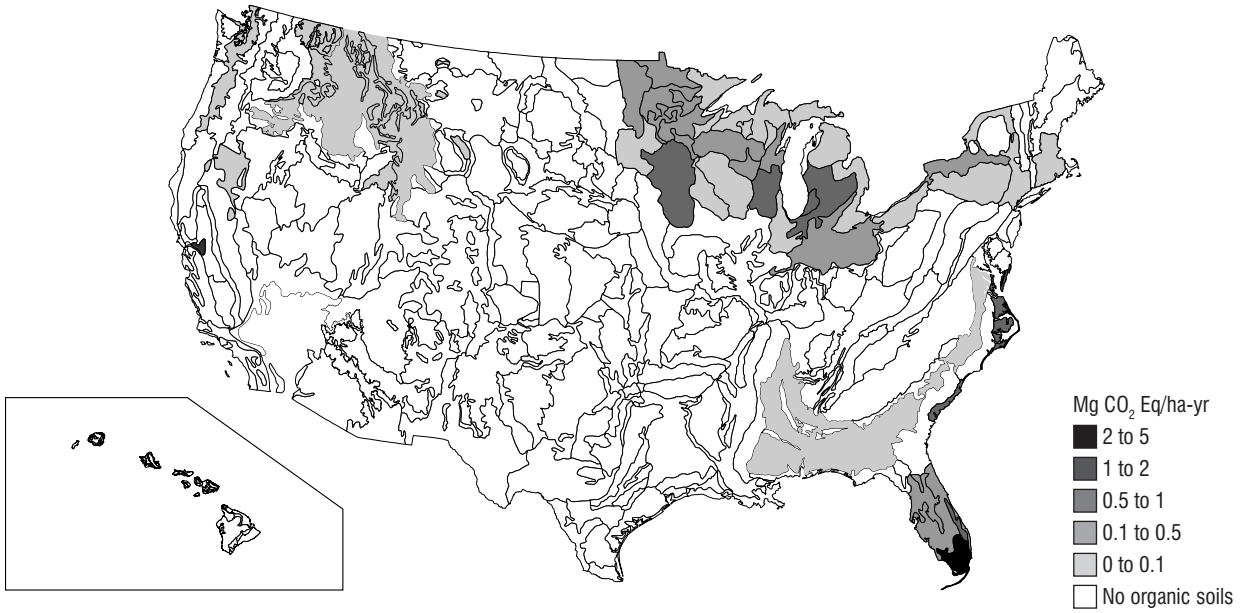


Note: Values greater than zero represent emissions, and values less than zero represent sequestration. Map accounts for fluxes associated with the Tier 2 and 3 inventory computations, but not the Tier 1 estimates. See text for additional details.

This map shows the spat
each polygon represents the average annual flux per hectare for the total area of managed mineral soils in that polygon.

Figure A-9

Net C Stock Change, per Hectare, for Organic Soils Under Agricultural Management, 1990-1992

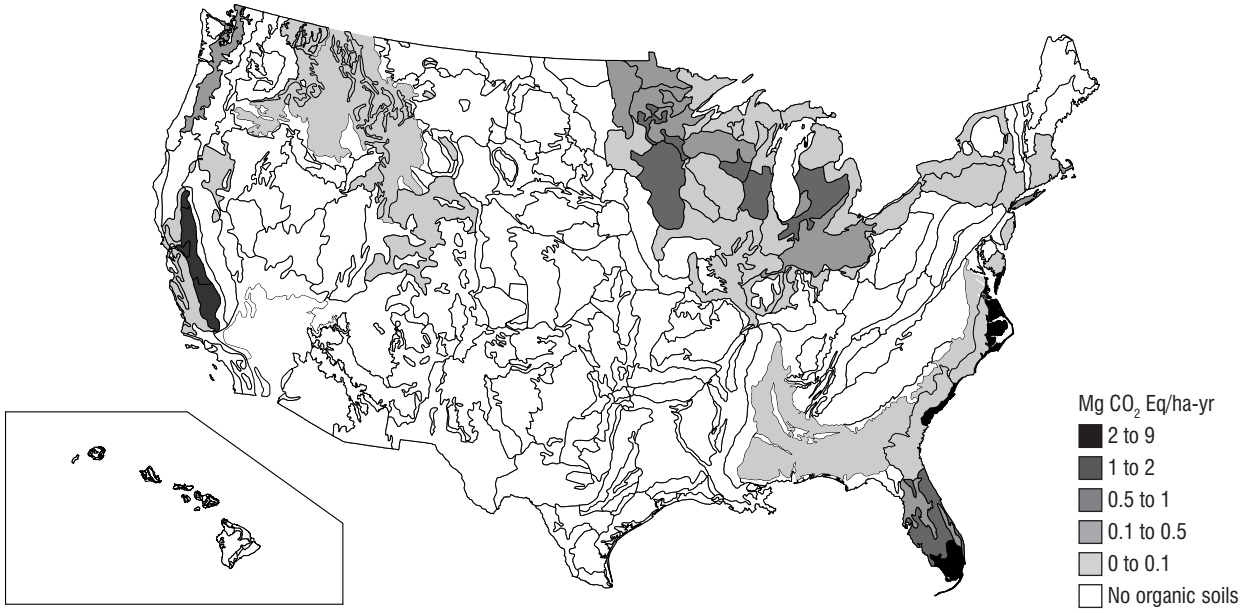


Note: Values greater than zero represent emissions.

This map shows the spat
each polygon represents the average annual flux per hectare for the total area of managed organic soils in that polygon.

Figure A-10

Net C Stock Change, per Hectare, for Organic Soils Under Agricultural Management, 1993-2004



Note: Values greater than zero represent emissions.

This map shows the spat
each polygon represents the average annual flux per hectare for the total area of managed organic soils in that polygon.

Descriptions of Figures: Annex 3

Figure A-4 illustrates a diagram of the carbon submodel and the nitrogen submodel.

Figure A-5 is a map of the U.S. showing the IPCC climate zones assigned to each Major Land Resource Area. Each Major Land Resource Area represents a geographic unit with relatively similar soils, climate, water resources, and land uses.

Figure A-6 illustrates the uncertainty in data inputs.

Figures A-7 through A-10 are maps of the United States illustrating CO_2 flux from mineral and organic soils for the years 1990-2004. For a full description of figures A-7 through A-10, refer to the Inventory text found in Chapter 7.

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 Annex 2.1. 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 carbon-based fuels are brought into a national economy, they are either saved in some way (e.g., stored in products, kept in fuel stocks, or left unoxidized in ash) or combusted, and therefore the carbon in them is oxidized and released into the atmosphere. Accounting for actual consumption of fuels at the sectoral or sub-national level is not required. 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, and ammonia; and other oil and residual fuel oil used in the manufacture of carbon 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-201.

The carbon 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-201 for 2004), 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-202. The resulting fuel type-specific energy data for 2004 are provided in Table A-203.

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, carbon 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 carbon 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 carbon 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 have different heat contents. Therefore, United States fuel statistics were converted to their heat equivalents before estimating apparent consumption. Results are provided in Table A-202.

Step 3: Estimate Carbon Emissions

Once apparent consumption is estimated, the remaining calculations are similar to those for the "bottom-up" Sectoral Approach (see Annex 2.1). Potential CO_2 emissions were estimated using fuel-specific carbon coefficients (see Table A-203).[1] The carbon in products from non-energy uses of fossil fuels (e.g., plastics or asphalt) was then estimated and subtracted (see Table A-205). 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 carbon that remained unoxidized as a result of incomplete combustion (e.g., carbon contained in ash or soot).[2]

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 carbon to units of CO_2. Actual carbon emissions were multiplied by the molecular-to-atomic weight ratio of CO_2 to carbon (44/12) to obtain total carbon dioxide emitted from fossil fuel combustion in teragrams (Tg). The results are contained in Table A-204.

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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-204 for more specific source information.

[2] For the portion of carbon that is unoxidized during coal combustion, the IPCC suggests a global average value of 2 percent. However, because combustion technologies in the United States are more efficient, the United States inventory uses 1 percent in its calculations for petroleum and coal and 0.5 percent for natural gas.

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 (Annex 2.1) and Carbon Emitted from Non-Energy Uses of Fossil Fuels (Annex 2.3). 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 carbon 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-207 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 2004. The greatest differences lie in lower estimates for both petroleum and natural gas consumption for the Reference Approach (1.0 percent).

There are several potential sources for the discrepancies in consumption estimates:

- *Product Definitions.* The fuel categories in the Reference Approach are different from those used in the Sectoral Approach, particularly for petroleum. For example, the Reference Approach estimates apparent consumption for crude oil. Crude oil is not typically consumed directly, but refined into other products. As a result, the United States does not focus on estimating the energy content of the various grades of crude oil, but rather estimating the energy content of the various products resulting from crude oil refining. The United States does not believe that estimating apparent consumption for crude oil, and the resulting energy content of the crude oil, is the most reliable method for the United States to estimate its energy consumption. Other differences in product definitions include using sector-specific coal statistics in the Sectoral Approach (i.e., residential, commercial, industrial coking, industrial other, and transportation coal), while the Reference Approach characterizes coal by rank (i.e. anthracite, bituminous, etc.). Also, the liquefied petroleum gas (LPG) statistics used in the bottom-up calculations are actually a composite category composed of natural gas liquids (NGL) and LPG.

- *Heat Equivalents.* It can be difficult to obtain heat equivalents for certain fuel types, particularly for categories such as "crude oil" where the key statistics are derived from thousands of producers in the United States and abroad.

- *Possible inconsistencies in U.S. Energy Data.* The United States has not focused its energy data collection efforts on obtaining the type of aggregated information used in the Reference Approach. Rather, the United States believes that its emphasis on collection of detailed energy consumption data is a more accurate methodology for the United States to obtain reliable energy data. Therefore, top-down statistics used in the Reference Approach may not be as accurately collected as bottom-up statistics applied to the Sectoral Approach.

- *Balancing Item.* The Reference Approach uses *apparent* consumption estimates while the Sectoral Approach uses *reported* consumption estimates. While these numbers should be equal, there always seems to be a slight difference that is often accounted for in energy statistics as a “balancing item.”

Differences in Estimated CO_2 Emissions

Given these differences in energy consumption data, the next step for each methodology involved estimating emissions of CO_2. Table A-208 summarizes the differences between the two methods in estimated carbon emissions.

As mentioned above, for 2004, 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 0.6 percent higher. Estimates of coal and natural gas emissions using each approach yield very

similar values (within 0.8 percent), though petroleum emission estimates from the Reference Approach are slightly higher (1.4 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 carbon content between many different sources of crude, particularly since information on the carbon content of crude oil is not regularly collected.

- *Carbon Coefficients.* The Reference Approach relies on several default carbon 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 carbon 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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USGS (1998) *CoalQual Database Version 2.0*, U.S. Geological Survey.

Table A-201: 2004 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	1,700	a	a	a			
	Bituminous Coal	546,605	a	a	a			
	Sub-bituminous Coal	479,634	a	a	a	423		
	Lignite	83,540	a	a	a	3,542		
	Coke		6,873	1,319	(28)			
	Unspecified Coal		27,280	47,998	(18,221)	15,857		1,783
Gas Fuels (Million Cubic Feet)	Natural Gas	19,027,423	4,258,558	854,138	110,436	236,320		24,010
Liquid Fuels (Thousand Barrels)	Crude Oil	1,983,302	3,692,063	9,783	54,078			
	Nat Gas Liquids and LRGs	662,151	111,710	16,649	10,196			3,484
	Other Liquids	(13,459)	361,583	22,976	19,177			
	Motor Gasoline	167,587	181,682	45,498	(3,680)	85,297		41,230
	Aviation Gasoline		119	0	139			
	Kerosene		765	1,333	(699)			1,717
	Jet Fuel		46,505	14,799	1,302		150,389	12,681
	Distillate Fuel		119,118	40,101	(10,270)		14,896	18,284
	Residual Fuel		156,024	74,885	4,563	9,000	56,257	34,869
	Naphtha for petrochemical feedstocks		48,800	0	(207)			
	Petroleum Coke		11,912	128,034	(1,939)	13,828		
	Other Oil for petrochemical feedstocks		57,804	0	245	27,456		
	Special Naphthas		2,984	9,902	(266)			
	Lubricants		2,912	14,916	481			281
	Waxes		1,470	1,532	(87)			
	Asphalt/Road Oil		15,604	2,215	2,829			
	Still Gas		0	0	0			
	Misc. Products		49	1,012	640			26,660

[a] Included in Unspecified Coal

Data Sources: Solid and Gas Fuels: EIA (2005a); Liquid Fuels: EIA (1995-2005).

Table A-202: Conversion Factors to Energy Units (Heat Equivalents)

Fuel Category (Units)	Fuel Type	Production	Imports	Exports	Stock Change	Adjustment	Bunkers	U.S. Territories
Solid Fuels (Million Btu/Short Ton)	Anthracite Coal	22.57						
	Bituminous Coal	23.89						
	Sub-bituminous Coal	17.14				28.16		
	Lignite	12.87				12.87		
	Coke		24.80	24.80	24.80			
	Unspecified		25.00	25.97	20.86	27.43		25.14
Natural Gas (BTU/Cubic Foot)		1,030	1,023	1,009	1,030	1,025		1,030
Liquid Fuels (Million Btu/Barrel)	Crude Oil	5.80	5.98	5.80	5.80		5.80	5.80
	Nat Gas Liquids and LRGs	3.72	3.72	3.72	3.72		3.72	3.72
	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 (2005c); Unspecified Solid Fuels: EIA (2005b); Coke, Natural Gas and Petroleum Products: EIA (2005a).

Table A-203: 2004 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	38.4							38.4
	Bituminous Coal	13,058.4							13,058.4
	Sub-bituminous Coal	8,220.9				11.9			8,209.0
	Lignite	1,074.8				45.6			1,029.3
	Coke		170.5	32.7	(0.7)				138.4
	Unspecified		682.0	1,246.6	(380.1)	434.9		44.8	(574.6)
Gas Fuels	Natural Gas	19,598.2	4,356.5	861.8	113.7	242.2		24.7	22,761.7
Liquid Fuels	Crude Oil	11,503.2	22,078.5	56.7	313.7				33,211.3
	Nat Gas Liquids and LRGs	2,465.9	416.0	62.0	38.0			13.0	2,794.9
	Other Liquids	(78.4)	2,106.2	133.8	111.7				1,782.3
	Motor Gasoline	874.0	947.5	237.3	(19.2)	444.8		215.0	1,373.5
	Aviation Gasoline		0.6	0.0	0.7				(0.1)
	Kerosene		4.3	7.6	(4.0)			9.7	10.5
	Jet Fuel		263.7	83.9	7.4		852.7	71.9	(608.4)
	Distillate Fuel		693.9	233.6	(59.8)		86.8	106.5	539.8
	Residual Oil		980.9	470.8	28.7	56.6	353.7	219.2	290.4
	Naphtha for petrochemical feedstocks		256.1	0.0	(1.1)				257.2
	Petroleum Coke		71.8	771.3	(11.7)	83.3			(771.1)
	Other Oil for petrochemical feedstocks		336.7	0.0	1.4	159.9			175.3
	Special Naphthas		15.7	52.0	(1.4)				(34.9)
	Lubricants		17.7	90.5	2.9			1.7	(74.0)
	Waxes		8.1	8.5	(0.5)				0.1
	Asphalt/Road Oil		103.5	14.7	18.8				70.1
	Still Gas		0.0	0.0	0.0				0.0
	Misc. Products		0.3	5.9	3.7			154.5	145.2
Total		56,755.3	33,510.5	4,369.6	162.3	1,479.2	1,293.2	861.1	83,822.7

Note: Totals may not sum due to independent rounding.

Table A-204: 2004 Potential Carbon Dioxide Emissions

Fuel Category	Fuel Type	Apparent Consumption (QBtu)	Carbon Coefficients (Tg Carbon/QBtu)	Potential Emissions (Tg CO_2 Eq.)
Solid Fuels	Anthracite Coal	0.038	28.26	4.0
	Bituminous Coal	13.058	25.49	1,220.5
	Sub-bituminous Coal	8.209	26.48	797.0
	Lignite	1.029	26.30	99.3
	Coke	0.138	31.00	15.7
	Unspecified	(0.620)	25.34	(53.4)
Gas Fuels	Natural Gas	22.762	14.47	1,207.7
Liquid Fuels	Crude Oil	33.211	20.33	2,475.4
	Nat Gas Liquids and LRGs	2.795	16.99	174.1
	Other Liquids	1.782	20.33	132.8
	Motor Gasoline	1.374	19.33	97.4
	Aviation Gasoline	(0.000)	18.87	(0.0)
	Kerosene	0.010	19.72	0.8
	Jet Fuel	(0.608)	19.33	(43.1)
	Distillate Fuel	0.540	19.95	39.5
	Residual Oil	0.290	21.49	22.9
	Naphtha for petrochemical feedstocks	0.257	18.14	17.1
	Petroleum Coke	(0.771)	27.85	(78.7)
	Other Oil for petrochemical feedstocks	0.175	19.95	12.8
	Special Naphthas	(0.035)	19.86	(2.5)
	Lubricants	(0.074)	20.24	(5.5)
	Waxes	0.000	19.81	0.0
	Asphalt/Road Oil	0.070	20.62	5.3
	Still Gas	0.000	17.51	0.0
	Misc. Products	0.145	20.33	10.8
Total				6,149.8

Data Sources: Carbon content coefficients by coal rank from USGS (1998) and SAIC (2004); Unspecified Solid Fuels, Natural Gas and Liquid Fuels: EIA (2005a).
Note: Totals may not sum due to independent rounding.

Table A-205: 2004 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	214.3	31.00	6.6	0.10	2.44
Natural Gas	380.1	14.47	5.5	0.62	12.60
Asphalt & Road Oil	1,303.9	20.62	26.9	1.00	98.58
LPG	1,437.5	16.81	24.2	0.62	55.36
Lubricants	314.8	20.24	6.4	0.09	2.16
Pentanes Plus	156.5	18.24	2.9	0.62	6.54
Petrochemical Feedstocks	a	a	a	a	57.52
Petroleum Coke	189.4	27.85	5.3	0.50	9.67
Special Naphtha	47.2	19.86	0.9	0.62	2.15
Waxes/Misc.	a	a	a	a	1.72
Misc. U.S. Territories Petroleum	a	a	a	a	1.13
Total					249.9

[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-206: 2004 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	2,083.1	2.4	2,080.7	99.0%	2,059.9
Petroleum	2,859.0	234.8	2,624.2	99.0%	2,597.9
Natural Gas	1,207.7	12.6	1,195.1	99.5%	1,189.1
Total	6,149.8	249.9	5,899.9	-	5,846.9

Note: Totals may not sum due to independent rounding.

Table A-207: 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
Sectoral	69,870.9	69,479.5	71,110.2	72,901.2	74,196.2	75,174.5	77,735.3	78,683.5	79,108.3	80,413.5	82,693.3	81,486.6	82,098.6	82,738.8	84,472.9
Coal	18,074.7	17,999.9	18,191.3	18,951.9	19,046.5	19,231.5	20,151.5	20,578.5	20,817.1	20,878.9	21,833.9	21,247.2	21,207.0	21,667.5	21,912.7
Natural Gas	19,375.8	19,765.4	20,438.1	20,994.7	21,455.7	22,426.5	22,837.6	22,966.8	22,559.5	22,641.7	23,554.5	22,642.7	23,370.3	22,866.9	22,987.1
Petroleum	32,420.3	31,714.3	32,480.8	32,954.6	33,694.0	33,516.5	34,746.2	35,138.2	35,731.6	36,892.9	37,305.0	37,596.7	37,521.3	38,204.4	39,573.1
Reference (Apparent)	69,125.2	68,348.8	69,894.8	71,695.3	73,205.3	74,113.3	76,558.8	77,991.3	78,072.3	79,240.4	81,675.2	80,741.0	81,582.5	82,149.4	83,822.7
Coal	17,602.8	17,400.9	17,725.1	18,260.8	18,724.4	18,610.6	19,519.0	20,160.7	20,033.0	20,080.7	21,039.2	20,781.3	20,875.0	21,178.1	21,898.9
Natural Gas	19,746.7	19,765.4	20,425.2	20,980.8	21,459.9	22,411.9	22,816.2	22,951.1	22,531.1	22,635.1	23,598.7	22,659.2	23,360.9	22,860.2	22,761.7
Petroleum	31,775.6	31,182.4	31,744.5	32,453.7	33,021.0	33,090.8	34,223.6	34,879.5	35,508.3	36,524.7	37,037.3	37,300.5	37,346.6	38,111.1	39,162.1
Difference	-1.1%	-1.6%	-1.7%	-1.7%	-1.3%	-1.4%	-1.5%	-0.9%	-1.3%	-1.5%	-1.2%	-0.9%	-0.6%	-0.7%	-0.8%
Coal	-2.6%	-3.3%	-2.6%	-3.6%	-1.7%	-3.2%	-3.1%	-2.0%	-3.8%	-3.8%	-3.6%	-2.2%	-1.6%	-2.3%	-0.1%
Natural Gas	1.9%	0.0%	-0.1%	-0.1%	0.0%	-0.1%	-0.1%	-0.1%	-0.1%	0.0%	0.2%	0.1%	0.0%	0.0%	-1.0%
Petroleum	-2.0%	-1.7%	-2.3%	-1.5%	-2.0%	-1.3%	-1.5%	-0.7%	-0.6%	-1.0%	-0.7%	-0.8%	-0.5%	-0.2%	-1.0%

* 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-208: 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
Sectoral	4,813.3	4,779.5	4,876.0	5,006.0	5,082.5	5,129.1	5,315.8	5,381.9	5,424.2	5,502.6	5,674.0	5,617.6	5,637.8	5,704.2	5,809.6
Coal	1,684.1	1,678.0	1,696.0	1,767.5	1,777.3	1,796.5	1,882.1	1,922.8	1,945.3	1,951.3	2,040.6	1,985.6	1,982.0	2,025.2	2,049.4
Natural Gas	1,013.1	1,034.0	1,070.5	1,099.0	1,121.7	1,172.6	1,194.0	1,200.3	1,177.9	1,181.6	1,228.7	1,182.0	1,219.8	1,192.9	1,198.7
Petroleum	2,116.1	2,067.6	2,109.5	2,139.4	2,183.5	2,160.1	2,239.7	2,258.7	2,301.1	2,369.7	2,404.7	2,450.0	2,436.1	2,486.1	2,561.5
Reference (Apparent)	4,771.6	4,717.7	4,819.9	4,951.9	5,048.9	5,092.9	5,273.5	5,383.1	5,392.4	5,455.9	5,642.1	5,608.0	5,657.9	5,719.3	5,846.9
Coal	1,641.6	1,625.0	1,655.1	1,708.1	1,752.6	1,743.4	1,827.8	1,888.8	1,880.8	1,889.0	1,977.1	1,954.6	1,963.5	1,990.8	2,059.9
Natural Gas	1,034.0	1,035.3	1,070.9	1,099.6	1,123.2	1,173.2	1,194.0	1,200.8	1,177.3	1,182.2	1,232.0	1,183.1	1,220.2	1,194.3	1,189.1
Petroleum	2,096.0	2,057.4	2,093.9	2,144.2	2,173.2	2,176.3	2,251.7	2,293.4	2,334.3	2,384.7	2,433.0	2,470.4	2,474.2	2,534.2	2,597.9
Difference	-0.9%	-1.3%	-1.2%	-1.1%	-0.7%	-0.7%	-0.8%	0.0%	-0.6%	-0.8%	-0.6%	-0.2%	0.4%	0.3%	0.6%
Coal	-2.5%	-3.2%	-2.4%	-3.4%	-1.4%	-3.0%	-2.9%	-1.8%	-3.3%	-3.2%	-3.1%	-1.6%	-0.9%	-1.7%	0.5%
Natural Gas	2.1%	0.1%	0.0%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.3%	0.1%	0.0%	0.1%	-0.8%
Petroleum	-0.9%	-0.5%	-0.7%	0.2%	-0.5%	0.7%	0.5%	1.5%	1.4%	0.6%	1.2%	0.8%	1.6%	1.9%	1.4%

+ 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[64] 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[65]
- 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.[66] 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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[64] 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).

[65] 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.

[66] 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)

Carbon dioxide is injected into underground formations to increase crude oil production, in a field technique known as Enhanced Oil Recovery (EOR). It is thought that much of the injected CO_2 may be effectively and permanently sequestered in the underground formations, however, the fraction of the injected CO_2 that is re-released remains uncertain. The fraction re-released varies from one formation to another depending upon the field geology and the gas capture/reinjection technology employed at the wellhead. In 2002 the amount of CO_2 derived from natural sources and natural gas processing plants and used in EOR was approximately 12 Tg CO_2. Further research into EOR is required before the resulting CO_2 emissions can be adequately quantified (see CO_2 Consumption in the Industrial Processes Chapter).

CO_2 from Natural Gas Processing

Carbon dioxide (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 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 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, and is assumed to remain sequestered in the underground formations.

Data obtained from EIA's Natural Gas Annual and the Minerals Management Service's report on emissions in the Gulf of Mexico were used to develop a preliminary estimate of emissions. In 2002, the total amount of CO_2 produced from natural gas processing was 29.5 Tg CO_2 Eq. (29,455 Gg). There are four gas processing plants currently in operation—one in Wyoming and three in Texas—that produce CO_2 for use in enhanced oil recovery. In 2002, the amount of CO_2 produced by these facilities and used for enhanced oil recovery was 4.7 Tg CO_2 Eq. (4,696 Gg). This amount is not emitted to the atmosphere and is therefore subtracted from the total amount of CO_2 produced from natural gas to calculate the total amount of CO_2 produced from natural gas processing that is emitted to the atmosphere, which was 24.7 Tg CO_2 Eq. (24,654 Gg) in 2002. However, since these estimates have not been integrated with CH_4 from Natural Gas Systems and CO_2 from Fossil Fuel Combustion estimates to ensure that there is no double-counting, they are not yet included in national estimates.

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.[67] It can be thought of as the geological predecessor to crude oil. Carbon dioxide 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

Carbon dioxide is formed by the oxidation of petroleum coke in the production of both calcium carbide and silicon 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 these sources explicitly. (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% of the carbon used in ferroalloy production is derived from petroleum coke and that all of the carbon used in iron and steel production is derived from coal coke or petroleum coke. It is also assumed that all of the carbon used in lead and zinc production is derived from coal coke. It is possible that some non-coke carbon 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 carbon 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 and Forestry chapter. It is assumed for the purposes of the CO_2 emission calculation that no wood or other biogenic carbon is used in any of these industrial processes. Some biogenic carbon 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 carbon used in manufacturing carbon 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 carbon 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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[67] 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. Carbon dioxide 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.[68] Annual nitrogen excretion rates were estimated from protein intake. The recommended protein intake for an average size adult of each animal type[69] 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.[70] 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.[71] 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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[68] Pet Food Institute (1999) *Pet Incidence Trend Report*. Pet Food Institute, Washington DC.

[69] Bright, S. (1999) Personal communication between Marco Alcaraz of ICF Consulting and Susan Bright of the Dupont Animal Clinic, Washington, DC, August 1999.

[70] Swenson, M.J. and W.G. Reece, eds. (1993) *Duke's Physiology of Domestic Animals*. Cornell University Press. 11th Edition.

[71] 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. garbage, industrial wastes, animal carcasses, etc.) The portion of emitted N_2O that originates from human excrement is currently estimated under the Human Sewage source category- based upon average dietary assumptions. 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>.

Freedonia Group, Inc. (2000) *Report 1091: Industrial Gases To 2003, Record 4, Carbon Dioxide Shipments and Production, 1989-2009.* Cleveland, OH.

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-209).

> *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.*[72]

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-209: 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

[72] 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-210 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-210: 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 Third Assessment Report (TAR), providing the most current and comprehensive scientific assessment of climate change (IPCC 2001). Within this report, the GWPs of several gases were revised relative to the IPCC's Second Assessment Report (SAR) (IPCC 1996), and new GWPs have been calculated for an expanded set of gases. Since the SAR, the IPCC has applied an improved calculation of CO_2 radiative forcing and an improved CO_2 response function (presented in WMO 1999). The GWPs are drawn from WMO (1999) and the SAR, 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 12 percent lower than that in the SAR, 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. The changes are described in the TAR as follows:

New categories of gases include fluorinated organic molecules, many of which are ethers that are proposed as halocarbon substitutes. Some of the GWPs have larger uncertainties than that of others, particularly for those gases where detailed laboratory data on lifetimes are not yet available. The direct GWPs have been calculated relative to CO_2 using an improved calculation of the CO_2 radiative forcing, the SAR response function for a CO_2 pulse, and new values for the radiative forcing and lifetimes for a number of halocarbons.

Table A- 211 compares the lifetimes and GWPs for the SAR and TAR. As can be seen in Table A- 211, GWPs changed anywhere from a decrease of 35 percent to an increase of 49 percent.

Table A- 211: Comparison of GWPs and lifetimes used in the SAR and the TAR

	Lifetime (years)		GWP (100 year)			
Gas	SAR	TAR	SAR	TAR	Difference	
Carbon dioxide (CO_2)	50-200	5-200[a]	1	1	NC	NC
Methane (CH_4)[b]	12±3	8.4/12[c]	21	23	2	10%
Nitrous oxide (N_2O)	120	120/114 [c]	310	296	(14)	(5%)
Hydrofluorocarbons						
HFC-23	264	260	11,700	12,000	300	3%
HFC-32	5.6	5.0	650	550	(100)	(15%)
HFC-41	3.7	2.6	150	97	(53)	(35%)
HFC-125	32.6	29	2,800	3,400	600	21%
HFC-134	10.6	9.6	1,000	1,100	100	10%
HFC-134a	14.6	13.8	1,300	1,300	NC	NC
HFC-143	3.8	3.4	300	330	30	10%
HFC-143a	48.3	52	3,800	4,300	500	13%
HFC-152	NA	0.5	NA	43	NA	NA
HFC-152a	1.5	1.4	140	120	(20)	(14%)
HFC-161	NA	0.3	NA	12	NA	NA
HFC-227ea	36.5	33.0	2,900	3,500	600	21%
HFC-236cb	NA	13.2	NA	1,300	NA	NA
HFC-236ea	NA	10	NA	1,200	NA	NA
HFC-236fa	209	220	6,300	9,400	3,100	49%
HFC-245ca	6.6	5.9	560	640	80	14%
HFC-245fa	NA	7.2	NA	950	NA	NA
HFC-365mfc	NA	9.9	NA	890	NA	NA
HFC-4310mee	17.1	15	1,300	1,500	200	15%
Iodocarbons						
FIC-1311	<0.005	0.005	<1	1	NC	NC
Fully Fluorinated Species						
SF_6	3,200	3,200	23,900	22,200	(1,900)	(7%)
CF_4	50,000	50,000	6,500	5,700	(800)	(12%)
C_2F_6	10,000	10,000	9,200	11,900	2,700	29%
C_3F_8	2,600	2,600	7,000	8,600	1,600	23%
C_4F_{10}	2,600	2,600	7,000	8,600	1,600	23%
c-C_4F_8	3,200	3,200	8,700	10,000	1,300	15%
C_5F_{12}	4,100	4,100	7,500	8,900	1,400	19%
C_6F_{14}	3,200	3,200	7,400	9,000	1,600	22%
Ethers and Halogenated Ethers						
CH_3OCH_3	NA	0.015	NA	1	NA	NA
$(CF_3)_2CFOCH_3$	NA	3.4	NA	330	NA	NA
$(CF_3)CH_2OH$	NA	0.5	NA	57	NA	NA
$CF_3CF_2CH_2OH$	NA	0.4	NA	40	NA	NA
$(CF_3)_2CHOH$	NA	1.8	NA	190	NA	NA
HFE-125	NA	150	NA	14,900	NA	NA
HFE-134	NA	26.2	NA	6,100	NA	NA
HFE-143a	NA	4.4	NA	750	NA	NA
HCFE-235da2	NA	2.6	NA	340	NA	NA
HFE-245cb2	NA	4.3	NA	580	NA	NA
HFE-245fa2	NA	4.4	NA	570	NA	NA
HFE-254cb2	NA	0.22	NA	30	NA	NA
HFE-347mcc3	NA	4.5	NA	480	NA	NA

HFE-356pcf3	NA	3.2	NA	430	NA	NA
HFE-374pcf2	NA	5.0	NA	540	NA	NA
HFE-7100	NA	5.0	NA	390	NA	NA
HFE-7200	NA	0.77	NA	55	NA	NA
H-Galden 1040x	NA	6.3	NA	1,800	NA	NA
HG-10	NA	12.1	NA	2,700	NA	NA
HG-01	NA	6.2	NA	1,500	NA	NA
Others[d]						
NF_3	NA	740	NA	10,800	NA	NA
SF_5CF_3	NA	>1,000	NA	>17,500	NA	NA
c-C_3F_6	NA	>1,000	NA	>16,800	NA	NA
HFE-227ea	NA	11	NA	1,500	NA	NA
HFE-236ea2	NA	5.8	NA	960	NA	NA
HFE-236fa	NA	3.7	NA	470	NA	NA
HFE-245fa1	NA	2.2	NA	280	NA	NA
HFE-263fb2	NA	0.1	NA	11	NA	NA
HFE-329mcc2	NA	6.8	NA	890	NA	NA
HFE-338mcf2	NA	4.3	NA	540	NA	NA
HFE-347-mcf2	NA	2.8	NA	360	NA	NA
HFE-356mec3	NA	0.94	NA	98	NA	NA
HFE-356pcc3	NA	0.93	NA	110	NA	NA
HFE-356pcf2	NA	2.0	NA	260	NA	NA
HFE-365mcf3	NA	0.11	NA	11	NA	NA
$(CF_3)_2CHOCHF_2$	NA	3.1	NA	370	NA	NA
$(CF_3)_2CHOCH_3$	NA	0.25	NA	26	NA	NA
-$(CF_2)_4CH(OH)$-	NA	0.85	NA	70	NA	NA

[a] No single lifetime can be determined for carbon dioxide. (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)

When the GWPs from the TAR are applied to the emission estimates presented in this report, total emissions for the year 2004 are 7,107.9 Tg CO_2 Eq., as compared to 7,074.4 Tg CO_2 Eq. when the GWPs from the SAR are used (a 0.5 percent difference). Table A-212 provides a detailed summary of U.S. greenhouse gas emissions and sinks for 1990 through 2004, using the GWPs from the TAR. The adjusted greenhouse gas emissions are shown for each gas in units of Tg CO_2 Eq. in Table A-213. The correlating percent change in emissions of each gas is shown in Table A-214. 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-215 summarizes the emissions and resulting change in emissions using GWPs from the SAR or the TAR for 1990 and 2004.

Table A-212: Recent Trends in U.S. Greenhouse Gas Emissions and Sinks using the TAR GWPs (Tg CO_2 Eq.)

Gas/Source	1990	1998	1999	2000	2001	2002	2003	2004
CO_2	5,005.3	5,620.2	5,695.0	5,864.5	5,795.2	5,815.9	5,877.7	5,988.0
Fossil Fuel Combustion	4,696.6	5,271.8	5,342.4	5,533.7	5,486.9	5,501.8	5,571.1	5,656.6
Non-Energy Use of Fuels	117.2	152.8	160.6	140.7	131.0	136.5	133.5	153.4
Natural Gas Flaring	5.8	6.6	6.9	5.8	6.1	6.2	6.1	6.0
Cement Manufacture	33.3	39.2	40.0	41.2	41.4	42.9	43.1	45.6
Lime Manufacture	11.2	13.9	13.5	13.3	12.8	12.3	13.0	13.7
Limestone and Dolomite Use	5.5	7.4	8.1	6.0	5.7	5.9	4.7	6.7
Soda Ash Manufacture and Consumption	4.1	4.3	4.2	4.2	4.1	4.1	4.1	4.2
Carbon Dioxide Consumption	0.9	0.9	0.8	1.0	0.8	1.0	1.3	1.2
Waste Combustion	10.9	17.1	17.6	17.9	18.6	18.9	19.4	19.4
Titanium Dioxide Production	1.3	1.8	1.9	1.9	1.9	2.0	2.0	2.3
Aluminum Production	7.0	6.4	6.5	6.2	4.5	4.6	4.6	4.3
Iron and Steel Production	85.0	67.7	63.8	65.3	57.8	54.6	53.3	51.3
Ferroalloys	2.0	2.0	2.0	1.7	1.3	1.2	1.2	1.3

Ammonia Manufacture	19.3	21.9	20.6	19.6	16.7	18.5	15.3	16.9
Phosphoric Acid Production	1.5	1.6	1.5	1.4	1.3	1.3	1.4	1.4
Petrochemical Production	2.2	3.0	3.1	3.0	2.8	2.9	2.8	2.9
Silicon Carbide Consumption	0.1	0.2	0.1	0.1	0.1	0.1	0.1	0.1
Lead Production	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Zinc Production	0.9	1.1	1.1	1.1	1.0	0.9	0.5	0.5
Land-Use Change and Forestry (Sink)[a]	*(910.4)*	(744.0)	(765.7)	(759.5)	(768.0)	(768.6)	(774.8)	(780.1)
International Bunker Fuels[b]	*113.5*	*114.6*	*105.2*	*101.4*	*97.8*	*89.5*	*84.1*	*94.5*
Biomass Combustion[b]	*216.7*	*217.2*	*222.3*	*226.8*	*200.5*	*194.4*	*202.1*	*211.2*
CH_4	676.9	634.7	623.2	620.9	613.6	613.1	618.1	609.8
Stationary Sources	8.6	7.5	7.7	7.9	7.3	6.8	7.2	7.1
Mobile Sources	5.2	4.2	4.0	3.8	3.7	3.5	3.3	3.2
Coal Mining	89.7	68.8	64.6	61.6	60.8	57.5	60.1	61.7
Abandoned Coal Mines	6.6	7.5	7.6	7.9	7.2	6.6	6.4	6.2
Natural Gas Systems	138.8	137.4	133.3	138.7	137.6	137.3	136.6	130.1
Petroleum Systems	37.7	32.5	31.2	30.5	30.0	29.3	28.4	28.1
Petrochemical Production	1.3	1.8	1.9	1.8	1.6	1.7	1.7	1.8
Silicon Carbide Production	+	+	+	+	+	+	+	+
Iron and Steel Production	1.4	1.3	1.3	1.3	1.2	1.1	1.1	1.1
Enteric Fermentation	129.1	127.9	127.9	126.7	125.6	125.6	126.1	123.3
Manure Management	34.1	42.5	41.8	41.7	42.6	43.0	42.9	43.1
Rice Cultivation	7.8	8.7	9.1	8.2	8.4	7.5	7.6	8.3
Agricultural Residue Burning	0.8	0.9	0.8	0.9	0.8	0.8	0.9	1.0
Landfills	188.7	158.1	155.1	152.2	149.1	153.2	156.0	154.3
Wastewater Treatment	27.1	35.7	36.9	37.6	38.0	39.2	40.1	40.4
International Bunker Fuels[b]	*0.2*	*0.2*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*
N_2O	377.0	420.7	400.4	397.4	394.2	389.0	368.6	369.2
Stationary Source	11.7	12.8	12.8	13.3	12.9	12.6	12.9	13.1
Mobile Sources	41.5	52.3	51.6	50.7	47.7	45.4	42.8	40.9
Adipic Acid	14.5	5.7	5.2	5.8	4.7	5.6	5.9	5.5
Nitric Acid	17.0	19.9	19.2	18.7	15.2	16.4	16.0	15.9
Manure Management	15.5	16.6	16.6	17.0	17.3	17.2	16.7	16.9
Agricultural Soil Management	254.1	287.5	268.5	265.6	270.2	265.3	247.5	249.7
Agricultural Residue Burning	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5
Human Sewage	12.3	14.2	14.7	14.8	14.9	14.9	15.1	15.3
N_2O Product Usage	4.1	4.6	4.6	4.6	4.6	4.6	4.6	4.6
Waste Combustion	0.5	0.4	0.4	0.4	0.4	0.5	0.5	0.5
Settlements Remaining Settlements	5.4	5.9	5.9	5.7	5.6	5.7	5.9	6.2
Forest Land Remaining Forest Land	0.1	0.3	0.4	0.3	0.4	0.4	0.4	0.4
International Bunker Fuels[b]	*0.9*	*1.0*	*0.9*	*0.9*	*0.8*	*0.8*	*0.7*	*0.8*
HFCs, PFCs, and SF_6	87.8	130.5	128.2	131.6	122.0	130.2	128.7	140.9
Substitution of Ozone Depleting Substances	+	52.0	60.1	68.6	76.3	84.0	91.6	101.4
Aluminum Production	17.1	8.4	8.3	8.2	3.7	4.9	3.5	2.7
HCFC-22 Production[c]	35.9	41.2	31.2	30.6	20.3	20.3	12.7	16.0
Semiconductor Manufacture	3.2	8.0	8.1	7.0	5.0	5.1	5.1	5.4
Electrical Transmission and Distribution[d]	26.6	15.5	14.9	14.2	14.3	13.5	13.0	12.8
Magnesium Production and Processing[d]	5.0	5.4	5.6	3.0	2.4	2.4	2.8	2.5
Total	6,147.1	6,806.0	6,846.8	7,014.4	6,925.0	6,948.2	6,993.1	7,107.9

+ 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.

[c] HFC-23 emitted

[d] Emissions from HFC-23, CF_4, C_2F_6, C_3F_8, SF_6, and the addition of NF_3

[e] SF_6 emitted

Note: Totals may not sum due to independent rounding.

Table A-213: Change in U.S. Greenhouse Gas Emissions and Sinks Using TAR vs. SAR GWPs (Tg CO_2 Eq.)

Gas	1990	1998	1999	2000	2001	2002	2003	2004
CO_2	NC	NC	NC	NC	NC	NC	NC	NC
CH_4	58.9	55.2	54.2	54.0	53.4	53.3	53.7	53.0
N_2O	(17.9)	(19.9)	(18.9)	(18.8)	(18.6)	(18.4)	(17.4)	(17.5)
HFCs, PFCs, and SF_6*	(2.9)	(2.9)	(3.3)	(3.1)	(2.8)	(2.5)	(2.3)	(2.1)

Total	38.1	32.4	31.9	32.1	31.9	32.4	34.0	33.5

NC (No change)
*Includes NF_3
Note: Totals may not sum due to independent rounding. Parentheses indicate negative values.

Table A-214: Change in U.S. Greenhouse Gas Emissions Using TAR vs. SAR GWPs (Percent)

Gas/Source	1990	1998	1999	2000	2001	2002	2003	2004
CO_2	NC	NC	NC	NC	NC	NC	NC	NC
CH_4	9.5%	9.5%	9.5%	9.5%	9.5%	9.5%	9.5%	9.5%
N_2O	(4.5%)	(4.5%)	(4.5%)	(4.5%)	(4.5%)	(4.5%)	(4.5%)	(4.5%)
HFCs, PFCs, and SF_6	(3.2%)	(2.2%)	(2.5%)	(2.3%)	(2.2%)	(1.9%)	(1.8%)	(1.5%)
Substitution of Ozone Depleting Substances	(98.6%)	(4.6%)	(4.3%)	(3.6%)	(3.0%)	(2.6%)	(2.0%)	(1.8%)
Aluminum Production[a]	(7.2%)	(7.9%)	(7.9%)	(8.1%)	(6.8%)	(6.8%)	(6.6%)	(6.0%)
HCFC-22 Production[b]	2.6%	2.6%	2.6%	2.6%	2.6%	2.6%	2.6%	2.6%
Semiconductor Manufacture[c]	11.6%	11.9%	11.9%	11.6%	12.7%	18.1%	16.4%	15.4%
Electrical Transmission and Distribution[d]	(7.1%)	(7.1%)	(7.1%)	(7.1%)	(7.1%)	(7.1%)	(7.1%)	(7.1%)
Magnesium Production and Processing[d]	(7.1%)	(7.1%)	(7.1%)	(7.1%)	(7.1%)	(7.1%)	(7.1%)	(7.1%)
Total	0.6%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%

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.

Table A-215: Effects on U.S. Greenhouse Gas Emissions Using TAR vs. SAR GWPs (Tg CO_2 Eq.)

Gas	Trend from 1990 to 2004		Revisions to Annual Estimates	
	SAR	TAR	1990	2004
CO_2	982.7	982.7	NC	NC
CH_4	(61.3)	(67.2)	58.9	53.0
N_2O	(8.2)	(7.8)	(17.8)	(17.5)
HFCs, PFCs, and SF_6*	52.2	53.0	(2.9)	(2.1)
Total	965.4	960.8	38.1	33.5
Percent Change	15.8%	15.6%	0.6%	0.5%

NC (No Change)
*Includes NF_3
Note: Totals may not sum due to independent rounding. 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-213 and Table A-214. Table A-216 below shows a comparison of total emissions estimates by sector using both the IPCC SAR and TAR GWP values. For most sectors, the change in emissions was minimal. The effect on emissions from waste was by far the greatest (8.4 percent in 2004), 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-216: Comparison of Emissions by Sector using IPCC SAR and TAR GWP Values (Tg CO_2 Eq.)

Sector	1990	1998	1999	2000	2001	2002	2003	2004
Energy								
SAR GWP (Used in Inventory)	5,148.3	5,752.3	5,822.3	5,994.3	5,931.6	5,944.6	6,009.8	6,108.2
TAR GWP	5,170.7	5,771.6	5,840.8	6,013.0	5,950.1	5,962.8	6,028.1	6,126.2
Difference (%)	0.4%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%
Industrial Processes								
SAR GWP (Used in Inventory)	301.1	335.1	327.5	329.6	300.7	310.9	304.1	320.7
TAR GWP	296.9	331.2	323.3	325.6	297.2	307.6	301.0	317.8
Difference (%)	(1.4%)	(1.2%)	(1.3%)	(1.2%)	(1.2%)	(1.1%)	(1.0%)	(0.9%)
Solvent and Other Product Use								
SAR GWP (Used in Inventory)	4.3	4.8	4.8	4.8	4.8	4.8	4.8	4.8
TAR GWP	4.1	4.6	4.6	4.6	4.6	4.6	4.6	4.6
Difference (%)	(4.5%)	(4.5%)	(4.5%)	(4.5%)	(4.5%)	(4.5%)	(4.5%)	(4.5%)
Agriculture								
SAR GWP (Used in Inventory)	439.6	483.2	463.1	458.4	463.4	457.8	439.1	440.1

TAR GWP	441.7	484.5	465.2	460.5	465.2	459.8	442.0	442.8
Difference (%)	0.5%	0.3%	0.5%	0.4%	0.4%	0.4%	0.7%	0.6%
Land Use, Land-Use Change, and Forestry								
SAR GWP (Used in Inventory)	(904.7)	(737.5)	(759.0)	(753.1)	(761.8)	(762.2)	(768.3)	(773.3)
TAR GWP	(905.0)	(737.8)	(759.3)	(753.4)	(762.0)	(762.5)	(768.6)	(773.6)
Difference (%)	+	+	+	+	+	+	+	+
Waste								
SAR GWP (Used in Inventory)	210.0	191.8	190.7	188.8	186.4	191.3	194.8	193.8
TAR GWP	228.2	208.0	206.7	204.7	202.0	207.3	211.2	210.0
Difference (%)	8.7%	8.4%	8.4%	8.4%	8.4%	8.4%	8.4%	8.4%
Net Emissions (Sources and Sinks)								
SAR GWP (Used in Inventory)	5,198.6	6,029.6	6,049.2	6,222.8	6,125.1	6,147.2	6,184.3	6,294.3
TAR GWP	5,236.7	6,062.0	6,081.1	6,254.9	6,157.0	6,179.5	6,218.3	6,327.8
Difference (%)	0.7%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%

NC (No change)
+ Does not exceed 0.05 Tg CO_2 Eq.
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,[73] where it shields the earth from harmful levels of ultraviolet radiation, and at lower concentrations in the troposphere,[74] 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.[75] 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,[76] 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 Annex 6.1 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- 217.

Table A- 217: Emissions of Ozone Depleting Substances (Gg)

Compound	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004

[73] 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.

[74] 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.

[75] 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.

[76] Older refrigeration and air-conditioning equipment, fire extinguishing systems, meter-dose inhalers, and foam products blown with CFCs/HCFCs may still contain ODS.

Class I															
CFC-11	29.0	29.8	13.3	12.4	11.3	10.1	8.6	8.1	7.6	7.0	10.5	10.0	9.6	9.1	8.5
CFC-12	341.7	345.2	341.1	327.2	267.9	209.1	182.7	159.0	131.1	110.0	93.1	75.6	61.3	47.3	33.4
CFC-113	77.7	79.3	73.7	67.9	45.7	15.1	+	+	+	+	+	+	+	+	+
CFC-114	12.9	9.2	5.5	1.5	1.5	1.4	1.4	1.5	1.3	0.8	0.5	0.3	0.1	+	+
CFC-115	11.4	11.8	11.3	10.5	9.9	8.9	7.4	6.1	4.6	4.1	3.8	3.5	3.2	2.9	2.7
Carbon Tetrachloride	1.6	1.7	1.4	1.0	0.7	0.4	+	+	+	+	+	+	+	+	+
Methyl Chloroform	6.1	6.2	5.7	5.2	4.0	2.0	0.2	+	+	+	+	+	+	+	+
Halon-1211	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Halon-1301	0.9	0.9	0.9	0.9	0.9	0.9	0.8	0.8	0.8	0.8	0.8	0.7	0.7	0.7	0.7
Class II															
HCFC-22	15.2	16.3	16.9	17.6	19.3	21.0	22.6	24.1	25.6	26.9	30.1	31.1	31.8	32.3	32.8
HCFC-123	+	+	+	+	+	+	+	+	+	+	0.1	0.1	0.1	0.1	0.1
HCFC-124	+	+	+	0.2	0.3	0.4	0.4	0.5	0.6	0.6	0.6	0.6	0.5	0.5	0.5
HCFC-141b	0.2	0.2	0.2	0.3	0.5	0.6	0.8	0.9	1.0	1.1	1.1	1.1	1.0	0.9	0.8
HCFC-142b	1.0	1.6	2.2	2.8	2.4	1.8	1.2	1.3	1.4	1.4	1.5	1.5	1.6	1.6	1.7
HCFC-225ca/cb	+	+	+	+	+	+	+	+	+	+	+	+	+	+	+

+ 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 Annex 3.8 of this Inventory for a more detailed discussion of the Vintaging Model.

Uncertainties

Uncertainties exist with regard to the levels of chemical production, equipment sales, equipment characteristics, and end-use emissions profiles that are used by these models. Please see the ODS Substitutes section of this report for a more detailed description of the uncertainties that exist in the Vintaging Model.

References

EPA (2004) *Air Emissions Trends—Continued Progress Through 2003*. U.S. Environmental Protection Agency, Washington DC. Available online at <http://www.epa.gov/airtrends/econ-emissions.html>. November 27, 2004.

EPA (2003) E-mail correspondence containing preliminary ambient air pollutant data between EPA OAP and EPA OAQPS. December 22, 2003.

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-218.

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-219); coal combustion accounted for approximately 92 percent of that total. The second largest source was industrial fuel combustion, which produced 7 percent of 2004 SO_2 emissions. Overall, SO_2 emissions in the United States decreased by 34 percent from 1990 to 2004. 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,[77] (2) New Source Performance Standards,[78] (3) the New Source Review/Prevention of Significant Deterioration Program,[79] and (4) the sulfur dioxide allowance program.[80]

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-218: SO_2 Emissions (Gg)

Sector/Source	1990	1998	1999	2000	2001	2002	2003	2004
Energy	19,629	16,196	14,932	13,796	13,404	12,917	13,197	12,899
Stationary Combustion	18,407	15,191	13,915	12,848	12,461	11,946	12,220	11,916
Mobile Combustion	793	665	704	632	624	631	637	644
Oil and Gas Activities	390	310	283	286	289	315	315	315
Waste Combustion	39	30	30	29	30	24	24	24
Industrial Processes	1,306	991	984	1,031	1,047	1,009	1,009	1,009
Chemical Manufacturing	269	237	295	307	310	298	298	298
Metals Processing	658	367	275	284	301	246	246	246
Storage and Transport	6	5	5	6	6	5	5	5
Other Industrial Processes	362	376	347	372	389	378	378	378

[77] [42 U.S.C § 7409, CAA § 109]
[78] [42 U.S.C § 7411, CAA § 111]
[79] [42 U.S.C § 7473, CAA § 163]
[80] [42 U.S.C § 7651, CAA § 401]

Miscellaneous*	11		5	61	63	40	82	82	82
Solvent Use	+		1	1	1	1	1	1	1
Degreasing	+		+	+	0	0	0	0	0
Graphic Arts	+		+	+	0	0	0	0	0
Dry Cleaning	NA		+	+	0	0	0	0	0
Surface Coating	+		+	+	0	0	0	0	0
Other Industrial	+		1	1	1	1	1	1	1
Non-industrial	NA		NA	NA	NA	NA	NA	NA	NA
Agriculture	NA		NA	NA	NA	NA	NA	NA	NA
Agricultural Burning	0		0	0	0	NA	NA	NA	NA
Waste	+		1	1	1	1	1	1	1
Landfills	+		1	1	1	1	1	1	1
Wastewater Treatment	+		+	+	+	+	+	+	+
Miscellaneous Waste	+		+	+	+	+	+	+	+
Total	20,936		17,189	15,917	14,829	14,452	13,928	14,208	13,910

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-219: SO_2 Emissions from Electricity Generation (Gg)

Fuel Type	1990		1998	1999	2000	2001	2002	2003	2004
Coal	13,807		11,312	10,639	9,621	9,056	8,587	8,839	8,560
Petroleum	580		691	527	429	478	453	466	451
Natural Gas	1		5	151	157	181	172	177	171
Misc. Internal Combustion	45		52	54	54	55	56	58	56
Other	NA		110	45	78	74	70	72	70
Total	14,432		12,170	11,416	10,339	9,843	9,338	9,612	9,308

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 Coal Mines	CH_4
Natural Gas Systems	CH_4
Petroleum Systems	CH_4
Natural Gas Flaring	CO_2
Waste Combustion	CO_2, N_2O
Industrial Processes	
Zinc Production	CO_2
Lead Production	CO_2
Titanium Dioxide Production	CO_2
Aluminum Production	CO_2, CF_4, C_2F_6
Iron and Steel Production	CO_2, CH_4
Ferroalloys	CO_2
Ammonia Production 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	CH_4, CO_2
Adipic Acid	N_2O
Nitric Acid	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
Agricultural Residue Burning	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)
Settlements Remaining Settlements	CO_2 (sink), N_2O
Forest Land Remaining Forest Land	CO_2 (sink), N_2O
Waste	
Landfills	CH_4
Wastewater Treatment	CH_4
Human Sewage	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] Included 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- 220 provides a guide for determining the magnitude of metric units.

Table A- 220: 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[81]

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-221 can be used as default factors, if local data are not available. See Appendix A of EIA's *Annual Energy Review 1997* (EIA 1998) for more detailed information on the energy content of various fuels.

Table A-221: 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

[81] Reference: EIA (1998a)

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	5.253
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 1997* (EIA 1998b). For coal ranks, *State Energy Data Report 1992* (EIA 1993). All values are given in higher heating values (gross calorific values).

References

EIA (1998a) *Emissions of Greenhouse Gases in the United States*, DOE/EIA-0573(97), Energy Information Administration, U.S. Department of Energy. Washington, DC. October.

EIA (1998b) A*nnual Energy Review*, DOE/EIA-0384(97), Energy Information Administration, U.S. Department of Energy. Washington, DC. July.

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-222: 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), and the Good Practice Guidance for Land Use, Land-Use Change and Forestry (IPCC 2003). 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

Some of the current inventory estimates, such as those for CO_2 Emissions from Fossil Fuel Combustion for example, have a relatively low level of uncertainty associated with them. Other categories of emissions exist, however, for which the inventory emission estimates are considered less certain. The 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 evaluated by comparing model results with those of other models developed to characterize the same emission (or removal) process and through sensitivity analysis. 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 most of the emission sources in the U.S. Inventory.

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, which represents the third year of this process, a Tier 2 approach was implemented for all source categories except HCFC-22 production and CO_2 from natural gas flaring, and some Land Use, Land-Use Change and Forestry 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. For the current Inventory, the Tier 1 approach was only adopted for one source category (i.e., HCFC-22 production), as compared to 10 source categories in the previous Inventory report. 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. Quantitative uncertainty estimates were not calculated for CO_2 from Natural Gas Flaring (IPCC Source Category 1B2), although the emissions from this source have been included in the national Inventory estimate for 2004. Future efforts will be made to quantify uncertainty of this source category's emissions estimates using the Tier 2 approach. Emissions and sinks from International Bunker Fuels, Biomass Burning, 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 distributions or PDFs. In the absence of particularly convincing data measurements, sufficient data samples, or expert judgments that determined otherwise, the PDFs incorporated in this year's 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- 223 summarizes results based on assessments of source category-level uncertainty.

The table presents base year (1990 or 1995) and current year (2004) emissions for each source category. The combined uncertainty for each source category is expressed as a percent of the total 2004 emissions estimated for that source category. Source category trend uncertainty is subsequently described in this Annex.

Table A- 223: Summary Results of Source Category Uncertainty Analyses

Source Category	Base Year Emissions*	2004 Emissions	2004 Uncertainty	
	Tg CO_2 Eq.	Tg CO_2 Eq.	Low	High
CO_2	5,005.3	5,987.98		
Fossil Fuel Combustion	4,696.6	5,656.6	-1%	6%
Non-Energy Use of Fuels	117.2	153.4	-20%	8%
Natural Gas Flaring	5.8	6.0	NE	NE
Cement Manufacture	33.3	45.6	-13%	14%
Lime Manufacture	11.2	13.7	-8%	8%
Limestone and Dolomite Use	5.5	6.7	-7%	8%
Soda Ash Manufacture and Consumption	4.1	4.2	-7%	7%
Carbon Dioxide Consumption	0.9	1.2	-14%	14%
Waste Combustion	10.9	19.4	-15%	10%
Titanium Dioxide Production	1.3	2.3	-16%	16%
Aluminum Production	7.0	4.3	-30%	30%
Iron and Steel Production	85.0	51.3	-11%	45%
Ferroalloys	2.0	1.3	-3%	3%
Ammonia Production and Urea Application	19.3	16.9	-8%	8%
Phosphoric Acid Production	1.5	1.4	-18%	19%
Petrochemical Production	2.2	2.9	-14%	5%
Silicon Carbide Consumption	0.1	0.1	-17%	18%
Lead Production	0.3	0.3	-11%	11%
Zinc Production	0.9	0.5	-12%	13%
Land-Use Change and Forestry (Sink)[a]	*(910.4)*	*(780.1)*		
International Bunker Fuels[b]	*113.5*	*94.5*		
Biomass Combustion[b]	*216.7*	*211.2*		
CH_4	618.1	556.7		
Stationary Sources	7.9	6.4	-26%	94%
Mobile Sources	4.7	2.9	-8%	4%
Coal Mining	81.9	56.3	-4%	4%
Abandoned Coal Mines	6.0	5.6	-18%	23%
Natural Gas Systems	126.7	118.8	-29%	31%
Petroleum Systems	34.4	25.7	-33%	141%
Petrochemical Production	1.2	1.6171	-8%	6%
Silicon Carbide Production	+	+	-10%	10%
Iron and Steel Production	1.3	1.0	-7%	9%
Enteric Fermentation	117.9	112.6	-11%	18%
Manure Management	31.2	39.4	-18%	20%
Rice Cultivation	7.1	7.6	-67%	157%
Agricultural Residue Burning	0.7	0.9	-75%	96%
Landfills	172.3	140.9	-36%	16%
Wastewater Treatment	24.8	36.9	-33%	39%
International Bunker Fuels[b]	*0.2*	*0.1*		
N_2O	394.9	386.7		
Stationary Sources	12.3	13.7	-24%	188%
Mobile Sources	43.5	42.8	-16%	29%
Adipic Acid	15.2	5.7	-45%	44%
Nitric Acid	17.8	16.6	-16%	17%
Manure Management	16.3	17.7	-16%	24%
Agricultural Soil Management	266.1	261.5	-82%	82%
Agricultural Residue Burning	0.4	0.5	-73%	85%
Human Sewage	12.9	16.0	-75%	89%
N_2O Product Usage	4.3	4.8	-7%	7%
Waste Combustion	0.5	0.5	-73%	157%
Settlements Remaining Settlements	5.6	6.4	-84%	349%
Forest Land Remaining Forest Land	0.1	0.4	-96%	483%

International Bunker Fuels[b]	*1.0*	*0.9*		
HFCs, PFCs, and SF_6	114.5	143.2		
Substitution of Ozone Depleting Substances	24.1	103.3	-13%	20%
Aluminum Production (CF_4)	16.2	2.4	-10%	12%
Aluminum Production (C_2F_6)	2.2	0.4	-16%	18%
HCFC-22 Production	35.0	15.6	-10%	10%
Semiconductor Manufacture[c]	2.9	5.0	-23%	23%
Electrical Transmission and Distribution	28.6	13.8	-13%	13%
Magnesium Production and Processing	5.4	2.7	-11%	13%
Total	6,132.7	7,074.7		
Net Emission (Sources and Sinks)	5,222.3	6,294.6		

*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] Sinks are only included in net emissions total.
[b] Emissions from International Bunker Fuels and Biomass Combustion are not included in totals.
[c] For the purposes of this uncertainty analysis, emissions from Semiconductor Manufacture presented here differ from those reported in the national totals. This was done to reflect that the uncertainty analysis was based on the individual gases, such as NF_3, rather than on an analysis on the total mix of gases for this source.
Note: Totals may not sum due to independent rounding.

Overall (Aggregate) Inventory Uncertainty Estimate

The overall uncertainty estimate for the U.S. greenhouse gas emissions inventory was developed using the IPCC Tier 2 uncertainty estimation methodology. For each source category, the Monte Carlo simulation output data, which were generated during its quantitative uncertainty analysis, were used to fit an appropriate probability distribution. If such detailed output data were not available for particular emissions sources, individual probability distributions were assigned to those source category emission estimates based on the most detailed output statistics available from the quantitative uncertainty analysis performed.

For the HCFC production source category, only Tier 1 uncertainty results were used in the overall uncertainty analysis estimation. However, for all other emission sources (excluding international bunker fuels, CO_2 from biomass combustion, land-use change and forestry source and sink categories, and natural gas flaring), Tier 2 uncertainty results were used in the overall uncertainty estimation.

The results from the overall uncertainty model indicate that the 2004 U.S. greenhouse gas emissions are estimated to be within the range of approximately 6,967 to 7,519 Tg of CO_2 equivalent emissions reflecting a relative 95 percent confidence interval uncertainty range of -2 percent to 6 percent with respect to the total U.S. greenhouse gas emissions estimate of about 7,075 Tg CO_2 Eq. The uncertainty interval associated with the total CO_2 emissions, which constitute about 85% of the total U.S. greenhouse gas emissions in 2004, ranges from about -1 percent to about 6 percent of the total CO_2 emissions estimated. The results indicate that the uncertainty associated with the inventory estimate of the total N_2O emissions is the largest (-39 percent to 48 percent), followed by the total inventory CH_4 emissions (±11 percent) and high GWP gas emissions (-9 percent to 15 percent).

A summary of the overall quantitative uncertainty estimates are shown below, in Table A- 224.

Table A- 224. Quantitative Uncertainty Assessment of Overall National Inventory Emissions (Tg CO_2 Eq. and Percent)

Gas	2004 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	5,988.0	5,920.5	6,329.8	-1%	6%	6,120.6	105.3
CH_4	556.7	495.3	620.2	-11%	11%	556.5	31.8
N_2O	386.7	235.1	571.5	-39%	48%	403.1	88.3
PFC, HFC & SF_6[d]	143.2	130.1	164.8	-9%	15%	147.2	8.9
Total	7,074.7	6,966.8	7,518.9	-2%	5%	7,245.2	142.2

Notes:
[a] Range of emission estimates for 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 add up 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 2004.

Trend Uncertainty

In addition to the 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 or 1995) and the current year (i.e., 2004) 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 2004 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 the base and the current year estimates often share input variables. For purposes of the current Inventory, a simple approach has been adopted, under which the base year source category emissions (or removals) are assumed to exhibit the same uncertainty characteristics as the current year emissions (or removals). Source category-specific PDFs for the base year estimates were developed using the 2004 uncertainty output data. These were adjusted to account for differences in magnitude between the the base and the current 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 2004, and are shown in Table A- 225.

Table A- 225. Quantitative Assessment of Trend Uncertainty (Tg CO_2 Eq. and Percent)

Gas/Source	Base Year*	2004	Emissions Trend	Trend Range[a]	
	(Tg CO_2 Eq.)		(%)	(%)	
				Lower Bound	Upper Bound
CO_2	5,005.3	5,988.0	20%	14%	25%
Fossil Fuel Combustion	4,696.6	5,656.6	20%	14%	26%
Non-Energy Use of Fuels	117.2	153.4	31%	5%	64%
Natural Gas Flaring	5.8	6.0	4%		
Cement Manufacture	33.3	45.6	37%	12%	66%
Lime Manufacture	11.2	13.7	22%	9%	37%
Limestone and Dolomite Use	5.5	6.7	21%	9%	35%
Soda Ash Manufacture and Consumption	4.1	4.2	2%	-9%	13%
Carbon Dioxide Consumption	0.9	1.2	38%	12%	68%
Waste Combustion	10.9	19.4	77%	48%	112%
Titanium Dioxide Production	1.3	2.3	73%	37%	119%
Aluminum Production	7.0	4.3	-38%	-60%	-6%
Iron and Steel Production	85.0	51.3	-40%	-57%	-15%
Ferroalloys	2.0	1.3	-35%	-38%	-32%
Ammonia Production and Urea Application	19.3	16.9	-12%	-22%	-2%
Phosphoric Acid Production	1.5	1.4	-9%	-30%	18%
Petrochemical Production	2.2	2.9	30%	8%	44%
Silicon Carbide Consumption	0.1	0.1	33%	3%	71%
Lead Production	0.3	0.3	-9%	-23%	6%
Zinc Production	0.9	0.5	-47%	-56%	-36%
Land-Use Change and Forestry (Sink)[b]	*(910.4)*	*(780.1)*	0%		
International Bunker Fuels[c]	*113.5*	*94.5*	0%		

Biomass Combustion[c]	*216.7*	*211.2*	0%		
CH_4	618.1	556.7	-10%	-25%	4%
Stationary Sources	7.9	6.4	-18%	-61%	73%
Mobile Sources	4.7	2.9	-38%	-52%	-43%
Coal Mining	81.9	56.3	-31%	-35%	-27%
Abandoned Coal Mines	6.0	5.6	-6%	-30%	26%
Natural Gas Systems	126.7	118.8	-6%	-40%	46%
Petroleum Systems	34.4	25.7	-26%	-76%	52%
Petrochemical Production	1.2	1.6	39%	24%	52%
Silicon Carbide Production	0.0	0.0	-67%	-71%	-62%
Iron and Steel Production	1.3	1.0	-21%	-29%	-11%
Enteric Fermentation	117.9	112.6	-4%	-22%	17%
Manure Management	31.2	39.4	26%	-3%	67%
Rice Cultivation	7.1	7.6	6%	-75%	351%
Agricultural Residue Burning	0.7	0.9	27%	-70%	448%
Landfills	172.3	140.9	-18%	-46%	24%
Wastewater Treatment	24.8	36.9	49%	-10%	150%
International Bunker Fuels[c]	*0.2*	*0.1*	-36%		
N_2O	394.9	386.7	-2%	-48%	86%
Stationary Sources	12.3	13.7	11%	-60%	222%
Mobile Sources	43.5	42.8	-1%	-35%	20%
Adipic Acid	15.2	5.7	-62%	-81%	-24%
Nitric Acid	17.8	16.6	-7%	-26%	18%
Manure Management	16.3	17.7	9%	-17%	46%
Agricultural Soil Management	266.1	261.5	-2%	-66%	206%
Agricultural Residue Burning	0.4	0.5	39%	-66%	481%
Human Sewage	12.9	16.0	24%	-71%	414%
N_2O Product Usage	4.3	4.8	11%	0%	24%
Waste Combustion	0.5	0.5	10%	-77%	532%
Settlements Remaining Settlements	5.6	6.4	15%	-90%	1145%
Forest Land Remaining Forest Land	0.1	0.4	556%	-38%	6527%
International Bunker Fuels[c]	*1.0*	*0.9*	-12%		
HFCs, PFCs, and SF_6	114.5	143.2	25%	12%	46%
Substitution of Ozone Depleting Substances	24.1	103.3	328%	241%	438%
Aluminum Production (CF_4)	16.2	2.4	-85%	-87%	-82%
Aluminum Production (C_2F_6)	2.2	0.4	-81%	-85%	-76%
HCFC-22 Production	35.0	15.6	-55%	-61%	-49%
Semiconductor Manufacture[d]	2.9	5.0	69%	15%	125%
Electrical Transmission and Distribution	28.6	13.8	-52%	-60%	-42%
Magnesium Production and Processing	5.4	2.7	-50%	-58%	-41%
Total	6,132.7	7,074.7	15%	8%	21%

*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 2004.
[b] Sinks are only included in net emissions total.
[c] Emissions from International Bunker Fuels and Biomass Combustion are not included in totals.
[d] For the purposes of this uncertainty analysis, emissions from Semiconductor Manufacture presented here differ from those reported in the national totals. This was done to reflect that the uncertainty analysis was based on the individual gases, such as NF3, rather than on an analysis on the total mix of gases for this source.
Note: Totals may not sum due to independent rounding.

7.3. Planned Improvements

Identifying the sources of uncertainty in the emission and sink estimates of the Inventory and quantifying the magnitude of the associated uncertainty is the crucial first step towards improving those estimates. Quantitative assessment of the parameter uncertainty may also provide information about the relative importance of input parameters (such as activity data and emission factors), based on their relative contribution to the uncertainty within the source category estimates. Such information can be used to prioritize resources with a goal of reducing uncertainty over time within or among inventory source categories and their input parameters. In the current Inventory, potential sources of model uncertainty have been identified for some emission sources, and preliminary uncertainty estimates based on their parameters' uncertainty have been developed for most of the emission source categories.

Specific areas that require further research include:

- *Incorporating excluded emission sources.* Quantitative estimates of the uncertainty associated with some of the sources and sinks of greenhouse gas emissions are not available at this time. In the future, efforts will focus on developing uncertainty estimates for all source categories for which emissions or removals 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 areas 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. In some cases, this might involve using measured or published statistics rather than relying on expert judgment if such data are 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 the base year Inventory estimates.* Improve characterization of the base year uncertainty estimates in order to improve the analysis of trend uncertainty, to replace the simplifying assumptions described in the "Trend Uncertainty" section above.

References

EPA (2002) Quality Assurance/Quality Control and Uncertainty Management Plan for the U.S. Greenhouse Gas Inventory: Background on the U.S. Greenhouse Gas Inventory Process, U.S. Environmental Protection Agency, Office of Atmospheric Programs, Greenhouse Gas Inventory Program, Washington, DC, EPA 430-R-02-007A, June 2002.

IPCC/UNEP/OECD/IEA (1997) Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories, Paris: Intergovernmental Panel on Climate Change, United Nations Environment Programme, Organization for Economic Co-Operation and Development, International Energy Agency.

IPCC (2000) Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories, Intergovernmental Panel on Climate Change, National Greenhouse Gas Inventories Programme, Montreal, IPCC-XVI/Doc. 10 (1.IV.2000), May 2000.

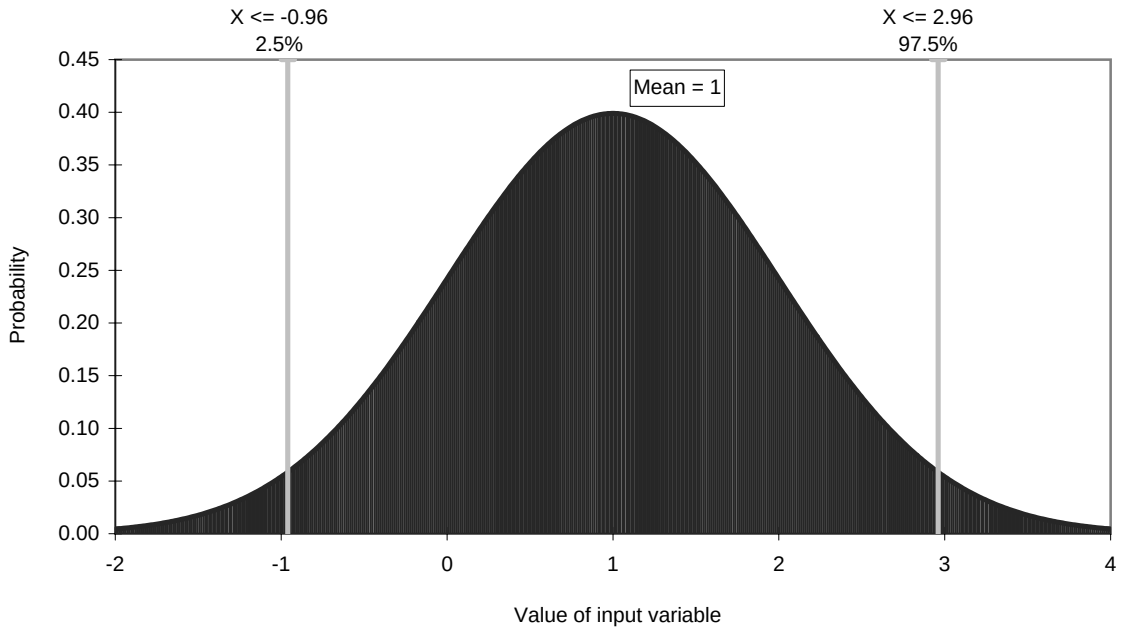

Figure A-11: Example of a Normal Distribution

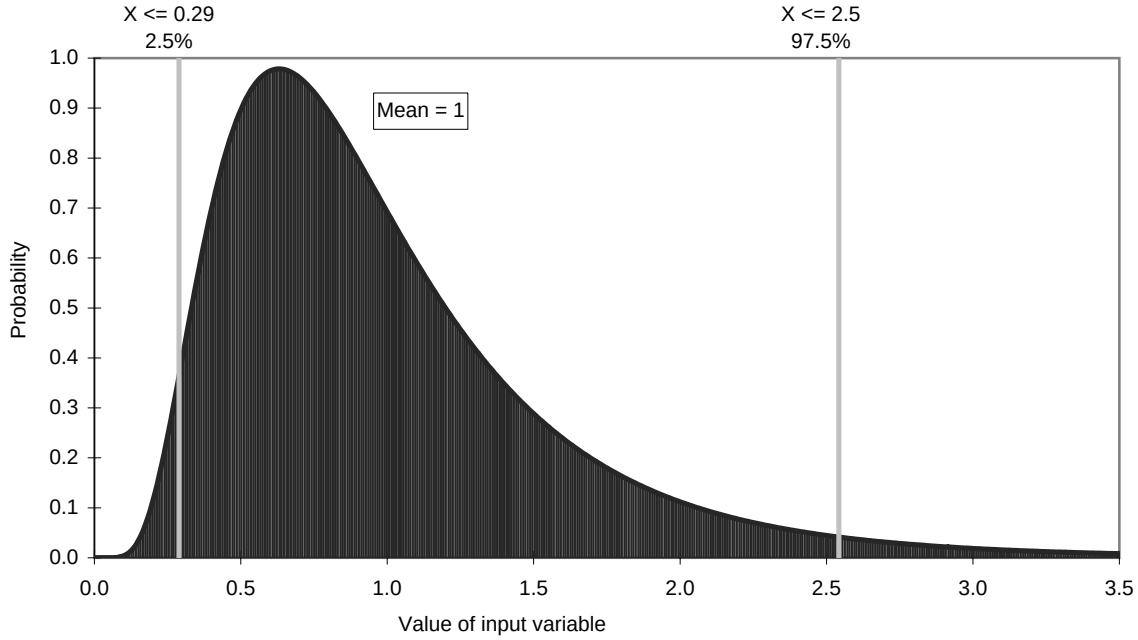

Figure A-12: Example of a Lognormal Distribution

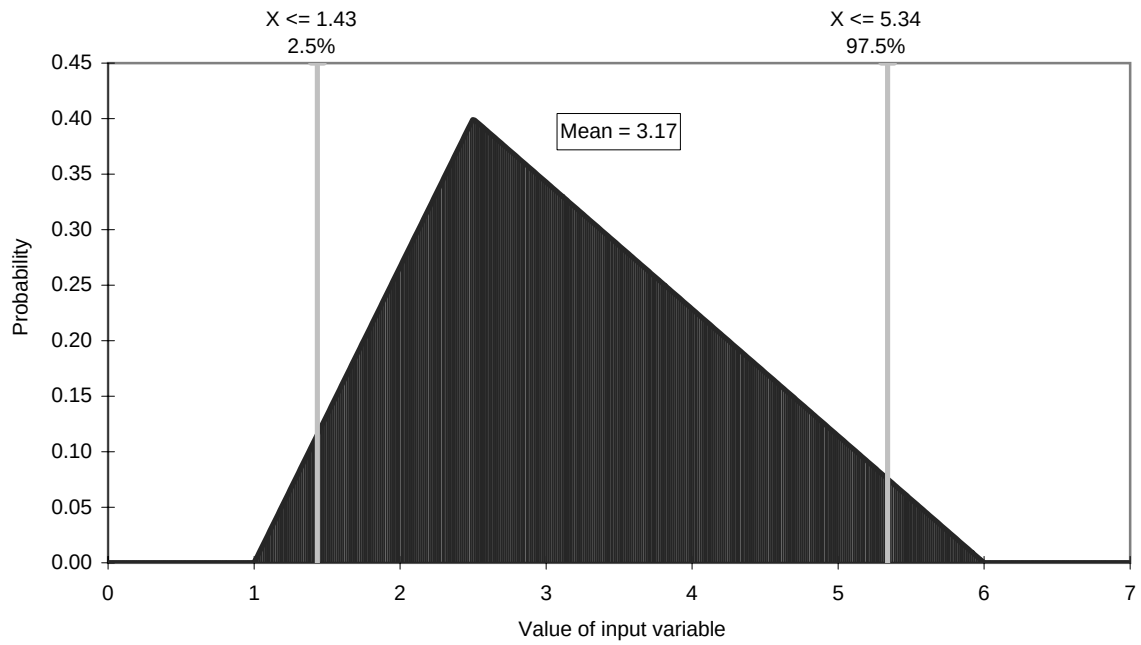

Figure A-13: Example of a Triangular Distribution

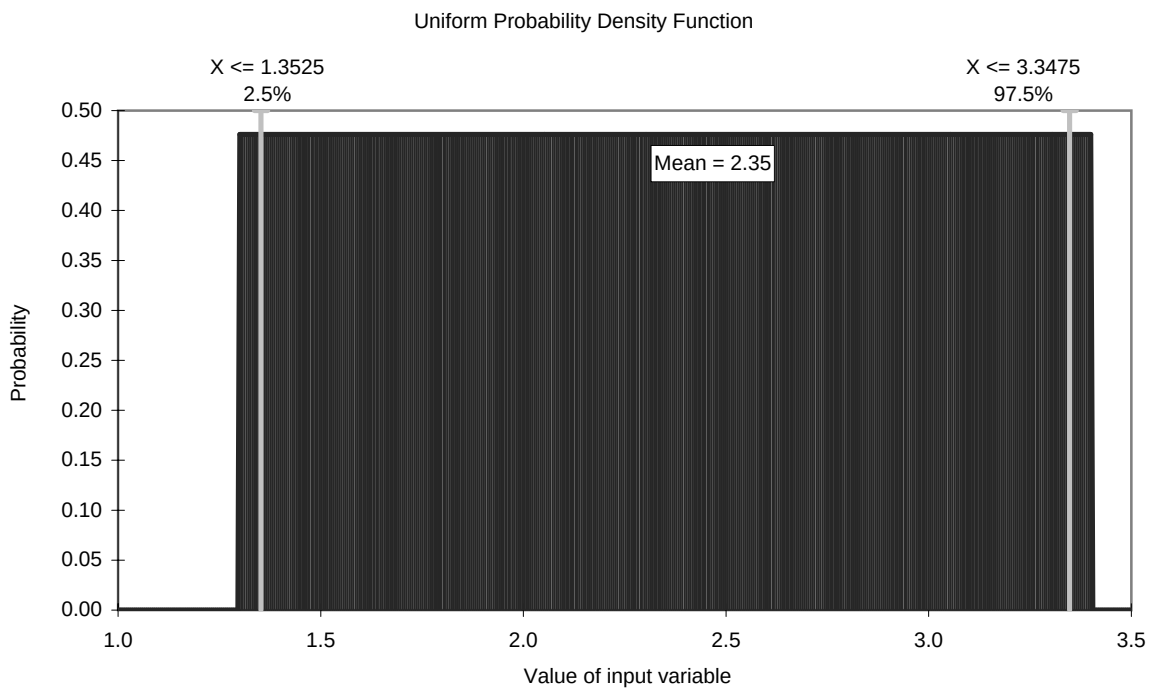

Figure A-14: Example of a Uniform Distribution

Descriptions of Figures: Annex 7

Figure A-11 illustrates a normal distribution. For a full description of a normal distribution, refer to the annex text.

Figure A-12 illustrates a lognormal distribution. For a full description of a lognormal distribution, refer to the annex text.

Figure A-13 illustrates a triangular distribution. For a full description of a triangular distribution, refer to the annex text.

Figure A-14 illustrates a uniform distribution. For a full description of a uniform distribution, refer to the annex text.